UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Building for the Future Through Electric	**)**	
Regional Transmission Planning and Cost	**)**	**Docket No. RM21-17-000**
Allocation and Generator Interconnection	**)**	

COMMENTS OF PUBLIC INTEREST ORGANIZATIONS

OCTOBER 12, 2021

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I. INTRODUCTION

Sustainable FERC Project, Natural Resources Defense Council, the Sierra Club, Conservation Law Foundation, Acadia Center, Western Resource Advocates, 350 New Orleans, Fresh Energy, Northwest Energy Coalition, Southern Environmental Law Center, and Southface Institute (together "Public Interest Organizations" or "PIOs") hereby submit these initial comments in response to the Federal Energy Regulatory Commission's ("FERC" or "the Commission") July 15, 2021, Advanced Notice of Proposed Rulemaking ("ANOPR").[1]

II. EXECUTIVE SUMMARY

Ten years ago, the Commission adopted landmark Order No. 1000, instituting reforms to the electric transmission planning and cost allocation requirements for public utility transmission providers, with the important goal to achieve "more efficient and cost-effective regional transmission planning."[2] That rule was promulgated "in light of changing conditions in the industry."[3] Unfortunately, as discussed in more detail below, the reforms adopted in Order No. 1000 have not satisfied their promise. Further, as recognized in the ANOPR, the electric industry is again faced with major transformation,[4] and it is essential that the transmission planning, cost allocation and generator interconnection processes reflect this evolution in order to meet the challenges faced by the electric industry.

The transmission planning and cost allocation rules adopted pursuant to Order No. 1000 have failed to result in the development of significant regional transmission and have produced virtually no interregional transmission. Both will be necessary to fulfill the promise of bringing

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[1] Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, 176 FERC ¶ 61,024 (2021), 86 Fed. Reg. 40266 (July 27, 2021) (hereinafter "ANOPR").
[2] Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities, Order No. 1000, 136 FERC ¶ 61,051, at PP 81, 2 (2011) (hereinafter "Order No. 1000").
[3] *See* ANOPR at ¶ 3 (citing Order No. 1000 ¶ 1).
[4] *Id.* ¶¶ 3-4.

new generating resources, many of which are clean, low-cost renewables sited far from load, onto the grid. The states and consumers are demanding this power, and transmission is critical to accessing it.

In Section V of these comments, PIOs provide evidence that the current transmission planning and cost allocation and generator interconnection processes result in unjust, unreasonable, unduly discriminatory rates. Order No. 1000 unintentionally resulted in perverse incentives for transmission owners to plan the system to meet local, rather than regional, needs. Because of this, data show that most transmission is built outside of Order No. 1000 regional planning processes in RTO regions and regional transmission planning in non-RTO regions is essentially nonexistent. Transmission projects that are planned outside of the regional transmission planning process are not subject to meaningful review. And the interregional coordination process has not produced any meaningful interregional transmission development.

Additionally, the criteria that transmission planning regions use to plan transmission fail to account for the correct benefits and costs of such transmission. These processes consider reliability, economic, and public policy benefits in separate, overly narrow silos, which results in a transmission plan that cannot capture the highest benefit at the lowest cost. Further, the rules to connect new generation to the grid are wholly separate from the transmission planning process. Each of the transmission planning and generator interconnection processes makes different assumptions about what generation should be studied in the base case.

Any one of these problems would render the transmission planning and cost allocation process and the generator interconnection process unjust and unreasonable. When considered together, they produce excessive costs and fail to meet the needs of the transmission system, particularly those set out by state policies. Thus, it imperative that FERC use its well-established authority, described in Section IV of these comments, to act quickly to create a just and reasonable way to plan the transmission system to meet future needs.

Transmission planning and implementation will require reforms to every phase of the process, starting from the ground up and the top down. To accomplish this, PIOs propose reforms that fall into five general categories:

- Correctly accounting for benefits;
- Aligning industry incentives to support regional planning;
- Establishing minimum criteria for transmission planning;
- Reforming benefit cost analysis and cost allocation; and
- Integrating state and local outreach early in the planning process.

First, Section IV.A discusses how, as identified in the ANOPR, transmission and lines built to interconnect new generation often provide multiple and inter-linked benefits to the grid, including economic benefits, reliability benefits, and additional related public policy benefits. It can no longer be acceptable to account for each of these benefits separately or in isolation. In this vein, PIOs are heartened that FERC has announced its aim to better incorporate environmental justice and equity concerns into the Commission's decision-making processes.[5] These same considerations must also be incorporated into the transmission planning and generator interconnection processes, among other important considerations.

Second, as discussed in Section VI.B, the entities entrusted with implementing Order No. 1000 have a powerful interest to undermine it. Currently, transmission owners have every incentive to evade the regional planning and interregional coordination processes in favor of building local

[5] *See* FERC, *FERC Chairman Acts to Ensure Prominent FERC Role for Environmental Justice* (Feb. 11, 2021), available at https://www.ferc.gov/news-events/news/ferc-chairman-acts-ensure-prominent-ferc-role-environmental-justice.

transmission. These projects are generally not reviewed for prudence or under a “used and useful” standard by state regulators. FERC must make evading regional planning less attractive. It should reverse the presumption that transmission expenses arising outside of regional independent planning processes are prudent and subject such expenses to a rigorous prudency review. In addition, the Commission should promulgate rules that recognize that transmission projects developed outside of the regional transmission planning process involve no competitive risk and reduce the rate of return on such projects to reflect this reality. The Commission must also strengthen the independence requirements for the transmission planning process and rigorously require all transmission planning entities to meet them. One way to do this would be to establish interregional planning boards or a national transmission planning authority. FERC must also review transmission investments to make sure they are actually used and useful.

Third, as discussed in Section VI.C, FERC must establish minimum criteria and procedures for transmission planning and cost allocation and generator interconnection. This should include requiring transmission planning regions to use scenario-based planning and look at the entire suite of benefits rather than evaluating each type of benefit in a silo. FERC should also require transmission planning regions to prioritize interregional planning over regional and regional over local. A single interregional line may satisfy the planning needs better than multiple local or regional lines at a lower overall cost, but the current process does not allow for this type of analysis. Further, the transmission planning process must meaningfully evaluate new technologies such as storage or grid enhancing technologies. If such technologies provide transmission benefits, then they should be cost allocated to those that benefit in the same way as traditional wires solutions. Finally, interregional transmission is critical to ensuring the energy transition is successful. The Commission must adopt a minimum set of guidelines for planning and benefit-cost analysis for all planning regions, which will make it easier to align interregional project evaluation processes. These guidelines must require transmission planning regions to study benefits to neighboring regions, as well as incorporate additional benefits that may be unique to interregional projects.

Fourth, as discussed in Section VI.D, the Commission must acknowledge that states are critical stakeholders for ensuring that transmission planning reforms are successful. FERC must ensure that transmission planning regions integrate state and local outreach early in the transmission planning process, not once a plan is already in place. The Commission's Office of Public Participation ("OPP") can and should play a critical role in transmission planning by working with states to develop and implement robust stakeholder engagement processes that can be used both in regional transmission planning and local transmission planning. FERC should also work with states to develop guiding principles that strike an appropriate balance between state jurisdiction over transmission siting and the Commission's jurisdiction over transmission planning, including considerations of equity and environmental justice and protection of natural resources, and federal jurisdiction over interstate and interregional transmission planning. The Commission should also work with its fellow federal agencies to streamline the permitting process for transmission projects on federal lands.

Finally, as discussed in Section VI.E, FERC must reform the benefit-cost analysis undertaken to plan and allocate the costs of transmission. This should include adopting a minimum set of guidelines for planning and benefit-cost analysis for all planning regions, which will make it easier to align interregional project evaluation processes. These guidelines must include a consideration of climate change vulnerabilities because reforming transmission is crucial to creating grid resilience in the face of climate disruption. As discussed at FERC's Climate Change technical conference, FERC should not allow transmission planning entities to plan transmission to remediate the effects of climate change in ways that that exacerbate or contribute to its effects.[6] The guidelines should also require transmission planning entities to include the federal social cost of carbon in their benefit-cost analysis. Finally, the Commission must discontinue the use of participant funding to allocate the costs of network upgrades to interconnection customers. These upgrades often have multiple beneficiaries and costs should be allocated to all those that benefit from the lines.

PIOs are motivated by the need to decarbonize the economy and it is widely considered that transmission investments play an important role in cost-effectively doing so.[7] However, these comments do not seek for the Commission to adopt an activist role or to assert powers that properly lie with legislatures. FERC's primary role is to prevent anti-competitive behavior and to ensure that planning is sufficiently robust to meet demands safely while avoiding unreasonably expensive or inefficient investments. At the same time, FERC is obligated to faithfully incorporate federal policy into transmission planning and cost allocation. States, acting in their role as retail rate makers and pursuant to their authority over public safety and welfare, may establish and allocate funds to achieve a range of state energy policy goals. This does not mean that states without environmental goals should foot the bill for other states' policies. However, neither should states without environmental policies be allowed to impede interstate commerce to protect favored local interests from competitive effects, nor should they be able to free ride on the benefits they receive. Balancing these considerations is well within FERC's existing statutory authority and traditional functions.

[6] *See* FERC Technical Conference to Discuss Climate Change, Extreme Weather, & Electric System Reliability June 1 Tr. at 95:3-11 (Romany Webb, Associate Research Scholar/Senior Fellow at the Sabin Center for Climate Change Law, Columbia University Law School).

[7] Although this is not a foregone conclusion, as technological advancement can change the relative cost-effectiveness of transmission and other approaches. *See, e.g.*, Goldman School of Public Policy, *2030 Report: Powering America's Clean Economy*, at 25 (Apr. 2021) (suggesting that lower cost solar and storage can displace transmission).

III. THE REFORMS PROMISED BY ORDER 1000 HAVE NOT MATERIALIZED

Following its promising issuance a decade ago, the transmission planning reforms envisioned by Order No. 1000 have largely failed to materialize. A primary reason for this is the persistence of structural and regulatory flaws within the power sector, including those that provide significant disincentives to transmission owner participation.[8] Transmission facilities are privately owned assets that enjoy publicly guaranteed rates of return.[9] Indeed, they enjoy very attractive publicly guaranteed returns. At present, 30-year Treasury bonds yield a return of just 2.06%,[10] while FERC regularly approves 20-year returns on transmission assets 500 or more basis points higher. A company with the opportunity to make investments on such favorable financial terms faces obvious incentives to maximize the amounts that they invest. In light of the fiduciary obligation a corporation holds to its shareholders, a rational transmission owner will typically seek to build as many projects as possible and to invest as much in each project as possible, while seeking to avoid competition from other potential investors.

But transmission is also a product inherently infused with the public interest and funded primarily by captive consumers, putting the primary interests of investors to maximize investments in conflict with the societal needs.[11] In this context, one of the regulator's duties becomes

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[8] *See, e.g.*, The Brattle Group and Grid Strategies, *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Cost*, at 19-23 (Oct. 2021) (this report was prepared to assist in responding to the Commission's ANOPR through partial funding from PIO member Natural Resources Defense Council and is attached as Ex. A) (hereinafter "Brattle-Grid Strategies Report"). Some of the key structural and regulatory problems identified by the Brattle-Grid Strategies Study include: (1) small utility planning areas encourage local transmission planning while discouraging regional transmission planning; (2) differing transmission owner incentives between local transmission and regional plans leads to inefficient levels of each; (3) economies of scale cause inefficiently small investments unless mitigated through regulations; (4) economies of scale cause inefficient plans unless mitigated through regulations; (5) externalities cause inefficient plans unless mitigated through regulations; (6) transmission owners are able to exercise horizontal market power by withholding service to raise prices through choosing to build smaller, less-efficient projects over more competitive, less lucrative projects; and (7) transmission owners are able to exercise vertical market power to prevent competition with their own generation resources.

[9] *Id.* at 20.

[10] Bloomberg Treasury Yields, accessed Oct. 1, 2021.

[11] 18 U.S.C. § 824(a); Brattle-Grid Strategies Report at 20, 23.

disciplining publicly backed investment by ensuring that investments earning guaranteed returns are useful, prudent, and in the public interest.[12] FERC fulfills this function through three primary mechanisms. First, in Order No. 1000 the Commission mandated that all transmission owners participate in regional planning to develop transmission solutions that are more efficient or cost-effective than those identified by individual transmission owners.[13] Second, also in Order No. 1000, FERC opened up investment in regional transmission facilities to competition, finding that the absence of competition risks unjust, unreasonable, or discriminatory rates.[14] Third, when a transmission owner wishes to recover costs for its investments, it must file with the Commission under section 205 of the Federal Power Act. FERC has authority to review such filings to ensure that the investments for which transmission owners request cost recovery are used, useful, and prudent.

Order No. 1000 requires transmission providers to participate in a regional planning process that evaluates "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."[15] Even absent competition, this is antithetical to the classic transmission business model. While a rational transmission owner will seek to maximize investments, Order No. 1000's regional planning mandate requires them to participate in a process designed to meet system needs more efficiently and cost effectively.

Even more concerning to incumbent transmission owners, Order No. 1000 eliminated their federal right of first refusal to make transmission investments, exposing them to competition.[16]

[12] *See, e.g.*, J. Lazar, *Electricity Regulation in the US: A Guide. Second Edition*, at Section 8.2.4: Rate Base, The Regulatory Assistance Project (2016), available at http://www.raponline.org/knowledge-center/electricity-regulation-in-the-us-a-guide-2.
[13] Order No. 1000 ¶ 81.
[14] *Id*. ¶ 253.
[15] *Id*. ¶ 148.
[16] *Id*. ¶ 253.

The Order No. 1000 regional planning regime thus threatens incumbent transmission owners' business model in at least three ways: it seeks cost-effective solutions, disciplines costs through the threat of competition, and creates a risk that other companies might make lucrative transmission investments rather than the incumbent.

Given such conflicts of interest, rational transmission owners typically seek to avoid or undermine Order No. 1000's regional planning. Unsurprisingly, the Order No. 1000 regime has not resulted in more regional and interregional transmission buildout. The Commission has decided that transmission investments for which cost recovery is sought are presumptively prudent,[17] and in any event, the Commission lacks the technical capacity required to perform a critical evaluation of cost recovery filings. This renders the section 205 review process, which is intended to discipline investment in sub-regional transmission projects, all but meaningless. This, in turn, creates incentives for transmission owners to avoid the regional planning and competition framework set forth in Order No. 1000. This has not proven difficult, as Order No. 1000 contains loopholes that transmission owners have exploited to exclude an ever-increasing type and number of projects from the competitive process for regional planning, perpetuating many of the unjust and unreasonable conditions that led to Order No. 1000 in the first place.[18]

An enormous body of evidence establishes that additional transmission would improve grid reliability and reduce wholesale electricity prices.[19] This is the basis of the Commission's determination in Order No. 1000 that effective regional and interregional planning is necessary for just and reasonable rates.[20] When a region cannot support its energy needs, either because of local

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[17] Ari Peskoe, *Is the Utility Syndicate Forever?*, 42 Energy L.J. 1, 54, n. 354 (2021).

[18] *See infra* the discussion beginning at 18 (showing that the vast majority of projects approved in RTOs are excluded from the competitive process for regional planning).

[19] *See* Rob Gramlich & Jay Caspary, *Planning for the Future: FERC's Opportunity to Spur More Cost-Effective Transmission Infrastructure*, at App. A, ACEG (Jan. 2021).

[20] Order No. 1000 ¶¶ 78-84.

outages or extreme weather events, an interconnected grid allows that region to import electricity from parts of the country with surplus capacity.[21] Regional and interregional transmission also reduce electricity prices because they increase the ability of low-cost generators to participate in wholesale markets. Transmission constraints often result in significant electricity price differences—even among neighboring regions—and thus limit the ability of low-cost generators to sell electricity to regions where prices are high. For the same reason, more transmission and greater interregional connection reduces generator market power, since generators that serve transmission-constrained areas are often able to take advantage of transmission bottlenecks to set uncompetitively high wholesale prices.

Despite this evidence, transmission planning and cost allocation have proven to be persistent challenges. As documented below, not enough transmission is being constructed and what is being built fails to reflect the wide-ranging and geographically broad benefits of additional transmission. Not only does a modern power grid require more transmission, it requires transmission in the right places. This in turn requires a process for transmission planning and cost allocation that properly accounts for the full range of benefits of such transmission. Just as when the Commission issued Order No. 1000, current processes for planning and allocating transmission costs lead to unnecessarily high wholesale electricity prices, impede the development of transmission infrastructure needed to support grid reliability and meet future demand, entrench generator and transmission operator market power, and undermine state clean energy policies. These problems are endemic in both RTO[22] and non-RTO regions.

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[21] *See* FERC-NERC, Presentation on February 2021 Cold Weather Grid Operations: Preliminary Findings and Recommendations, at Slide 7 (Sept. 23, 2021) ("Overall, MISO's and SPP's ability to transfer power through their many transmission ties with adjacent Balancing Authorities in the Eastern Interconnection helped to alleviate their generation shortfalls, preventing more severe firm load shed.").

[22] For brevity, we do not distinguish between RTOs and ISOs, using "RTO" to refer to both.

