UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Building for the Future Through Electric Regional	**)**	**RM21-17**
Transmission Planning and Cost Allocation and	**)**	
Generator Interconnection	**)**	

INITIAL COMMENTS OF

AMERICANS FOR A CLEAN ENERGY GRID

ACEG applauds this Commission initiative because transmission planning must be vastly improved. While there are many aspects of this initiative, it boils down to one simple idea that we think Yogi Berra would have said if he were submitting comments in this docket: "planning should be for the future." It seems obvious, but it is not happening, as we explain below.

I. Introduction and ACEG's interest in this proceeding

Pursuant to the Advanced Notice of Proposed Rulemaking issued in this docket and posted in the Federal Register on July 27, 2021 by the Federal Energy Regulatory Commission ("Commission"),[1] Americans for a Clean Energy Grid ("ACEG") is pleased to submit these comments.

ACEG represents a diverse coalition of stakeholders focused on the need to expand, integrate and modernize the high-voltage grid in the United States. The ACEG coalition includes multi-state utilities that develop, own, and operate transmission, trade groups that include transmission owners and transmission equipment manufacturers among their members, renewable energy trade groups and advocates, environmental advocacy organizations, buyers of energy, and energy policy experts. ACEG seeks to educate the public, opinion leaders, and public officials about the needs and potential of the transmission grid. These comments do not necessarily reflect the views of individual members.

II. Current tariffs are unjust and unreasonable

[1] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 86 Fed. Reg. 40,266 (July 27, 2021).

A. Interconnection queue processes are dysfunctional due primarily to the lack of proactive regional transmission planning

The interconnection processes in much of the country are dysfunctional. As described in the interconnection paper in Appendix B, the interconnection process is not working. It typically takes three years for generators to move through the process, the costs of the process are unpredictable to the generators entering the queue, the cost assignments are sometimes excessive, and the process results in significant "churn" of projects entering and exiting which itself adds to the delays and complexity. When one generator drops out of the queue it leads to the need to re-study other interconnection requests, delaying the process and changing the cost estimates for others.

While some interconnection reforms would improve the process as described in section VI below, none of them really solve the problem. The problem can only be solved by appropriate transmission planning that is proactive and multi-benefit as described herein and by various other reports such as the Brattle-Grid Strategies report in Appendix A and the Planning for the Future report in Appendix C.

B. Beneficiaries are free-riding on generator interconnection-related upgrades

The current approach to interconnection in ISOs and RTOs where full "participant funding" is allowed leads to network upgrades funded by generators to be used by all other network users without paying. Assigning all of the costs to just the next generator in the queue prevents a fair allocation of costs to all beneficiaries.[2]

C. Planning processes lead to unreasonably high costs

In side-by-side comparisons of the current reactive incremental approach to transmission through the generator interconnection process and a proactive multi-benefit approach, the costs are twice as high under the current approach.[3]

Real-world experience suggests that generation shortfalls resulting from severe weather and other threats are occurring with greater intensity and frequency. Because these events tend to be at their most extreme in areas smaller than fully interconnected power systems, transmission solves these shortfalls by enabling imports from other regions that are less affected. Yet extreme event scenarios are not incorporated into most prospective plans. The economic value of such regional and interregional transmission is significant. In fact, additional transmission capacity into ERCOT would have paid for itself just during winter storm Uri, and

[2] ICF, *Just & Reasonable? Transmission Upgrades Charged to Interconnecting Generators are Delivering System-Wide Benefits*, September 8, 2021.
[3] Johannes Pfeifenberger et al., *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs*, Table 2 at 15, October 2021.

one additional GW of transmission capacity into MISO would have provided $100 million in value just during those few days.[4]

As shown in the table below based on practices in each of the 11 Planning Authorities' most recent approved plans, they are failing to use the proven practices that would lead to just and reasonable costs. Even in some cases such as CAISO TEAM and NY public policy processes, those efforts are not integrated into a holistic multi-benefit plan. Only one of the 11 Planning Authorities in their latest regional plans employed multi-benefit planning and none of them employed more than two of the five necessary and proven practices. Some of these RTOs, including in particular NYISO, CAISO, and MISO, have begun processes to perform more of these practices but there is uncertainty about whether they will receive sufficient stakeholder support to proceed.

Table 1. Planning Authorities Current Use of Efficient Practices[5]

	Proactive Generation & Load	Multi-Value	Scenario-Based	Portfolio-Based	Joint Interregional Planning
ISO-NE	✗	✗	✗	✓	✗
NYISO	✗	✗	✗	✗	✗
– PPTPP only	✓	✓	✓	✓	✗
PJM	✗	✗	✗	✗	✗
Florida	✗	✗	✗	✗	✗
Southeastern Regional	✗	✗	✗	✗	✗
South Carolina Regional	✗	✗	✗	✗	✗
MISO (excl. MVP, RIIA)	✗	✗	✗	✗	✗
SPP (ITP)	✗	✓	✗	✓	✗
CAISO	✓	✗	✓	✗	✓
– TEAM only	✓	✓	✓	✓	✓
WestConnect	✗	✗	✗	✗	✗
NorthernGrid	✗	✗	✗	✗	✗

III. Current tariffs are unduly discriminatory

Current tariffs result in outcomes that impede the interconnection of needed new resources. The lack of proactive transmission planning, and the dysfunction of the interconnection queue

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[4] Michael Goggin, *Transmission Makes the Power System Resilient to Extreme Weather*, July 2021.

[5] Johannes Pfeifenberger et al., *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs*, Table 2 at 15, October 2021.

process, lead to high costs and extended processes for new generation seeking to connect to the grid. The process dysfunction is a barrier to entry that prevents competitive new entrants from entering into the market, leading to higher prices and reduced reliability due to scarcity as other generators seek to retire or load growth requires new resources. This failure results from current tariff planning and interconnection provisions and is described in the "Disconnected" paper in Appendix B and the "Transmission Planning for the 21st Century" paper in Appendix A. This barrier to entry leads to undue discrimination in transmission and interconnection services between new and existing generation. FERC must remedy undue discrimination under Section 206 of the FPA.

IV. Current tariffs should be replaced with proven holistic transmission planning practices

FPA Section 206 states "Whenever the Commission, after a hearing held upon its own motion or upon complaint, shall find that any rate, charges, or classification demanded, observed, charged, or collected by any public utility for any transmission or sale subject to the jurisdiction of the Commission, or that any rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory or preferential, the Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order." In this instance, with unjust, unreasonable, and unduly discriminatory rates resulting from current tariffs, the Commission must replace certain regulations.

ACEG suggests that the Commission requires all transmission providers to participate in a transmission planning process that employs the following proven practices. Each practice is described in the Brattle-Grid Strategies report:[6]

1. **Pro-actively plan for future generation and load** by incorporating the anticipated generation mix, publicly stated utility plans, public policy directives, load levels, and load profiles over the lifespan of the transmission investment. The factors listed by the Commission in the ANOPR are among those that should be incorporated (not just considered) in transmission plans: "(1) federal, state, and local climate and clean energy laws and regulations; (2) federal, state, and local climate and clean energy goals that have not been enshrined into law; (3) utility and corporate energy and climate goals; (4) trends in technology costs within and outside of the electricity supply industry, including shifts toward electrification of buildings and transportation; and (5) resource retirements."[7] Generation resource zones tend to be useful approaches for transmission planning. These can be resource-neutral but based on the likely locations of future generation.[8] In response to the question in ANOPR Paragraph 57, "whether any such

[6] *Ibid*., Section IV beginning at 24.
[7] ANOPR at P 46.
[8] *Ibid*., at P 54, 55.

requirement is consistent with the FPA's prohibition of unduly discriminatory or preferential rates," we are not asking for preferential treatment for resources based on their environmental performance or other factors.

2. **Account for the full range of transmission project benefits** and use multi-value planning to comprehensively identify investments that address all categories of needs and benefits. Reliability, resilience, reduced need for generating capacity, production cost reduction, and other power system benefits should be incorporated together.

3. **Address uncertainties and high-stress grid conditions explicitly through scenario-based planning**. Many of the successful regional planning process such as MISO MVPs (which grew out of MISO's Regional Generator Outlet Study, the CapX2020 projects, and the Upper Midwest Transmission Development Initiative) were based on a "least regrets" approach to planning in which lines were selected when they were valuable under a variety of potential futures. Scenario planning that considers reasonably possible severe weather and other threats enables an evaluation of the value of transmission in these situations, and the insurance value that transmission provides.

4. **Use comprehensive transmission network portfolios to** address system needs more efficiently than the single project-by-project approach, and consider all technologies (DC, AC, advanced conductors, grid-enhancing technologies), as they may contribute to an efficient and reliable network.

5. **Jointly plan neighboring interregional systems.** The Commission should first require a minimum amount of interregional capacity among power systems to protect against a variety of risks that can cause local generation shortfalls, as is used in Europe.[9] Beyond this minimum level, systems should be jointly planned with neighbors. In response to the question in ANOPR Paragraph 63, yes, we believe the Commission should "require joint planning processes, rather than simply joint coordination, for neighboring regions."

6. **Select the plan that maximizes expected net benefits.** Transmission plans should employ a decision rule of maximizing net benefits, once the methodologies above collect appropriate benefit and cost information. While metrics such as benefit-cost ratios are useful indicators, the efficient solution is the one that maximizes net benefits,

[9] *See* ENTSO-E, *10-Year Network Development Plan (TYNDP)*, at Section 1.5, 2016.

not maximizes the ratio of benefits to costs. We specify "expected" net benefits to reflect the incorporation of uncertainty and scenarios.

7. **FERC should require relevant information to be provided to interested stakeholders.** Currently, the planning regions possess and report disparate information on transmission needs and investments. Some regions do not publish cost information for approved projects, which limits the ability of stakeholders to assess such projects. Generators and their customers should have better information on where they can connect and what the costs might be.

V. FERC should review plans to ensure compliance in the future

In its planning rules, FERC pledged that it would "remain actively involved…beyond the compliance phase to ensure that the potential for undue discrimination in planning activities is adequately addressed."[10] Similarly, it concluded that Order No. 1000 processes would "provide the Commission and interested parties with a record that we believe will be able to highlight whether public utility transmission providers are engaging in undue discrimination."[11]

The Commission should actively ensure that the planning methodologies ultimately required in this rulemaking are in fact followed in future compliance filings and subsequent regional transmission plans.

VI. Cost allocation should follow the beneficiary pays principle, with appropriate identification and measurement of both benefits and beneficiaries

A new FERC rule should continue to adhere to the principle that transmission costs must be allocated in a manner roughly commensurate with benefits. This should be done in a way that recognizes the broad benefits that are created by large regional and interregional transmission infrastructure, while providing planning entities with flexibility in developing methodologies that adhere to this standard.

ACEG believes FERC Order No. 1000 policies on cost allocation are largely workable as long as the planning reforms discussed herein are accomplished. The current approach for transmission included in regional plans, as dictated in a set of court decisions, is that cost allocation should be roughly commensurate with benefits received. While the Commission should require all planning entities to better quantify the benefits of new transmission infrastructure, it should

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[10] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890-A, 121 FERC ¶ 61,297 at P 180, December 28, 2007.

[11] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000-A, 139 FERC ¶ 61,132, at P 267, May 17, 2012.

refrain from requiring that the costs of new infrastructure be allocated in a manner that matches these benefits based on overly narrow metrics or with exacting precision on a project-by-project basis. As stated by Judge Posner of the 7th Circuit, "It's not enough...to point out that MISO's and FERC's attempt to match the costs and the benefits of the MVP program is crude; if crude is all that is possible, it will have to suffice."[12] Cost allocation can be "roughly commensurate" with benefits and need not be allocated based on a narrow set of targeted benefits.[13] The Commission should continue to require that overall costs of the new transmission infrastructure be allocated in a manner roughly commensurate with benefits. Therefore, as the Commission carries out reforms to transmission regulation, it should largely adhere to the basic approach that it has taken on cost allocation in Order No. 1000. This topic is in paragraph 70 of the ANOPR.

The current approach of siloed reliability/economic/public policy benefits fails "to consider the suite of benefits that transmission facilities provide and therefore fails to allocate the costs of such facilities roughly commensurate with the benefits" per the Commission query in Paragraph 85. All projects have reliability, economic, and public policy benefits, so transmission cannot be efficiently planned in such silos. Beneficiaries experience all three types of benefits, and should be assigned costs accordingly.

We suggest that cost allocation includes the full range of electricity system benefits. This topic is raised in ANOPR Paragraph 90. These include promoting generation competition, production cost reductions, ancillary service cost reductions, capacity cost reductions, reliability, load diversity, resilience, and other factors as described in Appendix A. In particular, load diversity and its effect on reducing very expensive generation capacity costs is a major, under-appreciated benefit of large-scale interregional transmission. Because different regions experience peak demand at different times, mostly due to variations in climate and weather, transmission allows peak electricity demand to be met with less generating capacity. MISO has found that a lower need for capacity due to load diversity saves $1.9-2.5 billion annually, nearly two-thirds of the RTO's total value proposition of $3.1-3.9 billion annually.[14] Analysis indicates that on today's power system, transmission's load diversity benefits are significantly larger than its renewable output diversity benefits, confirming that transmission benefits all grid users and countering the misperception that the need for transmission investment is primarily driven by renewable growth.[15] Cost allocation should reflect the broad benefits accruing to all load.

[12] *Illinois Commerce Commission v. FERC*, 721 F.3d 764,775 (7th Cir. 2013).
[13] *Illinois Commerce Commission v. FERC*, 576 F.3d 470, 476-77 (7th Cir. 2009).
[14] MISO, *2020 MISO Value Proposition*, at 22, 2020.
[15] Michael Goggin, "Transmission Benefits All Users of the Power Grid," October 11, 2021.

Since interconnection processes, as governed by policy decisions made in Order No. 2003, do not follow beneficiary pays and instead follow "participant funding" (where 100% of network upgrades are assigned to the interconnecting generator), this inconsistency should be rectified by a new rule. Thus, the rule would be updating some provisions of Order No. 2003 and the interconnection processes of public utilities, as well as Order Nos. 890 and 1000 on planning provisions.

To minimize analysis and help ensure that costs are allocated in a stable and predictable way, the Commission should direct planning entities to allocate the costs of portfolios of projects as a group, rather than planning and cost-allocating only on a project-by-project basis. And to ensure that costs are not significantly mismatched with benefits, the Commission should direct that single, narrow metrics such as load flow analysis may not be the sole basis of cost allocation; rather, planning entities should account for the wide range of benefits that portfolios of projects bring the whole system. To avoid cost-shifting and process disruption, the rule should assign costs to loads whether or not they remain members of an RTO.

The Commission should clarify that planning entities may allocate a portion of total costs in the future to generators and customers who utilize the new transmission infrastructure. It may be appropriate to charge different customers different amounts where they are not similarly situated. For example, after well-planned transmission is in place, the costs of certain zones may be higher to the system than other zones, and charges could vary without causing the dysfunction we witness now in interconnection queues.[16]

Cost allocation should not be subverted by utilities leaving RTOs. RTOs at this time are voluntary organizations and cost allocation can be a contentious issue for utility members of RTOs. If one member of an RTO leaves the RTO, it could shift costs to other members. The threat of that dynamic can change participants' leverage and harm the development of reliable and efficient plans. The Commission should clarify that cost allocation can apply before, during, and after a utility's membership in an RTO.

VII. Interconnection queue policy should be replaced by just and reasonable planning and cost allocation policies

The policies recommended above on planning and cost allocation will resolve most of the problems with interconnection queues. In particular, replacing the policy of 100% participant funding and instituting proactive planning for anticipated future generation will significantly reduce the uncertainty in cost estimates, the incentive to submit multiple interconnection requests, and other aspects causing queue dysfunction.

The Commission should also require much more cost certainty in the near term and long term on interconnection cost assignments. Cost caps and bands may be useful to limit the uncertainty.

[16] ANOPR questions 154-156.

VIII. Governance of planning processes

Just and reasonable rates require an inclusive, transparent planning process involving states, consumers, and other parties. This input will improve the quality of the estimates of anticipated future generation and load, which are critical to assembling an efficient and reliable transmission plan.

The best way to contain costs is through an open, inclusive, transparent process with regular cost reporting to the RTO. The MISO MVP process is a good example of an open process where states, utilities, and others around the region were involved in the development of the "generation forecast," and at the table evaluating benefits and determining cost allocation agreements based on benefits assessment.

Competitive solicitation has worked better in some areas than in others. Some of the best examples of successful transmission planning, such as MISO MVPs, were based much more on "collaboration" than "competition." As a general matter, while competition in the generation sector has brought significant benefits, unlike generation, the transmission sector is not structurally competitive, and standard economic policy prescriptions differ based on the structure competitiveness of a sector.[17] Order 1000's removal of the right-of-first-refusal has had the unintended consequence of undermining regional transmission planning in some cases. As described in the Planning for the Future paper in Appendix C, whether Order No. 1000's conclusions about competitive transmission are true today is "dependent upon particular regional circumstances."[18] One reason the experience may vary is that even if transmission competition were a theoretically optimal solution, it is not clear that voluntary RTOs are an administratively workable means of achieving it. Whereas in Texas and the UK it is the regulator that administers the process, we have not heard that FERC is interested in performing the role. Given these structural and institutional factors that vary by region, the Commission can reasonably conclude that a rule relaxing the broad requirement for a competitive process is appropriate and upholds the Commission's duties under Sections 205 and 206 of the Federal Power Act. If the Commission reviews this aspect of Order No. 1000 it may also have an opportunity to evaluate joint ownership models, which has long been a priority of the public power sector.[19] By taking a region-by-region or even context specific approach to rights of first refusal, the Commission may achieve better results across all regions.

States can play a key role in the planning process to provide input on future generation and load, and viable transmission line routes. The Joint Federal-State Task Force is a great start on formalizing input from states, and this body should propose mechanisms at the regional level for states to formally participate.

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[17] Alfred Kahn, *The Economics of Regulation: Principles and Institutions*, at 125/II, MIT Press, June 1988.
[18] Rob Gramlich and Jay Caspary, *Planning for the Future: FERC's Opportunity to Spur More Cost-Effective Transmission Infrastructure*, at 75-79, January 2021.
[19] APPA, *Joint Ownership of Transmission*, February 2009.

IX. FERC has broad authority to undertake these reforms

As discussed in the Planning for the Future report, the Commission has ample authority to institute the reforms recommended herein. In particular, we note:

- The Commission is permitted to "recognize[] that state and federal policies might affect the transmission market" and plan accordingly.[20]
- Section 217(b)(4) of the Federal Power Act supports a requirement to plan based on the best available data and forecasting methodologies, and to include public policies and utility and corporate renewable procurement goals within planning scenarios. It requires the Commission to exercise its 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 load-serving entities."[21] Load serving entities' service obligations will be more accurately predicted by the best available forecasting methodologies, and will naturally depend upon both public policies and the resource preferences of their customers.[22]
- The recommendations here focus on "process" as did Order No. 1000 and is "not intended to dictate substantive outcomes."[23]
- As with Order No. 1000, "[t]he substance of a regional transmission plan and any subsequent formation of agreements to construct or operate regional transmission facilities" would "remain within the discretion of the decision-makers in each planning region."[24]
- As the D.C. Circuit explained in upholding Order No. 888 and Order No. 1000, Section 202(a) of the Federal Power Act's reference to voluntary coordination and Section 202(b) and 211's grant of authority to order interconnection and wheeling do not limit the ability of the Commission to compel rules for planning new facilities that remedy unjust, unreasonable, and discriminatory behavior under Section 206.[25] Here, as was the case in Order No. 1000, the evidence demonstrates that existing transmission planning practices are unjust, unreasonable, and unduly discriminatory with respect to interregional planning because they have not resulted in the approval of a single inter-

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[20] *South Carolina Public Service Authority v. FERC*, 762 F.3d at 89 (D.C. Cir. 2014).
[21] 16 U.S.C. 824q(b)(4).
[22] As the Commission explained in Order No. 1000-A, "many, if not all, of the Public Policy Requirements will likely impose legal obligations on load-serving entities." *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000-A, 139 FERC ¶ 61,132, at P 175, May 17, 2012.
[23] *South Carolina Public Service Authority v. FERC*, 762 F.3d at 58 (D.C. Cir. 2014), (quoting Order No. 1000-A, at P 188, 77 Fed. Reg. at 32,215).
[24] *Ibid*.
[25] *See Transmission Access Policy Study Group v. FERC*, 225 F.3d 667, 686 (D.C. Cir. 2000) ("*Otter Tail* does not constrain FERC from mandating open access where it finds circumstances of undue discrimination to exist."); *South Carolina Public Service Authority v. FERC*, 762 F.3d at 61 (2014), ("To the extent the court in *Central Iowa* interpreted Section 202(a) to mean that 'Congress intended coordination and interconnection arrangements be left to the 'voluntary' action of the utilities,' there is nothing to suggest that the court purported to interpret the meaning of 'coordination' in regard to the planning of future facilities.").

regional project, despite a large amount of evidence suggesting that such projects would yield net benefits.

- Section 219 of the FPA provides the Commission with more authority and responsibility for putting incentives in place that lead to just and reasonable outcomes. Here we mean planning and cost allocation rules themselves as the incentives (not ROE or other such financial rewards which are the subject of a separate rulemaking). Having effective planning and cost allocation rules in place, such as those utilized with MISO MVP projects, stimulated transmission planning and investment. In that way, planning and cost allocation rules are incentives. Section 219 says, "the Commission shall establish, by rule, incentive-based (including performance-based) rate treatments for the transmission of electric energy in interstate commerce by public utilities for the purpose of benefitting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion…The rule shall—promote reliable and economically efficient transmission and generation of electricity by promoting capital investment in the enlargement, improvement, maintenance, and operation of all facilities for the transmission of electric energy in interstate commerce, regardless of the ownership of the facilities." Thus, Section 219 provides additional authority to institute planning and cost allocation policies recommended here.
- As for regional planning authorities and potentially interregional processes and entities, as the Commission explained in its policy statement governing Regional Transmission Groups (similar entities that did not themselves operate transmission but governed transmission planning and operations by member entities), "under section 205(c) of the Federal Power Act (FPA), public utilities must file with the Commission the classifications, practices, and regulations affecting rates and charges for any transmission or sale subject to the Commission's jurisdiction, together with all contracts which in any manner affect or relate to such rates, charges, classifications and services."[26] Thus, an agreement governing planning entities, like a Regional Transmission Group Agreement "that in any manner affects or relates to jurisdictional transmission rates or services," would need to "be approved or accepted by [the] Commission as just, reasonable, and not unduly discriminatory or preferential under [section 205 of] the FPA."[27]
- On transparency, building on Order No. 890's transparency requirements, the Commission could require more specific minimum data transparency standards as part of a new rule, drawing on the examples set by leading regions such as MISO and SPP, which "currently maintain . . . transparent cost recording and tracking processes for projects approved through their regional planning processes."[28]

[26] *Policy Statement Regarding Regional Transmission Groups*, 58 Fed. Reg. 41,626, August 5, 1993.
[27] *Ibid*.
[28] *Ibid*.

- Opponents of Order No. 1000 argued that the Commission exceeded its authority in mandating regional transmission planning, as opposed to simply regulating voluntary planning arrangements.[29] Section 202(a) of the Federal Power Act "empower[s] and direct[s]" the Commission "to divide the country into regional districts for the *voluntary* interconnection and coordination of facilities."[30] But in upholding Order No. 1000, the Court of Appeals for the District of Columbia Circuit agreed with the Commission that Section 202(a)'s reference to voluntary coordination does not preclude mandatory planning activities. Rather, the voluntary coordination referred to in Section 202(a) applies only to the operation of existing facilities, not to the planning of new facilities, which "'occurs before [facilities] can be interconnected.'"[31]

X. FERC should proceed without delay to NOPR(s) and final rule(s)

Transmission takes a long time. Electricity consumers cannot wait for too long for the FERC process to unfold, and then regional implementation, then the actual planning, negotiations over cost allocation, FERC filings on specific plans, and then permitting and construction of lines. The FERC rules need to be put in place as soon as possible so the other steps can be completed in time to make a difference to achieve just and reasonable and not unduly discriminatory rates. Every day that current FERC transmission tariffs and planning requirements remain in place enables continuing unjust, unreasonable, and unduly discriminatory tariffs that violate the requirements in the Federal Power Act. Continuation of these unjust and unreasonable tariffs raises delivered electricity costs and reduces grid reliability and resilience to the detriment of the nation's electricity customers.

Signed,

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[29] *See* *South Carolina Public Service Authority v. FERC*, 762 F.3d, 41, 55-64 (D.C. Cir. 2014).
[30] 16 U.S.C. § 824a(a) (emphasis added).
[31] *South Carolina Public Service Authority v. FERC*, 762 F.3d at 59 (D.C. Cir. 2014). (quoting Order No. 1000, at P 124, 77 Fed. Reg. at 32,206).

Appendix A

Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs

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OCTOBER 2021

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NOTICE

This report was prepared with funding from the American Council on Renewable Energy (ACORE), with support from the Macro Grid Initiative, and the Natural Resource Defense Council (NRDC).

The report also incorporates research from our prior client engagements and public reports, including:

- Gramlich and Caspary, *Planning for the Future: FERC's Opportunity to Spur More Cost-Effective Transmission Infrastructure,* January 2021.
- Pfeifenberger, Ruiz, Horn, *The Value of Diversifying Uncertain Renewable Generation through the Transmission System*, published by Boston University's Institute for Sustainable Energy, September 1, 2020.
- Pfeifenberger and Chang, *Well-Planned Electric Transmission Saves Customer Costs: Improved Transmission Planning is Key to the Transition to a Carbon-Constrained Future*, prepared for WIRES May 2016.
- Gramlich and REBA Institute, *Designing the 21st Century Electricity System*, for Renewable Buyers Alliance Institute, March 2021.
- Caspary, Goggin, Gramlich, Schneider, Disconnected: The Need for a New Generator Interconnection Policy, for Americans for a Clean Energy Grid, January 2021.
- Pfeifenberger, Chang, and Sheilendranath, *Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid*, prepared for WIRES, April 2015.
- Chang, Pfeifenberger, Hagerty, *The Benefits of Electric Transmission Identifying and Analyzing the Value of Investments*, prepared for WIRES, July 2013.

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Executive Summary

The U.S. is at a critical juncture in transmission network planning. System vulnerabilities to severe weather are illuminating the need and opportunity for transmission to enable power sharing across and between regions. Existing transmission infrastructure, mostly constructed in the 1960s and 1970s, is nearing the end of its useful life, and decisions today about how this aging infrastructure is replaced will have long-lasting impacts on system costs and reliability. At the same time, public policy mandates, customer preferences, and the power generation mix necessary to address these needs are rapidly changing, causing a need for various types of transmission in different locations to maintain reliable and efficient service.

While the current transmission system and grid planning processes have functioned adequately in the past, they are failing to address these diverse 21st century needs. Current transmission planning processes routinely ignore realistic projections of the future resource mix, how the transmission system is utilized during severe weather events, and the economies of scale and scope that can reduce total costs. Today's planning is overwhelmingly reactive and focused on addressing near-term needs and business-as-usual trends.

The large majority of current transmission investments are narrowly focused on network reliability and what is needed to connect the next group of generators in interconnection queues, ignoring the efficiencies that occur when simultaneously and proactively planning for multiple future needs and benefits across the system. Even if Planning Authorities look beyond reliability-driven needs, they typically compartmentalize transmission into individual planning efforts that separately examine reliability, economic, public policy, and generator-interconnection driven transmission projects—instead of conducting multi-value planning that optimizes investments across all reliability, economic, public policy, or generator interconnection needs. The current approaches also lack a proactive scenario-based outlook that explicitly recognizes long-term planning uncertainties.

Together, these deficiencies yield an inefficient patchwork of incremental transmission projects and they limit the planning processes' ability to identify more cost-effective investments that meet both current and rapidly changing future system needs, address uncertainties, and reduce system-wide costs and risks. The inevitable outcome of such reactive and siloed planning is unreasonably high overall system costs and risks, which are ultimately passed on to electricity customers and can deter the development of low-cost generation resources.

Fortunately, there have been exceptions to the rule. Effective transmission planning efforts have proven repeatedly that proactive, multi-value, scenario-based planning delivers greater benefits to the entire electric system at lower overall costs and risks. These holistic transmission planning efforts have led to well-documented, highly beneficial transmission investments across the United States.

The available industry experience thus points to the following proven planning practices and core principles with which transmission planning can achieve reliable and efficient solutions capable of meeting the needs of the evolving 21st century power system at a lower total system cost:

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

As set forth in greater detail in the remainder of this report, these principles form the standard for efficient transmission planning that can maintain a reliable grid while more cost-effectively meeting all other transmission-related needs to avoid unreasonably high electricity costs. Policymakers and planners need to reform current transmission planning requirements 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.

I. Today's Transmission Planning Results in Unreasonably High Electricity Costs

This report focuses on improving transmission planning, including for generation interconnection, which consists of identifying transmission needs and evaluating and selecting solutions to address these needs. We recognize, however, that successful approval and development of planned transmission infrastructure also requires improvements to cost allocation and approval (including permitting) processes. Creating a more effective transmission planning and development process to build a grid that can cost-effectively meet 21st Century needs will require improving every phase of this process, as illustrated in the figure below. Improvements will have to specifically focus on: (1) expanding initial needs assessment and project identification; (2) improving the analyses of transmission solutions and their costs and benefits to determine the which are most effective from a total system-wide cost perspective; (3) refining project cost recovery (*i.e.*, cost allocation) to be roughly commensurate with benefits; and (4) presenting the needs, benefits, and proposed cost recovery to obtain approvals from the various federal and state permitting and regulatory agencies.

FIGURE 1. TRANSMISSION PLANNING PROCESS

Electricity costs consist of three major components: generation, transmission, and distribution costs. Transmission, the focus of this report, consists of the electrical wires and other equipment that transports electricity from generators to local distribution utilities. In many regions, including some served by regional transmission organizations (RTOs) or independent system operators (ISOs), these three functions are provided by one vertically integrated entity. Even in RTO areas with disaggregated generation and distribution ownership, transmission owners (TOs) are still primarily monopolies and affiliates of other utility entities.

Transmission currently accounts for about 13% of the total national average electricity costs, while generation accounts for 56% of the total.[1] Well-planned transmission investment reduces the total system-wide cost of electricity by allowing more electricity to be generated from lower-cost resources and making more efficient use of available generation resources. Unfortunately, current transmission planning processes fail to achieve the efficient quantity or type of investment needed to realize maximum reductions in generation costs and lowest total costs, which results in unreasonably high system-wide costs.

While the U.S. has recently been investing between $20 to $25 billion annually in improving the nation's transmission grid,[2] most of this investment addresses individual local asset replacement needs, near-term reliability compliance, and generation-interconnection-related reliability needs without considering a comprehensive set of multiple regional needs and system-wide benefits. In MISO, for example, baseline reliability projects and other, local projects approved through the annual regional transmission plan have grown dramatically since 2010 and have constituted 100% of approved transmission for the last three years and 80% since 2010.

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[1] U.S. Energy Information Administration, *Annual Energy Outlook 2021*, 2021, p4.

[2] See slide 2 of Pfeifenberger, Tsoukalis, *Transmission Investment Needs and Challenges*, JP Morgan Renewables and Grid Transformation Series, June 1, 2021.

TABLE 1. MISO MTEP APPROVED INVESTMENT BY PROJECT TYPE[3]

Year	Baseline Reliability Projects (BRP) ($ million)	Market Efficiency Projects (MEP) ($ million)	Multi-Value Projects (MVP) ($ million)	Other (local) ($ million)
2010	94	-	510	575
2011	424	-	5,100	681
2012	468	15	-	744
2013	372	-	-	1,100
2014	270	-	-	1,500
2015	1,200	67	-	1,380
2016	691	108	-	1,750
2017	957	130	-	1,400
2018	709	-	-	2,300
2019	836	-	-	2,800
2020	755	-	-	2,800

Most of the planning processes used today result in inefficient investments that increase total system-wide costs. The narrowly focused current approaches do not identify opportunities to take advantage of the large economies of scale in transmission that come from “up-sizing” reliability projects to capture additional benefits, such as congestion relief, reduced transmission losses, and facilitating the more cost-effective interconnection of the renewable and storage resources needed to meet public policy goals. Neither do the narrowly focused approaches identify investments that create option value by increasing flexibility to respond to changing market and system conditions. For example, in-kind replacement of aging existing facilities misses opportunities to better utilize scarce rights-of-way for upsized projects that can meet multiple other needs and provide additional benefits, thus driving up costs and inefficiencies. And the current piecemeal approach certainly does not yield any larger regional or interregional solutions, such as transmission overlays, that could more cost-effectively address the nation’s public policy needs. In short, and as shown through examples below, the current approach systematically results in inefficient infrastructure and excessive electricity costs.

The current lack of proactive, multi-value, and scenario-based planning for future generation and policy needs in most of the U.S. creates a situation where we are essentially trying to plan

[3] Years 2010 through 2019 from Coalition of MISO Transmission Customers, Industrial Energy Consumers of America, and LS Power Midcontinent, LLC, Section 206 Complaint and Request for Fast Track Processing, January 21, 2020 at 31–32. 2020 figures from *MTEP20* at p 15. See MISO, *MTEP 20 Full Report.*

an integrated and shared network through the generator interconnection, local upgrades, and reliability planning processes. The lack of proactive, multi-value planning also overburdens generators in the interconnection queue by making them responsible for network upgrades that provide large system-wide benefits.

A recent ICF study showed that generation developers essentially bear the entire cost of regional network upgrades required to interconnect generators, even though these upgrades often provide broad system-wide benefits.[4] PJM's proactive 2021 off-shore wind integration study (discussed below) shows the same: upgrades to accommodate generation interconnection requests provide broad system-wide benefits.[5] This cost allocation consequently is not roughly commensurate with benefits; having to bear the full costs of such upgrades forces many generation developers to withdraw their interconnection requests even if the network upgrade provides substantial regional benefits that exceed costs—resulting in inefficient outcomes and higher system-wide costs. In addition, many of the current generation interconnection processes do not provide interconnection options that rely on non-firm, energy-only injections that take advantage of generation re-dispatch or other solutions. Reforms consequently are needed to ensure cost-effective solutions that more fairly allocate transmission costs.

The higher system-wide costs and inefficiencies associated with the current planning approaches are evident when compared to different planning methods that have been applied to the same needs. For example, comparing the results of PJM's 2021 offshore wind integration analysis with the results of individual PJM generation interconnection studies shows that the current generation interconnection study process (evaluating one interconnection cluster at a time) approximately doubles the transmission-related interconnection costs of offshore wind generation compared to a more proactive, regional study process. Under PJM's current queue-based generation interconnection study process, the total costs of necessary onshore PJM network upgrades identified within individual PJM feasibility and system impact studies related

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4 ICF Resources, *Just & Reasonable? Transmission Upgrades Charged to Interconnecting Generators Are Delivering System-Wide Benefits*, prepared for American Council of Renewable Energy (ACORE), September 9, 2021. As the study notes, in SPP, 100% of the interconnection costs are assigned directly to generators in SPP. In MISO, generators are responsible for 90% of the cost for upgrades 345 kV and higher, with 10% allocated regionally

5 PJM, *Offshore Transmission Study Group Phase 1 Results,* presented to Independent State Agencies Committee (ISAC), July 29, 2021. See slide 24 for a discussion of the system-wide benefits associated with the network upgrades identified in this proactive study for interconnecting offshore wind generation.

to integrating 15.5 GW of offshore wind equals $6.4 billion.[6] This results in PJM onshore network upgrade costs that adds over $400/kW to the cost of the offshore generation (including offshore transmission), or roughly 13% of offshore generation capital costs.[7,8] By contrast, PJM's 2021 proactive region-wide study holistically evaluated onshore transmission investment needs to connect up to a cumulative 17 GW of offshore wind generation to its footprint (which reflects the offshore wind resource interconnection needs of multiple states' offshore wind plans).[9] This proactive regional study estimated only $3.2 billion in PJM onshore network upgrade costs would be needed for interconnecting 17 GW of offshore wind generation—less than half the costs identified through the individual interconnection request studies. This reduces average interconnection costs to $188/kW-wind, which is only 45% of the over $400/kW cost associated with the current reactive, incremental interconnection study approach. In addition, the regional PJM study found that these identified $3.2 billion in onshore network upgrades result in substantial additional regional benefits in the form of congestion relief, customer load LMP reduction, and reduced renewable generation curtailments that would not be realized using reactive interconnection methods.[10]

Thus, the July 2021 PJM offshore wind study shows that the reliability upgrades necessary to interconnect offshore wind generation needed to meet states' public policy goals also provide substantial benefits to a large portion of the PJM footprint beyond addressing interconnection-related reliability needs, thereby further reducing overall customer costs beyond the 50% of onshore transmission investment cost savings. Contrasting PJM's July 2021 study results to the results of its current interconnection study process demonstrates the inefficiency and excessive costs associated with the current reactive, interconnection- and reliability-driven planning process. The July 2021 PJM study is just one of many similar examples demonstrating the unreasonable expense and lost benefits associated with transmission planning processes that are not proactive and multi-value based.

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[6] Based on costs from PJM's feasibility and system impact studies for individual generation interconnection requests as reported in Burke and Goggin, *Offshore Wind Transmission Whitepaper*, October 2020 at p. 40.

[7] Reported global project data suggest a decline of the weighted average capital cost of offshore wind capacity to $3,000/kW by the mid-2020s. National Renewable Energy Laboratory, *Offshore Wind Market Report: 2021 Edition*, prepared for U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, DOE/GO-102021-5614, August 2021.

[8] If offshore wind generators accept the allocation of these onshore upgrade costs, they will need to pass them on to their wholesale customers, which then pass them on to retail customers, increasing electricity rates.

[9] PJM, *Offshore Transmission Study Group Phase 1 Results,* presented to ISAC, July 29, 2021. Across six scenarios studied by PJM, the identified onshore upgrade costs range from $627 million to $3.2 billion for OSW injections ranging from 6.4 GW to 17 GW.

[10] *Id*., slide 24.

Similarly, the optimized transmission plans produced as part of PJM's 2014 renewable generation integration study to accommodate large additions of wind, offshore wind, and solar resources also find lower interconnection costs than the individual PJM's interconnection studies. That 2014 study identified transmission costs of $106/kW of renewable generation to integrate the then-projected 35 GW of additional wind and solar capacity needed to meet the PJM-wide RPS requirements of 14%. For a 20% PJM-wide RPS requirement, the cost ranged from $57–$74/kW of new renewable capacity, depending on the mix of wind, offshore wind, and solar capacity.[11] The fact that renewable generation-related interconnection costs are so much lower in the 20% RPS cases than the 14% RPS case confirms the large economies of scale that are captured from a more proactive regional evaluation of transmission needs, further bolstering the case for proactive regional planning for public policy needs rather than relying on incremental reactive upgrades through the generation interconnection process.

Comparing the proactive 2021 and 2014 PJM studies with the results from PJM's individual generation interconnection studies clearly highlight how the current generator interconnection process is unreasonable in two ways. First, the current interconnection process leads to much higher-cost solutions for achieving state clean energy policies, which unreasonably increases overall electricity costs. Second, given the identified system-wide benefits, allocating 100% of the identified interconnection project costs to the interconnecting generators or participant funding does not yield an outcome in which all beneficiaries pay costs that are roughly commensurate to the benefits they receive. Allocating the entire costs of the interconnection-related network upgrades to generators, ignores that PJM's own studies found large benefits associated with these upgrades accrue to other PJM market participants and customers.

Across all FERC-jurisdictional ISO/RTOs, the current approach of identifying and funding network upgrades through the generator interconnection process is becoming unworkable as costs and queue backlogs increase. Grid Strategies' January 2021 report on interconnection

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[11] Transmission costs obtained from PJM scenarios were divided by the wind and solar capacity added in each RPS scenario (minus 5,122 MW of existing wind and 72 MW of existing solar. *PJM Renewable Integration Study, Task 3A Part C*, GE Energy Consulting prepared for PJM Interconnection, March 31, 2014, p 16. *Final Report: Task 2 Scenario Development and Analysis*, GE Energy Consulting prepared for PJM Interconnection, January 26, 2012.

Note that these projected costs of future upgrades, however, are still higher than the average of historical upgrade costs of generation interconnection request (in large part taking advantage of existing grid capabilities) as documented by the Lawrence Berkeley National Laboratory as reported in Will Gorman, Andrew Mills, Ryan Wiser, *Improving estimates of transmission capital costs for utility-scale wind and solar projects to inform renewable energy policy*, preprint version of a journal article published in *Energy Policy*. DOI: https://doi.org/10.1016/j.enpol.2019.110994, October 2019, p 12.

queues shows that recent network upgrade costs are 2 to 5 times higher now that the existing transmission capacity has been fully subscribed.[12] For example, the identified upgrade costs for recent entrants into the interconnection queue in western MISO now exceed $750/kW.[13] In contrast, the cost per kW for proactive regionally planned network solutions in these areas has been much lower. For example, the interconnection costs associated with MISO's Multi Value Projects (MVPs) was only approximately $400/kW in today's dollars even before netting out any system-wide benefits.[14] As quantified in the next section, the MVP projects and other comprehensive network solutions designed with multi-value planning approaches provide many other quantified benefits in addition to interconnecting generation, thereby reducing the net cost of generator interconnection.[15]

Since MISO approved its portfolio of MVPs a decade ago, MISO's 2014 MRITS study documented that even lower generation interconnection costs can be achieved if planned regionally rather than integrating renewable generation through the current interconnection process. This 2014 study found that MISO-wide transmission expansion of $2.567 billion would allow the interconnection of 17,245 MW of new wind capacity, at a cost of only $149/kW of wind.[16] The cost per kW may be lower because, unlike the MVP study, this study was not attempting to co-optimize regional economic and reliability benefits, which may yield lower transmission costs but higher net costs. However, comparing the $149/kW cost from the 2014 MRITS study to the $750/kW costs identified for the current interconnection queue in western MISO shows that proactively planned network additions are superior to incremental upgrades through the generation interconnection process. Given that MISO's 2014 Study yielded a plan that made extensive use of 345-kV transmission lines, it is not surprising that it could have achieved economies of scale and produced significant savings relative to the cost of incremental upgrades identified through the interconnection queue—documenting the high cost of the current planning process and the significant savings that could be realized through

12 J. Caspary, M. Goggin, R. Gramlich, J. Schneider, *Disconnected: The Need for New Generator Interconnection Policy*, Americans for a Clean Energy Grid, January 14, 2021, at pp 8–11

13 For example, the average cost for wind projects in MISO's August 2017 Definitive Planning Phase 2, West was $756/kW.

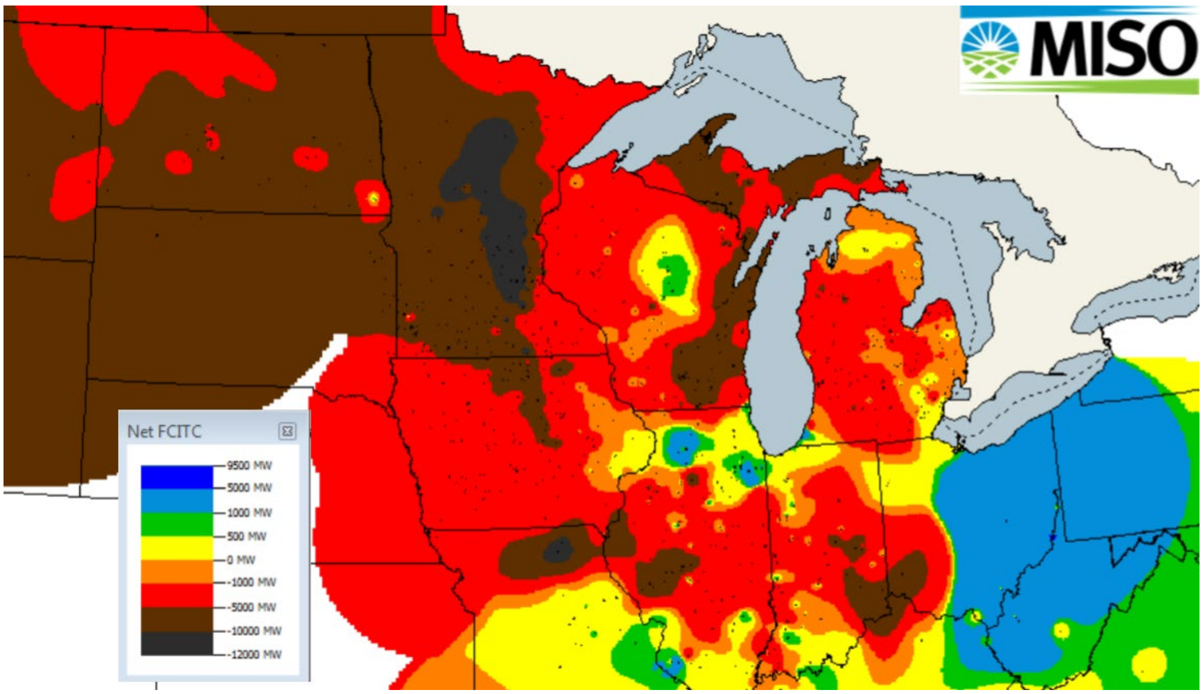
14 The MVP lines cost $6.57 billion, per MISO, *Regionally Cost Allocated Project Reporting Analysis, MVP Project Status July 2021*, and were designed to interconnect 15,949 MW of wind, per MISO, *MTEP17 MVP Triennial Review: A 2017 review of the public policy, economic, and qualitative benefits of the Multi-Value Project Portfolio*, September, 2017, which yields $412/kW of wind.

15 MISO's quantification of MVP-related benefits estimated that the total benefits of the transmission portfolio exceeds its total cost by a factor of 2.2-3.4. *Id.* at p 4.

16 GE Energy Consulting with MISO, *Minnesota Renewable Energy Integration and Transmission Study: Final Report*, October 31, 2014 at pp 4–21.

more proactive regional planning. Given MISO's analysis showing most of western MISO has a "transmission capacity deficit" of between 5,000 and 10,000 MW,[17] the brown areas in the map below, it is not surprising that the incremental upgrades produced through the current planning process are insufficient and unreasonably expensive solution to address regional transmission needs.

FIGURE 2. TRANSMISSION INTERCONNECTION CAPACITY DEFICIT IN MISO



Source: MISO, 2018.

Cost savings from regionally planned networks are confirmed by a 2009 analysis from Lawrence Berkeley National Laboratory (LBNL). The 2009 study reviewed 40 detailed transmission planning analyses for interconnecting wind generation and found the median cost of planned regional transmission was $300 per kW of wind (roughly $400/kW in today's dollars),[18] almost identical to the cost of the MISO MVP lines. That study also found strong evidence of cost reductions from comprehensive regional planning of transmission solutions that take into consideration a broad set of benefits (compared to relying on piecemeal upgrades planned

[17] MISO, *August 2017 Definitive Planning Phase Model for Central, MI, ATC, and South regions. August 2016 model for West region*, July 11, 2018.

[18] Andrew Mills, Ryan Wiser, and Kevin Porter, *The Cost of Transmission for Wind Energy: A Review of Transmission Planning Studies*, Ernest Orlando Lawrence Berkeley National Laboratory, LBNL-1471E, February 2009; $300/kW corresponds to $383/kW today based on the increase in the consumer price index from 2009 to 2021.

solely for the interconnection of new wind resources). As the authors conclude from their review of 40 studies:

> we find that transmission designed to accommodate the full nameplate capacity of all new generation during peak periods on sparsely interconnected transmission lines appears to have a higher cost than transmission designed to reduce congestion costs caused by new wind generation based on an economic dispatch of an interconnected transmission network. This finding may have implications for future transmission planning efforts oriented toward accessing additional wind energy.[19]

The LBNL authors argue that the median transmission cost per kilowatt of wind across these studies likely overstates the true cost by not reflecting the system-wide benefits of interconnecting wind through comprehensive transmission planning. As they explain, their "methodology assigns the full cost of the transmission line to the wind plant without taking into account the other benefits of the transmission line," after noting that "in reality, however, studies frequently point to the additional reliability benefits and congestion relief that new transmission will provide. In these cases, our methodology overstates the transmission costs that are attributable specifically to wind."[20]

While this LBNL study was conducted 12 years ago, the fundamental economic and physical factors driving the economies of scale and broader benefits of comprehensive, regionally planned network upgrades are the same today.[21] Recent analysis, such as the savings identified in PJM's proactive offshore wind plan relative to PJM's interconnection queue results, as discussed above, also confirms the high cost of the current reactive planning process and the cost savings and larger benefits of proactively planned transmission compared to the cost of incremental additions designed to address specific needs like generator interconnection.

While it is surely true that in some cases an incremental single project designed to address a specific need may be more efficient than a larger-scale regional solution, the efficiency of the choice will be known if the planning process quantifies and considers all the benefits and costs of the alternatives. Such a benefits-and-cost-based planning process is important for developing

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19 *Id.,* at xii

20 *Id.,* at 27

21 For a more comprehensive discussion of these underlying factors, see pp 3–5 and 29–30 at American Wind Energy Association (AWEA), *Grid Vision: The Electric Highway to a 21st Century Economy*, May 2019.

cost-effective transmission plans and investment strategies, valuing future investment options, and identifying "least-regrets" projects. Any least-regrets planning approach, however, needs to consider *both* (1) the possible regret that a project may not be cost effective in a particular future; *and* (2) the possible regret that customers may face excessive costs due to an insufficiently robust transmission grid in other futures.[22] A recent example of system planners failing to adequately consider the implications of insufficient expansion of interregional transfer capability to address extreme market conditions is the August 2020 blackouts in California. The final root cause analysis released by California policymakers concluded that "transmission constraints ultimately limited the amount of physical transfer capability into the CAISO footprint" and "more energy was available in the north than could be physically delivered."[23] CAISO had similarly concluded after the 2000−01 California power crisis, that the crisis and its extremely high costs could have been avoided if more interregional transmission capability had been available to the state.[24]

Even if the share of transmission relative to the total electricity cost increases above today's level, that is not an indication of inefficiency or consumer harm. To the contrary, well-planned transmission investments can have a significant impact on reducing overall costs of delivering reliable electricity. As generation costs continue to fall and transmission needs to provide resilience, reliability, and system efficiency rises, transmission costs may rise as a percentage of total electricity system costs, but system-wide total costs will be lower than they would be with less transmission investment.

Many recent studies that apply proactive, multi-value planning principles have shown the large benefits and overall cost reductions that a more robust transmission system can provide for the

[22] For a more detailed discussion on how transmission planners can use scenarios proactively to consider long-term uncertainties and the potentially high cost of insufficient infrastructure and associated risk mitigation benefit in transmission planning, see Pfeifenberger, Chang, Sheilendranath, *Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid*, prepared for WIRES Group, April 2015, pp 9−19 and Appendix B.

[23] California Independent System Operator (CAISO), California Public Utilities Commission (CPUC), and California Energy Commission (CEC), *Root Cause Analysis: Mid-August 2020 Extreme Heat Wave*, Final, January 13, 2021, p 48.

[24] CAISO estimated that if significant additional transmission capacity had been available during the California energy crisis from June 2000 to June 2001, electricity customer costs would have been reduced by up to $30 billion over the 12 month period during which the crisis occurred CAISO, Transmission Economic Assessment Methodology (TEAM), June 2004, p ES-9.

nation's future power system. Some studies show the need for a doubling[25] or tripling[26] of the nation's existing transmission capacity over the next several decades. These studies evaluate the location and timing of output from load and generation and co-optimize across generation and transmission. They find that transmission investments typically enable significant savings in generation costs. Numerous additional studies, listed in Appendix A, show that for varying resource-mix scenarios, large expansion of transmission is needed to achieve cost-effective outcomes, particularly investment in transmission facilities that enable long distance large-volume transfers of energy across regions and across the country and continent. While the cost of these transmission investments would be significant, it only makes up a small portion of total electricity system investment needs (likely under ten percent of total cost).

One such study finds that well-planned transmission expansion results in additional transmission costs of about a half a cent per kWh on average (well under ten percent of total cost) but—in combination with a national policy goal for a zero carbon grid— would result in system-wide cost reductions of over 40% compared to relying on transmission-limited regional and state-level solutions.[27] Figure 3 below displays transmission costs, shown as the gray slice near the top of the bars (and the cost of wind, solar, and storage resources shown as the blue, orange, and green slices below), of decarbonizing the U.S. electricity grid. Another study finds transmission costs of about a quarter cent per kWh, or well under 5% of the total cost of electricity, even with a large-scale buildout of transmission.[28]

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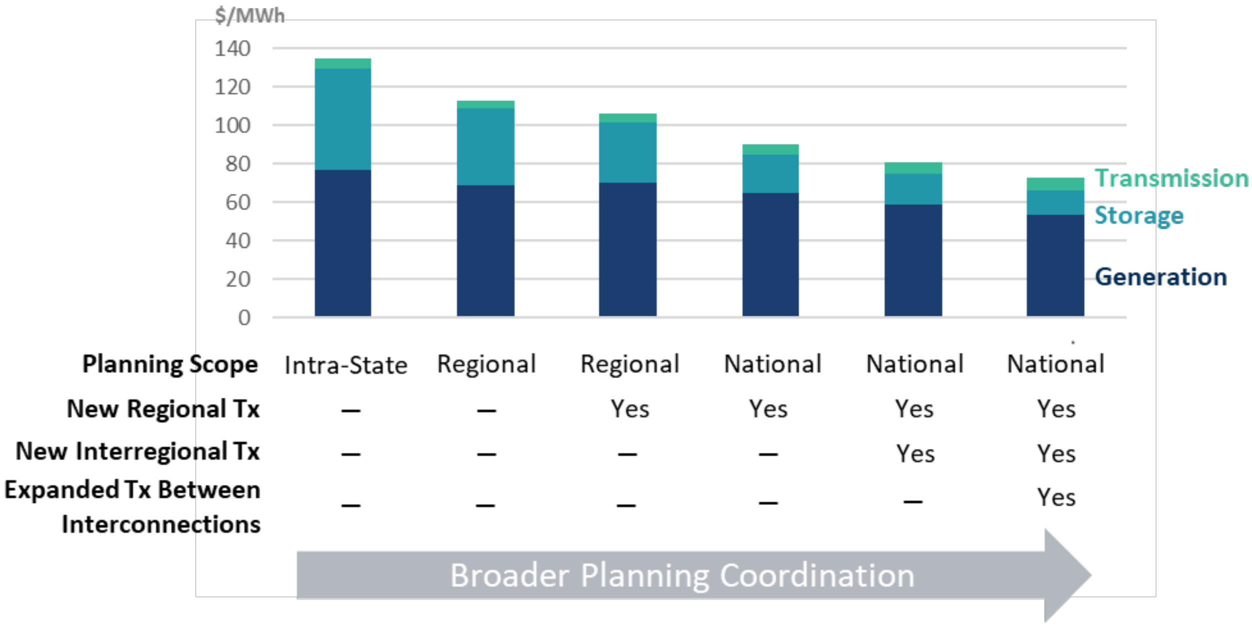
[25] P. R. Brown and A. Botterud, "*The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System*," *Joule*, Vol. 5, No. 1, p115–134, January 20, 2021.

[26] E. Larson, C. Greig, J. Jenkins, E. Mayfield, A. Pascale, C. Zhang, J. Drossman, R. Williams, S. Pacala, R. Socolow, EJ Baik, R. Birdsey, R. Duke, R. Jones, B. Haley, E. Leslie, K. Paustian, and A. Swan, *Net-Zero America: Potential Pathways, Infrastructure, and Impacts*, interim report, Princeton University, Princeton, NJ, December 15, 2020.

[27] P. R. Brown and A. Botterud, *op. cit.*

[28] C.T.M. Clack (Vibrant Clean Energy LLC), M. Goggin (Grid Strategies LLC), *et al.*, *Consumer, Employment, and Environmental Benefits of Electricity Transmission Expansion in the Eastern U.S*, Americans for a Clean Energy Grid, October 2020., at 9.

FIGURE 3. ELECTRICITY SYSTEM COSTS BY TYPE AND TRANSMISSION PLANNING SCENARIO



Source: Figure displays from data provided by MIT researchers Peter R. Brown and Audun Botterud based on their work modeling the decarbonization of the U.S. electricity system. Scenarios vary by the three planning parameters: (1) geographical scope, (2) whether new regional DC transmission is allowed, (3) whether new interregional DC transmission is allowed, and (4) whether new interconnectional transmission between East, WECC, and ERCOT is allowed.

It is clear that most of the current transmission planning processes are not leading to a cost-effective transmission infrastructure. Fortunately, some examples of better transmission planning, using existing and readily available tools, exist. While these experiences with improved planning process account for only a small portion of nation-wide transmission investments, they provide models for planning processes that, if broadly adopted by the nation's transmission planners, would yield better transmission solutions and lower system-wide costs.

II. Current Planning Generally Fails to Incorporate All Benefits, Scenarios, Portfolios, and Future Needs

Most of the planning processes used today result in inefficient investments that increase total system-wide costs. The table below shows which Planning Authorities are actually implementing these more-efficient planning methods, based on their most recent approved plans. While some of these entities are exploring improvements and have been performing relevant studies, in most cases their approved plans do not reflect these methods.

Table 2 shows the planning authorities' lack of use of proactive, scenario-based, multi-value processes. NYISO is applying this type of comprehensive planning framework in its public policy transmission planning process, but does not do so for addressing generation interconnection or reliability needs. CAISO has utilized such comprehensive planning when applying its TEAM approach, which reflects a multi-value transmission benefit framework that can effectively utilize scenarios, but the scope of benefits the CAISO considers outside of this process is limited. Similarly, MISO's MVP transmission planning benefit-cost analysis was an encouraging example of a comprehensive planning effort. However, since the MVPs were approved a decade ago, MISO's planning process has focused primarily on generation-interconnection and other reliability needs, a few minor market-efficiency projects based on narrowly defined benefits, and no other projects that were planned using MISO's multi-value approach.[29] While PJM has a "multi-driver" option in its planning process, it has never been used. PJM continues to rely primarily on its generation interconnection and reliability planning processes, which we showed in prior sections is much more costly than a comprehensive and proactive approach to build transmission. PJM's planning process for "market efficiency" projects considers only a narrow set of traditional production cost (load LMP) metrics and capacity market impact—which has yielded few such projects. Lastly, ISO-NE, Florida, Southeast Regional, and South Carolina Regional rank very low among the regional planning authorities, having rarely (if ever), applied any of the available comprehensive practices in their planning effort.

[29] Within MISO, American Transmission Company quantified a broad set of transmission benefits for range of different futures, but this process was used only for transmission siting cases before the Wisconsin Public Service Commission. MISO is also currently applying a proactive, scenario-based, multi-value planning framework in it RIIA effort, but has not yet approved any transmission projects based on it.

We offer the following criteria for the five efficient planning practices included in Table 2 below:

- **Proactively plan for future generation and load:** Incorporates a proactive perspective on reasonably anticipated load levels, load profiles, and generation mix over the lifespan of the transmission. Planning inputs extend beyond generic, baseline projections or considerations of such factors and actually include in the plans knowable information about enacted public policy mandates, publicly stated utility plans, and/or consumer procurement targets, which are used to evaluate the need, impacts, and benefits of the transmission.
- **Apply a multi-value planning framework to all transmission projects**: Accounts for a full range of transmission needs rather than separately assessing reliability, economic, and public policy needs. Quantifies and assesses a broad range of benefits, rather than narrow analyses based on traditional production cost savings.
- **Use scenario-based planning to address uncertainties**: Evaluates a set of distinct scenarios representing plausible futures (beyond the status-quo needs) that address the range of long-term uncertainties and also consider high-stress grid conditions. Incorporates plausible ranges of fuel price trends, locations and size of future load and generation, economic and public policy-driven changes to future market rules or industry structure, and/or technological changes to assess transmission effectiveness in multiple futures and any possible modifications needed from scenario differences.
- **Capture portfolio-synergy and use portfolio-based cost recovery**: Considers comprehensive portfolios of synergistic transmission projects to address system needs. Assesses benefits more accurately by taking into account network interactions, as well as other resources such as storage and other technologies. Applies portfolio-based cost recovery rather than a project-by-project cost-recovery approach.
- **Perform joint interregional planning:** Uses joint modeling and analysis of adjacent regions that jointly evaluates transmission regional and interregional needs and analyzes benefits based on multi-value framework, rather than being focused solely on each regions' needs and solutions independently of interregional needs and synergies.

TABLE 2. PLANNING AUTHORITIES CURRENT USE OF EFFICIENT PRACTICES

	Proactive Generation & Load	Multi-Value	Scenario-Based	Portfolio-Based[30]	Joint Interregional Planning
ISO-NE[31]	✗	✗	✗	✓	✗
NYISO[32,33]	✗	✗	✗	✗	✗
– PPTPP only	✓	✓	✓	✓	✗
PJM[34,35]	✗	✗	✗	✗	✗
Florida	✗	✗	✗	✗	✗
Southeastern Regional	✗	✗	✗	✗	✗
South Carolina Regional	✗	✗	✗	✗	✗
MISO (excl. MVP, RIIA)[36]	✗	✗	✗	✗	✗
SPP (ITP)[37,38]	✗	✓	✗	✓	✗
CAISO[39,40]	✓	✗	✓	✗	✓
– TEAM only	✓	✓	✓	✓	✓
WestConnect	✗	✗	✗	✗	✗
NorthernGrid[41]	✗	✗	✗	✗	✗

30 Includes portfolio-based cost recovery for projects approved by ISO-NE, NYISO, SPP, and CAISO. SPP also performs portfolio-based planning through its Integrated Transmission Planning (ITP) process.

31 ISO-NE transmission planning has been based solely on generation interconnection and network reliability needs. Cost recovery of network transmission costs, however, is broadly based on the entire ISO-NE portfolio (*i.e.*, utilizing postage stamp cost recovery)

32 NYISO applies proactive, multi-value, scenario-based planning only for the purpose of its Public Policy Transmission Planning Process (PPTPP). All other New York planning efforts, including for generation interconnection, remain solely reliability focused and individual (incremental) needs. In the most recent (2019) public policy transmission plan, transmission lines were studied using a base case, as well as a Clean Energy Standard + Retirement Scenario. See New York ISO (NYISO), *AC Transmission Public Policy Transmission Plan*, April 8, 2019, at p 14.

33 In the most recent (2019) public policy transmission plan, transmission lines were studied using: (1) a base case, (2) a Clean Energy Standard + Retirement Scenario, (3) a Clean Energy Standard +Retirement case with CO_2 emissions priced at the social cost of carbon. In a separate extended analysis, the NYISO studied two scenarios: (1) a base case, and (2) a case in which the capacity zones are reconstituted due to pending changes to the resource mix and the construction of the AC Transmission projects. See NYISO, *id.,* at pp 14, 19, and 25.

34 PJM's transmission planning manual has documentation on how PJM can develop a multi-driver approach. See PJM Transmission Planning Department, *PJM Manual 14B: PJM Region Transmission Planning Process, Revision: 49*, effective date: June 23, 2021, at p 32.

35 PJM and MISO Boards approved the first interregional market efficiency transmission project – replacement of the Michigan City-Trail Creek-Bosserman 138 kV line – based on a competitive planning process. See PJM, *RTEP: 2020 Regional Transmission Expansion Plan*, February 28, 2021, at p 2. The project has yet to be included in a MISO MTEP plan.

36 MISO's transmission planning manual has documentation on how to develop multi-value projects. See MISO, *Business Practices Manual: Transmission Planning*, Manual No. 020, BPM-020-r24, effective date, May 1, 2021,

To date, only a small portion of transmission spending is justified on economic criteria and full analysis of broader regional and interregional benefits and costs. Table 3 below shows what types of transmission are being planned based on recent spending as they report it (though in a number of cases the information was not readily available in time for publication of this report). As the table shows, the current planning processes do not consider the multiple values and wide-ranging benefits that well-planning transmission projects would be able to provide, which unreasonably increases system-wide costs.

at 160. MISO's transmission planning manual has documentation on constructing portfolios, and has approved and constructed MVP portfolios in the past. See MISO, *Ibid.*

Note that MISO has experience with pro-active, multi-value, scenario-based planning through its MVP and RIIA planning processes. However, no transmission projects have been approved through RIIA at this point and no MVPs were planned or approved by MISO in the last decade.

[37] SPP's multi-benefit Integrated Transmission Planning (ITP) process does not apply to generation interconnection. In SPP's screening of individual economic transmission projects, ITP projects are evaluated under only two "futures:" a reference case and an emerging technologies case. See SPP Engineering, *2020 Integrated Transmission Planning Assessment Report*, Version 1.0, October 27, 2020, at p 11.

[38] While SPP groups transmission into a "consolidated portfolio," all screened reliability projects are automatically included without further analysis. Economic projects are chosen based on the results of cost-benefit analyses; however, they are studied individually and the analysis does not account for the impacts of other economic lines in the portfolio. See SPP Engineering, *Id.*, p 81.

[39] CAISO's multi-value TEAM planning process is not utilized to address generation interconnection and network reliability needs. "CAISO's policy-driven transmission studies were based on a 60 percent RPS policy base portfolio provided by the CPUC, together with sensitivity portfolios based on higher approximately 71 percent – RPS levels." California ISO (CAISO), *2020–2021 Transmission Plan*, approved March 24, 2021, p 1.

[40] CAISO selects for approval of transmission elements that have a high likelihood of being needed and well-utilized under multiple scenarios: "1) the 2019-2020 Reference System Portfolio (RSP) adopted in the Decision, with the 46 million metric ton greenhouse gas target in 2030, as a policy-driven sensitivity, and (2) a portfolio based on the 30 million metric ton scenario, to test the impact of energy-only deliverability status for some generators on congestion and curtailment, as a second policy-driven sensitivity." CAISO, *Id.*, p 27.

[41] NothernGrid's 2020-2021 draft (and first ever) transmission plan has not yet been approved, but does offer a portfolio-based approach and includes a handful of proposed interregional lines. See Northern Grid, *Draft Regional Transmission Plan for the 2020–2021 NorthernGrid Planning Cycle*, n.d., pp 9 and 13.

TABLE 3. PLANNING AUTHORITIES'S RECENTLY APPROVED TRANSMISSION SPENDING FOR DIFFERENT TYPES OF PROJECTS ($ MILLION)

	Local Reliability	Regional Reliability	Economic	Generator Interconnection	Multi-Value Projects
ISO-NE	n/a	$437[42]	$0[43]	n/a	$0
NYISO[44]	n/a	n/a	n/a	n/a	n/a
PJM	$4,106[45]	$388.31[46]	$24.69[47]	$101[48]	$0
Florida	n/a	$0[49]	$0[50]	n/a	$0
Southeastern Regional	n/a	n/a	n/a	n/a	n/a
S Carolina Regional	n/a	n/a	n/a	n/a	n/a
MISO	$2,800[51]	$755[52]	$0[53]	$606[54]	$0
SPP	n/a	$213.5[55]	$318.8[56]	n/a	$0
CAISO	n/a	$3.6[57]	$0[58]	n/a	$0
WestConnect	n/a	n/a	n/a	n/a	n/a
NorthernGrid	n/a	n/a	n/a	n/a	n/a

42 See the list of transmission included under the most recent regional system plan (2019). The cost figure has been calculated for transmission defined as "planned." See ISO-New England, October 2019 ISO-New England Project Listing Update (Draft)–ISO-NE Public, Excel spreadsheet, October 2019. It is possible that some local reliability projects are included under this category, and likely that ISO-NE does not track local reliability projects in general.

43 "To date, the ISO has not identified the need for separate market-efficiency transmission upgrades (METUs), primarily designed to reduce the total net production cost to supply the system load." See ISO New England, *2019 Regional System Plan*, October 31, 2019 at 7.

44 NYISO does not report approved transmission investment cost figures.

45 PJM, *RTEP: 2020 Regional Transmission Expansion Plan*, February 28, 2021, p 259.

46 *Id.*, p 259. Of the $413 million in baseline projects approved under the 2020 PJM Regional Transmission Expansion Plan, one interregional market efficiency project at a total estimated cost of $24.69 million was approved. See *Id.*, p 75.

47 *Id., p* 75.

48 *Id.*, p 2.

49 "The Regional Projects Subcommittee (RPS) has completed its proactive planning analysis per the Biennial Transmission Planning Process (BTPP). In summary, no potential [Cost Effective or Efficient Regional Transmission Solutions] CEERTS Projects have been identified." See Florida Reliability Coordinating Council, Inc. (FRCC), FRCC Proactive Planning Results and CEERTS Proposal Solicitation Announcement, April 21, 2021.

50 *Ibid.*

51 MISO, *MTEP 20*, n.d., full report, p 15.

52 *Ibid.*

53 *Ibid.* No market efficiency projects were approved.

PJM's recent offshore wind generation study (discussed earlier in the report) shows that this absence of a multi-value framework in the generation interconnection process means that costs are higher than they would be under a proactive planning framework and, in the case of generation interconnections, they are unfairly placed on generators when large benefits accrue to the system as a whole. Fair treatment would align cost allocation for generation-interconnection-related network upgrades with benefits. If under such a multi-value framework there are generator interconnection-related network upgrades that do not show material benefits for load, generators would still be responsible for these costs.[59] However, many generation-interconnection-related network upgrades do provide economic and reliability benefits to load. A multi-value framework would correctly allocate a commensurate share of project costs to load.

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54 *Ibid.*

55 SPP offers the project cost figures for approved reliability projects. See SPP Engineering, *op. cit.*, pp 4–5. It is possible that some local reliability projects are included under this category, and likely that SPP does not track local reliability projects in general.

56 SPP offers the project costs of approved economic projects. See SPP Engineering, *op. cit.*, pp 4-5.

57 CAISO, *op. cit.*, p 440 –higher end of cost estimates chosen for each. It is possible that some local reliability projects are included under this category, and likely that CAISO does not track local reliability projects in general.

58 *Ibid*.

59 GIR are responsible for network upgrades needed to accommodate the full output of the generator on a non-firm, energy-only basis (N-0 conditions with optimal re-dispatch).

III. Market and Regulatory Failures Cause Under-Investment in Regional and Interregional Transmission

The lack of planning for and investment in the type of cost-effective, beneficial transmission that is needed to achieve reasonable electricity costs is caused by structural and regulatory problems in the electric industry. Below we comment on several of these problems.

1. Small utility planning areas encourage local transmission planning while discouraging regional transmission planning

There are 329 transmission owners (TOs) in the country, each of which evolved out of the early industry structure of local utilities serving local load with local generation resources.[60] Nearly all of these utilities were vertically integrated for most of their history and many remain so. Under this model, transmission was only built to serve the load and generation of the owner.[61] It was not until the late 1990s that regional operation and planning was introduced with the FERC Order 888 and the advent of RTOs and ISOs, and mandatory Planning Authorities were not established until FERC Order 1000 was issued in 2011.

Despite the formation of ISOs, RTOs, and regional Planning Authorities, much decision-making power over transmission planning and investments remains with the individual transmission owners. Planning authority over "local transmission" (which constitutes about half of the nation's transmission grid and is specifically exempt from regional planning requirements) has been retained by the individual transmission owners, which created barriers to coordinated planning over a larger regional footprint. Additionally, the regional planning efforts in the RTOs are collaborative processes that require broad consensus, as RTO membership is voluntary and individual members who do not support regional or interregional transmission investments

60 See NERC, Compliance Registry Matrix, tab "NCR Summary," under heading "TO." Accessed 10/2/2021

61 Vertically integrated utilities are generally monopoly entities that get full cost recovery through regulated, commission-approved rates.

have the option to leave the RTO. Regional planning outside of RTO areas is minimal to nonexistent.

2. Differing TO incentives between local transmission and regional plans leads to inefficient levels of each

TOs are allowed under current federal regulations to plan and install upgrades on their local systems without regional planning oversight; this also allows them to grow their transmission rate base on which they earn commission-approved rates of return, including incentive returns. While local transmission investment is necessary to replace aging infrastructure, regionally planned investments that address local needs may provide larger system-wide benefits. Some of these regionally planned projects may be bid out competitively, in which case incumbent TOs have to compete with independent third parties and are much less likely to end up owning the asset. Even where the incumbent TO wins a regional transmission project bid, the investment cost may be capped and the rate of return may have been reduced through the competitive bidding process. No such competitive pressure exists for local transmission facilities and many types of regional transmission, including any transmission that is not subject to regional cost sharing or that is located in states that (often at the urging of incumbent transmission owners) have prevented competitive bidding through their right of first refusal (ROFR). This creates a bias against larger regional solutions even if they are more innovative and cost-effective, but would involve cost sharing and competitive processes.

Current FERC regulations cause this regulatory failure. If there were not such a different ability to own and profit from regional vs local transmission, this bias would not exist.

3. Economies of scale cause inefficiently small investments unless mitigated through regulations

A very common "market failure" that is standard across regulated industries is the declining average cost at larger quantities of production, known as economies of scale. This physical and economic feature causes what is known as a "natural monopoly" in which the most efficient structure is to build and own large assets by a single company, with an economic regulator to determine the efficient level of investment and with cost recovery spread across all consumers. Economies of scale still exist in transmission such that the costs of high-capacity lines are much lower per unit of delivered energy than the cost of lower capacity lines. These economies mean that large regional lines would need to be planned through a regulatory process to achieve sufficient scale, rather than left to market forces alone or to processes where only small incremental upgrades are made by the local transmission owners. This regional planning process needs to function as intended to actually determine the most cost-effective scale of transmission investment, based on future needs over the life of the assets. This would require that the regional planning evaluate local transmission solutions and reject them if more cost effective regional solutions are available. The current planning processes, however, mostly accept the local transmission solutions (implemented by transmission owners outside the regional planning processes) and only add regional projects to address specific remaining needs, which are mostly reliability-only needs.

The current planning processes thus unreasonably lead to inefficiently small investments and higher system-wide costs by forgoing the economies of scale that regional projects would offer.

4. Economies of scope cause inefficient plans unless mitigated through regulations

When the production of one product reduces the cost of other products, there are "economies of scope." An apple orchard might sell both apple sauce and apples, for example, using the same inputs to production. In the case of transmission, there are a variety of uses and benefits that all come from the existence of high capacity transmission facilities. For example, transmission used to cover for the loss of generation due to extreme weather by sending power in the direction of the shortfall is also used to connect low-cost generation and reduce congestion costs, and vice versa. When transmission planning is based only on identifying least-cost transmission solutions for single drivers—such as generation interconnection and other reliability needs, economic and market efficiency needs, or public policy needs—these economies of scope provided by larger regional projects capable of simultaneously addressing multiple needs at both the regional and local transmission system levels are not captured, unreasonably raising system-wide electricity costs and rates.

Economies of scope can be captured only if multi-value/multi-driver planning is performed. Public policy that achieves cost-effective outcomes needs to require regional multi-value/multi-driver planning, particularly if the planning outcomes are not in the economic interest of TOs.

5. Externalities cause inefficient plans unless mitigated through regulations

When parties beyond the buyer and seller of a product are impacted, positively or negatively, from the transaction, that third-party impact is an "externality" of the transaction. Achieving efficient outcomes requires that the value of these externalities be taken into account. In transmission, electricity flows across the entire alternating-current network according to the laws of physics, which send power along the path of least electrical resistance (a function of the voltage levels, design, and length of transmission lines). For this reason, individual transactions and uses on the system impact all other transactions and uses. An expansion of transmission capacity to accommodate one transaction (or purpose) will thus increase or decrease capacity for other uses. The interactions of power flows across grid facilities also means that synergistic portfolios of transmission facilities can provide system-wide value that exceeds the value of the individual facilities.

Given the prevalence of network externalities, it is generally inefficient to plan transmission one line at a time and for one local (or even regional) system at a time. Efficiency requires planning a full portfolio of network assets together, across a wide geographic area. A transmission planning process that results in little regional (or interregional) capacity and only plans local or incremental regional upgrades at a time—and in response to a specific generator interconnection request or a single other need—will result in inefficient solutions that are unreasonably expensive from a system-wide perspective.

6. Horizontal market power

Another market failure in transmission relates to the exercise of horizontal market power, which is the power to withhold service to raise prices. Avoiding the exercise of such market power is a standard feature of the regulation of natural monopolies. Withholding is prevented by regulators requiring that all capacity is provided to any customer willing to pay the cost. For example, FERC's open access transmission regulations require that all "Available Transmission Capability" be provided to market participants. And the ability of entities with market power to raise prices is prevented by regulators establishing rates that are "just and reasonable," usually as a function of the total cost of providing the service. Thus, horizontal market power is largely addressed in the electric transmission industry through FERC regulations—but not completely.

Horizontal market power can still exist in electric transmission systems. When efficient transmission investments are not made by a TO with the power to determine which type of investments to make, then system-wide costs are increased. In the U.S. electric transmission industry, when more efficient regional and interregional transmission investments are not made due to barriers and biases in the planning processes such that less-efficient local and small regional upgrades are made instead, it is a form of unmitigated horizontal market power. A regulatory requirement to plan the efficient amount and scale of transmission, and charge only rates based on the cost of the efficient investment, is necessary to mitigate this market power.

7. Vertical market power

The ability to withhold service in one stage of production to increase profit in another stage of production is called vertical market power. Regulations that prevent the exercise of vertical market power are common in the electricity industry. If there were no such regulations related to the electric transmission system, TOs could withhold transmission and interconnection service from other market participants in order to increase the value of and the profits from their own generation. FERC open access rules introduced in 1996 through Order No. 888 and interconnection rules in Order No. 2003 are intended to mitigate the exercise of this type of vertical market power. But, again, these regulations are imperfect.

In the current electricity system, when interconnection and transmission planning processes are inefficient or even dysfunctional, then valuable transmission service is withheld, disadvantaging third party consumers and sellers, potentially advantaging a TO's owned generation, and unreasonably increasing system-wide costs. Most TOs in the country still own generation and thus have incentives to underinvest in regional transmission and prefer less efficient local transmission solutions. Transmission planning requirements thus need to ensure that remaining opportunities to exercise vertical market power are removed.

Overall, these barriers and incentives serve to bias transmission planning against more innovative and cost-effective regional and interregional solutions to address the identified (multiple) transmission needs, the result of which is an inefficient outcome with higher system-wide costs.

IV. Adoption of Pro-Active, Scenario-Based, Multi-Value, and Portfolio-Based Transmission Planning Practices Is Necessary to Avoid Unreasonably High Electricity Costs

As discussed in prior sections, structural and regulatory problems in the electric industry have resulted in a lack of comprehensive planning for and investment in the type of transmission that offers the most cost-effective system-wide results. Fortunately, significant experience exists with proactive, scenario-based transmission planning that quantifies the wide range of economic, reliability, and public policy ("multi-value") benefits of transmission investments, whether it be individual projects or synergistic portfolios. This experience shows that proactive, scenario-based, multi-value planning yields infrastructure that lowers the overall, system-wide costs of supplying and delivering electricity.

In the cases when such comprehensive transmission planning processes have been used, the outcomes have yielded lower-cost results (even though without explicit but-for analysis, this difference in costs cannot always be quantified precisely). One example is Texas' proactive Competitive Renewable Energy Zone (CREZ) project. Recognizing the economic potential of connecting western Texas' sparsely populated wind-rich areas to load, the Texas legislature passed a bill in 2005 that ordered that the Public Utility Commission of Texas to develop a transmission plan to deliver renewable power to customers. The $7 billion effort was designed to interconnect around 11.5 GW of new wind generation capacity. After its 2013 completion, wind curtailment fell from a previous high of 17% to 0.5%.[62] Unforeseen at the time it was planned, interest in developing solar capacity in West Texas, as well as load growth from shale oil and gas production in the region, has further elevated the benefits of the projects.

Similarly, MISO's multi-value projects serve as another planning success story. Over 10 years ago, MISO began proactively planning in anticipation of the development of wind generation capacity to meet the state-by-state Renewable Portfolio Standards in its territory. Diverging from the standard planning processes, the MVP planning process identified a comprehensive

[62] ERCOT, *The Texas Competitive Renewable Energy Zone Process*, September 2017.

set of upgrades across its footprint that would provide a mix of reliability, policy, and economic benefits to the system under a range of scenarios. The resulting transmission infrastructure offers a broad range of regional benefits and has allowed over 11 GW of wind to be interconnected and delivered, with total benefits that are estimated to exceed project costs by $7 to $39 billion over the next 20–40 years.[63] In other words, without the proactively and regionally planned MVP portfolio, MISO's system-wide costs would be $7–$39 billion higher.

The California Independent System Operator (CAISO) also has extensive experience with evaluating a broad range of benefits for transmission projects as documented in CAISO's case study of the Palo Verde to Devers No. 2 project, which is discussed in more detail below. Nevertheless, this multi-value transmission planning experience has not been broadly applied in the CAISO's recent planning efforts. Rather, candidates for economically justified transmission projects have been evaluated based mostly on their impacts on wholesale market prices or their ability to reduce congestion charges based on either historically observed congestion charges or the congestion cost observed in base-case production cost simulations.

The Southwest Power Pool (SPP) has similarly found that the transmission upgrades it installed between 2012 and 2014 through its integrated planning process (ITP) yield a broad range of benefits that exceed $4.6 billion of project costs by nearly $12 billion over the next 40 years.[64] The $16.6 billion in total benefits is higher than SPP's multi-value transmission planning models had initially estimated, and 3.5 times greater than the cost of the transmission upgrades. SPP is the only RTO which regularly quantifies a broad range of transmission-related benefits in its planning and cost allocation process. In contrast, for example, while PJM also has experience quantifying a wide range of benefits for transmission projects,[65] it has not been utilizing any of this experience in its transmission planning process.

NYISO has recently added a multi-value planning framework through its Public Policy Transmission Planning Process (PPTPP), which has yielded a number of transmission projects with benefits in excess of project costs, thereby reducing system-wide costs.[66] However, NYISO is not applying this multi-value planning framework to its generation interconnection and reliability-driven planning efforts.

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63 MISO, *MTEP17 MVP Triennial Review: A 2017 review of the public policy, economic, and qualitative benefits of the Multi-Value Project Portfolio*, September, 2017

64 Southwest Power Pool (SPP), *The Value of Transmission*, January 26, 2016.

65 PJM Interconnection, *The Benefits of the PJM Transmission System*, April 16, 2019.

66 NYISO, AC Transmission Public Policy Transmission Plan. April 8, 2019. Potomac Economic, *NYISO MMU Evaluation of the Proposed AC Public Policy Transmission Projects*, February 2019.

Proactive, multi-value, scenario-based planning approaches have also been successfully utilized in other countries. For example, the Australian Electricity Market Operator (AEMO) has used scenario-based planning for a number of years after an independent review found that Australian transmission planning processes needed to be improved.[67] In the latest "Integrated System Plan" (ISP), the AEMO drew upon an extensive stakeholder engagement and internal and external industry and power system expertise to develop a blueprint that maximises consumer benefits through a transition period of great complexity and uncertainty.[68] The ISP serves the regulatory purpose of identifying actionable and future ISP projects, as well as the broader purposes of informing market participants, investors, policy decision makers and consumers.[69] As the AEMO explains, the ISP is based on the following principles:

- *Whole-of-system plan:* A plan to maximize net market benefits and deliver low cost, secure, and reliable energy through a complex and comprehensive range of plausible energy futures. It identifies the optimal development path for the National Electricity Market (NEM), consisting of ISP projects and development opportunities, as well as necessary regulatory and market reforms.
- *Consultation and scenario modelling:* AEMO developed the ISP using cost-benefit analysis, least-regret scenario modelling, and detailed engineering analysis, covering five scenarios, four discrete market event sensitivities, and two additional sensitivities with materially different inputs. The scenarios, sensitivities, and assumptions have been developed in close consultation with a broad range of energy stakeholders.
- *Least-regret energy system:* This analysis identified the least system cost investments needed for Australia's future energy system. These are distributed energy resources (DER), variable renewable energy (VRE), supporting dispatchable resources, and power system services. Significant market and regulatory reforms will be needed to bring the right resources into the system in a timely fashion.

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67 A. Finkel, K. Moses, C. Munro, T. Effeney, and M. O'Kane, "*Independent Review into the Future Security of the National Electricity Market—Blueprint for the Future*," energy.gov.au, June 1, 2017, find that "Incremental planning and investment decision making based on the next marginal investment required is unlikely to produce the best outcomes for consumers or for the system as a whole over the long-term or support a smooth transition. Proactively planning key elements of the network now in order to create the flexibility to respond to changing technologies and preferences has the potential to reduce the cost of the system over the long-term" (at p 123)

68 AEMO, *2020 Integrated System Plan*, July 30, 2020.

69 Australian Energy Market Operator (AEMO), *Our 20-year plan for the National Electricity Market*, 2020. See also Transgrid, *Energy Vision 2050: A Clean Energy Future for Australia,* October 2020, as an example of a long-term, scenario-based energy industry and transmission grid analysis by one of the Australian transmission owners and developers, which explores alternative futures and their transmission implications through 2050.

- *Projects to augment the transmission grid:* The analysis identified targeted augmentations of the NEM transmission grid, and considered sets of investments that together with the non-grid developments could be considered candidate development paths for the ISP.
- *Optimal development path:* A path needed for Australia's energy system, with decision signposts to deliver the affordability, security, reliability and emissions outcome for consumers throughout the energy transition.
- *Benefits:* When implemented, these investments will create a modern and efficient energy system that is expected to deliver $11 billion in net market benefits and meets the system's reliability and security needs through its transition, while also satisfying existing competition, affordability, and emissions policies.

As we have shown with the examples in the prior section of this report, the current incremental and reactive transmission planning processes result in higher system-wide electricity costs than more proactive planning processes that simultaneously consider multiple needs and quantify a broad range of transmission benefits. The industry experience with such more effective planning and cost-allocation processes, where utilized, points to several core principles for transmission planning that can avoid these higher-cost traditional planning solutions.[70] The already-available experience with improved planning processes points to the following 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 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.

[70] While this report focuses on the need to improve transmission planning processes, we recognize that addressing cost allocation challenges will also be an important element to the development of just and reasonable transmission solutions. For recommendations on improving cost allocation frameworks, see slides 25–30 of Pfeifenberger, *Transmission Planning and Benefit-Cost Analyses*, prepared for FERC Staff, April 29, 2021. See also P.L. Joskow, *Facilitating Transmission Expansion to Support Efficient Decarbonization of the Electricity Sector*, Economics of Energy & Environmental Policy, Vol. 10, No. 2 (2021).

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.

The remaining section provides a more detailed examination of how these core planning principles work in practice.

1. Proactively Plan for Future Generation and Load

Most of today's transmission planning processes ignore the location, types, and quantities of the future generation mix needed to meet federal, state, utility, and customer clean energy goals, and thus do not consider how system needs will change as the grid continues to evolve. Looking further into the future to include knowable information about already enacted public policy mandates, publicly stated utility goals, and consumer preferences can identify more cost-effective grid solutions. From a system-wide cost perspective, the lack of proactive planning can lead to numerous piece-meal transmission upgrades that fail to holistically consider what is most cost-effective for the system over the 40–50 year life of the investments. Incorporating proactive forward-looking planning, identifies more efficient, integrated network solutions that cost significantly less than the sum of the often piecemeal upgrades identified through current planning processes.

As noted above, the recent PJM offshore wind integration study shows that the current generation interconnection study process (evaluating one interconnection cluster at a time) approximately doubles the onshore transmission costs of integrating offshore wind generation compared to a proactive planning process.

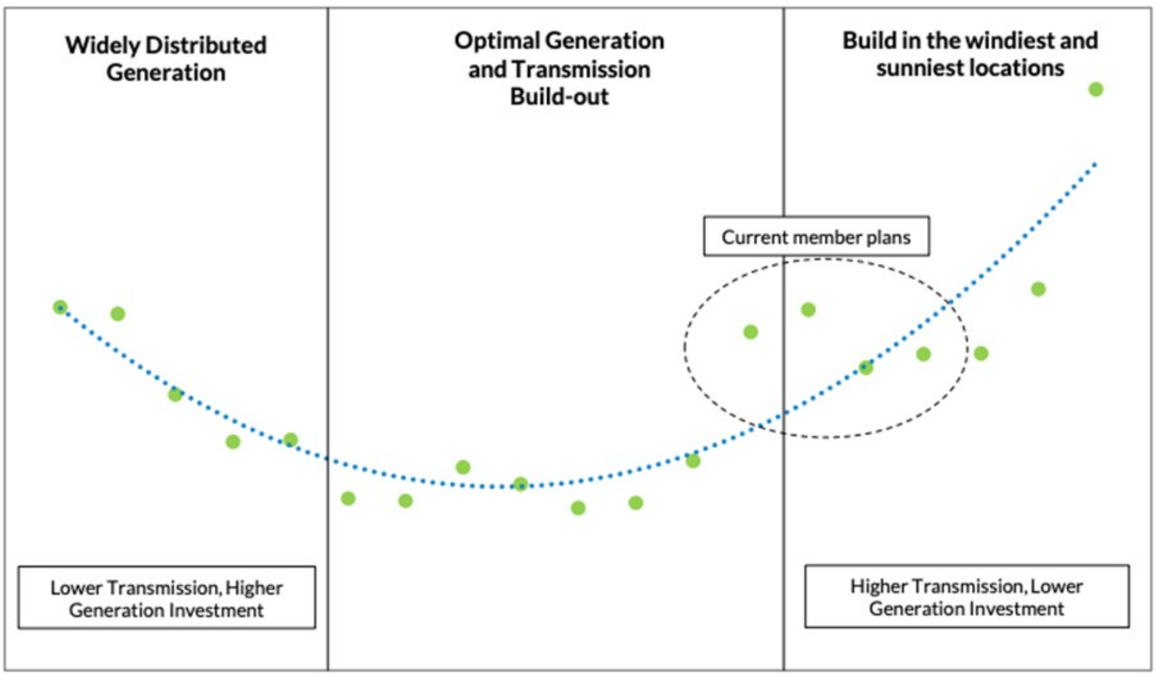
The MISO MVPs present another example of proactive forward-looking planning that resulted in transmission solutions that reduce system wide costs. The MVPs were the result of MISO's proactive planning effort prior to 2010, the Regional Generation Outlet Study (RGOS).[71] RGOS performed proactive planning and identified so-called "RGOS start projects." These projects were estimated to be beneficial in all scenarios evaluated by the study. These "no-regrets" RGOS start projects turned into the MVP portfolio that has allowed over 11 GW of wind to be integrated and delivered with system-wide cost savings (economic net-benefits) of $12–$53

[71] Midwest ISO (MISO), *RGOS: RGOS: Regional Generation Outlet Study*, November 19, 2010.

billion over the next 20–40 years.[72] MISO has found through its updated studies that the net benefits of the MVP portfolio exceed MISO's initial estimates.

Proactive planning also identifies transmission upgrades that guide the market towards the optimal mix of local and remote generation that can be delivered through the transmission grid. Local renewable generation can serve customers with less regional transmission but is often more expensive. Remote generation often has lower generation cost but requires more regional transmission. The trade-off can be evaluated through scenario-based proactive studies that consider generation in different locations and their transmission cost. The MISO "smile curve" illustrates this trade-off (Figure 4).

FIGURE 4. TOTAL MISO PROJECT GENERATION AND TRANSMISSION COSTS



Source: MISO Planning Advisory Committee, *Long Range Transmission Planning - Preparing for the Evolving Future Grid*, August 12, 2020, pg. 7.

Similarly, NYISO analyses of transmission projects evaluated under its public policy transmission planning processes (PPTPP) show significant benefits from placing up-sized public policy projects on the rights-of-way of aging existing transmission facilities, thereby avoiding the cost of the otherwise needed replacement of these existing facilities.[73] In fact, the avoided costs of

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[72] MISO, *MTEP17 MVP Triennial Review: A 2017 review of the public policy, economic, and qualitative benefits of the Multi-Value Project Portfolio*, September, 2017.

[73] Newell, *et al.*, *Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades*, September 15, 2015.

aging facility replacement was one of the largest benefits identified for some of the public policy projected studied in in New York.

2. Account for the Full Range of Transmission Project Benefits, and use Multi-Value Planning to Comprehensively Identify Investments that address all Categories of Needs and Benefits

To identify solutions that result in lower overall costs to customers, planning needs to consider the multiple values (system-wide cost reductions) offered by transmission investments, irrespective of whether the primary driver of transmission infrastructure is based on reliability, public policy, or economic needs. For example, two solutions to address a particular reliability need may offer vastly different total system-wide benefits. Thus, the higher-cost transmission solutions can actually result in significantly lower net cost from a system-wide perspective. Multi-value transmission planning identifies these lower-total-cost solutions, by quantifying and considering a larger portion of total transmission-related benefits. Multi-value transmission planning can also inform policymakers about the system-wide costs of not investing in transmission to provide a more comprehensive picture of overall costs and benefits beyond transmission project costs.

Table 4 summarizes the benefits quantified and considered in four RTOs' multi-value transmission planning efforts. In addition to this RTO experience, many industry and academic studies have discussed the cost savings that transmission investments can provide and how to quantify them.[74] Most current transmission planning processes, however, do not consider these benefits. And even the few transmission projects approved under RTOs' "economic" (or "market efficiency") planning processes have been evaluated solely based on a very narrow set of benefits, such as production cost savings simulated under highly normalized system conditions. As the multi-value planning examples of RTOs and industry studies show, however, there already is much experience in quantifying a larger set of transmission benefits using existing evaluation tools.

[74] For example, see: Joskow, *Facilitating Transmission Expansion to Support Efficient Decarbonization of the Electricity Sector*, Economics of Energy & Environmental Policy, Vol. 10, No. 2 (2021).

Pfeifenberger, *Transmission Planning and Benefit-Cost Analyses*, prepared for FERC Staff, April 29, 2021.

Pfeifenberger, Ruiz, Horn, *The Value of Diversifying Uncertain Renewable Generation through the Transmission System*, published by Boston University's Institute for Sustainable Energy, September 1, 2020.

Chang, Pfeifenberger, Hagerty, *The Benefits of electric Transmission Identifying and Analyzing the Value of Investments*, presentation prepared for WIRES, July 31, 2013.

TABLE 4. EXAMPLES OF EXPANDED TRANSMISSION BENEFITS ANALYSIS

SPP 2016 RCAR, 2013 MTF	MISO 2011 MVP ANALYSIS	CAISO 2007 TEAM ANALYSIS OF DPV2 PROJECT	NYISO 2015 PPTN STUDY OF AC UPGRADES
Quantified 1. **production cost savings** value of reduced emissions reduced AS costs 2. avoided transmission project costs 3. reduced transmission losses capacity benefit energy cost benefit 4. lower transmission outage costs 5. value of reliability projects 6. value of meeting policy goals 7. Increased wheeling revenues	**Quantified** 1. production cost savings 2. reduced operating reserves 3. reduced planning reserves 4. reduced transmission losses 5. reduced renewable generation investment costs 6. reduced future transmission investment costs	**Quantified** 1. production cost savings and reduced energy prices from both a societal and customer perspective 2. mitigation of market power 3. insurance value for high-impact low-probability events 4. capacity benefits due to reduced generation investment costs 5. operational benefits (RMR) 6. reduced transmission losses* 7. emissions benefit	**Quantified** 1. production cost savings (includes savings not captured by normalized simulations) 2. capacity resource cost savings 3. reduced refurbishment costs for aging transmission 4. reduced costs of achieving renewable & climate goals
Not Quantified 8. reduced cost of extreme events 9. reduced reserve margin 10. reduced loss of load probability 11. increased competition/liquidity 12. improved congestion hedging 13. mitigation of uncertainty 14. reduced plant cycling costs 15. societal economic benefits	**Not Quantified** 7. enhanced generation policy flexibility 8. increased system robustness 9. decreased nat. gas price risk 10. decreased CO2 emissions 11. decreased wind volatility 12. increased local investment and job creation	**Not Quantified** 8. facilitation of the retirement of aging power plants 9. encouraging fuel diversity 10. improved reserve sharing 11. increased voltage support	**Not Quantified** 5. protection against extreme market conditions 6. increased competition and liquidity 7. storm hardening and resilience 8. expandability benefits

Sources: SPP Regional Cost Allocation Review Report for RCAR II, July 11, 2016. SPP Metrics Task Force, Benefits for the 2013 Regional Cost Allocation Review, July, 5 2012; Proposed Multi Value Project Portfolio, Technical Study Task Force and Business Case Workshop August 22, 2011; CPUC Decision 07-01-040, January 25, 2007, Opinion Granting a Certificate of Public Convenience and Necessity; Newell, et al., Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades, September 15, 2015.

Unfortunately, most existing planning processes do not take advantage of the available experience or consider the multiple values proposed transmission investment can provide beyond addressing specific drivers and needs. If a project is driven by reliability needs, the broader economic and public policy benefits provided by the project are usually not quantified and considered. If a project is categorized as an economic or public policy project, but simultaneously provides reliability benefits without addressing a specific reliability violation, that reliability benefit usually is not considered either. This particular "compartmentalized" or "siloed" planning approach leads to an understatement of transmission-related system benefits and a significant under-appreciation of the costs and risks imposed on customers by an insufficiently robust and flexible transmission infrastructure.

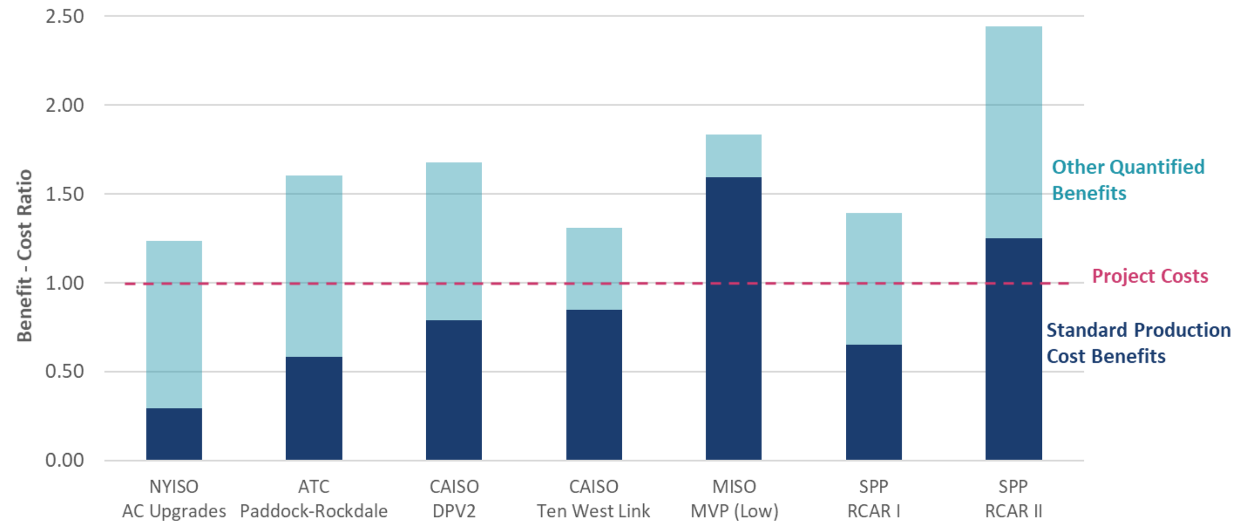
While not all proposed transmission investments provide benefits that exceed project costs, overlooking benefits because traditional tools and processes do not automatically capture these benefits leads to the premature rejection of valuable projects and underinvestment in transmission infrastructure. Many beneficial projects that have been built would not have passed cost-benefit ratios when only considering limited benefits, such as the traditionally quantified production cost benefits as shown in Figure 5 below. This leads to planning outcomes that impose unreasonable costs on customers.

Even though some of transmission-related benefits have been classified “unquantifiable” or “difficult to quantify,” such as increased liquidity, the available industry experience shows that this is not the case. Many of these (frequently not quantified) transmission-related benefits can be readily estimated using existing planning and market simulation tools as the RTO examples in Table 4 and industry reports clearly show.

Quantifying a broader range of transmission benefits for individual projects or a portfolio of synergistic transmission upgrades will yield a more accurate benefit-cost analysis, provide more insightful comparisons, and would avoid rejecting beneficial investments that would reduce system-wide costs. Not quantifying these transmission-related benefits where they likely exist, results in unreasonably imposing additional costs on customers.

An effective multi-value planning process would: (1) consider for each project (or synergistic portfolio of projects) the full set of benefits transmission can provide (*e.g.*, as shown in Table 5); (2) identify the set of benefits that plausibly exist and may be significant for that particular project or portfolio; and (3) then focus on quantifying those benefits. This will yield a clear list of all benefits considered and quantified (along with those considered only qualitatively), akin to the list of quantified and not quantified benefits shown in industry examples of effective planning processes as summarized in Table 4 above.

FIGURE 5. BENEFIT-COST RATIOS OF TRANSMISSION PROJECTS WITH AND WITHOUT A BROAD SCOPE OF BENEFITS



Sources: Newell, *et al.* (The Brattle Group), Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades, prepared for NYISO and DPS Staff. September 15, 2015. ATC uses expected benefits under "high environmental scenario." American Transmission Company, Planning Analysis of the Paddock-Rockdale Project, April 2007. CAISO, Economic Evaluation of the Palo Verde-Devers Line No. 2 (PVD2), February 24, 2005. Testimony of Yi Zhang on Behalf of the California Independent System Operator, In the Matter of the Application of DCR Transmission, LLC for a Certificate of Public Convenience and Necessity for the Ten West Link Project, submitted to California Public Utilities Commission, Application 16-10-012, December 20, 2019. MISO, MTEP19 MVP Limited Review Report, 2019. Southwest Power Pool (SPP), Regional Cost Allocation Review (RCAR I), October 8, 2013. Southwest Power Pool (SPP), Regional Cost Allocation Review (RCAR II), July 11, 2016.

We continue this section with a review of the types of transmission-related benefits and how they can and have been quantified. We then describe efforts to integrate them into multi-benefit planning.

a. Types of Transmission Benefits

Most economic analyses used in transmission planning rely primarily on traditional applications of production cost simulations to determine whether the "adjusted production cost savings" (typically simulated only for highly normalized system conditions) offered by a transmission project exceed the project's costs. These production cost savings, adjusted for wholesale purchases and sales (or imports and exports), are mostly composed of fuel cost savings. The many RTO planning processes that are focused on traditional production cost savings do not examine or quantify the expanded set of well-known and tested transmission-related benefits, including (but not limited to): other production cost savings (*e.g.*, lower line losses and operating reserves), greater reliability and resilience, greater resource adequacy through reduced planning reserves and higher capacity value, and market benefits.[75] Compiled from the available RTO and industry experience, a full set of transmission-related benefits is listed in Table 5 and discussed further below.

TABLE 5. ELECTRICITY SYSTEM BENEFITS OF TRANSMISSION INVESTMENTS

Benefit Category	Transmission Benefit
1. Traditional Production Cost Savings	Adjusted Production Cost (APC) savings as currently estimated in most planning processes
2. Additional Production Cost Savings	i. Impact of generation outages and A/S unit designations
	ii. Reduced transmission energy losses
	iii. Reduced congestion due to transmission outages
	iv. Reduced production cost during extreme events and system contingencies
	v. Mitigation of typical weather and load uncertainty, including the geographic diversification of uncertain renewable generation variability
	vi. Reduced cost due to imperfect foresight of real-time system conditions, including renewable forecasting errors and intra-hour variability
	vii. Reduced cost of cycling power plants
	viii. Reduced amounts and costs of operating reserves and other ancillary services
	ix. Mitigation of reliability-must-run (RMR) conditions
	x. More realistic "Day 1" market representation
3. Reliability and Resource Adequacy Benefits	i. Avoided/deferred cost of reliability projects (including aging infrastructure replacements) otherwise necessary
	ii. (a) Reduced loss of load probability or (b) reduced planning reserve margin
4. Generation Capacity Cost Savings	i. Capacity cost benefits from reduced peak energy losses
	ii. Deferred generation capacity investments
	iii. Access to lower-cost generation resources
5. Market Facilitation Benefits	i. Increased competition
	ii. Increased market liquidity
6. Environmental Benefits	i. Reduced expected cost of potential future emissions regulations
	ii. Improved utilization of transmission corridors
7. Public Policy Benefits	Reduced cost of meeting public policy goals
8. Other Project-Specific Benefits	Examples: increased storm hardening and wild-fire resilience, increased fuel diversity and system flexibility, reduced cost of future transmission needs, increased wheeling revenues, HVDC operational benefits

Benefits unrelated to electricity costs, such as jobs supported jobs supported, economic growth, and public health are shown in Table 6.[76]

[75] Chang, Pfeifenberger, Hagerty, *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments*, prepared for The WIRES Group. July 2013.

[76] We are not including these types of benefits, but rather limit the discussion to benefits that affect system-wide electricity costs as measure of whether rates paid by consumers are just and reasonable, which we understand is the main focus of FERC and the Federal Power Act.

TABLE 6. TRANSMISSION BENEFITS BEYOND ELECTRICITY SYSTEM IMPACTS

Benefit Category	Transmission Benefit
9. Employment and Economic Stimulus Benefits	Increased employment and economic activity; Increased tax revenues
10. Increased Health Benefits	Lower fossil-fuel burn can result in better air quality

1. Traditional Production Cost Savings

The most commonly used metric for measuring the economic benefits of transmission investments is the reduction in production costs. Production cost savings include savings in fuel and other variable operating costs of power generation that are realized when transmission projects allow for the increased dispatch of suppliers that have lower incremental costs of production, displacing higher-cost supplies. Lower production costs will generally also reduce market prices as lower-cost suppliers will set market clearing prices more frequently than without the transmission project. The tools used to estimate the changes in production costs and wholesale electricity prices are typically security-constrained production cost models that simulate the hourly operations of the electric system and the wholesale electricity market by emulating how system operators would commit and dispatch generation resources to serve load at least cost, subject to transmission and operating constraints.

Within production cost models, changes in system-wide production costs can be estimated readily. These estimated changes, however, do not necessarily capture how costs change within individual regions or utility service areas. This is because the cost of serving these regions and areas will depend not only on the production cost of generating plants within the region or area, but will also depend on the extent to which power is bought from or sold to neighbors. The production costs within individual areas thus need to be "adjusted" for such purchases and sales. This is approximated through a widely used benefit metric referred to as Adjusted Production Cost (APC).

APC for an individual utility is typically calculated as the sum of (1) the production costs of generating resources owned by or contracted to the utility, plus (2) the net cost of the utility's market-based power purchases and sales.[77] The traditional method for estimating the changes

[77] For example, APC for a utility is typically calculated as: (1) the production costs of generating resources owned by or contracted to the utility, plus (2) the cost of market-based power purchases valued at the simulated LMPs

in the APC associated with a proposed transmission project is to compare the adjusted production costs with and without the transmission project. Analysts typically call the market simulations without the transmission project the "Base Case" and the simulations with the transmission project the "Change Case."

2. Additional Production Cost Savings

While production cost simulations are a valuable tool for estimating the economic value of transmission projects and have been used in the industry for many years, the specific practices continue to evolve. RTOs and transmission planners are increasingly recognizing that traditional production cost simulations are quite limited in their ability to estimate the full congestion relief and production cost benefits. These limitations, caused by simplifications in assumptions and modeling approaches, tend to understate the likely future production cost savings associated with transmission projects. As an example, failure to consider transmission's value of diversifying uncertain renewable generation through the transmission system can significantly under-estimate benefits.[78]

This is problematic, as in most cases, the simplified market simulations assume:

- No change in transmission-related energy losses as a result of adding the proposed transmission project;
- No planned or unplanned transmission outages;
- No extreme contingencies, such as multiple or sustained generation and transmission outages;
- Only weather-normalized peak loads and monthly energy (*i.e.*, no typical heat waves, typical cold snaps, or more extreme weather conditions);
- Perfect foresight of all real-time market conditions (*i.e.*, no day-ahead and intra-day forecasting uncertainty of load and renewable generation);
- Incomplete cycling costs of conventional generation;
- Over-simplified modeling of ancillary service-related costs (*e.g.*, assuming all operating reserves are deliverable);

of the utility's load locations (Load LMP), net of (3) the revenues from market-based power sales valued at the simulated LMP of the utility's generation locations (Gen LMP).

78 Pfeifenberger, Ruiz, Van Horn, *The Value of Diversifying Uncertain Renewable Generation through the Transmission System*, BU-ISE, October 14, 2020.

- Incomplete simulation of reliability must-run conditions; and
- Unrealistically optimal system dispatch in non-RTO and "Day-1" markets.

Appendix B provides additional discussion regarding how to quantify the additional production cost savings (items 2.i through 2.x in Table 5 above) that are traditionally missed due to these simplifications.

3. Reliability and Resource Adequacy Benefits

Transmission investments will generally increase the reliability of the electric power system even when meeting reliability standards is not the primary purpose of the line. For example, additional transmission investments made to improve market efficiency and meet public policy goals also increase operating flexibility, reduce the risk of load shed events, and increase options for recovering from supply disruptions. This increase in reliability provides economic value by reducing the frequency, duration, and magnitude of load curtailments—or, alternatively, by reducing the planning reserve margins needed to maintain resource adequacy targets, such as a 1-day-in-10-year loss of load probability. These reliability benefits are not captured in production cost simulations, but can be estimated separately. Below we describe the categories of reliability and resource adequacy benefits.

i. Benefits from Avoided or Deferred Reliability Projects and Aging Infrastructure Replacement

When certain transmission projects are proposed for economic or public policy reasons, transmission upgrades that would otherwise have to be made to address reliability needs or replace aging facilities may be avoided or could be deferred for a number of years. These avoided or deferred reliability upgrades effectively reduce the incremental cost of the planned economic or public-policy projects. These benefits can be estimated by comparing the revenue requirements of reliability-based transmission upgrades without the proposed projects (the Base Case) to the lower revenue requirements reflecting the avoided or delayed reliability-based upgrades assuming the proposed projects would be in place (the Change Case). The present value of the difference in revenue requirements for the reliability projects (including the trajectory of when they are likely to be installed) represents the estimated value of avoiding or deferring certain projects. If the avoided or deferred projects can be identified, then the avoided costs associated with these projects can be counted as a benefit (*i.e.*, cost savings) associated with the proposed new projects.

SPP, for example, uses this method to analyze whether potential reliability upgrades could be deferred or replaced by proposed new economic transmission projects.[79] Similarly, a recent projection of deferred transmission upgrades for a potential portfolio of transmission lines considered by ITC in the Entergy region found the reduction in the present value of reliability project revenue requirements to be $357 million, or 25% of the costs of the proposed new transmission projects.[80] This method has also been used by MISO, which found that the proposed MVP projects would increase the system's overall reliability and decrease the need for future baseline reliability upgrades. In fact, MISO's MVP projects were found to eliminate future transmission investments of one bus tie, two transformers, 131 miles of transmission operating at less than 345 kV, and 29 miles of 345 kV transmission.[81] Similarly, NYISO has found that public policy projects that utilize the right of way of aging existing transmission facilities, often offer the significant benefit of avoiding having to replace the aging facility in the future.[82]

ii. Reduced Loss of Load Probability

Transmission provides tremendous flexibility to ensure reliable service through many situations, both predictable and unpredictable. Even if not targeted to address identified reliability needs, transmission investments can reduce the frequency and severity of necessary load curtailments by providing additional pathways for connecting generation resources with load in regions that can be constrained by weather events and unplanned outages. From a risk mitigation perspective, transmission projects provide insurance value to the system such that when contingencies, emergencies, and extreme market conditions stress the system, having a more robust grid would reduce: (1) the need to rely on high-cost measures to avoid shedding load (a production cost benefit considered in the previous section of this paper); and (2) the likelihood of load shed events, thus improving physical reliability.

Today, North American Reliability Corporation (NERC) sets the minimum requirements of transmission needed to comply with NERC reliability criteria. That is essentially the reliability planning that all transmission owners and planning authorities perform today.

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79 Southwest Power Pool (SPP), *Benefits for the 2013 Regional Cost Allocation Review*, September 13, 2012, Section 3.3.

80 Pfeifenberger, Direct Testimony on behalf of ITC Holdings, Exhibit No. ITC-600, before the Federal Energy Regulatory Commission, Docket Nos. EC12-145 *et al.*, September 24, 2012, pp 77-78.

81 Midwest ISO (MISO), Proposed Multi Value Project Portfolio, Technical Study Task Force and Business Case Workshop, August 22, 2011, pp 42-44.

82 Newell, *et al.* (The Brattle Group), *Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades*, prepared for NYISO and DPS Staff. September 15, 2015.

However, many transmission investments will generally increase the reliability of the electric power system even when meeting reliability standards is not the primary purpose of the line. Additional transmission investments made for market efficiency and public policy goals help to avoid or defer reliability upgrades that would otherwise be necessary, increase operating flexibility, reduce the risk of load shed events, and increase options for recovering from supply disruptions. This increase in reliability provides economic value by reducing the frequency, duration, and magnitude of load curtailments—or, alternatively, by reducing the planning reserve margins needed to maintain resource adequacy targets, such as a 1-day-in-10-year loss of load probability. Transmission's reduction in the required planning reserve margin accounted for a large share of the quantified transmission benefits in the MISO, SPP, and PJM studies discussed earlier in this section. These reliability benefits are not captured in production cost simulations, but can be estimated separately.

As recognized by SPP's Metrics Task Force, for example, such reliability benefits can be estimated through Monte Carlo simulations of systems under a wide range of load and outage conditions to obtain loss-of-load related reliability metrics, such as Loss of Load Hours (LOLH), Loss of Load Expectation (LOLE), and Expected Unserved Energy (EUE).[83] The reliability benefit of transmission investments can be estimated by multiplying the estimated reduction in EUE (in MWh) by the customer-weighted average Value of Lost Load (VOLL, in $/MWh). Estimates of the average VOLL can exceed $5,000 to $10,000 per curtailed MWh. The high value of lost load means that avoiding even a single reliability event that would have resulted in a blackout would be worth tens of millions to billions of dollars. As ATC notes, for example, had its Arrowhead-Weston line been built earlier, it would have reduced the impact of blackouts in the region.[84]

London Economics performed a similar study for hypothetical lines in the Western and Eastern Interconnects.[85] The study found over a single year period, under constrained system operating conditions, electric consumers are projected to save as much as $1.3 billion in PJM and $740

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[83] Southwest Power Pool (SPP), *Benefits for the 2013 Regional Cost Allocation Review*, September 13, 2012, Section 5.2.

LOLH measures the expected number of hours in which load shedding will occur. LOLE is a metric that accounts for the expected number of days, hours, or events during which load needs to be shed due to generation shortages. And EUE is calculated as the probability-weighted MWh of load that would be unserved during loss-of-load events.

[84] American Transmission Company LLC (ATC), *Arrowhead-Weston Transmission Line: Benefits Report*, February 2009.

[85] J. Frayer, E. Wang, R. Wang, *et al.*(London Economics International, Inc.), *How Does Electric Transmission Benefit You?: Identifying and Measuring the Life-Cycle Benefits of Infrastructure Investment*, A WIRES report, January 8, 2018.

million in MISO with the 1,300 MW Eastern Interconnect project. This is equal to savings of about $20 (in MISO) to $40 (PJM) on a typical household's annual electricity utility bill in the affected regions. As the authors note, "Although benefits of transmission investment are based on a simulation, they are nevertheless measurable and quantifiable."[86]

iii. Lower Planning Reserve Margins

When a transmission investment reduces the loss of load probabilities, system operators can reduce their resource adequacy requirements, in terms of the system-wide required planning reserve margin or the required reserve margins within individual resource adequacy zones of the region. If system operators choose to reduce resource adequacy requirements, the benefit associated with such reduction can be measured in terms of the reduced capital cost of generation. Effectively, the reduced cost would be estimated by calculating the difference in the cost of generation needed under the required reserve margins before adding the new transmission projects versus the cost of generation with the lower required reserve margins after adding the new transmission. Transmission investments tend to either reduce loss-of-load events (if the planning reserve margin is unchanged) or allow for the reduction in planning reserve margins (if holding loss-of-load events constant), but not both simultaneously.[87]

Using transmission to aggregate diverse loads allows peak electricity demand to be met with less generating capacity, as localized peaks in demand can be met using surplus generating capacity from other areas that are not experiencing peak demand at the same time. For example, the June 2021 West Coast heat wave was quantified as a 1-in-1000 year event in the Pacific Northwest,[88] yet grid operators were able to keep the lights on because the heat wave most severely affected California and the Pacific Northwest at different times, allowing each region to meet load using imports from the other region that were only possible because of sufficient transmission interconnection.

Load diversity is primarily driven by regional differences in weather and climate, and to some extent by time zone diversity across very large east-west aggregations of load. Climate diversity benefits occur in all regions, but are particularly pronounced in regions, like the Northwest and

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86 *Id.* p 43.

87 This is due to the overlap between the benefit obtained from a reduction in reserve margin requirements and the benefit associated with a reduced loss-of-load probability (if the reserve margin requirement is not adjusted). Only one of these benefits is typically realized.

88 R. Lindsey, "*Preliminary analysis concludes Pacific Northwest heat wave was a 1,000-year event…hopefully*," *Climate.gov*, July 20, 2021.

Southeast, that contain both winter-peaking and summer-peaking power systems. Transmission's ability to access weather diversity is also very valuable, particularly during severe weather events that tend to be at their most extreme across a relatively small footprint.[89] There are inherent diversity benefits from larger aggregations of load, as the variability in usage from even very large industrial loads is cancelled out.

The potential for transmission investments to reduce the reserve margin requirement has been recognized by a number of system operators. MISO recently estimated through LOLE reliability simulations that its MVP portfolio is expected to reduce required planning reserve margins by up to one percentage point. Such reduction in planning reserves translated into reduced generation capital investment needs ranging from $1.0 billion to $5.1 billion in present value terms, accounting for 10–30% of total MVP project costs.[90] This benefit was similarly recognized by the SPP Metrics Task Force,[91] as well as by the Public Service Commission of Wisconsin, which noted that "the addition of new transmission capacity strengthening Wisconsin's interstate connections" was one of three factors that allowed it to reduce the planning reserve margin requirements of Wisconsin utilities from 18% to 14.5%.[92]

As shown below, SPP's Value of Transmission report found its recent transmission investments provide an assumed two percent reduction in SPP's planning reserve margin, yielding 40-year net present value savings of $1.34 billion from reduced generating capacity costs, in addition to $92 million in net present value from a reduced need for generating capacity due to lower on-peak transmission losses.[93] MISO analysis shows that a lower need for capacity due to load diversity saves $1.9–$2.5 billion annually, nearly two-thirds of the RTO's total value proposition of $3.1–$3.9 billion annually.[94] Notably, this is 4–5 times larger than the roughly $500 million

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89 M. Goggin (Grid Strategies, LLC), *Transmission Makes the Power System Resilient to Extreme Weather*, Prepared for ACORE, with Support from the Macro Grid Initiative, July 2020.

90 Midwest ISO (MISO), *Proposed Multi Value Project Portfolio*, Technical Study Task Force and Business Case Workshop, August 22, 2011, pp 34-36.

91 Southwest Power Pool (SPP), *Benefits for the 2013 Regional Cost Allocation Review*, September 13, 2012, Section 5.1.

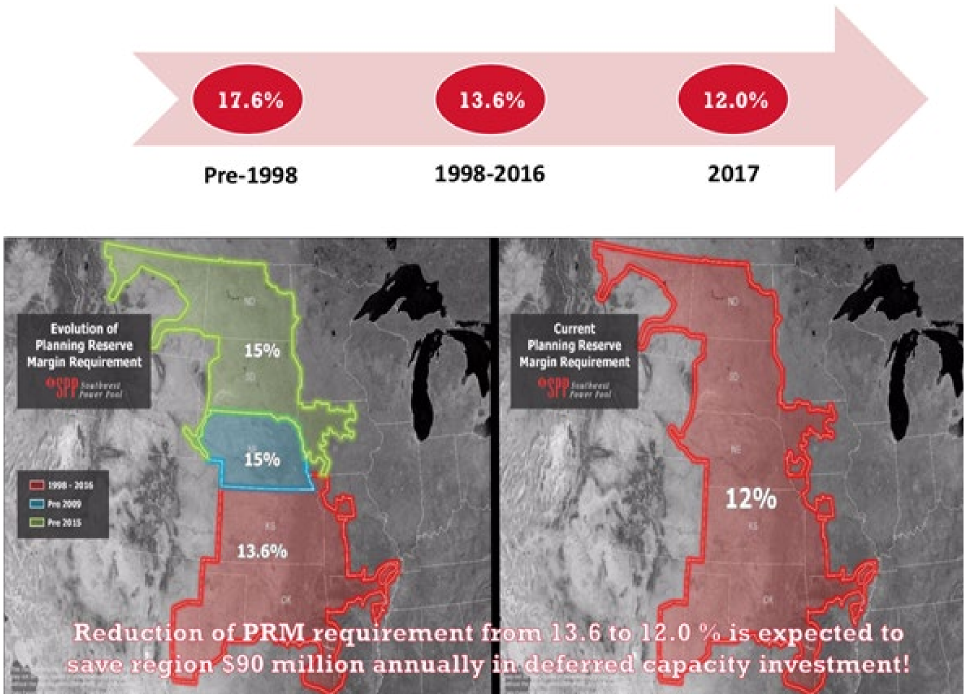
92 Public Service Commission (PSC) of Wisconsin (WI), *Order*, re Investigation on the Commission's Own Motion to Review the 18 Percent Planning Reserve Margin Requirement, Docket 5-EI-141, PSC REF#:102692, dated October 9, 2008, received October 11, 2008, p 5. Two other changes that contributed to this decision were the introduction of the Midwest ISO as a security constrained independent dispatcher of electricity and the development of additional generation in the state.

93 Southwest Power Pool (SPP), *The Value of Transmission*, January 26, 2016, p. 16.

94 MISO, *MISO Value Proposition 2020*, Detailed Circulation Description, n.d., p. 22.

annual benefit from being able to make use of higher quality wind resources. Similarly, PJM finds annual savings of $1.2–$1.8 billion from regional load diversity.[95]

FIGURE 6. SPP RESERVE MARGIN EVOLUTION



Source: L. Nickell (SPP), *Resource Adequacy in SPP*, Spring 2017 Joint CREPC-WIRAB Meeting, April 2017, slides 10 and 14.

As noted above, there is additional benefit when considering severe weather and unusual grid situations. For example, this year's winter storm Uri presented a situation where a variety of generation sources in the Central region were incapacitated. MISO was able to import 13 GW from the East and deliver some of that to SPP to the West. Both of those regions largely avoided blackouts. Interestingly, the lines that were used to ship power from the East to the West were the MISO MVP lines that had originally been justified and cost allocated on the assumption of West-to-East prevailing flow, illustrating the broad reliability benefits that result from interregional transmission. ERCOT which covers most of Texas, on the other hand, had only a maximum of 0.8 GW of import capability, which limited its ability to import power, to catastrophic effect.

Another way to quantify reliability benefit is to look back to an extreme event where reliability was compromised and consider the value of hypothetical lines. In a recent example, one such

[95] PJM, *Value Proposition*, 2019, p 2.

study found that an additional GW of delivery capacity into Texas during winter storm Uri would have fully paid for itself over the course of the four-day event.[96] The same study found that an additional GW of capacity into MISO from the East would have earned $100 million during that short period of time.

Transmission also provides a reliability benefit in the form of dynamic stability. The MISO RIIA study, for example, evaluated dynamic stability needs at a range of renewable energy penetration levels.[97] At 40% renewables, MISO found weak grid issues. As synchronous generators retire, significant HVDC was added to mitigate these issues.

4. Generation Capacity Value

Transmission investments can reduce generation investment costs beyond those related to increasing the reliability benefits and reduced reserve margin requirements. Transmission upgrades can also reduce generation capacity costs in the form of: (1) lowering generation investment needs by reducing losses during peak load conditions; (2) delaying needed new generation investment by allowing for additional imports from neighboring regions with surplus capacity; and (3) providing the infrastructure that allows for the development and integration of lower-cost generation resources. Below, we discuss each of these three benefits.

i. Capacity Cost Benefits from Reduced Transmission Losses

Investments in transmission often reduce generation investment needs by reducing system-wide energy losses during peak load conditions. This benefit is in addition to the production cost savings associated with reduced energy losses. During peak hours, a reduction in energy losses will reduce the additional generation capacity needed to meet the peak load, transmission losses, and reserve margin requirements. For example, in a system with a 15% planning reserve margin, a 100 MW reduction in peak-hour losses will reduce installed generating capacity needs by 115 MW.

The economic value of reduced losses during peak system conditions can be estimated through calculating the capital cost savings associated with the reduction in installed generation requirements. These capital cost savings can be calculated by multiplying the estimated net

[96] M. Goggin (Grid Strategies, LLC), *Transmission Makes the Power System Resilient to Extreme Weather*, Prepared for ACORE, with Support from the Macro Grid Initiative, July 2020.

[97] MISO, *MISO's Renewable Integration Impact Assessment (RIIA)*, Summary Report, February 2021.

cost of new entry (Net CONE), which is the cost of new generating capacity net of operating margins earned in energy and ancillary services markets when the region is resource-constrained, with the reduction in installed capacity requirements.[98]

Several planning regions have estimated the capacity cost savings associated with loss reductions due to transmission investments:

- SPP's evaluation of its Priority Projects showed $92 million in net present value capacity savings from reduced losses, or 3% of total project costs.[99]
- ATC found that its Paddock-Rockdale project provided an estimated $15 million in capacity savings benefits from reduced losses, or approximately 10% of total project costs.[100]
- MISO found that its MVP portfolio reduced transmission losses during system peak by approximately 150 MW, thereby reducing the need for future generation investments with a present value benefit in the range of $111 to $396 million, offsetting 1–2% of project costs.[101]
- An analysis of potential transmission projects in the Entergy footprint showed that the projects could reduce peak-period transmission losses by 32 MW to 49 MW, offering a benefit of approximately $50 million in reduced generating investment costs, offsetting approximately 2% of total project costs.[102]

ii. Deferred Generation Capacity Investments

Transmission projects can defer generation investment needs in resource-constrained areas by increasing the transfer capabilities from neighboring regions with surplus generation capacity. For example, an analysis for ITC of potential transmission projects in the Texas portion of Entergy's service area showed that the transmission projects provide increased import

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[98] Net CONE is an estimate of the annualized fixed cost of a new natural gas plant, net of its energy and ancillary service market profits. Fixed costs include both the recovery of the initial investment as well as the ongoing fixed operating costs of a new plant. This is an estimate of the capacity price that a utility or other buyer would have to pay each year—in addition to the market price for energy—for a contract that could finance a new generating plant.

[99] Southwest Power Pool, *SPP Priority Projects Phase II Report, Rev. 1*, April 27, 2010, p 26.

[100] American Transmission Company LLC (ATC), *Planning Analysis of the Paddock-Rockdale Project*, April 5, 2007 (filed in PSCW Docket 137-CE-149, PSC Reference # 75598), pp 4, 63.

[101] Midwest ISO (MISO), *Proposed Multi Value Project Portfolio*, Technical Study Task Force and Business Case Workshop, August 22, 2011, pp 25 and 27.

[102] Pfeifenberger, Direct Testimony on behalf of ITC Holdings, Exhibit No. ITC-600, before the Federal Energy Regulatory Commission, Docket Nos. EC12-145 *et al.*, September 24, 2012, pp 58-59.

capability from Louisiana and Arkansas. The imports allow surplus generating capacity in those regions to be delivered into Entergy's resource-constrained Texas service area, thereby deferring the need for building additional local generation. By doing so, existing power plants that have the option to serve the Entergy Texas service area and the rest of Texas (the ERCOT region) would be able to serve the resource-constrained ERCOT region, thereby addressing ERCOT resource adequacy challenges. The economy-wide benefit of the deferred generation investments was estimated at $320 million, about half of which was estimated to accrue to customers in Texas, with the other half of the benefit to accrue to merchant generators in Louisiana and Arkansas.[103] A similar analysis also identified approximately $400 million in resource adequacy benefits from deferred generation investments associated with a transmission project that increases the transfer capability from Entergy's Arkansas and Louisiana footprint to TVA. These overall economy-wide benefits would accrue to a combination of TVA customers, Arkansas and Louisiana merchant generators, and, through increased MISO wheeling-out revenues, Entergy and other MISO transmission customers.

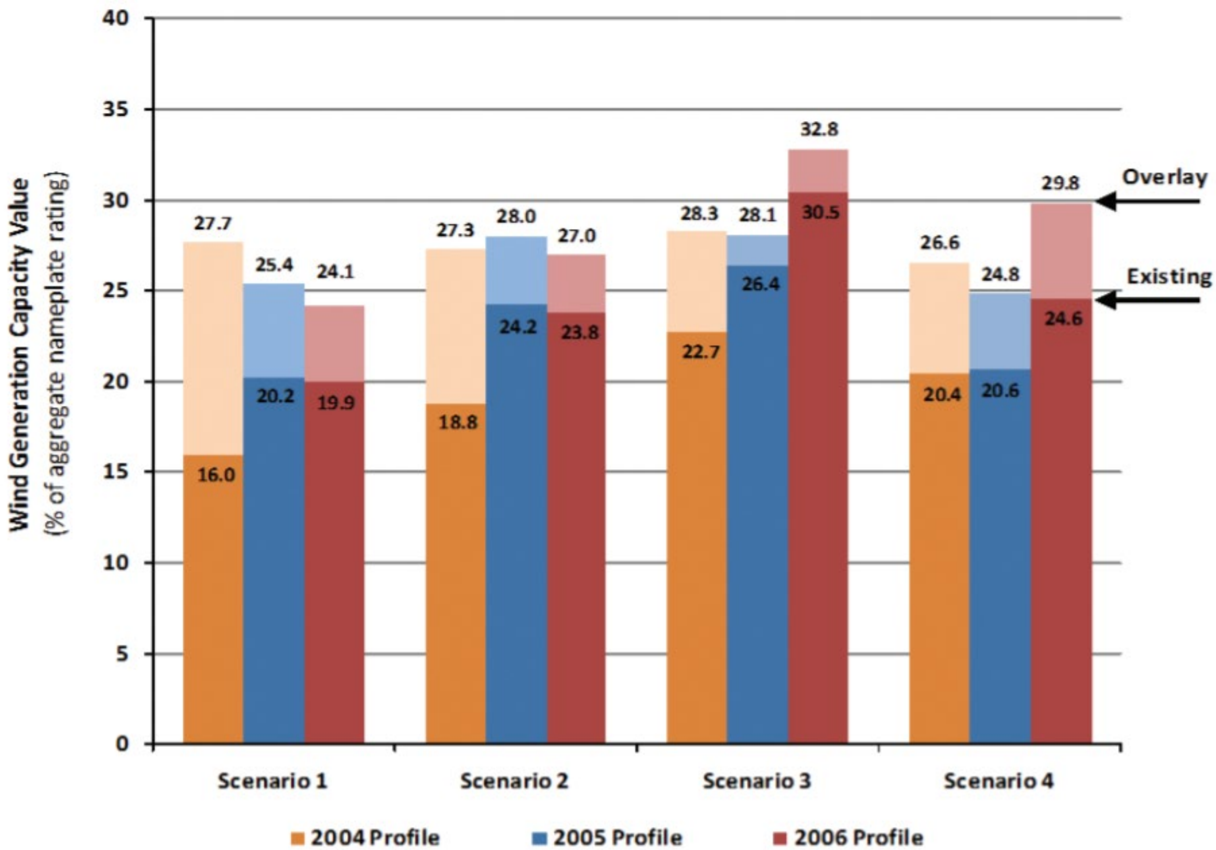
Transmission can increase the capacity value of existing resources, particularly wind and solar resources due to their geographic diversity. Higher capacity values reduce system (generation plus transmission) costs and increase net benefits. In the chart below from the Eastern Wind Integration and Transmission Study (EWITS),[104] higher wind capacity values of a few percentage points are achievable with the transmission "overlay" versus the "existing" grid. Other studies indicate even larger resource adequacy benefits from aggregating diverse renewable resources and loads.[105]

[103] *Id.*, pp 69.

[104] Enernex Corporation, *Eastern Wind Integration and Transmission Study*, prepared for The National Renewable Energy Laboratory (U.S. Department of Energy), NREL/SR-550-47078, January 2010.

[105] Energy and Environmental Economics, Inc., *Resource Adequacy in the Pacific Northwest*, March 2019.

FIGURE 7. ELCC RESULTS FOR HIGH PENETRATION SCENARIOS, WITH AND WITHOUT TRANSMISSION OVERLAYS



Source: EnerNex Corporation, *Eastern Wind Integration and Transmission Study*, prepared for The National Renewable Energy Laboratory (NREL), Revised February 2011, p 54

iii. Access to Lower-Cost Generating Resources

Some transmission investments increase access to generation resources located in low-cost areas. Generation developed in these areas may be low cost due to low permitting costs, low-cost sites on which plants can be built (*e.g.*, low-cost land and/or sites with easy access to existing infrastructure), low labor costs, low fuel costs (*e.g.*, mine mouth coal plants and natural gas plants built in locations that offer unique cost advantages), access to valuable natural resources (*e.g.*, hydroelectric or pumped storage options), locations with high-quality renewable energy resources (*e.g.*, wind, solar, geothermal, biomass), or low environmental costs (*e.g.*, low-cost carbon sequestration and storage options).

While production cost simulations can capture cost savings from fuel and variable operating costs if the different locational choices are correctly reflected in the Base and Change Case simulations, the simulations would still not capture the lower overall generation investment costs. To the extent that transmission investments provide access to locations that offer generation options with lower capital costs, these benefits need to be estimated through separate analyses. At times, to accurately capture the production cost savings of such options may require that a different generation mix is specified in the production cost simulations for the Base Case (*e.g.*, with generation located in lower-quality or higher-cost locations) and the Change Case *(e.g.*, with more generation located in higher-quality or lower-cost locations).

The benefits from transmission investments that provide improved access to lower-cost generating resources can be significant from both an economy-wide and electricity customer perspective. For example, the CAISO found that the Palo Verde-Devers transmission project was providing an additional link between Arizona and California that would have allowed California resource adequacy requirements to be met through the development of lower-cost new generation in Arizona.[106] The capital cost savings were estimated at $12 million per year from an economy-wide (*i.e.*, societal) perspective, or approximately 15% of the transmission project's cost, half of which it was assumed would accrue to California electricity customers. Similarly, ATC found that its Paddock-Rockdale transmission line enabled Wisconsin utilities to serve their growing load by building coal or IGCC generating capacity at mine-mouth coal sites in Illinois instead of building new plants in Wisconsin.[107] The analysis found that sites in Illinois offered significantly lower fuel costs (or, in the future, potentially lower carbon sequestration costs) and that the transmission investment likely reduced the total cost of serving Wisconsin load compared to new resources developed within Wisconsin.

Access to a lower-cost generation option can significantly reduce the cost of meeting public-policy requirements. For example, as discussed further under "public-policy benefits," the MISO evaluated different combinations of transmission investments and wind generation build-out options, ranging from low-quality wind locations that require less transmission investment to high-quality wind locations that require more transmission investment.[108] This analysis found that the total system costs could be significantly reduced through an optimized combination of transmission and wind generation investments that allowed a portion of total renewable energy needs to be met by wind generation in high-quality, low-cost locations. Similarly, the CREZ projects in Texas have provided new opportunities for fossil generation plants to be located away from densely populated load centers where it may be difficult to find suitable

[106] California ISO (CAISO) Department of Market Analysis & Grid Planning, *Board Report: Economic Evaluation of the Palo Verde-Devers Line No. 2 (PVD2)*, February 24, 2005, pp 25-26.

[107] American Transmission Company LLC (ATC) (2007), *Planning Analysis of the Paddock-Rockdale Project*, April 5, 2007, pp 54-55.

[108] Midwest ISO, *RGOS: Regional Generation Outlet Study*, November 19, 2010, p 32 and Appendix A.

sites for new generation facilities, where environmental limitations prevent the development of new plants, or where developing such generation is significantly more costly.

5. Market Benefits

Transmission expands the geographic reach of electric power markets, increasing competition, and reducing system costs. Transmission projects provide additional market benefits, both from an economy-wide and electricity customer rate perspective, by increasing competition in and the liquidity of wholesale power markets. As noted by Dr. Frank Wolak of Stanford University:

> Expansion of the transmission network typically increases the number of independent wholesale electricity suppliers that are able to compete to supply electricity at locations in the transmission network served by the upgrade...With the exception of the U.S., most countries re-structured at a time when they had significant excess transmission capacity, so the issue of how to expand the transmission network to serve the best interests of wholesale market participants has not yet become significant. In the U.S., determining how to expand the transmission network to serve the needs of wholesale market participants has been a major stumbling block to realizing the expected benefits of electricity industry re-structuring.[109]

i. Benefits of Increased Competition

Production cost simulations generally assume that generation is bid into wholesale markets at its variable operating costs. This assumption does not consider that some bids will include markups over variable costs, particularly in real-world wholesale power markets that are less than perfectly competitive. For this reason, the production cost and market price benefits associated with transmission investments could exceed the benefits quantified in cost-based simulations. This will be particularly true for transmission projects that expand access to broader geographic markets and allow more suppliers than otherwise to compete in the regional power market.[110]

[109] F. A. Wolak, "*Managing Unilateral Market Power in Electricity*," Policy Research Working Paper; No. 3691. World Bank, Washington, DC, 2005.p 8.