The Commission attempted to address these problems through Order No. 1000, which made several major reforms. Order No. 1000 required (1) regional transmission planning; (2) interregional coordination; (3) beneficiary pays cost allocation; and (4) competitive procurements. These reforms were intended to ensure that cost allocation reflected the reality that transmission often benefits regions located far away from the geographic area where the transmission is built. Hence Order No. 1000's mandate that each transmission planning region "create a regional transmission plan that identifies transmission facilities needed to meet reliability, economic and Public Policy Requirements."[23]

However, Order No. 1000 has not led to the results the Commission envisioned. This is both because of flaws in the Order itself, and because planning entities—both in RTO and non-RTO regions—have sought to evade its requirements. Five major weaknesses have undermined the success of Order No. 1000. First, for practical purposes, the implementation of Order No. 1000 in practice takes a bottom-up approach to planning, starting locally, then considering regional benefits, and only then nominally considering interregional benefits. This results in multiple opportunistic or ad hoc transmission upgrades displacing strategic investments of a regional or interregional nature that could have been more cost-effective overall. Second, planning entities use different methodologies to calculate the benefits of transmission, which generally prevents regional transmission planners from assessing the many benefits of regional and interregional transmission plans. Third, transmission planners very often define the benefits of transmission narrowly and discount - or ignore altogether - a wide range of related or additional benefits. Fourth, even where planning entities consider a broad range of transmission benefits, they often do so in a siloed fashion in which reliability is considered separately from other goals, which prevents

[23] Order No. 1000 ¶ 47.

planners from considering the most cost-effective way to achieve more than one goal. Finally, utilities in RTO regions can escape cost allocation by leaving or threatening to leave the planning region in which they operate. As a result, planning and cost allocation remain parochial processes that continue to be dominated by incumbent utilities.

These problems suggest the need for a more strategic approach to planning and cost allocation. As is more fully set out in these comments, FERC should institute reforms that address the following issues:

- Correctly accounting for benefits;
- Aligning industry incentives with public policy interests;
- Establishing minimum criteria for transmission planning;
- Integrating state and local outreach early in the planning process; and
- Reforming benefit cost analysis and cost allocation.

IV. FERC IS AUTHORIZED AND OBLIGED TO REFORM THE TRANSMISSION SECTOR

The power sector is undergoing a technological transformation that is profoundly reshaping not only the energy sector, but our entire economy. Advances in clean energy generation and transmission capabilities make it possible to produce large amounts of energy both in rural areas far from load and on rooftops and in garages behind the meter. Distributed energy resources and smart grid technologies allow utilities and customers to reduce demand or increase local production in response to system constraints, saving money, maximizing efficiency, and increasing resiliency and reliability of the system during times of peak load or emergency conditions. Interregional interties between grid systems provide operator flexibility and foster competition by opening up larger pools of resources to everyone – including renewable energy resources that may be concentrated far from load. While fossil fuels can be transported by rail or truck to individual power plants that may be located within communities (unfortunately resulting in adverse community impacts), utility-scale wind and solar resources that are necessary to meet state generation requirements, future demand, and a decarbonized economy require transmission lines, often in places where none currently exist, and will need to serve (and potentially cross) multiple RTO footprints. These same regional and interregional transmission lines also provide grid operators life-saving resources and are necessary to ensure reliability during increasingly frequent and more intense large-scale extreme weather events that can knock out generation within entire regions.

The evolution of the electrical grid to meet the changing landscape of the 21st century power sector is not optional. It is necessary to deliver reliable power at just and reasonable rates now and especially into the future. As set forth in greater detail in these comments, there is overwhelming evidence that the current transmission system is systematically costing customers billions of dollars in excess charges for a less reliable and resilient grid that is failing to meet changing needs, customer demand, and state generation requirements. This failure to evolve and the unjust, unreasonable, and unduly discriminatory rates that flow from this failure are occurring for two main reasons: (1) transmission owners have financial disincentives to embrace these changes and market power to thwart their advancement; and (2) there is currently a lack of effective federal regulation and oversight of transmission planning.

From a historical perspective, these fundamental challenges and the forces perpetuating these challenges are not new. The Federal Power Act was enacted in 1935, during a similar time of enormous transformation and expansion of the electric sector, and in response to "great concentrations of economic and even political power vested in power trusts, and the absence of antitrust enforcement to restrain the growth and practices of public utility holding companies."[24] The electric system was growing, but states could not control interstate transactions, leaving a significant regulatory gap and an inability to counter the power of multi-state holding companies.[25] Congressional investigations revealed the "necessity for Federal leadership in securing planned coordination of the facilities of the industry which alone can produce an abundance of electricity at the lowest possible cost" and thus the FPA sought "to bring about the regional coordination of the operating facilities of the interstate utilities."[26] The FPA gave FERC broad authority to serve "two primary and related purposes: to curb abusive practices of public utility companies by bringing them under effective control, and to provide effective federal regulation of the expanding business of transmitting and selling power in interstate commerce."[27]

The FPA reflects this dual Congressional purpose by not only giving the Commission broad authority to regulate the owners and operators of the power sector, but also the ongoing duty to ensure that the national electric system operates first and foremost in the public interest. As further discussed below, relevant provisions of the FPA establish that the Commission is not only authorized but obligated to remedy the systematic failures of the existing transmission system.

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[24] *Gulf States Util. Co. v. FPC*, 411 U.S. 747, 758 (1973) (*citing* S.Rep. No. 621, at 11-12; Utility Corporations-Summary Report, 70th Cong. 1st Sess. S. Doc. No. 92, Part 73-A, pp. 47-54; 79 Cong. Rec. 8392 (1935)).

[25] *Pub. Utilities Comm'n of R.I. v. Attleboro Steam & Elec. Co.*, 273 U.S. 83 (1927); *see also N. Am. Co. v. Sec. & Exch. Comm'n*, 327 U.S. 686, 704, n.13 (1946) (*citing* Report of the National Power Policy Committee on Public-Utility Holding Companies, H.Doc. 137, 74th Cong., 1st Sess., p. 5: "The growth of the holding company systems has frequently been primarily dictated by promoters' dreams of far-flung power and bankers' schemes for security profits, and has often been attained with the great waste and disregard of public benefit which might be expected from such motives. Whole strings of companies with no particular relation to, and often essentially unconnected with, units in an existing system have been absorbed from time to time. The prices paid for additional units not only have been based upon inflated values but frequently have been run up out of reason by the rivalry of contending systems. Because this growth has been actuated primarily by a desire for size and the power inherent in size, the controlling groups have in many instances done no more than pay lip service to the principle of building up a system as an integrated and economic whole, which might bring actual benefits to its component parts from related operations and unified management. Instead, they have too frequently given us massive, over-capitalized organizations of ever-increasing complexity and steadily diminishing coordination and efficiency.").

[26] *Jersey Cent. Power & Light Co. v. Fed. Power Comm'n*, 319 U.S. 61, 68 (1943) (*citing* S. Rep. No. 621, 74th Cong., 1st Sess., p. 17).

[27] *Gulf States Util. Co. v. FPC*, 411 U.S. 747, 758 (1973).

Prior Commission orders reinforce these principles and the ANOPR appropriately seeks to build upon them.

The Commission has asked whether it has authority to address several possible reforms, which generally fall into four broad categories: (1) governance and process reforms to address transmission owner market power and financial incentives; (2) mandating specific planning criteria and processes; (3) holistic coordination and outreach reforms; and (4) reforms to benefit analysis and cost allocation. As further discussed in these comments, and as reflected by decades of orders regulating the power sector on an increasingly systematic basis, FERC is authorized under the FPA to make any reforms to the transmission system necessary to mitigate anti-competitive conduct and ensure that transmission planning and cost allocation procedures produce a reliable and resilient transmission system that meets diverse stakeholder needs at rates are just, reasonable, and not unduly discriminatory.

A. THE COMMISSION HAS A DUTY TO ENACT REFORMS TO MITIGATE TRANSMISSION OWNER MARKET POWER AND PROTECT CUSTOMERS FROM UNJUST, UNREASONABLE, AND UNDULY DISCRIMINATORY RATES AND PRACTICES

As discussed further below, the PIOs support the Commission's proposal in the ANOPR to consider potential reforms to address current problems associated with transmission planning. The comments and proposed reforms offered below are intended to ensure transmission planning efforts result in rates and practices that are just, reasonable, and not unduly discriminatory and to mitigate transmission owner market power and anti-competitive conduct that are often the root cause of transmission planning failures. When, as is the case here, there are general findings of systemic conditions that result in – or theoretically could result in[28] – the potential for

[28] *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 64 (D.C. Cir. 2014).

anticompetitive and unduly discriminatory behavior, or unjust and unreasonable rates, the Commission is not only authorized but obligated to enact such reforms.

Sections 201, 205, and 206 of the FPA are at the heart of the Commission's sweeping authority and obligation to regulate the nation's transmission system. Section 201 establishes the guiding principle of the FPA that because the sale and distribution of electricity is "affected with a public interest," federal regulation of the transmission of electricity in interstate commerce and the sale of such energy at wholesale "is *necessary*" to serve that interest.[29] It also vests FERC with exclusive jurisdiction over "the transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce."[30]

Sections 205 and 206 expand upon this guiding principle to specifically target two main areas where injustices have often occurred: rates and access. Section 205 requires all "rates and charges . . . for or in connection with the transmission or sale of electric energy. . . and all rules and regulations affecting or pertaining to such rates or charges shall be just and reasonable" and declares that "any such rate or charge that is not just and reasonable is hereby declared to be unlawful."[31] Section 205 further prohibits any undue preference or advantage to any person or maintaining any unreasonable difference in rates, charges, service, or facilities.[32] In cases where the Commission determines that "any rate, charge, or classification demanded, observed, charged, or collected by any public utility for any transmission or sale. . . or that any rule, regulation, practice or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory or preferential," Section 206 requires the Commission to determine and order a new

[29] 18 U.S.C. § 824(a) (emphasis added).
[30] *Id*.
[31] 16 U.S.C. § 824a(b).
[32] *Id*. § 824d.

"just and reasonable rate, charge, classification, rule, regulation, practice or contract."[33] Sections 205 and 206 oblige the Commission to actively regulate all practices affecting the transmission system – including planning practices – in order to ensure that it is operating in a just, reasonable, and non-discriminatory manner across the country.[34]

Due to the modern grid's wide interconnection as well as technological developments — including distributed energy and demand response resources that can exist even at the user end of the system, and the ability to transmit energy at great distances at low cost that enables a "customer in Vermont [to] purchase electricity from an environmentally friendly power producer in California or a cogeneration facility in Oklahoma"[35]— there is now very little transmission that is not interstate.[36] With the exceptions of Hawaii, Alaska, and the Texas Interconnect, "in the rest of the country, any electricity that enters the grid immediately becomes a part of a vast pool of energy that is constantly moving in interstate commerce."[37] As a result, FERC has near-plenary jurisdiction over all transmission activities and a duty to ensure that the rules and practices affecting them are just and reasonable.[38]

Despite the diversification of resources connected to the grid, public utilities have largely retained monopoly ownership of the transmission lines that the system depends upon to deliver and receive electricity for both wholesale and retail customers, which gives transmission owners the ability to control what transmission gets built, when it gets built, for whom and for how much,

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[33] *Id.* § 824e.
[34] *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 48 (D.C. Cir. 2014).
[35] *Transmission Access Pol'y Study Grp*. v. *FERC*, 225 F.3d 667, 681 (D.C. Cir. 2000) ("*TAPS v. FERC*"*)*, aff'd sub nom. *New York v. FERC*, 535 U.S. 1 (2002).
[36] *Id.; see also* Matthew R. Christiansen & Joshua C. Macey*, Long Live the Federal Power Act's Bright Line,* 134 Harv. L. Rev. 1360, 1377-81 (2021).
[37] *New York v. FERC*, 535 U.S. at 7 and n.5 (explaining that "[e]nergy flowing onto a power network or grid *energizes the entire grid*, and consumers then draw undifferentiated energy from that grid," and thus "any activity on the interstate grid affects the rest of the grid").
[38] *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 49.

as well as who has access to it (and therefore access to the markets) and on what terms. As a result, "utilities owning or controlling transmission facilities possess substantial market power; that, as profit maximizing firms, they have and will continue to exercise that market power in order to maintain and increase market share, and will thus deny their wholesale customers access to competitively priced electric generation; and that these unduly discriminatory practices will deny consumers the substantial benefits of lower electricity prices."[39]

The Commission has already used its authority under FPA Sections 205 and 206 to issue rules that address these widespread market power problems with system-wide solutions on two fronts: one focusing primarily on operations and the other focusing primarily on how the system is built. The first front of system-wide reform is aimed at directly mitigating market power and anti-competitive practices that unduly discriminate against competitors by restructuring the electric industry to require all transmission owners to offer non-discriminatory, transparent, and open access transmission service.[40] Starting with Orders 888 and 889, the Commission mandated the "functional unbundling" of transmission service from generation service and required utilities to file "open access transmission tariffs" ("OATTs") containing terms of transmission applicable to all customers designed to open access to the transmission system on the terms and conditions comparable to those that utilities give themselves and to provide real-time transmission system information that mitigates transmission owners' informational advantage.[41] These reforms are

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[39] Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities, Recovery of Stranded Costs by Public Utilities and Transmitting Utilities; Proposed Rulemaking and Supplemental Notice of Proposed Rulemaking ("Order 888 NOPR"), 60 Fed. Reg. 17,662, 17,665 (Apr. 7, 1995).
[40] *TAPS v. FERC*, 224. F.3d at 682; *see also* Ari Peskoe, *Is the Utility Transmission Syndicate Forever?*, 42 Energy L.J. 1, 10 (2021).
[41] *Id.*; Federal Energy Regulatory Commission, Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities, Recovery of Stranded Costs by Public Utilities, 61 Fed. Reg. 21540, 21548 (May 10, 1996) ("Order No. 888"); Open-Access Same Time Information System and Standards of Conduct, Order No. 889, 61 Fed. Reg. 21,737 (1996) ("Order No. 889").

primarily focused around transmission system operations, and have pushed for the creation of independent transmission system operators (known as ISOs) and regional transmission organizations (known as RTOs) that are directly regulated by FERC under FPA Sections 205 and 206,[42] and must be factually independent of transmission owners and perceived as such—both operationally and financially.[43] In particular, ISO/RTO rules of governance "should prevent control, and appearance of control, of decision-making by any class of participants" since "[a] governance structure that includes fair representation of all types of users of the system would help ensure that the ISO formulates policies, operates the system, and resolves disputes in a fair and non-discriminatory manner."[44] The Commission's reform efforts have repeatedly been upheld on review, with courts repeatedly affirming that the Commission has broad authority to remedy "general findings of systemic monopoly conditions and the resulting potential for anti-competitive behavior, rather than evidence of monopoly and undue discrimination on the part of individual utilities."[45] In fact, the Supreme Court has held that while thus far FERC has chosen not to regulate bundled retail transmission as a means of addressing undue discrimination and anti-competitive behavior that were it to find undue discrimination in the retail electricity market, Section 206

[42] *See* Federal Energy Regulatory Commission, Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities, Recovery of Stranded Costs by Public Utilities, 61 Fed. Reg. 21,540, 21546-21,548 (May 10, 1996) ("Order 888"); Order No. 2000; Ari Peskoe, *Is the Utility Syndicate Forever?* 42 Energy L.J. 1, 13 (2021).

[43] Ari Peskoe, *Is the Utility Syndicate Forever?* 42 Energy L.J. 1, 28 (2021).

[44] *Id., citing* Order No. 888 at 21,596.

[45] *See, e.g., TAPS v. FERC*, 225 F.3d at 687-88 (finding that FERC has authority under Sections 205 and 206 to require open access as a generic remedy to prevent undue discrimination); *New York v. FERC*, 535 U.S. at 23-24 (holding the FPA "unquestionably supports FERC's jurisdiction to order unbundling of wholesale transactions (which none of the parties before us questions), as well as to regulate the unbundled transmissions of electricity retailers").