[110] Such effects are most pronounced during tight market conditions. Specifically, enlarging the market by transmission lines that increase transfer capability across multiple markets can decrease suppliers' market power and reduce overall market concentration. The overall magnitude of benefits from increased competition

A lack of transmission to ensure competitive wholesale markets can be particularly costly to customers. For example, the Chair of the CAISO's Market Surveillance Committee estimated that if significant additional transmission capacity had been available during the California energy crisis from June 2000 to June 2001, electricity customer costs would have been reduced by up to $30 billion over the 12-month period during which the crisis occurred.[111] More recently, ISO New England noted that increased transmission capacity into constrained areas such as Connecticut and Boston have significantly reduced congestion, "thereby significantly reducing the likelihood that resources in the submarkets could exercise market power."[112]

Given the experience during the California Power Crisis, the ability of transmission investment to increase competition in wholesale power markets has been considered explicitly in the CAISO's review of several proposed new transmission projects. For example, in its evaluation of the proposed Palo Verde-Devers transmission project, the CAISO noted that the "line will significantly augment the transmission infrastructure that is critical to support competitive wholesale energy markets for California consumers" and estimated that increased competition would provide $28 million in additional annual consumer and "modified societal" benefits, offsetting approximately 40% of the annualized project costs.[113] Similarly, in its evaluation of the Path 26 Upgrade transmission projects, the CAISO estimated the expected value of competitiveness benefits could offset up to 50 to 100% of the project costs, with a range depending on project costs and assumed future market conditions.[114] A similar analysis was performed for ATC's Paddock-Rockdale line, estimating that the benefits of increased competition would offset between 10 to 40% of the project costs, depending on assumed market structure and supplier behavior.[115]

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can range widely, from a small fraction to multiples of the simulated production cost savings, depending on: (1) the portion of load served by cost-of-service generation; (2) the generation mix and load obligations of market-based suppliers; and (3) the extent and effectiveness by which RTOs' market power mitigation rules yield competitive outcomes.

[111] California ISO, *Transmission Economic Assessment Methodology (TEAM)*, June 2004, pp ES-9.

[112] Federal Energy Regulatory Commission, *2011 Performance Metrics for Independent System Operators and Regional Transmission Organizations*, A Report to Congress in Response to Recommendations of the United States Government Accountability Office, April 7, 2011.

[113] California ISO (CAISO) Department of Market Analysis & Grid Planning, *Board Report: Economic Evaluation of the Palo Verde-Devers Line No. 2 (PVD2)*, February 24, 2005, pp 18 and 27. Under the "modified societal perspective" of the CAISO TEAM approach, producer benefits include net generator profits from competitive market conditions only. This modified societal perspective excludes generator profits due to uncompetitive market conditions.

[114] California ISO, *Transmission Economic Assessment Methodology (TEAM)*, June 2004.

[115] Pfeifenberger, Direct Testimony on behalf of American Transmission Company, before the Public Service Commission of Wisconsin, Docket 137-CE-149, January 17, 2008; and American Transmission Company LLC

ii. Benefits of Increased Market Liquidity

Limited liquidity in the wholesale electricity markets imposes higher transaction costs and price uncertainty on both buyers and sellers. Transmission expansions can increase market liquidity by increasing the number of buyers and sellers able to transact with each other, which in turn will reduce the transaction costs (*e.g.*, bid-ask spreads) of bilateral transactions, increase pricing transparency, increase the efficiency of risk management, improve contracting, and provide better clarity for long-term planning and investment decisions.

Estimating the value of increased liquidity is challenging, but the benefits can be sizeable in terms of increased market efficiency and thus reduced economy-wide costs. For example, the bid-ask spreads for bilateral trades at less liquid hubs have been found to be between $0.50 to $1.50/MWh higher than the bid-ask spreads at more liquid hubs.[116] At transaction volumes ranging from less than 10 million to over 100 million MWh per quarter at each of more than 30 electricity trading hubs in the U.S., even a $0.10/MWh reduction of bid-ask spreads due to a transmission-investment-related increase in market liquidity would save $4 million to $40 million per year for a single trading hub, which would amount to a transactions cost savings of approximately $500 million annually on a nation-wide basis.

6. Environmental Benefits

Depending on the effects of transmission expansions on the overall generation dispatch, some projects can reduce harmful emissions (*e.g.,* SO_2, NO_x, particulates, mercury, and greenhouse gases) by avoiding the dispatch of high-emissions generation resources. The benefits of reduced emissions with a market pricing mechanism are largely calculated in production cost simulations for pollutants with emissions prices such as SO_2 and NO_x. However, for pollutants that do not have a pricing mechanism yet, such as CO_2 in some regions, production cost simulations do not directly capture such environmental benefits unless specific assumptions about future emissions costs are incorporated into the simulations.

Not every proposed transmission project will necessarily provide environmental benefits. Some transmission investments can be environmentally neutral or even displace clean but more

(ATC), *Planning Analysis of the Paddock-Rockdale Project*, April 5, 2007 (filed in PSCW Docket 137-CE-149, PSC Reference # 75598C), pp 44-47.

116 Pfeifenberger, Oral Testimony on behalf of Southern California Edison Company re economic impacts of the proposed Devers-Palo Verde No. 2 transmission line, before the Arizona Power Plant and Transmission Line Siting Committee, Docket No. L-00000A-06-0295-00130, Case No. 130, September and October, 2006

expensive generation (*e.g.*, displacing natural gas-fired generation when gas prices are high) with lower-cost but higher-emissions generation. In some instances, a reduction in local emissions may be valuable (*e.g.*, reduced ozone and particulates) but not result in reduced regional (or national) emissions due to a cap and trade program that already limits the total of allowed emissions in the region. Nevertheless, even if specific transmission projects do not reduce the overall emissions, they may affect the costs of emissions allowances which in turn could affect the cost of delivered power to customers.

As more and more transmission projects are proposed to interconnect and better integrate renewable resources, some project proponents have quantified specific emissions reductions associated with those projects. For example, Southern California Edison estimated that the proposed Palo Verde-Devers No. 2 project would reduce annual NO_x emissions in WECC by approximately 390 tons and CO_2 emissions by about 360,000 tons per year. These emissions reductions were estimated to be worth in the range of $1 million to $10 million per year.[117] Similarly, an analysis of a portfolio of transmission projects in the Entergy service area estimated that the congestion and RMR relief provided by the projects would eliminate approximately one million tons of CO_2 emissions from fossil-fuel generators every year.[118] That estimated emissions reduction is equivalent to removing the annual CO_2 emissions from over 200,000 cars.

7. Public Policy Benefits

Some transmission projects can help regions reduce the cost of reaching public-policy goals, such as meeting the region's renewable energy targets by facilitating the integration of lower-cost renewable resources located in remote areas; while enlarging markets by interconnecting regions can also decrease a region's cost of balancing intermittent renewable resources.

As an illustration of these savings, transmission investments that allow the integration of wind generation in locations with a 40% average annual capacity factor can reduce the investment cost of wind generation by *one quarter* for the same amount of renewable energy produced compared to the investment costs of wind generation in locations with a 30% capacity factor.[119]

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[117] California ISO (CAISO) Department of Market Analysis & Grid Planning, *Board Report: Economic Evaluation of the Palo Verde-Devers Line No. 2 (PVD2)*, February 24, 2005, pp 26.

[118] Pfeifenberger, Direct Testimony on behalf of ITC Holdings, Exhibit No. ITC-600, before the Federal Energy Regulatory Commission, Docket Nos. EC12-145 *et al.*, September 24, 2012, pp 83.

[119] Burns & McDonnell Engineering Company, Inc., *Wind Energy Transmission Economics Assessment*, prepared for WPPI Energy, Project No. 55056, March 2010, pp 1–2, Figure 2.

Access to higher quality wind resources will reduce both economy-wide and electricity customer costs if the higher-quality wind resources can be integrated with additional transmission investment of less than the benefit, estimated to be $500 to $700 per kW of installed wind capacity.

As noted earlier, the MISO has assessed this benefit by evaluating different combinations of transmission investments and wind generation build-out options. The MISO analysis shows that the total cost of wind plants and transmission can be reduced from over $110 billion for either all local or all regional wind resources to $80 billion for a combination of local and regional wind development. The savings achieved from an optimized combination of local and regional wind and transmission investment would be over $30 billion.[120] These cost savings could be achieved by increasing the transmission investment per kW of wind generation from $422/kW in the all-local-wind case to $597/kW in the lowest-total-cost case.

A similar analysis was carried over into MISO's analysis of its portfolio of multi-value projects, which were targeted to help the Midwestern states meet their renewable energy goals. By facilitating the integration of high-quality wind resources, MISO's initial analysis found that its MVP portfolio reduced the present value of wind generation investments by between $1.4 billion and $2.5 billion, offsetting approximately 15% of the transmission project costs.[121] Similarly, ATC found that its Arrowhead-Weston transmission project has the capability to deliver hydro resources from Canada and wind power from the Dakotas and interconnect local renewable generation to help meet Wisconsin's RPS requirement.[122]

Additional transmission investment can help reduce the cost associated with balancing intermittent resources. Interconnecting regions and expanding the grid allow a region to simultaneously access a more diverse set of intermittent resources than smaller systems. Such diversity would reduce the cost of balancing the system due to the "self-balancing" effect of generation output diversity and the larger pool of conventional resources that are available to compensate for the variable and uncertain nature of intermittent resources. The associated savings can be estimated in terms of the reduction of the balancing resources required (which is a fixed cost reduction) and a more efficient unit-commitment and system operation (which includes a variable cost reduction). If less generating capacity from conventional generation is

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120 Midwest ISO (MISO), *RGOS: Regional Generation Outlet Study*, November 19, 2010, p 32 and Appendix A.

121 Midwest ISO (MISO), *Proposed Multi Value Project Portfolio*, Technical Study Task Force and Business Case Workshop, August 22, 2011, pp 25 and 38-41.

122 American Transmission Company LLC (ATC), *Arrowhead-Weston Transmission Line: Benefits Report*, February 2009, p 7.

needed, the reduction in capacity costs can be estimated using the Net Cost of New Entry. For the potential reduction in the operational costs associated with balancing renewable resources, if we assume that the renewable generation balancing benefit of an expanded regional grid reduces balancing costs by only $1/MWh of wind generation, the annual savings associated with 10,000 MW of wind generation at 30% capacity factor would exceed $25 million.

To summarize, even though making significant transmission investments to gain access to remotely located renewable resources seems to increase the cost of delivering renewable generation, the savings associated with reducing the renewable generation costs (by obtaining access to high quality renewable resources), reducing the system balancing costs, and achieving other reliability and economic benefits can exceed the incremental cost of those transmission projects. In such cases, despite the fact that both transmission and retail electricity rates may increase, the transmission investment can reduce the overall cost of satisfying public policy goals.[123] While this rationale will not apply to every public-policy-driven transmission project, it is instructive to consider these benefits and, if needed, estimate all potential benefits when evaluating large regional transmission investments.

8. Other Benefits

Some transmission investments can create additional benefits that are very specific to the particular set of projects. These benefits may include improved storm hardening and wild-fire resilience, increased load-serving capability, synergies with future transmission projects, the option value of large transmission facilities to improve future utilization of available transmission corridors, fuel diversity benefits, increased resource planning and system operational flexibility, increased wheeling revenues, and the creation of additional physical or financial transmission rights to improve congestion hedging opportunities. Please see Appendix C for more details.

b. Multi-Value Planning Examples

As Table 4 has summarized in the beginning of this section, significant experience with multi-value transmission planning already exists within SPP, MISO, CAISO, and NYISO.

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[123] In developing public policy goals, state or federal policy makers may have identified benefits inherent in the policies that are not necessarily economic or immediate. For the evaluation of public policy transmission projects, however, the objective is not to assess the benefits and costs of the public policy goal, but the extent to which transmission investments can reduce the overall cost of meeting the public policy goal.

1. SPP Integrated Transmission Planning (ITP), Metrics Task Force (MTF), and Regional Cost Allocation Review (RCAR)

The ITP efforts by SPP have moved toward examining a range of transmission-related benefits in its transmission project evaluations, which included: production cost savings, reduced transmission losses, wind revenue impacts, natural gas market benefits, reliability benefits, and economic stimulus benefits of transmission and wind generation construction. Along with the benefits for which monetary values were estimated, the SPP's Economic Studies Working Group agreed that a number of transmission benefits that require further analysis include, enabling future markets, storm hardening, Improving operating practices/maintenance schedules, lowering reliability margins, improving dynamic performance and grid stability during extreme events, societal economic benefits.

Later, to support cost allocation efforts, SPP's MTF further expanded SPP's frameworks for estimating additional transmission benefits to include the value of reduced energy losses, the mitigation of transmission outage-related costs, the reduced cost of extreme events, the value of reduced planning reserve margins or the loss of load probabilities, the increased wheeling through and out of revenues (which can offset a portion of transmission costs that need to be recovered from SPP's internal loads), and the value of meeting public-policy goals. SPP's MTF also recommended further evaluation of methodologies to estimate the value of other benefits such as the mitigation of costs associated with weather uncertainty and the reduced cycling of baseload generating units.

SPP's Regional Cost Allocation Review has further expanded the scope of benefits to include avoided or delayed reliability projects, capacity savings due to reduced on-peak transmission losses, transmission outage cost savings, and marginal energy loss benefits.[124]

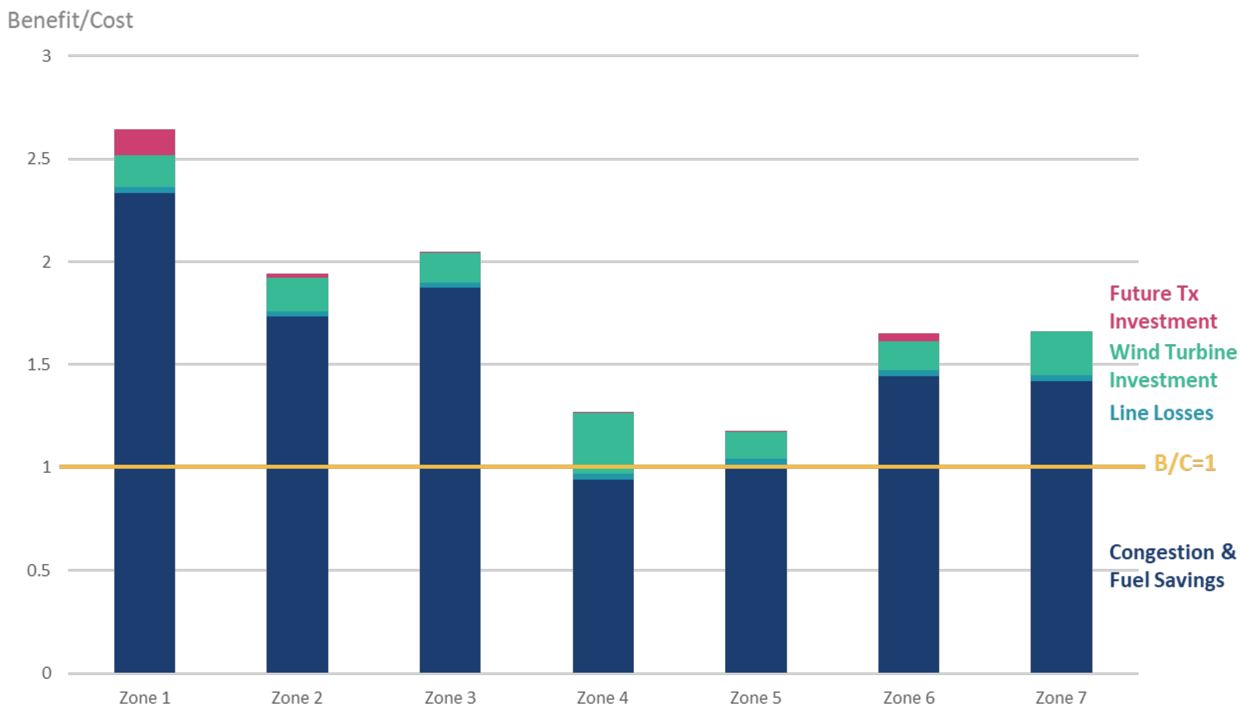
2. MISO Multi Value Projects (MVP)

MISO's evaluation and development of its MVP portfolio is a good example of a pro-active planning process that considered multiple benefits. The quantified benefits included: (1) congestion and fuel cost savings; (2) reduced costs of operating reserves; (3) reduced planning reserve margin requirements; (4) deferred generation investment needs due to

[124] Southwest Power Pool (SPP), *Regional Cost Allocation Review (RCAR II)*, July 11, 2016.

reduced on-peak transmission losses; (5) reduced renewable investment costs to meet public policy goals; and (6) reduced other future transmission investments. When approving projects in 2011, the MISO board of directors based their approval on the need to support a variety of state energy policies, to maintain reliability, and to obtain economic benefits in excess of costs. The $6.6 billion worth of MVP projects that resulted are now estimated to provide economic net-benefits of $7.3 to $39 billion over the next 20 to 40 years, which (as shown in Figure 8) produces net benefits in each of MISO's planning zones.[125]

FIGURE 8. MISO MVP BENEFITS BY ZONE



Source: Low range 20 year NPV from MISO, MTEP19 MVP Limited Review Report, 2019.

3. New York Public Policy Transmission Planning Process

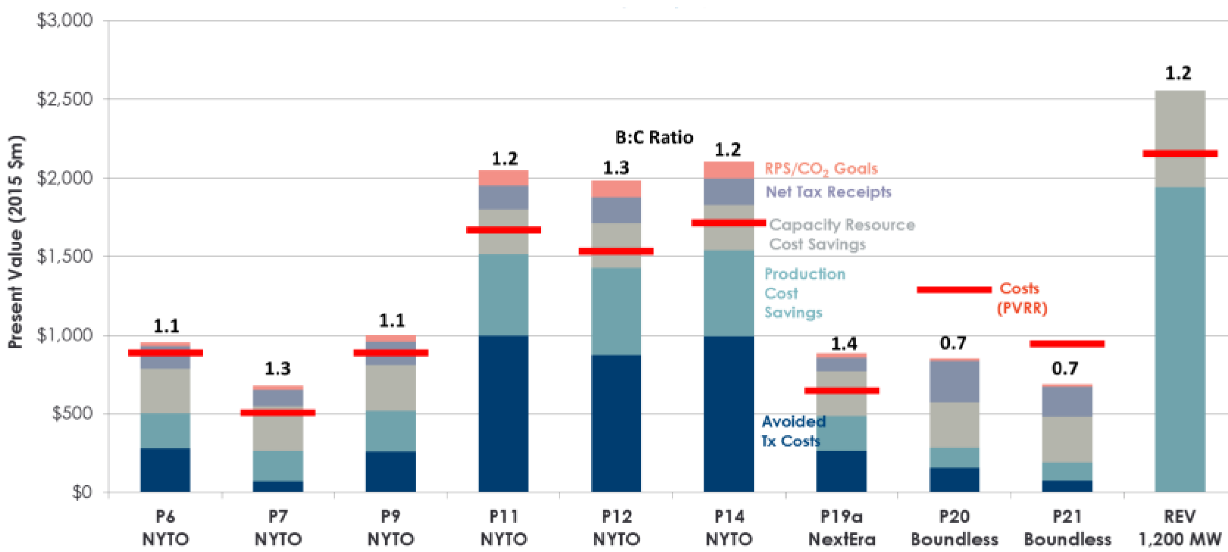
In New York, NYISO implemented a multi-value "public policy" transmission planning process after the New York Public Service Commission (PSC) mandated that approach in 2015. Prior, the existing approach for identifying "economic" projects through the NYISO Congestion Assessment and Resource Integration Study (CARIS) failed to identify regional projects to be built due to its limited scope of benefits considered: it focused solely on adjusted production

[125] MISO, *MTEP19 MVP Limited Review Report*, 2019.

cost savings over a 10-year period.[126] The PPTPP starts with the suggestions of public policy transmission needs (PPTN) by market participations. After the PSC approves specific needs, the NYISO solicits solutions from market participations, which are then being evaluated based on a multi-value framework that recognizes and quantifies the broad set of benefits that the proposed solutions may provide.

Considering the broader range of benefits that transmission provides, and that a large portion of total benefits are the avoided costs of not having to upgrade the aging infrastructure later (due to facilities nearing the end of their useful life), seven portfolios of initially proposed projects and the Reforming the Energy Vision (REV) resources were found to provide net societal benefits as (see Figure 9) and two upgrades were ultimately approved.

FIGURE 9. SUMMARY OF NEW YORK SOCIETAL BENEFIT-COST ANALYSIS



Source: Newell, *et al.* (The Brattle Group), Benefit-Cost Analysis of Proposed New York AC Trans9ission Upgrades, prepared for NYISO and DPS Staff. September 15, 2015.

[126] Newell, *et al.* (The Brattle Group), *Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades*, prepared for NYISO and DPS Staff. September 15, 2015.

4. CAISO Transmission Economic Assessment Methodology (TEAM)

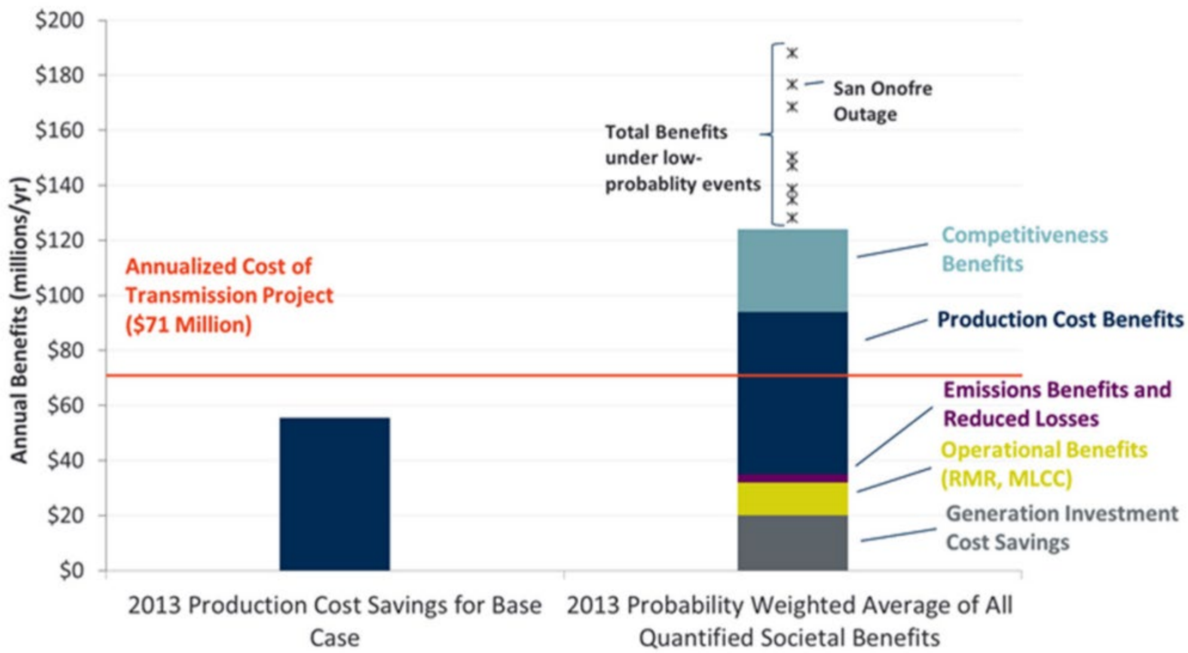
CAISO has occasionally utilized its TEAM approach in its transmission planning effort, which considers multiple benefits.[127] When initially evaluating CAISO's Palo Verde-Devers 2 (PVD2) line, the California Public Utility Commission (CPUC) relied on results from the TEAM approach.[128] Quantified benefits included production cost benefits, operational benefits, generation investment cost savings, reduced losses, competitiveness benefits, and emissions benefits.[129] This proved critical, as the PVD2 project benefits exceeded project costs by more than 50%, but only if multiple benefits were quantified (Figure 10). Thus, traditional planning approaches would have rejected the PVD2 transmission investment despite the fact that the CAISO's more comprehensive analysis shows it offered overall costs savings in excess of the project costs including significant risk mitigation benefits. In contrast, the CAISO TEAM analysis of PVD2 went beyond a base-case production cost analysis to identify a much broader range of transmission-related benefits and estimated the value associated with them more comprehensively than what most economic analyses of transmission projects do today.

[127] CAISO, Transmission Economic Assessment Methodology (TEAM), June 2004.

[128] CAISO, Economic Evaluation of the Palo Verde-Devers Line No. 2 (PVD2), February 24, 2005.

[129] The CAISO identified a number of project-related benefits that were not quantified for the purpose of comparing benefits and costs. These unquantified benefits included: increased operational flexibility (providing the system operator with more options for responding to transmission and generation outages); facilitation of the retirement of aging power plants; encouraging fuel diversity; improved reserve sharing; and increased voltage support.

FIGURE 10. PVD2 ANNUAL BENEFITS IN COMPARISON TO COSTS



However, despite its experience with TEAM, most of CAISO's recent planning efforts focus solely on reliability needs or impacts on wholesale market prices, congestion, and production costs. We are aware of only two recent transmission projects—the Harry Allen to Eldorado 500 kV line and the Delaney to Colorado River 500 kV line (the successor of the PVD2 project first evaluated in 2004)—which the CAISO justified and approved based on quantification of multiple economic benefits.

3. Address Uncertainties and High-Stress Conditions Explicitly through Scenario-Based Planning

While proactive planning improves planning beyond considering status-quo needs or reliability needs (including those created by generation interconnection requests), it may still only consider a single "base case" scenario (as was done in the PJM offshore wind study). Scenario-based planning takes the planning process a step further by explicitly recognizing that planning for the future requires dealing with uncertainty. Because the industry, its market conditions, and even its regulations are invariably uncertain, today's conditions or current trends should not be the primary scenario, let alone the exclusive basis, for how the industry plans transmission facilities in the next decade or two for service 20, 30, or 40 years in the future. This type of scenario-based long-term planning is widely used by other industries, such as the oil and gas, utility planning, and many other industries.[130] Such scenario-based planning using existing tools and proven methods can be deployed to identify robust solutions that are beneficial across a range of scenarios.

Reactive planning to meet near-term reliability or interconnection needs often completely ignores uncertainty, as other future needs are not even considered in the planning effort. Uncertainties about future regulations, industry structure, or generation technology (and associated investments and retirements) can substantially affect the need and size of future transmission projects. A well-planned, flexible transmission system can insure against the risks of high-cost outcomes in the future ("insurance value"). Because future outcomes are highly uncertain, it is important to plan in such a way to minimise "regret" in all plausible scenarios and consider "option value." Without considering a range of plausible scenarios, planning procedures do not address the risk of leaving customers with few options beyond a cost-ineffective set of infrastructure that results in very high system-wide costs. Factors to consider in scenario-based planning include (but not limited to):

- Public Policy Mandates and Goals
- Electrification and Efficiency Adoption
- Economic Growth
- Commodity Costs
- Technology Costs & Availability
- Generation Type and Location
- Future Weather/Climate Conditions, including Extreme Weather Frequency
- Resource Adequacy and Reserve Needs
- Customer Preferences

Finding efficient solutions under conditions of uncertainty is a well-established field of economic policy. One methodological approach relies on the concept of "expected value," which is a calculation of the (probability-weighted) average of multiple potential outcomes in the future. In transmission planning, this methodology is very important because transmission can be extremely valuable in scenarios that can occur in reality but are often not considered in current planning processes' analyses. For example during winter storm Uri in February 2021, additional transmission lines into Texas would have provided so many benefits that they would

[130] Royal Dutch Shell plc, *New Lens Scenarios: A Shift in Perspective for a World in Transition*, March 2013; Wilkinson, Angela and Roland Kupers, "*Living in the Futures*," Harvard Business Review, May 2013.

have fully paid for themselves in 2.5 days, and an additional Gigawatt of transmission capacity into MISO would have provided $100 million in benefit over the event.[131] Prospectively, such scenarios can be considered with proper weighting for the likelihood or probability of such events. For example, even if only one such extreme event can be expected in any decade, the probability weighted annual average would be 1/10th of the benefits the transmission is estimated to provide. However, the distribution of possible outcomes needs to be considered beyond the probability-weighted expected value, since two projects with the same expected value may have vastly different risk profile—with one project significantly reducing the risk of very high cost outcomes relative to the other project.

A frequently voiced concern is that effective transmission planning is not possible until key uncertainties are resolved. This concern has effectively stalled regional and interregional planning processes. However, delaying long-term planning because the future is uncertain will necessarily limit transmission upgrades and miss opportunities to capture higher values through investments that could address longer-term needs more cost effectively. While objectively determining a reasonable set of scenarios that captures possible future market conditions requires careful considerations, it will be much more efficient to do that than ignore uncertainties all together or wait for uncertainties to resolve themselves.

Evaluating long-term uncertainties by defining various distinctive (and equally plausible) “futures” is important given the long useful life of new transmission facilities that can exceed four or five decades. Long-term uncertainties around fuel price trends, locations, and size of future load and generation patterns, economic and public policy-driven changes to future market rules or industry structure, and technological changes can substantially affect the need and size of future transmission projects. Results from scenario-based analyses of these long-term uncertainties can then be used to: (1) identify “least-regrets” projects that mitigate the risk of high-cost outcomes and whose value would be robust across most futures;[132] and (2) identify or evaluate possible project modifications (such as building a single circuit line on double circuit towers) in order to create valuable options that can be exercised in the future depending on how the industry actually evolves. In other words, the range in long-term values

[131] M. Goggin (Grid Strategies, LLC), *Transmission Makes the Power System Resilient to Extreme Weather*, Prepared for ACORE, with Support from the Macro Grid Initiative, July 2020.

[132] For least regret’s planning to deliver robust planning choices, it is important to consider how transmission projects can reduce the risk that some future outcomes may lead to either (a) the regret that the cost of building the project significantly exceeds the project’s benefits, or (b) the regret that not building the project results in very-high-cost outcomes that far exceed the project’s cost. Reducing the cost of both types of regrettable outcomes is necessary to reduce the project’s overall risk in light of an uncertain future.

of economic transmission projects under the various scenarios can be used both to assess the robustness of a project's cost effectiveness and to help identify project modifications that increase the flexibility of the system to adapt to changing market conditions.

For example, a scenario-based long-term transmission planning study was first presented to the Public Service Commission of Wisconsin by American Transmission Company (ATC) in 2007.[133] In its Planning Analysis of the Paddock-Rockdale Project, ATC evaluated the benefit that the project would provide under seven plausible futures. That ATC study, which evaluated a wide range of transmission-related benefits, found that while the 40-year present value of the project's customer benefits fell short of the project's revenue requirement in the "Slow Growth" future, the present value of the potential benefits substantially exceeded the costs in other futures scenarios analyzed. The other scenarios also showed that not investing in the project could leave customers as much as $700 million worse off. Overall, the Paddock-Rockdale analysis showed that understanding the potential impact of projects across plausible futures is necessary for transmission planning under uncertainties and for assessing the long-term risk mitigation benefit of a more robust, more flexible transmission grid.

In 2014, ERCOT improved their stakeholder-driven long-term transmission planning process by applying a scenario-based planning framework to identify the key trends, uncertainties, and drivers of long-term transmission needs in ERCOT.[134] ERCOT converted the detailed scenario descriptions (developed jointly by stakeholders) into transmission planning assumptions, which differed in their projections for load growth, environmental regulations, generation technology options/costs, oil and gas prices, transmission regulations and policies, resource adequacy, end-use markets, and weather and water conditions. Following that, ERCOT performed initial planning analyses for ten scenarios—including projections of likely locations and magnitudes of generation investments and retirements—and identified four scenarios that covered the most distinct range of possible futures to carry forward for detailed long-term system modeling analyses.

MISO's MVP planning effort, noted for its proactive planning in the prior section, also utilized a scenario-based approach to identify the selected projects. In MISO's original RGOS process, three scenarios were considered and the projects that yielded beneficial outcomes in all scenarios eventually went on to become the MVP projects.

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[133] Before the Public Service Commission of Wisconsin, Docket 137-CE-149, Planning Analysis of the Paddock-Rockdale Project, American Transmission Company, April 5, 2007.

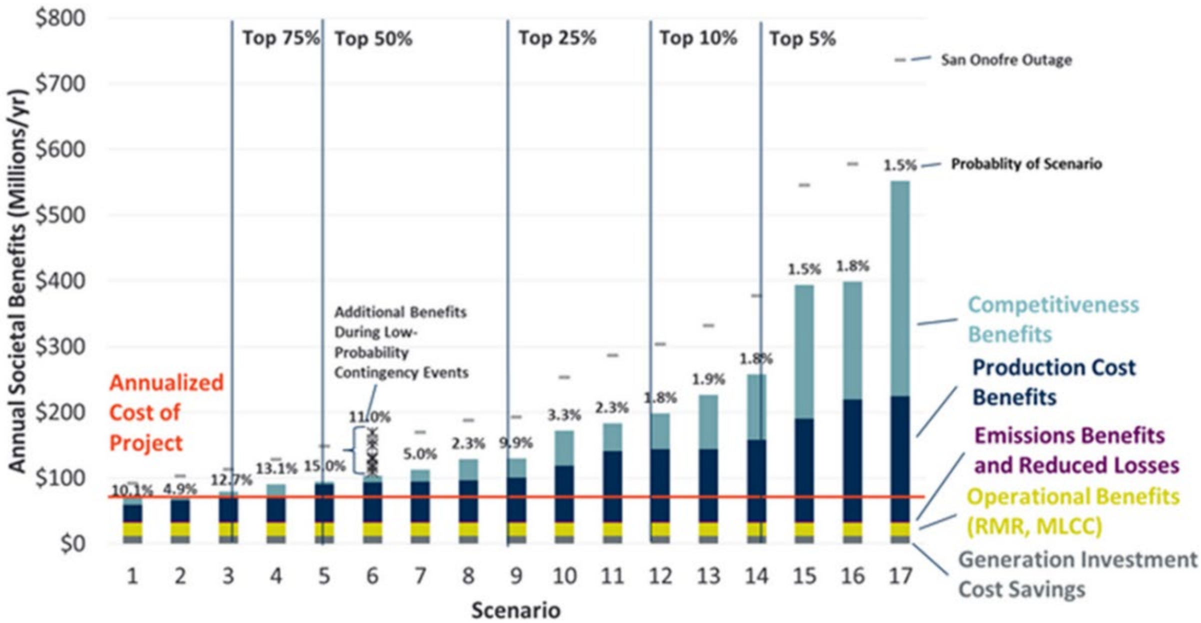
[134] ERCOT, *2014 Long-Term System Assessment for the ERCOT Region*, December, 2014; Chang, Pfiefenberger and Hagerty (The Brattle Group), *Stakeholder-Driven Scenario Development for the ERCOT 2014 Long-Term System Assessment*, September 30, 2014.

California's planners similarly have applied scenario-based approaches in the past. CAISO's 2004 analysis of its Palo Verde to Devers (PVD2) project considered seventeen plausible scenarios and a number of long-term contingencies (which could happen in any of the scenarios) to show that base-case results still significantly understated the overall cost-reductions and risk mitigation offered by the project.[135] Based on the range of scenarios, CAISO showed that the probability-weighted average of the project benefits exceeded the savings estimated in the base-case scenario, which did not have benefits that exceeded costs (Figure 11). Thus, most economic transmission planning processes that focus solely on such base-case benefit and cost comparisons would have rejected the PVD2 transmission project because the quantified benefits do not appear to justify the project's costs.

The CAISO analysis found that if certain low-probability events (such as a long-term outage of the San Onofre nuclear plant) were considered, the proposed transmission investment could avoid up to $70 million of additional cost per year, significantly increasing the projected value of the project. *Ex post*, we now know that one of such high-impact, low-probability events turned out to be quite real: the San Onofre nuclear plant has been out of service since early 2012 and has now been closed permanently. Such "hard-to-anticipate" events are very likely to occur over the long life of transmission facilities. Ignoring that possibility understates the value of new transmission, particularly those projects that reduce exposure to costly events.

[135] California ISO (CAISO) Department of Market Analysis & Grid Planning, *Board Report: Economic Evaluation of the Palo Verde-Devers Line No. 2 (PVD2)*, February 24, 2005.

FIGURE 11. RANGE OF PROJECTED SOCIETAL BENEFITS OF PVD2 PROJECT COMPARED TO PROJECT COSTS



Source: Pfeifenberger, Chang, Sheilendranath, *Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid*, prepared for WIRES Group, April 2015.

Thus, while proactive planning already offers a significant improvement over current planning processes, it may understate project benefits if only a "base case" is evaluated. This risks projects not moving forward due to a lack of understanding of possible benefits in an uncertain future. In addition, the lack of scenarios can result in an inadequate understanding of the potentially high costs of not pursing the project. Recognizing the uncertainties about the future with the use of scenario-based planning can improve current transmission planning processes that are focused solely (or mostly) on a "base case" that reflects the status quo or current trends.

One scenario that is increasingly more likely to be reflective of future market conditions is one with stringent state or federal clean-energy regulation. Over the last decade, numerous and ambitious state clean energy standards have already changed system needs. It is possible, if not likely, that there will be additional significant state or federal clean energy or climate policies. Even if such policies are outside the confines of electricity regulation, they impact the generation mix, power flows, and the value of transmission that has to be expected. Even if some such policies are not yet implemented, it is prudent to consider the possibility of such future policies through scenario-based planning (along with scenarios that envision a future that may not impose such policies). Of course, once such policies are passed they should be considered proactively in "base case" planning scenarios and transmission plans.

A London Economics report described scenario planning this way:

> Utilizing scenario analysis can help decision makers to better understand and quantify the expected range of benefits over the long term. Scenario analysis can capture the impact of uncertainty or the magnitude and longevity of benefits, and even identify beneficiaries that were not anticipated under a "base case" or most likely forecast. In some cases, scenario analysis can also show that benefits may arise irrespective to future market outcomes.[136]

A Brattle Group report for WIRES contains a more detailed discussion on the use of scenarios (to address long-term future uncertainties) and sensitivities (to address short term uncertainties that can happen in each scenario of future market conditions)[137]

4. Use Portfolios of Transmission Projects

Planning a portfolio of synergistic transmission projects can reduce electricity costs by identifying solutions that are more valuable than the sum of the individual projects' value. A synergistic portfolio of projects might also consider both storage and other technologies. Studies that co-optimize storage and transmission tend to find that they are complementary components and not substitutes. There is usually a "sweet spot" where the optimal amount of both storage and transmission lead to the lowest system cost.

For example, MISO evaluated both transmission and storage in its RIIA study.[138] In this study, if the model was allowed to optimize transmission and storage it selected 0.5 GW of storage plus significant additional transmission. If it was allowed to build only storage without additional transmission, the model selected 16 GW at a much higher total system-wide cost. The combined transmission and storage solution achieved a lower system-wide cost than either transmission or storage alone. The graph below shows this "sweet spot" of an optimal combination of transmission and storage.

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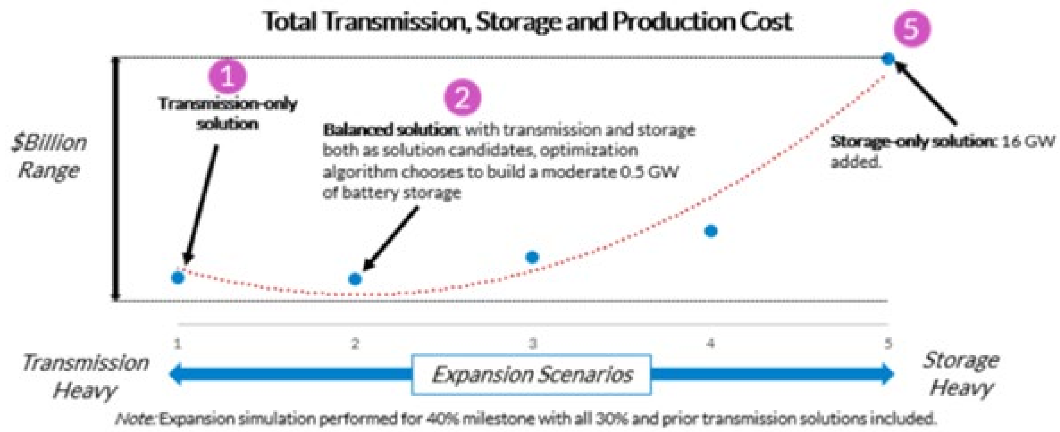
136 J. Frayer, E. Wang, R. Wang, *et al.*(London Economics International, Inc.), *How Does Electric Transmission Benefit You?: Identifying and Measuring the Life-Cycle Benefits of Infrastructure Investment*, A WIRES report, January 8, 2018, p 46.

137 Pfeifenberger, Chang, Sheilendranath, *Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid*, prepared for WIRES Group, April 2015, pp 9−19 and Appendix B.

138 MISO, *MISO's Renewable Integration Impact Assessment (RIIA)*, Summer Report, February 2021.

FIGURE 12. COSTS FOR SCENARIOS VARYING IN TRANSMISSION AND STORAGE EXPANSION



Source: MISO, *MISO's Renewable Integration Impact Assessment (RIIA)*, Summer Report, February 2021, p 93.

Similarly, portfolio-based planning can consider and co-optimize transmission and distributed energy resources (DERs). Studies that co-optimize DERs, transmission, and small and large generation sources can achieve a lower system-wide cost than those that focus on one over the others. Notably, such studies (even with high levels of DERs) still find transmission system expansion to be very valuable. In fact, in one recent study that considered a high DER scenario, 10 million more MW-miles more transmission is required to minimize system-wide costs due to the complementarity (not substitutability) of DERs and transmission.[139]

For the purpose of cost allocation, however, considering even larger portfolios offers additional advantages—it will reduce the contentiousness of cost allocations since the benefits of larger transmission portfolios will be more evenly distributed and stable over time.[140] Such portfolio-wide cost allocation approach is widely used for other infrastructure, including roads or electric distribution systems.

Because the benefits of a portfolio of transmission projects will generally be more evenly distributed and stable than for a single project, portfolio-based cost recovery allows for less complex (and contentious) cost allocation approaches while still ensuring that the sum of costs allocated is roughly commensurate with the sum of benefits received. While the SPP highway-byway and MISO MVP examples demonstrate that the benefits of portfolio of projects are

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[139] C. T. M. Clack, A. Choukulkar, B. Coté, and S. A. McKee (Vibrant Clean Energy LLC), *Why Local Solar For All Costs Less: A New Roadmap for the Lowest Cost Grid*, Technical Report, December 1, 2020.

[140] See, for example, *Transmission Cost Allocation: Principles, Methodologies, and Recommendations*, presentation to the OMS Cost Allocation Principles Committee, November 16, 2020.

roughly commensurate with allocated costs, the MVP cost allocation approach would not meet that standard for individual ITP and MVP projects.[141]

5. Jointly Plan Neighboring Interregional Systems

Improving interregional transmission planning is the subject of several other reports.[142] We address this topic here only briefly. Interregional transmission can provide large economic, reliability, and public policy benefits that can lower electricity costs, as already discussed for several examples above. Similar to regional transmission planning, however, interregional planning also suffers from lack of pro-active, multi-value, and scenario-based analysis.

Most of the existing joint interregional planning processes (such as the PJM-MISO interregional planning process) allow only for the evaluation of transmission needs that are of the same type (*i.e.*, reliability, market efficiency, or public policy) in both regions. As illustrated in Figure 13,[143] these types of interregional planning processes may not allow for the evaluation of needs that differ across the regions, which can disqualify from consideration many valuable interregional projects.

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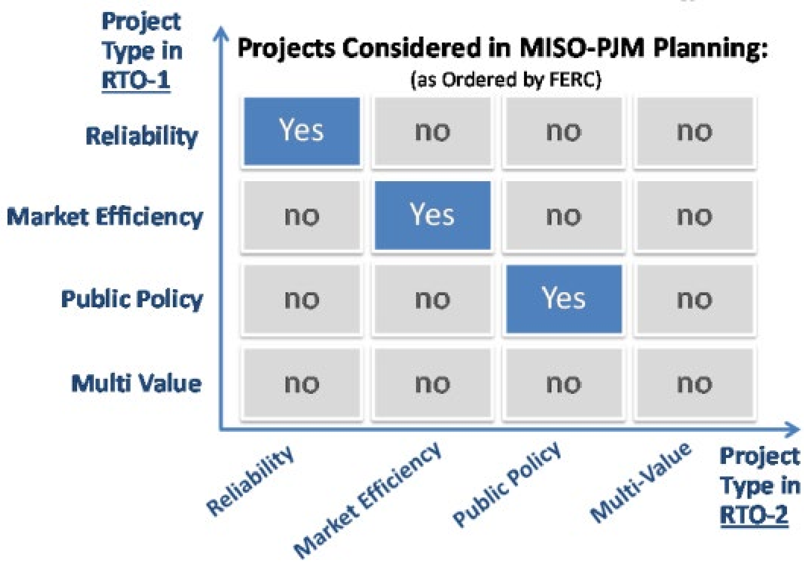
[141] This approach is widely used for infrastructure costs, such as roads or distribution systems. The portfolio-based approach has also been applied, for example, by SPP for the highway-byway cost allocation of projects approved through its Integrated Transmission Planning (ITP) process and MISO for the postage-stamp-based cost allocation of its portfolio of Multi-Value Projects (MVP). While SPP and MISO have demonstrated that the benefits of portfolio of projects are roughly commensurate with allocated costs, the cost allocation approach would not meet that standard for individual ITP and MVP projects. Note, however, that the approval of individual projects (or synergistic groups of projects) still needs to be based on the need for and total benefits of the individual projects.

[142] Southwest Power Pool, *Benefits for the 2013 Regional Cost Allocation Review*, September 13, 2012; Pfeifenberger, Chang, Sheilendranath, *Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid*, prepared for WIRES Group, April 2015.

[143] For a summary of the PJM-MISO interregional planning process, see Appendix C of Pfeifenberger, Chang, Sheilendranath, *Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid*, Prepared for WIRES Group, April 2015.

FIGURE 13. SOME INTERREGIONAL PLANNING PROCESSES DO NOT ALLOW FOR THE EVALUATION OF PROJECTS THAT ADDRESS DIFFERENT NEEDS IN EACH RTO

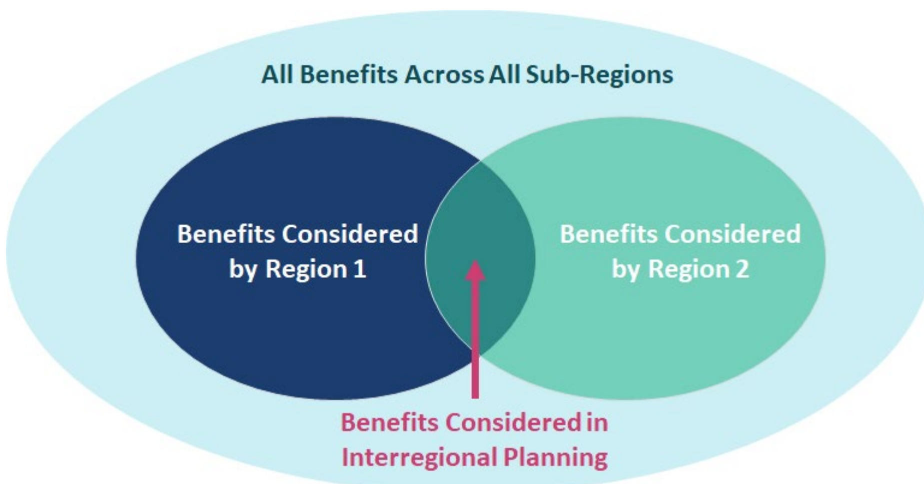


By focusing only on projects that address reliability, market efficiency, or public policy needs in both regions, the planning process inadvertently excludes any interregional projects that, for example, would address reliability needs in one region but address market efficiency or public policy needs in the neighboring region. Unless the two adjacent regions categorize the interregional project in exactly the same way, the regions' interregional planning rules do not exist or may outright reject evaluating the project. More often than not, however, a transmission project will provide multiple types of benefits and these benefits may differ across regions. Finding and approving transmission solutions solely based on reliability needs can, thus, lead to missed opportunities to build lower-cost or higher-value transmission projects that could provide benefits beyond meeting reliability needs to reduce the overall costs and risks to customers in both regions.

The geographic scope of regional and interregional RTO planning processes tends to be narrowly focused in its consideration of the transmission-related benefits geographic scope, typically quantifying only a subset of transmission-related economic and public policy benefits and considering only benefits that accrue to their own region without considering the broader set of interregional benefits. Projects near the regional boundaries, such as an upgrade to a shared flowgate, can address the needs of neighboring regions and need to be considered if the goal is to determine the infrastructure that most lowers cost. Without considering this, quantified benefits will be understated and even "regional" projects near RTO seams could fail to meet applicable benefit-cost thresholds for regional market-efficiency and public policy needs simply because the planning process ignores the benefits that accrue on the other side of the seam. This limitation has been addressed in some interregional planning processes (*e.g.*, PJM-MISO and MISO-SPP joint interregional planning[144]), but is often not considered in regional planning for projects located entirely within one of the RTOs.

This approach tends to disadvantage interregional projects because the jointly agreed-upon criteria and metrics generally will tend to represent the "*least common denominator*" subset of the criteria and metrics used in the adjoining regions. Worse, as show, the range of benefits considered for interregional projects tends be more limited than the narrow scope of benefits considered in intra-regional planning processes, reducing the set of benefits to the least-common denominator of benefits considered in planning within each of the two regions. Similarly, interregional planning processes do not recognize the unique benefits often offered by an expanded interregional transmission system, which include increased load and resource diversity.[145]

FIGURE 14. THE "LEAST COMMON DENOMINATOR" CHALLENGE OF BENEFIT-COST ANALYSIS FOR INTERREGIONAL PROJECTS



In addition, barriers can be created due to the disjointed nature of the existing interregional and regional planning processes. For example, interregional transmission projects may be subjected to three separate benefit-cost thresholds: a joint interregional benefit-cost threshold as well as each of the two neighboring region's individual internal planning criteria. This means, for example, that projects that pass each RTO's individual benefit-cost thresholds may fail the threshold imposed through the least-common denominator approach to interregional planning;

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[144] SPP-MISO and MISO-PJM Joint Operating Agreements available at MISO, *Interregional Coordination*.

[145] Pfeifenberger, Ruiz, Van Horn, *The Value of Diversifying Uncertain Renewable Generation through the Transmission System*, BU-ISE, October 14, 2020.

or projects that pass the benefit-cost threshold of the interregional planning process may be rejected because they may fail one of the individual RTOs' planning criteria. In combination with evaluating only a subset of benefits of a few scenarios of future market conditions, this adds to the challenge of approving even very valuable projects.

Interregional planning also lacks proactive scenario-based analyses. This is partly caused by the lack of inputs from states on how they plan on achieving clean energy goals. States generally have specific goals for local renewable energy resource development that are not well articulated or challenging to incorporate into regional and interregional planning processes. One of the key drivers of the MISO MVP process was that state representatives were requesting that MISO evaluate transmission solutions that could cost-effectively meet the region's combined state-level renewable portfolio standards by integrating a combination of local and regional renewable resources. A high-level outlook of how states wish to pursue meeting their goals, or a more detailed set of scenarios, would greatly improve the ability of RTOs to plan their future system without having to develop a specific portfolio of resources to do so.

6. Summary of Examples of Proven Efficient Planning Studies and Methods

As described above, there are many examples where efficient transmission planning methods have been performed. The following table lists transmission studies and analyses and shows what type of planning method was performed (Table 7). Table 7 classifies proactive as considering beyond status-quo scenarios, multi-benefit as considering a comprehensive set of benefits (*i.e.*, not just a couple), and scenario-based planning to reflect a broad set of divergent futures.

TABLE 7. EXAMPLES USING PROVEN EFFICIENT PLANNING METHODS

	Proactive Planning	Multi-Benefit	Scenario-Based	Portfolio-Based	Interregional Transmission
CAISO TEAM (2004)[146]	✓	✓	✓		
ATC Paddock-Rockdale (2007)[147]	✓	✓	✓		
ERCOT CREZ (2008)[148]	✓			✓	
MISO RGOS (2010)[149]	✓	✓		✓	
EIPC (2010-2013)[150]	✓		✓	✓	✓
PJM renewable integration study (2014)[151]	✓		✓	✓	
NYISO PPTPP (2019)[152]	✓	✓	✓	✓	
ERCOT LTSA (2020)[153]	✓		✓		
SPP ITP Process (2020)[154]		✓		✓	
PJM Offshore Tx Study (2021)[155]	✓		✓	✓	
MISO RIIA (2021)[156]	✓	✓	✓	✓	
Australian Examples:					
- AEMO ISP (2020)[157]	✓	✓	✓	✓	✓
- Transgrid Energy Vision (2021)[158]	✓	✓	✓	✓	✓

146 CAISO, Transmission Economic Assessment Methodology (TEAM), June 2004.

147 American Transmission Company, Planning Analysis of the Paddock-Rockdale Project, April 2007.

148 D. Woodfin (ERCOT), *CREZ Transmission Optimization Study Summary*, presented to the ERCOT Board of Directors, April 15, 2008.

149 Midwest ISO, *RGOS: Regional Generation Outlet Study*, November 19, 2010.

150 See *Eastern Interconnection Planning Collaborative*, including Phase I and Phase II planning reports

151 GE Energy Consulting, *PJM Renewable Integration Study, Task 3A Part C: Transmission Analysis*, March 31, 2014.

152 NYISO, AC Transmission Public Policy Transmission Plan, April 8, 2019.

153 ERCOT, *2020 LTSA Review*, December 15, 2020 and *2020 Long-Term System Assessment for the ERCOT Region*, December 20202, as posted at: Planning (ercot.com).

154 SPP, *2020 Integrated Transmission Planning Report*, October 27, 2020. As noted in the report (at p 8), the (multi-value) objectives of the SPP ITP process are to: resolve reliability criteria violations; Improve access to markets; Improve interconnections with SPP neighbors; meet expected load-growth demands; facilitate or respond to expected facility retirements; synergize with the Generator Interconnection (GI), Aggregate Transmission Service Studies (ATSS), and Attachment AQ processes; address persistent operational issues as defined in the scope; Facilitate continuity in the overall transmission expansion plan; and facilitate a cost-effective, responsive, and flexible transmission network.

155 PJM, *Offshore Transmission Study Group Phase 1 Results,* presented to Independent State Agencies Committee (ISAC), July 29, 2021.

156 Midwest ISO, *MISO's Renewable Integration Impact Assessment (RIIA)*, February 2021.

157 AEMO, *2020 Integrated System Plan*, July 30, 2020.

158 Transgrid, *Energy Vision: A Clean Energy Future for Australia*, October 2021.

V. Summary and Conclusions

The currently predominant use of reactive, single-driver approaches to transmission planning is systematically failing to identify and implement transmission options that offer the lowest system-wide costs and highest benefits for customers. A set of market and regulatory failures create perverse incentives that lead to under-investment in the type of regional and interregional transmission that would increase reliability and system-wide efficiency.

This failure is widespread across the country, and present to a greater or lesser extent in all 11 Planning Authority regions. These transmission planning processes are not leading to a cost-effective transmission infrastructure. Fortunately, some proven examples of more effective transmission planning, using existing and readily available tools, exist. Continuing current practices without reforms will mean higher-than-necessary electricity costs. Existing experience with effective planning and cost-allocation processes shows that transmission planners have the tools needed to significantly reduce system-wide electricity costs. To do so, effective planning process need to:

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

Policymakers and planners need to reform transmission planning requirements to avoid the unreasonably high system-wide costs that result from the current planning approaches and enable customers to pay just and reasonable rates by implementing these principles.

Appendix A – Evidence of the Need for Regional and Interregional Transmission Infrastructure to Lower Costs

Numerous studies of the future resource mix find that large amounts of power must be able to move back and forth across regions, and large regional and interregional transmission expansion is needed for this to happen. This evidence includes:

- A study by leading grid experts at the National Oceanic and Atmospheric Administration (NOAA) found that moving away from a regionally divided network to a national network of HVDC transmission can save consumers up to $47 billion annually while integrating 523 GWs of wind and 371 GWs of solar onto the grid.[159]
- The NREL Interconnections Seam Study shows that significant transmission expansion and the creation of a national network will be essential in incorporating high levels of renewable resources, all the while returning more than $2.50 for every dollar invested.[160] The study found a need for 40–60 million MW-miles of alternating current (AC) and up to 63 million MW-miles of direct current (DC) transmission for one scenario. The U.S. has approximately 150 million MW-miles in operation today.
- A study by ScottMadden Management Consultants on behalf of WIRES, concluded that as more states, utilities, and other companies are mandating or committing to clean energy targets and agendas, it will not be possible to meet those goals without additional transmission to connect desired resources to load. Similarly, the current transmission system will need further expansion and hardening beyond the traditional focus on meeting reliability needs if the system is to be adequately designed and constructed to withstand and timely recover from disruptive or low probability, high-impact events affecting the resilience of the bulk power system."[161]

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[159] Alexander E. MacDonald et al., *Future Cost-Competitive Electricity Systems and Their Impact on U.S. CO2 Emissions*, Nature Climate Change 6, at 526-531, January 25, 2016.

[160] Aaron Bloom, *Interconnections Seam Study*, August 2018.

[161] Scott Madden, *Informing the Transmission Discussion: A Look at Renewables Integration and Resilience Issues for Power Transmission in Selected Regions of the United States*, January 2020.

- Dr. Paul Joskow of MIT has reviewed transmission planning needs and concluded that "[s]ubstantial investment in new transmission capacity will be needed to allow wind and solar generators to develop projects where the most attractive natural wind and solar resources are located. Barriers to expanding the needed inter-regional and internetwork transmission capacity are being addressed either too slowly or not at all."[162]
- The Commission itself recently reviewed transmission needs and barriers and "found that high voltage transmission, as individual lines or as an overlay, can improve reliability by allowing utilities to share generating resources, enhance the stability of the existing transmission system, aid with restoration and recovery after an event, and improve frequency response and ancillary services throughout the existing system."[163]
- A study of the Eastern Interconnection for the state of Minnesota found that scenarios with interstate transmission expansion can introduce annual savings to Minnesota consumers of up to $2.8 billion, with an annual savings for Minnesotan households of up to $1,165 per year.[164]
- Analysts at The Brattle Group estimate that providing access to areas with lower cost generation to meet Renewable Portfolio Standards (RPS) and clean energy needs through 2030 could create $30–70 billion in benefits for customers, and multiple studies have identified potential benefits of over $100 billion.[165]
- The Princeton University Net Zero America study of a low carbon economy found "[h]igh voltage transmission capacity expands ~60% by 2030 and triples through 2050 to connect wind and solar facilities to demand; total capital invested in transmission is $360 billion through 2030 and $2.4 trillion by 2050."[166]
- A study by MIT scientists found that inter-state coordination and transmission expansion reduces the cost of zero-carbon electricity by up to 46% compared to a state-by-state

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[162] Paul Joskow, *Transmission Capacity Expansion is Needed to Decarbonize the Electricity Sector Efficiently*, Joule 4, at 1-3, January 15, 2020. See also Joskow, *Facilitating Transmission Expansion to Support Efficient Decarbonization of the Electricity Sector*, Economics of Energy & Environmental Policy, Vol. 10, No. 2 (2021).

[163] FERC, *Report on Barriers and Opportunities for High Voltage Transmission*, at 39, June 2020.

[164] Vibrant Clean Energy, *Minnesota's Smarter Grid*, July 31, 2018.

[165] J. Michael Hagerty, Johannes Pfeifenberger, and Judy Chang, *Transmission Planning Strategies to Accommodate Renewables*, at 17, September 11, 2017.

[166] Eric Larson, *et al.*, *Net-Zero America: Potential Pathways, Infrastructure, and Impacts*, at 77, December 15, 2020.

approach.[167] To achieve these cost reductions the study found a need for approximately doubling transmission capacity, and "[e]ven in the ''5× transmission cost'' case there are substantial transmission additions."[168]

- A recent study to compare the "flexibility cost-benefits of geographic aggregation, renewable overgeneration, storage, and flexible electric vehicle charging," as "pathways to a fully renewable electricity system" found that "[g]eographic aggregation provides the largest flexibility benefit with ~5–50% cost savings.[169] The study found that "With a major expansion of long-distance transmission interconnection to smooth renewable energy variation across the continent, curtailment falls to negligible levels at a 60% renewable penetration, from 5% in the case without transmission. In the 80% renewable case, transmission reduced curtailment from 12% to 5%.[170]
- The Brattle Group analysts find that "$30–90 billion dollars of incremental transmission investments will be necessary in the U.S. by 2030 to meet the changing needs of the system due to electrification, with an additional $200–600 billion needed from 2030 to 2050."[171]
- Analysis conducted for MISO found that significant transmission expansion was economical under all future scenarios, with the largest transmission expansion needed in Minnesota, the Dakotas, and Iowa. In the carbon reduction case, transmission provided $3.8 billion in annual savings, reducing total power system costs by 5.3%.[172]
- MISO's Renewable Integration Impact Assessment conducted a diverse set of power system studies examining up to 50% Variable Energy Resources (VER) (570GW VER) in the eastern interconnection. Within the MISO footprint, this included the following transmission expansion: 590 circuit-miles of 345kV and below, 820 circuit-miles of 500kV, 2040 circuit-miles of 765kV, and 640 circuit-miles of HVDC.[173]

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[167] P. R. Brown and A. Botterud, *The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System*, Joule, December 11, 2020.

[168] *Id.*, at 12.

[169] B. A. Frew, *et al.*, *Flexibility Mechanisms and Pathways to a Highly Renewable U.S. Electricity Future*, Energy, Volume 101, at 65-78, April 15, 2016.

[170] *Ibid*.

[171] Dr. J. Weiss, J. M. Hagerty, and M. Castañer, *The Coming Electrification of the North American Economy*, at ii, March 2019.

[172] Vibrant Clean Energy, *MISO High Penetration Renewable Energy Study for 2050*, at 23-24, January 2016

[173] Wind Solar Alliance, *Renewable Integration Impact Assessment Finding Integration Inflection Points of Increasing Renewable Energy*, January 21, 2020.

- The Brattle Group analysts, on behalf of WIRES, demonstrate that transmission expansion creates trading opportunities across existing regional and interregional constraints. The report finds, using existing wholesale power price differences between SPP and the Northwestern U.S., that "adding 1,000 MW of transmission capability would create approximately $3 billion in economic benefits on a present value basis."[174]
- In its HVDC Network Concept study, MISO estimates that expanding east-to-west and north-to-south transmission interties can generate investment cost savings of approximately $38 billion through load diversity benefits that would reduce nation-wide generation capacity needs by 36,000 MW.[175]
- A study prepared for the Eastern Interconnection States Planning Council, National Association of Regulatory Utility Commissioners, and the Department of Energy estimates that $50–110 billion of interregional transmission will be needed over the next 20 years to cost-effectively support new generation investment. A co-optimized, anticipatory transmission planning process is estimated to reduce total generation costs by $150 billion, compared to a traditional transmission planning approach, and would generate approximately $90 billion in overall system-wide savings.[176]
- SPP found that a portfolio of transmission projects constructed in the region between 2012 and 2014 at a cost of $3.4 billion is estimated to generate upwards of $12 billion in net benefits over the next 40 years. The net present value is expected to total over $16.6 billion over the 40-year period, resulting in a benefit-to-cost ratio of 3.5.[177]
- MISO estimates that its 17 Multi-Value Projects (MVPs), approved in 2011, will generate between $7.3 to $39 billion in net benefits over the next 20 to 40 years, which will result in a total cost-benefit ratio of between 1.8 to 3.1. Typical residential households could realize an estimated $4.23 to $5.13 in monthly benefits over the 40-year period.[178]
- A study conducted by the Eastern Interconnection Planning Collaborative on the need for interregional transmission projects to meet national environmental goals found that an efficient interregional transmission planning approach to meet a 25% nation-wide RPS

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[174] Pfeifenberger and Chang, *Well-Planned Electric Transmission Saves Customer Costs: Improved Transmission Planning is Key to the Transition to a Carbon Constrained Future*, at 16, June 2016.

[175] MISO, *HVDC Network Concept*, at 3, January 7, 2014.

[176] A. Liu, *et al.*, *Co-optimization of Transmission and Other Supply Resources*, September 2013.

[177] SPP, *The Value of Transmission*, at 5, January 26, 2016.

[178] MISO, *MTEP19*, 2019.

standard would reduce generation costs by $163–$197 billion compared to traditional planning approaches.[179]

- Phase 2 of the study found that the transmission investment necessary to support the generation and the environmental compliance scenarios associated with these savings ranges from $67 to $98 billion.[180] These results indicate that the combination of interregional environmental policy compliance and interregional transmission may offer net savings of up to $100 billion.
- A study comparing proactive planning to reactive planning found significant benefits to proactive planning because it is able to co-optimize generation and transmission. "Transmission planning has traditionally followed a "generation first" or "reactive" logic, in which network reinforcements are planned to accommodate assumed generation build-outs. The emergence of renewables has revealed deficiencies in this approach, in that it ignores the interdependence of transmission and generation investments. For instance, grid investments can provide access to higher quality renewables and thus affect plant siting. Disregarding this complementarity increases costs. In theory, this can be corrected by "proactive" transmission planning, which anticipates how generation investment responds by co-optimizing transmission and generation investments. We evaluate the potential usefulness of co-optimization by applying a mixed-integer linear programming formulation to a 24-bus stakeholder-developed representation of the U.S. Eastern Interconnection. We estimate cost savings from co-optimization compared to both reactive planning and an approach that iterates between generation and transmission investment optimization. These savings turn out to be comparable in magnitude to the amount of incremental transmission investment."[181]

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[179] Eastern Interconnection Planning Collaborative, *Phase 1 Report: Formation of Stakeholder Process, Regional Plan Integration and Macroeconomic Analysis*, December 2011.

[180] Eastern Interconnection Planning Collaborative, *Phase 2 Report: Interregional Transmission Development and Analysis for Three Stakeholder Selected Scenarios and Gas-Electric System Interface Study*, June 2, 2015.

[181] E. Spyrou, J. L. Ho, B. F. Hobbs, R. M. Johnson, and J. D. McCalley, *What Are the Benefits of Co-Optimizing Transmission and Generation Investment? Eastern Interconnection Case Study*. IEEE Transactions on Power Systems 32 (6): 4265–77, January 27, 2017.

Appendix B – Quantifying the Additional Production Cost Savings of Transmission Investments

As noted in the main report, RTOs and transmission planners are increasingly recognizing that traditional production cost simulations and the traditional "adjusted production cost" metrics are quite limited in their ability to estimate the full congestion relief and production cost benefits. Below we describe the quantification of additional production-cost-related savings (*i.e.*, beyond the production cost savings traditionally quantified) that need to be considered when evaluating the full range of transmission benefits.

TABLE 8. ADDITOINAL PRODUCTION COST SAVING CATEGORIES

i. Impact of generation outages and A/S unit designations
ii. Reduced transmission energy losses
iii. Reduced congestion due to transmission outages
iv. Reduced production cost during extreme events and system contingencies
v. Mitigation of typical weather and load uncertainty, including the geographic diversification of uncertain renewable generation variability
vi. Reduced cost due to imperfect foresight of real-time system conditions, including renewable forecasting errors and intra-hour variability
vii. Reduced cost of cycling power plants
viii. Reduced amounts and costs of operating reserves and other ancillary services
ix. Mitigation of reliability-must-run (RMR) conditions
x. More realistic "Day 1" market representation

B.1 Estimating Changes in Transmission Losses

In some cases, transmission additions or upgrades can reduce the energy losses incurred in the transmittal of power from generation sources to loads. However, due to significant increases in simulation run-times, a constant loss factor is typically provided as an input assumption into the production cost simulations. This approach ignores that the transmission investment may reduce the total quantity of energy that needs to be generated, thereby understating the production cost savings of transmission upgrades.

To properly account for changes in energy losses resulting from transmission additions will require either: (1) simulating changes in transmission losses; (2) running power flow models to estimate changes in transmission losses for the system peak and a selection of other hours; or (3) utilizing marginal loss charges (from production cost simulations with constant loss approximation) to estimate how the cost of transmission losses will likely change as a result of the transmission investment.[182] Through any of these approaches, the additional changes in production costs associated with changes in energy losses (if any) can be estimated.

In some cases, the economic benefits associated with reduced transmission losses can be surprisingly large, especially during system peak-load conditions. For instance, the energy cost savings of reduced energy losses associated with a 345 kV transmission project in Wisconsin were sufficient to offset roughly 30% of the project's investment costs.[183] Similarly, in the case of a proposed 765 kV transmission project, the present value of reduced system-wide losses was estimated to be equal to roughly half of the project's cost.[184] For transmission projects that specifically use advanced technologies that reduce energy losses, these benefits are particularly important to capture. For example, a recent analysis of a proposed 765 kV project using "low-loss transmission" technology showed that this would provide an additional $11 to 29 million in annual savings compared to the older technology.[185]

B.2 Estimating the Additional Benefits Associated with Transmission Outages

Production cost simulations typically consider planned generation outages and, in most cases, a random distribution of unplanned generation outages. In contrast, they do not generally reflect *transmission* outages, planned or unplanned. Both generation and transmission outages can have significant impacts on transmission congestion and production costs. By assuming that transmission facilities are available 100% of the time, the analyses tend to under-estimate the value of transmission upgrades and additions because outages, when they occur, typically

[182] For a discussion of estimating loss-related production cost savings from the marginal loss results of production cost simulations see Pfeifenberger, Direct Testimony on behalf of American Transmission Company, before the Public Service Commission of Wisconsin, Docket 137-CE-149, January 17, 2008.

[183] American Transmission Company LLC (ATC), *Planning Analysis of the Paddock-Rockdale Project*, April 5, 2007 (filed in PSCW Docket 137-CE-149, PSC Reference # 75598), pp 4 (project cost) and 63 (losses benefit).

[184] Pioneer Transmission, LLC, Letter from David B. Raskin and Steven J. Ross (Steptoe & Johnson) to Hon. Kimberly D. Bose (FERC) Re: Formula Rate and Incentive Rate Filing, Pioneer Transmission LLC, Docket No. ER09-75-000, no attachments, January, 26, 2009, at p 7. These benefits include not only the energy value (*i.e.*, production cost savings) but also the capacity value of reduced losses during system peak.

[185] Pfeifenberger and S. A. Newell, Direct Testimony, FERC Docket No. ER11-4069-000 (RITELine), filed July 18, 2011.

cause transmission constraints to bind more frequently and increase transmission congestion and the associated production costs significantly.[186]

Transmission outages account for a significant and increasing portion of real-world congestion. For example, when the PJM FTR Task Force reported a $260 million FTR congestion revenue inadequacy (or approximately 18% of total PJM congestion revenues during the 2010–11 operating year), approximately 70% of this revenue inadequacy was due to major construction-related transmission outages (16%), maintenance outages (44%), and unforeseen transmission de-ratings or forced outages (9%). In fact, the frequency of PJM transmission facility rating reductions due to transmission outages has increased from approximately 500 per year in 2007 to over 2,000 in 2012.[187] Similarly, while the exact amount attributable to transmission outages is not specified, the Midwest ISO's independent market monitor noted that congestion costs in the day-ahead and real-time markets in 2010 rose 54 percent to nearly $500 million due to higher loads and transmission outages.[188] MISO also recently addressed the challenge of FTR revenue inadequacy by using a representation of the transmission system in its simultaneous FTR feasibility modeling that incorporates planned outages and a derate of flowgate capacity to account for unmodelled events such as unplanned transmission outages and loop flows.[189] As aging transmission facilities need to be rebuilt, the magnitude and impact of transmission outages will only increase.

A 2005 study of PJM assessed the impact of transmission outages. That analysis showed that without transmission outages, total PJM congestion charges would have been 20% lower; the value of FTRs from the AEP Generation Hub to the PJM Eastern Hub would have been 37% lower; the value of FTRs into Atlantic Electric, for example, would have been more than 50% lower; and that simulations without outages generally understated prices in eastern PJM and

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[186] For an additional discussion of simulating the transmission outage mitigation value of transmission investments, see Southwest Power Pool (SPP), *SPP Priority Projects Phase II Report, Rev. 1*, April 27, 2010, Section 4.3.

Also note that, while not related to production costs, the transmission outages can also result in reduced system flexibility that can delay certain maintenance activities (because maintenance activities could require further line outages), which in turn can reduce network reliability.

[187] PJM Interconnection (PJM), *FTR Revenue Stakeholder Report*, April 30, 2012, p 32.

[188] D. Patton, "*2010 State of the Market Report: Midwest ISO*," presented by Midwest ISO Independent Market Monitor, Potomac Economics, May 2011. (Patton, 2011) Posted at https://www.potomaceconomics.com/wp-content/uploads/2017/02/2010-State-of-the-Market-Presentation.pdf, 2011.

[189] See Section 7.1 (Simultaneous Feasibility Test) of the MISO Business Practices Manual 4. Posted at: https://cdn.misoenergy.org//BPM%20004%20-%20FTR%20and%20ARR49548.zip.

west-east price differentials.[190] These examples show that real-world congestion costs are higher than congestion costs in a world without transmission outages. This means that the typical production cost simulations, which do not consider transmission outages, tend to understate the extent of congestion on the system and, as a result, the congestion-relief benefit provided by transmission upgrades.

Production cost simulations can be augmented to reflect reasonable levels of outages, either by building a data set of a normalized outage schedule (not including extreme events) that can be introduced into simulations or by reducing the limits that will induce system constraints more frequently. For the RITELine transmission project, specific production cost benefits were analyzed for the planned outages of four existing high-voltage lines. It was found that a one-week (non-simultaneous) outage for each of the four existing lines increased the production cost benefits of the RITELine project by more than $10 million a year, with PJM's Load locational pricing payments decreasing by more than $40 million a year. Because there are several hundred high-voltage transmission elements in the region of the proposed RITELine, the actual transmission-outage-related savings can be expected to be significantly larger than the simulated savings for the four lines examined in that analysis.[191]

At the time of writing this report, our ongoing work for SPP indicates that applying the most important transmission outages from the last year to forward-looking simulations of transmission investments increases the estimates of adjusted production cost savings by approximately 10% to 15% even under normalized system (*e.g.*, peak load) conditions. Higher additional transmission–outage-related savings are expected in portions of the grid that already have very limited operating flexibility and during challenging (*i.e.*, not normalized) system conditions.

The fact that transmission outages increase congestion and associated production costs is also documented for non-RTO regions. For example, Entergy's Transmission Service Monitor (TSM) found that transmission constraints existed during 80% of all hours, leading to 331 curtailments of transmission services, at least some of which was the result of the more than 2,000 transmission outages that affected available transmission capability during a three month period.[192] The TSM report also showed that, for the five most constrained flowgates on the

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[190] Pfeifenberger and S. Newell, "*Modeling Power Markets: Uses and Abuses of Locational Market Simulation Models*," Energy (Brattle Group Newsletter) No. 1, 2006.

[191] Pfeifenberger and S. A. Newell, Direct Testimony, FERC Docket No. ER11-4069-000 (RITELine), filed July 18, 2011.

[192] Potomac Economics, Quarterly Transmission Service Monitoring Report on Entergy Services, Inc.¸ December 2012 through March 2013, April 30, 2013.

Entergy system, the available flowgate capacity during real-time operations generally fluctuated by several hundred MW over time. This means that the actual available transmission capacity is less on average than the limits used in the market simulation models, which assume a constant transmission capability equal to the flowgate limits used for planning purposes. This indicates that the traditional simulations tend to understate transmission congestion by not reflecting the lower transmission limits in real-time. The TSM report also stated that the identified transmission constraints resulted in the refusal of transmission service requests for approximately 1.2 million MWh during the same three month period.

These examples show that real-world congestion costs are higher than the congestion costs simulated through traditional production cost modeling that assumes a world without transmission outages. These values associated with new transmission's ability to mitigate the cost of transmission outages will be particularly relevant in areas of the grid with constrained import capability and limited system flexibility.

B.3 Estimating the Benefits of Mitigating the Impacts of Extreme Events and System Contingencies

Transmission upgrades can provide insurance against extreme events, such as unusual weather conditions, fuel shortages, and multiple or sustained generation and transmission outages. Even if a range of typical generation and transmission outage scenarios are simulated during analyses of proposed projects, production cost simulations will not capture the impacts of extreme events; nor will they capture how proposed transmission investments can mitigate the potentially high costs resulting from these events. Although extreme events occur very infrequently, when they do they can significantly reduce the reliability of the system, induce load shed events, and impose high emergency power costs. Production cost savings from having a more robust transmission system under these circumstances include the reduction of high-cost generation and emergency procurements necessary to support the system. Additional economic value (discussed further below) includes the value of avoided load shed events.

The insurance value of additional transmission in reducing the impact of extreme events can be significant, despite the relatively low likelihood of occurrence. While the value of increased system flexibility during extreme contingencies is difficult to estimate, system operators intrinsically know that increased system flexibility provides significant value. One approach to estimate these additional values is to use extreme historical market conditions and calculate the probability-weighted production cost benefits through simulations of the selected extreme events. For example, a production cost simulation analysis of the insurance benefits for the

Paddock-Rockdale 345 kV transmission project in Wisconsin found that the project's probability-weighted savings from reducing the production and power purchase costs during a number of simulated extreme events (such as multiple transmission or nuclear plant outages similar to actual events that occurred in prior years) added as much as $28 million to the production cost savings, offsetting 20% of total project costs.[193]

For the PVD2 project, several contingency events were modeled to determine the value of the line during these high-impact, low-probability events. The events included the loss of major transmission lines and the loss of the San Onofre nuclear plant. The analysis found significant benefits, including a 61% increase in energy benefits, to CAISO ratepayers in the case of the San Onofre outage.[194] This simulated high-impact, low-probability event turned out to be quite real, as the San Onofre nuclear plant has been out of service since early 2012 and will now be closed permanently.[195]

Further, the analysis of high-impact, low-probability events documented that—while the estimated societal benefit (including competitive benefit) of the PVD2 line was only $77 million for 2013—there was a 10% probability that the annual benefit would exceed $190 million under various combinations of higher-than-normal load, higher-than-base-case gas prices, lower-than-normal hydro generation, and the benefits of increased competition. There was also a 4.8% probability that the annual benefit ranged between $360 and $517 million.[196]

In a recent example, one such study found that the development of an additional 1,000 MW of transmission capacity into Texas during would have fully paid for itself over the course of four days during winter storm Uri.[197] The same study found that an additional 1,000 MW of transmission capacity into MISO from the East would have saved $100 million during that short period of time.

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[193] American Transmission Company LLC (ATC), *Planning Analysis of the Paddock-Rockdale Project*, April 5, 2007 (filed in PSCW Docket 137-CE-149, PSC Reference # 75598, p 4 (project cost) and 50-53 (insurance benefit).

[194] California Public Utilities Commission (CPUC), Decision 07-01-040: *Opinion Granting a Certificate of Public Convenience and Necessity*, in the Matter of the Application of Southern California Edison Company (U 338-E) for a Certificate of Public Convenience and Necessity Concerning the Devers-Palo Verde No. 2 Transmission Line Project, Application 05-04-015 (filed April 11, 2005), January 25, 2007, pp 37–41.

[195] M. L. Wald, "Nuclear Power Plant in Limbo Decides to Close, *The New York Times*, June 7, 2013.

[196] California ISO (CAISO) Department of Market Analysis & Grid Planning, *Board Report: Economic Evaluation of the Palo Verde-Devers Line No. 2 (PVD2)*, February 24, 2005, p 24.

[197] M. Goggin (Grid Strategies, LLC), *Transmission Makes the Power System Resilient to Extreme Weather*, Prepared for ACORE, with Support from the Macro Grid Initiative, July 2020.

B.4 Estimating the Benefits of Mitigating Weather and Load Uncertainty

Production cost simulations are typically performed for all hours of the year, though the load profiles used typically reflect only normalized monthly and peak load conditions. Such methodology does not fully consider the regional and sub-regional load variances that will occur due to changing weather patterns and ignores the potential benefit of transmission expansions when the system experiences higher-than-normal load conditions or significant shifts in regional weather patterns that change the relative power consumption levels across multiple regions or sub-regions. For example, a heat wave in the southern portion of a region, combined with relatively cool summer weather in the north, could create much greater power flows from the north to the south than what is experienced under the simulated normalized load conditions. Such greater power flows would create more transmission congestion and greater production costs. In these situations, transmission upgrades would be more valuable if they increased the transfer capability from the cooler to hotter regions.[198]

SPP's Metrics Task Force recently suggested that SPP's production simulations should be developed and tested for load profiles that represent 90/10 and 10/90 peak load conditions—rather than just for base case simulations (reflecting 50/50 peak load conditions)—as well as scenarios reflecting north-south differences in weather patterns.[199] Such simulations may help analyze the potential incremental value of transmission projects during different load conditions. While it is difficult to estimate how often such conditions might occur in the future, they do occur, and ignoring them disregards the additional value that transmission projects provide under these circumstances. For example, simulations performed by ERCOT for normal loads, higher-than-normal loads, and lower-than-normal loads in its evaluation of a Houston Import Project showed a $45.3 million annual consumer benefit for the base case simulation (normal load) compared to a $57.8 million probability-weighted average of benefits for all three simulated load conditions.[200]

[198] Because the incremental system costs associated with higher-than-normal loads tend to exceed the decremental system costs of lower-than-normal loads, the probability-weighted average production costs across the full spectrum of load conditions tend to be above the production costs for normalized conditions.

[199] Southwest Power Pool (SPP), *Benefits for the 2013 Regional Cost Allocation Review*, September 13, 2012, Section 9.6.

[200] Energy Reliability Council of Texas (ERCOT), *Economic Planning Criteria: Question 1: 1/7/2011 Joint CMWG/PLWG Meeting*, March 4, 2011, p10. The $57.8 million probability-weighted estimate is calculated based on ERCOT's simulation results for three load scenarios and Luminant's estimated probabilities for the same scenarios.

Mitigating the variability and uncertainty of renewable generation by diversifying it over geographic areas that exceed in size the scale of typical weather system has also been shown to provide substantial economic benefits, but requires the explicit simulation of both renewable generation variability and the day-ahead and intra-day uncertainty associated with intra-hour real-time generation as discussed in more detail in the subsection below.[201]

B.5 Estimating the Impacts of Imperfect Foresight of Real-Time System Conditions

Another simplification inherent in traditional production cost simulations is the deterministic nature of the models that assumes perfect foresight of all real-time system conditions. Assuming that system operators know exactly how real-time conditions will materialize when system operators must commit generation units in the day-ahead market means that the impact of many real-world uncertainties are not captured in the simulations. Changes in the forecasted load conditions, intermittent resource generation, or plant outages can significantly change the transmission congestion and production costs that are incurred due to these uncertainties.

Uncertainties associated with load, generation, and outages can impose additional costs during unexpected real-time conditions, including over-generation conditions that impose additional congestion costs. For example, comparing the number of negatively priced hours in the real-time versus the day-ahead markets in the ComEd load zone of PJM provides an example of how dramatically load and intermittent resource conditions can change.[202] From 2008 to 2010, there were 763 negatively priced hours in the real-time market, but only 99 negatively priced hours in the day-ahead market. The increase in negative prices in the real-time, relative to the day-ahead, market is due to the combined effects of lower-than-anticipated loads with the significantly higher-than-predicted output of intermittent wind resources. While this example illustrates the impact of uncertainties within the day-ahead time frame, traditional production cost simulations do not consider these uncertainties and their impacts.

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[201] Pfeifenberger, Ruiz, and Van Horn, *The Value of Diversifying Uncertain Renewable Generation Through the Transmission System*, BU-ISE Working Paper, September 2020.

[202] Pfeifenberger and Newell, Direct Testimony, FERC Docket No. ER11-4069-000 (RITELine), filed July 18, 2011.

In a recent study, analysts at The Brattle Group and researchers at Boston University estimated the value of diversifying uncertain renewable generation through the transmission system.[203] The analysis indicates that the benefits of transmission expansion between areas with diverse renewable generation resources are greater than typically estimated, with significant reductions in system-wide costs and renewable generation curtailments in both hourly day-ahead and intra-hour power market operations. For renewable generation levels from 10% to 60% of annual energy consumption, interconnecting two power market sub-regions with different wind regimes through transmission investments can reduce annual production costs by between 2% and 23% and annual renewable curtailments by 45% to 90%. When real-time uncertainties of renewable generation and loads relative to their day-ahead forecasts are taken into consideration, the benefit of geographic diversification through the transmission grid are 2 to 20 times higher than benefits typically quantified based only on "perfect forecasts."

Thus, to estimate the additional benefits that transmission upgrades can provide with the uncertainties associated with actual real-time system conditions, traditional production cost simulations need to be supplemented. For example, existing tools can be modified so that they simulate one set of load and generation conditions anticipated during the time that the system operators must commit the resources, and another set of load and generation conditions during real-time. The potential benefits of transmission investments also extend to uncertainties that need to be addressed through intra-hour system operations, including the reduced quantities and prices for ancillary services (such as regulation and spinning reserves) needed to balance the system as discussed further below.[204] These benefits will generally be more significant if transmission investments allow for increased diversification of uncertainties across the region, or if the investments increase transmission capabilities between renewables-

[203] Pfeifenberger, *Ruiz, Van Horn.*, The Value of Diversifying Uncertain Renewable Generation through the Transmission System: Cost Savings Associated with Interconnecting Systems with High Renewables Generation: Cost Savings Associated with Interconnecting Systems with High Renewables Penetration, presented for Boston University Institute for Sustainable Energy Webinar Series, October 14, 2020.

[204] For example, a recent study for the National Renewable Energy Laboratory (NREL) concluded that, with 20% to 30% wind energy penetration levels for the Eastern Interconnection and assuming substantial transmission expansions and balancing-area consolidation, total system operational costs caused by wind variability and uncertainty range from $5.77 to $8.00 per MWh of wind energy injected. The day-ahead wind forecast error contributes between $2.26/MWh and $2.84/MWh, while within-day variability accounts for $2.93/MWh to $5.74/MWh of wind energy injected. ($/MWh in US$2024). EnerNex Corporation, prepared for National Renewable Energy Laboratory (NREL), NREL/SR-5500-47078, Revised February 2013.

rich areas and resources in the rest of the grid that can be used to balance variances in renewable generation output.[205]

B.6 Estimating the Additional Benefits of Reducing the Frequency and Cost of Cycling Power Plants

With increased power production from intermittent renewable resources, some conventional generation units may be required to operate at their minimum operating levels and cycle up and down more frequently to accommodate the variability of intermittent resources on the system. Additional cycling of plants can be particularly pronounced when considering the uncertainties related to renewable generation that can lead to over-commitment and over-generation conditions during low loads periods. Such uncertainty-related over-generation conditions lead to excessive up/down and on/off cycling of generating units. The increased cycling of aging generating units may reduce their reliability, and the generating plants that are asked to shut down during off-peak hours may not be available for the following morning ramp and peak load periods, reducing the operational flexibility of the system. Some of these operational issues could reduce resource adequacy and increase market prices when the system must dispatch higher-cost resources.

Transmission investments can provide benefits by reducing the need for cycling fossil fuel power plants by spreading the impact of intermittent generation across a wider geographic region. Such projects provide access to a broader market and a wider set of generation plants to respond to the changes in generation output of renewable generation.

The cost savings associated with the reduction in plant cycling would vary across plants. A recent study of power plants in the Western U.S. found that increased cycling can increase the plants' maintenance costs and forced outage rates, accelerate heat rate deterioration, and reduce the lifespan of critical equipment and the generating plant overall. The study estimated

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[205] For a simplified framework to consider both short-term and long-term uncertainties in the context of transmission and renewable generation investments, see F. D. Munoz, B. F. Hobbs, J. Ho, and S. Kasina, "*An Engineering-Economic Approach to Transmission Planning Under Market and Regulatory Uncertainties: WECC Case Study*," Working Paper, JHU, March 2013;
A. H. Van Der Weijde, B. F. Hobbs, "*The Economics of Planning Electricity Transmission to Accommodate Renewables: Using Two-Stage Optimisation to Evaluate Flexibility and the Cost of Disregarding Uncertainty*," *Energy Economics*, 34(5). 2089-2101.
H. Park and R. Baldick, "Transmission Planning Under Uncertainties of Wind and Load: Sequential Approximation Approach," *IEEE Transactions on Power Systems*, vol. PP, no.99, March 22, 2013 pp1–8.

that the total hot-start costs for a conventional 500 MW coal unit are about $200/MW per start (with a range between $160/MW and $260/MW). The costs associated with equipment damage account for more than 80% of this total.[206]

Production cost simulations can be used to measure the impact of transmission investments on the frequency and cost of cycling fossil fuel power plants. However, the simplified representation of plant cycling costs in traditional production cost simulations—in combination with deterministic modeling that does not reflect many real-world uncertainties—will not fully capture the cycling-related benefits of transmission investments. Although SPP's Metrics Task Force recently suggested that production simulations be developed and tested,[207] this is an area where standard analytical methodology still needs to be developed.

B.7 Estimating the Additional Benefits of Reduced Amounts of Operating Reserves

Traditional production cost simulations assume that a fixed amount of operating reserves is required throughout the year, irrespective of transmission investments. Most market simulations set aside generation capacity for spinning reserves; regulation-up requirements may be added to that. Regulation-down requirements and non-spinning reserves are not typically considered. Such simplifications will understate the costs or benefits associated with any changes in ancillary service requirements. The analyses typically disregard the costs that integrating additional renewable resources may impose on the system or the potential benefits that transmission facilities can offer by reducing the quantity of ancillary services required. Such costs and benefits will become more important with the growth of variable renewable generation.

The estimation of these benefits consequently requires an analysis of the quantity and types of ancillary services at various levels of intermittent renewable generation, with and without the contemplated transmission investments. The Midwest ISO recently performed such an analysis,

[206] N. Kumar, *et al.*, Power Plant Cycling Costs, AES 12047831-2-1, prepared by Intertek APTECH for National Renewable Energy Laboratory and Western Electricity Coordinating Council, April 2012. The study is based on a bottom-up analysis of individual maintenance orders and failure events related to cycling operations, combined with a top-down statistical analysis of the relationship between cycling operations and overall maintenance costs. See *Id.* (2011), p 14. Costs inflated from $2008 to $2012. Note that the Intertek-APTECH's 2012 study prepared for NREL (Kumar, *et al.*, 2012) reported only 'lower-bound' estimates to the public.

[207] Southwest Power Pool (SPP), *Benefits for the 2013 Regional Cost Allocation Review*, September 13, 2012,, Section 9.4.

finding that its portfolio of multi-value transmission projects reduced the amount of operating reserves that would have to be held within individual zones, which allowed reserves to be sourced from the most economic locations. MISO estimated that this benefit was very modest, with a present value of $28 to $87 million, or less than one percent of the cost of the transmission projects evaluated.[208] In other circumstances, where transmission can interconnect regions that require additional supply of ancillary services with regions rich in resources that can provide ancillary services at relatively low costs (such as certain hydro-rich regions), these savings may be significantly larger. However, to quantify these benefits may require specialized (but available) simulation tools that can simulate both the impacts of imperfect foresight and the costs of intra-hour load following and regulation requirements.[209] Most production cost simulations are limited to simulating market conditions with perfect foresight and on an hourly basis.

FIGURE 15. DELIVERABILITY CAPACITY NEEDS AT 40% RENEWABLE ENERGY

Source: MISO, *MISO's Renewable Integration Impact Assessment (RIIA)*, Summer Report, February 2021, p 99.

Finally, a number of organized power markets do not co-optimize the dispatch of energy and ancillary services resources. Other regions with co-optimized markets may still require some location-specific unit commitment to provide ancillary services. If not considered in market simulations, this can understate the potential benefits associated with transmission-related congestion relief.

208 Midwest ISO, *Proposed Multi Value Project Portfolio*, Technical Study Task Force and Business Case Workshop, August 22, 2011. , pp 29-33.

209 For an example of the quantification of these benefits, see Pfeifenberger, Ruiz, Van Horn, The Value of Diversifying Uncertain Renewable Generation through the Transmission System, BU-ISE, October 14, 2020.

B.8 Estimating the Benefits of Mitigating Reliability Must-Run Conditions

Traditional production cost simulation models determine unit commitment and dispatch based on first contingency transmission constraints, utilizing a simple direct current (DC) power-flow model. This means that the simulation models will not by themselves be able to determine the extent to which generation plants would need to be committed for certain local reliability considerations, such as for system stability and voltage support and to avoid loss of load under second system contingencies. Instead, any such “reliability must run” (RMR) conditions must be identified and implemented as a specific simulation input assumption. Both existing RMR requirements and the reduction in these RMR conditions as a consequence of transmission upgrades need to be determined and provided as a modeling input separately for the Base Case and Change Case simulations.

RMR-related production cost savings provided by transmission investments can be significant. For example, a recent analysis of transmission upgrades into the New Orleans region shows that certain transmission projects would significantly alleviate the need for RMR commitments of several local generators. Replacing the higher production costs from these local RMR resources with the market-based dispatch of lower-cost resources resulted in estimated annual production cost savings ranging from approximately $50 million to $100 million per year.[210] Avoiding or eliminating a set of pre-existing RMR requirements needed to be specified as model input assumptions.

B.9 Estimating Production Costs in “Day-1” Markets

When analyzing transmission benefits in bilateral, non-RTO markets, it is important to recognize that generation unit commitment and dispatch in such “Day-1” markets is not the same as in an LMP-based RTO market. Thus, if simulated as security-constrained LMP-based regional markets, the simulations would understate the benefit of transmission investments in non-RTO markets by over-optimizing the system operations compared to real-world outcomes. To recognize some of the realities of such “Day-1” markets, planners have traditionally imposed “hurdle rates” on transactions between individual balancing areas. This is important to prevent the simulations from over-optimizing system dispatch relative to actual market outcomes. However, relying solely on hurdle rates to approximate realistic market outcomes may not be

[210] Pfeifenberger, Direct Testimony on behalf of ITC Holdings, Exhibit No. ITC-600, before the Federal Energy Regulatory Commission, Docket Nos. EC12-145 et al., September 24, 2012.

sufficient. Thus, derates of transmission limits may also be necessary to capture the fact that congestion management through transmission loading relief (TLR) processes in "Day-1" markets typically results in under-utilization of flow-gate limits. For example, an analysis of RTO-market benefits by the Department of Energy (DOE) assumed that improved congestion management and internalization of power flows by ISOs result in a 5–10% increase in the total transfer capabilities on transmission interfaces.[211] Similarly, a study of congestion management in MISO's "Day-1" market found that, during 2003, available flowgate capacities were underutilized by between 7.7% to 16.4% on average within MISO subregions during TLR events compared to the flows that could have been accommodated had the grid been efficiently dispatched using a regional security-constrained economic dispatch.[212]

We recommend that "Day-1" market simulations use both hurdle rates and derates to more realistically approximate actual market conditions (in both base and change case simulations). Hurdle rates as traditionally used will appropriately decrease flows between balancing areas, reduce congestion, and thus reduce the economic value of increased transmission between balancing areas. In contrast, derates will tend to simulate more realistic level of congestion within and across balancing areas, which will tend to increase the estimated production cost savings of transmission upgrades. These potential additional production cost savings will not be captured in traditional market simulations that rely solely on hurdle rates to approximate "Day-1" market conditions.

[211] U.S. Department of Energy, Report to Congress, *Impacts of the Federal Energy Regulatory Commission's Proposal for Standard Market Design*, DOE/S-0138, April 30, 2003, pp 7-8 and 41-42.

[212] R.R. McNamara, Affidavit on behalf of Midwest ISO before the Federal Energy Regulatory Commission, Docket ER04-691-000, on June 25, 2004, p 14.

Appendix C – Other Potential Project-Specific Benefits

Some transmission investments can create additional benefits that are very specific to the particular set of projects. These benefits may include improved storm hardening, increased loadserving capability, synergies with future transmission projects, the option value of large transmission facilities to improve future utilization of available transmission corridors, fuel diversity and resource planning flexibility, increased wheeling revenues, and the creation of additional physical or financial transmission rights to improve congestion hedging opportunities. Below, we discuss each briefly.

C.1 Storm Hardening and Wildfire Resilience

In regions that experience storm- or wild-fire induced transmission outages, certain transmission upgrades can improve the resilience of the existing grid transmission system. Strong storms that damage transmission lines can drastically affect an entire region where production cost impacts and the value of lost load can be very large. Even if new transmission lines intended to increase system resilience are built along similar routes as existing transmission lines (and thus seemingly can be damaged by the same natural disasters), newer technologies and construction standards would allow the new projects to offer greater storm resilience than the existing transmission lines.[213] Adding transmission on geographically sufficiently separate rights of ways will mitigate risks even if each of the transmission paths face equal risks of storm or wild-fire induced outages.

C.2 Increased Load Serving Capability

A transmission project's ability to increase future load-serving capability ahead of specific transmission service requests is usually not considered when evaluating transmission benefits. For example, in regions experiencing significant load growth, the existing electric system often requires costly and possibly time-consuming system upgrades when a new industrial or commercial customer with a significant amount of load is contemplating locating in a utility's service area. At times, new transmission lines built to serve other needs (such as to increase

[213] Pfeifenberger, Direct Testimony on behalf of ITC Holdings, Exhibit No. ITC-600, before the Federal Energy Regulatory Commission, Docket Nos. EC12-145 *et al.*, September 24, 2012, pp 79–80.

market efficiency or to meet public-policy objectives) can also create low-cost options to quickly increase load-serving capability in the future.[214]

C.3 Synergies with Future Transmission Projects and Asset Replacement Needs

Certain transmission projects provide synergies with future transmission investments. For example, the building of the Tehachapi transmission project to access 4,500 MW of wind resources in the CAISO provides the option for a lower-cost upgrade of Path 26 than would otherwise be possible, as well as additional options for future transmission expansions in that region.[215] Planning a set of “no-regrets” projects that will be needed under a wide range of future market conditions can help capitalize on such “option value.” For instance, the RITELine Project (spanning from western Illinois to Ohio) provides a “no regrets” step toward the creation of a larger regional transmission overlay that can integrate the substantial amount of renewable generation needed to meet the regional states’ RPS requirements over the next 10 to 20 years.[216] A number of regional planning efforts (such as RGOS I, RGOS II, and SMART) have shown that the expansion of renewable generation over the next 20 years may require construction of a Midwest-wide regional transmission overlay. The RITELine Project is an element common to the transmission configurations recommended in each of these larger regional transmission studies and, thus, in addition to the project’s standalone merit, creates the option of becoming an integrated part of such a regional overlay. Because the project is both valuable on a stand-alone basis and can be used as an element of the larger potential regional overlays, it can be seen as a first step that provides the option for future regional transmission buildout. Finally, as discussed in the main body of this report, New York’s Public Policy Transmission Projects, built on the right of way of aging transmission facilities that would need to be replaced within the next decade, offer significant cost savings by avoiding having to replace the aging facilities in the future.[217] These benefit of synergies with the replacement of aging facilities on scarce and valuable rights of way is particularly important because as PJM explains, for example:

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[214] For example, see *id.*, p 80.

[215] California ISO, *Transmission Economic Assessment Methodology (TEAM)*, June 2004, pp 9–21. Tehachapi region referred to as Kern County.

[216] Pfeifenberger and S. A. Newell, Direct Testimony, FERC Docket No. ER11-4069-000 (RITELine), filed July 18, 2011.

[217] Newell, *et al.*, *Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades*, September 15, 2015.

> The regional high-voltage transmission system is aging. Many facilities were placed in service in the 1960s or earlier and are deteriorating and reaching the end of their useful lives. Within PJM, nearly two-thirds of all bulk electric system assets are more than 40 years old and more than one third are more than 50 years old. Some local lower-voltage equipment, especially below 230 kV, is approaching 90 years old.[218]

C.4 Up-Sizing Lines and Improved Utilization of Available Transmission Corridors

The number of right-of-way "corridors" on which new transmission lines can be built is often extremely limited, particularly in heavily populated or environmentally sensitive areas. As a result, constructing a new line on a particular right-of-way may limit or foreclose future options of building a higher-capacity line or additional lines. Foreclosing that option can turn out to be very costly. It will often be possible, however, to preserve this option or reduce the cost of foreclosing that option through the design of the transmission line that is planned and constructed now. For example, "upsizing" a transmission line ahead of actual need (*e.g.*, to a double-circuit or higher-voltage line) requires incremental investment but will greatly reduce the cost of foreclosing the option to increase capacity along the same corridor when additional transfer capability would be needed in the future. Similarly, the option to increase transmission capabilities in the future can be created, for example, by building a single-circuit line on double-circuit towers that create the option to add a second circuit in the future. Building a line rated for a higher voltage level than the voltage level at which it is initially operated (*e.g.*, building a line with 765kV equipment that is initially operated only at 345kV) creates the option to increase the transfer capability of the line at modest incremental costs in the future. While investing more today to create such low-cost options to "up-size" lines in the future may be valuable even without right of way limits, this option will be particularly valuable if finding additional right of ways would be very difficult or expensive.

[218] PJM "*The Benefits of the PJM Transmission System*" PJM Interconnection at 5 (April 16, 2019). See also see also Affidavit of Johannes P. Pfeifenberger and John Michael Hagerty in FERC Docket ER20-2308-000, on behalf of LS Power, July 23, 2020.

C.5 Increased Fuel Diversity and Resource Planning Flexibility

Transmission upgrades sometimes can help interconnect areas with very different resource mixes, thereby diversifying the fuel mix in the combined region and reducing price and production cost uncertainties. Projects also can provide resource planning flexibility by strengthening the regional power grid and lowering the cost of addressing future uncertainties, such as changes in the relative fuel costs, public policy objectives, coal plant retirements, or natural gas delivery constraints.

C.6 Benefits Related to Relieving Constraints in Fuel Markets

Additional transmission lines can provide benefits associated with relieving constraints in fuel markets. For example, recent reliability concerns in New England concerning gas-electric coordination issues caused by the increasing reliance on natural gas fired generation and limitations on pipeline capacity could be alleviated by additional import capacity for wholesale power from outside New England. In addition, increased diversity of generation resources enabled by new transmission lines can reduce the demand and price of fuel.[219]

C.7 Increased Wheeling Revenues

As mentioned in the context of interregional cost allocation, a transmission line that increases exports (or wheeling through) of low-cost generation to a neighboring region can provide additional benefits to the exporting region's customers through increased wheeling out revenues. The increase in wheeling revenues, paid for by the exporting generator or importing buyer, will offset a portion of the transmission projects' revenue requirements, thus reducing the net costs to the region's own transmission customers. While not an economy-wide benefit, increasing a transmission owner's wheeling revenues is equivalent to allocating some of the project costs to exporters and/or neighboring regions. For example, our analysis of an illustrative portfolio of transmission projects in the Entergy region estimated that approximately $400 million of potential resource adequacy benefits were realized from

[219] V. Budhraja, J. Balance, J. Dyer, and F. Mobasher, *Transmission Benefit Quantification, Cost Allocation and Cost Recovery*, Final Project Report prepared for CIEE by Lawrence Berkeley National Laboratory and CERTS, Proj. Mgr. J. Eto, June 2008, pp 43-44.

deferred generation investment needs in the TVA service area by exporting additional amounts of surplus capacity from merchant generators in the Entergy region. While this is a benefit that accrues in large part to TVA customers and merchant generators in the Entergy region, approximately $130 million of the $400 million benefits accrue to Entergy and MISO customers in the form of additional MISO wheeling revenues after Entergy joins MISO, which partially offset the transmission projects' revenue requirements that would need to be recovered from Entergy/MISO customers and other market participants.[220] SPP has also estimated that the additional export capability created by its portfolio of ITP projects increases SPP wheeling-out revenues, which offsets the present value of its transmission revenue requirements by over $600 million, thereby offsetting a meaningful portion of the costs of SPP regional transmission project, even though these projects were not specifically planned to increase export capability.[221]

C.8 Increased Transmission Rights and Customer Congestion-Hedging Value

A transmission project that increases transfer capabilities between lower-cost and higher-cost regions of the power grid can provide customer benefits by providing access in the form of increasing the availability of physical transmission rights in non-RTO markets or across RTO boundaries. Within RTOs, the transmission upgrade would increase financial transmission rights that can be requested by and allocated to load-serving entities. The availability of additional FTRs increases the proportion of congestion charges that can be hedged by LSEs, thereby reducing congestion-related uncertainty. The additional FTRs can also reduce an area's customer costs by allowing imports from lower-cost portions of the region.[222] While a transmission upgrade may result in increased FTR revenues to LSEs from additional FTRs, the customer benefit of these additional revenues tends to be offset by revenue decreases from existing FTRs because the project will reduce congestion charges (and therefore reduce revenues from existing FTRs). For example, our analysis of the congestion and FTR-related impacts for the Paddock-Rockdale project in Wisconsin showed that these customer impacts

[220] For example, see Pfeifenberger, Direct Testimony on behalf of ITC Holdings, Exhibit No. ITC-600, before the Federal Energy Regulatory Commission, Docket Nos. EC12-145 *et al.*, September 24, 2012, pp 73-76.

[221] SPP, *RCAR 2 Report* (spp.org), July 11, 2016, Figure 7.1

[222] As noted earlier, this benefit is not captured in the traditional adjusted production cost (APC) and Load LMP metrics, because the metrics assume that all imports are priced at the load's location (*i.e.*, the area-internal Load LMP).

can range widely—from increasing traditional APC estimates by approximately 50% in scenarios with low APC savings to decreasing traditional APC estimates by approximately 35% in scenarios with high APC savings.[223]

C.9 Operational Benefits of High-Voltage Direct-Current Transmission Lines

The addition of high-voltage direct-current ("HVDC") transmission lines can provide a range of operational benefits to system operators by enhancing reliability and reducing the cost of system operations. These operational benefits of HVDC lines, which in large part stem from the projects' new converter technologies, are broadly recognized in the industry. For example, various authors note that the technology can be used to: (1) provide dynamic voltage support to the AC system, thereby increasing its transfer capability;[224] (2) supply voltage and frequency support;[225] (3) improve transient stability[226] and reactive performance;[227] (4) provide AC system damping;[228] (5) serve as a "firewall" to limit the spread of system disturbances;[229] (6) "decouple" the interconnected system so that faults and frequency variations between the wind farms and the AC network or between different parts of the AC network do not affect each other;[230] and (7) provide blackstart capability to re-energize a 100% blacked-out portion of

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[223] Pfeifenberger, Direct Testimony on behalf of American Transmission Company, before the Public Service Commission of Wisconsin, Docket 137-CE-149, January 17, 2008, Appendix A.

[224] M. P. Bahrman, "HVDC Transmission Overview," *Transmission and Distribution Conference and Exposition, 2008*. T&D. IEEE/PES, April 21-24, 2008), p 5.

[225] S. Wang, J. Zhu, L. Trinh, and J Pan, "Economic Assessment of HVDC Project in Deregulated Energy Markets," *Electric Utility Deregulation and Restructuring and Power Technologies*, 2008. DRPT 2008. IEEE Third International Conference, pp18, 23, 6-9 April 2008, p 19.

[226] Institute of Electrical and Electronics Engineers (IEEE) Power & Energy Society (PES), *HVDC Systems & Trans Bay Cable*, presentation, March 16, 2005, p 75.

[227] As noted in several sources including: (1) University of Maryland Center for Integrative Environmental Research, *Maryland Offshore Wind Development: Regulatory Environment, Potential Interconnection Points, Investment Model, and Select Conflict Areas*, October 2010, p 51; (2) European Wind Energy Association, *Oceans of Opportunity: Harnessing Europe's Largest Domestic Energy Resource*, September 2009, p 27; and (3) S. D. Wright, A. L. Rogers, J. F. Manwell, A> Ellis, "Transmission Options for Offshore Wind Farms in the United States," in Proceedings of the American Wind Energy Association (AWEA) Annual Conference, 2002, p 5.

[228] Institute of Electrical and Electronics Engineers (IEEE) Power & Energy Society, *HVDC Systems & Trans Bay Cable*, presentation, March 16, 2005, p 75.

[229] Siemens, "HVDC PLUS (VSC Technology): Benefits," n.d. .

[230] L. P. Lazaridis, *Economic Comparison of HVAC and HVDC Solutions for Large Offshore Wind Farms under Special Consideration of Reliability*, Master's Thesis X-ETS/ESS-0505, Royal Institute of Technology Department of Electrical Engineering, 2005, p 34.

the network.[231] For example, PJM recognized these benefits in its evaluation of the HVDC option for the Mid-Atlantic Power Pathway project.[232] It was also found that the proposed Atlantic Wind Connection HVDC submarine project's ability to redirect flow instantaneously will provide PJM with additional flexibility to address reliability challenges, system stability, voltage support, improved reactive performance, and blackstart capability.[233]

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[231] As noted in several sources including: (1) University of Maryland Center for Integrative Environmental Research, Maryland Offshore Wind Development: Regulatory Environment, Potential Interconnection Points, Investment Model, and Select Conflict Areas, October 2010, p 51; (2) European Wind Energy Association, Oceans of Opportunity: Harnessing Europe's Largest Domestic Energy Resource, September 2009, p 27; and (3) S. D. Wright, A. L. Rogers, J. F. Manwell, A. Ellis, "Transmission Options for Offshore Wind Farms in the United States," in Proceedings of the American Wind Energy Association (AWEA) Annual Conference, 2002, p 5.

[232] PJM Interconnection, "2008 RTEP — Reliability Analysis Update," Transmission Expansion Advisory Committee (TEAC) Meeting, October 15, 2008, pp 8-10.

[233] Pfeifenberger and S. A. Newell, Direct Testimony on behalf of The AWC Companies, before the Federal Energy Regulatory Commission, Docket No. EL11-13-000, December 20, 2010.

Appendix D – Approaches Used to Quantify Transmission Benefits

(Source: 2013 Brattle report for WIRES[234])

	Transmission Benefit	Benefit Description	Approach to Estimating Benefit	Examples
1. Traditional Production Cost Savings – See Section IV.2.				
2. Additional Production Cost Savings				
--	Reduced impact of forced generation outages	Consideration of both planned and forced generation outages will increase impact	Consider both planned and (at least one draw of) forced outages in market simulations.	Already considered in most (but not all) RTOs
a.	Reduced transmission energy losses	Reduced energy losses incurred in transmittal of power from generation to loads reduces production costs	Either (1) simulate losses in production cost models; (2) estimate changes in losses with power flow models for range of hours; or (3) estimate how cost of supplying losses will likely change with marginal loss charges	CAISO (PVD2) ATC Paddock-Rockdale SPP (RCAR)
b.	Reduced congestion due to transmission outages	Reduced production costs during transmission outages that significantly increase transmission congestion	Introduce data set of normalized outage schedule (not including extreme events) into simulations or reduce limits of constraints that make constraints bind more frequently	SPP (RCAR) RITELine
c.	Mitigation of extreme events and system contingencies	Reduced production costs during extreme events, such as unusual weather conditions, fuel shortages, or multiple outages.	Calculate the probability-weighed production cost benefits through production cost simulation for a set of extreme historical market conditions	CAISO (PVD2) ATC Paddock-Rockdale
d.	Mitigation of weather and load uncertainty	Reduced production costs during higher than normal load conditions or significant shifts in regional weather patterns	Use SPP suggested modeling of 90/10 and 10/90 load conditions as well as scenarios reflecting common regional weather patterns	SPP (RCAR)
e.	Reduced costs due to imperfect foresight of real-time conditions	Reduced production costs during deviations from forecasted load conditions, intermittent resource generation, or plant outages	Simulate one set of anticipated load and generation conditions for commitment (*e.g.*, day ahead) and another set of load and generation conditions during real-time based on historical data	
f.	Reduced cost of cycling power plants	Reduced production costs due to reduction in costly cycling of power plants	Further develop and test production cost simulation to fully quantify this potential benefit ; include long-term impact on maintenance costs	WECC study

[234] Chang, Pfeifenberger, and Hagerty, *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments*, prepared for WIRES, July 2013.

	Transmission Benefit	Benefit Description	Approach to Estimating Benefit	Examples
g.	Reduced amounts and costs of ancillary services	Reduced production costs for required level of operating reserves	Analyze quantity and type of ancillary services needed with and without the contemplated transmission investments	NTTG WestConnect MISO MVP
h.	Mitigation RMR conditions	Reduced dispatch of high-cost RMR generators	Changes in RMR determined with external model used as input to production cost simulations	ITC-Entergy CAISO (PVD2)
i.	More realistic representation of system utilization in "Day-1" markets	Transmission offers higher benefits if market design is utilizing the existing grid less efficiently	Use flowgate derates (in addition to the traditional use of hurdle rates between balancing areas) in production cost simulations to more realistically approximate system utilization in "Day-1" markets	MISO "Day-2" Market benefit analysis
3–4. Reliability and Resource Adequacy Benefits and Generation Capacity Cost Savings				
Transmission Benefit		**Benefit Description**	**Approach to Estimating Benefit**	**Examples**
3. Reliability and Resource Adequacy Benefits				
a.	Avoided or deferred reliability projects	Reduced costs on avoided or delayed transmission lines otherwise required to meet future reliability standards	Calculate present value of difference in revenue requirements of future reliability projects with and without transmission line, including trajectory of when lines are likely to be installed	ERCOT All RTOs and non-RTOs ITC-Entergy analysis MISO MVP
b.	Reduced loss of load probability Or:	Reduced frequency of loss of load events (if planning reserve margin is not changed despite lower LOLEs)	Calculate value of reliability benefit by multiplying the estimated reduction in Expected Unserved Energy (MWh) by the customer-weighted average Value of Lost Load ($/MWh)	SPP (RCAR)
c.	Reduced planning reserve margin	Reduced investment in capacity to meet resource adequacy requirements (if planning reserve margin is reduced)	Calculate present value of difference in estimated net cost of new entry (Net CONE) with and without transmission line due to reduced resource adequacy requirements	MISO MVP SPP (RCAR)
4. Generation Capacity Cost Savings				
a.	Capacity cost benefits from reduced peak energy losses	Reduced energy losses during peak load reduces generation capacity investment needs	Calculate present value of difference in estimated net cost of new entry (Net CONE) with and without transmission line due to capacity savings from reduced energy losses	ATC Paddock-Rockdale MISO MVP SPP ITC-Entergy
b.	Deferred generation capacity investments	Reduced costs of generation capacity investments through expanded import capability into resource-constrained areas	Calculate present value of capacity cost savings due to deferred generation investments based on Net CONE or capacity market price data	ITC-Entergy

	Transmission Benefit	Benefit Description	Approach to Estimating Benefit	Examples
c.	Access to lower-cost generation	Reduced total cost of generation due to ability to locate units in a more economically efficient location	Calculate reduction in total costs from changes in the location of generation attributed to access provided by new transmission line	CAISO (PVD2) MISO ATC Paddock-Rockdale

5–6. Market, Environmental and Public Policy

	Transmission Benefit	Benefit Description	Approach to Estimating Benefit	Examples
5. Market Benefits				
a.	Increased competition	Reduced bid prices in wholesale market due to increased competition amongst generators	Calculate reduction in bids due to increased competition by modeling supplier bid behavior based on market structure and prevalence of "pivotal suppliers"	ATC Paddock-Rockdale CAISO (PVD2, Path 26 Upgrade)
b.	Increased market liquidity	Reduced transaction costs and price uncertainty	Estimate differences in bid-ask spreads for more and less liquid markets; estimate impact on transmission upgrades on market liquidity	SCE (PVD2)
6. Environmental Benefits				
a.	Reduced emissions of air pollutants	Reduced output from generation resources with high emissions	Additional calculations to determine net benefit emissions reductions not already reflected in production cost savings	NYISO CAISO
b.	Improved utilization of transmission corridors	Preserve option to build transmission upgrade on an existing corridor or reduce the cost of foreclosing that option	Compare cost and benefits of upsizing transmission project (*e.g.*, single circuit line on double-circuit towers; 765kV line operated at 345kV)	
7.	**Public Policy Benefits**	Reduced cost of meeting policy goals, such as RPS	Calculate avoided cost of most cost-effective solution to provide compliance to policy goal	ERCOT CREZ ISO-NE, CAISO MISO MVP SPP (RCAR)

Appendix B

January 2021

Americans for a Clean Energy Grid

DISCONNECTED: THE NEED FOR A NEW GENERATOR INTERCONNECTION POLICY

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Report Sponsors

This report was sponsored by Americans for a Clean Energy Grid, with support from the Macro Grid Initiative.

About Americans for a Clean Energy Grid

Americans for a Clean Energy Grid (ACEG) is the only non-profit broad-based public interest advocacy coalition focused on the need to expand, integrate, and modernize the North American high voltage grid.

Expanded high voltage transmission will make America's electric grid more affordable, reliable, and sustainable and allow America to tap all economic energy resources, overcome system management challenges, and create thousands of well-compensated jobs. But an insular, outdated and often short-sighted regional transmission planning and permitting system stands in the way of achieving those goals.

ACEG brings together the diverse support for an expanded and modernized grid from business, labor, consumer and environmental groups, and other transmission supporters to educate policymakers and key opinion leaders to support policy which recognizes the benefits of a robust transmission grid.

About the Macro Grid Initiative

The Macro Grid Initiative is a joint effort of the American Council on Renewable Energy and Americans for a Clean Energy Grid to promote investment in a 21st century transmission infrastructure that enhances reliability, improves efficiency and delivers more low-cost clean energy. The Initiative works closely with the American Wind Energy Association, the Solar Energy Industries Association, the Advanced Power Alliance and the Clean Grid Alliance to advance our shared goals.

Table of Contents

I. Executive Summary

America's system for planning and paying for the nation's transmission grid is causing a massive backlog and delay in the construction of new power projects. While locally produced electric power is gaining in popularity, most of the lowest cost new power production comes from projects which are located in rural areas and, thus, depend on new electricity lines to deliver power to the urban and suburban areas which use most of the nation's power. Project developers must apply for interconnection to the transmission network, and until the network capacity is expanded to accommodate the resources, the projects must wait in an "interconnection queue." At the end of 2019, 734 gigawatts of proposed generation were waiting in interconnection queues nationwide.[1]

This massive backlog has multiple negative impacts on the nation. First, it needlessly increases electricity costs for America's homes and businesses in two ways: (1) it slows or prevents the adoption of new power sources which are cheaper than existing power generation; and (2) it also significantly increases the costs of each new power source. Americans for a Clean Energy Grid's (ACEG) recent study demonstrates that a comprehensive approach to building transmission to connect remote power resources to electricity load centers in the Eastern half of the U.S. can cut consumers electric bills by $100 billion and decrease the average electric bill rate by more than one-third, from over 9 cents/kWh today to around 6 cents/kWh by 2050,

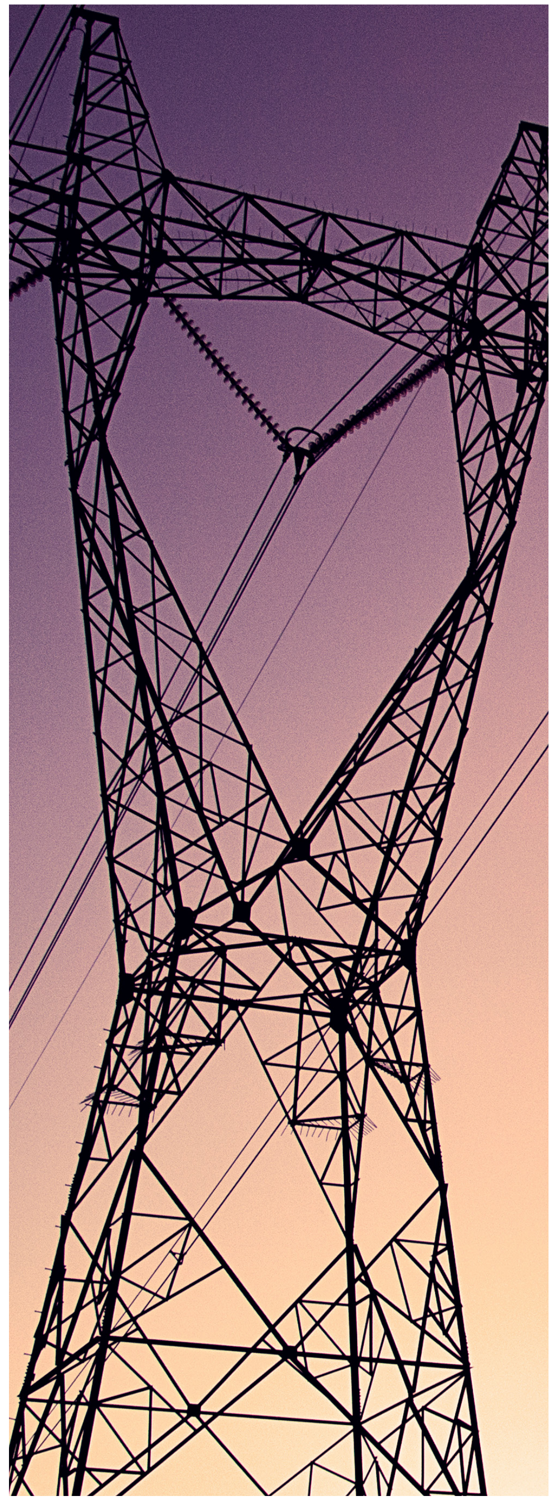
[1] Ryan Wiser et al., *Wind Energy Technology Data Update: 2020 Edition*, at 18, August 2020. *See* also underlying data in the *2020 Wind Energy Technology Data Update* accompanying the slide deck.

Key Findings

- The current system for planning and paying for expansion of the transmission grid is so unworkable and inefficient it is creating a huge backlog of unbuilt energy projects. At the end of 2019, 734 gigawatts of proposed generation were waiting in interconnection queues nationwide.
- This backlog is needlessly increasing electricity costs for consumers by delaying the construction of new projects which are cheaper than existing electricity production.
- Because most of these projects are located in remote rural areas, this backlog is harming rural economic development and job creation.
- Almost 90 percent of the backlog is for wind, solar, and storage projects. The backlog may delay or prevent achievement of commitments that states, utilities, and Fortune 500 companies have made to scale up their renewable energy use or reduce their pollution.
- The risk from the uncertainty of the interconnection process significantly increases the cost of capital for generation developers, which increases the cost of energy for customers.
- Although Regional Transmission Orginizations (RTOs) and the Federal Energy Regulatory Commission (FERC) have undertaken worthwhile attempts to alleviate interconnection backlogs, the interconnection queues remain costly, lengthy, and unpredictable.
- The current "participant funding "policy that places nearly all costs of shared large network upgrades on the interconnection customer violates FERC's "beneficiary pays" principle and is therefore no longer a "just and reasonable" policy and violates the Federal Power Act.

Key Recommendations

- FERC should discontinue the policy of participant funding for new generation. Shared network upgrades resulting from generation interconnection requests provide economic and reliability benefits to loads and reduce congestion to improve grid efficiencies and operational flexibility, and therefore should not be fully assigned to interconnection generators.
- FERC and planning authorities should expand and improve regional and inter-regional transmission planning processes to be pro-active, incorporating future generation additions and retirements and the multiple benefits, and spread costs to all beneficiaries.



saving a typical household more than $300 per year.[2]

Second, because the lowest cost proposed power projects are often located in rural areas, this backlog is blocking rural economic development and job creation. In addition, rural power projects expand the tax base of local communities and typically generate lease payments or other revenue for farmers and other landowners. New transmission in the Eastern half of the U.S. alone will unleash up to $7.8 trillion in investment in rural America and create more than 6 million net new domestic jobs.[3]

Third, almost 90 percent of the backlog is for wind and solar projects, thus blocking the resources which dominate new electricity production, reflecting the changing resource mix in the power sector and America's abundance of high-quality renewable resource areas where the sun shines bright and the wind blows strong.[4] The U.S. Energy Information Administration (EIA) projects wind and solar will account for 75 percent of new electricity generation in 2020.[5] Many states, utilities, Fortune 500 companies and other institutions have adopted large commitments or requirements to scale up their renewable energy use or reduce their carbon pollution and this backlog may delay or impede achievement of these commitments or requirements. In addition, delays in developing these projects unnecessarily exposes Americans, especially those in environmental justice communities, to the harmful impacts of smog, and nitrogen oxide, sulfur dioxide, fine particulate and carbon dioxide pollution.

Policies governing the interconnection of generators to the grid network stand in the way of accessing these remote resources. Interconnection policies and procedures governing transmission engineering studies, queuing, and allocating transmission upgrade costs are set by the Federal Energy Regulatory Commission (FERC) and implemented in

2 Christopher T.M. Clack et al., *Consumer, Employment, and Environmental Benefits of Electricity Transmission Expansion in the Eastern U.S.*, October 2020.

3 *Id.*

4 Ryan Wiser et al., *Wind Energy Technology Data Update: 2020 Edition*, at 18, August 2020. *See* also underlying data in the *2020 Wind Energy Technology Data Update* accompanying the slide deck.

5 U.S. Energy Information Administration, *New Electric Generating Capacity in 2020 Will Come Primarily From Wind and Solar*, January 14, 2020.

detail by all of the hundreds of transmission providers around the country including the Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs).[6]

Although FERC and the RTOs have undertaken worthwhile reforms to alleviate interconnection backlogs, the interconnection queues are costly, lengthy, and unpredictable. Power project developers are uncertain if their project will be approved and this risk significantly increases the cost of capital for generation developers, which increases the cost of energy for customers.

The current process also places nearly all costs of network upgrades on the energy project developer, even though many others will benefit from the construction of the project. Until a few years ago, these interconnection charges for new renewable resources would comprise under 10 percent of the total project cost for most projects. In recent years - due to the lack of sufficient large-scale transmission build - these costs have dramatically risen and interconnection charges now can comprise as much as 50 to 100 percent of the generation project costs. The system has reached a breaking point recently as spare transmission has been used up. Presently in most regions, new network capacity is needed for almost all of the projects in the queues.

Participant funding for new grid connections is no longer a "just and reasonable" policy and violates FERC's "beneficiary pays" principle and the Federal Power Act. Relying on the interconnection process to identify needed transmission leads to a piecemeal approach and inefficiently small upgrades, raising costs to consumers. The incremental reforms at the RTO-level over the past decade have only served to treat symptoms of this fundamental issue – the lack of alignment between regional planning processes and the interconnection process.

There is a better way. RTOs could conduct comprehensive transmission planning which would identify the transmission lines to connect many new energy projects to the grid and deliver the greatest benefits for consumers. It is time for FERC and RTOs to undertake a fundamental re-thinking of interconnection and transmission planning policy based on different circumstances than those that existed when these policies were developed. Full participant funding should no longer be allowed in RTO or non-RTO areas.

More broadly, FERC and RTOs should pursue planning reforms. Consumers would benefit from more efficient transmission at a scale that brings down the total delivered cost, rather than continuing the current cycle of incremental transmission built in the project-by-project or generator-only cost assignment regime. That shift will not happen in the current interconnection process. Instead, FERC should fundamentally reform the regional and inter-regional transmission planning process to require broader pro-active and multi-purpose transmission planning.

This paper is structured as follows:

- Section II explains the origin of current interconnection policy;
- Section III describes implications of a different set of resources than those for which the policies were designed;
- Section IV provides evidence that the current policy no longer works for the current mix;
- Section V describes incremental solutions to those problems;
- Section VI argues that the real solution must involve broader transmission planning reform; and
- Section VII concludes.

[6] Throughout this paper, we refer to RTOs and ISOs together simply as "RTOs."

II. Interconnection Queue Policy Inherited from a Bygone Era

Generator interconnection policy was established two decades ago when almost all new interconnecting generators were natural gas-fired. Gas generators can interconnect with transmission systems in a relatively wide variety of locations, allowing them to avoid transmission constraints. As a result, transmission planning is less important with gas generation, as locational wholesale market prices and network upgrade costs assigned to interconnecting generators are able to direct gas generation investment to economically efficient locations.

Our current interconnection policies are an increasingly obsolete vestige of that era. FERC Order No. 2003, issued in the year 2003, standardized Large Generator Interconnection Procedures (LGIPs) and Large Generator Interconnection Agreements (LGIAs). As part of the Order, FERC determined that RTOs may propose that interconnecting generators be solely responsible for paying for Generation Interconnection (GI) network upgrades—a cost allocation policy referred to as "participant funding."[7] The Commission reasoned that "...under the right circumstances, a well-designed and independently administered participant funding policy for Network Upgrades offers the potential to provide more efficient price signals and a more equitable allocation of costs than [a] crediting approach."[8] The policy also included a serial approach to interconnection, wherein each generator was reviewed independently for its own impacts on the network in the order they enter the interconnection queue. The Commission's participant funding policy applied only to RTOs and not to utilities non-RTO areas.

That policy of a generator-by-generator transmission planning process and individual assignment of network upgrade costs worked reasonably well for the gas generation additions of the early 2000s. A whopping 191,745 megawatts (MW) of natural gas capacity was added between 2000 and 2005,

[7] *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103, at P 28, July 24, 2003. *Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 715, July 21, 2011 (defining "participant funding").

[8] *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103, at P 695, July 24, 2003.

compared to 23,434 MW for the entire decade from 2010-2019.[9] After that gas generation boom, the resource mix of new interconnecting generators changed as interest in renewable energy grew among states and customers and the costs of utility-scale wind and solar projects continued to decline. Utility-scale wind and solar projects have dominated generating capacity additions over the last decade, with around 100,000 MW added, and they are expected to account for an even larger share of capacity additions going forward.

The transmission policy embodied in FERC Order 2003 that provided efficient incentives for the siting of gas generation has proven inefficient and unworkable for today's resource mix. Wind, and to a lesser extent solar generation, is heavily location-constrained, unlike gas generation. Wind turbines located near the best wind resources are several times more productive than wind turbines at a typical site selected at random, while the best solar resource sites are about twice as productive as less optimal sites, corresponding to a proportional impact on the cost of energy from renewable energy resources. Wind and solar are also scalable and benefit from economies of scale, so most projects are large and built in remote areas where large amounts of land are available at low cost.[10] As a result, these renewable projects often require larger transmission upgrades to serve load.

As wind capacity grew in the late 2000s, interconnection queues became overloaded in certain areas. When transmission capacity extending to good wind resource areas reached capacity, large network upgrade costs would be assigned to the next wind projects entering the queue. When these wind project owners saw the hefty price tag and the difference between what they were paying compared to their competitors that might have been just ahead of them or behind them in the queue, they would often drop out of the queue. Often one project would be assigned a high cost to upgrade the network, but then subsequent projects could utilize the capacity that project created, such that the subsequent project would be assigned a lower cost. When one project drops out, costs are typically shifted onto others, causing a domino effect of cancellations. Project developers, knowing there was a chance of getting lucky with a lower network upgrade cost assignment, had an incentive to enter multiple project proposals and multiple locations. Thus, many projects would enter queues, and many projects would cancel, leading to a cycle of continuous churn. RTOs are required to study all projects, leading to lengthy workloads and inevitable delays.

Over the years FERC and RTOs have noticed the problem and attempted to fix it with process changes. In 2008, FERC held a technical conference to discuss interconnection queue-related issues that arose after Order No. 2003, and issued an Order directing RTOs to develop solutions to address queue delays and backlogs.[11] RTOs held numerous interconnection queue reform stakeholder processes, many resulting in FERC filings and tariff changes. Some of these incremental reforms, as described in more detail below, helped to reduce the churn and the quantities of projects backlogged in the queue. MISO stakeholder fora such as the Interconnection Process Task Force and the Planning Advisory Committee, for example, developed a series of queue reforms between 2008 and 2012 to address queue delays and project cancellations.[12] In 2016, MISO proposed tariff revisions to minimize restudies and introduced new milestones to improve project readiness, among other revisions to improve process efficiency.[13] MISO later built upon these reforms in 2018 to reduce cancellations and logjams by eliminating fully refundable milestone payments and requiring site control demonstration.[14]

SPP, like MISO, experienced high renewable energy interconnection interest in the late 2000s and reformed its interconnection process to transition to an approach that discouraged speculative projects

9 Headwaters Economics, *U.S. Generation Capacity, 1950-2030*, Updated April 2020.

10 American Wind Energy Association, *Grid Vision: The Electric Highway to a 21st Century Economy*, at 30-42, May 2019.

11 *Interconnection Queuing Practices*, 122 FERC ¶ 61,252, March 20, 2008.

12 MISO, *Filing of Revisions to the Open Access Transmission, Energy and Operating Reserve Markets Tariff to Reform MISO's Generator Interconnection Procedures*, at 5-6, December 31, 2015.

13 *Id.* at 3-4.

14 Jasmin Melvin, *FERC Clears MISO Interconnection Reforms Targeting Recent Influx in Speculative Projects*, December 4, 2019.

from proceeding through the queue. These reforms included a "first-ready, first served" policy and a greater use of cluster interconnection studies, among other measures.[15] In 2013, SPP further increased milestone requirements and required generators to post a financial milestone upon execution of a Generator Interconnection Agreement (GIA),[16] and in 2019 further refined its interconnection process to include a three-stage study process with financial deposits required at each stage.[17]

As renewable energy expanded into the Mid-Atlantic states in the 2010s, PJM began facing the same challenges. In 2012, FERC accepted PJM tariff modifications selected by the PJM Interconnection Process Senior Task Force, which among other changes, extended the length of the queue cluster to avoid queue study overlap and associated restudies.[18] The reforms also included an alternate queue for the hundreds of projects under 20 MW that were observed to drop out at higher rates and trigger constant restudies.

California proceeded down a similar policy evolution as MISO, SPP, and PJM. After transitioning to a cluster approach in 2008 and creating requirements to demonstrate project viability,[19] CAISO filed tariff revisions in 2010 to combine its small and large generator interconnection procedures in an attempt to streamline the processes.[20] Citing an increase in renewable generator interconnection requests due to renewable portfolio standards and related dropouts, CAISO later filed additional revisions in 2012 to integrate the transmission planning process and generation interconnection procedures.[21] In 2013, CAISO launched its first Interconnection Process Enhancement initiative, a stakeholder process to improve interconnection procedures.[22]

Despite these various incremental reforms at the RTO level, however, the fundamental problem driving the queue backlog, a reliance on participant funding and individual generators to build a large share of needed transmission upgrades, remains in place. The share of location-constrained relative to location-flexible generation continued rising through the 2010s, and increasingly affected solar generation as well as wind. Multiple RTOs continue to tinker with reforms to generator interconnection queue processes.[23]

FERC also acted again in 2016 by holding another technical conference[24] on generator interconnection issues partially in response to a 2015 request of formal rulemaking from the American Wind Energy Association to revise FERC's proforma LGIP and LGIAs.[25] The Commission later issued Order No. 845 in 2018,[26] which addressed queue interconnection procedure issues by revising FERC's pro forma LGIP and LGIA's to implement ten specific reforms. The Order was followed up by Order No. 845-A in 2019,[27] which left Order No. 845's major reforms intact, but amended the LGIP and LGIA in an attempt to further improve interconnection processes.

15 *Southwest Power Pool, Inc.*, 167 FERC ¶ 61,275, at P 4, June 28, 2019.

16 *Id.* at P 5.

17 *Id.* at P 11-13.

18 *PJM Interconnection L.L.C. Filing Via eTariff*, at 5, February 29, 2012.

19 K. Porter, S. Fink, C. Mudd, and J. DeCesaro, *Generation Interconnection Policies and Wind Power: A Discussion of Issues, Problems, and Potential Solutions*, at 28, January 2009.

20 *California Independent System Operator Corporation*, 140 FERC ¶ 61,070, at P 3, July 24, 2012.

21 *Id.*

22 *Reform of Generator Interconnection Procedures and Agreements*, Docket No. RM17-8, at 4, April 13, 2017.

23 MISO, for example, recently created the Coordinated Planning Process Task Team in November of 2019 to examine how MISO can better coordinate the separate studies underlying the generator interconnection process and the MISO transmission expansion plan. See Amanda Durish Cook, *MISO Floats Ideas on MTEP, Interconnection Coupling*, May 17, 2020. PJM is in the midst of holding interconnection process workshops to explore potential queue reforms that would allow for more renewable and storage resources to interconnect. See PJM, *Update: Interconnection Process Workshop Dates Announced*, October 6, 2020.

24 *Transcript of FERC Technical Conference on Generator Interconnection Agreements and Procedures and the American Wind Energy Association*, Docket No. RM16-12, May 13, 2016.

25 *Petition for Rulemaking of the American Wind Energy Association to Revise Generator Interconnection Rules and Procedures*, Docket No RM15-21-000, June 19, 2015.

26 *Reform of Generator Interconnection Procedures and Agreements*, Order No. 845, 163 FERC ¶ 61,043, April 19, 2018.

27 *Reform of Generator Interconnection Procedures and Agreements*, Order No. 845-A, 166 FERC ¶ 61,137, February 21, 2019.

III. Implications of a Different Resource Mix

Interconnection policy must work for the resource being interconnected, and the resource mix is clearly changing.[28] Regardless of climate or clean energy policies, renewable energy growth is nearly certain because the costs of renewables have fallen so much to make them competitive with any other resource. Wind and solar energy costs have fallen 70 and 89 percent, respectively, in the last ten years, from 2009 through 2019.[29] As a result of falling costs, consumer preferences, and public policies, wind and solar resources now make up the majority of resources in interconnection queues across the country.[30] There were 734 GW of proposed generators waiting in interconnection queues nationwide at the end of 2019, almost 90 percent of which were renewable and storage resources.[31] In 2019 alone, 168 GW of solar and 64 GW of wind projects entered interconnection queues, as shown in figure 1. The U.S. EIA forecasts that wind and solar will make up over 75 percent of new capacity additions in 2020.[32]

When an increasing amount of location-constrained generation applies for interconnection in the same area, the grid begins to require not only "driveway" type transmission facilities, but also bigger roads and highways. Much like a new community of homes requires a webwork of larger roads to connect to neighboring towns, a more regional network is needed for the U.S. power system. What we are observing is that interconnection studies for individual generators (or groups of generators) are increasingly identifying costly regional upgrades. This is a predictable dynamic.