"would require FERC to provide a remedy for that discrimination . . . And such a remedy could very well involve FERC's decision to regulate bundled retail transmission[.]"[46]

The second main front of reform efforts has focused on addressing how transmission owner control over building the system itself leads to unjust, unreasonable, and unduly discriminatory rates and practices, which FERC has addressed by requiring competitive regional and interregional transmission planning processes.[47] Starting with Order 890,[48] the Commission addressed continuing opportunities for undue discrimination and underinvestment in grid infrastructure by mandating an open, transparent, and coordinated transmission planning process. FERC found transmission planning to be a critical function of open access tariffs "because it is the means by which customers consider and access new sources of energy and have an opportunity to explore

[46] *New York v. FERC*, 535 U.S. at 27. In fact, the partial dissent by Justice Thomas and joined by Justices Scalia and Kennedy centered on the failure of FERC to explain why the regulation of bundled retail transmission was unnecessary, stating:

> Given that it is impossible to identify which utility's lines are used for any given transmission, FERC's decision to exclude transmission because it is associated with a particular type of transaction appears to make little sense. And this decision may conflict with FERC's statutory mandate to regulate when it finds unjust, unreasonable, unduly discriminatory, or preferential treatment with respect to any transmission subject to its jurisdiction. . . The fact that FERC found undue discrimination with respect to transmission used in connection with both bundled and unbundled wholesale sales and unbundled retail sales indicates that such discrimination exists regardless of whether the transmission is used in bundled or unbundled sales. Without more, FERC's conclusory statement that "unbundling of retail transmission" is not "necessary" lends little support to its decision not to regulate such transmission. And it simply cannot be the case that the nature of the commercial transaction controls the scope of FERC's jurisdiction.
>
> *   *   *
>
> Finally, to the extent that FERC has concluded that it *lacks* jurisdiction over transmission connected to bundled retail sales, it ignores the clear statutory mandate. By refusing to regulate the transmission associated with retail sales in States that have chosen not to unbundle retail sales, FERC has set up a system under which: (a) each State's internal policy decisions concerning whether to require unbundling controls the nature of federal jurisdiction; (b) a utility's voluntary decision to unbundle determines whether FERC has jurisdiction; and (c) utilities that are allowed to continue bundling may discriminate against other companies attempting to use their transmission lines. The statute neither draws these distinctions nor provides that the jurisdictional lines shift based on actions taken by the States, the public utilities, or FERC itself. While Congress understood that transmission is a necessary component of all energy sales, it granted FERC jurisdiction over all interstate transmission, without qualification. As such, these distinctions belie the statutory text.

Id. at 34–35, 41-42.

[47] Order No. 888; *see also* Ari Peskoe, *Is the Utility Transmission Syndicate Forever?*, 42 Energy L.J. 1, 9 (2021).

[48] Preventing Undue Discrimination and Preference in Transmission Service, 72 Fed. Reg. 12,266 (2007).

the feasibility of non-transmission alternatives."[49] The Commission also found that because of the disincentives of transmission providers to remedy congestion, it could not "rely on the self-interest of transmission providers to expand the grid in a nondiscriminatory manner,"[50] and that the existing OATT did not counteract these disincentives because there were no clear criteria regarding the transmission providers' planning obligation; there was no requirement that the overall planning process be open to customers, competitors, and state commissions; and there was no requirement that critical assumptions and data underlying transmission plans be made available.[51] "Taken together, this lack of coordination, openness, and transparency results in opportunities for undue discrimination in transmission planning."[52] The Commission further relied on the recently passed FPA Section 217, which 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 [their] service obligations"—including requirements to provide service under federal, state, or local law, or under long-term contracts.[53] Order No. 890 required each transmission provider to comply with nine planning principles[54] in establishing an open, coordinated, and transparent planning process.

Building upon Order No. 890, Order No. 1000 determined that further transmission planning requirements were necessary to address significant changes in the nation's power sector—including the failure to plan for transmission needs driven by public policy requirements established by federal, state, or local laws. FERC noted that:

> The need for additional transmission facilities is being driven, in large part, by changes in the generation mix. As NERC notes in its 2009 Assessment, existing and potential

[49] Order No. 890 at 12,267.
[50] *Id.* at 12,318.
[51] *Id.*
[52] *Id.*
[53] 16 U.S.C. § 824q(a)(3), (b)(4).
[54] These are: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, congestion studies, and cost allocation.

> environmental regulation and state renewable portfolio standards are driving significant changes in the mix of generation resources, resulting in early retirements of coal-fired generation, an increasing reliance on natural gas, and large-scale integration of renewable generation. NERC has identified approximately 131,000 megawatts of new generation planned for construction over the next ten years, with the largest fuel-type growth in gas-fired and wind generation resources. These shifts in the generation fleet increase the need for new transmission. Additionally, the existing transmission system was not built to accommodate this shifting generation fleet. Of the total miles of bulk power transmission under construction, planned, and in a conceptual stage, NERC estimates that 50 percent will be needed strictly for reliability and an additional 27 percent will be needed to integrate variable and renewable generation across North America.
>
> Rather than demonstrating a lack of need for action, as claimed by some commenters, the recent increases in constructed and planned transmission facilities supports issuance of this Final Rule at this time to ensure that the Commission's transmission planning and cost allocation requirements are adequate to support more efficient and cost-effective investment decisions. The increased focus on investment in new transmission projects makes it even more critical to implement these reforms to ensure that the more efficient or cost-effective projects come to fruition. The record in this proceeding and the reports cited above confirm that additional, and potentially significant, investment in new transmission facilities will be required in the future to meet reliability needs and integrate new sources of generation. It is therefore critical that the Commission act now to address deficiencies to ensure that more efficient or cost-effective investments are made as the industry addresses its challenges.[55]

The Commission proposed additional reforms to correct the deficiencies of Order No. 890 to enhance the ability of the grid to support wholesale power markets and thereby ensure that Commission jurisdictional services are provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential.[56] Like its open access orders, FERC's transmission planning orders have received similar deference from the courts. In *South Carolina Public Service Authority v. FERC*, the D.C. Circuit discussed the history of the FPA and FERC's major open access and transmission planning orders to affirm the Commission's broad authority to protect the grid and customers against even theoretical threats.[57] Walking through an extensive

[55] Order No. 1000 at 49,851.
[56] *Id.* at 49,847.
[57] *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014).

record documenting estimated cost savings that would come with improved regional and interregional transmission planning, the Court determined that FERC:

> reasonably balanced the costs stemming from deficient transmission planning and cost allocation practices against the growth in demand for transmission service, concluding that the public interest in just and reasonable electricity rates outweighed claimed burdens and warranted implementing the reforms now. The Brattle Group's report was but one example of record evidence documenting the costs of inefficient and irregular planning. Industry projections, and the reasons therefor, established the likelihood of huge growth in demand for electric service. The Commission concluded that the required reforms "will promote considerable economic benefits in the form of lower congestion, greater reliability, and greater access to generation resources." It also concluded that it was "prudent" to act now rather than "wait for systemic problems to undermine transmission planning.[58]

While the Commission's open access and transmission planning rules have led to some significant improvements, those improvements are uneven and transmission owner market power continues to dominate the transmission system, both within RTOs and especially in non-RTO regions. Regional transmission projects are more of an exception than the norm, and overwhelming evidence indicates that transmission owners are largely able to evade the requirements of Order No. 1000 and, in the decade since its issuance, have primarily invested in local projects where they maintain a right of first refusal and complete control of what is built.[59] This has led to a system that is failing to meet current needs and is ill-prepared for fast-approaching deadlines to meet state and local generation requirements—the very future threat that Order No. 1000 was trying to address. This has also led to billions of dollars in excessive costs for consumers.[60] The Commission can and must use its authority under sections 205 and 206 to address directly and substantively the market power abuses and undue discrimination that have led to unjust and unreasonable costs to consumers and jeopardize the reliability of the grid. Under this authority, and in light of the

[58] *Id.* at 70.
[59] *See* Brattle-Grid Strategies Report at 20.
[60] *See generally id.*, Section I.

extensive record of systemic failures relating to transmission planning, the Commission could undertake any of the reforms proposed in the ANOPR or suggested by PIOs.

While reforms are necessary to improve the criteria used for transmission planning and procedures, including coordination among stakeholders and better benefit analyses and cost allocation, far and away the greatest need is for the Commission to enact reforms that will have the effect of finally and decisively mitigating transmission owner market power and preventing undue discrimination. The closest the Commission has come to success in truly mitigating these pervasive issues was when it mandated open and non-discriminatory access to the transmission system. However, the Commission has repeatedly hesitated in regulating anything having to do with bundled transactions despite clear grounds and explicit authority for doing so. This leaves the door open for transmission owners to exercise market power – especially in non-RTO regions where their incentives to protect their own generation resources are highest – but also in RTO regions where they can heavily influence outcomes, including by threatening to leave if the RTO does not meet their demands.[61] Without a level playing field for competition across the country, consumers everywhere will continue to pay excessively high rates. As discussed below, the Commission can and should use its authority to enact significant governance reforms aimed at leveling the playing field and ensuring independence in transmission planning, such as improving prudence review of local transmission projects,[62] creating interregional planning boards or a

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[61] *See, e.g.*, *New York v. FERC*, 535 U.S. at 27, 37-41. The Commission's most notable failure in this regard was its decision to back away from its 2002 Standard Market Design Notice of Proposed Rulemaking in a seven paragraph order with only five sentences of discussion, after three years of consideration, a staff white paper of potential improvements, and extensive findings by the Commission of continuing anti-competitive behavior and undue discrimination by transmission owners making clear the need for a level playing field for all entities seeking to participate in wholesale electric markets. *See* Remedying Undue Discrimination Through Open Access Transmission Serv. & Standard Elec. Mkt. Design, 112 FERC ¶ 61073 (2005); *cf.* Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design, 67 Fed. Reg. 55,452 (Aug. 29, 2002).

[62] In its Comment, the Harvard Electricity Law Initiative lays out an extensive legal rationale for enhanced prudence review of transmission filings with which PIOs agree. *See* Comment of the Harvard Electricity Law Initiative, Docket No. RM21-17 at Section II (Oct. 12, 2021).

national transmission planning authority, increasing transparency, and creating broader access to transmission models and assumptions.

B. THE COMMISSION HAS THE AUTHORITY TO MANDATE TRANSMISSION PLANNING CRITERIA AND PROCESSES TO MEET CURRENT AND FUTURE NEEDS

Equally important to ensuring just, reasonable, and not unduly discriminatory rates and practices, the Commission must also use its broad authority under Sections 205 and 206 to improve its existing transmission planning orders to mandate the establishment and use of any transmission planning criteria and processes necessary to meet current and future grid needs. The original planning principles of Order Nos. 890 and 1000 already establish the Commission's authority to mandate transmission planning requirements, and they are still relevant to the current needs. Achieving the aims of the planning principles set forth first in Order No. 890 and expanded in Order 1000 should continue to serve as a foundation for further reform: [63]

- **Coordination**: transmission providers "must meet with all of their transmission customers and interconnected neighbors to develop a transmission plan on a nondiscriminatory basis;"[64]
- **Openness**: transmission planning meetings transmission planning meetings be open to all affected parties including, but not limited to: all transmission and interconnection customers, State commissions, and other stakeholders;[65]
- **Transparency**: all transmission providers—including non-public ones—must disclose to all customers and other stakeholders the basic criteria, assumptions, and data that underlie their transmission system plans. This information must make available the basic methodology, criteria, and processes transmission providers use to develop their transmission plans, including how they treat retail native loads, in order to ensure that standards are consistently applied, and should enable customers, other stakeholders, or an independent third party to replicate the results of planning studies in order to reduce the incidence of after-the-fact disputes regarding whether planning has been conducted in an unduly discriminatory fashion;[66]
- **Information Exchange**: transmission providers must develop guidelines and a schedule for the submittal of information in consultation with their customers and

[63] Order No. 890 at Sec. V.B.2.
[64] *Id.* at 12,321-322.
[65] *Id.* at 12,323.
[66] *Id.* at 12,324-12,325.

other stakeholders. Information collected by transmission providers to provide transmission service to their native load customers must be transparent and equivalent information must be provided by transmission customers to ensure effective planning and comparability. Information exchanged should be a continual process. Point-to-point customers must submit any projections they have of a need for service over the planning horizon and at what receipt and delivery points. To the extent applicable, transmission customers also should provide information on existing and planned demand resources and their impacts on demand and peak demand. Most importantly, transmission planning is not intended to be limited to the mere exchange of information and then a review of transmission provider plans after the fact, but must provide transmission customers and other stakeholders a meaningful opportunity to engage in planning along with their transmission providers;[67]

- **Comparability**: transmission providers, after considering the data and comments supplied by customers and other stakeholders, must develop a transmission system plan that (1) meets the specific service requests of its transmission customers and (2) otherwise treats similarly-situated customers comparably—including customer demand resources;[68]
- **Dispute Resolution**: transmission providers must develop a dispute resolution process to manage disputes that is available to address both procedural and substantive planning issues;[69]
- **Regional Participation**: Each transmission provider will be required to coordinate with interconnected systems to (1) share system plans to ensure that they are simultaneously feasible and otherwise use consistent assumptions and data and (2) identify system enhancements that could relieve congestion or integrate new resources. greater coordination and openness in transmission planning is required, on both a local and regional level, to remedy undue discrimination. The coordination of planning on a regional basis will also increase efficiency through the coordination of transmission upgrades that have region-wide benefits, as opposed to pursuing transmission expansion on a piecemeal basis. Each regional planning process will be addressed in the context of the relevant compliance filing;[70]
- **Regional Planning Process**: transmission providers must prepare and post studies identifying "significant and recurring" congestion that analyze and report on (1) the location and magnitude of the congestion, (2) possible remedies for the elimination of the congestion, in whole or in part, (3) the associated costs of congestion, and (4) the cost associated with relieving congestion through system enhancements (or other means). Local and regional planning must also coordinate with stakeholders to identify transmission needs driven by public policy requirements and evaluates potential solutions to meet those needs to ensure that each utility's planning process supports rates, terms, and conditions of transmission that are just, reasonable, and

[67] *Id.* at 12, 327.
[68] *Id.* at 12,237-12,328.
[69] *Id.* at 12,328.
[70] *Id.* at 12,331-12,332

not unduly discriminatory or preferential.[71] The primary objective *is to ensure that the transmission planning process encompasses more than reliability considerations*. Although planning to maintain reliability is a critical priority, it is not the only one. A prudent transmission provider will plan not only to maintain reliability, but also consider whether transmission upgrades or other investments can reduce the overall costs of serving native load and ensure compliance with relevant public policy requirements. Such upgrades can, for example, reduce congestion (redispatch) costs or integrate efficient new resources (including demand resources) and new or growing loads.[72] Thus, to represent good utility practice and provide comparable service, the transmission planning process under the pro forma OATT must consider reliability, economic, public policy requirements, and any public policy objectives approved in consultation with stakeholders in both local and regional planning processes in order to meet future generation needs;[73] and

- **Cost Allocation**: the planning process must include cost allocation that weighs several factors, namely: (1) fair assignation of costs among participants that avoids free ridership by including those who cause them to be incurred and those who otherwise benefit from them—either now or in the future—even if they do not support them; (2) whether it provides adequate incentives to construct new transmission; (3) whether the proposal is generally supported by State authorities and participants across the region.[74] The final cost allocation must be roughly commensurate with benefits.[75]

As further discussed throughout PIOs' filings, these principles continue to form a firm foundation for good transmission planning. The problem has been that regional planning authorities were essentially allowed to implement them however they have seen fit, with little to no Commission oversight. As a result, they have thus far primarily served as aspirational ideals, rather than enforceable standards. This lack of specificity as to what criteria must be considered, by who, and how has largely thwarted implementation of the transmission planning orders. But it is clear that the Commission has authority pursuant to Sections 205 and 206 to explicitly set the minimum

[71] Order No. 1000 at 49,871, 49,876.
[72] Order No. 890 at 12,333-12,334.
[73] Order No. 1000 at 49,855-49,857.
[74] Order No. 890. at 12,337.
[75] Order No. 1000 at 49,846.

terms and criteria for compliance and has considerable authority to enhance the regional planning process.[76]

In addition to Sections 205 and 206, the Commission has authority to use other tools it can use to achieve meaningful compliance with these principles, including:

- **Establish joint boards of cooperation with state commissions** under Section 209, which can be vested "with the same power and be subject to the same duties and liabilities as a Commission member designated to hold a hearing,[77] and the actions of which "shall have such force and affect and its proceedings shall be conducted in such manner as the Commission shall by regulations prescribe."[78] Further, the Commission "may confer with any state commission regarding the relationship between rate structures, costs, accounts, charges, practices, classification, and regulations of public utilities,"[79] and is authorized, under such rules and regulations as the Commission shall prescribe, to hold joint hearings with any State commission in connection with any matter with respect to which the Commission is authorized to act."[80]

- **Devise incentives** pursuant to Section 219 of the FPA to "establish, by rule, incentive-based (including performance-based) rate treatments" for transmission that benefits "consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion." Among other things the rule must (a) "promote reliable and economically efficient transmission and generation . . . regardless of ownership of the facilities; (2) "provide a return on equity that attracts new investment in transmission facilities (including related transmission technologies)"; and (3) encourage deployment of measures that increase the capacity and efficiency of existing transmission facilities and improve their operation.

- **Order Production of Necessary Information for Meaningful Planning**: Pursuant to Sections 208, 213, 220, 301, 304, and 307 the Commission has authority to gather any information it deems necessary for transmission planning and cost allocation purposes. Section 208 entitles to the Commission to actual cost and depreciation information of any public utility property. Section 213(b) requires transmitting utilities to submit annual reports to provide information on "potentially available transmission capacity and known constraints." Section 220 directs the Commission to issue any rules it deems necessary to "facilitate price transparency" in generation and transmission markets "having due regard for the public interest, the integrity of those markets, fair competition, and the protection of consumers." Such rules shall require the dissemination of information from any market participant about the availability and prices of wholesale electric energy and transmission service to the Commission, State

[76] *See generally, S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41(D.C. Cir. 2014).
[77] 16 U.S.C. § 824h.
[78] 16 U.S.C. § 824h(a).
[79] 16 U.S.C. § 824h(b).
[80] 16 U.S.C. § 824h(b).

commissions, and the public (among others), and may also require that this information be received and made public by other entities besides the Commission. Broader still, Section 301 gives the Commission authority to require any recordkeeping and reporting requirements it deems necessary for purposes of administering the FPA, and Section 304 allows the Commission to establish rules for periodic reporting that may include "among other things, full information as to assets and liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project, and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution delivery, use, and sale of electric energy." The Commission may also require that "any such person make adequate provision for currently determining such costs and other facts," and shall make such reports under oath unless otherwise specified. Pursuant to Section 307, the Commission has sweeping authority to "investigate any facts, conditions, practices or matters which it may find necessary or proper" in order to determine whether any party has violated any provision of the FPA or its implementing regulations, "or to aid in the enforcement . . . or in obtaining information" about the sale of energy at wholesale and the transmission of energy in interstate commerce. The Commission is also authorized to designate officers empowered to take evidence and require document production the Commission finds relevant to the inquiry.