The future resource mix is made up increasingly of wind and solar energy, which are location-constrained, so it is quite predictable that larger regional network upgrades will be identified in the interconnection processes. Unfortunately, large system upgrades are not efficiently planned or paid for by the interconnection process, which relies on generator-by-generator assessments and participant

28 Ryan Wiser et al., *Wind Energy Technology Data Update: 2020 Edition*, at 18, August 2020. See also underlying data in the *2020 Wind Energy Technology Data* Update accompanying the slide deck.

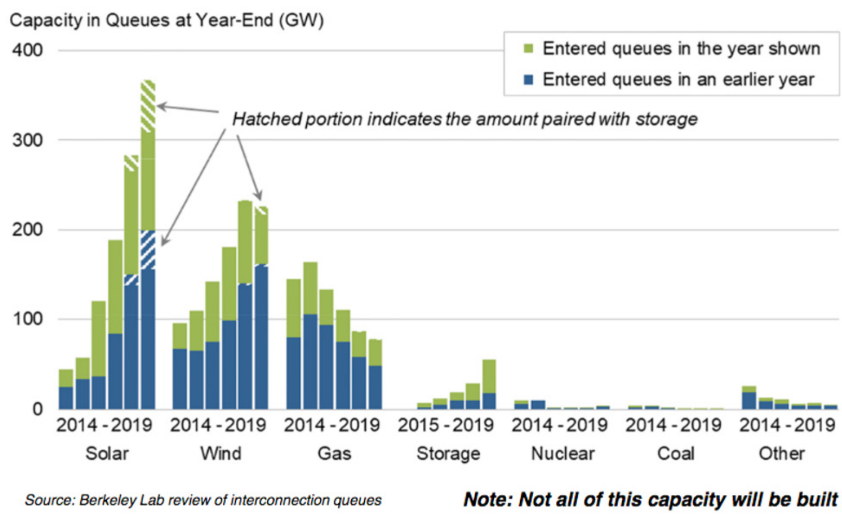
29 Lazard, Lazard's *Levelized Cost of Energy Analysis - Version 13.0*, a 8, November 2019.

30 Ryan Wiser et al., *Wind Energy Technology Data Update: 2020 Edition*, at 18, August 2020. See also underlying data in the *2020 Wind Energy Technology Data Update* accompanying the slide deck.

31 *Id.*

32 U.S. Energy Information Administration, *New Electric Generating Capacity in 2020 Will Come Primarily From Wind and Solar*, January 14, 2020.

Figure 1: Capacity in Queues at Year-End by Resource Type



funding for network upgrades. Interconnection costs are governed by Order No. 2003, which established the "at or beyond rule," pursuant to which the costs of facilities and equipment that lie between the generation source and the point of interconnection with the transmission network are borne by the incoming generator.[33] While Order No. 2003 set a default rule that transmission owners would cover the cost of "network upgrades," (equipment "at or beyond" the point of interconnection), it gave RTOs "flexibility to customize . . . interconnection procedures and agreements to meet regional needs."[34] Some RTOs have since adopted methodologies that place the lion's share of network costs on the interconnecting generator.[35]

The current interconnection process simply does not work well when there is not adequate regional transmission capacity or a functioning mechanism to plan and pay for regional transmission. Without transmission planning reform that links the interconnection and regional transmission planning processes and eliminates the use of participant funding for significant system upgrades in the interconnection process, interconnection processes will become mired in ever-longer delays. This problem could potentially be addressed by broader transmission planning reform to support holistic, proactive planning processes in conjunction with accompanying narrow Order No. 2003 reform eliminating participant funding.

33 See *Ameren Services Co. v. FERC*, 880 F.3d 571, 574 (D.C. Cir. 2018).

34 *Id.*

35 For example, MISO adopted a methodology allocating 90 percent of even network upgrades above 345 kV to generation owners, and requiring generation owners to pay 100 percent of such costs for lines below 345 kV. See *Ameren Services Co. v. FERC*, 880 F.3d 571, 574 (D.C. Cir. 2018).

The current process also misses opportunities to design new infrastructure in a more cost-effective fashion and of sufficient scale that maximizes all benefits of transmission, including reliability and economic benefits, and accommodates all likely new generation rather than just the particular generator(s) supporting the upgrades. Given the broad benefits of large-scale regional transmission, it is a violation of FERC's "beneficiary pays" principle to place all the costs of large network upgrades on the interconnection customer. It is clear that the large upgrades being identified and assigned to generators in interconnection studies would provide benefits to users across the network, even if those may be difficult to quantify with certainty. FERC Commissioner LaFleur noted the challenges with the siloed study processes when she commented "...where does the interconnection process leave off and the transmission planning process start?"[36]

Transmission expansion planning for generator interconnections based on generator-by-generator assessments will not result in optimal plans as the resource mix continues to change. Moving to studying clusters of generators simultaneously, as some areas have done, is a step in the right direction. However, current cluster approaches are still based only on what is in the current queue rather than well-known information about what generation is coming and where it is likely to be, and still does not account for the economic and reliability benefits of the transmission expansion.

36 *See* transcript of FERC technical conference in the matter of *Review of Generator Interconnection Agreements and Procedures*, Docket No. RM16-12, at 47, May 13, 2020.

IV. Evidence of a Broken Interconnection Policy

a) Upgrade costs assigned to customers are high

Analysis by Lawrence Berkeley National Laboratory, shown in tables 1 and 2 below, indicates that the costs to integrate new resources, not just renewable projects, have reached levels that are unreasonably high for a developer to proceed in MISO and PJM. As expected, the costs for integrating new resources in MISO are rising substantially relative to previous years, indicating that the large-scale network has reached its capacity and needs to expand to connect more generation. In other words, much more than "driveway" type facilities are needed; larger roads and highways are required to alleviate the traffic. Table 1[37] below shows that historically, interconnecting wind projects have incurred interconnection costs of $0.85 per megawatt hour (MWh) or $66 per kilowatt (kW). However, newly proposed wind projects now face interconnection costs that are nearly five times higher, at $4.05/MWh or $317/kW. For reference, this is about 23 percent of the capital cost of building a wind project.

Table 1: MISO Interconnection Costs for Selected Utility-Scale Projects (as of 2018)

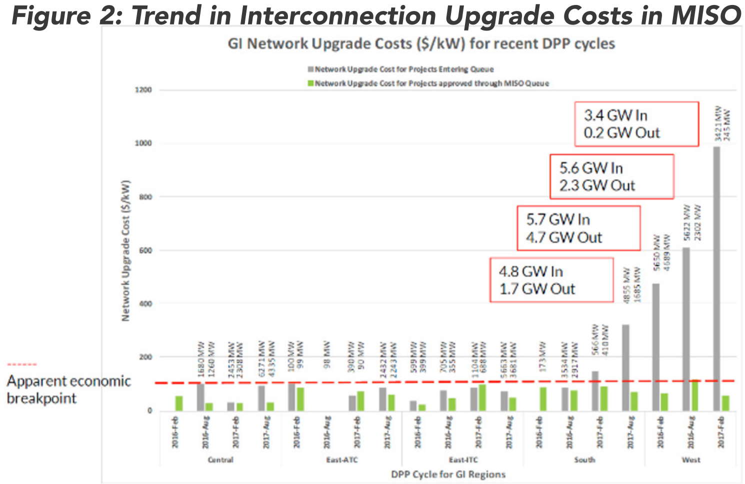
				Unit Cost ($/kW)			Levelized ($/MWh)		
Generator Type	**Projects**	**Costs ($2018 B)**	**MW**	**Overall**	**Constructed Projects**	**Proposed Projects**	**Overall**	**Constructed Projects**	**Proposed Projects**
Natural Gas	55	$0.55	14,642	$38	$31	$55	$0.34	$0.28	$0.50
Wind	161	$4.51	23,232	$194	$66	$317	$2.48	$0.85	$4.05
Solar	33	$0.18	3,277	$56	$70	$53	$1.56	$1.95	$1.48
Coal	19	$0.01	2,991	$4	$4	NA	$0.03	$0.03	NA
Hydro	13	$0.06	4,234	$13	$13	NA	$0.18	$0.18	NA

[37] Will Gorman, Andrew Mills, and Ryan Wiser, *Improving Estimates of Transmission Capital Costs for Utility-Scale Wind and Solar Projects to Inform Renewable Energy Policy*, at 10, October 2019.

New solar projects in MISO South have much higher upgrade costs. The most recent 2019 system impact study for solar projects in MISO South estimated upgrade costs to total $307/kW, with upgrade costs for individual interconnection requests as high as $677/kW.[38]

The rapidly increasing cost of interconnection in recent years shows that the breaking point has been reached. MISO, for example, has reported that "...interconnection studies for new generation resources in MISO's West sub-region have indicated the need for network upgrades exceeding $3 billion to accommodate the initial queue volume, and a similar trend is expected to occur in other areas with high wind and solar potential, including MISO's Central and South sub-regions."[39] Figure 2[40] below illustrates the large increase in assigned network upgrade costs to generators in MISO West, from approximately $300/kW in 2016 to nearly $1,000/kW in 2017. The costs to build proposed wind projects will likely result in developers abandoning those resources as project integration costs exceed $100/kW.

Figure 2: Trend in Interconnection Upgrade Costs in MISO



The same trend of rising network upgrade cost assignments is occurring in PJM. Historically, the levelized costs for constructed wind and solar projects were $0.25/MWh and $1.72/MWh, respectively, or $19.07 kW and $61.83/kW, respectively. As shown in Table 2,[41] upgrade costs for newly proposed wind and solar projects, however, have now risen to $0.69/MWh and $3.66/MWh, respectively, or $54/kW and $131.90/kW, respectively – more than a 100 percent increase.

Table 2: PJM Interconnection Costs for Selected Utility-Scale Projects (as of 2019)

				Unit Cost ($/kW)			Levelized ($/MWh)		
Generator Type	Projects	Costs ($2018 B)	MW	Overall	Constructed Projects	Proposed Projects	Overall	Constructed Projects	Proposed Projects
Natural Gas	98	$1.43	38,733	$36.92	$18.40	$76.63	$0.34	$0.17	$0.70
Wind	72	$0.25	10,859	$22.73	$19.07	$54.10	$0.30	$0.25	$0.69
Solar	134	$1.17	10,057	$116.17	$61.83	$131.90	$3.22	$1.72	$3.66
Coal	4	$0.05	1,303	$36.26	$36.26	NA	$0.25	$0.25	NA
Nuclear	2	$0.03	1,674	$19.63	$19.63	NA	$0.12	$0.12	NA

38 MISO, *Final MISO DPP 2019 Cycle 1 South Area Study Phase I Report*, at 8-15, July 16, 2020.

39 MISO, *MISO 2020 Interconnection Queue Outlook*, at 9, May 2020.

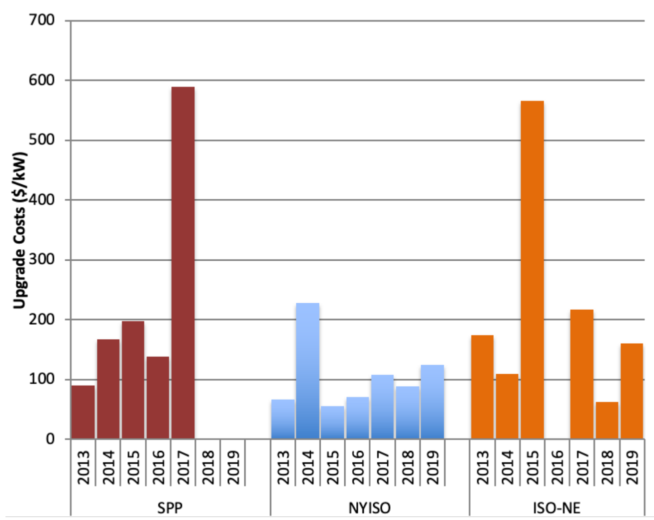
40 ITC, *MISO Generation Queue and Renewable Generation: Update to the Advisory Committee*, at 5, May 20, 2020.

41 Will Gorman, Andrew Mills, and Ryan Wiser, *Improving Estimates of Transmission Capital Costs for Utility-Scale Wind and Solar Projects to Inform Renewable Energy Policy*, at 12, October 2019.

In 2019, one 120 MW solar plus storage project in southern Virginia was informed it could be required to pay as much as $1.5 billion, or $12,086/kW, in system upgrades in order to connect to the PJM grid.[42] Among the many upgrade costs associated with the GI request includes the demolition and rebuilding of a handful of 500kV lines.[43] The construction of large transmission lines required by some interconnection studies which leads to such high network upgrade costs are not isolated incidents. A number of offshore wind projects in PJM, for example, are expected to build long, 500kV lines that are clearly network elements that benefit the entire region and should be planned and paid for through the regional planning process.[44]

This trend of rising network upgrade costs is happening across RTOs as the ratio of location-constrained generation rises and the existing network in the renewable resource areas becomes constrained. The typical increase in costs over time associated with GI studies, as shown in Figure 3[45] below, are indicative that the assigned network upgrades are high enough that most projects will not proceed.

Figure 3: Trend in Generator Interconnection Network Upgrade Costs in SPP, NYISO, and ISO-NE ($/kW)



In SPP, GI-assigned network upgrade costs from the 2013 interconnection queue were roughly $89/kW while the most recent 2017 study costs approached $600/kW. Put differently, network upgrade costs increase from composing around 8 percent of the capital cost of wind generation, to over 43 percent.[46] The most recent 2017 SPP study upgrade costs included massive 765kV lines up to 165 miles long.[47]

42 PJM, *Generation Interconnection Feasibility Study Report for Queue Project AE1-135*, at 6, January 2019.

43 *Id.* at 18.

44 *See* PJM, *Generator Interconnection Feasibility Study Report for Queue Project AF2-193*, at 15, Revised August 2020; PJM, *Generation Interconnection Impact Study Report for Queue Project AE2-251*, at 58, February 2020; PJM, *Generation Interconnection Impact Study Report for Queue Project AE2-122*, at 28, February 2020.

45 *See* publicly available SPP, *Generator Interconnection Studies* (note that SPP is behind in processing impact studies). NYISO and ISO-NE generator interconnection studies are not available to the public and require a Critical Energy Infrastructure Information (CEII) non-disclosure agreement with the ISOs.

46 In 2019, installed wind power project costs were approximately $1,387/kW in the region that includes most of SPP and MISO. We use the range of network cost increases from SPP generator interconnection studies and the aforementioned cost of installed wind power projects to estimate network upgrade costs as a share of the cost of generation in 2013/2014 vs. 2016. See Ryan Wiser et al., *Wind Energy Technology Data Update: 2020* Edition, at 56, August 2020. See also underlying data in the *2020 Wind Energy Technology Data Update* accompanying the slide deck.

47 *See* tab titled "Assigned Upgrade Costs" in SPP *DISIS-2017-001 Phase One*, Revised, November 11, 2020.

NYISO has also experienced an increase in upgrade costs from $67/kW in 2013 to $124/kW in 2019. Experience in ISO-NE on the other hand, while not a linear display of upgrade cost increases, demonstrates how high the network upgrade costs can get in any given year with 2015 upgrade costs reaching $566/kWs. Upgrade costs for ISO-NE also increased by 160 percent from 2018 to 2019.

b) Paying for transmission through the interconnection process fails to capture efficiencies that benefit all users

The system of funding major transmission upgrades through the generation interconnection process is ineffective and violates the beneficiaries pays principle. Large new transmission additions create broad-based regional benefits by providing customers with more affordable and reliable power, so charging only interconnecting generators for this equipment requires them to fund infrastructure that benefits others. MISO, for example, has estimated that its 17 Multi-Value Projects (MVPs) approved in 2011 will generate between $7.3 to $39 billion in net benefits over the next 20 to 40 years, producing cost-to-benefit ratios ranging from 1.8 to 3.1.[48] Additionally, SPP's portfolio of transmission projects constructed between 2012 and 2014 is estimated to generate upwards of $12 billion in net benefits over the next 40 years, with a cost-to-benefit ratio of 3.5.[49] Charging only interconnecting generators for the construction of transmission additions that generate benefits similar to those found in MISO and SPP is a classic example of the "free rider" problem. This type of market failure found in various other economic sectors involving networks, such as water and sewage systems and highways, signals why it is more efficient to broadly allocate the cost of "public goods." If required to pay for upgrades that mostly benefit others, interconnecting generators tend to balk and drop out of the interconnection queue.

c) Interconnection queue project cancellations are rising

The interconnection process relies upon sequential studies that are highly unpredictable for participating generators who do not know whether their interconnection request

48 MISO, *MTEP19*, at 6-7, n.d.

49 SPP, *The Value of Transmission*, at 5, January 26, 2016.

will require large upgrades. The uncertainty of interconnection costs leads wind and solar developers to often submit multiple interconnection applications for the same generator, typically for different project sizes, configurations, and interconnection points, which leads to a queue with far more projects than will actually be developed. This is a rational strategy from the developer's perspective; however, the proliferation of projects only exacerbates the number of re-studies and the number of uncertainties that can affect every project. When studies reveal significant costs, those projects tend to drop out of the process, necessitating restudies for all remaining generators and prompting delays (and often higher costs) for projects that are part of the same interconnection class year or further down in the interconnection queue. That vicious cycle continues, with the next round of wind and solar projects submitting even more interconnection applications to protect against this uncertainty. Cancelled projects lead to a vicious reinforcing cycle increasing the potential of further cancellations.

The high cost of interconnection is increasing the rate at which generators drop out of the interconnection queue, which exacerbates the uncertainty. Between January of 2016 and July of 2020, 245 clean energy projects in advanced stages of the MISO generator interconnection process chose to withdraw from the queue.[50] Interviews with the owners of these projects indicates that network upgrade costs were the primary reason for withdrawing.

Queue dropout rates are increasing. In 2019, approximately 3.5 of 5 GWs of renewable energy projects that had been a part of the MISO West 2017 study group dropped out of the interconnection queue due to high transmission upgrade costs. These projects, some of which already had power purchase agreements in place,[51] each faced transmission upgrade costs in the range of tens to hundreds of millions of dollars.[52] As of December of 2019, all but 250 MW of the 5,000 MWs had withdrawn from the queue. The remaining 250 MW was comprised of a 200 MW wind project and a 50 MW solar project; it is unlikely that the wind project will move forward as its engineering study showed the project would require transmission upgrades totaling $500 million.[53] This leaves the success rate at 1 percent for the MW in that queue study group.

Queue reform has attempted to reduce queue length and dropouts with larger financial deposits from interconnecting generators, yet queue backlogs continue to grow because queue reform has not addressed the fundamental problem of requiring interconnecting generators to pay for large network transmission elements that benefit the entire region.

d) Queue backlogs are large and growing

Interconnection queue timelines are increasing across the country due to the churn of re-studies and the high and unpredictable upgrade costs assignments, harming consumers' ability to access generation. Developers have said processing interconnection requests in PJM can take over two years, while processing in SPP can take nearly four years in some areas.[54] Currently, the MISO interconnection queue suggests processing times to be around three years, with the time it takes for a request to get through the process trending up over time.[55]

50 Sustainable FERC, *New Interactive Map Shows Clean Energy Projects Withdrawn from MISO Queue*, n.d.

51 Advanced Power Alliance, Clean Grid Alliance, and the American Wind Energy Association, *Comments to the SPP RSC and OMS Regarding Interregional Transmission Planning*, at 3, 2019.

52 Peder Mewis and Kelley Welf, *Clarion Call! Success has Brought Us to the Limits of the Current Transmission System*, November 12, 2019.

53 Jeffery Tomich, *Renewables 'Hit a Wall' in Saturated Upper Midwest Grid*, December 12, 2019.

54 Interviews with developers.

55 *See* MISO, *Interactive Queue*. We approximate the time it takes for an interconnection request to be processed by taking the difference between the "done date" of a request and the date the project entered the queue.

e) Interconnection challenges exist for offshore as well as onshore projects

Limitations of the current interconnection process hinder offshore wind development and state clean energy goals. Interconnection studies for offshore wind illustrate that most interconnection sites have a finite amount of capacity for new power injection before upgrade costs increase considerably, as the supply curve of available injection capacity among sites and at individual sites slopes steeply upward. According to upgrade costs estimated in PJM offshore wind interconnection studies and as shown in Appendix A, one can see that the first tranche of 605 MWs can be accommodated for an upgrade cost of around $275/kW at an interconnection site. The second tranche of 605 MW, however, incurs a marginal upgrade cost of over $1,100/kW, and the third tranche of 300 MWs incurs a marginal upgrade cost of over $1,300/kW. In this case, costs quadruple for projects later in the queue. The upgrades required for the later tranches involve rebuilding large segments of the transmission system. These investments benefit all interconnecting generators and consumers, who receive lower-cost and more reliable electricity from a stronger grid.

Appendix A also demonstrates that onshore transmission upgrade costs for interconnecting offshore generators tend to be very large. A review of 24 interconnection studies comprising 15,582 MWs of offshore wind capacity that have proposed to interconnect to PJM reveals $6.4 billion in total onshore grid upgrade costs for those projects, with an average of $413 per kW of offshore wind capacity.[56] Onshore grid upgrade costs for these offshore projects range from $10 per kW to $1,850 per kW.[57]

The status quo approach of relying on sequential interconnection studies with participant funding, without any pro-active regional planning, is leading to ballooning costs for offshore wind just like land-based renewables.

f) The problems occur mainly where participant funding is allowed—in RTOs and ISOs

FERC's interconnection policy as established in Order No. 2003 allowed participant funding inside RTOs and ISOs and not for transmission providers outside RTO/ISO areas. The problems described above are all in RTO/ISO areas. Where transmission upgrade costs are rolled into rates for all users, we do not find evidence of similar problems.

[56] Brandon W. Burke, Michael Goggin, and Rob Gramlich, *Offshore Wind Transmission White Paper*, at 14, October 2020.

[57] *Id.*

V. Incremental Solutions Can Help but Not Solve the Problem

a) Cluster study approaches have been a modest improvement

Some regions have implemented "cluster" interconnection studies, in which many interconnection requests are evaluated in the same study, as opposed to sequential project-by-project studies. The sequential processing approach is untenable for each new project that is the proverbial straw that breaks the camel's back and incurs a disproportionate share of upgrade costs. Clusters of similarly situated GI study requests, on the other hand, proved to be a preferred approach as transmission expansion is lumpy with large economies of scope and scale, so several developers in one area are able to pay a prorated share of the costs of required network upgrades. Additionally, grouping many interconnecting projects together instead of studying them individually allows for less queue reshuffling. Despite these advantages of a clustered approach, however, this does not solve the fundamental problem that all, or nearly all, costs are still assigned to interconnecting generators.

While clustering has helped in the past, it alone cannot solve the challenges associated with efficient and effective processing of generation interconnection queue requests. Current cluster sizes are extremely large in many cases, and planning for only one tranche of the future grid does not address the long-range needs, and certainly doesn't allow the capture of economies of scope and scale for large regional and interregional solutions to address aggregate network needs of resolving economic congestion and reliability concerns.

b) Eliminating participant funding would help

As part of FERC's Notice of Proposed Rulemaking (NOPR) for Order No. 2003, the Commission sought comment on whether or not they should retain their interconnection pricing policy.[58] At the time of the

[58] *Standardizing Generator Interconnection Agreements Procedures*, Notice of Proposed Rulemaking, Docket No. RM02-1, at 25, April 24, 2002.

NOPR, FERC's current policy required generators to pay 100 percent of the cost of "interconnection facilities" needed to establish the direct electrical connection between the generator and the existing transmission provider network. The costs of "network facilities," however – facilities at or beyond the point of interconnection to assist in accommodating the new generation facility (e.g. facilities needed for stability and short-circuit issues) – were borne initially by the generator and subsequently credited back to the generator through credits applied through transmission rates.[59]

In the final rule for Order No. 2003, FERC explained its reasoning for switching from such a "rolled-in" credit approach to one that is participant-funded.[60] One main reason included the credit approach's potential to provide price signals to direct developers to better locations from a network perspective. FERC argued at the time that a participant-funded pricing policy under which those who benefit from the project pay would help solve this problem.

FERC's decision to allow participant funding was based on the gas generation being added at the time. The Commission agreed with a number of commenters that objected to how the credit approach diminishes the incentive for interconnection customers to make efficient siting decisions while taking into account new network upgrade transmission costs, while effectively subsidizing interconnection customers who decide to sell output off-system.[61] The participant funding of network upgrades, FERC argued, would send more efficient price signals, more equally allocate costs, and potentially provide the framework necessary to allow incumbent transmission owners to overcome their reluctance to build much needed transmission.

The failure of the current system under the new resource mix, including excessive costs and risk, an inability to build needed transmission, and generators paying for large network upgrades that primarily benefit customers suggest that participant funding may no longer be a just and reasonable policy. Participant funding of network upgrades not only imposes costs on interconnection customers that are often exorbitant and rising, but is also not the solution to the inability to build large-scale transmission.

One policy solution would be to end participant funding for new generation. It is clear that major network upgrades resulting from generation interconnection requests provide economic and reliability benefits to loads and reduce congestion to improve grid efficiencies and operational flexibility, and therefore should not be direct assigned as a result of participant funding. The Commission can and should change this policy within the scope of interconnection policy.

c) Other incremental reforms to the interconnection process would help

The American Wind Energy Association (AWEA) petition for rulemaking in June of 2015 urged FERC to revise the pro forma LGIP and LGIA to alleviate "...unduly discriminatory and unreasonable barriers to generator market access."[62] AWEA's petition detailed a total of 14 recommendations and FERC later adopted 10 of the 14 under Order No. 845. The four recommendations FERC declined to adopt were regarding periodic restudies requirements, self-funding of network upgrades, publication of congestion and curtailment information, and the modeling of electric storage resources. In Order No. 845, FERC did not provide insight into what steps still needed to be taken to address these deficiencies in the current interconnection process.

59 *Standardizing Generator Interconnection Agreements Procedures*, Advance Notice of Proposed Rulemaking, Docket No. RM02-1, at 15, October 25, 2001. This was true unless the transmission provider elected to fund the network upgrades.

60 *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103, at P 678, July 24, 2003.

61 *Id.* at P 695.

62 *Petition for Rulemaking of the American Wind Energy Association to Revise Generator Interconnection Rules and Procedures*, Docket No RM15-21-000, at 1, June 19, 2015.

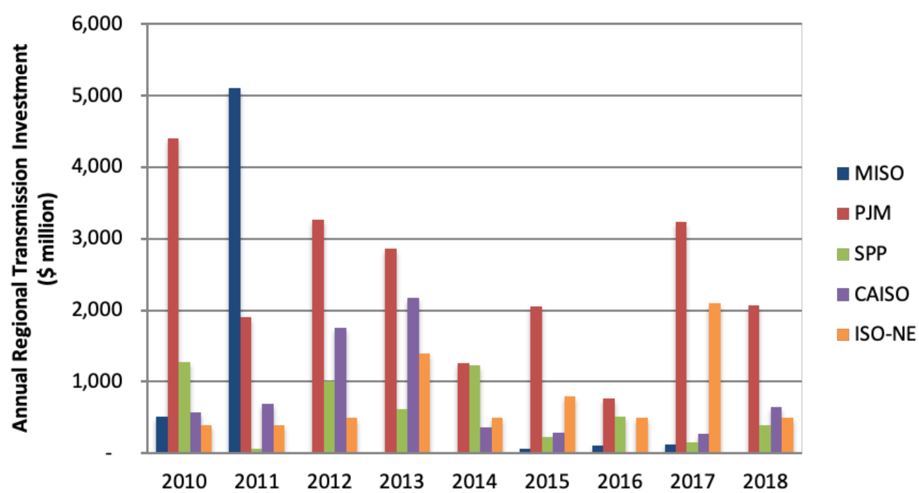
d) Interconnection process changes would still leave a shortage of efficient regional transmission

Even with the incremental changes above, there would be a continued lack of efficient regional transmission without more fundamental reforms. Integrated and comprehensive planning efforts to address to effectively integrate expected generation while also meeting economic and reliability needs have not happened since major initiatives such as Competitive Renewable Energy Zones (CREZ) in ERCOT, MVPs in MISO, and Priority Projects in SPP. Once those lines were fully subscribed, upgrade costs and queue backlogs quickly returned to unworkable levels.

While current transmission investment numbers are relatively high by historical standards, the majority of recent transmission investments have been small local projects, as demonstrated by Brattle: "[A]bout one-half of the approximately $70 billion of aggregate transmission investments by FERC-jurisdictional transmission owners in ISO/RTO regions are approved outside the regional planning processes or with limited ISO/RTO stakeholder engagement."[63]

Without sufficient regional and interregional transmission capacity to facilitate the integration of location-constrained resources onto the grid, the cost of constructing the network upgrades necessary to interconnect new wind and solar resources falls on generators as part of the interconnection process. As demonstrated in most RTO regional transmission planning statistics and reports, regionally planned transmission investment has decreased substantially since 2010. Specifically, between 2010 and 2018, total regionally planned transmission investment in RTOs decreased by 50 percent as shown in Figure 4.[64]

Figure 4: Annual Regionally Planned Transmission Investment in RTOs/ISOs ($ million)



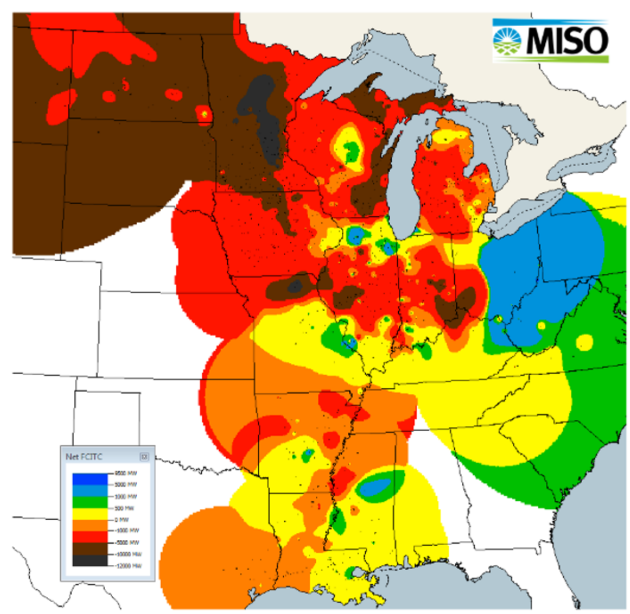
63 Johannes P. Pfeifenberger et al., *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value*, at 4, April 2019 ("Significant investments have been made, but relatively little has been built to meet the broader regional and interregional economic and public policy needs envisioned when FERC issued Order No. 1000. Instead, most of these transmission investments addressed reliability and local needs.")

64 Note: all RTOs/ISOs provide regional transmission investment information. Grid Strategies assembled data using the following sources to assemble figure 4: Coalition of MISO Transmission Customers, Industrial Energy Consumers of America, and LS Power Midcontinent, LLC, *Section 206 Complaint and Request for Fast Track Processing*, at 31-32, January 21, 2020; PJM, *Project Statistics*, at 6, January 10, 2019; Lanny Nickell, *Transmission Investment in SPP*, at 5, July 15, 2019; CAISO, *ISO Board Approved Transmission Plans*, years 2012-2021 available under "Transmission planning and studies" section of webpage; CAISO, *2011-2012 Transmission Plan*, March 14, 2012; CAISO, *Briefing on 2010 Transmission Plan*, 2010; and ISO New-England, *Transmission*, accessed October 2020.

There have been successful examples of region-wide coordination in planning and cost allocation achieving efficient levels of transmission investment. Transmission expansion efforts with pro-active multi-value planning and broad cost allocation, like the CREZ in ERCOT, MVPs in MISO, and Priority Projects in SPP, for example, have led to the large buildout of backbone transmission. These transmission expansion plans pro-actively incorporated wind and solar development assumptions, and also designed transmission upgrades that would maximize other economic and reliability benefits. Most importantly, these policies were successful because the costs of transmission were broadly allocated across the region, consistent with the benefits of the transmission being broadly spread across the region, instead of unworkably attempting to recover the costs through the generator interconnection process. However, these successful pro-active transmission planning efforts were not sustained. Subsequent renewable development requests in these areas have been burdened with unreasonable costs for interconnections, and queue backlogs have grown as a result.

The decline of regional plans is inconsistent with the evolving resource mix. Because the best locations for wind and solar resources are significantly different from those of retiring coal and other thermal resources, the current grid based on approved plans cannot be expected to support future needs. Transmission has a long infrastructure life, so the infrastructure built today should be designed with the next 50 years in mind. While almost all generation resources are location-constrained to some extent, wind and solar tend to be more constrained to areas with high-quality resources and therefore require more transmission.[65] Yet less transmission is being planned as wind and solar resources make up an increasing portion of the resource mix, which can severely constrain the amount of transmission transfer capacity out of renewable-heavy areas. Figure 5[66] below, for example, shows the majority of western MISO (highlighted in blue) had an estimated 5 GW or more deficit of transfer capacity to the rest of the region in 2016. This means that at least that amount of transmission capacity must be constructed across MISO and into the PJM region before any new generation can be added.

Figure 5: MISO West Transfer Capacity Deficit

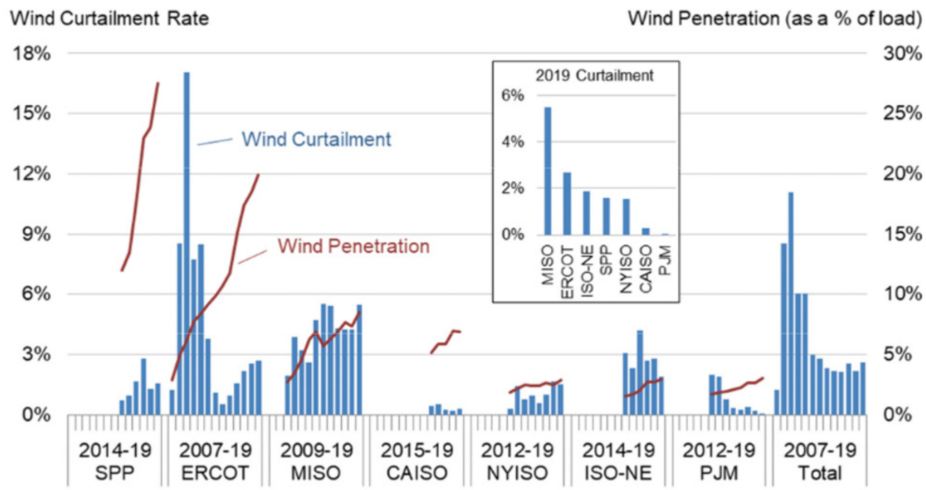


[65] *See* American Wind Energy Association, *Grid Vision: The Electric Highway to a 21st Century Economy*, at 31, May 2019; Scott Madden, *Informing the Transmission Discussion*, at 29, January 2020; FERC, *Report on Barriers and Opportunities for High Voltage Transmission*, at 12-14, June 2020.

[66] *See* MISO transfer capacity contour map, available at https://cdn.misoenergy.org/GI-Contour_Map108143.pdf, July, 11, 2018.

Efficient regional transmission capacity for location-constrained renewables can help lower renewable curtailment levels. Average wind curtailment levels for the RTOs hovered around 2.6 percent in 2019, up from 2.2 percent in 2018, with the highest levels in MISO and ERCOT at 5.5 percent and 2.7 percent, respectively.[67] Regions with high wind curtailment levels, specifically in western MISO and northwestern ERCOT, benefitted from the construction of new, large regional transmission. As shown in Figure 6[68] below, wind curtailment in MISO decreased from 2015 through 2018 shortly after the completion of a number of MVPs in western MISO between 2013-2017.[69] Similarly, wind curtailment in ERCOT has declined dramatically since 2011 after the completion of CREZ transmission projects from 2010 through 2013 allowed more than 18,500 MWs of wind capacity to be transported throughout the state.[70]

Figure 6: Wind Curtailment and Penetration Rates by ISO



Sources: ERCOT, MISO, CAISO, NYISO, PJM, ISO-NE, SPP

[67] Ryan Wiser et al., *Wind Energy Technology Data Update: 2020 Edition*, at 49, August 2020. See also underlying data in the *2020 Wind Energy Technology Data Update* accompanying the slide deck.

[68] Id.

[69] MISO, *Regionally Cost Allocated Project Reporting Analysis*, October 2020.

[70] ERCOT, *Report on Existing and Potential Electric System Constraints and Needs*, at iii, December 2018. U.S. Energy Information Administration, *Fewer Wind Curtailments and Negative Power Prices Seen in Texas After Major Grid Expansion*, June 24, 2014

VI. The Real Solution Must Be Regional and Inter-regional Planning Reforms

Transmission expansion needs to be driven by a multi-value plan to address overall system needs, including economics, reliability, and generator interconnection. Some regions have demonstrated success in integrated transmission plans to accommodate projected futures that resulted in very cost-effective transmission expansion. CREZ in ERCOT, MVPs in MISO and Priority Projects in SPP are case studies where loads, generators and stakeholders benefited from holistic planning efforts. SPP and MISO have found the benefits of that transmission expansion exceeded the cost by 2 to 3 times.[71]

The changing resource mix and electrification of the energy sector will have a profound impact on the future grid, yet in many cases those factors are not being included in regional and interregional planning efforts. Most recent regional planning studies have not included reasonable projections regarding the changing resource mix and expected retirements. State policies should also be accounted for in regional transmission planning process.

Network upgrades benefit everyone, and all costs ultimately flow to customers, so cost allocation needs to reflect that reality. Consumers benefit from minimizing costs and maximizing the benefits of transmission expansion. Customers are also harmed by the inefficient and unworkable status quo that attempts to force upgrade costs on interconnecting generators. This policy leads to a sub-optimal level of transmission investment, driving billions of dollars annually in unnecessary congestion and reliability costs, while the cost of energy offered to customers by generators is higher than necessary due to lengthy queue delays and risk and an inability to build generation in low-cost resource areas.

Transmission policy can and should include Grid-Enhancing Technologies (GETs), not just new infrastructure. As FERC has recognized, a set of GETs are now widely commercialized and deployable to address a number of transmission challenges speedily and at low cost. GETs can be incorporated into interconnection policy, transmission planning, and FERC incentives policy. As with infrastructure,

[71] *See* SPP, *The Value of Transmission*, at 5, January 26, 2016; MISO, *MTEP17 MVP Triennial Review*, at 4, September 2017.

addressing only interconnection policy will not be sufficient for GETs.

a) Generator lead lines should be incorporated into regional plan

In many cases, a lack of transmission capacity, queue backlogs, and excessive participant funding upgrade costs have forced renewable developers to build and own generator lead lines that are dozens of miles long. For example, wind projects such as Horse Hollow in ERCOT and Flat Ridge in SPP had in-service dates and commitments for deliveries that could not wait for approved, regionally funded Extra High Voltage (EHV) network upgrades. As a result, developers of these projects built long, high capacity EHV generator leads to integrate their projects into existing transmission facilities in advance of planned regionally funded upgrades. In the case of Horse Hollow, the developer constructed a private 345 kV line extending from West ERCOT to South ERCOT – a distance spanning ten Texas counties.[72] Often long generator leads reduce congestion and curtailments and become network elements benefitting everyone.

b) Affected system studies need to be part of improved interregional planning processes

Affected system studies occur when a generator interconnection in one RTO triggers a need for transmission upgrades in more than one RTO. These studies increase upgrade costs for generators. The fact that the transmission need is large enough to cross into another RTO clearly indicates that the transmission expansion benefits others, and therefore should be planned and paid for in a regional, and ideally inter-regional, process.

Planning is tough enough within an RTO, and the planning and cost allocation obstacles for building transmission between RTOs are currently insurmountable. Part of the problem is there is significant divergence among RTO planning processes, with different models, assumptions, benefit-cost thresholds, and timing. As a result, no large-scale transmission upgrades have been able to pass what is called the "triple hurdle," which requires an inter-regional transmission project to pass a benefit-cost ratio test in each RTO and for the entire region. The free rider problem is an even greater challenge for inter-regional cost allocation than it is within RTOs. However, the large need for inter-regional transmission will not be met without solving that problem, likely by broadly allocating the cost of inter-regional lines across those regions.

The voluntary nature of RTOs has resulted in footprints that create seams issues that stymie collaborative planning. Expansion of RTO footprints helps to mitigate seams issues to a large extent and needs to be strongly encouraged. The lack of transmission capabilities between zones of an RTO creates challenges that have plagued effective expansion planning. Transmission capabilities are critical to an efficient and effective bulk power system and electricity market, as transmission is the critical link to enabling and defining markets.

c) Regional planning studies and generation interconnection studies need better alignment

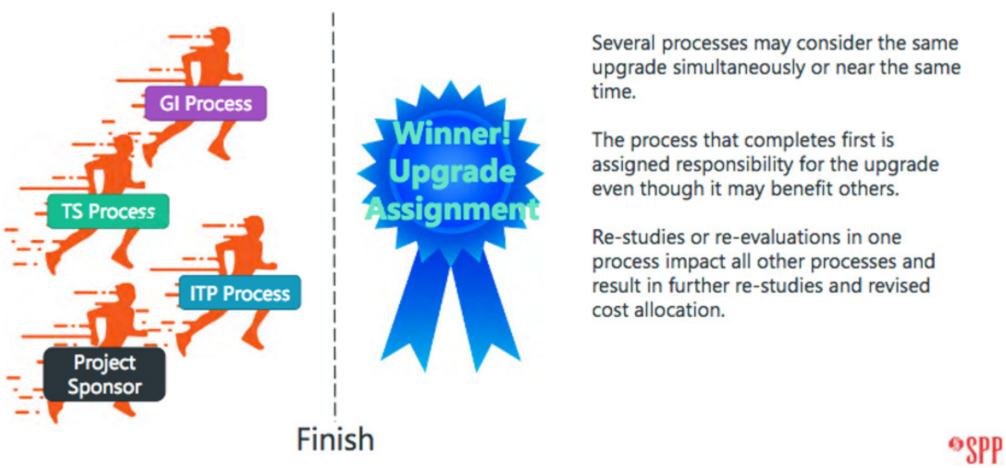
Planning entities often employ siloed study processes that consider reliability, economic, and public policy

72 Hillard Energy, *Horse Hollow Generation Tie*, Comfort, Texas, n.d.

transmission projects separately rather than considering all benefits at once under a holistic planning approach. The main factor driving siloed planning processes is that different cost allocation methods for each category of transmission project results in a race that no one wants to win, as it will result in them bearing the cost for the transmission upgrades. Said another way, each group of stakeholders attempts to free ride on other groups of stakeholders by failing to plan transmission that they would have to pay for, in the hope another group of stakeholders will plan and pay for it. Unfortunately, the typical result is that nobody builds the transmission, and all customers suffer from increased congested and reduced reliability.

A great case study that demonstrates this failure in action involves SPP's filing of an unexecuted GIA between SPP - the transmission provider, Oklahoma Gas & Electric (OG&E) Company - the transmission owner, and Frontier Windpower II - the interconnection customer.[73] After Frontier's GIA identified shared network upgrades including a new transmission line with a $62 million price tag, of which Frontier had been allocated 22.5 percent of the total cost, Frontier then asked SPP to file the GIA as an unexecuted agreement. When SPP later revised Frontier's GIA to remove all costs associated with the new transmission line, the back-and-forth continued as OG&E submitted a filing in protest of SPP's decision as they believed that because Frontier is imposing costs on the SPP system, they should bear their share of the cost so others, including OG&E, do not have to pay more.[74] SPP's Strategic & Creative Re-Engineering of Integrated Planning Team (SCRIPT) has identified this problem, as shown in Figure 7.[75]

Figure 7: Process Interaction



SPP is working on a solution, which builds on the successes achieved through pro-active transmission planning and broad cost allocation identified a decade ago with the ERCOT CREZ, MISO MVP, and SPP Priority Project lines. The new SCRIPT effort at SPP appears to be a positive step forward and may serve as a model for other RTOs. The scope of the SCRIPT at SPP is noteworthy in several respects. "The SCRIPT is tasked with developing policy recommendations that result in:

- Appropriate consolidation, modification, or elimination of SPP's transmission planning and study processes, in order to:
    - » Develop more optimal solutions that meet a broader set of customer needs

[73] *Protest of Oklahoma Gas and Electric Company*, Docket No. ER19-2747-002, March 16, 2020.

[74] Id. at 7-8.

[75] *See* the minutes and meeting materials for SCRIPT's meeting held on October 9th, 2020 (attachment D at slide 49).

» Synergize analysis so that beneficiaries and cost-causers can be identified in a holistic, uniform fashion

» Improve planning efficiency, effectiveness and timeliness

» Reduce the number of model sets needed

» Reduce reliance on customer-requested, queue-driven studies

- Improved responsiveness, efficiency and cost certainty of studies needed to provide customer-requested service
- Reduced dependence on queue-driven studies, with consideration given to development of proactive processes that identify and make transparent underutilized transmission capacity
- Utilization of processes and information needed to ensure decisions being made about future investment in transmission infrastructure are made with a high degree of confidence and quality
- Optimization of the existing and planned transmission network to most cost effectively meet future needs while providing maximum value to the region
- Facilitation of generation transfers in a way that will provide future net benefits to the SPP region
- Improved cost sharing among users of the transmission system that appropriately recognizes causers and beneficiaries of transmission investment decisions"

d) Both incremental and broader reforms would still be fuel-neutral

If FERC were to change its policies based in part on the evolving resource mix, that could still be a fuel neutral policy. FERC has always tried to be neutral, with no discrimination or preference to any particular resource, and that can remain true. Transmission policy necessarily takes into account the physical location of resources. For example, in 2007, FERC issued policies on interconnection and transmission service for "location-constrained" resources that differed from the Order 2003 approach in CAISO.[76] It was not a preference or any value judgment on the renewable resources, just the recognition that there was a large resource area that could be tapped with a higher voltage transmission lines than any one generator or group of generators could be assigned, leading to more just and reasonable rates for consumers. Transmission planning reforms could follow this general approach.

[76] See *California Independent System Operator Corporation*, Order Granting Petition for Declaratory Order, 119 FERC ¶ 61,061, April 2007; and Bracewell LLP, *FERC Tailors Transmission to Connect Renewables*, May 1, 2007. See also Pedro J. Pizarro, *Transmission Planning and Development: Examples and Lessons*, at 17, February 25, 2010; CAISO, *Memorandum re: Decision on Tehachapi Project*, at 6, fn. 3 January 18, 2007 (explaining how generators would pay a pro-rata share to the extent the Tehachapi improvements are characterized as bulk transfer gen-tie lines, with customers in SCE's service territory paying the costs of the network upgrade portions of the project).

VII. Conclusion: Transmission Planning as Well as Interconnection Policy Reforms Are Needed

The current system of participant funding and network planning through the interconnection process is increasingly unworkable and inefficient. While participant funding and serial interconnection studies created workable signals for siting interconnecting gas plants, they create inefficiencies for interconnecting location-constrained renewable resources. Needed transmission remains unbuilt because the vast majority of new proposed projects drop out of the queue, lengthy queue backlogs create massive uncertainty and risk for generation developers, and congestion and reliability problems from a constrained grid impose billions of dollars per year in unnecessary costs on customers. All generation and transmission costs ultimately flow to electricity consumers, so there is no benefit from policies that seek to shift transmission costs from RTO customers exclusively to generators. The risk from the uncertainty of the interconnection process significantly increases the cost of capital for generation developers, which increases the cost of energy for customers. The question for policymakers is how to create a workable and efficient system of planning and paying for transmission that minimizes customer costs.

Interconnection policy and transmission planning policy both need to fit the resource mix going forward. This paper provides evidence of how the interconnection policy is broken now, given the current and expected future resource mix. It proposes some recommendations within the scope of interconnection policy such as ending the policy of assigning all the costs of network upgrades just to generators. However, major progress requires improved transmission expansion policies in order to build out grid capacity to accommodate the future resource mix. Reform to regional transmission planning raises a number of issues that are beyond the scope of this paper. A companion paper from ACEG will address the need for planning reform, consider various policy options, and recommend a number of specific policy changes. It is clear that regional and inter-regional planning must be pro-active, consider future generation additions and retirements, consider multiple benefits, and spread costs to all beneficiaries. That is the only real solution to the broken interconnection processes around the country.

Appendix[77]

Queue Position	MW	Request Date	COD	Interconnection Point	State	County	Trans. Owner	Feasibility Study	System Impact Study	Facilities Study	$ upgrade cost	$/kW upgrade cost
Z1-035	18	7/5/13	9/30/17	Lake Road 11.5 kV	OH	Unknown	ATSI	Complete	Complete	Not required	$2,468,558	$137
AB1-056	255.1	8/31/15	10/31/21	Indian River 230kV I	DE	Sussex	DPL	Complete	Complete	Complete	$2,556,112	$10
AE1-020	816	5/22/18	6/1/23	Oyster Creek 230 kV	NJ	Ocean	JCPL	Complete	Complete	In Progress	$111,316,644	$136
AE1-104	432	9/6/18	6/1/23	BL England 138 kV	NJ	Cape May	AEC	Complete	Complete	In Progress	$65,050,000	$151
AE1-117	152	9/14/18	6/1/22	Bethany 138 kV	DE	Sussex	DPL	Complete	Complete	In Progress	$9,698,945	$64
AE1-238	816	9/28/18	6/1/24	Oceanview Wind 230 kV	NJ	Monmouth	JCPL	Complete	Complete	In Progress	$13,498,200	$17
AE2-020	604.8	12/14/18	12/1/24	Cardiff 230 kV I	NJ	Atlantic	AEC	Complete	Complete	In Progress	$167,856,800	$278
AE2-021	604.8	12/14/18	12/1/25	Cardiff 230 kV II	NJ	Atlantic	AEC	Complete	Complete	In Progress	$668,716,213	$1,106
AE2-022	300	12/14/18	12/1/24	Cardiff 230 kV III	NJ	Atlantic	AEC	Complete	Complete	In Progress	$399,595,257	$1,332
AE2-024	882	12/14/18	12/1/25	Larrabee 230 kV I	NJ	Ocean	JCPL	Complete	Complete	In Progress	$179,417,245	$203
AE2-025	445.2	12/14/18	12/1/26	Larrabee 230 kV II	NJ	Ocean	JCPL	Complete	Complete	In Progress	$171,405,063	$385
AE2-122	800.1	2/28/19	12/31/25	Birdneck-Landstown 230 kV	VA	City of Virginia Beach	Dominion	Complete	Complete	In Progress	$304,108,327	$380
AE2-123	800.1	2/28/19	12/31/27	Birdneck-Landstown 230 kV	VA	City of Virginia Beach	Dominion	Complete	Complete	In Progress	$243,757,023	$305
AE2-124	800.1	2/28/19	12/31/29	Landstown 230 kV	VA	City of Virginia Beach	Dominion	Complete	Complete	In Progress	$215,266,218	$269
AE2-222	300	3/22/19	6/1/23	Higbee 69 kV	NJ	Atlantic	AEC	Complete	Complete	In Progress	$285,840,760	$953
AE2-251	1200	3/26/19	6/1/24	Cardiff 230 kV	NJ	Monmouth	AEC	Complete	Complete	In Progress	$923,771,404	$770
AE2-257	120	3/27/19	6/1/22	Cedar Neck 69 kV	DE	Sussex	DPL	Complete	Complete	In Progress	$105,062,883	$876
AF1-101	800	9/6/19	11/23/22	Oyster Creek 230 kV III	NJ	Atlantic	JCPL	Complete	Complete		$572,211,265	$715
AF1-123	880	9/17/19	12/31/25	Fentress 500 kV	VA	City of Chesapeake	Dominion	Complete	Complete		$76,200,000	$87
AF1-124	880	9/17/19	12/31/26	Fentress 500 kV	VA	City of Chesapeake	Dominion	Complete	Complete		$156,865,407	$178
AF1-125	880	9/17/19	12/31/24	Fentress 500 kV	VA	City of Chesapeake	Dominion	Complete	Complete		$149,505,894	$170
AF1-222	1326	9/27/19	12/30/25	Oceanview Wind 2 230 kV	NJ	Monmouth	JCPL	Complete	Complete		$131,556,667	$99
AF2-193	440	3/23/20	10/31/26	Indian River 230 kV I	DE	Sussex	DPL	Complete			$534,708,000	$1,215
AF2-194	880	3/23/20	10/31/26	Indian River 230 kV II	DE	Sussex	DPL	Complete			$664,582,000	$755
AF2-196	150	3/23/20	6/1/22	Cedar Neck 69 kV II	DE	Sussex	DPL	Complete			$277,459,000	$1,850
											$6,432,473,885	**$413/kW average**

77 See PJM, New Services Queue. To gather the data found in Appendix A, we filtered the queue for offshore wind projects. Upgrade cost information was taken from the most recent interconnection study available for each request (e.g. feasibility study, system impact study, or facilities study).

Americans for a
Clean Energy Grid

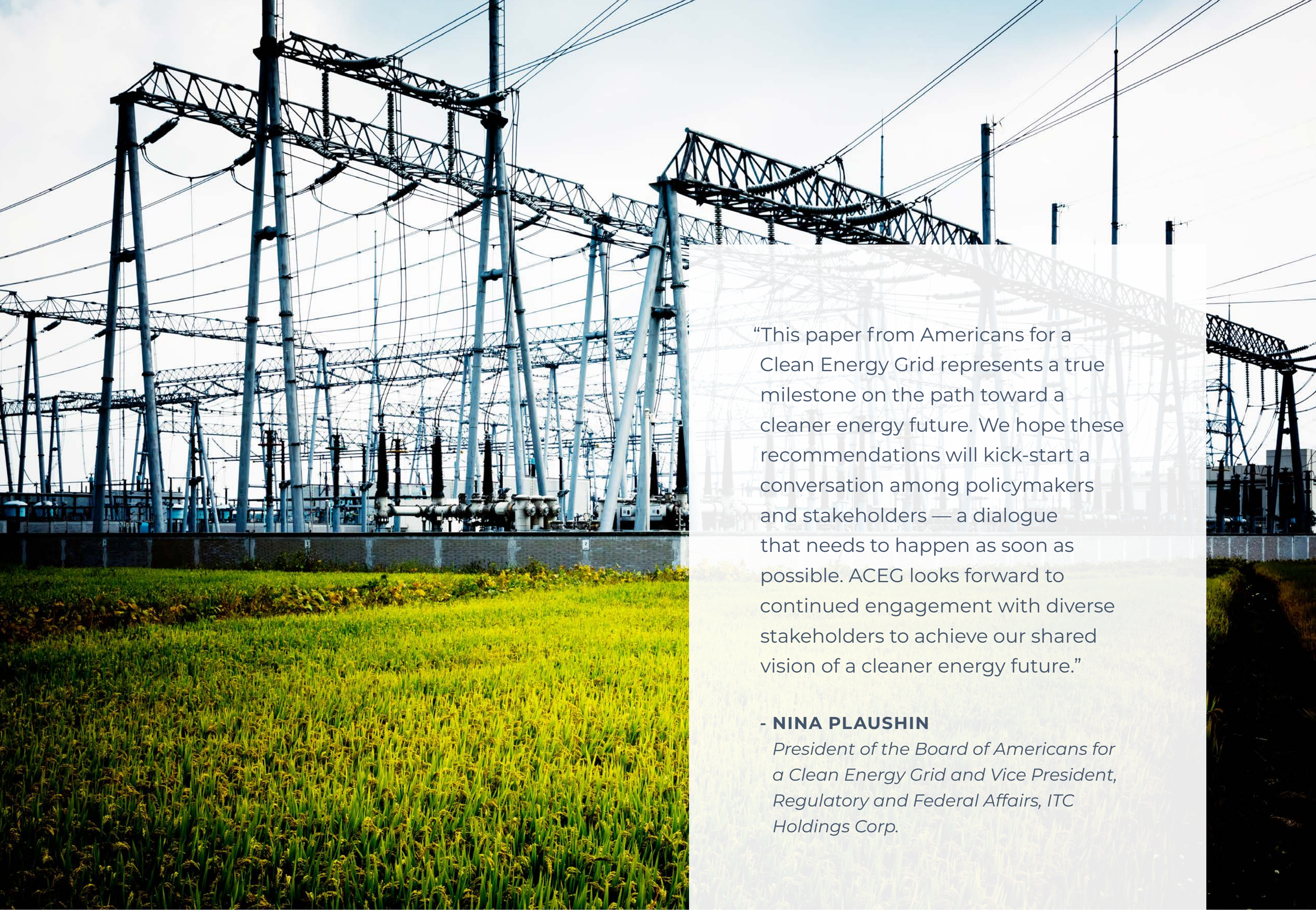
Appendix C

Americans for a Clean Energy Grid

JANUARY 2021

PLANNING FOR THE FUTURE

FERC'S OPPORTUNITY TO SPUR MORE COST-EFFECTIVE TRANSMISSION INFRASTRUCTURE



> "This paper from Americans for a Clean Energy Grid represents a true milestone on the path toward a cleaner energy future. We hope these recommendations will kick-start a conversation among policymakers and stakeholders — a dialogue that needs to happen as soon as possible. ACEG looks forward to continued engagement with diverse stakeholders to achieve our shared vision of a cleaner energy future."
>
> **- NINA PLAUSHIN**
> *President of the Board of Americans for a Clean Energy Grid and Vice President, Regulatory and Federal Affairs, ITC Holdings Corp.*

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The authors thank Lauren Azar, Jennie Chen, Jenny Erwin, Miles Farmer, Michael Goggin, Bill Hogan, John Jimison, Paul L. Joskow, Alexandra Klass, Natalie McIntire, Ari Peskoe, Johannes Pfeifenberger, Pablo Ruiz, Jesse Schneider, Tyler Stoff, Gabe Tabak, Avi Zevin, and Devin McMackin for valuable contributions. Acknowledgment of their contributions does not imply endorsement of the recommendations.

REPORT SPONSORS

Commissioned by Americans for a Clean Energy Grid with support from the Macro Grid Initiative, a project of the American Council on Renewable Energy.

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LIST OF ACRONYMS

AC	Alternating Current
ACEG	Americans for a Clean Energy Grid
AEMO	Australian Energy Market Operator
BCA	Benefit-Cost Analysis
BRP	Baseline Reliability Projects
CAISO	California Independent System Operator
CLCPA	Climate Leadership and Community Protection Act
CREZ	Competitive Renewable Energy Zones
DC	Direct Current
DFAX	Distribution Factor
DPP	Definitive Planning Phase
EIA AEO	U.S. Energy Information Administration's Annual Energy Outlook
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
GET	Grid-Enhancing Technologies
GHG	Greenhouse Gases
GI	Generator Interconnection
GW	Gigawatt
HVDC	High Voltage Direct Current
IPP	Independent Power Producer
ISO	Independent System Operator
ISO-NE	ISO New England
ITP	Integrated Transmission Plan
LMP	Locational Marginal Price
LOLE	Loss of Load Expectation
MEP	Market Efficiency Projects
MISO	Midcontinent Independent System Operator
MIT	Massachusetts Institute of Technology
MTEP	MISO Transmission Expansion Plan
MVP	Multi-Value Projects
MW	Megawatt
MWh	Megawatt-hour
NERC	North American Electric Reliability Council
NIMBY	"Not In My Backyard"
NOAA	National Oceanic and Atmospheric Administration
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
PJM	PJM Interconnection
REBA	Renewable Energy Buyers Alliance
ROFR	Right of First Refusal
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Organization
SPP	Southwest Power Pool
TPL	Transmission Planning
TWh	Terawatt-hour
U.S. DOE	United States Department of Energy
U.S. EIA	United States Energy Information Agency
VER	Variable Energy Resources
VOLL	Value of Lost Load
WATT Coalition	Working for Advanced Transmission Technologies Coalition

I. Executive Summary

A. The time has come for the Federal Energy Regulatory Commission (FERC) to build on its previous orders and strengthen transmission planning through a new nationwide transmission planning and cost allocation rule

Over the last 25 years, four major FERC orders, No. 888, 2000, 890 and 1000, each made incremental progress building regional transmission infrastructure, moving the industry away from its past balkanized structure with relatively weak connections between utility systems towards a more reliable and efficient system allowing for more regional exchange of power. As we look to the future, much more regional and inter-regional power exchange will be needed for national energy security, reliability, resilience, cost-effectiveness, and economic competitiveness. A decade after Order No. 1000's issuance, the nation faces new challenges and it is clear that neither the current infrastructure nor the rules governing its development match this need.

Numerous studies, as well as the experiences of regional planning entities, demonstrate that more robust interregional infrastructure is needed to ensure system resilience and reliability, and would yield substantial consumer benefits and help ensure affordable rates for customers if built. The combination of an aging transmission system and a changing resource mix heighten the need for proactive planning of regional and inter-regional transmission infrastructure. While a large amount of transmission infrastructure built in the 1960s and 70s is due for replacement, simply rebuilding this infrastructure is inefficient in light of a changing resource mix and shifting demand patterns. By all accounts, wind and solar resources will become a much larger portion of the resource mix in the future, and electrification of transportation and buildings will substantially increase demand. These trends magnify the benefits of building large regional and inter-regional transmission infrastructure to connect resource rich areas with load centers.

For all of the best efforts of the Commission and regional planning authorities, the current set of transmission regulations have resulted in inadequate levels of infrastructure that have burdened the interconnection process with the task of planning new network facilities — a task that should instead take place in the planning process. Further, existing regulations have created a system that disproportionately yields projects that address only local needs, that address reliability without more broadly assessing other benefits, or that simply replace old retiring transmission assets with the same type and design despite the potential for larger projects to more cost effectively meet the same needs. While local projects, reliability projects, and asset replacements will continue to be necessary, there is an opportunity to make better use of valuable existing rights of way, install newer technologies as assets are replaced, provide greater transparency and guidance over transmission expenditures, and reconfigure the grid to vastly increase regional and inter-regional delivery capacity. This would improve the cost effectiveness of new transmission investments for customers, reducing congestion, and enhancing reliability.

To achieve these outcomes, the Commission should undertake a comprehensive rulemaking to reform planning, cost allocation, and review of transmission. Reforms designed to ensure adequate, cost-effective investment in transmission infrastructure takes place are necessary for rates to be "just and reasonable" and consistent with the Federal Power Act's requirements. The Commission has an obligation to find under Section 206 of the Federal Power Act that current tariffs are unjust and unreasonable, and must be replaced with new transmission planning, cost allocation, and review guidelines. Reforms to ensure that regional and interregional planning processes better assess future needs, evaluate a full range of solutions, and focus on increasing cost effectiveness of new infrastructure for customers are well within the Commission's statutory authority, and its mandate to identify and serve the interests of electricity consumers.

B. A new comprehensive FERC planning rule should establish basic guidelines for transmission planning processes to ensure they meet future needs

The Commission should build on its longstanding work to improve regional and interregional transmission planning. Beginning with an industry of separate vertically integrated utilities, with around 500 owners of transmission, FERC began to foster regional exchange of power in the mid-1990s. Order No. 888, issued in 1996, encouraged "Regional Transmission Groups"[1] and "Independent System Operators"[2] with transmission planning coordination functions.[3] Order No. 2000, issued in 1999, encouraged the voluntary formation of Regional Transmission Organizations with transmission planning as a core function, both for reliability and efficiency.[4] Order No. 890, issued in 2007, established a set of more specific transmission planning principles that help to facilitate stakehold-

1 The Commission's 1994 Regional Transmission Group Policy Statement was an important precursor to Order No. 888.

2 Throughout this paper, we refer to RTOs and ISOs together simply as "RTOs."

3 *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 75 FERC ¶ 61,080, April 24, 1996.

4 *Regional Transmission Organizations*, Order No. 2000, 89 FERC ¶ 61,285, December 20, 1999.

er input and help ensure a more efficient mix of transmission infrastructure. It requires transmission planning processes to be open and transparent, provide for coordination between entities through information exchange and other practices, and utilize economic planning studies to evaluate projects.[5] Order No. 1000, issued in 2011, built on these principles by enacting a series of reforms designed to "identify and evaluate transmission alternatives at the regional level that may resolve the region's needs more efficiently or cost-effectively than solutions identified in the local transmission plans of individual public utility transmission providers,"[6] and requiring greater interregional coordination. These signature orders, issued by bipartisan commissions led by Chairs from both parties, have all explicitly endeavored to bolster regional transmission infrastructure for reliability and efficiency of the overall power system.

We now have ample evidence to see that the current transmission planning regulations leave a large gap remaining between what is being done and what is needed to address current and future needs. Regions have taken a wide variety of approaches to implementing the orders, and their collective experience has yielded important lessons. The time has come to build on the experience from these four major FERC planning orders and to take another step in reforming the planning processes to ensure that they yield just and reasonable solutions. In particular, the time has come to apply those lessons to yield greater development of region-spanning and inter-regional transmission capacity, and a sharper focus on ensuring that new development is as cost effective as possible.

The Commission should undertake a rulemaking to provide greater specificity in how regional and interregional planning processes must be conducted, adding four new pillars to these planning processes to ensure that planning properly identifies infrastructure that best meets future needs:

1. ***A new FERC rule should require planning processes to rely upon the best available data and forecasting methodologies.***

Regional planning entities' implementation of Order No. 1000 has shown that many regions fall short in identifying transmission needs based on assessments of plausible futures that are as accurate as possible. Changes in the resource mix driven by public policies and utility resource plans, growth in electric vehicles and building heating, quantity and location of generation in interconnection queues, and other changes to electrici-

5 *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 18 CFR Parts 35 and 37, at PP 418-601, February 16, 2007.

6 *Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 78, July 21, 2011.

ty demand and supply are important factors for which information is publicly available. Failing to fully incorporate these factors into planning leads to unjust and unreasonable outcomes because it yields infrastructure that will not meet future needs as cost effectively as possible. Rather than focus on the status quo, planners should incorporate the best available information about changing system needs as they assemble plans. The Commission should require planning entities to evaluate needs based on a range of reasonable planning scenarios based on plausible futures that cover the full range of factors that are likely to influence future demand and resource mix. The Commission should also require transmission planners to account for project siting considerations and information about new technologies, and non-transmission alternatives that may be funded outside of the planning process as key inputs. In short, planning processes must be about the future in order to be deemed just and reasonable.

2. ***A new FERC rule should require planning authorities to consider all of the benefits of transmission together.***

Planning entities generally employ siloed planning processes that often only partially evaluate the benefits of transmission projects by classifying projects as "reliability," "public policy," or "economic" projects. This siloed approach leads to unjust and unreasonable outcomes by failing to consider the economies of scope, where transmission typically provides multiple benefits that span these artificial categories. While planning entities may continue to provide for cost allocations that appropriately reflect benefits, and provide individual assessments of lines for permitting purposes, the Commission should ensure that transmission needs and solutions are identified in a manner that recognizes all of the multiple benefits of all types of transmission projects.

3. ***A new FERC rule should require transmission planning entities to evaluate all available solutions, including new physical infrastructure options and grid-enhancing technologies, within regional transmission plans to more efficiently serve customers.***

Current approaches are unjust and unreasonable by failing to consider lower cost or better performing options, and should be changed to include them.

4. ***A new FERC rule should direct transmission planning entities to select a portfolio of solutions for each regional and interregional transmission plan that is likely to maximize aggregate net benefits.***

The Commission should direct all planning entities to engage in portfolio assessments and benefit-cost analysis, providing guidelines with regard to how they should do so.

To ensure consumers benefit from transmission plans, benefit-cost analysis should be performed using methods that address uncertainty by quantifying benefits and costs in a range of plausible future scenarios. All planning entities should be required to adhere to a minimum set of best practices that ensure that all benefits will be quantified across the full life of the applicable infrastructure. Innovations in the full and accurate quantifications of transmission-related benefits should be encouraged.

C. A new FERC rule should continue to adhere to the principle that transmission costs must be allocated in a manner roughly commensurate with benefits in a way that recognizes the broad benefits that are created by large regional and interregional transmission infrastructure, while providing planning entities with flexibility in developing methodologies that adhere to this standard

FERC Order No. 1000 policies on cost allocation are largely workable as long as the planning reforms discussed herein are accomplished. The current approach for transmission included in regional plans, as dictated in a set of court decisions, is that cost allocation should be roughly commensurate with benefits received. While the Commission should require all planning entities to better quantify the benefits of new transmission infrastructure, it should refrain from requiring that the costs of new infrastructure be allocated in a manner that matches these benefits based on overly narrow metric or with exacting precision on a project-by-project basis. Instead, it should continue to require that overall costs of the new transmission infrastructure be allocated in a manner roughly commensurate with benefits. Therefore, as the Commission carries out reforms to transmission regulation, it should largely adhere to the basic approach that it has taken on cost allocation in Order 1000. Since interconnection processes, as governed by policy decisions made in Order 2003, do not follow beneficiary pays and instead follow "participant funding," this inconsistency should be rectified by a new rule. Thus the rule would be updating some provisions of Order No. 2003 and the interconnection processes of public utilities, as well as Orders No. 890 and 1000 on planning provisions.

To minimize analysis and help ensure that costs are allocated in a stable and predictable way, the Commission should direct planning entities to allocate the costs of portfolios of projects as a group, rather than proceeding only on a project-by-project basis. And to ensure that costs are not significantly mismatched with benefits, it should provide that single metrics such as load flow analysis may not be the sole basis of cost allocation, instead directing planning entities to use methods that account for a broader range of benefits that projects bring the whole system. To avoid cost-shifting and process disruption, the rule should assign costs to loads whether or not their affiliated company remains in a Regional Transmission Organization (RTO). Finally, the Commission should clarify that planning entities may allocate a portion of total costs in the future to generators and customers who utilize the new transmission infrastructure.

D. The Commission should ensure transmission investment is as cost-effective as possible

Consumer interests must be central to transmission policy, as the Federal Power Act is a consumer protection statute first and foremost. In recent years, as aging assets have been replaced, spending on transmission has increased without always providing for a process for consumers to know whether the expenses are justified or the type of upgrade is cost-effective. The Commission should build on Orders No. 888, 2000, 890, and 1000 by enacting further reforms to governance and oversight processes to ensure that costs incurred benefit customers. Broadly, these reforms should (i) ensure that local and end-of-life projects are more carefully evaluated as part of regional planning processes, to determine whether needs may be more efficiently served by larger, regional, and interregional projects rather than simple replacements; (ii)

ensure there is cost transparency and oversight of transmission costs and that public utility transmission providers are appropriately incented to pursue a more optimal mix of transmission solutions; (iii) consider targeted forms of performance based rate making that can incent efficiency in project development, (iv) develop a more collaborative approach to transmission planning and ownership among utilities and (v) ensure that interregional and possibly national transmission infrastructure is more seamlessly facilitated.

In particular, the Commission should reform the interregional planning process to eliminate the multi-stage process that currently prevents interregional projects from being constructed. To do so, the Commission should consider the formation of new interregional planning boards that have full authority to make section 205 filings to FERC that select and allocate costs for interregional transmission projects. This could allow projects to proceed without separately securing the approval of each individual RTO board.

The Commission should also take on a greater role in overseeing transmission planning. The Commission should better incent public utility transmission providers to pursue a more optimal mix of projects. To do this the Commission should consider evaluating the cost-effectiveness of local transmission projects where there is evidence that a project addresses a need that could be met more efficiently by a regional or interregional project. The Commission should consider performance-based ratemaking techniques to reward transmission owners that pursue more cost-effective solutions. Finally, recognizing the critical role that states play in transmission planning, the Commission should consider requiring planning entities to grant state representatives an explicit governance role in the regional transmission planning process. The Commission should solicit comments from stakeholders on whether this step is appropriate and if so, what in particular the Commission should require with regard to governance reforms.

II. The Commission should replace current tariffs with planning requirements that will achieve just and reasonable rates

Reforms are necessary to meet Federal Power Act requirements of just and reasonable rates given new circumstances and demands on the grid. It has become clear that transmission investments need to be better targeted to the regional and inter-regional levels. Study after study shows substantial net benefits of such infrastructure, while broader trends in generator additions and retirements dictate that new regional and inter-regional infrastructure will be needed to integrate low-cost wind and solar generation into the system. Electrification of transportation and building end-uses will create a heightened need for new infrastructure. Market forces alone will not meet these needs. Transmission infrastructure's large economies of scale and scope make it a natural monopoly that is deployed most cost-effectively via a central coordinator.[7] As a large amount of transmission infrastructure is replaced in the coming decades, the Commission must seize the opportunity to ensure that it is built to cost-effectively meet the needs of the future system. And yet, current tariffs are failing to meet these needs.

A. Just and reasonable rates require plans that include more high voltage long distance transmission given future resource portfolios

As laid out in Appendix A, a number of studies have been conducted that demonstrate that significantly greater levels of transmission construction would yield substantial benefits to customers and enhance grid reliability.

These studies all point to the need for significant expansion of regional and inter-regional transmission infrastructure in order to create a reliable, efficient power system given reasonable projections of future needs.

7 William W. Hogan, *Transmission Investment Beneficiaries and Cost Allocation: New Zealand Electricity Authority Proposal*, at 1, February 1, 2020.

B. System threats require plans that provide greater resilience

Power systems are subject to an increasing variety and magnitude of threats. While reliability protocols have traditionally planned for reliable operation during and after system contingencies such as large generator or transmission line outages, there are other types of threats that result in the need for more robust regional and interregional transmission.

A recent report by national security experts noted: “Our electricity grid’s resilience—its ability to withstand shocks, attacks and damages from natural events, systemic failures, cyber attack or extreme electromagnetic events, both natural and man-made—has emerged as a major concern for U.S. national security and a stable civilian society.”[8] The report described large scale transmission as a solution: “Transmission buildout is critical to resilience as it can relieve line overloading—or “congestion” in industry jargon—on the existing system, lessening the compounding risks that come with a strained grid that could then be tested by an extreme weather event or an attack incident. Moreover, by enabling further development of renewable energy resources over wider geographic areas, well-planned transmission expansion can make targeted attacks on the grid more difficult to plan and carry out.”[9]

When the Commission opened a proceeding about system resilience, grid operators and experts emphasized first and foremost the importance of robust regional and interregional transmission in protecting against modern threats. For example:

- NYISO: “[R]esiliency is closely linked to the importance of maintaining and expanding interregional interconnections, [and] the building out of a robust transmission system;”[10]
- ISO-NE: “The system’s ability to withstand various transmission facility and generator contingencies and move power around without dependence on local resources under many operating conditions . . . results in a grid that is, as defined by the Commission, resilient.”[11]
- PJM: “Robust long-term planning, including developing and incorporating resilience criteria into the [Regional Transmission Expansion Plan], can also help to protect the transmission system from threats to resilience.”[12]

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8 NCGR, *Grid Resilience: Priorities for the Next Administration*, at 1, 2020.

9 *Ibid.*, at 42.

10 *Response of the New York Independent System Operator, Inc.*, Docket No. AD18-7, at 4, March 9, 2018.

11 *Response of ISO New England Inc.*, Docket No. AD18-7, at 15, March 9, 2018.

12 *Comments and Responses of PJM Interconnection, L.L.C.*, Docket No. AD18-7, at 49, March 9, 2018.

- SPP: "The transmission infrastructure requirements that are identified through the [Integrated Transmission Plan (ITP)] process are intended to ensure that low cost generation is available to load, but the requirements also support resilience in that needs are identified beyond shorter term reliability needs. For example, the ITP identified the need for a number of 345 kV transmission lines connecting the panhandle of Texas to Oklahoma. These lines were identified as being economically beneficial for bringing low-cost, renewable energy to market, but their construction has also supported resilience by creating and strengthening alternate paths within SPP."[13]

- Brattle Group analysts: "The power system can be vulnerable to disruptions originating at multiple levels, including events where a significant number of generating units experience unexpected outages. The transmission system provides an effective bulwark against threats to the generation fleet through the diversification of resources and multiple pathways for power to flow to distribution systems and ultimately customers. By providing customers access to generation resources with diverse geography, technology, and fuel sources, the transmission network buffers customers against extreme weather events that affect a specific geographic location or some external phenomenon (unavailability of fuel and physical or cyber-attacks) that affect only a portion of the generating units."[14]

Similarly, a National Academies of Sciences study of power system resilience noted the need for planning improvements to protect against modern threats.[15] The report draws several conclusions that weigh toward enacting reforms to ensure that regional transmission plans improve system resilience:

- "[L]arge-scale physical destruction of key parts of the power system by terrorists is a real danger."[16]

- "[T]he risks posed by cyber attacks are very real and could cause major disruptions in system operations."[17]

- "The probability, intensity, and spatial distribution of many of the hazards that can disrupt the power system are changing. These changes are due in part to the consequences of ongoing climate change. Traditional measures, based on an assumption

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13 *Comments of Southwest Power Pool, Inc. on Grid Resilience Issues*, Docket No. AD18-7, at 8, March 9, 2018.

14 Mark Chupka and Pearl Donohoo-Vallett, *Recognizing the Role of Transmission in Electric System Resilience*, at 3, May 9, 2018.

15 National Academies of Sciences, Engineering, and Medicine, *Enhancing the Resilience of the Nation's Electricity System*, The National Academies Press, 2017.

16 *Ibid.*, at 64.

17 *Ibid.*

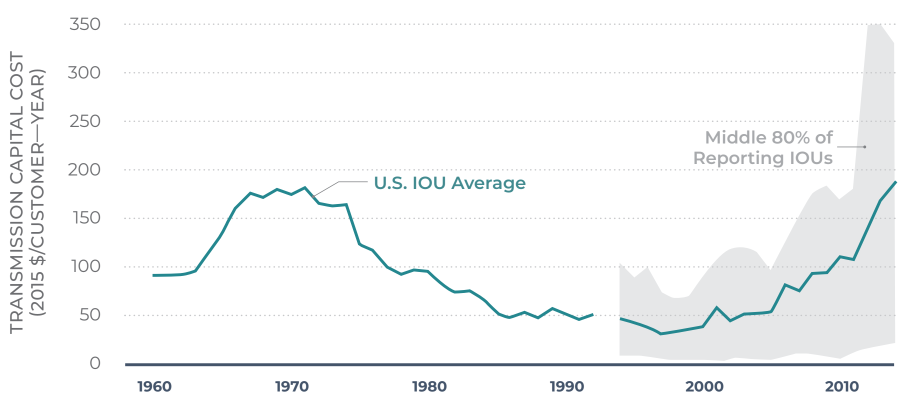
of statistical stationarity (e.g., 100-year flood), may need to be revised to produce measures that reflect the changing nature of some hazards."[18]

- "As the complexity and scale of the grid as a cyber-physical system continues to grow, there are opportunities to plan and design the system to reduce the criticality of individual components and to fail gracefully as opposed to catastrophically."[19]
- "In most cases, an electricity system that is designed, constructed, and operated solely on the basis of economic efficiency to meet standard reliability criteria will not be sufficiently resilient."[20]

C. The combination of an aging transmission system and a changing resource mix heighten the need for proactively planned transmission

The United States experienced a transmission construction boom in the 1960s and 70s, with the average annual investment cost of new transmission system capital infrastructure for U.S. Investor Owned Utilities climbing to nearly $200/customer-year at its peak during the late 1960s and early 70s before falling to less than $100/customer-year in the 1980s and 90s.[21]

FIGURE 1 Average Cost of Investment in New Transmission System Capital Infrastructure



Copyright The University of Texas at Austin, 2016

18 *Ibid.*, at 65.

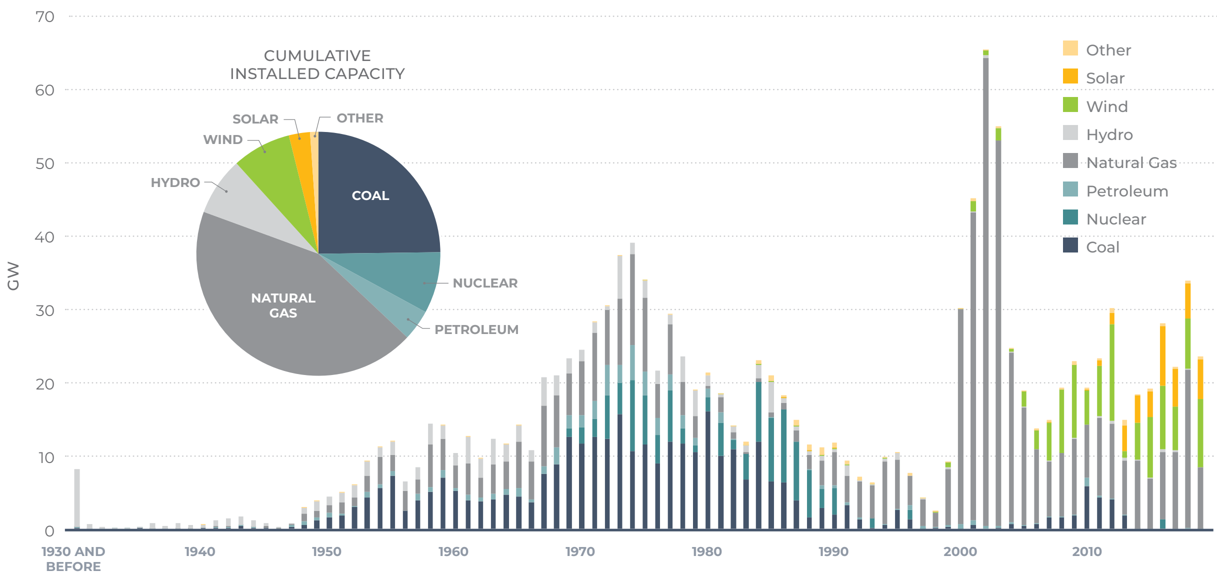
19 *Ibid.*, at 67.

20 *Ibid.*, at 71.

21 Robert L. Fares and Carey W. King, *Trends in Transmission, Distribution, and Administration Costs for U.S. Investor Owned Electric Utilities*, at 8, August 2016.

This construction boom coincided with a wave of power plant construction that consisted largely of coal, nuclear, and some gas facilities.[22] Transmission integrated these power plants with the system, building an infrastructure network well suited to large, centrally located power plants.

FIGURE 2 **U.S. Electric Utility and Independent Power Producer Generating Capacity by Initial Operating Year[23]**

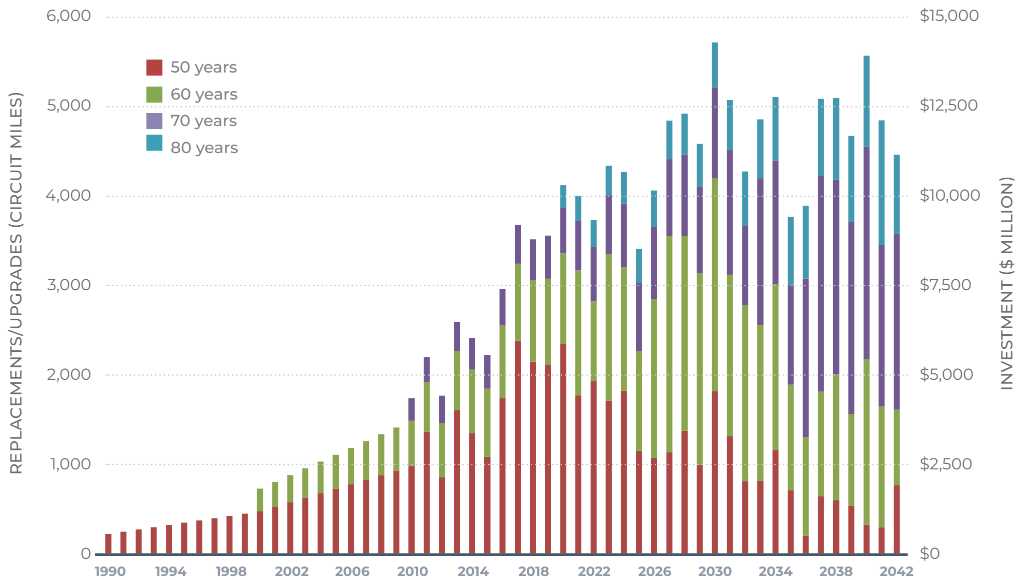


As this infrastructure ages, with transmission built in the 1960s now more than 50 years old, the system is facing a widespread need for maintenance, repair, and reconstruction. Yet as a second wave of transmission construction is playing out, new construction is too frequently focusing on simply rebuilding transmission infrastructure of the past, or addressing needs based on the current resource mix.

22 U.S. Energy Information Administration, *Most U.S. Nuclear Power Plants Were Built Between 1970 and 1990*, April 27, 2017.

23 U.S. Energy Information Administration, *Form 860*. Grid Strategies uses final 2019 data to aggregate electric generating units and their associated generating capacity by resource type and operating year.

FIGURE 3 Projected Circuit Miles Replaced/Upgraded and Total Projected investment ($ million)[24]

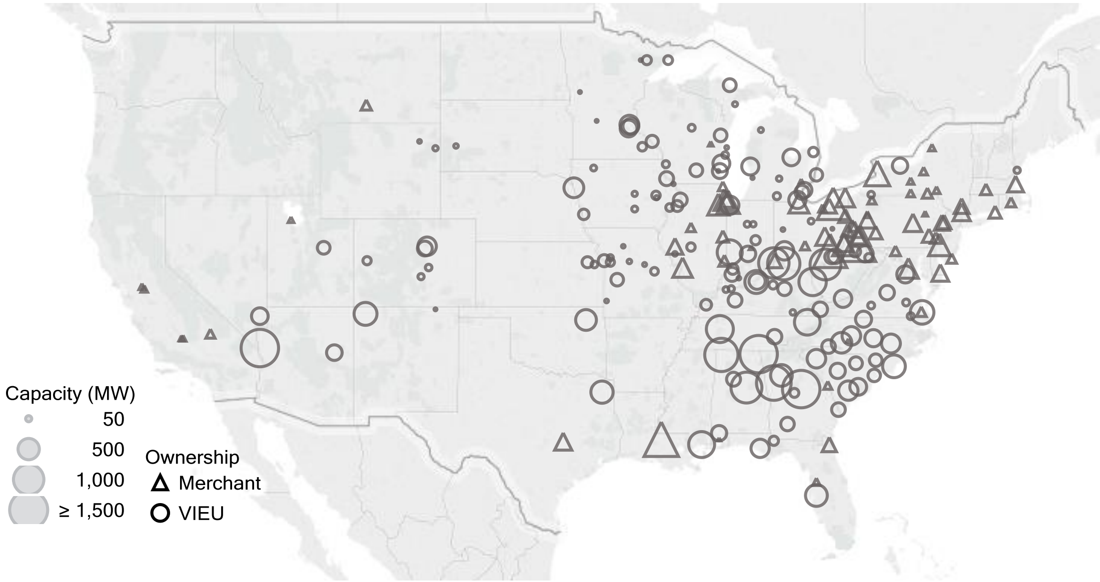


Such planning, blind to the retirement of aging generating plants and the forces shaping the future resource mix, is a recipe for a suboptimal infrastructure network that fails to meet future needs. As detailed in the U.S. Department of Energy's 2017 Staff Report to the Secretary on Electricity Markets and Reliability, a substantial portion of the nation's coal fleet has recently retired, and more coal plants and a significant number of nuclear plants are slated for retirement in the next 10 years.[25]

24 AEP, *Transmission's Future Today*, at 5, 2015, citing Johannes Pfeifenberger, Judy Chang, and John Tsoukalis, *Dynamics and Opportunities in Transmission Development*, December 2, 2014 (Assumes circuit mile costs equal to those of new lines).

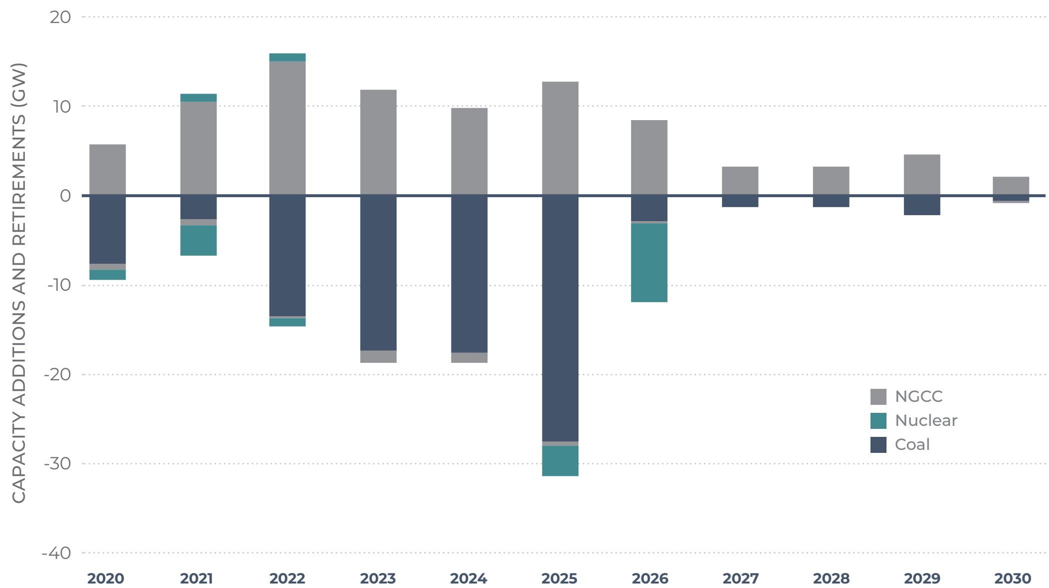
25 *See* U.S. Department of Energy, *Staff Report to the Secretary on Electricity Markets and Reliability*, August 2017.

FIGURE 4 Location of Coal Retirements (2002-2016)[26]



26 *Ibid.*, at 21.

FIGURE 5 Capacity Additions and Retirements from EIA Annual Energy Outlook (AEO) 2020 Reference Case[27]

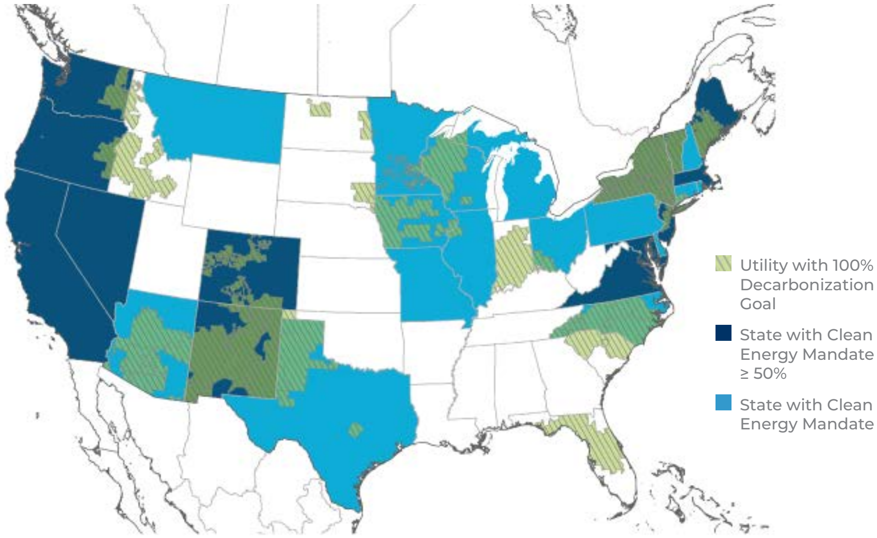


At the same time, wind and solar resources are rapidly proliferating. Wind and solar energy costs have fallen 70 and 89 percent, respectively, in the last ten years, from 2009 through 2019.[28] A number of additional factors are spurring their deployment as well, including public policies and corporate and utility procurement targets, as shown in Figure 6 below.

27 U.S. Energy Information Administration, *Annual Energy Outlook 2020*, Reference Table 9. Grid strategies uses EIA-projected electric generating capacity data to aggregate annual Coal, NGCC, and nuclear additions and retirements through 2030. The figure includes both "planned" and "unplanned" or projected additions and retirements.

28 Lazard, *Lazard's Levelized Cost of Energy Analysis - Version 13.0*, at 8, November 2019.

FIGURE 6 U.S. States with Clean Electricity Mandates & Utilities with Decarbonization Goals, 2020[29]

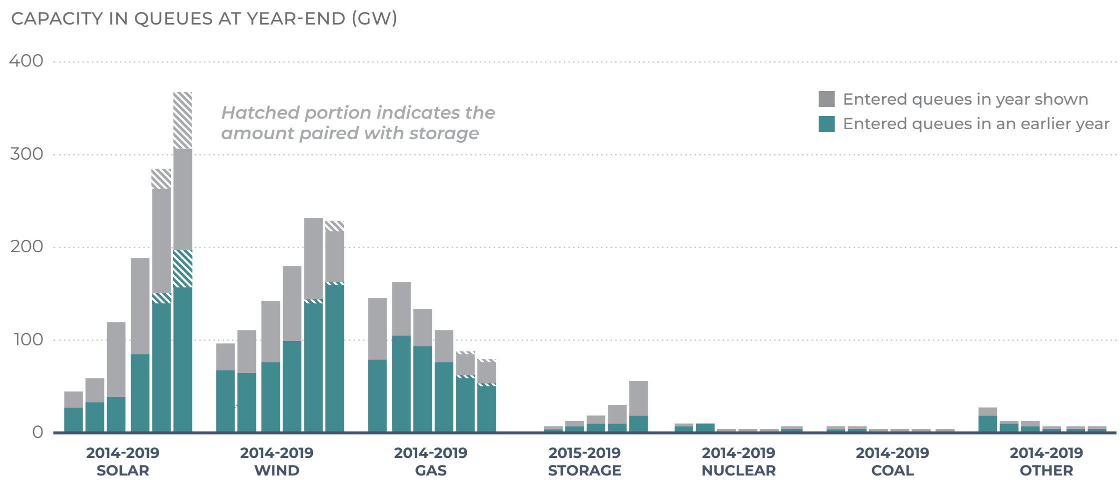


Source: WRI and Smart Electric Power Alliance. Updated on April 17, 2020

29 Lori Bird and Tyler Clevenger, *2019 Was a Watershed Year for Clean Energy Commitments from U.S. States and Utilities*, December 20, 2019.

Wind and solar resources make up the majority of resources in interconnection queues across the country.[30] There were 734 gigawatts (GW) of proposed generators waiting in interconnection queues nationwide at the end of 2019, almost 90% of which are renewable and storage resources as shown in Figure 7 below. 168 GW of solar and 64 GW of wind projects entered interconnection queues in 2019. The U.S. EIA forecasts that wind and solar will make up over 75% of new capacity additions in 2020,[31] and these resources will likely make up the lion's share of new additions for the foreseeable future.[32]

FIGURE 7 Capacity in Queues at Year-End by Resource Type



Source: Berkeley Lab review of interconnection queues

Note: Not all of this capacity will be built

Because the best locations for wind and solar resources are significantly different from those of retiring coal and nuclear resources, reconstructing the grid of the past is a poor match for future needs. Transmission has a long infrastructure life, so the infrastructure built today should be designed with the next 50 years in mind.

30 Ryan Wiser et al., *Wind Energy Technology Data Update: 2020 Edition*, at 18, August 2020. *See* also underlying data in the *2020 Wind Energy Technology Data Update* accompanying the slide deck.

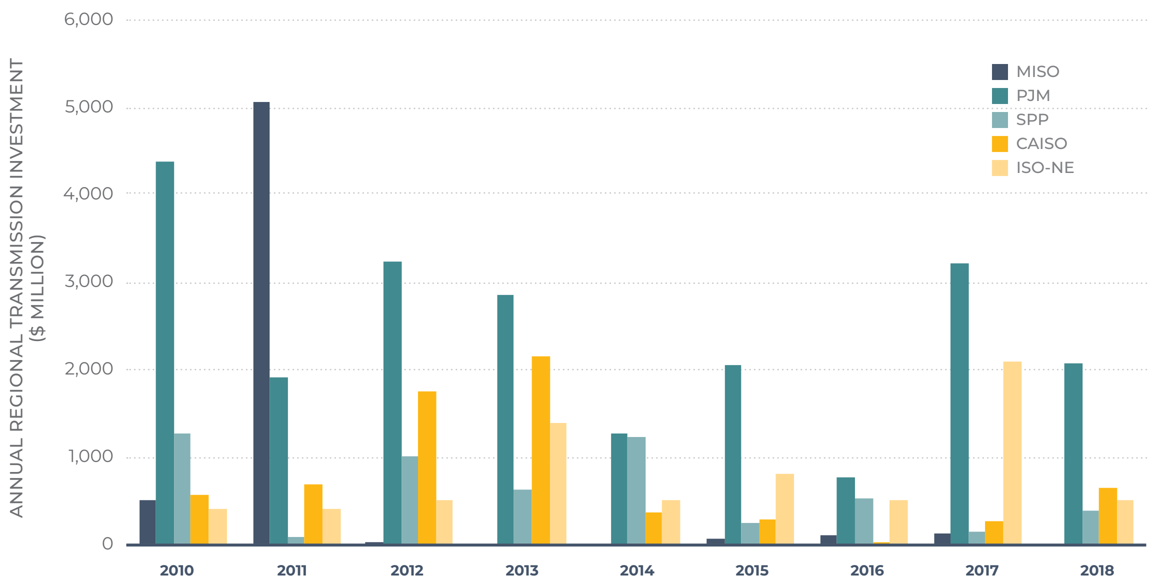
31 U.S. Energy Information Administration, *New Electric Generating Capacity in 2020 Will Come Primarily From Wind and Solar*, January 14, 2020.

32 *See*, e.g., U.S. Department of Energy, *Wind Vision: A New Era for Wind Power in the United States*, Figure 3-24 at 171, March 12, 2015.

D. The vast majority of new projects serve local needs or reconstruction of aging facilities, despite the large and growing need for bigger regional and inter-regional capacity

Despite the many benefits and economies of scale that regional and interregional transmission would bring, regional transmission investment (when excluding local transmission investments not subject to regional planning processes) has been stable or declining over the past decade.

FIGURE 8 **Annual Regionally-Planned Transmission Investment in RTOs/ISOs ($ million)**[33]



And while total annual transmission investment levels remain relatively robust, the majority of that investment has been in local transmission and low-voltage projects, planned without a full regional assessment that examines their cost-effectiveness relative to regional alternatives, or in regional infrastructure that is planned to meet reliability needs without assessing how to maximize other types of benefits, or that simply rebuilds or

33 Not all RTOs/ISOs provide regional transmission investment information. *See* Coalition of MISO Transmission Customers, Industrial Energy Consumers of America, and LS Power Midcontinent, LLC, *Section 206 Complaint and Request for Fast Track Processing*, at 31-32, January 21, 2020; PJM, *Project Statistics*, at 6, January 10, 2019; Lanny Nickell, *Transmission Investment in SPP*, at 5, July 15, 2019; CAISO, *ISO Board Approved Transmission Plans*, years 2012-2021 available under "Transmission planning and studies" section of webpage; CAISO, *2011-2012 Transmission Plan*, March 14, 2012; CAISO, *Briefing on 2010 Transmission Plan*, 2010; and ISO New-England, *Transmission*, accessed October 2020.

replaces existing infrastructure.[34] While utilities are understandably investing in local reliability upgrades when those needs are not addressed via regional and inter-regional infrastructure, this approach to transmission infrastructure investment results in higher total energy bills for customers than would result from more forward-looking, holistic transmission planning.

According to analysis by the Brattle Group, between 2013 and 2017, "about one-half of the approximately $70 billion of aggregate transmission investments by FERC-jurisdictional transmission owners in ISO/RTO regions [was] approved outside the regional planning processes or with limited ISO/RTO stakeholder engagement."[35] Further, the remaining transmission infrastructure that was included within regional transmission plans was skewed largely toward local projects, and projects built to meet near-term reliability needs. In addition, the Brattle Group analysts found that 97% of all transmission approved in their study period was not subject to a competitive selection process, either because it was built to address a near-term reliability need, upgraded existing infrastructure, or fell below RTO thresholds for competitive process, such as a specified voltage level.[36] Some RTOs do include RTO review of local projects,[37] but this is not consistent across Planning Authorities.

E. Generation interconnection processes are stretched to their breaking point

The lack of large regional transmission projects that connect resource rich areas with load centers has put the onus of building upgrades to interconnect wind and solar generators on generation interconnection processes. This has over-burdened them with a task they were never intended to perform: the job of planning the regional network in addition to the more local interconnection-related facilities.

Interconnection studies for individual generators (or groups of generators) are increasingly identifying costly regional upgrades and are projected to do so with greater fre-

34 Johannes P. Pfeifenberger et al., *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value*, at 4, April 2019 ("Significant investments have been made, but relatively little has been built to meet the broader regional and interregional economic and public policy needs envisioned when FERC issued Order No. 1000. Instead, most of these transmission investments addressed reliability and local needs.")

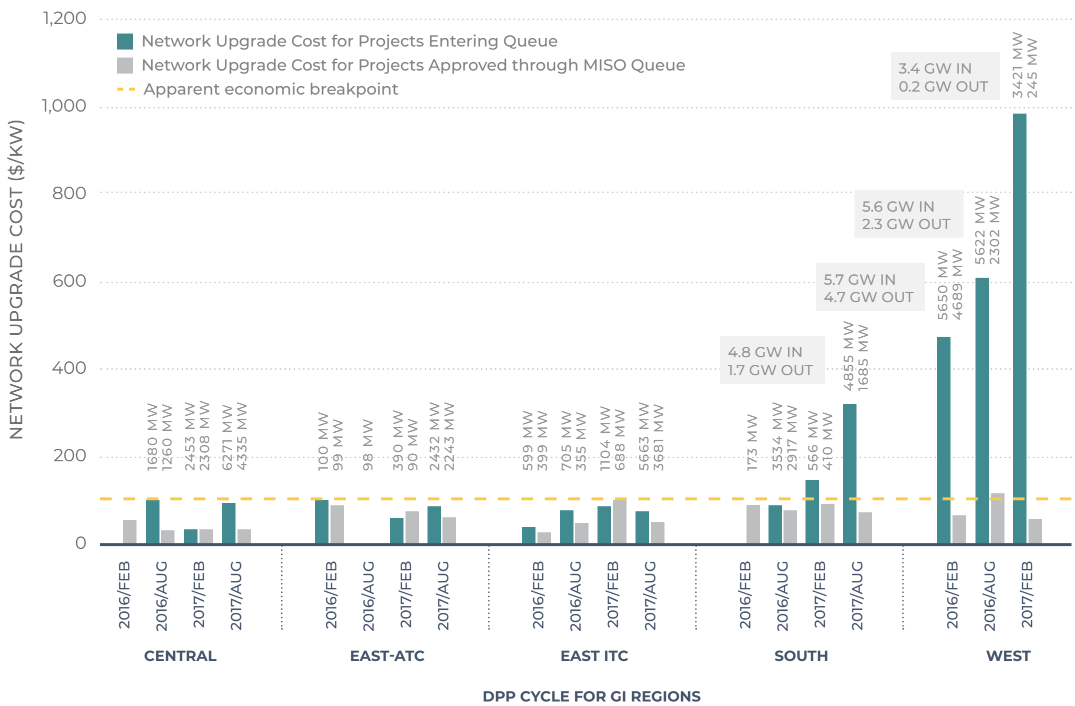
35 *Ibid*., 6-7.

36 *Ibid*., 17-20. *See also* MISO, *MTEP20 Appendix A - New Project List*, n.d., and PJM, *2019 Project Statistics*, at 3, May 12, 2020.

37 *See* MISO, *Business Practices Manual Transmission Planning*, BPM-020-r21, at 22, January 1, 2020. "In its role as the Planning Coordinator (PC), MISO will evaluate all bottom-up projects submitted by Transmission Owner(s) and validate that the projects represent prudent solutions to one or more identified Transmission Issues. In some situations, MISO, as the Planning Coordinator, may also recommend certain bottom-up projects if MISO analysis determines that additional expansion is necessary to comply with the NERC or regional reliability standards. Furthermore, MISO may also recommend alternative solutions to bottom-up projects submitted by Transmission Owner(s), and the expansion planning process will consider those alternative solutions along with the submitted bottom-up projects."

quency in the future. Costly system upgrades are not easily achieved by the interconnection process, which relies on participant funding — the practice of allocating project costs only to those who volunteer to pay them.[38] Interconnection costs are governed by Order No. 2003, which established the "at or beyond rule," pursuant to which the costs of facilities and equipment that lie between the generation source and the point of interconnection with the transmission network are born by the incoming generator.[39] While Order No. 2003 set a default rule that transmission owners would cover the cost of "network upgrades," (equipment "at or beyond" the point of interconnection), it gave RTOs "flexibility to customize . . . interconnection procedures and agreements to meet regional needs."[40] Some RTOs have since adopted methodologies that place the lion's share of network costs on the interconnecting generator.[41]

FIGURE 9 GI Network upgrade Costs ($/kW) for Recent MISO DPP Cycles[42]



38 *Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 715, July 21, 2011 (defining "participant funding").

39 *See Ameren Services Co. v. FERC*, 880 F.3d 571, 574 (D.C. Cir. 2018).

40 *Ibid.*

41 For example, MISO adopted a methodology allocating 90 percent of even network upgrades above 345 kV to generation owners, and requiring generation owners to pay 100 percent of such costs for lines below 345 kV. *See Ibid.*

42 ITC, *MISO Generation Queue and Renewable Generation: Update to the Advisory Committee*, at 5, May 20, 2020.

The system of funding major transmission upgrades through the generation interconnection process is ineffective for several reasons. First, large new transmission additions create broad-based regional benefits, so charging only interconnecting generators for this equipment requires them to fund infrastructure that others benefit from. This is the classic "free rider" problem in economics that makes it efficient to broadly allocate the cost of "public goods" like transmission, roads, water and sewer networks, etc. Second, it relies upon a study process that is highly unpredictable for participating generators, who do not know whether or not their interconnection request will require large upgrades. When studies reveal significant costs, generators tend to drop out of the process, necessitating restudies for all remaining generators and prompting delays (and potentially higher costs) for projects that are part of the same interconnection class year or further down in the interconnection queue. Third, there is a timing mismatch where transmission can take over five years, and it is not possible to know in advance which generation owners might want to connect at that point in the future. Finally, it misses opportunities to design new infrastructure in a more cost-effective fashion and of sufficient scale that maximizes all benefits of transmission, including reliability and economic benefits, and accommodates all likely new generation rather than just the particular generator(s) supporting the upgrades.

The current interconnection process simply does not work well when there is not adequate regional transmission capacity or a functioning mechanism to plan and pay for regional transmission. Without transmission planning reform that links the interconnection and transmission planning processes and eliminates the use of participant funding for significant system upgrades in the interconnection process, interconnection processes will become mired in ever-longer delays.[43]

43 Jay Caspary, Michael Goggin, Rob Gramlich, Jesse Schneider, *Disconnected: The Need for a New Generator Interconnection Policy*, January 2021.

III. FERC planning rule reforms

As the nation's resource mix evolves, the transmission system should be built to address future needs. Well-known commitments by major end use customers, utilities, cities, and states in support of net-zero or minimal carbon futures have not been adequately captured in grid planning scenarios. Information about the changing costs of different resource types are also widely recognized as driving significant system changes. Transmission plans can only yield reliable and efficient outcomes if they account for widely known trends and reasonable projections of future transmission needs. In short, plans should be about the future.

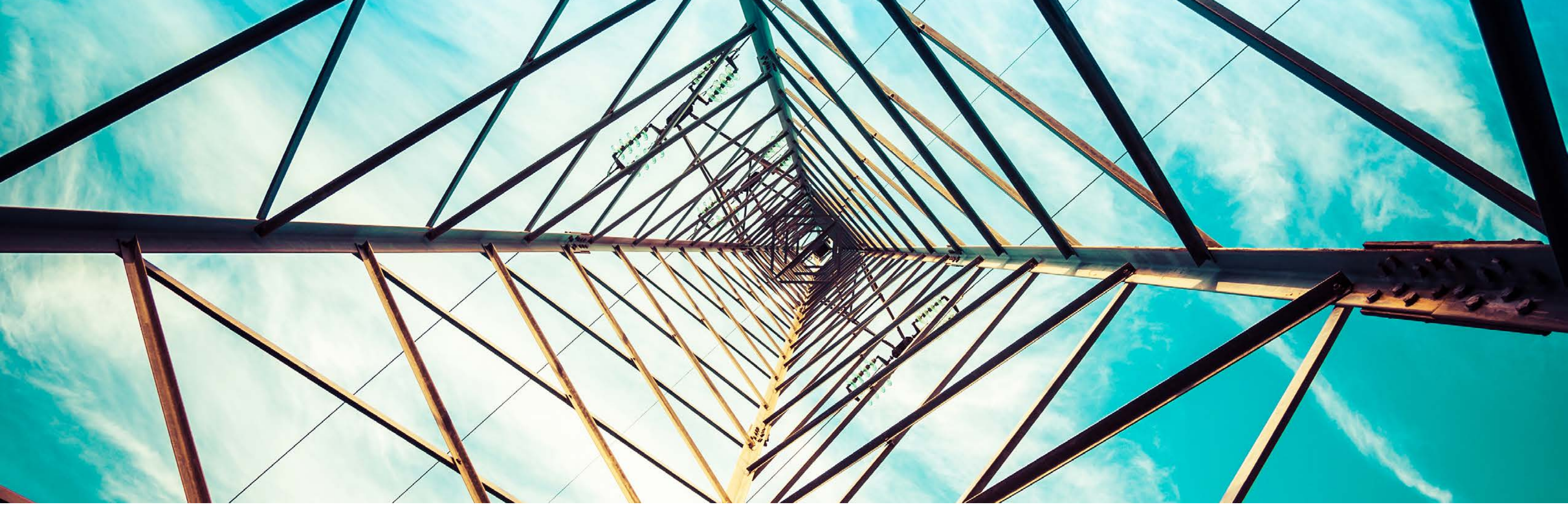
In most cases today, regional planning is limited to near term knowns and protecting firm service using scenarios which do not adequately incorporate likely future changes. In Appendix B, we describe and evaluate existing processes. In this section, we suggest reforms the Commission should enact to encourage better regional planning.

A. Integrated transmission planning should consider all benefits of transmission together

Many regions have segregated transmission planning studies for economic, reliability, public policy, and generator interconnection (GI) transmission projects. As discussed further in Appendix B, regions have separate planning processes for "Reliability" and "Economic" projects, and many regions have additional processes for "Public Policy" projects. Requiring a transmission project to be categorized as only one type of project fails to recognize all of the values and benefits of a transmission investment.[44] This siloed approach fails to consider the economies of scope across different categories and results in more poorly targeted transmission investments are accordingly less value per dollar spent by customers relative to regions that have taken an integrated approach to planning a network that optimizes across all categories of benefits.

While some regions have a process for "Multi-Value" projects, recognizing the fact that a single project may bring many types of benefits, these processes are not regularly used.

44 For example, *see* Judy W. Chang, Johannes P. Pfeifenberger, and J. Michael Hagerty, *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments*, Appendix A, July 2013.



Rather than being the exception, they should be the norm. FERC should require regional planning entities, as a general course of practice, to plan projects in a multi-value frame that considers all of the different benefits they are capable of providing.

B. Transmission needs should be determined with the best available data and scenario-based forecasting methodologies

A primary reason that the regional planning process has yielded few projects is that the scenarios modeled at the regional level do not reflect a reasonable projection of future supply and demand. To remedy this, the Commission should direct regional planning entities to carry out regional planning using scenarios constructed according to the best available data and forecasting methodologies. While reliability planning processes must necessarily evaluate solutions according to projections of the status quo future system across a variety of time scales, the economic planning process should provide an overlay to this process that is based on a more realistic assessment of future system needs, including resource mix projections that incorporate the best available data on future market trends. These should include (i) technology costs, (ii) public policies, (iii) corporate and utility procurement targets, (iv) interconnection queues, (iv) investments outside the planning process in non-wires alternatives, and (v) retirement projections. Demand projections must include reasonable electrification projections, accounting for market trends as well as public policies that require or incentivize electrification of buildings and transportation end uses. Planning entities should formulate a variety of reasonable future resource and demand mixes, recognizing the uncertainty inherent in the planning processes, identifying transmission needs across a wide range of plausible scenarios.[45]

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45 *See* Johannes Pfeifenberger, Judy Chang, and Akarsh Sheilendranath, *Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid*, Appendix B at B-1, April 2015; and Johannes Pfeifenberger and Judy Chang, *Well-Planned Electric Transmission Saves Customer Costs: Improved Transmission Planning is Key to the Transition to a Carbon Constrained Future*, Section V at 17, June 2016.

Formulating these planning scenarios is challenging insofar as it will require synthesizing a range of factors to project future generation and supply mixes. But by working with National Labs, states, and stakeholders to formulate reasonable assumptions, planning entities can greatly improve upon status quo approaches. To help guide regional planning entities, the Commission could encourage National Labs to focus on developing scenario analysis that can be used by regions, specifying that such projections are likely to constitute the best available data and forecasting methodologies.

1. *Plans should address needs according to reasonable estimates of the future resource mix*

Regional planning processes have tended to under-forecast the future mix of wind and solar. For example, in a 2019 planning assessment, SPP concluded that "[p]revious ITP assessments have been conservative in forecasting the amount of renewable generation expected to interconnect to the grid. When the studies were completed, installed amounts had nearly surpassed 10-year forecasts."[46] A variety of factors may contribute to this. Perhaps most significantly, planning processes may limit scenarios assessed to known generator interconnections and retirements, and fail to include new generation as part of the mix except insofar as needed to meet load growth.

For example, PJM's market efficiency planning process includes only facilities that have an "executed Interconnection Service Agreement or executed Interim Interconnection Service Agreement for which Interconnection Service Agreement is expected to be executed."[47] While PJM's methodology was adopted with the recognition that not all projects will come to fruition, protesting parties and the Market Monitor provided persuasive evidence that PJM's methodology will lead to inaccurate projections.[48] Likewise, SPP only includes generation resources in its economic models if they meet a set of criteria that includes "an effective Generator Interconnection Agreement," unless it grants a special case-by-case exemption.[49]

Such processes neglect the core function of the transmission planning process: to build infrastructure that connects the future resource mix to load. By default, generation that has secured interconnection agreements will have already agreed to pay for network upgrades necessary to integrate the generation. The generation that could benefit from

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46 SPP, *2019 Integrated Transmission Planning Assessment Report*, at 2, November 6, 2019.

47 PJM, *Amended and Restated Operating Agreement of PJM Interconnection*, L.L.C., Schedule 6, § 1.5.7(i)(iv), effective date September 17, 2010

48 *PJM Interconnection, L.L.C.*, 166 FERC ¶ 61,104, at PP 14-20, February 12, 2019.

49 SPP, *Integrated Transmission Planning Manual*, § 2.2.1.4, July 20, 2017.

transmission planning is necessarily the generation deeper in the queue. Generator retirements also should not be ignored, as they are a major factor impacting grid planning. In many cases, new resources of a different type will be installed at the same substation or zone where aging generators are being idled and retired. The lead time to install replacement resources has been reduced for inverter-based resources such as wind, solar and battery projects, so in many cases likely generator retirement may be a useful indicator of future resource mix locations. The recent announcements by many utilities in support of clean energy mandates and goals will require a significant amount of generator retirements that are not reflected in current long-range resource plans incorporated into regional planning assessments, and public policies can likewise cause generation retirements.

Rather than permitting status quo modeling that assesses only generation built to meet new load, the Commission should require regions to carry out economic planning processes according to more realistic projections of retirements, utilizing the best available information, including generation interconnection queues,[50] to predict the set of resources most likely to meet the needs currently served by existing generation that is likely to retire. The Midcontinent Independent System Operator's (MISO's) planning process provides a general template of how regions can conduct such a process. While its Regional Resource Forecasting model formulates the region's baseline scenario using only "existing generators and future generators with a filed Interconnection Agreement and in-service date prior to the point in time represented by the model," and reflects retirement only of "existing generators with approved Attachment Y [retirement] Notices,"[51] the model is then used as the basis for "Futures" assessments that project a range of resource additions and subtractions based on cost inputs and other factors.[52] In such analyses, a base case used for reliability assessments that contains only known resource retirements and additions should be given zero weight, reflecting the fact that a projection that relies solely on known resource retirements and additions has virtually zero probability of coming to pass.

Future resource mix projections should also be required to incorporate public policies. FERC should go beyond the Order 1000 requirement that regions simply "consider" public policy, and require that they incorporate it into a holistic assessment of transmission needs. While some regions incorporate state renewable portfolio standards into their

50 While interconnection queues will not perfectly match likely future generation, they are a data point that regional planning entities should critically evaluate along with other inputs.

51 SPP, *Integrated Transmission Planning Manual*, § 2.2.1.4, July 20, 2017

52 *See*, e.g., MISO, *MTEP19 Futures: Summary of Definitions, Uncertainty Variables, Resource Forecasts, Siting Process, and Siting Results*, n.d.

standard economic planning projections, not all regions do so.[53] Regions should account both for policies such as renewable portfolio or clean energy standards that encourage particular generation types, and also for emissions regulations that may cause the retirement of polluting resources, including federal, state, and local requirements. For example, NYISO incorporated peaker plant retirement scenarios into its most recent Comprehensive Reliability Plan, reflecting the likelihood that such plants would be impacted by state emissions regulations.[54] Local public policies are playing an increasing role in shaping the resource mix and should therefore be specifically accounted for by planning entities. Over "200 cities and counties have achieved or committed to 100 percent clean electricity," with the vast majority of these commitments having been made in the past three years.[55] With the increasing use of Community Choice Aggregation to enable such resource commitments, additional local commitments may become more likely in future years.

In addition, projections should reflect corporate and utility procurement targets. Incorporating such targets is necessary to accurately project future needs, which is required in order to ensure just and reasonable rates that reflect the right amount and type of infrastructure to serve those needs. Further, incorporating corporate and utility procurement targets will help facilitate an infrastructure mix that meets consumer preferences.

While MISO has recently proposed to incorporate corporate and utility procurement targets into its future planning scenarios,[56] most regions do not currently do so. Corporate procurement of renewables is a large and growing factor shaping future resource mix. Six utilities have adopted 100 percent clean energy or zero greenhouse gas emissions targets.[57] Corporations have signed power purchase agreements to procure over 21,000 megawatts of renewable capacity since 2018,[58] and will likely be seeking to procure thousands more in the coming years pursuant to renewable procurement targets. The Renewable Energy Buyers Alliance (REBA) has set a goal of catalyzing 60,000 megawatts of renewable energy projects by 2025.[59]

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53 For example, PJM does not include public policies within its standard economic planning forecast, instead requiring any transmission driven by public policy needs to be funded separately by states. PJM, *Amended and Restated Operating Agreement of PJM Interconnection*, L.L.C., Schedule 6, § 1.5.9, effective date September 17, 2010.

54 NYISO, *2019-2028 Comprehensive Reliability Plan*, at 14-29, 2019.

55 UCLA Luskin Center for Innovation, *Progress Toward 100% Clean Energy in Cities & States Across the U.S.*, at 10-11, November 2019.

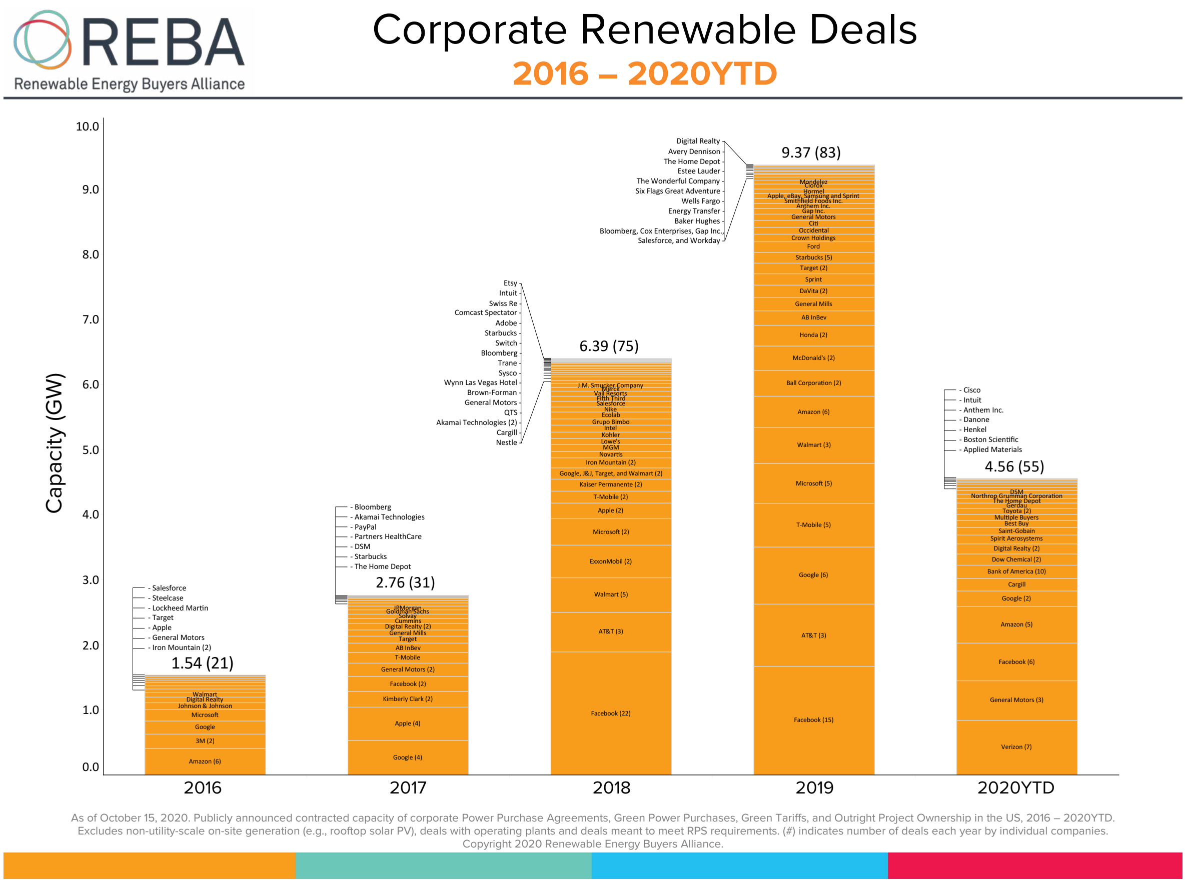
56 *See* MISO, *MISO Futures – Final*, Futures Siting Workshop, at 5, April 27, 2020, (incorporating utility and corporate procurement targets into Futures I and II).

57 UCLA Luskin Center for Innovation, *Progress Toward 100% Clean Energy in Cities & States Across the U.S.*, at 6, November 2019.

58 Renewable Energy Buyers Alliance, *REBA Deal Tracker*, accessed October 2020.

59 Renewable Energy Buyers Alliance, *Our Mission*, accessed Nov. 12, 2020. Corporate procurement goals can be more easily incorporated into regional transmission plans where companies have made time and location-specific commitments.

FIGURE 10 Corporate Renewable Deals (2016-2020)



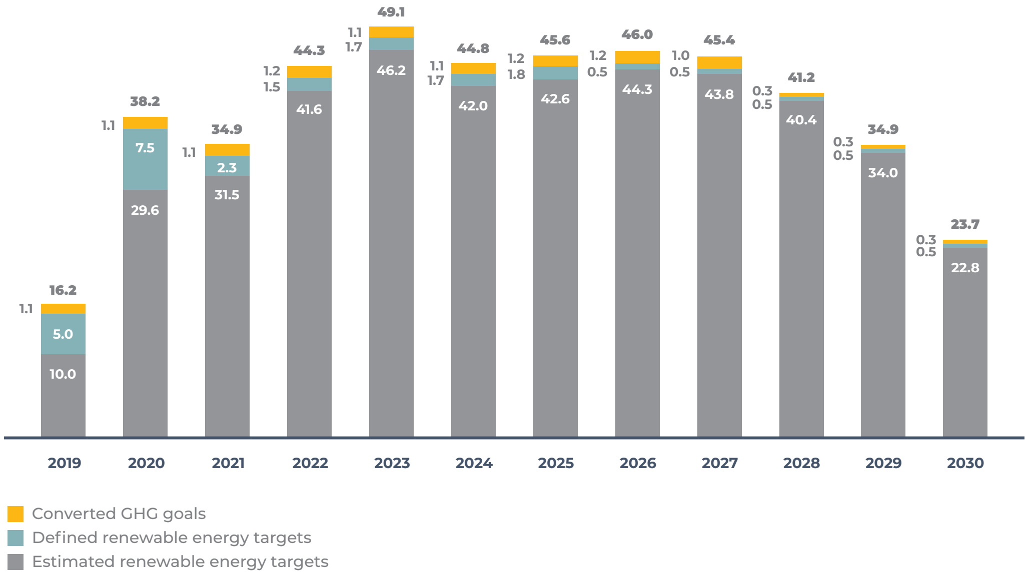
Credit: Renewable Energy Buyer's Alliance

Further, nearly half of Fortune 500 companies have set a greenhouse gas (GHG) reduction target.[60] Wood Mackenzie estimates that corporate and industrial renewable energy demand by the U.S. Fortune 1000 companies will be up to 85,000 megawatts by 2030.[61]

60 Nicolette Santos, David Gardiner and Associates, Nashville Carbon Competitiveness, at 7, September 2020.

61 Dan Shreve, Analysis of Commercial and Industrial Wind Energy Demand in the United States, at 5, August 2019.

FIGURE 11 **Fortune 1000 Annual C&I Renewable Energy Procurement Requirements (TWh)**



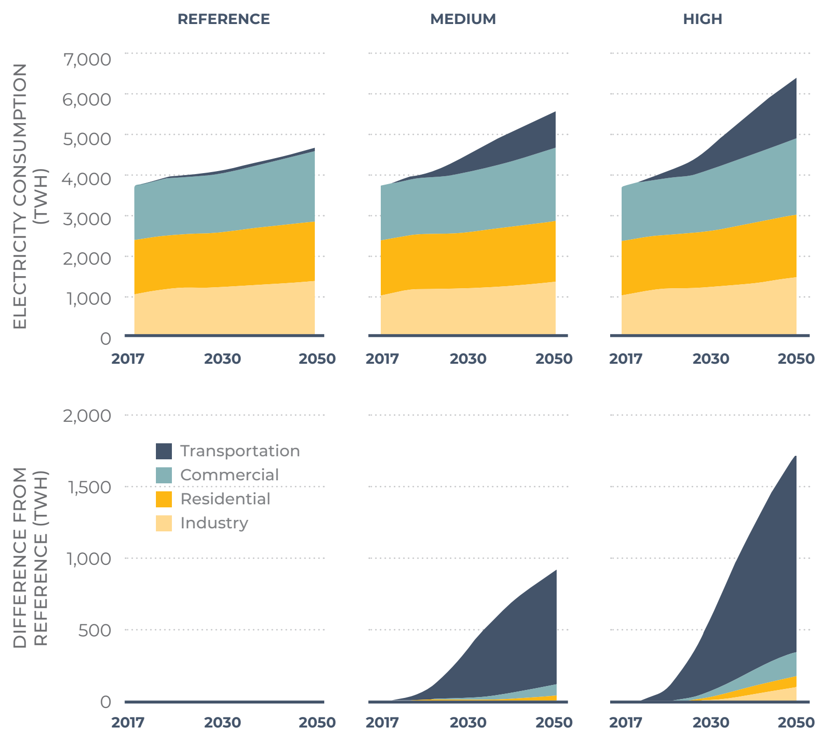
We are not aware of any reports that track total customer demand for particular resource types by region, so it is difficult to determine the extent to which such corporate targets will drive transmission planning needs. To fill this gap, the Commission should require regional planning entities to develop a process for estimating demand preferences from wholesale customers in their region. In sum, the Commission should require planning entities to plan for future resource mixes that respond to customers' preferences regarding supply sources, allocating costs appropriately, as described further in Section IV.

2. Plans should incorporate the effects of electrification on electricity demand

Electrification of transportation and buildings end-uses will have an enormous effect on future system needs. While regional transmission planning processes have made some strides forward to address this growing trend, they generally have not caught up to it and do not have adequate processes in place to ensure that demand projections will reflect reasonable electrification scenarios.

In its "medium electrification" case, which projects buildings and transportation electrification using only technology price forecasts and other factors without incorporating public policy, National Renewable Energy Laboratory (NREL) projects that transportation electrification will create nearly 1000 TWh of new demand in 2050, around a 25 percent increase from today's level, with building electrification more than making up for load reductions in the building sector caused by energy efficiency.[62]

FIGURE 12 Annual U.S. Electricity Consumption (top) and Difference from Reference (bottom)[63]



And national, state and local public policies will accelerate this trend. Recently passed state climate laws have included economy-wide emissions targets alongside generation sector requirements. For example, Maine's 2019 climate law requires the state to reduce GHG emissions to at least 80 percent below 1990 levels by 2050.[64] New York's Climate Leadership and Community Protection Act sets a target of net-zero emissions economy-wide by 2050.[65] In total, nine states and the District of Columbia have set targets of net zero economy-wide emissions by 2050 or sooner.[66]

62 Trieu Mai et al., *Electrification Futures Study: Scenarios of Electric Technology Adoption and Power Consumption for the United States*, at 60, 2018.

63 *Ibid.*, Figure 7.1 at 60.

64 *S.P. 550*, An Act to Establish the Maine Climate Change Council to Assist Maine to Mitigate, Prepare for and Adapt to Climate Change, 129th Maine Legislature, Legislative Document No. 1679, May 2, 2019.

65 *S. 6599*, An Act to Amend the Environmental Conservation Law, the Public Service Law, the Public Authorities Law, the Labor Law and the Community Risk and Resilience Act, in Relation to Establishing the New York State Climate Leadership and Community Protection Act, June 18, 2019.

66 John Podesta et al., *State Fact Sheet: A 100 Percent Clean Future*, Oct. 16, 2019.

Building codes are increasingly likely to incentivize or require electrification of some building segments, with the International Energy Conservation Code making its first ever electrification proposals for three features of its 2021 code.[67] New York City, the nation's largest local jurisdiction, has adopted a buildings efficiency standard that focuses on total building emissions and requires substantial reductions by 2030.[68] In California, "[m]ore than 50 cities and counties are considering requiring or encouraging all-electric new construction with local ordinances and zero-emission reach codes for buildings."[69] Furthermore, states and local jurisdictions also have a wide range of legal tools to electrify transportation fleets,[70] and are increasingly adopting plans to do so. For example, many states have adopted financial incentives for EV ownership, as well as incentives for EV charging infrastructure, often recoverable in rates.[71] California's governor recently signed an order banning sales of new gasoline cars by 2035.[72]

The Brattle Group analysts estimate that between $3 billion and $7 billion in annual incremental transmission investment will be need to meet increased demand caused by electrification between 2018 and 2030, with between $7 billion and $25 billion in annual incremental investment required between 2031 and 2050.[73]

In theory, reasonable electrification projections should already be guiding regional transmission planning processes, as they all include a load forecasting process to assess future demand.[74] In practice, however, load forecasting processes are not generally calibrated to capture the likelihood that electrification will drive a significant increase in future demand. Some regions, such as PJM, have begun to adjust their load forecasts to factor in electrification. PJM's forecast used for RTEP19 incorporates "an explicit adjustment for plug-in electric vehicle (PEV) charging in its peak and energy forecasts."[75] Building on these efforts, the Commission should require all regions to explicitly account for additional load from electrification of both transportation and buildings. Further, as with generation mix projections, it should require regions to plan according to a variety of scenarios. Scenario analysis is particularly appropriate with regard to electrification because, as Brattle analysts observe, "[t]he dynamics of electrification adoption, like the adoption of all new technologies, are likely to be characterized by hard to predict tipping points

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67 *See* Stacey Hobart, *Electrification Nation?*, July 29, 2020.

68 *See* *Local Law No. 97 of 2019:* To amend the New York city charter and the administrative code of the city of New York, in relation to the commitment to achieve certain reductions in greenhouse gas emissions by 2050.

69 Sierra Club, *Building Electrification Action Plan for Climate Leaders*, at 7, December 2019.

70 *See* MJB&A, *Toolkit for Advanced Transportation Policies*, October 2018.

71 *See*, e.g., Center for Climate and Energy Solutions, *U.S. State Clean Vehicle Policies and Incentives*, last updated January 2019.

72 Lauren Sommer and Scott Neuman, *California Governor Signs Order Banning Sales Of New Gasoline Cars By 2035*, September 23, 2020.

73 Dr. Jürgen Weiss, J. Michael Hagerty, and María Castañer, *The Coming Electrification of the North American Economy*, at 17, March 2019.

74 *See*, e.g., PJM, *Regional Transmission Expansion Plan*, at 25, February 29, 2020, (describing PJM's load forecasting model).

75 PJM, *Regional Transmission Expansion Plan*, at 37, February 29, 2020.

that result in rapid and widespread changes in consumer preferences and exponential growth once a certain tipping point is reached."[76] For this reason, MISO's methodology, that uses electrification as an overlay to the load forecast included in its Futures assessment, is appropriate, beyond updating the underlying load forecast itself.

3. Plans should incorporate resilience and reliability

The National Commission on Grid Resilience, noting the national security risks and the benefits of large-scale transmission described above, recommended, "Order 1000 ... failed to anticipate the need for inter-regional transmission over larger geographic scales between multiple grid regions in the wake of rising penetrations of renewable energy."[77] The report recommended "We agree with calls for reform, and specifically recommend that FERC strengthen requirements for interregional transmission planning, encourage longer term thinking about the value of larger lines (including high voltage direct current (HVDC) lines) and advanced technologies such as power flow controls and dynamic line ratings, and require RTOs/ISOs to assert leadership in planning processes and represent the public interest in doing so."[78] National security interests and expertise should be included in transmission planning processes.

4. Needs assessments should incorporate information on the use of non-wires options

Order No. 1000 rightly requires regional and inter-regional planning entities to "consider proposed non-transmission alternatives on a comparable basis."[79] Yet, because they are not currently given cost recovery in the transmission planning process, developers of such solutions, which include distributed energy resources such as energy efficiency, demand response, and energy storage, have little incentive to propose these solutions in the planning process. Therefore, the Commission should require regional planning entities to develop methods that assess the extent to which such solutions are likely to be able to cost-effectively reduce or replace the need for transmission solutions, without requiring them to be formally proposed. Such processes may consist of refinements to load forecasting analysis to account for the fact that solutions are more likely to be put forward in pockets with higher value, as well as linkages to state non-transmission solutions planning proceedings.

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76 Dr. Jürgen Weiss, J. Michael Hagerty, and María Castañer, *The Coming Electrification of the North American Economy*, at 6, March 2019.

77 NCGR, *Grid Resilience: Priorities for the Next Administration*, at 42, 2020.

78 *Ibid.*, at 42.

79 *Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 148, July 21, 2011.

Planning should also assess how strategically sited energy storage or advanced types of demand response deployed as transmission assets, included within state integrated resource plans, or likely to be built via competitive market forces, can serve as a complement to transmission expansion, allowing more efficient utilization of new transmission equipment. This includes benefits from storage charging when downstream transmission is congested and later discharging that energy when it is not, which is particularly advantageous for storage located in wind or solar producing areas. It also includes use of the fast charge and discharge response of storage devices to help accommodate system contingencies, instead of the current approach of leaving transmission capacity unutilized at all times so the system remains stable during flow conditions following a contingency.

5. ***Planning entities should incorporate input from states on siting***

Information from states will be critical to developing reasonable planning scenarios, considering the role states play with regard to the siting and permitting of transmission infrastructure. Reasonable planning scenarios should reflect siting constraints. The timing of the regional transmission planning processes means that the Commission should not reverse its determination in Order No. 1000-A "that it would be an impermissible barrier to entry to require, as part of the qualifica-

tion criteria, that a transmission developer demonstrate that it either has, or can obtain, state approvals necessary to operate in a state, including state public utility status and the right to eminent domain, to be eligible to propose a transmission facility."[80] But the Commission should go beyond Order No. 1000 in seeking ways to incorporate state input on siting and other related issues into the regional and interregional planning processes.

For example, the Commission can require regional planning entities to solicit input from states on siting considerations in advance, so that regional planning processes are designed with an eye toward state siting processes. Where states have broad siting priorities, such as prioritizing construction in existing corridors, that can be taken into account. Where particular projects have already obtained siting approval, or particular corridors have been designated by states, U.S. DOE,[81] or the Bureau of Land Management[82] as ripe for transmission development, regional planning entities can prioritize those projects or locations.

Because states have jurisdiction to set policies that control the mix of resources on the system, they will provide critical input to RTOs and other regional planning entities in constructing grid mix scenarios.

6. Planning scenarios and models should be consistent with operational practice

The scenarios and resulting models developed for planning efforts should reflect plausible and expected system conditions, including the realistic response those conditions would elicit from system operators.

Historically, planning was focused on meeting peak demand, which necessitated most generating resources to be online and dispatched at high levels to meet the peak. With increased renewable generation, many times the most stringent transmission needs occur during periods with lower demand, when there can be significant flexibility to reschedule and redispatch resources, as not all of them are needed to meet demand under those conditions. However, planning models have tended to not account for this flexibility, and instead assume a certain fixed schedule and output of dispatchable thermal generation. These dispatch levels can be inconsistent with how these resources would behave under real system and market conditions in operations. As a result, the transmission system is modeled in planning as more burdened or with less capacity than it would have in operations under those same conditions. Planning models and power flow cases

80 *Ibid.*, at P 441.

81 *See 16 U.S.C. § 824p.*

82 *See Energy Policy Act of 2005, § 368*, Pub. L. No. 109-58, H.R., August 8, 2005.

should reflect system conditions that are consistent with how the system is operated, including dispatching units using the same least-cost dispatch logic used to dispatch units in operations.

C. Transmission plans should construct the best feasible portfolios based on all available technologies, configurations, and options

Beyond carrying out planning according to reasonable scenarios projecting supply and demand mix, the Commission should also build on Order No. 1000's requirements to ensure that the scenarios modeled draw on all types of solutions to serve transmission needs, and include in plans all types of technologies and configurations.