- **Hire Staff and Appoint Independent Officers**: Pursuant to Section 309 the Commission the "power to perform any and all acts, and to prescribe . . . such orders, rules, and regulations as it may find necessary or appropriate to carry out" the FPA, and "may prescribe the form or forms of all statements, declarations, applications, and reports . . . the information which they shall contain, and the time within which they shall be filed." Section 210 permits the Commission to "appoint and fix the compensation of such officers, attorneys, examiners, and experts as may be necessary for carrying out its functions under this Act, without regard to the provisions of other laws applicable to the employment and compensation of officers and employees of the United States." It may also hire any other officers or employees subject to civil-service laws as necessary.

As suggested by the Comment of the Harvard Electricity Law Initiative in this docket, the Commission could use these tools to ground its new planning rule in a survey of evolving transmission needs.[81] "Today, transmission is needed to enhance reliability and system resilience in the face of climate-related disasters, operational challenges, . . . shifting supply-demand conditions" and the domination of new capacity "by wind and solar, whose transmission needs

[81] *See id.* at Sections I.A, I.B.

differ from traditional forms of generation."[82] It can and should also conduct a survey of *all* potential benefits that can result from multi-value, scenario-based planning and should require that they be considered.[83] Above all, the Commission must craft a rule that is based on specific, mandatory requirements. While the application of any given criteria may vary by project, that various types of benefits, regulatory requirements, and potential types of system vulnerabilities do not themselves vary significantly or at all. In order to meet the goals of the planning principles set forth in Orders 890 and 1000, the Commission must require consideration of mandatory benefit and cost criteria, meaningful stakeholders and state coordination throughout the planning process, and most importantly, must ensure active oversight by the Commission.

V. CURRENT TRANSMISSION SYSTEM PLANNING RESULTS IN UNJUST, UNREASONABLE, AND UNDULY DISCRIMINATORY RATES AND PRACTICES

As set forth in more detail below, the problems that Order No. 1000 sought to address unfortunately are as true today as they were a decade ago. Most transmission built in recent years is not subject to Order No. 1000's regional planning requirement. In RTO regions, exceptions from regional planning constitute the vast majority of approved projects, and in most non-RTO regions, regional planning pursuant to Order No. 1000 is functionally non-existent. Further, transmission projects outside of regional planning are not subject to meaningful review by FERC to determine whether they are prudent. Finally, Order No. 1000 has resulted in virtually no significant interregional transmision projects.

The failure to conduct planning at the interregional and regional level has several negative consequences for transmission customers, including the inability to maximize efficiencies of scale to eliminate redundant or build outs. Most planning regions also routinely fail to engage in scenario-based planning to prepare the grid for a range of possible futures. Finally, the lack of multi-value, scenario-based regional and interregional planning results in excess costs to consumers and leads to a failure to meet current and future system demands.

A. TEN YEARS AFTER ORDER NO. 1000, THE PROBLEMS IT SOUGHT TO CORRECT REMAIN

[82] *See id.* at Section I.A.
[83] *See* Brattle-Grid Strategies Report, *in passim* and Apps B-D.

This section outlines the outcomes of the Order No. 1000 transmission planning regime after a decade of implementation. In the ANOPR, the Commission seeks to understand whether the current transmission planning processes result in a narrow set of transmission needs, often located in a single transmission owner's footprint.[84] The answer to this question is yes, and PIOs agree that the fact that transmission providers predominately build local transmission facilities indicates that the regional transmission planning processes "fail to identify more efficient or cost-effective transmission facilities needed to accommodate anticipated future generation."[85] This section presents empirical data, followed by a sampling of instances where the intent of Order No. 1000 has been subverted. Suggestions for reform follow in later sections. Common themes emerge in nearly all planning regions: the mechanisms intended to ensure independence, competition and oversight have been eroded, often to the point of irrelevance. The vast majority of transmission projects arise from transmission-owner internal processes and are built without competition or effective oversight. In brief, the exact same conditions that led the Commission to the Order No. 1000 finding that transmission planning reform is needed remain today. This factual record alone provides sufficient basis for the Commission to reaffirm those findings and engage in a second round of planning, cost allocation, and oversight reform.

1. *Most transmission built in recent years is not subject to Order No. 1000's regional planning requirement*

Order No. 1000 was intended to "support the more efficient and cost-effective development of transmission facilities" and "address the opportunities to engage in undue discrimination by public utility transmission providers."[86] Since Order No. 1000 was issued, however, the Commission has approved tariff provisions that serve to undermine its own objectives under Order

[84] ANOPR ¶ 37.
[85] *Id*.
[86] Order No. 1000 ¶ 59.

No. 1000's regional planning and competitive procurement requirements, as the examples below demonstrate. 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."[87] These exceptions to regional planning now drive most of the transmission projects in planning regions. As described in more detail below, in non-RTO regions, regional planning is functionally non-existent.

a. In planning regions, exceptions from regional planning now constitute the vast majority of approved projects

PJM: Shortly after Order No. 1000 was issued, PJM and its Transmission Owners entered into an agreement[88] to pursue "mutually agreeable" Order No. 1000 compliance filings and establish that communications between PJM and Transmission Owners related to Order No. 1000 compliance filings was privileged and confidential.[89] At the same time that PJM was engaging in an open stakeholder process to develop its Order No. 1000 compliance, it joined something that appears much like a shadow stakeholder process working on the same issue. A related 2017 agreement[90] extends this treatment to transmission related filings generally. Although lack of transparency into PJM-transmission owner deliberations makes it impossible to ascribe cause and effect, we note that PJM has implemented exceptions to regional planning in ways that FERC has found to violate both PJM's tariff and Order No. 1000.[91] PJM has also taken the unusual step of

[87] 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, The Brattle Group (Apr. 2019).
[88] Confidentially and Common Interest Agreement (September 13, 2011), *available at* https://go.pjm.com/e/678183/ommon-interest-agreements-ashx/5dpsq/249778337?h=SzdOKOVpXgNa8EFvscO783ycAgnNkkiniCMCmFaGeHk.
[89] *Id.* at 2-3.
[90] Confidentiality and Common Interest Agreement (January 24, 2017), *available at* https://go.pjm.com/e/678183/ommon-interest-agreements-ashx/5dpsq/249778337?h=SzdOKOVpXgNa8EFvscO783ycAgnNkkiniCMCmFaGeHk.
[91] *See* Order on Section 206 Investigation and Directing Compliance (June 18, 2020), 171 FERC ¶ 61,212.

overriding a stakeholder vote to discipline use of Order No. 1000 end-of-life exceptions, instead filing a transmission owner proposal with FERC.[92]

The outcome has been to facilitate widespread use of exceptions to Order No. 1000's planning and competition mandates. In PJM, the vast majority of projects approved both in terms of numbers and total cost are non-competitive owner-initiated projects. For example, in 2019, PJM approved 80 regionally planned baseline projects totaling $1.27 billion[93] versus 383 transmission owner-planned supplemental projects totaling $3.75 billion.[94] In 2020, these numbers were even more stark: PJM approved 43 baseline investment projects totaling $413 million[95] versus 236 supplemental projects at a total cost of $4.7 billion.[96] In these two years, owner-initiated projects constituted 75% and 91% respectively of total transmission investments approved. Competitive procurement has been even worse, with a study by The Brattle Group finding that from 2013 to 2017, only five percent of transmission investment in PJM was made under open competitive processes.[97] Local or "end of life" projects are now responsible for the vast majority of new transmission built in PJM. Since Order No. 1000 went into effect, spending on these local projects has tripled and is now three times greater than spending on regional projects.[98] Thus, while PJM has overseen a significant amount of transmission investment since 2011, most of those

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[92] *See* Request for Rehearing of the Joint Stakeholders, at 4-7, Docket ER20-2308 (Jan. 19, 2021).
[93] PJM, *2019 Regional Transmission Expansion Plan*, at 4 (Feb. 29, 2020), https://www.pjm.com/-/media/library/reports-notices/2019-rtep/2019-rtep-book-1.ashx?la=en.
[94] *Id*. at 50.
[95] PJM, *2020 Regional Transmission Expansion Plan*, at 4 (Feb. 28, 2021), https://www.pjm.com/-/media/library/reports-notices/2020-rtep/2020-rtep-book-1.ashx.
[96] *Id*. at 58.
[97] Johannes P. Pfeifenberger, et. al., *Cost Savings Offered by Competition in Electric Transmission*, at 5, The Brattle Group (Apr. 2019).
[98] PJM Transmission Expansion Advisory Committee, Project Statistics (May 12, 2020). Annual spending on Supplemental Projects ballooned in the aftermath of Order No. 1000. Between 2005 and 2013, spending on supplemental projects was $1.25 billion a year. That number increased to $3.73 billion a year from 2014 to 2019. At the same time, spending on regional projects declined from $2.76 billion to $1.86 billion per year. *See id*.

investments are made without any assessment of whether they are cost effective relative to regional alternatives.[99]

SPP: In SPP, most transmission upgrades coming out of the planning process both in terms of numbers and total cost are non-competitive reliability projects. For example, the 386 transmission projects currently included in SPP's transmission expansion plan have a total estimated cost of $3.2 billion. Only three of the 386 current projects are owned by independent transmission companies, with twelve projects having ownership status coded as "to be determined."[100]

Two hundred forty-one of the 386 projects in SPP's current plan are "regional reliability" projects totaling $1.7 billion in estimated costs, representing 51% of estimated total costs across all projects currently included in the expansion plan. In contrast, only 44 of the 386 projects are "economic" projects, with an estimated cost of $419 million, representing 13% of estimated costs across all projects.[101]

In addition, a lack of clarity surrounding Order No. 1000 requirements has stifled transmission planning efforts in SPP. A consistent lack of resources dedicated to meeting the requirements of Order No. 1000 in SPP region has resulted in delays and inconsistent planning efforts. Earlier this year, SPP staff proposed a "mitigation plan" to address transmission expansion planning backlogs and delays. One option presented by staff was to limit the upcoming

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[99] *See* Rob Gramlich & Jay Caspary, *Planning for the Future: FERC's Opportunity to Spur More Cost-Effective Transmission Infrastructure*, at 25, ACEG (Jan. 2021) ("[T]he majority of [transmission] 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 replaces existing infrastructure.").

[100] Data pulled from Southwest Power Pool website, *Integrated Transmission Planning*, *available at* https://spp.org/engineering/transmission-planning (last accessed Oct. 10, 2021).

[101] *See id*.

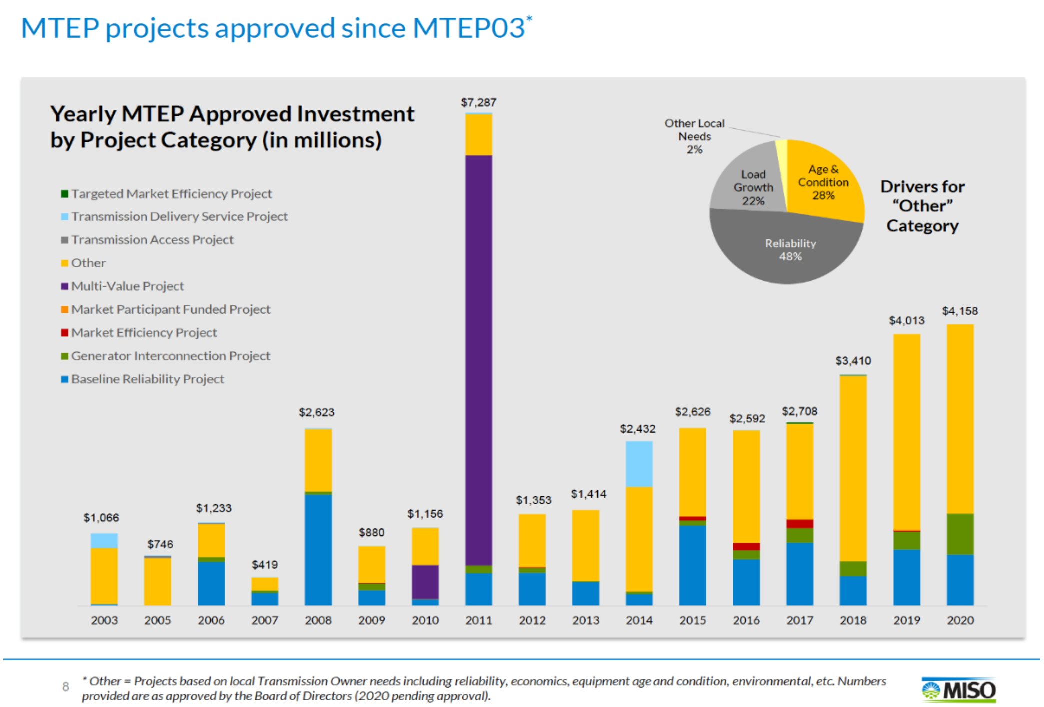
transmission planning year study scope to "reliability only" planning.[102] SPP staff cited a lack of capacity and resources to complete a full study in the upcoming planning year, one which would include economic and public policy considerations as required by Order No. 1000. SPP staff and leadership concluded that they would not need to seek a waiver from FERC in order to proceed with the limited study process proposed by staff.

Significant problems with the planning process in SPP include the futures and other assumptions that help ensure that less transmission appears to be needed or beneficial. SPP has a track record of underestimating the growth of renewable resources. In several ITPs the assumptions for wind growth over a ten-year horizon are met before the study is completed. This results in a failure to identify important transmission needs and solutions and impacts planning for a reliable cost-effective grid. Other assumptions adopted also tend to produce this result. Because SPP makes decisions based upon its members' votes, self-interest rather than good planning often controls the outcome. As a result, large network upgrades that should have been examined in the planning process are pushed into the generation interconnection study process, where the participant funding mechanism frequently fails to provide solutions and cost allocation places all of the burden on generator interconnection customers.

MISO: MISO has not successfully planned for large-scale regional lines since the multi-value project ("MVP") lines which were approved in 2010 and 2011. Until 2013, MISO approved seventeen MVP projects (the multi-value projects that satisfy Order 1000's regional planning requirements under MISO's MTEP process), which generated $3 in benefits for every $1 spent to

[102] Southwest Power Pool. Presentation to the Board of Directors, *ITP Mitigation Proposal Update* (July 2021), *available at* https://spp.org/documents/65012/bod%20mc%20materials%2020210727%20v3.pdf (last accessed Oct. 10, 2021).

build those projects.[103] Those projects supported the deployment of 14,000 of wind power and have played a crucial role in keeping the lights on, saving an estimated $18 billion in outages and high energy prices.[104] It is noteworthy that the MVP projects were approved before the publication of Order No. 1000. As the below chart shows, with the exception of 2011, the vast majority of transmission projects approved through the MTEP process have been projects that address local reliability, end of life, or interconnection issues rather than projects that address regional issues. Though MISO conducts regional planning, with the exception of the MVPs, it has not resulted in the approval of regional lines.[105]



[103] *See* Alliance for Affordable Energy, *An Entergy-Run Transmission Grid is Bad for Affordability, Climate Resilience and Efficiency* (Sept. 15, 2021), https://www.all4energy.org/watchdog/an-entergy-run-transmission-grid-is-bad-for-affordability-climate-resilience-and-efficiency.
[104] *See id*.
[105] MISO has approved seven market efficiency projects (2015, 2016, 2017 and 2019). These projects primarily resolve localized congestion relief.

As the chart above demonstrates, nearly all new transmission in MISO is based on local needs and thus built outside of the regional planning process.[106] Immediate need reliability projects and baseline reliability projects are not subject to the same obligations as regional projects and, while needed to maintain the reliability of the system, fundamentally undermine the regional planning process.

MISO's transmission planning process does not appear to meet the standard of eliminating the "opportunity and incentive" for anticompetitive behavior. In 2012, the Department of Justice ("DOJ") was investigating whether transmission owner Entergy exercised its control over its transmission system and dominant fleet of gas-fired power plants to exclude rival operators of low-cost combined-cycle gas turbine ("CCGT") power plants from competing to sell long-term power. In particular, the DOJ had been evaluating whether Entergy's practices had effectively foreclosed these more efficient rivals from obtaining long-term firm transmission service.[107] The DOJ ended this investigation based on Entergy's stated intent to join an RTO, speculating that a "a third party with the incentive to make efficient transmission investments" would "elimin[ate] Entergy's ability to maintain barriers to wholesale power markets."[108]

Although we appreciate the DOJ's optimism, Entergy's MISO membership has instead become a case study in how transmission owners can maintain opportunity and incentive for anticompetitive behavior while being RTO members. According to the FERC Commissioner who oversaw the process, preserving the opportunity for anticompetitive behavior began with the

[106] *See* MISO Transmission Expansion Plan 2020 (MTEP20), Appendix A. *See also* https://cdn.misoenergy.org/20210915%20System%20Planning%20Committee%20of%20the%20BOD%20Item%2006%20Preliminary%20MTEP%202021%20Review588027.pdf, slide 5 (showing that most projects approved by MISO are "based on local needs.").