1. Plans should consider and include all grid enhancing technologies

As a number of parties commented in the Commission's Notice of Proposed Rulemaking on transmission incentives, Grid Enhancing Technologies (GETs) should be included in the transmission planning process.[83] Dynamic Line Ratings, power flow control, topology optimization, and storage as transmission are "transmission assets," which can be directly included in plans, with costs recovered in RTO tariffs just like other transmission technologies. The American Public Power Association explains that regional processes for identifying solutions should "identify efficient and cost-effective GETs deployments (e.g., by ascertaining transmission paths with severe congestion that GETs might alleviate at a lower cost than alternatives)."[84] GETs should be modeled consistent with how they would be operated to deliver both reliability and economic benefits. These technologies often provide a great deal of flexibility that may be useful in a variety of potential system conditions. GETs are also generally modular (can be sized to the need) and mobile (can be physically moved to different points on the grid), which provides option value to any facility acquired.[85] These forms of optionality value should be incorporated into benefits assessments.

83 *See*, e.g., *Comments of Transmission Access Policy Study Group*, Docket No. RM20-10, at 8-9, July 1, 2020 ("While the NOPR rightly does not propose the highly problematic shared-savings incentives, its proposed incentives for deployment of transmission technologies needlessly increase cost without addressing the real obstacles to deploying new technologies. A better approach would be to integrate advanced technologies into Order 890 and Order 1000 processes."); *Comments of Alliance Energy Corporate Services, Inc. and DTE Electric Company*, Docket No. RM20-10, at 35, July 1, 2020 ("The Commission should ensure that required transmission planning processes appropriately consider new technologies and alternative, non-transmission solutions.").

84 *Comments of the American Public Power Association*, Docket No. RM20-10, at 65, July 1, 2020.

85 Kerinia Cusick, Jon Wellinghoff, and Lorenzo Kristov, *Transmission Planning Protocol: Leveraging Technology to Optimize Existing Infrastructure*, August 2019.

Because the impacts of GETs are sometimes easier to measure in the shorter-term time frame (months to hours) rather than years, the Commission should consider whether an incremental step in the planning process may be appropriate that is particularly targeted at measuring ways in which GETs could improve operations of the existing system. At the same time, the inclusion of GETs in the long-term solution mix may frequently yield benefits, and may be used in conjunction with new infrastructure improvements to offer a more efficient solution than would otherwise be provided.

2. ***Plans should consider options of non-traditional physical assets and configurations***

Future needs will likely call for more long-distance transfers of power across time zones and areas with asynchronous loads shapes. That factor along with the falling costs of High Voltage Direct Current (HVDC) will likely lead to more applications of HVDC into plans. Regional planners have not utilized HVDC much in recent decades, and it raises issues about control and operation that are different from current systems. Planners should address these opportunities and changes that may be needed.

New types of conductors, converters, transformers, and other assets provide potential reliability, resilience, and efficiency benefits that should be considered in transmission plans. For example, HVDC lines with Voltage Source Converters present opportunities for black starting whole regions with power from neighboring regions. Composite core transmission lines can deliver more and withstand more severe weather events than traditional conductors. All such options should be considered and incorporated as appropriate.

3. ***Benefits of individual and merchant lines should be assessed in regional and inter-regional planning, whether or not they are not cost allocated***

Order No. 1000 does not require merchant transmission developers to participate in regional planning processes because they do not receive regional cost allocation.[86] It does, however, require merchant developers "to provide adequate information and data to allow public utility transmission providers in the transmission planning region to assess the potential reliability and operational impacts of the merchant transmission developer's proposed transmission facilities on other systems in the region," and allows merchant transmission developers to voluntarily participate in the regional transmission planning

86 *Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 163, July 21, 2011.

process.[87]

Assessing the benefits of merchant transmission development in regional transmission plans is appropriate because, even though such infrastructure does not receive regional cost allocation, it impacts the overall mix of solutions that may be built. Further, assessing the benefits and costs of merchant transmission solutions could help these projects secure state-level siting permits, by demonstrating the need for these projects. For this reason, the Commission should build on Order No. 1000's requirement for merchant developers to provide data to inform the regional transmission planning process[88] by directing planning entities to conduct planning scenarios that quantify the benefits of merchant projects. In addition to helping inform regional processes, this would help merchant developers drive projects forward by giving them some evidence of need that they could use in state permitting processes. Similarly, cost allocated lines that are assessed through portfolio benefits assessments should be studied for individual benefits upon request, for use in permitting proceedings.

D. FERC should direct planning entities to select infrastructure for inclusion in regional plans by maximizing net benefits of a portfolio

Once needs are assessed based on best available information, all benefits are considered together, and all technology and configuration options are considered, regional planning entities should be directed to select plans that maximize the net benefits of a portfolio of transmission investments.

The Commission should build on Order No. 1000 to provide greater direction and clarity about the wide range of benefit metrics regional planning entities should use to assess whether solutions are beneficial and should thus be included in the regional plan, directing planning entities to achieve just and reasonable rates by using Benefit-Cost Analysis (BCA). There will be many trade-offs between different options. Some investment options will be more costly in the near-term but carry much greater benefits over the long term. Some will be extremely low cost and fast to deploy with benefits that well exceed their costs, even though those benefits may not be as great as long-term large-scale options. In some cases, the options will be mutually exclusive and in other cases they will be complementary such that they could be done together. BCA provides a clear planning protocol that prioritizes among these potentially competing or complementary invest-

87 *Ibid.*, at PP 164-165.

88 *Ibid.*, at PP 163-165.

ments based on what would be most likely to result in just, reasonable, and not unduly discriminatory rates.[89]

1. ***Pro-active holistic transmission planning to maximize net benefits is fully compatible with standard RTO market designs and competitive generation markets***

The six FERC-jurisdictional RTOs (ISO-NE, NYISO, PJM, MISO, SPP, and CAISO) as well as the ERCOT all use a form of bid-based security constrained economic dispatch with locational prices and financial transmission rights. The academic literature behind locational marginal price (LMP) design does not make the claim that the efficient level of transmission is achieved by relying only on voluntary investment. To the contrary, the leading economists and engineers were clear that planned investment is required to achieve efficiency. As perhaps the leading international expert and proponent of the LMP design, Dr. William Hogan of Harvard University, wrote recently:

> If there were no economies of scale and scope for transmission investment, electricity markets could follow the same competitive model for transmission where beneficiaries determine and pay for their own investments. Given the large economies of scale and scope, transmission is a natural monopoly and investment requires a central coordinator.[90]

Dr. Hogan explains the appropriate decision rule for transmission planning is Benefit-Cost Analysis: "A forward-looking cost-benefit analysis provides the gold standard for ensuring that transmission investments are efficient."[91] He continues to explain BCA as the only reasonable option for efficient grid planning:

> There is no other way of determining whether a grid investment is efficient. Whatever the purpose of the grid investment, it will only be efficient if the benefits it provides — for example, in terms of lower energy production costs or increased reliability — exceed the cost of the investment. No investment should proceed without being subject to a cost-benefit assessment which quantifies all benefits and costs.[92]

Some parties may prefer to rely only on voluntary investment and Financial Transmission Rights as the incentive for such investment, and some market participants would

89 *See* generally Avi Zevin, *Regulating the Energy Transition: FERC and Cost-Benefit Analysis*, May 2020 (arguing that greater use of cost-benefit analysis will further the Commission's mission of cost-effectively serving customers).

90 William W. Hogan, *Transmission Investment Beneficiaries and Cost Allocation: New Zealand Electricity Authority Proposal*, at 1, February 1, 2020.

91 *Ibid.*

92 *Ibid.*, at 5.

probably fare better in that model. However, that is not efficient for consumers as Dr. Hogan's paper thoroughly describes. Relying only on voluntary investment by market participants does not work in theory because public goods are always under-provided when relying only on voluntary market participant investments. It does not work in practice either, as we have seen persistent congestion and a lack of infrastructure development as described in the first section.

Similarly Dr. Paul Joskow, the economist who initiated the movement towards competitive generation markets perhaps more than any other economist with his 1983 book Markets for Power,[93] has long recognized the natural monopoly and public goods aspects of transmission that do not lend themselves to a competitive structure for that sector. Instead he advocates for pro-active broad regional planning to achieve the efficient transmission network: "Barriers to expanding the needed inter-regional and internetwork transmission capacity are being addressed either too slowly or not at all."[94] During restructuring he advised the Commission:

> There are numerous reasons why we should not expect "the market" to produce transmission enhancements that meet reasonable economic and reliability goals. *Indeed, proceeding under the assumption that, at the present time, "the market" will provide needed transmission network enhancements is the road to ruin*. There is abundant evidence that market forces are drawing tens of thousands of megawatts *of new generating capacity* into the system. There is no evidence that market forces are drawing significant quantities of entrepreneurial investments in new transmission capacity. While third parties should be given the opportunity to propose market-based private initiatives to expand transmission capacity, incumbent transmission owners, in the context of a sound RTO/ISO planning process, must be relied upon to play a central role in expanding the transmission system.[95]

The arguments above from leading economists apply both to RTO structures as well as to transmission outside of RTO where traditional "contract path" transmission service is utilized. In either case, just and reasonable rates are also best achieved by pro-active holistic planning that maximizes net benefits.

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93 Paul L. Joskow and Richard Schmalensee, *Markets for Power*, MIT Press, November 1983.

94 Paul Joskow, *Transmission Capacity Expansion is Needed to Decarbonize the Electricity Sector Efficiently*, Joule 4, at 1-3, January 15, 2020.

95 *Comments of Professor Paul L. Joskow*, Docket RM 99-2, at v, August 16, 1999.

2. The Commission should direct planning entities to apply standard methods of incorporating uncertainty into BCA

BCA analysis of transmission portfolios will be shaped by the planning process, as the core of the analysis will be a forward-looking projection of benefits and costs across the scenarios examined. As recommended above, the Commission can ensure a wide range of benefits are accurately assessed by requiring incorporation of all factors likely to shape the future demand and supply mix, mandating consideration of all relevant technologies.

BCA can and should handle uncertainties, of which there are many in transmission. Fuel prices, load growth, load shapes, generation mix, and weather patterns can all change and lead to differing results on which transmission has benefits that exceed costs. Public policies may be expressed via actions such as Executive Orders that do not have the full force of statutes or regulations yet may nevertheless be likely to guide the transmission mix. Standard BCA uses the concept of "expected value" to address uncertainty. Expected value arrives at a single expected benefit number when considering two scenarios by multiplying the probability of the scenario times the value of it.

Certain scenarios significantly influence the expected value of transmission. For example, transmission enables existing power plants to be dispatched in real-time as fuel prices fluctuate or demand shifts. The value of transmission can be particularly high during extreme events, especially where they cause fuel prices and demand to spike while suppressing supply in localized region, making imports from other regions extremely valu-

able. For example, additional transmission would likely have yielded hundreds of millions of dollars in savings over a matter of days during recent Polar Vortex and Bomb Cyclone events.[96] Probabilistic transmission analysis will also become increasingly valuable as the penetration of variable renewable resources increases, which can make transmission ties extremely valuable during periods of regional renewable over-supply or shortage.

Transmission also creates optionality for new power plants to be built to take advantage of unexpected shifts in the economics of different energy sources. Over the last decade, transmission has not only allowed customers to benefit from the large cost reductions for wind and solar generation, but also the increased availability of low-cost shale natural gas in many regions where gas resources were not previously available. Because it takes much longer to plan, permit, and build transmission than generation, it is often not possible to wait for economic and policy shifts to occur before investing in the transmission needed to optimally respond to them.

SPP and Brattle Group analysts have documented the value of transmission for providing optionality to hedge against uncertainty in future fuel prices, the generation mix, and other factors.[97] Additional analysis has shown the optionality value of transmission to be very large and found that standard transmission planning methods greatly underestimates the value of transmission.

Plans that ignore important scenarios will produce inefficient outcomes. Analysis by Dr. Ben Hobbs and Francisco Espinoza from Johns Hopkins University shows that current transmission planning methods, which at best use several deterministic scenarios to highlight ranges of future outcomes for the power system, are "a weak tool for decisions under uncertainty" and "don't account for flexibility."[98] Relative to standard deterministic methods that do not account for uncertainty, probabilistic transmission planning methods that account for uncertainty by simultaneously evaluating a large number of possible scenarios result in both a larger and more optimal transmission build, potentially saving consumers tens or even hundreds of billions of dollars.[99]

Other recent analysis found that the consumer savings from use of such probabilistic (stochastic) tools in the Western U.S. "can be as much as or even exceed the cost of the

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96 Michael Goggin, *How Transmission Helped Keep the Lights on During the Polar Vortex*, February 14, 2019.

97 Johannes Pfeifenberger and Judy Chang, *Well-Planned Electric Transmission Saves Customer Costs: Improved Transmission Planning is Key to the Transition to a Carbon Constrained Future*, June 2016; and SPP, *The Value of Transmission*, January 26, 2016.

98 Francisco D. Munoz, Jean-Paul Watson, and Benjamin F. Hobbs, *Optimizing Your Options: Extracting the Full Economic Value of Transmission When Planning Under Uncertainty*, The Electricity Journal, Volume 28, Issue 5, at 26-38, June 2015; and Benjamin F. Hobbs, Francisco D. Munoz, Saamrat Kasina, and Jonathan Ho, *Assessing Transmission Investments under Uncertainty*, August 2013.

99 Francisco David Muñoz Espinoza, *Engineering-Economic Methods for Power Transmission Planning Under Uncertainty and Renewable Resource Policies*, at 102, January 2014.

recommended transmission facilities themselves."[100] The analysis "provide[s] evidence that the transmission recommendations of stochastic programming models are more robust to scenarios that haven't been considered than recommendations by deterministic models. That is, stochastic plans appear to make the network more adaptable in the face of all uncertainties, not just those that were included as specific scenarios."[101]

Transmission planning analysis often identifies certain scenarios where the value of transmission is extremely high even if it is not in the base case. But while many planning entities currently assess projects across a range of scenarios, they do not generally assign probabilities to these scenarios or clarify how the different scenario results factor into project selection. For the reasons above, BCA applied to transmission should consider scenarios and probabilities to arrive at expected value of transmission.

3. The Commission should provide a minimum set of benefits that must be included in any BCA analysis conducted by planning entities

Beyond ensuring that BCA is performed according to the reasonable likelihood of future scenarios, the Commission should also set a minimum standard for quantifying benefits and encourage planners to innovate and learn from one another's experience in quantifying benefits.

While many planning entities currently perform BCA analysis, none fully quantify the full range of benefits provided.[102] For example, SPP's benefit-cost methodology excludes transmission's benefits in lowering reliability margins, improving grid resilience to extreme weather, enabling more efficient operating practices and maintenance schedules, and enabling future markets.[103] To remedy these failures to accurately quantify benefits and provide a more consistent standard for judging projects, the Commission should mandate a minimum set of standards for quantifying benefits.

BCA should simultaneously evaluate all categories of benefits provided by transmission, instead of the siloed approach currently used in many regions. It should also include benefits that are not currently quantified in most regional transmission planning processes,

100 Jonathan L. Ho et al., *Planning Transmission for Uncertainty: Applications and Lessons for the Western Interconnection*, January 2016.
101 *Ibid*.
102 *See*, e.g., Burcin Unel, *A Path Forward for the Federal Energy Regulatory Commission: Near-Term Steps to Address Climate Change*, at 14-15, September 2020.
103 *See* Johannes Pfeifenberger, *Improving Transmission Planning: Benefits, Risks, and Cost Allocation*, at 12, November 6, 2019, (citing SPP, *Priority Projects Phase II Report*, February 2010, and SPP Metrics Task Force, *Benefits for the 2013 Regional Cost Allocation Review*, July 5, 2012).

but for which quantification methods exist.[104] As shown in the following table from SPP's report on the topic, transmission provides many benefits, though many are typically not quantified (listed as "N/Q"). BCA determines which options are efficient to pursue, taking all factors into account, and ensures that options that do not reduce rates in the long term are not chosen.

104 For example, *see* Judy W. Chang, Johannes P. Pfeifenberger, and J. Michael Hagerty, *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments*, Appendix A, July 2013; and Judy W. Chang et al., *Recommendations for Enhancing ERCOT's Long-Term Transmission Planning Process*, Appendix B, October 2013.

TABLE 1 **Projected Net Present Value (NPV) of SPP Transmission Projects Installed in 2012-14, Based on the First Year of SPP's Integrated Marketplace (Mar 2014 - Feb 2015)**[105]

BENEFIT CATEGORY	TRANSMISSION BENEFIT	NPV ($M)
Adjusted Production Cost Savings	Reduced production costs due to lower unit commitment, economic dispatch, and economically efficient transactions with neighboring systems	10,442*
1. Additional Production Cost Savings **	a. Impact of generation outages and A/S unit designations	INCLUDED
	b. Reduced transmission energy losses	INCLUDED
	c. Reduced congestion due to transmission outages	INCLUDED
	d. Mitigation of extreme events and system contingencies	PARTIAL
	e. Mitigation of weather and load uncertainty	PARTIAL
	f. Reduced cost due to imperfect foresight of real-time system conditions	INCLUDED
	g. Reduced cost of cycling power plants	PARTIAL
	h. Reduced amounts and costs of operating reserves and other ancillary services	PARTIAL
	i. Mitigation of reliability-must-run (RMR) conditions	N/Q
	j. More realistic "Day 1" market representation	N/Q
2. Reliability and Resource Adequacy Benefits	a. Avoided/deferred reliability projects	105
	b. Reduced loss of load probability or c. reduced planning reserve margin (2% assumed)	1,354
	c. Mandated reliability projects	2,166
3. Generation Capacity Cost Savings	a. Capacity cost benefits from reduced peak energy losses	171
	b. Deferred generation capacity investments	N/Q
	c. Access to lower-cost generation resources	PARTIAL
4. Market Benefits	a. increased competition	N/Q
	b. Increased market liquidity	N/Q
5. Other Benefits	a. storm hardening	N/Q
	b. fuel diversity	N/Q
	c. flexibility	N/Q
	d. reducing the costs of future transmission needs	N/Q
	e. wheeling revenues	1,133
	f. HVDC operational benefits	N /A
6. Environmental Benefits	a. Reduced emissions of air pollutants	N/Q
	b. Improved utilization of transmission corridors	
7. Public Policy Benefits	a. Optimal wind development	1,283
8. Employment and Economic Development Benefits	b. Other benefits of meeting public policy goals	N/Q
	Increased employment and economic activity; Increased tax revenues	N/Q
	TOTAL	**16,670 +**

105 SPP, *The Value of Transmission*, Appendix B, January 26, 2016.

To address these gaps, and similar gaps in other planning regions, the Commission should require all planning entities to at least:

- Fully capture production cost savings, including many categories in traditional analyses (reduced transmission energy losses, reduced congestion due to transmission outages, reduced cost of cycling power plants, etc.);[106]
- Consider the extent to which the transmission project can avoid the need to replace aging facilities in the future, as NYISO did in its assessment of a recently approved public policy project;[107] and
- Fully capture the reliability value of transmission infrastructure, including (i) avoided/deferred reliability projects, (ii) reduced expected unserved energy or reduced planning reserve margin, (iii) reduced capacity needs from reduced losses at times when the grid is stressed, (iv) enabling market access to less costly capacity resources, (v), improved reserves sharing, and (vi) increased voltage support.

Because methodologies for assessing benefits are likely to improve over time, criteria adopted by the Commission should establish a floor, but not a ceiling for benefits to be considered.

4. BCA should include reliability and resilience factors

BCA can handle "reliability" and "resilience" factors as well as production costs and more measurable economic factors. Of course, transmission that is strictly required for compliance with reliability standards will be incorporated into plans. Beyond what is required, however, are reliability and resilience benefits associated with any given transmission investment option. Reliability and resilience values can be quantified, measured, and monetized.[108] It will matter, for example, whether a scenario results in 1% of load being shed for a short period of time versus all load for an extended period. Therefore "loss of load probability" (percent chance of load loss) will be less useful than "expected unserved energy" (expected MWhs of load lost). BCA using expected values can take into account real-world instances like what we have recently witnessed with cold snap conditions and generator outages leading to maximum possible transfers of power from one region to

106 The Brattle Group report provides a set of best practices on benefits to include in analyses, as well as an overview describing how different RTOs capture different benefits, but all leave certain benefit categories out of their analysis. *See* Johannes Pfeifenberger, *Improving Transmission Planning: Benefits, Risks, and Cost Allocation*, at 12-13, November 6, 2019.

107 *See* NYISO, *AC Transmission Public Policy Transmission Plan*, at 3, April 8, 2019, (assessing "quantitative and qualitative metrics include the project's capital cost, cost per MW, expandability, operability, performance, property rights and routing, schedule, metrics identified by the NYPSC (e.g., replacement of aging infrastructure), and other metrics (e.g., production cost savings, Location Based Marginal Pricing ("LBMP") savings, Installed Capacity ("ICAP") savings, and emissions savings").

108 *See* Burcin Unel and Avi Zevin, *Toward Resilience: Defining, Measuring, and Monetizing Resilience in the Electricity System*, August 1, 2018.

the next. Even if that is expected to happen a few times over the life of a transmission investment, it can justify the investment. Planners can quantify expected value using the principle of expected loss of load (LOLE) times value of lost load (VOLL), as with the treatment of uncertainty described above. But as explained further below, there is no legal requirement to fully quantify all or most components of benefits. The economic principle can be followed regardless of how much quantification is performed, as the best way to achieve just and reasonable rates.

5. BCA should incorporate social benefits if public policies include them

Where applicable, regional planning entities should also include societal benefits as reflected by public policies. For example, the New York System Operator already applies a "Social Cost of Carbon" sensitivity to its analyses of public policy projects,[109] reflecting New York State's public policies that place a negative value on carbon emissions.[110] The Commission should require planning entities to build this approach wherever the applicable public policymakers have put a value on emissions, using that value as the base case for all planning scenarios across applicable market nodes, rather than using it merely as a sensitivity and only for public policy projects.[111] To the extent that different public policy requirements are in place across a region, planning entities can apply different values at different market nodes.

6. BCA time frames should reflect the full life of the transmission assets

Standard BCA is performed over the life of assets. This is intuitive to traditional transmission planners. For example, the Pacific direct current (DC) Intertie is a key part of the Western power system 50 years after its dedication.[112] It is obvious that if today's common approach of assessing benefits over 10 to 15 years were applied, such important infrastructure would never have been built. The Commission should direct planning entities to assess benefits across the full useful life of transmission infrastructure, which is generally over 40 years.[113] Despite transmission's long asset life, regional planning entities often carry out benefit-cost analysis using a much shorter forecast period. Because the benefits tend to grow over time (often faster than the relevant discount rate) but regulated

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109 *See*, e.g., NYISO, *AC Transmission Public Policy Transmission Plan*, at 20-22, April 8, 2019.

110 For example, the New York Public Service Commission's Benefit-cost Analysis framework factors in the social cost of carbon. *See Order Establishing the Benefit Cost Analysis Framework*, Case 14-M-0101, January 21, 2016.

111 Where incorporating quantified social benefits is not supported by the relevant public policies, it is nevertheless critical that supply, demand, and congestion created by those policies factor into other components of the benefits analysis.

112 Bonneville Power Administration, *Direct current line still hot after 40 years*, May 26, 2010.

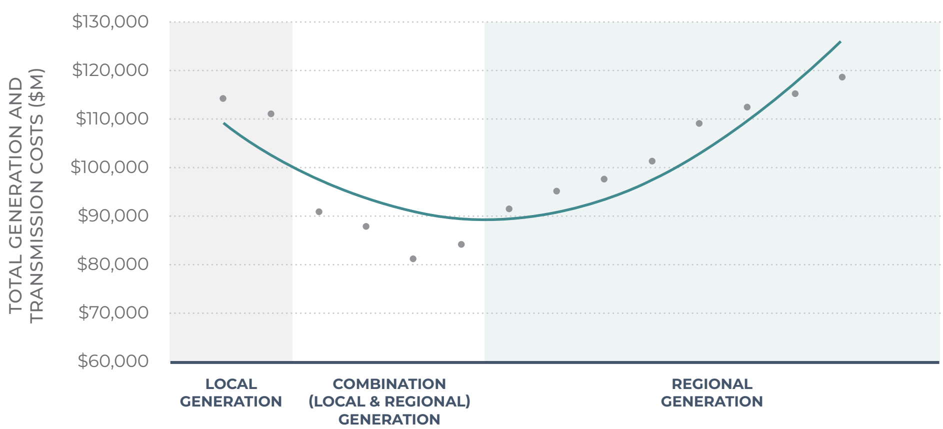
113 Union of Concerned Scientists, *Average Life Expectancy of Select Infrastructure Types and Potential Climate-Related Vulnerabilities*, n.d.

cost of transmission declines over time as assets are depreciated, BCA horizons that do not cover the life of the asset will understate benefit-to-cost ratios. For example, PJM's market efficiency planning process assesses benefits across only a 15-year planning period.[114]

7. BCA should include the trade-off the consumer benefits of local vs remote resources

In selecting projects to maximize net benefits, the Commission should direct planning entities to co-optimize transmission investments with generation expansion planning, particularly renewable resources needed to meet public policy requirements, to minimize the total cost of generation plus transmission. This was the cornerstone of MISO's approach in its Regional Generation Outlet Study and Multi-Value Projects (MVP) analysis, as shown in the MISO chart below.[115]

FIGURE 13 **MISO "Bathtub" Curve of Optimal Local vs Remote/Regional Generation**



8. BCA Assessments should include full portfolios

Consistent with the recommendation above of incorporating multiple benefits together, BCA should be performed on the full portfolio of transmission projects. Assessing the full portfolio accounts for instances where some options will be mutually exclusive and others will be additive—the latter will show up with greater benefits than the former as it should. BCA on the portfolio will also account for trade-offs between smaller speedier

114 *See* PJM, *PJM Manual 14B: PJM Region Transmission Planning Process*, Attachment E at 108, October 1, 2020.

115 MISO, *MTEP17 MVP Triennial Review*, at 31, September 2017.

technology and grid operations investments versus larger longer-term options. If each transmission line or investment were assessed separately, these interactions would be ignored and net benefits would be misleading. Assessing the benefit of a portfolio of transmission assets will also facilitate cost allocation as discussed further below.

9. BCA assessments should not only be quantitative

While the Commission should require a robust approach to quantifying transmission benefits, not all benefits and costs can be quantified or boiled down to a dollar figure. Some pros and cons that may be attributed to different options will be inherently subjective. While the common metrics described above will be useful when comparing various options, and can provide clearer guidance and an objective recipe for decision-making, they cannot possibly address all of the relevant considerations that should be weighed in transmission planning, so regional entities will require some flexibility to prioritize certain projects over others due to qualitative criteria. "The sensible way to deal with uncertainty about some aspects of a benefit or a cost is to quantify what can be quantified, to array and rank nonquantifiable factors, and to proceed as far as possible."[116]

Legal requirements do not require full quantification. Where the rubber meets the road in assigning costs to beneficiaries, as described in Section IV of this report, the legal standard is that the assignment be "roughly commensurate" with beneficiaries, not that every electron be assigned to every individual customer. At the upstream planning stage of the process, before we reach the cost allocation stage, that same "roughly commensurate" standard can be applied. What is important is the conceptual framework of maximizing net benefits of a portfolio.

10. Resource diversity value and the value of transmission to mitigate operational uncertainty can and should be quantified in the benefits assessment

An increasing set of benefits have been quantified, and can and should be quantified and incorporated into benefits assessments. Recently a study was issued by the Boston University Institute for Sustainable Energy quantifying the benefits of transmission from connecting wind energy from different wind regions, given the uncertainties of wind output in the day ahead time frame.[117] Since the correlation of wind output decreases significantly with distance, there is a steadier supply of zero variable cost energy when

116 Edward M. Gramlich, *A Guide to Benefit-Cost Analysis,* 2nd edition, at 5, Waveland Press, 1988.

117 Kai Van Horn, Pablo Ruiz, and Johannes Pfeifenberger, *The Value of Diversifying Uncertain Renewable Generation Through the Transmission System*, October 2020.

different wind sites are connected to each other, reducing system dispatch costs.

11. The BCA decision rule should be to maximize net benefits

The Commission should require planning entities to adopt a general objective of maximizing net benefits from the various portfolio options considered. Maximizing net benefits accounts for the differing scales of different options. For example, a set of larger more expensive lines will have much higher costs but potentially much larger benefits than a smaller cheaper portfolio. Maximizing net benefits leads to the greatest benefits to consumers over the long run. Maximizing net benefits is more appropriate than a benefit-cost ratio because, as in the example above, a high ratio could yield lower net benefits to consumers. "The last step is reasonably clear…find the program that maximizes net benefits…do not even get tempted to show benefit-cost ratios — they can just get you into trouble."[118] Once again, full quantification is not required. What is important is the conceptual framework.

Order No. 1000 provides that where regional planning entities use a benefit-cost analysis threshold to evaluate projects, "such a threshold may not include a ratio of benefits to costs that exceeds 1.25 unless the transmission planning region or public utility transmission provider justifies and the Commission approves a greater ratio."[119] In accordance with this rule, many regional planning entities rely upon benefit-cost thresholds of 1.25. This approach, by its nature, will deny projects the opportunity to proceed even where they would provide net benefits. This is exacerbated by the fact that many difficult-to-quantify benefits of transmission may not be quantified. Thus, a project may yield significant net benefits even where its official BCA score is 1 or lower. Of course, when maximizing net benefits, the BCA ratio for any portfolio that performs better than a no-investment option will necessarily exceed 1.0, so a BCA ratio of 1.0 can also be a guideline but is not separately needed as a standard.

E. Planning methods should be made compatible across regions to enable inter-regional transmission

While Order No. 1000 attempted to address inter-regional coordination and planning, designing and implementing projects to address needs across transmission planning re-

118 Edward M. Gramlich, *A Guide to Benefit-Cost Analysis,* 2nd edition, at 230, Waveland Press, 1988.

119 *Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 586, July 21, 2011.

gions remains extremely challenging. No significant inter-regional transmission project has been approved. This lack of approval of any significant inter-regional projects under Order No. 1000 combined with studies finding that such projects would yield significant consumer benefits if built,[120] demonstrate need for inter-regional planning reform.

Inter-regional projects face a "triple hurdle" in that they must not only be selected via the inter-regional process, but also must gain approval from each respective RTO. This "triple hurdle" is the heart of the challenge in inter-regional planning. To address this barrier, the Commission should at a minimum require compatible benefits metrics, and study approaches between neighboring regions in approving interregional projects, and mandate that these metrics seek to maximize net benefits on an inter-regional, not regional basis. As part of this exercise in aligning the regional planning processes, the Commission should require all regions to treat inter-regional projects as multi-value projects, rather than placing them in siloes according to the benefits they create (which creates a risk that the siloes used for a given project by each region will not match). Aligning regional approval processes in this manner would help to address the challenge inter-regional projects face in being subject to different metrics and approval standards in the different RTOs from which they must obtain approval.

SPP and MISO have recently attempted to address the barrier of unaligned regional processes by seeking to limit the extent to which the coordinated interregional process must rely upon a single model, recognizing neighboring RTOs have different assumptions underlying their transmission planning processes, and a single model cannot possibly match the assumptions used by both RTOs.[121] The Commission approved SPP's and MISO's proposal to eliminate the use of a single regional model,[122] and the regions have now announced a new joint study which will focus on better and collaborative plans to address generation interconnection needs initially,[123] which presumably will be able to be fed through different modeling assumptions in each region. But while this may facilitate more review of inter-regional projects between SPP and MISO by each respective RTO board without excluding benefits due to a mismatch of approach between regions, a more direct approach is to ensure that the RTO planning methods are aligned such that a unified model can be compatible with each region's evaluation framework.

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120 Scott Madden projects, based on enacted clean energy standards and corporate and utility clean energy procurement policies, that "many regions are projected to have adequate or excess renewable supply compared with 'headline' clean energy demand," whereas other regions, including California, New York, and New England, will have a need for additional supply which could be served by import from other regions. Scott Madden, *Informing the Transmission Discussion: A Look at Renewables Integration and Resilience Issues for Power Transmission in Selected Regions of the United States*, at 17, January 2020.

121 *Midcontinent Independent System Operator, Inc., Southwest Power Pool, Inc.*, 168 FERC ¶ 61,018, at P 7, July 16, 2019.

122 *Ibid*., at P 41.

123 SPP, *MISO and SPP to Conduct Joint Study Targeting Interconnection Challenges*, September 14, 2020.

Adopting the minimum guidelines for planning and benefit-cost analysis we have recommended in this section for all regions will make it easier for regions to find alignment in inter-regional project evaluation processes. Beyond establishing this minimum set of guidelines, the Commission should also enable and encourage regions to incorporate additional benefits including in neighboring regional methodologies, as well as incorporate additional benefits that may be unique to interregional projects.[124] As Brattle Group analysts recommend, each seams entity should be given "the option, but not the obligation, to consider some or all of the benefits and metrics used by the other seams entity even if these benefits and metrics are not currently used in the entity's internal transmission planning process."[125] Further, seams entities may "agree to develop metrics to capture any [unique] seams-related benefits."[126]

Regions can update their planning processes with an eye toward inter-regional compatibility such that the primary changes they need to make that are particular to inter-regional review relate to evaluating such projects by maximizing inter-regional benefits as opposed to maximizing benefits solely within the region's borders. The Commission should require the method established to provide that all projects capable of providing net benefits are eligible for inclusion in an interregional plan, disallowing exclusions for projects of arbitrary voltage levels or sizes that currently exist in some interregional planning processes. Interregional planning processes should be conducted at annual intervals, and include a process for ensuring that projects included in the plans are not duplicative of projects being approved within regional planning processes.

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124 *See* Johannes P. Pfeifenberger and Delphine Hou, *Seams Cost Allocation: A Flexible Framework to Support Interregional Transmission Planning*, at 53, April 2012 (recommending a set of principles for quantifying benefits of seams projects).

125 *Ibid.*

126 *Ibid.*

IV. Cost allocation

As the Commission recognized in Order Nos. 890 and 1000, "knowing how the costs of transmission facilities [will] be allocated is critical to the development of new infrastructure because transmission providers and customers cannot be expected to support the construction of new transmission unless they understand who will pay the associated costs."[127] The Commission made significant progress in clarifying cost allocation issues in Order No. 1000, requiring public utility transmission providers to establish regional and interregional cost allocation methodologies that meet a set of six principles established by the Commission, but allowing cost allocation methodologies to vary by project type.[128] Very different approaches to regional cost allocation have been deployed in compliance with Order No. 1000, and several have evolved with time to align beneficiaries and cost assignments. Others, such as MISO-planned reliability projects, have moved away from regional cost allocation to avoid competitive processes.[129] And the generator interconnection process marches to a different drummer altogether, using "participant funding;" these differences should be remedied.

With a few limited exceptions described further below, the Commission should continue to use beneficiary pays principles for cost allocation, as they appropriately straddle the need to provide clarity to stakeholders, while at the same time providing planning entities with flexibility to develop methodologies supported by a broad range of stakeholders given region-specific circumstances that affect the distribution of benefits for regional transmission projects. The Commission can facilitate more cost-effective transmission development by refining the application of its cost allocation principles, while adhering to the same general framework it has already applied. Any changes should be applied prospectively only, and not undermine previous cost allocation agreements on operating or approved projects.

127 *Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 496, July 21, 2011. (citing Order No. 890, at P 557).

128 *Ibid*., at PP 558-750.

129 Johannes P. Pfeifenberger et al., *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value*, at 20, April 2019

A. The Commission should continue to require that costs of regional and interregional transmission projects be allocated in a manner roughly commensurate with their benefits

The cornerstone of cost allocation should continue to be that public utility transmission providers must provide for processes by which costs are allocated fairly — in a way that is at least roughly commensurate with the benefits. This standard is the first principle articulated by the Commission in Order No. 1000,[130] is well-supported by economic theory,[131] and has also been required by the courts. As the U.S. Court of Appeals for the Seventh Circuit articulated in *Illinois Commerce Commission v. FERC*, to approve a cost allocation methodology, the Commission must have "an articulable and plausible reason to believe that the benefits are at least roughly commensurate" with how the costs are allocated.[132] This principle dictates not only that the Commission may not approve regionally allocated costs without reasons to believe benefits are allocated regionally, but also that it may not approve cost recovery only from local customers where benefits are regional.[133] The Commission should continue to adhere to this approach, which provides flexibility to planning entities and fulfills the Commission's duty under the Federal Power Act to ensure just and reasonable and not unduly discriminatory rates.

While Order No. 1000 declined to prescribe "a particular definition of 'benefits' or 'beneficiaries,'"[134] we recommend that the Commission provide a minimum standard for a broad set of benefits to be included within benefit-cost analysis, as discussed in Section III.D of this paper. Importantly, we recommend a robust benefit-cost methodology that includes what used to be considered "difficult to quantify" benefits. While planners can use benefit-cost analyses to help allocate costs, as described below, the ability to allocate a particular benefit must not be used as a constraint to reduce the scope of benefit-cost assessment. "Benefits that can be allocated readily or accurately tend to be only a subset of readily-quantifiable benefits," so "[r]elying on allocated benefits to assess individual projects would result in rejection of many desirable projects."[135]

Beneficiary-pays principles can be implemented using benefit-cost analysis, despite the challenge of tracing all benefits to beneficiaries. William Hogan explains that where "to-

130 *See* Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities, Order No. 1000, 136 FERC ¶ 61,051, at PP 622-629, July 21, 2011.

131 *See*, e.g., William W. Hogan, *A Primer on Transmission Benefits and Cost Allocation*, Economics of Energy & Environmental Policy, Volume 7, Issue 1, March 2018.

132 *Illinois Commerce Commission v. FERC*, 576 F.3d 470, 477 (7th Cir. 2009).

133 *See Old Dominion Electric Coop. v. FERC*, 898 F.3d 1254, 1261 (2018).

134 *See* Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities, Order No. 1000, 136 FERC ¶ 61,051, at P 624, July 21, 2011.

135 *Ibid.*

tal quantifiable benefits exceed the transmission investment cost, then allocating in proportion to the quantifiable benefits would be consistent with efficient investments."[136] And where "easily quantifiable benefits are less than the investment cost, but the subjective estimate is that total benefits are greater . . . a simple rule would be to allocate the costs equal to and according to the quantifiable benefits . . . and then allocate the residual costs . . . according to the regulator's subjective distribution of benefits," which may be distributed evenly across the region, for example.[137] Similarly, Brattle Group analysts explain that a 2-step approach can be used that first determines whether projects are beneficial overall, and next evaluates "how the cost of a portfolio of beneficial projects should be allocated based on distribution of benefits."[138] In this manner, benefit-cost analyses used to guide planning decisions will not be artificially constrained to benefits that can easily be allocated, but will nevertheless serve as the core input to cost allocation decisions.

To provide certainty to market participants, costs should continue to be allocated based on ex ante analysis.[139] Allocating costs to beneficiaries, when the benefits can be measured and beneficiaries can be identified, improves economic efficiency. Transmission is sometimes a complement to other resources and sometimes a substitute. When generation, demand response, or storage closer to load is more economic than transmission, then it should not be discouraged by fully socialized transmission cost allocation without any attempt to determine beneficiaries.[140] Argentina used a governance model of stakeholder support levels to find appropriate cost allocation alignment, which could be a model.[141] State involvement will be important as representatives of load interests.

At the same time, the Commission should retain a degree of flexibility with regard to how costs are allocated. The legal standard under the Federal Power Act does not require a

136 William W. Hogan, *A Primer on Transmission Benefits and Cost Allocation*, Economics of Energy & Environmental Policy, Volume 7, Issue 1, at 39, March 2018.

137 *Ibid*.

138 Johannes Pfeifenberger, *Improving Transmission Planning: Benefits, Risks, and Cost Allocation*, at 28, November 6, 2019.

139 *See Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 499, July 21, 2011 (finding "that the lack of clear ex ante cost allocation methods" prior to Order No. 1000's enactment "may be impairing the ability of public utility transmission providers to implement more efficient or cost-effective solutions); William W. Hogan, *Transmission Investment Beneficiaries and Cost Allocation: New Zealand Electricity Authority Proposal*, at 4, February 1, 2020 ("A cost-benefit evaluation should be done before the investment decision.").

140 William W. Hogan, *A Primer on Transmission Benefits and Cost Allocation*, Economics of Energy & Environmental Policy, Volume 7, Issue 1, at 39, March 2018.

141 Stephen C. Littlechild, and Carlos J. Skerk, *Transmission Expansion in Argentina 2: The Fourth Line Revisited*, Energy Economics, 30(4), at 1385–1419, July 2008.

precise tracing of benefits to costs,[142] and the Commission should clarify in a new planning rule that even though benefits may be quantified via benefit-cost analysis, they need not be precisely traced to beneficiaries in cost allocation. There are good reasons to refrain from an overly prescriptive approach.

For example, regions may provide for methodologies that do not precisely quantify all benefits so as to provide for greater administrative simplicity. There is a trade-off between relying on analysis to identify the beneficiaries of projects (which inherently cannot be done until a particular project or set of projects have been proposed and evaluated by the relevant planning entity), and setting rules that provide a high degree of clarity at the outset as to how costs will be allocated. As the Commission found in Order No. 1000, "the lack of clear ex ante cost allocation methods that identify beneficiaries of proposed regional and interregional transmission facilities may be impairing the ability of public utility transmission providers to implement more efficient or cost-effective transmission solutions identified during the transmission planning process."[143]

Methods such as postage stamp cost allocation (allocating costs equally to all customers in a region) for certain facilities benefitting entire regions can provide for clear rules on allocation of costs prior to any such analysis, and FERC should continue to permit them to be used where processes are in place to ensure they result in costs being allocated in a manner roughly commensurate to beneficiaries. The imprecise nature of analytical techniques used to apportion project benefits may weigh toward the adoption of techniques such as postage stamp cost allocation that set a clear formula at the outset that is not dependent on precise modeling. As the Commission observed in Order No. 1000, there are cases where "the distribution of benefits associated with a class or group of transmission facilities is likely to vary considerably over the long depreciation life of the transmission facilities amid changing power flows, fuel prices, population patters, and local economic considerations," for which such methods are particularly appropriate.[144] While the courts have rejected postage stamp allocation where there is no reason to believe that the approach would allocate costs in a manner roughly commensurate to benefits,[145] it passes

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142 *See South Carolina Public Service Authority v. FERC*, 762 F.3d, 41, at 88 ("We recognize that feasibility concerns play a role in approving rates, such that the Commission is not bound to reject any rate mechanism that tracks the cost-causation principle less than perfectly."). As the U.S. Court of Appeals for the Seventh Circuit has articulated, the Commission need not "calculate benefits to the last penny, or for that matter to the last million or ten million or perhaps hundred million dollars." *Illinois Commerce Commission v. FERC*, 576 F.3d 470, 477 (7th Cir. 2009).

143 *Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 496, July 21, 2011.

144 *Ibid.,* at P 605.

145 *See Illinois Commerce Commission v. FERC*, 576 F.3d 470, 477 (7th Cir. 2009) (noting that the Commission may not use the presumption that "new transmission lines benefit the entire network" to overcome its "duty of 'comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party'"); and *Illinois Commerce Commission v. FERC*, 756 F.3d 556 (7th Cir. 2014) (same).

legal muster where the Commission does have reason to believe this is so.[146] SPP's transmission planning and cost allocation methods provides an example of such approach, allocating the costs of "highway" projects on a postage stamp basis, but SPP is periodically conducting a review that assesses net benefits across SPP's various load zones to ensure that benefits are reasonably distributed — such as, for example, that there is a "Balanced Portfolio" of projects[147] — and reallocating costs to the extent that a given zone does not receive sufficient benefits.[148]

The success of MISO's MVP portfolio similarly demonstrates the benefits of a simple cost allocation approach where the portfolio of projects approved provides reason to believe that it will yield benefits roughly commensurate with the largely postage-stamp allocation of costs. FERC approved the MVP portfolio despite the fact that MISO did not "determine the costs and benefits of the projects subregion by subregion and utility by utility."[149] While MISO now estimates subregional benefits, such an analysis could initially have bogged down MISO's approval of the portfolio, which MISO now projects to create average monthly benefits between $4.23 and $5.13 for the average residential customers over the next 40-year period, as compared to only $1.50 per month in average costs.[150]

B. The Commission should encourage portfolio-based cost allocation

The Commission should require planning entities to provide for a cost allocation process that groups projects together to prevent the need for a multitude of time-consuming project-specific cost-allocation studies and provide for more durable results that engender stakeholder support. Conducting cost allocation at the portfolio level makes sense because "[b]enefits of a portfolio of projects will tend to be more stable and distributed more evenly."[151] The MISO MVP experience again demonstrates the value of allocating costs for a portfolio of projects together, rather than doing so one-by-one. By simultaneously pursuing 17 projects distributed across the region's geographic footprint,[152] the MISO MVP portfolio provided stakeholders with confidence that benefits would accrue to all load across the region. MISO's periodic analyses of the portfolio shows that this is in

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146 *See Illinois Commerce Commission v. FERC*, 721 F.3d 764 (7th Cir. 2013) (upholding FERC orders approving postage stamp cost allocation for a portfolio of projects); *Illinois Commerce Commission v. FERC*, 756 F.3d 556, 562 (7th Cir. 2014) (explaining that MISO's allocation of the costs of MISO's MVP portfolio on a postage stamp basis was appropriate because "[t]here was evidence that the lines would not yield highly disparate benefits to the utilities asked to contribute to their costs").

147 *See* SPP, *Open Access Transmission Tariff*, Sixth Revised Volume No. 1, Attachment O § IV, effective date: July 26, 2010.

148 *Ibid*., at Attachment J § IV.

149 *Illinois Commerce Commission v. FERC*, 721 F.3d 764, 774 (7th Cir. 2013), ICC II at 774.

150 MISO, *MTEP19*, at 7, n.d.

151 Johannes Pfeifenberger, *Improving Transmission Planning: Benefits, Risks, and Cost Allocation*, at 28, November 6, 2019.

152 *See* MISO, *Multi Value Project Portfolio: Results and Analyses*, January 10, 2012.

fact the case, with significant net benefits accruing across every local resource zone over which costs were apportioned.[153] Likewise, SPP's portfolio approach allows for a simple approach to cost allocation that nevertheless ensures benefits accrue to every load zone. And portfolio planning also underlies the use of cluster studies for interconnection which has been an improvement over project-by-project processes, as multiple projects and the transmission that they share are considered together. Portfolio planning expands those efficiencies to consider all the transmission needed for multiple purposes, not just interconnection.

A portfolio-based approach more accurately captures the benefits of proposed transmission infrastructure because one project's benefits depend on the future system as a whole, including the presence of other projects. By grouping together all projects that will be approved in a single planning period (e.g. annually), planning entities can capture these interactive effects in any benefit-cost studies that may then also be used to support cost allocation.

As we have described above, we recommend the Commission require planning entities to carry out scenario-based planning analysis that refrain from grouping projects into siloes by project type, and that instead models projects together, recognizing their multiple values and using reliability constraints as binding inputs. This modeling process lends itself to a planning process by which the costs of projects within the portfolio are allocated together. While needs may nevertheless arise for individual projects to be cost allocated outside of this general process, we recommend that the Commission recommend planning entities use a portfolio approach as a baseline.

The Commission should explicitly provide guidance against the use of load flow analysis techniques as the sole basis for cost allocation, in favor of an economically-driven approach that relies upon a broader conception of total benefits that recognizes the value of projects in the portfolio that address reliability needs alongside other benefits. This would guard against cases such as the Artificial Island development, where "PJM reported that only 10% of the estimated benefits would appear in [the] Delmarva region, but these customers would bear 90% of the costs,"[154] and the Commission ultimately found on rehearing that PJM's load-flow based distribution factor (DFAX) analysis was an unjust and unreasonable mechanism for allocating the costs of a stability-related reliability issue.[155]

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153 *See* MISO, *MTEP17 MVP Triennial Review*, at 8, September 2017.

154 *Ibid.*

155 *PJM Interconnection, L.L.C. and Certain Transmission Owners Designated,* Order Granting Rehearing and Establishing Paper Hearing Procedures, 164 FERC ¶ 61,035, at P 41, July 19, 2018.

Because a portfolio of projects will necessarily provide a wide range of different benefits, any cost allocation methodology must ensure that the sum total of these benefits is allocated in a roughly commensurate fashion. Approaches such as SPP's meet this standard because, while they rely on simplified postage stamp allocation, they include a mechanism that ensures that the approach yields the fair apportionment of costs based on benefit-cost analysis that incorporates many types of benefits. Techniques based solely on load-flow analysis fail for this purpose because they do not account for both reliability and other benefits and, therefore, may bear little relationship to the total value of benefits received.

Portfolio plans and cost allocation should be performed on a regular schedule to maximize the economies of scale and scope of considering all the projects together. However, it may also be appropriate to pursue occasional project-based plans and cost allocation in between larger less frequent portfolio plans.

C. The Commission should remedy the inconsistency with the "participant funding" approach in interconnection processes while clarifying that generators and customers who derive particularized benefits from transmission upgrades can be relied upon to a limited extent to fund new transmission infrastructure, where applicable, as part of a broader cost allocation formula

"Participant funding" is an "approach to cost allocation, in which the costs of a new transmission facility are allocated *only* to entities that volunteer to bear those costs."[156] Interconnection processes are allowed to rely on participant funding, based on the interconnection policies established by the Commission going back to Order No. 2003 issued in that year. Since interconnecting generators are often being asked to pay for network facilities that benefit other generators and other loads all around the region, the Commission should make sure that its policies remedy this inconsistency and disallow full participant funding on interconnecting generators.

At the same time, the Commission should clarify that regional cost allocation methods may, where appropriate, require limited contributions by project participants as they use the facilities in the future. In transmission planning which operates as a completely separate process from interconnection, Order No. 1000 prohibits participant funding from being used as a regional or interregional cost allocation method.[157] But while the Com-

156 *Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 715, July 21, 2011 (emphasis added).

157 *Ibid.*, at PP 723-729.

mission was appropriately fearful "that reliance on participant funding as a regional or interregional cost allocation method increases the incentive of any individual beneficiary to defer investment in the hopes that other beneficiaries will value a transmission project enough to fund its development,"[158] we recommend that the Commission clarify that this prohibition allows for approaches to cost allocation by which project participants pay for a limited portion but not all of the costs of a project.

As discussed in Section III.B, we recommend that the Commission require planning entities to formulate reasonable scenarios that include corporate and utility resource procurement targets. But while a scenario-based approach is the best way to plan for an uncertain future by covering a range of plausible futures, it raises the possible objection that, depending on cost allocation methodology, there may be a probability that infrastructure development could burden non-beneficiaries with the costs for achieving corporate and utility procurement targets more appropriately borne by the entities setting those targets.

To allow for appropriate cost allocation in such cases, the Commission should provide that where the evidence supports such an approach, planning entities may require particular customers and generators that derive unique benefits from the infrastructure to fund it to a limited extent. The Commission should set a specified limit on the portion of project costs that can be recovered in this manner for regional projects (e.g. 10 percent) to prevent the problems seen under participant funding schemes. Participant funding as the sole mechanism for cost recovery has proven to be problematic because it is akin to charging the next car to enter a congested highway for the cost of building a new lane. This approach is subject to the free rider problem because the entity being charged has an incentive to pull out of the process and attempt to enter once someone else has picked up the charge, and it is unfair because the new infrastructure will create system wide benefits. But requiring direct beneficiaries to fund upgrades (e.g., on a joint basis), when used to a more limited extent, could be effective. Just as tolls can prove to be an effective highway financing mechanism, assessing a charge that is truly proportional to the benefit an entity gets could help facilitate the construction of net beneficial transmission infrastructure. CAISO has a Location Constrained Resource Interconnection provision in its tariff that follows this approach.[159] Planning entities could establish models that initially assign costs to load serving entities, allowing them to get paid back as projects using the infrastructure enter the system, drawing lessons from experiences such

158 *Ibid.*, at P 723.

159 *See California Independent System Operator Corporation*, Order Granting Petition for Declaratory Order, 119 FERC ¶ 61,061, April 2007; and Bracewell LLP, *FERC Tailors Transmission to Connect Renewables*, May 1, 2007.

as the CAISO Tehachapi trunkline, where current wholesale RTO customers financed the line but are being paid back over time as generators interconnect.[160]

This type of cost allocation formula will not be necessary in all cases where a corporate or utility procurement target drives transmission needs. Facilitating corporate procurement targets may reduce total costs for regional customers by adding load or low-cost generation to the region and thereby reducing the proportion of regional costs that other customers must bear. Similarly, interconnecting electric vehicle charging equipment could benefit the system as a whole by increasing total (off-peak) system load. But it may prove to be a useful arrow in the regional cost allocation quiver in cases where an entity's procurement goal creates costs appropriately borne by that customer alone.

D. The Commission should provide more specific cost allocation requirements for inter-regional projects

Finding alignment on cost allocation for inter-regional projects is especially challenging given the potentially disparate approaches that regions may take for projects that fall solely within their borders, as well as the risk that one region could seek to impose costs on a neighboring region through this process. To address this challenge, the Commission should require regions to adopt unified cost-allocation processes for projects at their respective seams, and provide specific guardrails around the cost allocation approaches that may be used for such projects. The Commission should require that the cost allocation processes be a beneficiary pays methodology that relies on a quantified assessment of benefits and costs for every inter-regional project portfolio. To facilitate interregional cooperation and collaboration, the Commission could specify that the primary mechanism for cost allocation for seams projects should be to allocate seams project costs based on monetized benefits,[161] while allowing regions flexibility to agree on alternate cost allocation mechanisms to modify this baseline rule. Brattle Group analysts Hannes Pfeifenberger and Delphine Hou outline a number of potential cost allocation mechanisms that may facilitate interregional agreement in *Seams Cost Allocation: A Flexible Framework to Support Interregional Transmission Planning, including allocation according to contribution to the need, usage share of the project, or allocating costs based*

160 *See* Pedro J. Pizarro, *Transmission Planning and Development: Examples and Lessons*, at 17, February 25, 2010; CAISO, *Memorandum re: Decision on Tehachapi Project*, at 6, fn. 3 January 18, 2007 (explaining how generators would pay a pro-rata share to the extent the Tehachapi improvements are characterized as bulk transfer gen-tie lines, with customers in SCE's service territory paying the costs of the network upgrade portions of the project).

161 *See* Johannes P. Pfeifenberger and Delphine Hou, *Seams Cost Allocation: A Flexible Framework to Support Interregional Transmission Planning*, at 61, April 2012 (recommending such a mechanism as the first of several potential cost allocation mechanisms for Seams projects).

on the project's physical location.[162]

E. The Commission should assign costs to loads regardless of the utility's choice of whether to be an RTO member

When costs are allocated to voluntary members of Regional Transmission Organizations, those utilities can shift costs and disrupt the transmission planning process by resigning from the RTO. FERC should prevent RTO members from using this power to choose whether to be an RTO member to game the process once it becomes apparent that they may be assigned costs. Without rules put in place by the Commission, threats to leave the RTO in response to particular planning decisions may be a hindrance to efficient and reliable transmission development. Accordingly, the Commission should put a rule in place that allocates costs to regardless of such choices. For example, it may put in place a rule that assigns costs to TOs based on their planning region membership at the beginning of the planning cycle, thus preventing RTO exit from avoiding a specific cost that may become apparent during the planning process.

162 *Ibid.*

V. Ensuring cost-effectiveness

A. The Commission should ensure sufficiently broad geographic scope of planning authorities and consider requiring the formation of inter-regional planning boards with full authority to propose filings to FERC that select and cost allocate inter-regional projects

Much of the system need is interregional, connecting areas addressed by separate planning entities. Since these "regional" planning entities are really "sub-regional" and do not cover the full geographic breadth of the transmission system, the Commission should consider structural reforms to broaden transmission planning.

The Commission should consider collapsing sub-regional planning entities into larger Planning Authorities. For example, in the West, there are four Planning Authorities as shown in the map below, while the region really operates as one interconnected grid. The large load centers in the state of California cause the state to import 30 percent of its power from other parts of the region. Collapsing the four regions into one could make transmission planning more optimal.

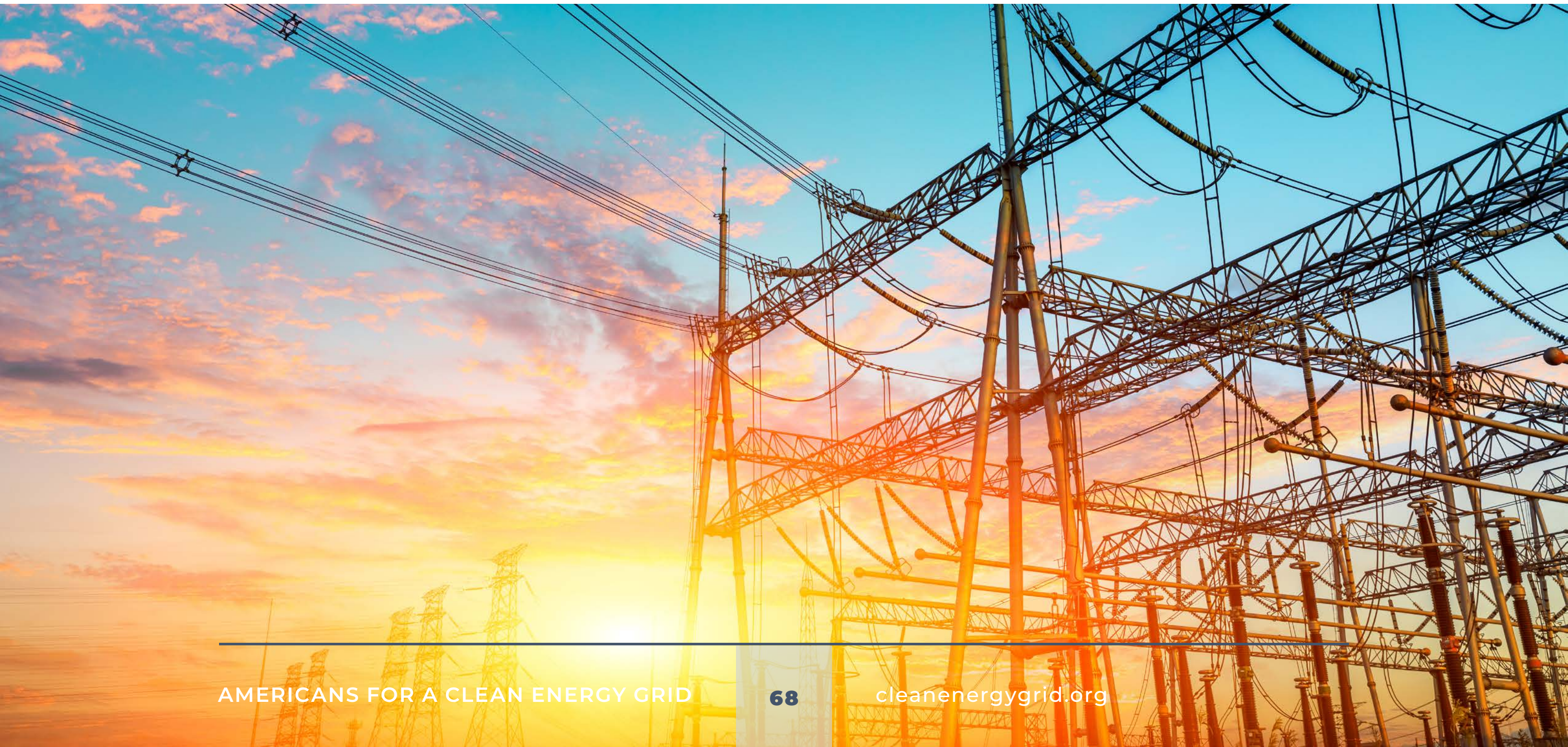
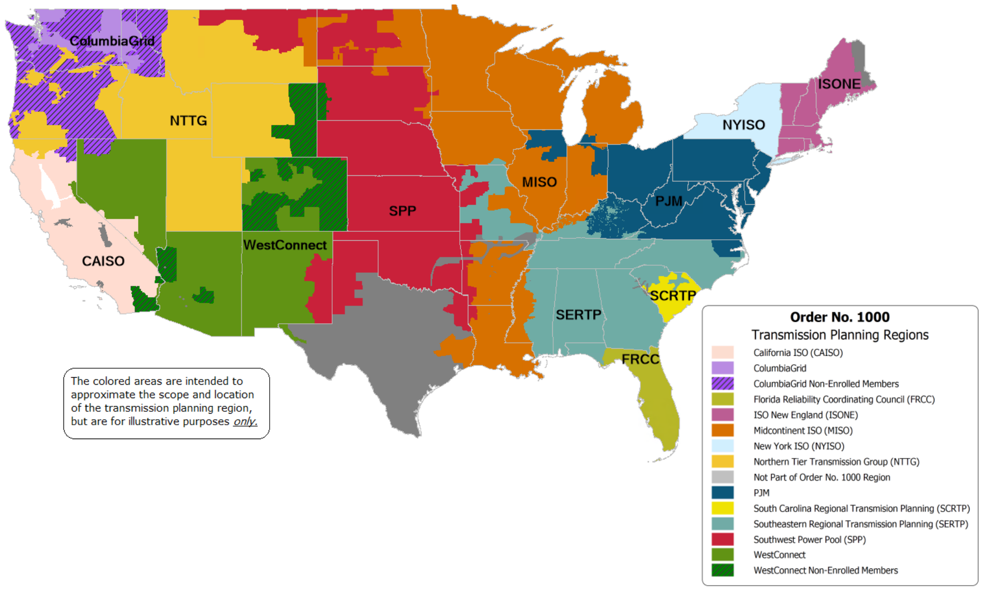


FIGURE 14 Planning Authority Regions[163]



The Commission should also consider unifying inter-regional planning into a single process whereby a single entity composed of representatives of the applicable RTOs identifies transmission needs and solutions, selects projects and quantifies their benefits and costs, and allocates costs in a manner roughly commensurate with benefits. Doing so would completely eliminate the "triple hurdle."

The Commission could accomplish this reform by requiring the applicable regional planning entities (consistent with Order No. 1000's geographic criteria) to establish a process for the creation of joint regional boards that have full authority to independently approve projects and allocate costs across both regions.

In the event the Commission requires the establishment of such boards, it should require the planning and benefit-cost analysis processes established by such interregional planning boards to adhere to the same minimum requirements set forth in Section III, with the additional requirement that the interregional planning process must consider benefits and costs across both regions or the applicable group of regions (for multi-region planning boards).

163 FERC, *Order No. 1000 Transmission Planning Regions*, n.d.

B. FERC should take on a greater role in ensuring new transmission investment is as cost-effective as possible

More balance is needed between the bottom up and top-down planning processes, such that plans conducted by regional planning entities identify more opportunities to address transmission needs in a more cost-effective manner, and local utility plans are altered where needs are served more effectively by regional solutions.

1. The Commission should more carefully evaluate local projects that serve needs that could be addressed more cost-effectively by regional facilities

One step to remedy this imbalance would be a set of reforms designed to provide greater transparency surrounding local transmission planning and end-of-life asset management, better evaluate whether regional projects can more efficiently serve needs being met by local projects or project replacements, and closer evaluation of local projects where there is reason to believe a more efficient regional solution exists.

Order No. 890 requires "each public utility transmission provider to have a coordinated, open, and transparent regional transmission planning process,"[164] and Order No. 1000 requires every such transmission provider to "participate in a regional transmission planning process that produces a regional transmission plan and that complies with the transmission planning principles of Order No. 890."[165] Further, Order No. 1000 requires identification of "alternative transmission solutions that might meet the needs of the transmission planning region more efficiently or cost-effectively than solutions identified by individual public utility transmission providers in their local transmission planning process."[166] The examination required under Order No. 1000 is supposed to assess regional solutions that address all types of transmission needs, including "transmission facilities needed to meet reliability requirements, address economic considerations, and/or meet transmission needs driven by Public Policy Requirements."[167]

Yet, despite these requirements, as described above, implementation of Order No. 1000 in many regions has yielded a flood of local projects that are either entirely exempt from the regional process, or that remain uninfluenced by it. For example, while the PJM Board approved $1.27 in baseline transmission investment,[168] it has approved nearly three times that amount — $3.5 billion — in "supplemental" projects.[169] As PJM explains, "Supplemental projects are identified and developed by transmission owners to address local reliability needs, including customer service and load growth, equipment material condition, operational performance and risk, and infrastructure resilience."[170] PJM reviews them to "evaluate their impact on the regional transmission system,"[171] and provides for a stakeholder process that allows for limited input,[172] but they are not subject to Board approval.[173]

There is often no close review of local projects via any other process. Despite Section 205 of the Federal Power Act's explicit language that "the burden of proof to show that the increased rate or charge is just and reasonable shall be upon the public utility," the Commission has implemented a policy that "presumes that all [transmission] expenditures

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164 *Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 1, July 21, 2011.

165 *Ibid.*, at P 146.

166 *Ibid.*, at P 148.

167 *Ibid.*

168 PJM, *Regional Transmission Expansion Plan*, at 4, February 29, 2020.

169 *Ibid.*, at 50.

170 *Ibid.*, at 4.

171 *Ibid.*

172 *Ibid.*, at 49.

173 Ibid. Further, regional transmission planning processes are yielding a mix of increasingly local projects even for infrastructure that is approved as part of regional transmission plans. *See*, e.g., Ibid., at 4. As discussed in **Section III.B**, this result is driven to a significant extent by the fact that processes used to identify regional solutions often do not base needs on the best available data and forecasting methodologies, and do not include all project benefits in their assessments of regional solutions.

are prudent."[174] Given this burden shifting, cases where costs are "disallowed and excluded from the revenue requirement . . . are rare."[175] As Dr. Paul Joskow puts it, "[f]or all intents and purposes the FERC [transmission] regulatory process is a model of cost pass-through regulation with little scrutiny of costs."[176] As noted above, some RTOs do include RTO review of local projects,[177] but this is not consistent across Planning Authorities.

Failing to proactively review the cost-effectiveness of transmission investments even where there are reasons to believe alternatives would be more appropriate has potentially tremendous costs. Utilities have an incentive to add capital assets to their rate base, so as with all regulated industries, the basic economic regulatory structure should provide for scrutiny of investments by any entity holding a license to serve as the public utility. The current approach also likely squanders valuable rights-of-way. End-of-life replacements, maintenance expenditures, and local projects by their nature utilize existing rights-of-way controlled by utilities. Upgrading and up-sizing this infrastructure in many cases will make better use of these rights-of-way, which should be fully leveraged given the challenges associated with siting transmission infrastructure. Finally, even if the investments turn out to be necessary and appropriate, the current process engenders mistrust by consumers. Many consumer and state interests have become skeptical of transmission costs being added to their bills, at a time when certain types of transmission expenditures are sorely needed.

The Commission can remedy this failure in two ways. First, it should directly require that all regional transmission planning processes better address the potential to improve upon end-of-life planning decisions by (i) requiring transmission owners to notify the regional planning entity of aging infrastructure needs far in advance of the end of an asset's life (e.g. 10 years), unless there are circumstances that prevent early notification, and (ii) requiring such projects to be approved via regional planning processes through which they may be assessed against alternatives identified by region-wide top down planning processes and assessed for benefits beyond the immediate need for repair or replacement. While some regions currently classify end-of-life projects as asset maintenance not subject to regional transmission planning processes,[178] as explained in Section VI.B.2

174 *Potomac-Appalachian Transmission Highline, LLC, PJM Interconnection, L.L.C.*, 158 FERC ¶ 61,050, at P 100, January 19, 2017; *see also Iroquois Gas Transmission System, L.P.*, 87 FERC ¶ 61,295, 62,168, June 17, 1999 ("As a matter of procedural practice to ensure that rate cases are manageable, the Commission does not require regulated entities to 'demonstrate in their cases-in-chief that all expenditures were prudent unless the Commission's filing requirements, policy, or precedent otherwise require.' There is, in effect, a presumption of prudence which can be rebutted at hearing whenever another party 'creates serious doubt as to the prudence of an expenditure.'").

175 Paul L. Joskow, *Competition for Electric Transmission projects in the U.S.: FERC Order 1000*, at 13, March 2019.

176 *Ibid*.

177 *See* MISO, *Business Practices Manual Transmission Planning*, BPM-020-r21, at 22, January 1, 2020.

178 *See*, e.g., *PJM Interconnection, L.L.C.*, 172 FERC ¶ 61,136, at P 85, August 11, 2020 (holding that regional planning requirements do not apply to "Asset Management Projects" in PJM, a category that includes end-of-life transmission infrastructure replacements).

below, the Commission has authority to reform the planning process to require more fulsome consideration of these needs via regional planning. The MISO approach noted above may be a good model for this component of the rule.

Second, the Commission should consider proactively evaluating the cost-effectiveness of local projects and end-of-life project replacements where there is reason to believe that the same needs could have been addressed more cost-effectively by a regional solution.[179] Reason to doubt the cost-effectiveness of an investment will exist where (a) scenario analysis conducted by a regional planning entity demonstrates that the need could be addressed more effectively by a regional solution; or (b) the regional planning process does not include a step that effectively examines the ability of regional solutions to more efficiently address the need.