[107] Justice Department, *Statement on Entergy Corp.'s Transmission System Commitments and Acquisition of KGen Power Corp.'s Plants in Arkansas and Mississippi* (2012), *available at* https://www.justice.gov/opa/pr/justice-department-statement-entergy-corp-s-transmission-system-commitments-and-acquisition.

[108] *Id.*

choice to join electrically distant MISO rather than adjacent SPP.[109] Since Entergy joined MISO, MISO has proposed to carve out Entergy's service area from an otherwise promising proposal building on their Multi-Value Project approach.[110] Instead, MISO stakeholders were presented an Entergy-authored proposal to constrain benefits analysis and cost allocation for projects affecting Entergy's generation assets.[111] Ironically, a vote on this proposal was postponed after a large-scale failure of Entergy's transmission system.

ISO-NE: Similar to other RTOs, regional transmission planning in ISO-NE is functionally non-existent. Virtually all projects approved by ISO-NE in 2020 and 2021 were non-competitive owner-initiated projects.[112] Further, most of these projects were reliability upgrades and none of the projects were "public policy transmission upgrades," *i.e.*, "addition[s] or upgrade[s] designed to meet transmission needs driven by public policy requirements."[113] Indeed, while ISO-NE has planned or proposed $1.1 billion in transmission upgrades through the end of the decade, all of these upgrades are for reliability reasons.[114] The competitive Boston 2028 procurement process, described below in greater detail, which was officially initiated for reliability reasons, had the potential to integrate state policies regarding decarbonization and renewables. However, ISO-NE's

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[109] Former Commissioner John Norris, quoted in The Lens NOLA (October 5, 2021): "My opinion now, having reflected on this and seeing how they've acted since joining MISO in 2013, I think largely it was because there's a bottleneck of where Entergy joined into MISO. As long as they can maintain that bottleneck, they can really restrict power flows in both directions. Joining MISO was more of a strategy by Entergy I think that's consistent with what they've done, which is try and protect themselves from competition."

[110] *See* MISO Regional Expansion Criteria and Benefits Working Group ("RECBWG"), *MISO'S LRTP Cost Allocation Proposal* (July 28, 2021), *available at* https://cdn.misoenergy.org/20210728%20RECBWG%20Item%2002%20LRTP%20Cost%20Allocation%20Proposal574153.pdf.

[111] *See* MISO RECBWG, *Review of Stakeholder Feedback on MISO July28th Cost Allocation Proposal* (August 12, 2021), *available at* https://cdn.misoenergy.org/20210812%20RECBWG%20Item%2002a%20Stakeholder%20Feedback%20Review578907.pdf.

[112] June 2021 Final Project List, ISO-NE (June 2021), *available at* https://www.iso-ne.com/system-planning/system-plans-studies/rsp/; June 2020 Final Project List, ISO-NE (June 2020), *available at* https://www.iso-ne.com/system-planning/system-plans-studies/rsp/.

[113] *Id.*; Types of Transmission Upgrades, ISO-NE (Sept. 2020), *available at* https://www.iso-ne.com/system-planning/system-plans-studies/rsp/.

[114] Draft 2021 Regional System Plan, ISO-NE, at 101-102 (Sept. 3, 2021), *available at* https://www.iso-ne.com/system-planning/system-plans-studies/rsp/.

ultimate selection of a proposal solely for reliability reasons reflects its general failure to make transmission planning decisions that incorporate a broader consideration of regional needs.

At the close of 2019, ISO-NE announced its first and only solicitation for transmission solutions pursuant to Order No. 1000, the Boston 2028 Request for Proposal.[115] ISO-NE initiated this solicitation to ensure reliability following the anticipated closure of Exelon's Mystic Generating Station and did so under Order No. 1000 because the upgrades were "deemed to not be time-sensitive."[116] To the extent FERC Order No. 1000 was intended to promote the integration of state policy considerations, this procurement failed and also likely increased total costs for the region.

ISO-NE received 36 proposals in the Boston 2028 procurement process.[117] It cut short the procurement at Phase 1 without proceeding to a comparison of projects as planned in Phase 2, declaring that only one proposal met its requirements.[118] It awarded the procurement to a joint proposal by New England's two largest investor-owned utilities, Eversource and National Grid.[119] In doing so, ISO-NE passed over proposals that would have offered transmission solutions for offshore wind, integrated other clean energy, and supported the retirement of additional fossil fuel-fired generators in the region in compliance with state decarbonization and offshore wind procurement goals.[120] While ISO-NE deemed its process successful because it resulted in an ostensibly least-cost set of limited upgrades rather than more comprehensive investments,[121] the

[115] *See* https://www.iso-ne.com/static-assets/documents/2019/12/boston_2028_rfp_announcement.pdf.
[116] *See* https://isonewswire.com/2019/12/20/iso-ne-releases-rfp-for-boston-area-transmission-upgrades/.
[117] *See* https://isonewswire.com/2020/07/24/iso-ne-makes-selection-in-first-order-1000-transmission-rfp/.
[118] *See* https://www.utilitydive.com/news/simple-or-a-band-aid-iso-ne-leans-toward-eversourcenational-grid-49m/580953/.
[119] *See* https://isonewswire.com/2020/07/24/iso-ne-makes-selection-in-first-order-1000-transmission-rfp/.
[120] *See* https://www.iso-ne.com/static-assets/documents/2020/07/final_boston_2028_rfp_review_of_phase_one_proposals_appendix_a.pdf. *See also, e.g.,* https://www.utilitydive.com/news/simple-or-a-band-aid-iso-ne-leans-toward-eversourcenational-grid-49m/580953/; https://energynews.us/2020/09/01/groups-say-boston-electric-grid-upgrades-should-anticipate-offshore-wind/.
[121] *See* https://isonewswire.com/2020/07/24/iso-ne-makes-selection-in-first-order-1000-transmission-rfp/.

outcome failed to co-optimize reliability objectives together with other goals such as connecting new offshore wind resources to the regional grid.[122] As a consequence, the region remains without the transmission needed to support New England states' decarbonization mandates and clean energy procurements, and must spend additional funds to achieve those goals separately from other investments.[123] By siloing investment decisions, such as the Boston 2028 "reliability" upgrade, into overly narrow "reliability" and "economic" buckets without broader consideration of regional needs, ISO-NE fails to co-optimize investments by combining multiple needed outcomes into a single project, which is neither least-cost nor efficient.

b. <u>Regional planning pursuant to Order No. 1000 in non-RTO regions is functionally non-existent</u>

SERC: In the Southeast, the Southeastern Regional Transmission Planning (SERTP) process is the only regional transmission expansion planning opportunity that currently exists for public stakeholder participation. However, SERTP is an ineffective and broken planning process, lacking opportunity for meaningful public input and participation by independent transmission developers.

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[122] *See, e.g.*, https://energynews.us/2020/09/01/groups-say-boston-electric-grid-upgrades-should-anticipate-offshore-wind/.

[123] In connection with ISO-NE's persistent failure to reflect state policy objectives in its decision-making, in October 2020 the New England States released a joint Vision Statement finding that "[t]o help achieve a decarbonized system, as required by laws and mandates in Connecticut, Maine, Massachusetts, Rhode Island, and Vermont, it will be necessary to fully plan how to unlock wind resources located far from load centers, to integrate significant levels of new offshore wind resources and new hydro resources, and to facilitate widespread adoption of DERs." *See* New England States' Vision for a Clean, Affordable, and Reliable 21st Century Regional Electric Grid, at 3-4, Oct. 16, 2020, available at https://nescoe.com/resource-center/vision-stmt-oct2020/. The states ultimately issued a joint request that ISO-NE "[i]nitiate a regional transmission planning effort that provides a high-level transmission system plan to meet the needs of the States' energy transition," including the use of "scenarios that have been developed and used in various States' analyses of pathways to decarbonization as a starting point." *See* Report to the Governors – Advancing the Vision, by the Managers of the New England States Committee on Electricity, June 2021, at 10, available at https://nescoe.com/resource-center/advancing_the_vision/. In response, ISO-NE has launched a study seeking to better understand how to meet the transmission needs of the region, given prevailing public policy including decarbonization goals adopted by states across the region. *See* https://www.iso-ne.com/static-assets/documents/2021/09/iso-ne-response_to_states-vision_sept_23_2021.pdf. However, concerns persist that ISO-NE's planning and cost-allocation processes are not designed to satisfy broad regional needs and that the states' representatives do not even have a vote in ISO-NE decision-making.

SERTP's regional transmission expansion plan process does not provide basic and essential information that is necessary for meaningful public engagement. For example, the SERTP regional plan does not provide estimates of the costs of transmission projects proposed, and ultimately included, in the plan, leaving public stakeholders unable to evaluate whether the proposed projects contained in the plan are cost-effective and creating a barrier to consideration of alternatives from public stakeholders. Additionally, SERTP members restrict public access to essential planning information, requiring public stakeholders to apply for CEII clearance prior to accessing information and data that is often open to the public in other planning regions.[124] Essentially, the SERTP process relies on members to self-identify generation changes within the next 10 years and those utilities are under no obligation to present realistic demand forecasts. The result are often barebones assertions that go untested within the SERTP process, such as AECI's statement that it "has no generation assumptions expected to change throughout the ten year planning horizon for the 2021 SERTP Process."[125] Further, none of the projects provided in the preliminary transmission expansion plan for 2021 have any transmission solutions or upgrades between two independent members.[126] Unsurprisingly, then, transmission projects by independent developers do not appear to have been included any regional transmission expansion plans to date. Furthermore, zero pre-qualification applications by independent transmission developers have been submitted and approved by SERTP for at least the last nine years.[127] Only two regional transmission projects have been identified in the SERTP planning process since 2014.[128]

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[124] *See* http://www.southeasternrtp.com/secure_area.cshtml.
[125] *See* http://www.southeasternrtp.com/docs/general/2021/2021-SERTP-2nd-Quarter-Meeting-Presentation.pdf, slide 12.
[126] *See* http://www.southeasternrtp.com/docs/general/2021/2021-SERTP-2nd-Quarter-Meeting-Presentation.pdf.
[127] *See* Southeastern Regional Transmission Planning, "Archive," *available at* http://www.southeasternrtp.com/archive.cshtml#2020 (last accessed October 10, 2021).
[128] *Id*.

The incorporation of Public Policy Requirements (PPRs) is a particular failing of the implementation of Order No. 1000's requirements in the 10-year transmission expansion plan process undertaken annually by the SERTP members. The SERTP sponsor utilities accept requests from public stakeholders to study transmission needs driven by PPRs once a year. Under this process, public stakeholders must submit a form request to the SERTP sponsors, detailing the policy requirement and explaining possible transmission needs that would be driven by the requirement. In 2015, 2016, and 2017, several non-utility stakeholders made requests to evaluate state and federal public policies, including North Carolina's Renewable Energy and Energy Efficiency Portfolio Standard ("NCREPS"), the Clean Power Plan, and several other EPA regulations.[129] The response provided by SERTP sponsors to the PPR study requests were rejected as either "premature" or unnecessary based on the bald assertion that any impact of the PPRs would have been accounted for by the load serving entities. For instance, the SERTP sponsors claimed that any resource changes that would occur as a result of the NCREPS would "be evaluated through Duke Energy's local transmission planning process. Until such resource decisions are made, typically through state-regulated processes, the proposed PPRs do not drive a transmission need(s)." Thus, based on the process outlined in both the SERTP member's written response to the PPR requests as well as discussions in SERTP stakeholder meetings, it is unclear how a public policy recommendation would ever be seriously considered in the SERTP. The only thing that is clear is that it will not come from the SERTP members themselves. From 2018 through 2021, SERTP has stated,

> The SERTP did not receive any input or proposals for possible transmission needs driven by Public Policy Requirements for the [applicable calendar year] planning

[129] *See* http://www.southeasternrtp.com/docs/general/2015/2015%20SERTP%20PPR%20Results.pdf; http://www.southeasternrtp.com/docs/general/2016/2016%20SERTP%20PPR%20Results.pdf; http://www.southeasternrtp.com/docs/general/2017/2017%20Planning%20Cycle%20Transmission%20Needs%20Driven%20by%20Public%20Policy%20Requirements.pdf.

> cycle. Therefore, no possible transmission needs driven by Public Policy Requirements have been identified for further evaluation of potential transmission solutions in the [applicable calendar year] SERTP planning cycle.[130]

Western Interconnection: Following the adoption of Order No. 1000 in July 2011, western transmission owners decided to use their existing organizations, including the CAISO, WestConnect, Northern Tier Transmission Group ("NTTG"), and ColumbiaGrid, to comply with the new requirements. In many respects, their assessments have simply rolled up utility power and transmission plans. The planning regions have prepared base cases, including new resources and transmission expansion planned by utilities for the next 10 years, considered a small number of independent transmission projects submitted for review, and conducted a basic system adequacy and reliability check.

The resulting regional plans have generally selected most or all incumbent transmission projects, but no independent developer or conceptual projects have been selected through several planning cycles. Furthermore, while the plans have validated basic reliability under the assumptions of the underlying utility plans, the planning regions have not been receptive to suggestions for wider scenario assessment or conceptual transmission projects as proposed by outside stakeholders, and in some cases have not conducted studies in a transparent way.

Like PJM and SPP, in the non-regulated markets in the Western Interconnection, transmission plans have largely served individual utilities' reliability needs within their own balancing areas. Since each utility is either not rate-regulated or regulated by a state commission, nearly all projects are non-competitive, owner-initiated projects designed to meet only reliability needs. In 2019, the Brattle Group reported that none of the transmission expansion investments in

[130] *See,* e.g., http://www.southeasternrtp.com/docs/general/2021/2021-SERTP-PPR-Results.pdf.

non-ISO regions including in the Western Interconnection had been subject to the regional planning entities' competitive transmission processes through 2017.[131]

The rate of investment also lags behind the growth in renewable energy, as reflected by the growing interconnection queues. For example, between 2013-17, the non-CAISO transmission investment in the Western Interconnection totaled a mere $5.2 billion on an annual basis. Despite the rich renewable energy resources and increasing renewable portfolio standards in a number of western states, WestConnect analyzed nine non-incumbent projects in its 2016–17 planning process, but did not identify any projects that warranted inclusion in the Base Transmission Plan.[132] In addition, WestConnect did not identify any reliability, economic, or public policy needs in the 2016–17 study and therefore did not consider the projects for regional cost allocation.[133]

Furthermore, regional transmission lines which are presented for state utility commission review are not necessarily subjected to the regional transmission planning review and approval, which would identify the most efficient plan to serve all regional needs. In Colorado, for example, transmission plans from each utility are filed with the state commission for compliance purposes, but they do not incorporate joint planning to meet regional needs and there is minimal commission review.[134]

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[131] The Brattle Group, *Cost Savings Offered by Competition in Electric Transmission* (Apr. 2019) 47, *available at* https://brattlefiles.blob.core.windows.net/files/15987_brattle_competitive_transmission_report_final_with_data_tables_04-09-2019.pdf.

[132] *Id.*(*citing* WestConnect, Regional Study Plan, WestConnect Regional Transmission 2016–17 Planning Cycle, March 16, 2016, p. 39, *available at* https://doc.westconnect.com/Documents.aspx?NID=17180&dl=1).

[133] WestConnect, Regional Transmission Plan, WestConnect Regional Transmission Planning 2016–17 Cycle, at 39 (Dec. 20, 2017), *available at* https://doc.westconnect.com/Documents.aspx?NID=18010&dl=1.

[134] Colorado Resource planning rules, 4 Code of Colo. Regs. 723-3, Rule 3627 ("Notwithstanding the apparent shortcomings of the Transmission Planning Rules and the transmission plans they cause the Utilities to file on a biennial basis, the ALJ concludes that the 10-Year Transmission Plan filed in this Proceeding complies with the requirements of Rule 3627 and is adequate to meet the present and future energy needs of Colorado in a reliable manner consistent with the Commission's review of the Utilities' two previous plans from 2016 and 2018, as addressed by Decision Nos. R17-0580 and C17-1079 and Decision No. R18-1139, respectively.

In addition, the Order No. 1000 interregional coordination process has essentially become a box checking exercise. The four original planning regions (now three with the combination of NTTG and ColumbiaGrid into NorthernGrid) have conducted an annual interregional coordination conference. Early hopes for open discussion and consideration of transmission alternatives meeting needs across planning region boundaries never came to pass. By 2021, the annual conference had become a single morning online session with report-outs from the three western planning regions on their ongoing planning processes, and little time for stakeholder questions and input.