In taking this step, the Commission should carefully calibrate the scope of projects subject to review. The Commission's current presumption of prudence for all projects is designed to ensure the administrability of rate cases,[180] and any revision to this review policy must be done according to a plan that anticipates the additional responsibilities such a change in approach would vest with the Commission. To ensure that review is aimed narrowly at the set of circumstances where the failure to interface between local and regional planning produces the most acute problems, and is carried out in the most efficient manner possible, the Commission should request input from stakeholders on how to design its criteria for review, as well as procedure for examining the prudence of such projects. For example, projects below a certain kilovolt threshold may be very unlikely to interact with regional needs, and thus should be automatically exempt from any shifting of the review burden.

Beyond incorporating such criteria at a high level into a new planning rule, the Commission could provide further guidance while retaining a degree of flexibility in implementation by issuing a policy statement explaining the scope of its new process for scrutinizing applicable local projects.[181]

179 Ari Peskoe has proposed a broader shifting of the burden of proving projects are prudent, suggesting that the Commission reverse the burden for any local project that is not incorporated into a planning process conducted by an independent entity. As Ari Peskoe discusses in his forthcoming paper, the Commission has ample authority to reverse the presumption of prudence, and could likely even directly require that local transmission planning be conducted by independent entities. *See* Ari Peskoe, Is the Utility Transmission Syndicate Forever?, forthcoming 2021.

180 *Ibid.*

181 *Ibid. (suggesting a policy statement guide FERC prudence review of transmission investments).*

2. ***The Commission should consider performance-based ratemaking techniques to incentivize more cost-effective transmission development***

Beyond the threshold determination whether these expenditures are prudent, the Commission should assess whether and how rates may be adjusted in response to planning deficiencies. For example, there may be circumstances where a local upgrade becomes prudent to address a reliability concern, but the transmission owner's failure to appropriately examine alternatives means that the solution is not as efficient or cost-effective as it could or should have been. In such circumstances, it may be appropriate to reduce or eliminate the transmission owner's return on equity. Conversely, it may be appropriate to reward transmission owners that establish particularly effective mechanisms for identifying cost-effective regional solutions, through incentives such as shared savings mechanisms. The Commission is currently considering incentives including performance-based incentives in a rulemaking proceeding, RM20-10. Depending on how that rulemaking proceeds, there could be overlap with the recommendations in this paper.

As Dr. Paul Joskow explains, the "conventional incentive/performance based regulation mechanisms," that the Commission could theoretically apply are distinct from the "financial incentives for transmission investments meeting several specified goals."[182] The incentive mechanisms prescribed by Section 219 of the Federal Power Act are "not the kind of cost control and operating performance incentives that would normally be an important part of a performance-based incentive regulation tool kit. Rather, the incentive scheme is basically cost of service regulation with higher returns to take certain actions that advance FERC Policies."[183] But while Section 219 provides additional authority for the Commission to implement certain types of incentives, it does not constrain the Commission's ratemaking authority under Sections 205 and 206, which could be employed to apply more conventional performance-based regulation to ensure just and reasonable rates.

One performance-based option would be to adopt something like an 80/20 rule for regional/interregional projects. If a project goes over its budget, the transmission owner only recovers 20 percent of the overage. If it goes underbudget, the transmission owner recovers 80 percent of the variance, and customers get the rest.

Another option is the shared savings congestion reduction proposal by Americans for a Clean Energy Grid (ACEG), the Working for Advanced Transmission Technologies (WATT)

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182 Paul L. Joskow, *Competition for Electric Transmission projects in the U.S.: FERC Order 1000*, at 13, March 2019.

183 *Ibid.*, at 14. *See also* *Economic Regulation and its Reform: What Have We Learned?* (Nancy Rose, ed.), "Incentive Regulation in Theory and Practice: Electric Distribution and Transmission Networks," Chapter 5, University of Chicago Press, 2014.

Coalition and other entities in the Commission's incentive proceeding.[184]

A third performance-based option is the Australian Energy Market Operator (AEMO) where for everyday operations and maintenance work, there is a scheme called Service Target Performance Incentive Scheme that gives utilities an incentive payment to reduce impact on the market.[185]

C. Re-establish a more collaborative approach to transmission ownership and allow RTOs more flexibility to regionally cost allocate infrastructure that has not been selected via competitive processes

Beyond the lack of efficiency between local and regional projects, another factor that in some circumstances has contributed to regional processes yielding fewer large multi-benefit projects than they otherwise could have is the perverse incentive unintentionally created by Order No. 1000's requirement that regional planning processes provide "a nonincumbent transmission developer" with "the same eligibility as an incumbent transmission developer to use a regional cost allocation method."[186]

Some regions, such as NYISO and CAISO, have successfully conducted competitive solicitations to meet regional needs, with significant stakeholder support. In other regions, however, Order No. 1000's elimination of rights of first refusal for regionally cost allocated projects has degraded the necessary planning collaboration to pursue regional projects in favor of local projects. MISO provides a stark example of the manner in which the Commission's well-intentioned push toward a more competitive framework may have had unintended consequences. The MVP portfolio approach was a collaborative effort among utilities negotiated prior to Order No. 1000. The region has since failed to assemble a comparable portfolio of large multi-benefit projects. Instead, responding to their incentives, incumbent investor owned utilities have primarily pursued local baseline reliability and other transmission projects that are subject to utility rights of first refusal.[187] In the most recent MISO Transmission Expansion Plan (MTEP), for example, nearly all projects were local and not subject to competition.[188] In former Commissioner Tony Clark's view "FERC's insistence that even one penny of regional cost allocation ended an incumbent transmis-

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184 *WATT Coalition Initial Comments*, Inquiry Regarding the Commission's Transmission Electric Incentives Policy, Docket No. PL19-3, June 26, 2019.

185 Australian Energy Regulator, *Service Target Performance Incentive Scheme*, December 2015.

186 *Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 332, July 21, 2011.

187 *MISO Transmission Owners v. FERC*, 819 F.3d 329 (7th Cir. 2016) (FERC permissibly exempted local baseline reliability projects from bar on rights of first refusal).

188 MISO, *MTEP19*, at 17, n.d.

sion owner's federal right of first refusal caused a series of cost allocation methodologies that previously had garnered widespread acceptance to fall apart."[189] In promulgating and affirming Order No. 1000 on rehearing, the Commission concluded that subjecting transmission projects proposed by incumbent utilities to competition was justified in order to provide for planning practices likely to yield just and reasonable rates, and to ensure those practices are not unduly discriminatory.[190] FERC concluded that "the inclusion of a federal right of first refusal, can have the effect of limiting the identification and evaluation of potential solutions to regional transmission needs," which "in turn can directly increase the cost of new transmission development that is recovered from jurisdictional customers through rates."[191] And it reasoned that "federal rights of first refusal create opportunities for undue discrimination and preferential treatment against nonincumbent transmission developers within existing regional transmission planning processes."[192]

The evidence gathered since Order No. 1000's enactment, however, has demonstrated that these conclusions are dependent upon particular regional circumstances. Economic theory suggests that competition will deliver savings in structurally competitive sectors,[193] and comparisons of costs of competitive processes versus those of non-competitive processes have been put forward to demonstrate the benefits of competition.[194] But the transmission sector, unlike generation, is not structurally competitive. There are still large economies of scale and network externalities where all projects impact flows on the broad network, so it better fits the standard economic model of "natural monopoly," for which the standard public policy prescription is to allow monopoly entities to invest as long as a regulator is overseeing the quality and price of service. As stated fifty years ago in the classic work on the economics of regulation by Alfred Kahn "[a]s long as the tendency prevails for unit costs to decline with an increasing volume of business, because of economies of scale internal to the firm, it is more efficient, other things being equal, to have one supplier than several."[195] As a practical matter, the distortion of incumbent utili-

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189 Tony Clark, *Order No. 1000 at the Crossroads: Reflections on the Rule and Its Future*, at 10, April 2018.

190 *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000-A, 139 FERC ¶ 61,132, at PP 357-363, May 17, 2012.

191 *Ibid.*, at P 358.

192 *Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 286, July 21, 2011; *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000-A, 139 FERC ¶ 61,132, at PP 363, May 17, 2012 (affirming in relevant part).

193 *See*, e.g. J Paul L. Joskow, *Competition for Electric Transmission projects in the U.S.: FERC Order 1000*, March 2019; Burcin Unel, *A Path Forward for the Federal Energy Regulatory Commission Near-Term Steps to Address Climate Change*, at 13-14, September 2020.

194 *See* Johannes P. Pfeifenberger et al., *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value*, at 5, April 2019. Estimating the potential benefits of competition for transmission projects is difficult and different experts have come to conflicting conclusions. *See also* Paul L. Joskow, *Competition for Electric Transmission projects in the U.S.: FERC Order 1000*, March 2019; Concentric Energy Advisors *Building New Transmission Experience To-Date Does Not Support Expanding Solicitations*, June 2019.

195 Alfred Kahn, *The Economics of Regulation: Principles and Institutions*, at 125/II, MIT Press, June 1988.

ty incentives that has been created by subjecting regional projects to competition while continuing to insulate local projects from competitive pressures has yielded and will likely continue to yield a suboptimal mix of new projects skewed toward local projects that is likely to yield unjust and unreasonable rates for customers. Brattle analysts observe that "[i]n some developers' views, subjecting regionally-planned projects to competition has discouraged transmission companies from suggesting potentially valuable regional projects, anticipating that the projects would need to go through competitive processes and thus could be delayed."[196] Further, as Judge Posner observed in MISO Transmission Owners v. FERC, "competition is [not] an unmixed blessing. It can result in costly duplication, and in politicking aimed at courting favor with [the regional planning entity] or FERC."[197]

Even if transmission competition were a theoretically optimal solution, it is not clear that voluntary RTOs are an administratively workable means of achieving it. Voluntary RTOs are not government regulators; they are more like associations of companies when it comes to transmission planning. They cannot be expected to choose among their members or effectively apply cost regulation to them. As Dr. Paul Joskow stated, "a competitive bidding program for new transmission links allows competing transmission developers effectively to propose alternative regulatory cost recovery formulas for determining annual revenue requirements... However, ISO's are not economic regulators in the traditional sense and have neither the expertise nor authority to adopt transmission ratemaking procedures."[198] Experience demonstrates that given RTOs' institutional structure — they are not cost regulators — a planning process that relies upon the RTO to mediate a competitive process for some projects and not others may often yield a suboptimal asset mix.

We are not arguing that competition for transmission cannot work or has not. It appears to have been successful in certain areas such as with ERCOT Competitive Renewable Energy Zones (CREZ) lines and in the U.K. where government agencies run the solicitation, and in NYISO and CAISO where utility participation in the ISO is effectively mandatory. It could also potentially work if the federal government oversaw a process for granting rights to projects from competing bidders. We are only observing that there are factors that in many cases have and should be expected to inhibit its effective use by voluntary RTOs in cases where incumbent transmission owners develop projects.

We also note the long history of success in the electric industry with joint ownership by utilities of regional network facilities. There are many forms of joint ownership in various

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196 *See* Johannes P. Pfeifenberger et al., *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value*, at 21-22, April 2019.

197 *MISO Transmission Owners v. FERC*, 819 F.3d 329 (7th Cir. 2016).

198 *See* Paul L. Joskow, *Competition for Electric Transmission projects in the U.S.: FERC Order 1000*, at 2, March 2019.

regions. This collaborative approach has worked in many instances to pool the benefits and share the costs of regionally beneficial transmission.[199]

Regional circumstances may also dictate that incumbent utilities are not similarly situated with other developers, due to their unique ability to design a portfolio of local and regional transmission projects that together best serves customers. In many regions utilities are vertically integrated and subject to integrated resource planning processes at the state level that position incumbents uniquely to develop holistic solutions that will leverage generation, demand adjustments, and transmission solutions to serve future resource mixes and facilitate public policies. And siting concerns may have different effects in different regions, depend on the approach states take to these issues. In some cases, states will prioritize low-impact projects and siting constraints will dictate that only viable near-term opportunities for grid expansion is on scarce and valuable existing rights of way that utilities own. State input into the planning process may also identify occasions where, given the challenge of siting new projects that may be particularly acute in some regions, limiting competition may be a catalyst for new development because it limits the number of developers that may stir up "not in my backyard" or "NIMBY" opposition via project development activities.

Regardless, it is clear that Order No. 1000's removal of the right-of-first-refusal has had the unintended consequence of undermining regional transmission planning in some cases. Given this evidence, the Commission can reasonably conclude that a rule relaxing the broad requirement for a competitive process to be used to yield any project that gets regional cost allocation is appropriate and upholds the Commission's duties under Sections 205 and 206 of the Federal Power Act.

This approach, coupled with closer and more robust evaluation of whether regional projects can more efficiently serve local needs, as described in Section V.B above, will allow regional planning entities flexibility to find regionally appropriate solutions that will rebalance transmission portfolios in favor of a project mix that will best serve customers. In MISO, comprised almost exclusively of vertically integrated utilities, a compliance approach that centers on reinstituting a right of first refusal may be warranted. At the same time, in ISO-NE, which has experienced a similar project skew with not "a single competitive transmission project bid, selected or completed" "more than eight years after the Commission issued Order 1000,"[200] it is possible that a different approach may be war-

199 APPA, *Joint Ownership of Transmission*, February 2009.

200 *Comments of William Tong, Attorney General for the State of Connecticut, Maura Healey, Massachusetts Attorney General, Connecticut Department of Energy and Environmental Protection, Connecticut Office of Consumer Counsel and Maine Office for the Public Advocate*, Docket No. EL19-90, at 9, January 24, 2020.

ranted. Rather than reinstituting a right of first refusal, the region could prevent a skew towards local projects by better incorporating local project needs and end-of-asset-life planning into the regional process, and relying upon the Commission applying greater scrutiny to local projects for which regional planning suggests a better alternative is available. These are hypotheticals. We do not necessarily predict that the evidence will play out in this manner in these regions, but we raise these examples simply to illustrate the point that by taking a region-by-region or even context specific approach to rights of first refusal, the Commission may achieve better results across all regions.

D. The Commission should consider requiring regional planning entities to grant states a governance role in regional transmission planning

States play a central role in transmission planning that is only becoming more critical. States are the arbiters of the transmission siting process, and have a role in overseeing utilities' transmission and distribution plans as retail regulators. State involvement was critical to the successful regional transmission plans that have occurred, including MISO MVPs and SPP Priority Projects. Further, as discussed above, state public policies are playing an increasingly large role in shaping the future demand and supply mix.

Beyond standard regulatory processes, state legislation is sometimes specifically directed at transmission planning. For example, New York's Accelerated Renewable Energy Growth and Community Benefit Act calls for the New York Department of Public Service, in consultation with NYISO, the state's utilities, and other state agencies, to carry out a comprehensive power grid study at regular intervals that examines both local transmission and distribution and bulk transmission system improvements needed to reach the state's ambitious climate goals enshrined in the Climate Leadership and Community Protection Act.[201] The Act also grants the New York Power Authority, acting by itself or in collaboration with other parties, special rights to construct transmission projects found to be needed to be "completed expeditiously to meet the Climate Leadership and Community Protection Act (CLCPA) targets."[202] Other states, such as New Mexico, have transmission authorities to help plan and finance transmission that serves state energy policy goals.[203] In the wake of Order No. 1000, several states, including Minnesota, North Dakota, South Dakota, Nebraska, and Oklahoma, have enacted their own laws instituting a right

201 *See New York Accelerated Renewable Energy Growth and Community Benefit Act*, Chapter XVIII, Title 19 of NYCRR Part 900, §900-2.18 (State power grid study and program to achieve CLCPA targets).

202 *Ibid.*

203 *See* https://nmreta.com/.

of first refusal for incumbent utilities at the state level.[204] The dismissal of a challenge to Minnesota's right of first refusal law was recently affirmed by the U.S. Court of Appeals for the Eighth Circuit.[205]

Given the central importance of states to transmission planning, the Commission should consider initiating governance changes to regional planning entities so as to give states a more significant role in regional transmission planning. Some regions already give states a special role on transmission cost allocation issues.[206] And special state roles in resource adequacy are common in RTO tariffs and governing documents, another area where states have a unique statutory role.[207] For example, SPP's bylaws provide that the Regional State Committee will "determine the approach for resource adequacy across the entire region," and transmission cost allocation policy for the region.[208] The Commission should gather input from stakeholders regarding whether it would be appropriate to require governance changes of regional planning entities to incorporate a state role, and if so, what changes should be required or encouraged. Recognizing the differences in governance between RTO and non-RTO regions, the Commission should seek input on whether and how this should vary according to a region's characteristics on this dimension.

In single state transmission planning regions, the benefits of integrating states into the governance of regional transmission planning processes could be particularly acute. But larger regions will likely also see significant benefits by giving regional state committees a special governance role.

Beyond considering requiring regional planning entities to grant states a governance role in transmission planning decisions, the Commission could also facilitate better integration between the regional planning process and state proceedings by using Section 209 of the Federal Power Act to convene joint boards. Such a board could be used, for example, if one or more states demonstrate interest in aligning their transmission siting process with the regional planning process of the relevant regional planning entity(ies).

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204 *See LSP Transmission Holdings, LLC v. Sieben*, 954 F.3d 1018, 1024 n. 3 (8th Cir. 2020), (citing N.D. Cent. Code § 49-09-02.2, S.D. Codified Laws § 49-32-20, Neb. Rev. Stat.§ 70-1028, 17 Okla. Stat. § 292).

205 *Ibid.*, at 1031.

206 *See* SPP, *Governing Documents Tariff, Bylaws*, First Revised Volume No. 4, at 67, effective date: August 5, 2010, (giving the Regional State Committee authority over certain transmission cost allocation issues).

207 For a discussion of resource adequacy governance provisions in multi-state RTOs, *see* Jennifer Chen and Gabrielle Murnan, *State Participation in Resource Adequacy Decisions in Multistate Regional Transmission Organizations*, March 2019.

208 SPP, *Governing Documents Tariff, Bylaws*, First Revised Volume No. 4, at 67, effective date: August 5, 2010; *Southwest Power Pool*, 106 FERC ¶ 61,110, at P 220, February 10, 2004 ("The RSC should . . . determine the approach for resource adequacy across the entire region."); *Southwest Power Pool, Inc.*, 109 FERC ¶ 61,010, at P 93, October 1, 2004, ("We reject arguments that the RSC is infringing on SPP's own section 205 filing rights.").

E. Produce plans on a regular schedule

To ensure effective planning that is updated to evolving circumstances, the Commission should require regular updates, such as every two years.

F. Produce plans in operations time frame

A FERC planning rule should provide for planning in different time frames. Congestion on the system is widespread and costs consumers roughly $6.1 billion per year.[209] Yet if one only looks at the system a year or two ahead of time, much of that congestion does not exist. That is because congestion is often a function of planned transmission line outages that are not known in that time frame. Transmission planning should include an operational time frame component. Looking out two or three months ahead when planned outages are known allows fast deployment of Grid-Enhancing Technologies to reduce or resolve that congestion.

209 Jesse Schneider, *Transmission Congestion Costs in the U.S. RTOs*, August 14, 2019 (updated November 12, 2020).

VI. The Commission has authority to carry out these reforms

Broadly speaking, to issue a new planning rule under Section 206 of the Federal Power Act, the Commission must find based on substantial evidence that existing planning practices are not just and reasonable or are unduly discriminatory. Evidence of challenges that have persisted despite the progress made under Orders No. 890 and 1000 clears this bar with room to spare. As discussed in Appendix A, numerous studies demonstrate that large, high-voltage transmission infrastructure would yield significant net benefits. Yet regional planning processes are largely not approving such infrastructure, instead yielding locally focused projects that in many cases are likely not as cost-effective as regional or interregional solutions could be. This has overburdened interconnection processes, which are becoming clogged and unworkable. These factors all demonstrate the need for broad planning reforms.

At a more granular level, the Commission has ample authority to adopt the specific solutions we have suggested in this report, as discussed further below.

A. Planning

1. The Commission can require regions to plan based on the best available data and forecasting methodologies

We recommend that the Commission require regions to plan based on reasonable future scenarios that use the best available data and forecasting methodologies. Such planning, which requires the incorporation of not only factors such as resource cost curves, but also public policies as well as corporate and utility procurement targets, falls under FERC's standard power to require planning to be conducted using reasonably available information, just as FERC requires RTOs establish capacity requirements based on their projections of load that is influenced by state energy efficiency policies and other factors. The Commission is permitted to "recognize[] that state and federal policies might affect the transmission market" and plan accordingly.[210]

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210 *South Carolina Public Service Authority v. FERC*, 762 F.3d at 89 (D.C. Cir. 2014).

Section 217(b)(4) of the Federal Power Act also supports a requirement to plan based on the best available data and forecasting methodologies, and to include public policies and utility and corporate renewable procurement goals within planning scenarios. It requires the Commission to exercise its 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 load-serving entities."[211] Load serving entities' service obligations will be more accurately predicted by the best available forecasting methodologies, and will naturally depend upon both public policies and the resource preferences of their customers.[212]

2. The Commission can require regional planning entities to approve transmission plans that maximize net benefits

The Commission can also require regional planning entities to approve transmission plans that maximize net benefits using the same general authority it relied upon in promulgating Order No. 1000. Like Order No. 1000, such a requirement focuses on "process" and is "not intended to dictate substantive outcomes."[213] While establishing minimum standards for benefit-cost analysis is a more detailed requirement than requirements such as Order No. 1000's directive that any threshold regional planning entities apply for benefit-cost analysis must be no lower than 1.25, it likewise does not dictate that public utility transmission providers build any particular infrastructure and instead simply mandates that they follow a series of prescribed steps designed to yield just and reasonable rates. As with Order No. 1000, "[t]he substance of a regional transmission plan and any subsequent formation of agreements to construct or operate regional transmission facilities" would "remain within the discretion of the decision-makers in each planning region."[214]

211 *16 U.S.C. 824q(b)(4)*.

212 As the Commission explained in Order No. 1000-A, "many, if not all, of the Public Policy Requirements will likely impose legal obligations on load-serving entities." *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000-A, 139 FERC ¶ 61,132, at P 175, May 17, 2012.

213 *South Carolina Public Service Authority v. FERC*, 762 F.3d at 58 (D.C. Cir. 2014), (quoting Order No. 1000-A, at P 188, 77 Fed. Reg. at 32,215).

214 *Ibid.*

B. Governance, oversight, and formation of new planning entities

1. The Commission can require regions to form joint inter-regional planning boards that have full authority to propose FPA section 205 filings that select projects and allocate their costs, and form a new planning entity to assess national transmission opportunities

In considering the establishment of joint inter-regional planning boards that hold full authority to select and dictate cost allocation methodologies for projects included within an inter-regional plan, the Commission could rely on the same authority it used in Order No. 1000 to require regional planning to be conducted even in non-RTO regions.

As the D.C. Circuit explained in upholding Order No. 888 and Order No. 1000, Section 202(a) of the Federal Power Act's reference to voluntary coordination and Section 202(b) and 211's grant of authority to order interconnection and wheeling do not limit the ability of the Commission to compel rules for planning new facilities that remedy unjust, unreasonable, and discriminatory behavior under Section 206.[215] Here, as was the case in Order No. 1000, the evidence demonstrates that existing transmission planning practices are unjust, unreasonable, and unduly discriminatory with respect to interregional planning because they have not resulted in the approval of a single inter-regional project, despite a large amount of evidence suggesting that such projects would yield net benefits.

The Commission may explore different potential organizational structures for such interregional planning boards. One option may be to require the formation of new, independent entities. While such entities would not themselves be "public utilities" under the Federal Power Act, the Commission could nevertheless require transmission owners in the relevant regions to file agreements governing each interregional board with the Commission. As the Commission explained in its policy statement governing Regional Transmission Groups (similar entities that did not themselves operate transmission but governed transmission planning and operations by member entities), "under section 205(c) of the Federal Power Act (FPA), public utilities must file with the Commission the classifications, practices, and regulations affecting rates and charges for any transmission or sale subject to the Commission's jurisdiction, together with all contracts which in any manner affect or relate to such rates, charges, classifications and services."[216] Thus,

215 *See Transmission Access Policy Study Group v. FERC*, 225 F.3d 667, 686 (D.C. Cir. 2000) ("Otter Tail does not constrain FERC from mandating open access where it finds circumstances of undue discrimination to exist."); *South Carolina Public Service Authority v. FERC*, 762 F.3d at 61 (2014), ("To the extent the court in Central Iowa interpreted Section 202(a) to mean that 'Congress intended coordination and interconnection arrangements be left to the 'voluntary' action of the utilities,' there is nothing to suggest that the court purported to interpret the meaning of 'coordination' in regard to the planning of future facilities.").

216 *Policy Statement Regarding Regional Transmission Groups*, 58 Fed. Reg. 41,626, August 5, 1993.

an agreement governing such an interregional planning board, like a Regional Transmission Group Agreement "that in any manner affects or relates to jurisdictional transmission rates or services," would need to "be approved or accepted by [the] Commission as just, reasonable, and not unduly discriminatory or preferential under [section 205 of] the FPA."[217]

Another option may be to refrain from establishing new, independent organizations and instead dictate that relevant RTO agreements and utility tariffs provide for the participation in such a board and designation to such board full, binding authority to select and cost allocate projects in a manner that cannot be subsequently second guessed by the relevant individual RTO boards or utilities.

2. The Commission can enhance the transparency of transmission planning

Currently, the planning regions possess and report disparate information[218] on transmission needs and investments. Some regions do not publish cost information for approved projects, which limits the ability of stakeholders to assess such projects.[219] Further, there is no centralized place that tracks the costs of transmission projects "planned by the local transmission owners that are not subject to full ISO/RTO regional planning review."[220]

Building on Order No. 890's transparency requirements, the Commission could require more specific minimum data transparency standards as part of a new rule, drawing on the examples set by leading regions such as MISO and SPP, which "currently maintain . . . transparent cost recording and tracking processes for projects approved through their regional planning processes."[221] As Brattle Group analysts have recommended, the Commission should require that regional planning entities at minimum "have a detailed project tracking mechanism that consistently document[s] project cost estimates at various stages of the project, particularly when the project needs are first identified and at the completion of the projects."[222]

217 *Ibid.*

218 Johannes P. Pfeifenberger et al., *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value*, at 24, April 2019.

219 *Ibid.*, at 23-26 (describing data reporting practices, noting that their "analysis was not able to cover NYISO, which does not publish cost information on approved projects").

220 *Ibid.*, at 26.

221 *Ibid.*

222 *Ibid.*, at 24.

3. *The Commission can require regional transmission plans to incorporate end-of-life project planning*

The Commission could mandate end-of-life project planning be considered as part of the regional planning process by reasoning that such planning must be conducted in order to design new transmission facilities where appropriate. Regulating this planning process can be articulated as a requirement to plan *new* projects, without requiring coordination of existing facilities.

Opponents of Order No. 1000 argued that the Commission exceeded its authority in mandating regional transmission planning, as opposed to simply regulating *voluntary* planning arrangements.[223] Section 202(a) of the Federal Power Act "empower[s] and direct[s]" the Commission "to divide the country into regional districts for the voluntary interconnection and coordination of facilities."[224] But in upholding Order No. 1000, the Court of Appeals for the District of Columbia Circuit agreed with the Commission that Section 202(a)'s reference to voluntary coordination does not preclude mandatory planning activities. Rather, the voluntary coordination referred to in Section 202(a) applies only to the operation of existing facilities, not to the planning of new facilities, which "'occurs before [facilities] can be interconnected.'"[225]

We recommend that the Commission explicitly include end-of-life planning decisions within the scope of its new planning rule. While it is true that end-of-life infrastructure replacements are currently classified as asset maintenance in some regions,[226] the Federal Power Act provides the Commission with discretion to reclassify such projects as new construction. The Federal Power Act does not specify what constitutes a "facility" with regard to section 202(a)'s language governing "voluntary interconnection and coordination of facilities"; an interpretation by the Commission that rebuilding all or a significant part of an existing facility constitutes the creation of a new facility rather than maintenance of an existing one is reasonable and not arbitrary and capricious,[227] and would constitute the same type of interpretation that was upheld in *South Carolina Public Service Authority v. FERC* as permissibly distinguishing between planning new facilities and regulating the coordination of existing ones.[228] The Commission, without requiring a transmission owner to engage in any involuntary coordination of an existing facility while it is being

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223 *See South Carolina Public Service Authority v. FERC*, 762 F.3d, 41, 55-64 (D.C. Cir. 2014).

224 *16 U.S.C. § 824a(a)* (emphasis added).

225 *South Carolina Public Service Authority v. FERC*, 762 F.3d at 59 (D.C. Cir. 2014). (quoting Order No. 1000, at P 124, 77 Fed. Reg. at 32,206).

226 *See,* e.g., *PJM Interconnection, L.L.C.*, 172 FERC ¶ 61,136, at P 85, August 11, 2020, (holding that regional planning requirements do not apply to "Asset Management Projects" in PJM, a category that includes end-of-life transmission infrastructure replacements).

227 *See Chevron U.S.A. Inc. v. Natural Resources Defense Council, Inc.*, 467 U.S. 837 (1984) (holding that where a statute is "silent or ambiguous on [a] specific issue," courts must defer to an agency's reasonable interpretation).

228 *See South Carolina Public Service Authority v. FERC*, 762 F.3d at 59.

planned, can nevertheless establish rules with regard to whether a new facility should be built in its place that more efficiently meets regional needs.

The Commission can provide guidance dictating that when expenditures exceed a certain threshold, they no longer constitute 'maintenance' activities that are excluded from regional transmission planning.[229] The Commission can reason that rules that classify "asset management" activities as maintenance, even where those activities involve replacement of all or most of a given existing facility,[230] create an inappropriate incentive for utilities to reconstruct existing lines even where other alternatives are more efficient, and is not compelled by the text of the Federal Power Act.

To the extent that the Commission's directive in this area conflicts with existing RTO operating agreements concerning which facilities are subject to regional planning, the Commission can argue that the *Mobile-Sierra* doctrine does not apply, just as it did not apply with regard to the Commission's mandate that Rights-of-First-Refusal be removed from tariffs governing regional planning processes.[231] In upholding the Commission's Right of First Refusal (ROFR) removal mandate, the D.C. Circuit reasoned that *Mobile-Sierra* did not apply because the contractual terms altered by the Commission's directive were "arrived at by horizontal competitors with a common interest to exclude any future competition."[232] The same is true here. Transmission Owners' decision not to give PJM control over end-of-life planning decisions was one made by horizontal competitors to exclude such projects from future competition, and is not reflective of arm's length bargaining that could be expected to arrive at a competitive result.

4. The Commission can apply greater oversight to local transmission plans

The Commission has authority to evaluate local transmission projects where appropriate to ensure the same needs cannot be more cost-effectively met via regional and interre-

229 In many cases, this would require broadening the scope of planning tariffs and agreements. For example, FERC recently held that PJM's Consolidated Transmission Owner's Agreement (CTOA) requires a project to "expand" or "enhance" the PJM grid for planning to be transferred to PJM. *See PJM Interconnection, L.L.C.*, 172 FERC ¶ 61,136, at P 83, August 11, 2020. In adopting new criteria to distinguish infrastructure maintenance from grid upgrades, the Commission should gather input from stakeholders regarding how to define the threshold dividing these activities (e.g. whether as an absolute dollar amount or as a percentage of an existing facility, how to define the scope of a facility for purposes of this rule, etc.).

230 *See*, e.g., *Ibid.*, at P 85 (finding that PJM's proposal to designate replacement projects as "asset management" projects exempt from Order No. 890's requirements is just and reasonable). *See also* Johannes P. Pfeifenberger et al., *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value*, April 2019.

231 *See Oklahoma Gas and Electric Co. v. FERC*, 827 F.3d 75 (D.C. Cir. 2016).

232 *Ibid.*, at 80 (D.C. Cir. 2016).

gional infrastructure.[233] Evaluating the cost-effectiveness of such projects would be more consistent with Section 205 of the Federal Power Act, which places the "burden of proof" on the filing party.[234]

To prevent such a change in the burden of proof for some projects from overburdening the Commission's capacity to administer rate cases, the Commission could issue policy guidance regarding its scope and process for review.

5. The Commission can take a case-by-case approach to approving regional planning tariffs that reinstitute a right of first refusal

While the Commission was justified in mandating the removal of rights of first refusal from regional transmission planning tariffs, as discussed in Section V.D, evidence in implementing Order No. 1000 warrants a change in position by the Commission.

In determining that in some circumstances a new tariff proposal that contains a right of first refusal may yield just and reasonable rates, the Commission can point to the manner in which a mismatch in rights of first refusal at the regional and local level has led to a skewed, non-optimal project mix. At the same time, the Commission could approve a regional transmission plan that continues to omit a right of first refusal if the evidence dictates that inclusion of end-of-life project decisions within such a plan, coupled with a process for evaluating whether a regional project more efficiently serves a local need, creates incentives that will prevent the project skew we have seen in the past.

As explained in Section V.D, the Commission can also point to the experience in implementing Order No. 1000 as demonstrating that in certain circumstances, different treatment between incumbent transmission owners and non-incumbents is justified and not "undue discrimination," recognizing the role incumbents play in operating the local system, and in some regions, participating in integrated resource planning processes at the state level.

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233 Existing Commission precedent applies a presumption of prudence to local transmission plans. *See Potomac-Appalachian Transmission Highline, LLC PJM Interconnection, L.L.C.*, 158 FERC ¶ 61,050, at P 100, January 19, 2017; *see also Iroquois Gas Transmission System, L.P.*, 87 FERC ¶ 61,295, 62,168, June 17, 1999, ("As a matter of procedural practice to ensure that rate cases are manageable, the Commission does not require regulated entities to 'demonstrate in their cases-in-chief that all expenditures were prudent unless the Commission's filing requirements, policy, or precedent otherwise require.' There is, in effect, a presumption of prudence which can be rebutted at hearing whenever another party 'creates serious doubt as to the prudence of an expenditure.'"). Nevertheless, the Commission could appropriately reason that such a presumption is not appropriate where evidence suggests that a regional transmission solution may more efficiently meet the same need.

234 *16 U.S.C. § 824d(e)*; *see* Ari Peskoe, Is the Utility Transmission Syndicate Forever?, forthcoming 2021.

Appendix A

EVIDENCE OF THE NEED FOR LARGE REGIONAL AND INTERREGIONAL TRANSMISSION

Numerous studies of the future resource mix find that large amounts of power must be able to move back and forth across regions, and large regional and interregional transmission is needed for this to happen. This evidence includes:

- A study by leading grid experts at the National Oceanic and Atmospheric Administration (NOAA), found that moving away from a regionally divided network to a national network of HVDC transmission can save consumers up to $47 billion annually while integrating 523 GWs of wind and 371 GWs of solar onto the grid.[235]

- The NREL *Interconnections Seam Study* shows that significant transmission expansion and the creation of a national network will be essential in incorporating high levels of renewable resources, all the while returning more than $2.50 for every dollar invested.[236] The study found a need for 40-60 million MW-miles of alternating current (AC) and up to 63 million MW-miles of direct current (DC) transmission for one scenario. The U.S. has approximately 150 million MW-miles in operation today.

- A study by ScottMadden Management Consultants on behalf of WIRES concluded, "as more states, utilities, and other companies are mandating or committing to clean energy targets and agendas, it will not be possible to meet those goals without additional transmission to connect desired resources to load. Similarly, the current transmission system will need further expansion and hardening beyond the traditional focus on meeting reliability needs if the system is to be adequately designed and constructed to withstand and timely recover from disruptive or low probability, high-impact events affecting the resilience of the bulk power system."[237]

- Dr. Paul Joskow of MIT has reviewed transmission planning needs and concluded that "[s]ubstantial investment in new transmission capacity will be needed to allow wind and solar generators to develop projects where the most attractive natural

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235 Alexander E. MacDonald et al., *Future Cost-Competitive Electricity Systems and Their Impact on U.S. CO2 Emissions*, Nature Climate Change 6, at 526-531, January 25, 2016.

236 Aaron Bloom, *Interconnections Seam Study*, August 2018.

237 Scott Madden, *Informing the Transmission Discussion: A Look at Renewables Integration and Resilience Issues for Power Transmission in Selected Regions of the United States*, January 2020.

wind and solar resources are located. Barriers to expanding the needed inter-regional and internetwork transmission capacity are being addressed either too slowly or not at all."[238]

- The Commission itself recently reviewed transmission needs and barriers and "found that high voltage transmission, as individual lines or as an overlay, can improve reliability by allowing utilities to share generating resources, enhance the stability of the existing transmission system, aid with restoration and recovery after an event, and improve frequency response and ancillary services throughout the existing system."[239]

- A study of the Eastern Interconnection for the state of Minnesota found that scenarios with interstate transmission expansion can introduce annual savings to Minnesota consumers of up to $2.8 billion, with an annual savings for Minnesotan households of up to $1,165 per year.[240]

- Analysts at The Brattle Group estimate that providing access to areas with lower cost generation to meet Renewable Portfolio Standards (RPS) and clean energy needs through 2030 could create $30-70 billion in benefits for customers, and multiple studies have identified potential benefits of over $100 billion.[241]

- The Princeton University Net Zero America study of a low carbon economy found "[h]igh voltage transmission capacity expands ~60% by 2030 and triples through 2050 to connect wind and solar facilities to demand; total capital invested in transmission is $360 billion through 2030 and $2.4 trillion by 2050."[242]

- A study by MIT scientists found that inter-state coordination and transmission expansion reduces the cost of zero-carbon electricity by up to 46% compared to a state-by-state approach.[243] To achieve these cost reductions the study found a need for approximately doubling transmission capacity, and "[e]ven in the ''5x transmission cost'' case there are substantial transmission additions."[244]

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238 Paul Joskow, *Transmission Capacity Expansion is Needed to Decarbonize the Electricity Sector Efficiently*, Joule 4, at 1-3, January 15, 2020.

239 FERC, *Report on Barriers and Opportunities for High Voltage Transmission*, at 39, June 2020.

240 Vibrant Clean Energy, *Minnesota's Smarter Grid*, July 31, 2018.

241 J. Michael Hagerty, Johannes Pfeifenberger, and Judy Chang, *Transmission Planning Strategies to Accommodate Renewables*, at 17, September 11, 2017.

242 Eric Larson et al., *Net-Zero America: Potential Pathways, Infrastructure, and Impacts*, at 77, December 15, 2020.

243 Patrick R. Brown and Audun Botterud, *The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System*, Joule, December 11, 2020.

244 *Ibid., at 12.*

- A recent study to compare the "flexibility cost-benefits of geographic aggregation, renewable overgeneration, storage, and flexible electric vehicle charging," as "pathways to a fully renewable electricity system" found that "[g]eographic aggregation provides the largest flexibility benefit with ~5–50% cost savings.[245] The study found that "With a major expansion of long-distance transmission interconnection to smooth renewable energy variation across the continent, curtailment falls to negligible levels" at a 60% renewable penetration, from 5% in the case without transmission. In the 80% renewable case, transmission reduced curtailment from 12% to 5%."[246]

- The Brattle Group analysts find that "$30–90 billion dollars of incremental transmission investments will be necessary in the U.S. by 2030 to meet the changing needs of the system due to electrification, with an additional $200–600 billion needed from 2030 to 2050."[247]

- Analysis conducted for MISO found that significant transmission expansion was economical under all future scenarios, with the largest transmission expansion needed in Minnesota, the Dakotas, and Iowa. In the carbon reduction case, transmission provided $3.8 billion in annual savings, reducing total power system costs by 5.3%.[248] MISO's Renewable Integration Impact Assessment conducted a diverse set of power system studies examining up to 50% Variable Energy Resources (VER) (570GW VER) in the eastern interconnection. Within the MISO footprint, this included the following transmission expansion: 590 circuit-miles of 345kV and below, 820 circuit-miles of 500kV, 2040 circuit-miles of 765kV and 640 circuit-miles of HVDC.[249]

- Brattle group analysts, on behalf of WIRES, demonstrate that transmission expansion creates trading opportunities across existing regional and interregional constraints. The report finds, using existing wholesale power price differences between SPP and the Northwestern U.S., that "adding 1,000 MW of transmission capability would create approximately $3 billion in economic benefits on a present value basis."[250]

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245 Bethany A. Frew et al., *Flexibility Mechanisms and Pathways to a Highly Renewable U.S. Electricity Future*, Energy, Volume 101, at 65-78, April 15, 2016.

246 *Ibid*.

247 Dr. Jürgen Weiss, J. Michael Hagerty, and María Castañer, *The Coming Electrification of the North American Economy*, at ii, March 2019.

248 Vibrant Clean Energy, *MISO High Penetration Renewable Energy Study for 2050*, at 23-24, January 2016.

249 Wind Solar Alliance, *Renewable Integration Impact Assessment Finding Integration Inflection Points of Increasing Renewable Energy*, January 21, 2020.

250 Johannes Pfeifenberger and Judy Chang, *Well-Planned Electric Transmission Saves Customer Costs: Improved Transmission Planning is Key to the Transition to a Carbon Constrained Future*, at 16, June 2016.

- In its HVDC Network Concept study, MISO estimates that expanding east-to-west and north-to-south transmission interties can generate investment cost savings of approximately $38 billion through load diversity benefits that would reduce nation-wide generation capacity needs by 36,000 MW.[251]

- A study prepared for the Eastern Interconnection States Planning Council, National Association of Regulatory Utility Commissioners, and the Department of Energy estimates that $50–110 billion of interregional transmission will be needed over the next 20 years to cost-effectively support new generation investment. A co-optimized, anticipatory transmission planning process is estimated to reduce total generation costs by $150 billion, compared to a traditional transmission planning approach, and would generate approximately $90 billion in overall system-wide savings.[252]

- SPP found that a portfolio of transmission projects constructed in the region between 2012 and 2014 at a cost of $3.4 billion is estimated to generate upwards of $12 billion in net benefits over the next 40 years. The net present value is expected to total over $16.6 billion over the 40-year period, resulting in a benefit-to-cost ratio of 3.5.[253]

- MISO estimates that its 17 Multi-Value Projects (MVPs), approved in 2011, will generate between $7.3 to $39 billion in net benefits over the next 20 to 40 years, which will result in a total cost-benefit ratio of between 1.8 to 3.1. Typical residential households could realize an estimated $4.23 to $5.13 in monthly benefits over the 40-year period.[254]

- A study conducted by the Eastern Interconnection Planning Collaborative on the need for interregional transmission projects to meet national environmental goals found that an efficient interregional transmission planning approach to meet a 25% nation-wide RPS standard would reduce generation costs by $163–197 billion compared to traditional planning approaches.[255] Phase 2 of the study found that the transmission investment necessary to support the generation and the environmental compliance scenarios associated with these savings ranges from $67 to $98

251 MISO, *HVDC Network Concept*, at 3, January 7, 2014.

252 Andrew Liu et al., *Co-optimization of Transmission and Other Supply Resources*, September 2013.

253 SPP, *The Value of Transmission*, at 5, January 26, 2016.

254 MISO, *MTEP19*, at 6-7, n.d.

255 Eastern Interconnection Planning Collaborative, *Phase 1 Report: Formation of Stakeholder Process, Regional Plan Integration and Macroeconomic Analysis*, December 2011.

billion.[256] These results indicate that the combination of interregional environmental policy compliance and interregional transmission may offer net savings of up to $100 billion.

- A study comparing pro-active planning to reactive planning found significant benefits to pro-active planning because it is able to co-optimize generation and transmission. "Transmission planning has traditionally followed a "generation first" or "reactive" logic, in which network reinforcements are planned to accommodate assumed generation build-outs. The emergence of renewables has revealed deficiencies in this approach, in that it ignores the interdependence of transmission and generation investments. For instance, grid investments can provide access to higher quality renewables and thus affect plant siting. Disregarding this complementarity increases costs. In theory, this can be corrected by "proactive" transmission planning, which anticipates how generation investment responds by co-optimizing transmission and generation investments. We evaluate the potential usefulness of co-optimization by applying a mixed-integer linear programming formulation to a 24-bus stakeholder-developed representation of the U.S. Eastern Interconnection. We estimate cost savings from co-optimization compared to both reactive planning and an approach that iterates between generation and transmission investment optimization. These savings turn out to be comparable in magnitude to the amount of incremental transmission investment."[257]

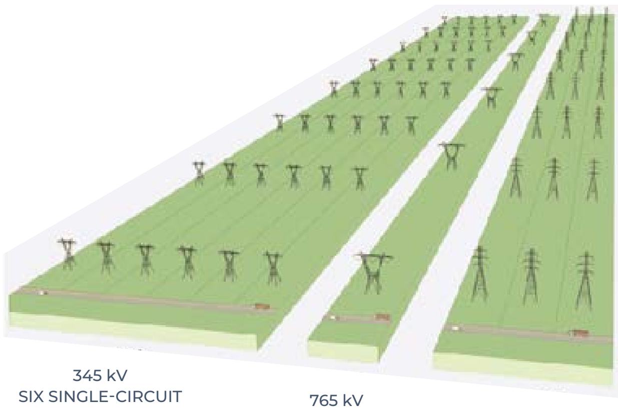
- There are extremely large economies of scale in transmission, such that building at the appropriate scale achieves lower costs for each Megawatt-hour delivered. The chart below shows the much lower cost for larger conductor sizes.[258]

256 Eastern Interconnection Planning Collaborative, *Phase 2 Report: Interregional Transmission Development and Analysis for Three Stakeholder Selected Scenarios and Gas-Electric System Interface Study*, June 2, 2015.

257 Evangelia Spyrou, Jonathan L. Ho, Benjamin F. Hobbs, Randell M. Johnson, and James D. McCalley, *What Are the Benefits of Co-Optimizing Transmission and Generation Investment? Eastern Interconnection Case Study*. IEEE Transactions on Power Systems 32 (6): 4265–77, January 27, 2017.

258 *Fabricators & Manufacturers Association, International*.

FIGURE 15 Lower Transmission Cost per MW-Mile for Larger Conductors



TRANSMISSION VOLTAGE (KV)	COST PER MILE ($/MILE)	CAPACITY (MW)	COST PER UNIT OF CAPACITY ($/MW-MILE)
230	$2.077 million	500	$5,460
345	$2.539 million	967	$2,850
500	$4.328 million	2,040	$1,450
765	$6.578 million	5,000	$1,320

Customer and reliability benefits from an increase in transmission construction have also been noted in studies focused on networks outside of the U.S. that have the same fundamental physics and economics at work.

- The "European e-Highway 2050" study found that interregional transmission investments allow for the integration of lower-cost, region-wide renewable resources, which reduce the cost of achieving a low-carbon electricity sector. Additionally, in high-renewable generation scenarios, interregional transmission investments are found to be highly cost effective with a payback period of just one year.[259]

- A study conducted by McKinsey & Company analysts found that, in Europe, the most cost-effective way to reach 40% to 45% renewable generation targets in 2050 requires doubling existing region-wide transmission capabilities by 2020 and quadrupling transmission capabilities by 2050. Germany, in particular, would need to significantly expand its interregional transmission capabilities to facilitate Europe-wide resource planning coordination.[260]

- Achieving Europe's overall renewable energy policy objectives, according to a report prepared for the Directorate General for Energy of the European Commission, finds

259 E-Highway 2050, Modular Development Plan of the Pan-European Transmission System 2050, *D2.3 System Simulations Analysis and Overlay-Grid Development*, April 16, 2015.

260 McKinsey & Company, *Transformation of Europe's power system until 2050Including specific considerations for Germany*, October 2010.

the most cost-effective path to achieving Europe's renewable energy policy objectives involves a substantial expansion of transmission networks, which composes 15% to 20% of total investment needs in all scenarios. A delay or lack of regional and interregional transmission was found to increase overall system-wide costs as well as increase levels of price volatility within regional markets.[261]

261 DNV GL - Energy, *Integration of Renewable Energy in Europe*, June 12, 2014.

Appendix B

HIGH LEVEL OVERVIEW AND ASSESSMENT OF CURRENT PLANNING APPROACHES

In most cases today, regional planning is limited to near term knowns and protecting firm service using scenarios which do not adequately incorporate likely future changes. Below, we summarize existing processes and their infirmities.

Order Nos. 890 and 1000 require a regional planning process in all areas of the country, extending transmission planning regions beyond ISO and RTOs. In almost all non-RTO areas, the participating utilities' individual transmission plans are consolidated to create a baseline regional reliability plan which is used to evaluate other proposals for both regional transmission needs and solutions. In these transmission planning regions, analysis of opportunities to expand beyond the baseline regional reliability plan are seldom robust, and as a result few projects have resulted from the regional planning process in non-RTO areas.

RTOs tend to have more robust regional planning processes than non-RTO regional planning entities. These RTO planning processes consist of at least two main steps: (1) a regional reliability assessment that identifies projects to meet reliability needs; and (2) a process designed to identify projects that will enhance the regional economic efficiency of the transmission system. They also carry out separate "tariff services" processes to develop transmission pursuant to customer load additions, transmission service requests, or generator interconnection requests. Infrastructure built pursuant to these tariff services processes is incorporated into regional transmission plans, but not driven by them. In addition, tariff service processes result in minimal system upgrades to provide the requested service, with little or no consideration of optimal long-term plans. Regions vary in the degree to which local projects, as well as upgrades and maintenance of existing infrastructure, are included in the regional reliability planning process or instead pursued according to separate local planning processes that later feed into the regional needs assessment. They also vary in the extent to which they have a separate process designed to identify projects to serve public policy goals, or projects driven by both economics and policy.

A. Reliability planning

Utilities have always focused on providing reliable service to customers as the top priority. Reliability planning processes, as their name suggests, tend to focus solely on meeting reliability standards and identifying projects based on their ability to address projected violations of reliability standards.[262] North American Electric Reliability Corporation (NERC) reliability criteria have evolved to establish system performance requirements to address thermal, voltage and stability needs of a secure bulk power system. Regional plans incorporate not only NERC criteria, but also regional and local criteria. Criteria have traditionally focused on deterministic needs of the bulk power system to evaluate system performance during system peak conditions, light load, and other planning scenarios.

Reliability planning processes begin with a baseline reliability assessment that identifies the ability of local and regional transmission infrastructure to meet reliability criteria. For example, MISO's baseline reliability study examines all infrastructure rated 100 kV and above, carrying out "power-flow models reflective of two-year out, five-year out, and ten-year out system conditions in accordance with NERC Transmision Planning (TPL) standards,"[263] as well as a variety of other studies such as a load deliverability analysis to assess system performance across relatively-near term conditions.[264]

RTOs then assess reliability according to a range of future scenarios that project system resource mix and demand across a longer time horizon. For example, MISO annually develops "Futures" to project various potential system resource mix and demand scenarios, which are used as an input into the reliability planning process.[265] The process for developing such future scenarios varies widely by region. Some regions, such as MISO and SPP, incorporate state renewable portfolio standards into their future grid mix scenarios.[266] Others, such as PJM, do not.[267] Efforts are underway in many regions to complement deterministic assessments with probabilistic techniques, which are paramount to manage the allocation of limited capital to the best system improvements given the variable na-

262 *See*, e.g., PJM, *PJM Manual 14B: PJM Region Transmission Planning Process*, § 2.1.2, October 1, 2020.

263 MISO, *Business Practices Manual Transmission Planning*, § 4.3.3, effective date: May 1, 2020.

264 *Ibid.*, § 4.5.1.

265 *Ibid.*, at § 4.4.2.5 ("It is necessary that the transmission plan is developed to be effective under the range of Futures studied. Therefore, the proposed transmission plan will be tested under each of the agreed upon Future for economic results (e.g. benefit-to-cost ratios, etc.), reliability performance (e.g., NERC standards, etc.), and public policy performance (e.g. compliance with RPS mandates, etc.).

266 *See*, e.g., Ibid., at § 4.3.3.2 ("[S]ufficient renewable generation will be modeled to meet renewable portfolio standard mandates effective during the applicable planning horizon."); SPP, *Integrated Transmission Planning Manual*, § 2.2.1.3, July 20, 2017, (requiring renewable resource targets set by state renewable portfolio standard requirements to "be met in each of the study years").

267 *See* PJM, *Amended and Restated Operating Agreement of PJM Interconnection, L.L.C.*, Schedule 6, § 1.5.7, effective date September 17, 2010.

ture of new renewable resources and loads, plus uncertainties regarding key variables. [268]

B. Local projects and maintenance activities

Transmission owners have an obligation to serve and must maintain assets, including those that have been placed under the operational control and authority of an RTO. Regions vary in how they conduct planning of local assets and maintenance activities based on the degree of control that has been given to the RTO. The Commission held in 2018 that Order No. 890 does not require Transmission owners "to allow the RTO to do to all planning for local or Supplemental Projects."[269] In many regions, such as PJM, transmission owners carry out separate local planning processes, which address a wide range of transmission needs, including upgrades and maintenance of existing infrastructure.[270] These local processes act as an input to regional plans, but are not subject to approval by the regional planning entity and there is often minimal coordination between the local and regional planning process to facilitate modification of local projects in response to the development of regional solutions. Other regions, such as SPP, have a very close degree of coordination between local and regional planning. With the exception of Southwestern Public Service Company, all transmission owners in SPP carry out their transmission planning via a process that is fully integrated (i.e. not separate from) SPP's regional planning process, with SPP collecting local planning criteria from each transmission owner in accordance with its tariff.[271]

Local planning processes may address not only local planning criteria but also project upgrades and replacements. Most RTOs have long-standing processes which exempt end of life projects from the full rigors of the regional planning process and allow incumbent TOs to rebuild, replace or upgrade select assets as they approach the end of their useful life.[272] Non-RTO regions have processes which are more opaque or non-existent, leaving end-of-life project planning entirely to local planning processes that are not subject to the transparency requirements of the regional planning process. In such local planning processes, the opportunity to leverage project upgrades to meet needs beyond the immediate reliability issue may or may not be considered, but are not assessed in the con-

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268 *See,* e.g., ISO New-England, *Transmission Planning Assumptions*, September 6, 2017; PJM, *PJM Manual 14B: PJM Region Transmission Planning Process*, § 2.7.2, October 1, 2020; and MISO, *Planning Models Used by MISO*, April 24, 2018.

269 *Monongahela Power Company et al.*, Order on Rehearing and Compliance, 164 FERC ¶ 61,217, at P 13, September 26, 2018.

270 *See* PJM, *PJM Manual 14B: PJM Region Transmission Planning Process*, § 1.1, October 1, 2020 (providing an overview of the PJM transmission planning process).

271 SPP, *Integrated Transmission Planning Manual*, § 4.2.6, July 20, 2017.

272 *See* Johannes P. Pfeifenberger et al., *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value*, at 20, April 2019. (noting that all RTOs examined exempt certain upgrade projects from competitive solicitation processes).

text of larger regional needs. Local projects must be coordinated with regional planning entities in advance of being placed in-service per NERC standards, but process simply checks for operational issues, not economic efficiency.

Local projects exempt from regional cost allocation can address a wide range of needs. PJM's supplemental project planning process, for example, may identify any "need associated with a transmission expansion or enhancement not required to comply with the PJM reliability, operational performance, FERC Form No. 715 or economic criteria.[273] MISO's "Other" projects, which comprised the majority of projects included in MTEP19, are driven by a variety of needs including reliability, age and condition, load growth, and other planning needs.[274]

Overall, the dividing line between what constitutes a "local" versus a regional project is murky, and varies significantly by region, as does the extent of interfacing between the local and regional planning processes. Generally speaking, four related factors contribute to whether a project is local or regional: (i) the project's voltage – with low voltage projects being local and higher voltage being more regional in nature; (ii) whether the project is built to address a local transmission owner's reliability criteria, regional or NERC criteria, or to provide economic or public policy benefits; (iii) whether the project involves maintenance or replacement of a transmission owner's system; and (iv) whether the project creates regional benefits.[275] Further, as discussed above, whether a project is "local" or "regional" has different consequences across different regions, as some regions will include local projects within a regional plan but not allocate costs regionally, whereas other regions will simply exclude such projects from regional plans entirely.

C. Economic, public policy, and multi-value planning processes

Regional planning entities are required to study potential transmission expansion projects to reduce congestion and improve grid efficiencies.[276] To do so, RTOs engage in an economic planning process. Economic planning is based on futures which reflect baseline assumptions for key variables like load growth, natural gas prices, resource additions that include projects which are expected to be approved and installed.

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273 PJM, *PJM Manual 14B: PJM Region Transmission Planning Process*, § 1.4.1.5, October 1, 2020.

274 MISO, *MTEP19*, at 16, n.d. (showing that 43% of "Other" projects were driven by reliability, 27% by age and condition, 26% by load growth, and 4% by other needs).

275 The D.C. Circuit recently held that if a project creates regional benefits, its costs cannot be allocated solely to the local zone, even where the project is driven solely by local reliability planning criteria. *See Old Dominion Electric Cooperative v. FERC*, 898 F.3d 1254, 1260-64 (D.C. Cir. 2018).

276 *Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 147, July 21, 2011.

RTOs vary in how they establish the future scenarios, as well as in the planning horizon assessed. Some regions, such as MISO, use the same future scenarios to inform both reliability and economic planning processes,[277] whereas others like PJM vary the assumptions used at the economic planning stage.[278] Generally speaking, the generation and demand profiles used by regions for purposes of economic planning processes reflect known retirements and interconnections rather than reasonable projections of future retirement and interconnection scenarios, with a few limited exceptions.[279] For example, PJM's planning processes include new generation sensitivities in its transmission modeling process only "[w]hen the PJM load in the RTEP model exceeds the sum of the available in-service generation plus generation with an executed [Interconnection Service Agreement]," and they do so by simply "including queued generation that has received an Impact Study" rather than conducting more sophisticated analysis.[280]

While economic planning processes are primarily designed to reduce congestion rather than solve reliability challenges, reliability and economics are interrelated. In many cases, today's economic upgrade addresses tomorrow's reliability need. Economic projects can displace reliability solutions, as long as they pass the same parameters that are being considered for the reliability portfolio. Some planning regions have taken the positive step of using market efficiency planning processes to determine if proposed reliability-based enhancements could have economic benefits if accelerated, or yield greater benefits if modified.[281] But no economic planning process accounts for the full range of reliability benefits that can be provided by economically planned projects.

Beyond this core economic planning process, many regions also have a particularized process to identify projects driven by public policies, or projects driven by a range of factors, including reliability, economic efficiency, and public policies. Needs are assessed according to a range of different metrics, which in many regions depend on the project pathway chosen. Project pathways may be dependent on relatively arbitrary buckets or artificially restrict the potential benefits of solutions to be provided to address transmission needs. For example, MISO has separate processes for Market Efficiency Projects and Multi-Value Projects, despite the fact that in theory Market Efficiency Projects are identified according to a process that incorporates both public policy and reliability needs. Market Efficiency Projects must meet a specified set of cost savings metrics with a BCA ratio

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277 MISO, *Business Practices Manual Transmission Planning*, § 4.4.2.5, effective date: May 1, 2020, (explaining that economic transmission planning solutions are examined according to performance in the "Futures" selected).

278 *See* PJM, *PJM Manual 14B: PJM Region Transmission Planning Process*, § 1.3.2, October 1, 2020.

279 MISO's "Futures" process includes a more robust scenario assessment.

280 PJM, *PJM Manual 14B: PJM Region Transmission Planning Process*, Attachment B.4 Scenario Planning Procedure, October 1, 2020.

281 *See*, e.g., PJM, *Regional Transmission Expansion Plan*, at 61, February 29, 2020.

of at least 1.25,[282] whereas Multi-Value Projects must meet one of three criteria that involve (1) reliably and economically delivering energy in support of a state policy mandate; (2) providing multiple types of economic value across multiple pricing zones for a BCA of 1.0 or higher; or (3) address a projected violation of a reliability standard and have a total project BCA of 1.0 or higher.[283] The MISO planning rules are not clear when one project pathway will be pursued to identify solutions versus another, or how exactly identifying transmission needs differs under each process. Neither MISO nor other Planning Authorities have begun Multi-Value processes in the last ten years. This structure of including several different project pathways with a lack of clarity around when each pathway is used is common among RTOs.

D. Inter-regional planning

Order No. 1000 expanded the planning requirements of Order No. 890 to require regional planning entities to establish procedures with each of its neighboring regional planning entities within existing interconnections for the purposes of coordinating and sharing regional plans to identify potential transmission solutions that are more efficient and effective than separate regional solutions to each region's needs.[284] Order No. 1000 specifies that this coordination process must include "a formal procedure to identify and jointly evaluate interregional transmission facilities."[285] It also requires "each public utility transmission provider to develop procedures by which differences in data, models, assumptions, transmission planning horizons, and criteria used to study a proposed interregional transmission project can be identified and resolved for purposes of joint evaluation."[286]

While Joint Operating Agreements have been in place for years, the focus has been for model and data exchanges to support operations, not efficient planning. A key challenge in implementing Order No. 1000 has been that the agreements between regional planning entities have a multi-stage process on interregional project approvals that requires any proposed solution to not only emerge from the coordinated interregional process, but also separately secure approvals from each RTO individually. For example, MISO and SPP have a joint planning committee responsible for carrying out a process that may arrive at identified solutions, at which point "each RTO considers the recommended interregional

282 *See* MISO, *Business Practices Manual Transmission Planning*, § 7.4.2, effective date: May 1, 2020.

283 MISO, *Tariff - Attachment FF*, §§ II.C.1, II.C.2, and II.C.3, effective date: August 11, 2020.

284 *Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at PP 374-481, July 21, 2011.

285 *Ibid.*, at P 435.

286 *Midcontinent Independent System Operator, Inc., Southwest Power Pool, Inc.*, 168 FERC ¶ 61,018, at P 5, July 16, 2019.

transmission solutions in its respective regional transmission planning process."[287] For a project to be approved it must first "be vetted through both RTO regional processes and approved by each RTO's Board of Directors."[288] Recent reforms have collapsed one stage between these RTOs it is still unlikely for the separate processes to find the same project result from their analyses.

E. Project selection for reliability, economic, public policy, multi-value, and inter-regional projects

Order No. 1000 eliminated the Right of First Refusal for utilities to build regionally and inter-regionally cost-allocated projects. In implementing this directive, the goal of planning entities, at least in theory, is to identify and select the best performing portfolio of projects according to the regional metrics, and approve those projects for regional cost allocation. All regions approach this task by first conducting the reliability and economic needs assessments described above. Some regions follow this by defining with particularity the types of infrastructure that can meet these needs, then using a competitive solicitation process to select projects.[289] Other regions use a "sponsorship model," where transmission providers are invited to propose projects that meet the needs.[290]

In practice, however, competitive solicitation is seldom used. The Commission has approved exclusions for reliability projects if those projects are needed in a short time frame, reasoning that the 6-18 months required to conduct a solicitation makes competition an inappropriate mechanism to select projects to meet those needs.[291] Regions also exclude projects from competition based on voltage level and/or total cost, with lower voltage or smaller sized local projects not subject to competition.[292] The voltage and size thresholds vary widely by region.[293] For example, MISO requires economic efficiency projects selected by competition to have a minimum voltage level of 230kV and $5 million in total costs,[294] while ISO-NE only applies a voltage threshold of less than 100 kV.[295]

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287 *Ibid.*, at P 2.

288 *Ibid.*, at P 3.

289 Joseph H. Eto and Giulia Gallo, *Regional Transmission Planning: A Review of Practices Following FERC Order Nos. 890 and 1000*, at 5-6, November 2017.

290 *Ibid.*, at 5.

291 See Johannes P. Pfeifenberger et al., Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value, at 20, April 2019.

292 *Ibid.*

293 *Ibid.*

294 MISO, *Tariff - Attachment FF*, § II.B, effective date: August 11, 2020.

295 *See* Johannes P. Pfeifenberger et al., *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value*, at 20, April 2019.

These exclusions, along with state Right of First Refusal laws, contributed to the outcome of only 3% of total RTO-region transmission investments being competitively selected between 2013 and 2017, according to the Brattle Group analysis.[296] As Order No. 1000 requires regional cost allocation for regionally beneficial projects that are planned with a long lead time, the lack of competitively selected projects shows that very few projects are being planned with regional needs in mind.

Rather, the dominant trend has been of regional plans composed almost entirely of projects that (i) address local needs and are not designed to provide greater regional economic efficiency or address public policy needs, and (ii) projects built to replace existing infrastructure, executed with short lead time in advance of the reliability need being addressed and accordingly, often without assessing potential synergies with broader regional needs and leveraging the opportunity to build larger or differently designed infrastructure utilizing the right-of-way to more cost-effectively address more regional needs.

MISO's MVP Portfolio included within MTEP11, and SPP's Priority Projects portfolio, approved in 2010, are the two main exceptions to this trend, but both occurred prior to the passage of Order No. 1000.[297] Accordingly, Order No. 1000's requirement for competitive selection did not apply and those broad portfolios consisted of solutions identified by regional planners and implemented by incumbent utilities.

296 *Ibid*., at 18.

297 SPP's 2010 Priority Projects portfolio was spurred by the Synergistic Planning Project Team (SPPT) report which outlined a new transmission planning process as well as a new cost allocation methodology, both of which were ultimately approved. SPP, *SPP Priority Projects Phase II Report*, February 2010. The portfolio consisted of 6 projects including three double-circuit, high capacity 345kV backbone projects in western SPP be approved to address benefit projected Generation Interconnection and Aggregate Transmission Service Study processes, address known and anticipated congestion patterns and also to better integrate the west and east portions of the SPP transmission system. Construction of these projects was projected to result in large local economic benefits.

MISO provides a paradigmatic example of the near exclusive reliance on locally planned projects and projects exclusively focused on reliability since Order No. 1000 was implemented:

TABLE 2 **MISO MTEP Investment by Project Type**[298]

YEAR	BASELINE RELIABILITY PROJECTS (BRP) ($ MILLION)	MARKET EFFICIENCY PROJECTS (MEP) ($ MILLION)	MULTI-VALUE PROJECTS (MVP) ($ MILLION)	OTHER (LOCAL) ($ MILLION)
2010	94	-	510	575
2011	424	-	5,100	681
2012	468	15	-	744
2013	372	-	-	1,100
2014	270	-	-	1,500
2015	1,200	67	-	1,380
2016	691	108	-	1,750
2017	957	130	-	1,400
2018	709	-	-	2,300
2019	836	-	-	2,800

Likewise, in PJM, about two thirds of projects were Supplemental Projects planned outside the regional process, 75 percent of which were driven by end-of-life planning decisions.[299]

F. Overall assessment of the current approach

The lack of regionally planned projects should not be taken as evidence that such planning would not yield benefits. Experience with MISO's MVP portfolio and SPP's priority projects portfolio has shown that, where proactive planning has been utilized, the resulting projects have been highly beneficial with total benefits approximately three times

298 Coalition of MISO Transmission Customers, Industrial Energy Consumers of America, and LS Power Midcontinent, LLC, *Section 206 Complaint and Request for Fast Track Processing*, at 31-32, January 21, 2020.

299 Paul L. Joskow, *Competition for Electric Transmission projects in the U.S.: FERC Order 1000*, March 2019; and Mohammad Reza Hesamzadeh, Juan Rosellon, and Ingo Vogelsang, *Transmission Network Investment in Liberalized Power Markets*, Springer 2020. *See also* PJM Interconnection, L.L.C., *Affidavit of Johannes P. Pfeifenberger and John Michael Hagerty on Behalf of LS Power*, Docket No. ER20-2308, at 7, July 23, 2020.

larger than costs.[300]

And as discussed in Appendix A, studies from National Labs and other sources suggest that benefits of more regionally planned projects would greatly exceed costs, and the backlog of projects in the interconnection queue suggest that more transmission planned to resource rich regions would eliminate costly delays and provide customers with access to lower cost supply.

Rather than reflecting their lack of net benefits, the lack of proactively planned projects is the result of shortcomings in regional planning processes, cost allocation, governance and oversight. Regional planning processes suffer from four primary deficiencies. First, many regional plans identify transmission needs through a siloed process that considers reliability, economic, and public policy benefits separately, rather than looking at all needs holistically. Second, in identifying transmission needs, regional planning entities generally rely upon modeling that does not accurately forecast future supply mixes or electricity demand. Third, regional processes used for identifying solutions to transmission needs do not include the full range of technologies available to serve needs. Fourth, benefit-cost analyses applied to regional transmission projects generally do not accurately reflect the full range of project benefits or select the option that maximizes aggregate net benefits to consumers.

By remedying these deficiencies, together with overcoming shortcomings in cost allocation, governance, and oversight processes discussed in Sections IV and V, the Commission can create a process through which regional planning processes more cost-effectively meet future needs and result in just and reasonable rates.

300 MISO now projects to create average monthly benefits between $4.23 and $5.13 for the average residential customers over the next 40-year period, as compared to only $1.50 per month in average costs. MISO, *MTEP19*, at 7, n.d. SPP found $3.4 billion in transmission upgrades it installed between 2012 and 2014 created over $16 billion in gross savings – 3.5 times greater than the cost of the transmission upgrades. SPP, *The Value of Transmission*, January 26, 2016.