2. *Transmission projects outside of regional planning are not subject to meaningful review*

Transmission projects seeking cost recovery file at the Commission under FPA Section 205, where the investments are, in theory, subject to prudence review. However, since at least 1980, FERC has treated transmission investments as presumptively prudent.[135] Few, if any, applications for transmission cost recovery are rejected by FERC. Most are approved with no review of the investment whatsoever.

While this state of affairs is problematic in and of itself, it raises additional problems in the context of regional planning. Regional planning processes are required to review the costs and benefits of proposed projects and identify more efficient or cost-effective solutions. Projects that have emerged from regional planning thus have passed a round of (at least nominally) independent prudence review, giving some confidence that they may reasonably be approved by FERC without detailed further review. Much as the Commission may approve a formula-based rate by finding the process just and reasonable rather than reviewing each individual result, the reasonableness of regional transmission investments relies on the planning processes.

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[135] Ari Peskoe, *Is the Utility Syndicate Forever?* 42 Energy L.J. 1, 58, n. 387 (2021).

For projects not arising from regional planning, those safeguards are not in place. Transmission owners can have high confidence that by avoiding regional planning, they also avoid review of their investments. For all practical purposes, "FERC cost of service regulation is cost pass through regulation with little scrutiny of costs."[136] By creating an attractive alternative to participating in regional planning, the presumption of transmission investment prudence fatally undermines the transmission planning regime.

Order No. 1000 does not require all new transmission to go through the regional planning process. It permits exceptions for transmission needed to serve immediate reliability needs.[137] As a result, the Order creates a perverse incentive for utilities to avoid the regional planning process and instead build transmission through the patchwork of exceptions that let utilities build transmission that is not part of a regional plan. These exceptions have put the country on a path to building a transmission system that fails to fully consider the extent to which large projects can improve reliability, harmonize the country's electric grid with state policies, and provide cheaper solutions to the country's energy needs. The result has been insufficient and inefficient transmission investment, leading to clogged interconnection queues, barriers to competition, and higher prices for generation owners and end-use customers.

3. *Order No. 1000 has not resulted in any significant interregional transmission projects*

The ANOPR asked whether reforms to the current interregional coordination process are needed to implement a process that identifies geographic zones that have the potential for the development of large amounts of new generation, particularly renewable resources.[138] The fact

[136] Paul Joskow, *Competition for Electric Transmission Projects in the U.S.: FERC Order 1000*, at 17.
[137] Order No. 1000 ¶ 262 ([O]ur actions today are not intended to diminish the significance of an incumbent transmission provider's reliability needs or service obligations.").
[138] ANOPR ¶ 56.

that no significant interregional transmission project has been approved since Order No. 1000 went into effect[139] despite a large amount of evidence suggesting that such projects would yield net benefits[140] demonstrates that existing interregional transmission planning practices are unjust, unreasonable, and unduly discriminatory that interregional planning reform is sorely needed.

While Order No. 1000 attempted to address interregional coordination, it did not specifically address interregional planning, and selecting and implementing projects to address needs across planning regions remains extremely challenging. Order No. 1000 found that the lack of effective interregional coordination could render transmission providers "unable to identify more efficient or cost-effective solutions to the individual needs identified in their respective local and regional transmission planning processes."[141] Order No. 1000 does not specify how close to an ideally efficient and cost-effective process transmission planning must get to be just and reasonable, but the near-total lack of results from Order No. 1000 concerning interregional coordination saves us from having to make any fine distinctions. The lack of meaningful change in outcomes since 2011 demonstrates that the Order No. 1000 finding that existing interregional transmission coordination practices are unjust, unreasonable, and unduly discriminatory stands.

When FERC issued Order No. 1000 in 2011, it found that its then-existing Order No. 890 transmission planning mandates failed to adequately account for the potential benefits that could be derived if neighboring regions were able to develop interregional transmission facilities.[142]

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[139] In 2009, along with the Eastern Interconnection States Planning Committee composed of state commissioners, the utilities and RTOs in the eastern interconnect formed the Eastern Interconnection Planning Collaborative (EIPC). *See* https://eipconline.com/. The EIPC runs an opaque inter-utility and inter-RTO group closed to public discussion, participation and input. Significantly it is closed to any state commissioner participation. The state effort was funded temporarily with federal funds that expired leaving only the utilities and RTOs to run a forum for bi-lateral discussions closed to the public and states. The results of the EIPC group speak for themselves: a number of studies and little to no substantial interregional collaboration on planning or transmission projects. It has become a forum for closed discussions and study and no action and no effective planning. PIOs urge FERC to avoid this ineffective model "to plan to not plan," the failure of which speaks for itself.

[140] *See* Brattle-Grid Strategies Report, at 15-18.

[141] Order No. 1000 ¶ 368.

[142] *Id*. ¶¶ 369-70.

Order No. 1000 therefore directed RTOs to establish procedures with neighboring RTOs that have existing interconnections to coordinate and share regional plans to identify interregional planning solutions that are more efficient or cost effective than separate regional plans.[143]

Order No. 1000 requires that this process include "a formal procedure to identify and jointly evaluate inter-regional transmission facilities."[144] Rather than requiring joint planning, FERC only mandated a coordinated approach, where neighboring regions plan separately then compare results and jointly evaluate any potential interregional projects that arise.[145] A key problem in implementing this approach has been that the agreements between RTOs have a multi-stage approval process for interregional projects that requires a solution to go through a coordinated interregional process as well as two separate regional approval processes, the so-called "triple hurdle" problem.[146] Because potential solutions must successfully meet three separate benefit-to-cost ratios, it is almost never the case that all three processes will result in one agreed-upon solution. Thus, interregional projects almost never move forward. Instead, interregional project development has been limited to a small number of projects, primarily in the form of HVDC lines with associated capacity rights and projects sited in one region but electrically connected in another region. Otherwise, projects have generally been proposed and developed to address the internal needs of a particular region.

In addition, interregional coordination processes only allow for the evaluation of projects that address an identical need in both regions. Thus, an interregional project meeting a reliability

[143] *Id.* ¶¶ 374-481.
[144] *Id.* ¶ 435.
[145] Order No. 1000-A ¶ 493.
[146] 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 inter-regional transmission solutions in its respective regional transmission planning process." Midcontinent Independent System Operator, Inc., Southwest Power Pool, Inc., 168 FERC ¶ 61,018, ¶ 2 (July 16, 2019). An approved project must first "be vetted through both RTO regional processes and approved by each RTO's Board of Directors." *Id.* ¶ 3. Recent reforms have collapsed one part of this process.

need in one region but not a reliability need in another region cannot be considered, even if it provides some other benefit in that region. Further, some interregional planning processes exclude upgrades below a specific project size or voltage-level threshold, resulting in some beneficial projects not being considered.[147]

Beyond these structural hurdles, this after-the-fact coordination approach suffers from moving interregional planning out of RTOs' main planning workflow. Much as, we suspect, the mandated Paperwork Reduction Act[148] portion of FERC rulings rarely enjoy the Commission's full attention, interregional coordination meetings tend to be sleepy affairs, and often devolve into little more than "check the box" exercises.

B. CRITERIA CURRENTLY USED IN TRANSMISSION PLANNING FAIL TO ACCURATELY ACCOUNT FOR BENEFITS OR ALLOCATE COSTS

The failure to conduct planning at the interregional and regional level has several negative consequences for transmission customers, the first of which is the inability to maximize efficiencies of scale to eliminate redundant build outs. Additionally, the vast majority of current transmission projects are narrowly focused either solely on network reliability or connecting the next generator in the interconnection queue and ignore any other potential benefits or economies of scale or other efficiencies that might occur by considering multiple future needs.[149] To the rare extent that regional planning goes beyond these immediate needs, in most cases transmission planners still compartmentalize transmission into siloed projects that separately examine projects

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[147] For example, the MISO and SPP interregional planning process does not include projects under 345 kV.
[148] 44 U.S.C. 3507(d).
[149] Brattle-Grid Strategies Report at iii, 2, noting that "[w]hile the U.S. has recently been investing between $20 to $25 billion annually in improving the nation's transmission grid, 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.)

with reliability, economic, public policy, or generator-interconnection benefits instead of conducting a multi-value analysis that considers them simultaneously.[150] As a result, current transmission planning approaches and processes ignore opportunities to benefit from economies of scale that come from "up-sizing" transmission projects to capture additional benefits, including: congestion relief, reduced transmission losses, increased flexibility to respond to changing market or system conditions, and facilitating larger regional or interregional solutions that more cost-effectively interconnect the renewable and storage resources needed to meet public policy goals.[151] One common example of this is the routine use of in-kind replacement of aging existing facilities, which "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."[152]

Current transmission planning approaches are also primarily reactive instead of proactive and routinely fail to engage in scenario-based planning that prepares the grid for a larger number of possible futures, such as future extreme weather impacts or anticipated increases in renewable generation or demand from electric products,[153] making the grid ill prepared for steady or sudden impacts where transmission constraints can prove inconvenient – or catastrophic.

This failure to appropriately consider and maximize a wide array of benefits also results in an unfair and inefficient allocation of costs. Because current planning methods routinely fail to consider multiple benefits across the system, they also fail to fairly allocate costs for those paying for them. Planning reactively based on individual projects instead of systematically across a

[150] *Id*. at iii, 31.
[151] *Id*. at 3.
[152] *Id*.
[153] *Id*. at iii.

portfolio underestimates multiple benefits and unfairly burdens fewer parties with the costs.[154] For example, many generator interconnection-related network upgrades could be streamlined and upsized to deliver greater benefits across the system with costs more fairly distributed among the greater number of beneficiaries. Taken together, the failure to conduct transmission planning across a regional (and interregional) portfolio and using a multi-value and scenario-based methodology produces 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" that "systematically results in inefficient infrastructure and excessive electricity costs."[155]

C. THE LACK OF MULTI-VALUE, SCENARIO-BASED REGIONAL AND INTERREGIONAL PLANNING RESULTS IN EXCESSIVE COSTS AND FAILURE TO MEET SYSTEM DEMANDS

The failure to conduct multi-value, scenario-based transmission planning on a regional and interregional portfolio basis is endemic to the grid, as shown in Tables 2 and 3 of the Brattle-Grid Strategies Report:[156]

[154] *Id.* at 4.
[155] *Id*. at iii, 3.
[156] *Id*. at 15, Table 2

TABLE 2. PLANNING AUTHORITIES CURRENT USE OF EFFICIENT PRACTICES

	Proactive Generation & Load	Multi-Value	Scenario-Based	Portfolio-Based[1]	Joint Interregiona Planning
ISO-NE[2]	✗	✗	✗	✓	✗
NYISO[3,4]	✗	✗	✗	✗	✗
– PPTPP only	✓	✓	✓	✓	✗
PJM[5.6]	✗	✗	✗	✗	✗
Florida	✗	✗	✗	✗	✗
Southeastern Regional	✗	✗	✗	✗	✗
South Carolina Regional	✗	✗	✗	✗	✗
MISO (excl. MVP, RIIA)[7]	✗	✗	✗	✗	✗
SPP (ITP)[8,9]	✗	✓	✗	✓	✗
CAISO[10,11]	✓	✗	✓	✗	✓
– TEAM only	✓	✓	✓	✓	✓
WestConnect	✗	✗	✗	✗	✗
NorthernGrid[12]	✗	✗	✗	✗	✗

TABLE 3. PLANNING AUTHORITIES' 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[1]	$0[2]	n/a	$0
NYISO[3]	n/a	n/a	n/a	n/a	n/a
PJM	$4,106[4]	$388.31[5]	$24.69[6]	$101[7]	$0
Florida	n/a	$0[8]	$0[9]	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[10]	$755[11]	$0[12]	$606[13]	$0
SPP	n/a	$213.5[14]	$318.8[15]	n/a	$0
CAISO	n/a	$3.6[16]	$0[17]	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

As a result, current planning processes across the nation result in inefficient investments that foreclose meaningful competition, miss out on economies of scale, and result in consumers paying considerably more for significantly less—less choice, less capacity, less flexibility, less resiliency, and ultimately less reliability. This is the textbook example of unjust, unreasonable, and unduly discriminatory rates and practices.

1. *The lack of holistic regional and interregional transmission threatens reliability*

The failure to conduct multi-variable, scenario-based planning on a regional and interregional portfolio basis is increasingly necessary to meet reliability needs in the face of extreme weather events that are increasing in frequency and intensity and other wide-scale power sector emergencies. Transmission constraints, which can sometimes benefit transmission owners, are also predictable points of failure when generation problems arise. For example, the failure to adequately consider the implications for insufficient interregional transfer capability played a significant role in the August 2020 blackouts in California. A root cause analysis of the event determined that while there was energy availability in the north that could have alleviated the crisis, "transmission constraints ultimately limited the amount of physical transfer capability into the CAISO footprint."[157] CAISO also estimated that during the 2000-2001 energy crisis, $30 billion in consumer costs could have been avoided if additional interregional transmission capacity had been available.[158]

To far more devastating effect, 2021's winter storm Uri provided a stark lesson in the critical importance of interregional transmission in ensuring reliability. Due to the breadth and

[157] Brattle-Grid Strategies Report at 10 (citing 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, at http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf).
[158] *Id.* at 10.

duration of the storm, wide swaths of generating resources in the Central region were incapacitated. Because of its interconnection with the East, MISO was able to import 13 GW of power and deliver some of that to SPP and to the West, enabling those regions to largely avoid blackouts.[159] Some of these lines had been built as part of MISO's MVP process, where power flows had assumed to flow on a prevailing West-to-East flow, but ultimately also providing critical reliability benefits that had not even been considered.[160] ERCOT, on the other hand, had limited its import capacity to a maximum of 0.8 GW—to catastrophic and deadly effect.[161] In addition to the hundreds of lives that were lost due to the power outage,[162] post-storm analysis estimated that additional interregional transmission capacity would have paid for itself in days.[163]

2. *Interregional and regional planning is necessary to meet public policy requirements in a cost-effective manner*

As the Commission established in Order No. 1000, changes in the generation makeup due to shifting customer demands, environmental regulations, and public policy requirements are driving the need for enormous investment in an existing transmission system "that was not built to accommodate this shifting generation fleet."[164] The Commission further held that because the record reports demonstrated "that additional, and potentially significant, investment in new transmission facilities will be required in the future to meet reliability needs and integrate new

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[159] *Id*. at 42.
[160] *Id.*
[161] *Id.*
[162] Peter Aldhous et al., *The Texas Winter Storm And Power Outages Killed Hundreds More People Than The State Says*, BuzzFeed News (May 26, 2021), https://www.buzzfeednews.com/article/peteraldhous/texas-winter-storm-power-outage-death-toll. In addition to the lives lost in Uri, power outages due to extreme weather events also led to the deaths of over 1,000 people in Puerto Rico from Hurricane Maria. *See* Eliza Barclay, *1,427 deaths: Puerto Rico is coming clean about Hurricane Maria's true toll*, Vox (Aug. 9, 2018), at https://www.vox.com/2018/8/9/17670762/puerto-rico-hurricane-maria-death-toll-congress. Eleven people are estimated to have died as a result of power outages in New Orleans during Hurricane Ida linked to the failure of all 8 transmission lines serving the city as well as the natural gas plant Entergy claimed would serve as a blackstart resource. *See* Max Blau et al., *Entergy Resisted Upgrading New Orleans' Power Grid. Residents Paid The Price*, NPR (Sept. 22, 2021), https://www.npr.org/2021/09/22/1039110522/entergy-resisted-upgrading-new-orleans-power-grid-residents-paid-the-price.
[163] Brattle-Grid Strategies Report at 42, 59-60.
[164] Order No. 1000 at 49,851.

sources of generation" it was critical for the Commission to "act now to address deficiencies to ensure that more efficient or cost-effective investments are made as the industry addresses its challenges."[165]

As pointed out by Professor Joskow of MIT, we cannot stumble our way into meeting deep decarbonization requirements mandated by public policies and increasingly by consumer demand:

> In the U.S., most core transmission planning processes do not explicitly include valuations of carbon free resources to meet decarbonization commitments, focusing on traditional reliability and (reluctantly) internal market efficiency (e.g. congestion mitigation) opportunities. Nor do they take account of potential reliability or security of supply benefits that may result from "public policy" projects that seek to improve access to wind, solar, storage, and other carbon-free generators (Single state ISOs in California and New York are a partial exception within their footprints). Unless the direct (decarbonization) and indirect benefits (reliability, market efficiency) of expanding access to and integration of zero or low carbon resources are included in the core transmission planning process, potential transmission projects to support access to and integration of these resources will not be identified and efficiently integrated into the core transmission plan except by accident.[166]

Recent studies continue to indicate that large expansions of transmission are necessary to achieve cost-effective outcomes in accommodating the future generation resource mix; some indicating a need for two to five times the nation's existing transmission capacity by 2050.[167] These studies also demonstrate how holistic regional and interregional transmission planning results in significant system-wide cost reductions compared to the current interconnection queue- and reliability-only driven system currently in use.[168]

A comparative analysis of the costs of interconnecting offshore wind generation into PJM's footprint has produced a particularly compelling example of the magnitude of excess costs that

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[165] *Id.*
[166] P.L. Joskow, *Facilitating Transmission Expansion to Support Efficient Decarbonization of the Electricity Sector*, Economics of Energy & Environmental Policy, Vol. 10, No. 2 (2021) at http://ceepr.mit.edu/publications/working-papers/758.
[167] *See, e.g.*, Brattle-Grid Strategies Report at 10 and Appendix A; E. Larson, et al., *Net-Zero America: Potential Pathways, Infrastructure, and Impacts*, Slide 10, Princeton University, (Dec. 15, 2020), available at https://netzeroamerica.princeton.edu/img/Princeton_NZA_Interim_Report_15_Dec_2020_FINAL.pdf.
[168] Brattle-Grid Strategies Report at 8-12.

come using the interconnection queue to build transmission instead of using a proactive, multi-benefit and scenario-based planning methodology that assesses costs and benefits across the entire regional portfolio. An analysis of the PJM interconnection queue found that integrating 15.5 GW of offshore wind into the PJM footprint had estimated total costs of $6.3 billion.[169] But a proactive, multi-benefit, scenario-driven study conducted by PJM in response to a request by OPSI in 2021 estimated the transmission upgrade costs to bring in 17 GW of offshore wind to be only $3.2 billion *or less* – half or more of the costs that would result from building such interconnection via queue requests, and including an extra 1.5 GW of capacity.[170] PJM also found that the 2021 study resulted in onshore network upgrades that resulted in substantial additional regional benefits such as congestion relief, customer load LMP reduction, and reduced renewable generation curtailments, that would not otherwise have been realized.[171] Meeting public policy requirements also delivers more traditional reliability and customer benefits.

Comparing proactive PJM studies with the results from PJM's individual generation interconnection queue also reveals 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.[172]

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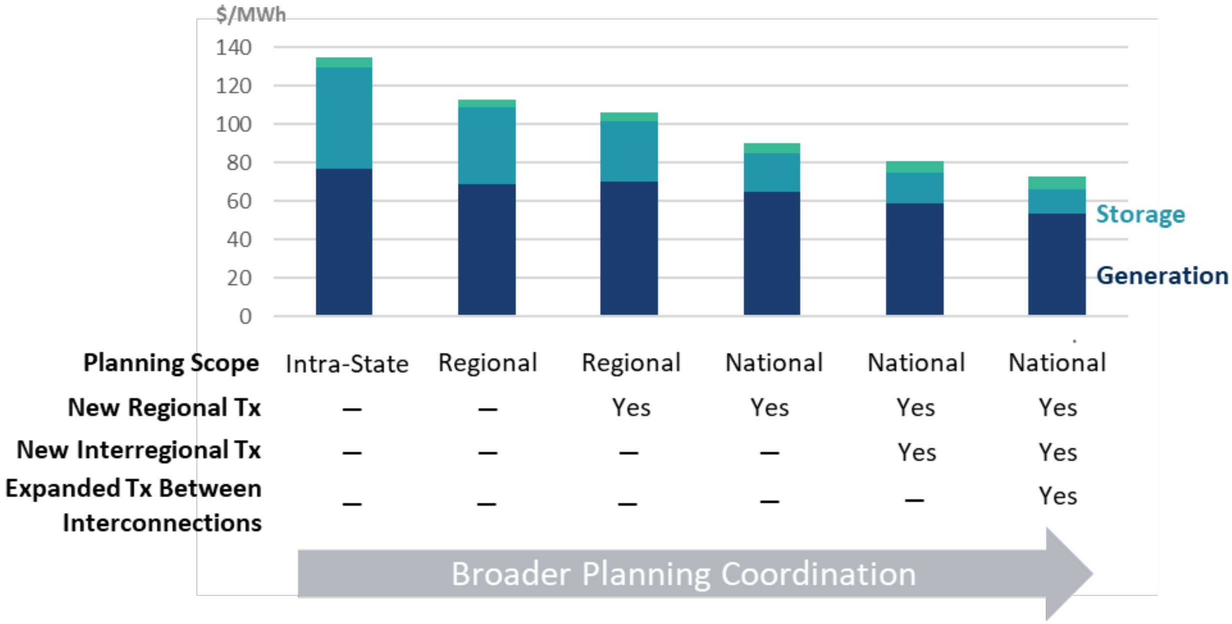
[169] *Id.* at 4-5.
[170] *Id.*
[171] *Id.*
[172] *Id.* at 6.

Other estimates also bolster the potential cost savings from interregional, holistic transmission planning, including an estimate that in combination with a national policy goal for a zero-carbon grid, holistic interregional transmission expansion can reduce overall system costs by over 40% compared to state-by-state efforts:

FIGURE 3. ELECTRICITY SYSTEM COSTS BY TYPE AND TRANSMISSION PLANNING SCENARIO[173]



If anything, there is even more evidence today than a decade ago of the need for holistic transmission planning conducted primarily at the regional and interregional level to maximize access to all resources, estimate all benefits and fairly allocate costs, meet public policy requirements, and provide a resilient, reliable system at just, reasonable, and non-discriminatory rates.

VI. PROPOSED REFORMS

A. IMPROVED TRANSMISSION PLANNING WILL YIELD MULTIPLE BENEFITS

In order to cost-effectively meet the current and future needs of the grid, transmission planning and implementation will require reforms to every phase of the process, starting from the

[173] *Id.* at 11, Fig. 3.

ground up *and* the top down, that do the following: (1) align industry incentives with public policy to help mitigate anti-competitive conduct and ensure an independent and open planning process (2) expand the scope of the initial needs assessment and project identification at every level to avoid redundancies and maximize economies of scale; (3) use multi-value and scenario-based tools to assess the costs and benefits of all projects to determine which combination of projects results in the most cost-effective solution from a system-wide portfolio perspective; (4) refine cost allocation methods to be roughly commensurate with benefits across the regional and interregional portfolio, including those benefits that may vary depending on future scenarios; and (5) coordinate with and approval from stakeholders and various regulatory agencies.[174] As further detailed throughout Section IV, *supra*, such reforms are necessary to curb the exercise of market power and ensure that transmission planning results in rates and practices that are just, reasonable, and not unduly discriminatory.

1. *Economic benefits of holistic transmission planning*

Although far from routine, most of the RTO areas have had experience implementing "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."[175] Results from those experiences have demonstrated repeatedly that this kind of holistic planning results in transmission infrastructure that lowers overall system-wide costs, increases diversity of resource access, and is often critical to realizing public policy goals.[176] One such example is Texas' Competitive Renewable Energy Zone (CREZ) project, which grew out a public policy initiative to develop the economic potential of connecting

[174] Brattle-Grid Strategies Report at 1.
[175] *Id*. at 29.
[176] *Id.* at 24.

wind-rich areas in remote sections of western Texas to population areas.[177] The $7 billion project was designed to interconnect approximately 11.5 GW of wind generation capacity, and after its completion in 2013, wind curtailment fell from a high of 17% down to 0.5%.[178] As is often typical in such large transmission projects, once you build it, others will come; although intended for wind, the CREZ project also opened development of solar capacity in West Texas as well as load growth from shale oil and gas production, resulting in benefits that exceeded those projected.[179]

Another frequently examined transmission planning effort was the MISO multi-value ("MVP") projects that were planned proactively ten years ago in order to meet planned wind development pursuant to Renewable Portfolio Standards in the region. By design, the MVP planning process identified a comprehensive set of transmission upgrades throughout the system that "would provide a mix of reliability, policy, and economic benefits to the system under a range of scenarios."[180] The transmission infrastructure developed pursuant to the MVP process has allowed for the incorporation of over 11 GW of wind, with total benefits exceeding estimated project costs by $7-39 billion.[181]

The Southwest Power Pool ("SPP"), which is the only RTO area to routinely consider multi-value benefits as part of its integrated planning process, has determined that transmission upgrades installed between 2012 and 2014 have project benefits exceeding costs by nearly $12 billion over the next 40 years.[182] Other jurisdictions, such as Australia, have mandated holistic planning. The Australian Electricity Market Operator ("AEMO") has used scenario-based planning measures for some time, and its most recent "Integrated System Plan) ("ISP") mandates

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[177] *Id.* at 29.
[178] *Id.*
[179] *Id.*
[180] *Id.* at 24-25.
[181] *Id.* at 25
[182] *Id.*

multi-value, scenario-based, and cross-portfolio planning.[183] The considerable domestic and international experience with holistic transmission planning has led to the following five core principles that are necessary for transmission planning that delivers cost-efficient results that account for the various needs of the system—including meeting public policy requirements—and which should guide the Commission in developing transmission reforms as part of the ANOPR:

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.

B. FERC SHOULD ELIMATE INCENTIVES TO AVOID REGIONAL PLANNING AND ENSURE INDEPENDENT OVERSIGHT OF TRANSMISSION

From the above, we believe that the root cause of Order No. 1000's disappointing results is that the entities entrusted with implementing it have an interest, and sometimes lucrative incentives, to undermine it.[184] Correcting this is a prerequisite for any further reforms to be successful. Put bluntly, any transmission planning system implemented by entities opposed to its purpose will fail. In this section we discuss the primary governance issues that have created the

[183] *Id.*at 25-26.
[184] *See id.* at Sec. III.

current situation and offer proposals to create truly independent transmission planning and restore effective oversight over transmission investment.

We identify four reforms that, taken together, will align industry incentives with federal and state policy interests, help mitigate anti-competitive behavior, ensure independence, and open transmission planning up to robust public and government participation.

- As a foundation for all other reforms, FERC should remove incentives to evade regional planning by improving prudence review of projects outside of regional planning, and ensure that the returns on those investments reflect their lower risk and near-guaranteed revenues.
- Strengthen independence requirements and require all regional planning entities to meet them.
- Consider creation of interregional planning boards or a national transmission planning authority.
- Ensure at least a basic level of review of transmission investments by either an appropriately staffed FERC office or Independent Transmission Monitors.

1. *Improve prudence review of projects outside regional planning*

The first step in aligning transmission owners' interests with FERC's goals is to make evading regional planning less attractive. Ultimately, participating in regional planning must be beneficial to transmission owners' shareholders. Otherwise, the fiduciary duty of transmission owners to maximize profits for their shareholders will effectively undermine and evade planning processes. Accomplishing this requires two reforms, both well within FERC's traditional section 205 authority.

First, FERC should reverse its presumption that transmission expenses arising outside of regional independent planning processes are prudent.[185] Section 205[186] places the burden of proof on the filing utility to demonstrate that the proposed charges are just and reasonable. FERC can return to what is arguably the intent of Section 205 simply through a policy statement. In making such a statement, FERC can provide guidance that its evaluation of transmission cost recovery filings will rest on several criteria: (1) to be prudent, a transmission owner-initiated project should demonstrate that the need the project meets has been considered by an independent regional planning entity, and the transmission owner should explain why the need is best met by a local solution; (2) the transmission owner should demonstrate that the project will be used and useful by showing that would meet the regional planning criteria for reliability, cost/benefit, or other drivers. In reviewing transmission cost recovery Section 205 filings, the Commission should also give great weight to independent evaluation of the project such as a review carried out by an independent regional planning body, an RTO/ISO, or a hypothetical Independent Transmission Monitor. Conversely, the Commission should take a dim view of approving cost recovery for investments that are not susceptible to review. In particular, rate recovery for projects where insufficient data is available to allow for third party evaluation should be presumptively imprudent.

Second, FERC should revisit the rate of return it approves for transmission investments. Currently, FERC generally approves transmission cost recovery on the basis of *pro forma* formula rates that consider return on equity, cost of debt, and debt/equity ratios.[187] This typically results in

[185] *See* Ari Peskoe, *Is the Utility Syndicate Forever?* 42 Energy L.J. 1, 58, n. 387, citing *Iroquois Gas Transmission System, L.P.*, 87 F.E.R.C. ¶ 61,295, at p. 62,168 (1999) (quoting *Minnesota Power & Light Co*., 11 F.E.R.C. ¶ 61,312, at pp. 61,644–45 (1980) ("MN P&L"); *Id*. (stating that FERC adopted this policy as "a matter of procedural practice to ensure that rate cases are manageable"). *See also* Ari Peskoe, *Is the Utility Syndicate Forever?* 42 Energy L.J. 1, 54, 58-60; *see also* Comment of the Harvard Electricity Law Initiative, Docket No. RM21-17, Oct. 12, 2021, at Sec. II.
[186] 16 U.S.C. § 824d (2012).
[187] *See, e.g.*, PJM Tariff Attachment H.

returns in the neighborhood of 7.5% over the 20-year life of a transmission investment.[188] For comparison, the Federal Reserve quotes B-rated ("non-investment grade") corporate bonds are earning 4.66%.[189] In contrast, the current 20-year "risk free" rate of return as represented by U.S. Treasury yields is slightly over 2%. Under the FERC-endorsed Capital Asset Pricing Model (CAPM) methodology, the only justification for returns in excess of the risk-free rate is risk.[190] However, it is unclear what risk, if any, transmission owners are taking on with their investments. Projects developed outside of regional planning involve no competitive risk. Potential cost overruns that would create risk for ordinary enterprises are easily included in rate base. Revenues are guaranteed by ratepayers. In many cases, especially end-of-life projects and improvements to existing facilities, the transmission owner already has site control and has resolved permitting and environmental issues.

Reflecting their recourse to ratepayers, transmission owners are able to borrow at rates only slightly higher than the federal government.[191] Because the return on transmission investments is a weighted average between the transmission owner's debt rate and their much higher return on equity, this creates incentive for transmission owners to structure their finances to increase the equity portion of their investments beyond what might otherwise be reasonable. On the face of it, transmission investments with guaranteed long-term revenue make attractive candidates for debt financing. It is also unclear what *bona fide* equity investment transmission owners make in these projects. While merchant developers face out-of-pocket project identification and early development costs that justify an equity share, incumbent utilities can recover those costs from

[188] *See id*.
[189] St. Louis Federal Reserve Bank, *FRED Economic Data: ICE BofA Single-B US High Yield Index Effective Yield*, retrieved October 5, 2021, *available at* https://fred.stlouisfed.org/series/BAMLH0A2HYBEY.
[190] 171 FERC ¶ 61,154.
[191] *See, e.g.,* AEP Transmission Company Prospectus Supplement, offering 30 year bonds at 2.75% (2021), *available at* https://www.aep.com/Assets/docs/investors/currentProspectus/AEPTransco-ProspectusSupplementAugust2-2021_86083506_1.pdf.

their rate base. Transmission owners' financing of projects through a roughly 50/50 debt/equity ratio appears to reflect their appetite for equity returns rather than any fundamental obstacle to higher, low-cost debt financing. The result is unjust and unreasonable rates that serve simply to transfer wealth from ratepayers to transmission owner shareholders.

To counter these two factors, FERC should critically review both the rate of return and the capital structure of transmission investments made outside of regional planning. The proper returns on those investments should reflect the absence of competition, low risk, and publicly-guaranteed revenue those projects enjoy. Transmission owners seeking returns on these projects through section 205 should bear the burden of proof of quantitatively identifying the risks they are taking on that justify their ROE rate and affirmatively demonstrating that the capital structure behind uncompetitive transmission investments reflects a prudent attempt to minimize ratepayer costs through debt financing.

The main obstacle to such an approach may be administrative burden. To address this, the Commission could consider "ROE subtractors" analogous to the ROE adder transmission owners currently enjoy when they join an RTO. Factors that may justify lower ROE include projects originating outside of independent planning, lack of competitive bidding, use of existing rights of way, and untimely identification of project need.

The need for critical review of non-competitive transmission ROEs does not arise simply from consumer protection concerns (although those are certainly important). As an axiom of financing, investments that offer returns in excess of their risk will attract capital without limit, sometimes to the point of recklessness.[192] Transmission owners with opportunity to make low-risk, high-yield investments will rationally use every means within their power to maximize those

[192] *See, e.g.*, Federal Reserve Bank, *Subprime Mortgage Crisis* (2013), *available at* https://www.federalreservehistory.org/essays/subprime-mortgage-crisis.

investments, including subverting regional planning. Without exaggeration, any effort at transmission planning reform will fail if FERC does not make alternatives to independent planning less attractive.

2. *Strengthen independence requirements and require all regional planning entities to meet them*

From the review of transmission planning outcomes above, it becomes clear that transmission planning in non-RTO regions has gone about as well as can be expected from an arrangement where the foxes not only guard the henhouse, but design and build it. RTO regions are functioning better than non-RTO regions, but at least some RTOs have become forums for transmission owners to circumscribe and devise exceptions to independent transmission planning. Although RTOs may have faithfully met their tariff responsibilities to run independent planning processes,[193] their stakeholder processes and the evolution of their tariffs are decidedly not independent.

The prudence and ROE reforms proposed in the previous section will ameliorate these issues by reducing incentives to evade regional planning. However, those reforms cannot address issues that stem from lack of a truly independent regional planning process. In the worst case, regional planning is subject to capture by incumbent transmission owners, leading to rubber-stamp approval of transmission owner sponsored projects, failure to consider lower cost solutions or non-transmission alternatives, anticompetitive protection of incumbent generation assets, exceptions to competitive procurement, and a host of other potential unjust, unreasonable, or unduly discriminatory outcomes.

[193] Or they may have not: *see, e.g.*, *Order on Section 206 Investigation and Directing Compliance* (June 2020), 171 FERC ¶ 61,212.

We propose that the remedy for this situation is for regional planning to be carried out by entities distinct from transmission owners, and for FERC to set strong independence standards for those entities. The functions of regional planning entities would be to carry out transmission planning, recommend cost allocation, and conduct competitive solicitations for transmission projects. In RTO regions, these functions can be expected to be carried out by the incumbent RTO, subject to them meeting the additional independence standards described below.

Outside of RTO regions, the situation is slightly more complex. It is not clear that entities that engage solely in the listed functions are public utilities as defined in the FPA.[194] Should the Commission determine that planning, cost allocation and solicitation are sufficient to meet the "operates facilities subject to the jurisdiction of the Commission" standard, regional planning entities would be considered public utilities and could be constituted and regulated in much the same manner as RTOs. In the alternative, FERC may not be able to directly regulate non-RTO regional planners. Instead, FERC can define the standards planning entities must meet to be considered independent for the purposes of prudence review and ROI determination discussed above.[195] Transmission owners filing for rate recovery under section 205 for investments pursuant to transmission and cost allocation plans developed by an independent entity meeting FERC standards will enjoy presumption of prudence and ROIs that reflect incentives for participating in regional planning;[196] those who do not will not. The relationship of non-RTO regional planning entities with transmission owners and their funding can be established within transmission owner tariffs, along the same lines as PJM's Independent Market Monitor is empowered and funded within PJM's tariff.[197] Should FERC make a Section 206 finding that existing non-RTO regional

[194] 16 U.S.C. 824(e)
[195] *See* p. *53, supra.*
[196] Or, as we suggest, avoid disincentives for not participating in regional planning.
[197] *See* PJM Open Access Transmission Tariff, Attachment M and Schedule 9-MMU.

planning practices are unjust or unreasonable, it would have authority to order transmission owners file the necessary tariff provisions to participate in and fund regional planning entities. Significantly, because the locus of regional planning entities' authority would lie in how FERC handles future Section 205 filings, they can be implemented without impinging upon transmission owners' statutory rights.

The independence criteria set in Order No. 2000 and the stakeholder responsiveness criteria set in Order No. 719[198] are necessary but not sufficient to ensure independent regional planning entities. Ownership, financial, and management independence are necessary to prevent the most direct types of anticompetitive influence. Stakeholder responsiveness is necessary for the same reasons described in Order No. 719: to ensure adequate consideration of customer interests, balanced decision making, and to avoid dominance by any single stakeholder group.[199]

FERC has found that existing RTOs meet those criteria. However, experience since Order No. 1000 has shown that those criteria by themselves are not sufficient to ensure robust planning and guarantee just and reasonable transmission rates. Two additional features will help promote fully independent planning. The first is a matter of capability: planning entities, including RTOs, must have sufficient internal capability to execute all their functions without assistance from transmission owners. This mitigates the problematic practice of RTOs delegating some of their planning tasks to transmission owners and the accompanying threats of anticompetitive behavior.[200]

The second is mandatory participation. FERC has noted that transmission owners may exercise "implicit" influence over RTOs through the threat to exit.[201] RTOs remain aware that they

[198] 89 FERC ¶ 61,285 (Order 2000) at III.D.1 and 125 FERC ¶ 61,071 (Order 719) at III.D, respectively.
[199] Order No. 719 at ¶¶ 506-509.
[200] *See* Monitoring Analytics, *2020 State of the Market Report for PJM* (2021), p. 614.
[201] 81 F.E.R.C. ¶ 61,257 at 57.

must be attractive to transmission owners' interests to grow and are sensitive to the risk of transmission owners leaving RTOs should membership become unattractive.[202] FERC has attempted to address this issue by arguing that utility decisions to exit RTOs fell under Section 203 authority over disposition of jurisdictional facilities, and thus subject to prior Commission approval. This approach was struck down as an unreasonable interpretation of statue.[203] In contrast, FERC can empower regional planning entities to exercise their functions through straightforward application of Sections 205 and 206, along with existing authority to access utility information.[204]

In order to square mandatory transmission planning participation with utility rights to exit RTOs, we propose that FERC require RTOs to create a new planning-only membership category; RTO responsibility for members in this category would be limited to transmission planning, information sharing, but not include transmission operation, power markets or resource adequacy. RTOs would also have authority to recommend benefit and cost recovery allocations for regionally planned projects. However, we are not proposing that RTOs gain section 205 rights over transmission facilities owned by planning-only members. Instead, planning-only members retain those rights, but will exercise them in the knowledge that FERC's prudence review of their transmission cost recovery filings will consider whether their investments occurred as part a regional plan.

In 1999, FERC examined the question of mandatory RTO membership, concluding that "it is clear that RTOs are needed to resolve impediments to fully competitive markets."[205] Nonetheless, FERC declined at the time to mandate RTO membership. Instead, FERC

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[202] *See, e.g.,* PJM Interconnection, *Comments of PJM Interconnection, L.L.C.,* in reply to the Notice of Proposed Rulemaking on RTO incentives, filed in Docket RM20-10-000 on June 25, 2021 at 17-18.
[203] *Atlantic City Elec. Co. v. F.E.R.C*, 295 F.3d 1 (D.C. Cir. 2002) at 11-12.
[204] 16 U.S.C. 825(b).
[205] Order No. 2000 at ¶ 115.

"…expect[ed] that all transmission owners will participate in good faith in the collaborative process that we are establishing…"[206] Unfortunately, the long history of attempts to encourage good faith cooperation in the power market have demonstrated repeatedly that such optimistic expectations will not come to fruition without effective – and mandatory – regulation that realigns financial incentives, rebalances stakeholder power, and sets clear and enforceable process and performance standards.

Our proposed approach has the merit of reducing litigation risk, as it can be implemented under established FERC authority to directly regulate utilities that already have filing rights. That is what the Commission did in Order No. 1000 and what the DC Circuit upheld in upheld in *South Carolina PSA* and *ICC I* and *II*.[207] FERC has authority to address "theoretical threat[s]" to just and reasonable rates when it is demonstrated that there is incentive and ability for anticompetitive behavior.[208] Under this test, reform is necessary to the transmission planning and cost recovery regime put in place by Order No. 1000 and predecessors, as incumbent transmission owners have both incentive and ability to construct uneconomic projects. Order No. 1000's finding that failure to consider more cost-effective or efficient transmission alternatives leads to unjust and reasonable ratemaking places remedying this situation squarely within FERC's authority.

3. *Consider creation of interregional planning boards or a national transmission planning authority*

Order No. 1000 found that effective interregional planning was necessary to ensure just and regional rates. Changing circumstances since Order No. 1000 was issued have only increased this need.[209] The interregional coordination approach directed in Order No. 1000 was, even in

[206] *Id.* at ¶ 117.
[207] *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014); *Illinois Commerce Comm'n v. F.E.R.C*, 576 F.3d 470 (7th Cir. 2009); *Illinois Commerce Comm'n v. Fed. Energy Regulatory Comm'n*, 756 F.3d 556 (7th Cir. 2014).
[208] Order No. 888 at 21,548 (citing Am. Elec. Power, 67 FERC ¶ 61,317, at p. 61,489 (1994)).
[209] *See* p. 53, *supra*.

theory, only a partial solution, as simply reconciling needs of adjacent regions cannot reasonably be expected to identify all the solutions full-fledged interregional planning would. In any event, experience has shown that for practical purposes, interregional coordination does not produce effective results.[210] Now as in 2011, the lack of interregional planning results in unjust and unreasonable rates.

To address this and resolve the conflicts that may arise between regions in selecting interregional projects and allocating their costs, the Commission could require regions to form joint interregional planning boards that have full authority to propose FPA section 205 filings that select projects and allocate their costs. In considering the establishment of these planning boards, 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.[211] As the D.C. Circuit held 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 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.[212] As was the case in Order No. 1000, the evidence demonstrates that existing interregional transmission planning practices are unjust, unreasonable, and unduly discriminatory because they have not resulted in the approval of a single interregional project, despite numerous studies demonstrating that these projects would result in net benefits.[213]

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[210] *See* p. 45, *supra*.
[211] *See* Order No. 1000 at ¶ 146.
[212] *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.").
[213] *See* Brattle-Grid Strategies Report at 16-18.

One option for doing this would be to require the formation of new, independent entities. Such entities could be formed in collaboration with states, pursuant to section 209, or instituted along the same lines as the regional planning entities discussed in the previous section. Such entities would have authority to identify needs and solutions, select projects and quantify their benefits and costs across the applicable group of regions, and allocate costs for interregional transmission projects.[214] While such entities would not themselves be "public utilities" under the Federal Power Act, the Commission could nevertheless require transmission owners in planning regions to file agreements governing each interregional board with the Commission. The formation of these boards would allow these projects to proceed without securing the approval of each individual regional planning organization, which would eliminate the conflicts of interest that often plague this process. As the Commission stated 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 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."[215] Thus, 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."[216] Another option that the Commission could consider is requiring that relevant RTO

[214] *See* Fed. Power Act Sec. 209. It is not clear whether section 209 currently grants such interregional planning boards section 205 filing rights. *See* section 209(a).
[215] *Policy Statement Regarding Regional Transmission Groups*, 58 Fed. Reg. 41,626, August 5, 1993.
[216] *Id*.

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.

There is little doubt that FERC has authority to fix transmission planning and cost allocation. The harder question is at what scale FERC should do so. Taking the concepts above to their conclusion, an ideal solution may be to create a National Transmission Planning Authority ("NTPA") that would perform planning and cost allocation to meet the 47 contiguous states' transmission needs. Other logical arrangements would be to create entities for the western and eastern interconnections, or a larger number, each responsible for electrically reasonable groupings of existing transmission planning regions. Regardless of the specific configuration, any arrangement should take care to ensure no gaps remain where no entity is responsible with considering transmission expansion. Given the value that recent studies[217] foresee from large-scale HVDC lines spanning both interconnections, FERC should ensure that there exists some process for discovering possible national level transmission projects.

4. *To meet its FPA obligations, FERC must review transmission investments to ensure they are actually prudent and useful*

The ANOPR seeks comment on multiple issues related to the creation of an independent transmission monitor.[218] The need is apparent: the vast majority of transmission investment since Order No. 1000 is in the form of transmission owner-initiated projects arising outside of regional planning. These projects are generally not reviewed for prudence or to a "used and useful" standard by state regulators. In some regions, they may be "rolled up" into regional planning through a process that provides for stakeholder comment, but stakeholders suffer from lack of information

[217] *See, e.g.*, NREL, Interconnections Seams Study (2020), available at https://www.nrel.gov/analysis/seams.html.
[218] ANOPR at ¶¶ 163-75.

needed to meaningfully review the projects, and in any event, transmission owners have no obligation to heed comments. Finally, projects are incorporated into the rate base and gain cost recovery through section 205 filings made at FERC. In an effort to reduce administrative burden, FERC has declined to engage in the type of evidence-based ratemaking needed to if determine these investments are prudent.

This state of affairs has allowed billions of dollars to flow into ratebase with no analysis whatsoever if the investments are prudent or even useful. Effectively, the statutory requirement that "the burden of proof to show that the increased rate or charge is just and reasonable shall be upon the public utility"[219] has been eliminated. In the past, FERC has reconciled this practice with the letter of the FPA by conditioning the utilities' burden of proof on receipt of opposing evidence that "needs to be more than a 'bare allegation of imprudence,' but cannot be so extensive that it in effect reverses the statutory burden of proof"[220] We submit that the Order No. 1000 finding that lack of effective planning may lead to unjust and unreasonable rates, combined with the record showing the increase in unplanned projects since Order 1000, creates sufficient record for FERC to revisit this precedent, and urge the Commission to do so in a future NOPR.

Section 205 places little bounds on how utilities may demonstrate their rates are just and reasonable, and nothing we suggest would prevent utilities from attempting to do so in whatever manner they see fit. However, for purposes of administrative efficiency, FERC may issue policy guidance explaining under what circumstances a filing enjoys a presumption of prudence.

As discussed in the previous two sections, the most efficient solution to these problems is to empower truly independent regional and interregional planning bodies and condition the presumption of prudence on transmission plans emerging from their planning process. However,

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[219] 16 U.S.C. 824d(f).
[220] *Iroquois Gas Transmission System, L.P.*, 87 F.E.R.C. ¶ 61,295, at ¶ 62,168 (1999).

should FERC decide not to follow that path, at the very least it should create a transmission monitoring function to exercise oversight over the existing planning system. Prudent transmission investments must include independent review verifying the cost/benefit analysis, showing adequate consideration of alternatives, and identifying any anti-competitive concerns or confirming none exist.

The standards of independence articulated in Order No. 2000[221] and Order No. 719[222] serve well here. To be deemed independent, an entity reviewing transmission investments must be free of ownership entanglements with transmission owners or other market participants, must have management unaffiliated with market participants, and must not otherwise be subject to undue influence. In this context, financial independence should also include a specific requirement that the reviewing entity not receive payments from the filing party; a consultant with interest in future work cannot reasonably be expected to act independently.

In the context of transmission planning, adequate consideration of alternatives must include review of whether the need addressed by a non-regionally planned project may be more efficiently or cost-effectively met through regional solution. A critical flaw of the current approach to transmission owner-initiated projects is that they "may displace projects that would have otherwise been implemented through the RTEP process."[223] Less efficient and more expensive local projects can displace superior regional solutions without review or oversight. This state of affairs begs anti-competitive behavior, is anathema to regional planning and must be remediated. Such review could be carried out as a matter of course in regional planning processes, where local upgrades are identified by an independent planner as part of an integrated process that considers both regional

[221] Order No. 2000 ¶ 194.
[222] Order No. 719 ¶¶ 326-32.
[223] Monitoring Analytics, *2020 State of the Market Report for PJM* (2021), p. 614.

and local solutions. However, for transmission owner-initiated projects that are either rolled-up into a regional plan or advanced by the transmission owner themselves, third party review is vital for just and reasonable rates.

C. FERC SHOULD ESTABLISH MINIMUM CRITERIA AND PROCEDURES FOR TRANSMISSION PLANNING

Currently, transmission is planned through a fractured maze of requirements that considers various needs completely separately from one another. Transmission planners conduct 10 to 15-year reliability planning studies to ensure sufficient transmission to serve firm load. They separately plan for transmission facilities to meet economic needs, and conduct what even

FERC acknowledges is a "limited" review of public policy requirements.[224] Further, the generator interconnection process plans for network upgrades that must be paid for by the interconnection customer, but may benefit multiple entities. FERC raises the concern "that existing regional transmission planning processes may be siloed, fragmented, and not sufficiently forward-looking, such that transmission facilities are being developed through a piecemeal approach that is unlikely to produce the type of transmission solutions that could more efficiently and cost-effectively meet the needs of the changing resource mix."[225] PIOs could not agree more that this fractured and siloed approach needs to be reformed because it produces unjust and unreasonable rates

Moreover, the ANOPR seeks comment on whether reforms are needed regarding how the regional transmission planning and cost allocation processes model future scenarios to ensure that those scenarios incorporate sufficiently long-term and comprehensive forecasts of future transmission needs. It also seeks comment on what factors transmission planners should use to

[224] ANOPR at ¶ 16.
[225] *Id*. ¶ 8.

plan transmission and whether the Commission should establish minimum requirements regarding future scenarios for transmission planners to plan for.[226] Currently, as acknowledged in the ANOPR, the transmission planning models generally only incorporate interconnection projects that are near the end of the interconnection process and have completed a facilities study,[227] which does not appropriately take into account realistic future generation and therefore produces transmission plans that do not meet their needs. Thus, PIOs believe that FERC needs to establish minimum criteria for transmission planning and provide our recommendations on what criteria to use below. We also look forward to the discussion of these issues at the Commission's November 15, 2021 technical conference.

1. *Planning regions should be required to incorporate scenario-based planning*

The ANOPR sought comment on whether developing plausible long-term scenarios would lead to the identification of more efficient or cost-effective transmission solutions in regional transmission plans.[228] It also asks if greater use of probabilistic transmission planning approaches may better assess the benefits of regional transmission facilities.[229] As discussed above, and established by several studies,[230] PIOs believe that the development of such plausible long-term scenarios will lead to the identification of more cost-effective transmission solutions and that the use of such an approach will better assess the benefits of regional transmission facilities.

For this reason, the Commission should examine whether the absence of forward-looking scenario-based planning in the past decade is evidence of discrimination under section 206 by biasing transmission planning in favor of incumbent generators, or unreasonable by failing to

[226] *Id.* ¶ 46.
[227] *Id.* ¶ 23.
[228] *Id.* ¶ 48.
[229] *Id.* ¶ 49.
[230] *See generally* Brattle-Grid Strategies Study *in passim* and App. B.

account for foreseeable future conditions. Transmission planning cannot be limited to examination of only deterministic and minimal near-term needs. Most regions, whether within or outside of RTOs, fail to identify potential transmission needs based on plausible futures that not only reflect known facts, but that also capture current trends and near-term risks that will necessitate transmission system investments (including transformational change in the generation portfolio, increased extreme weather and anticipated electrification of end uses). Planning that is devoid of this situational awareness leads to unjust and unreasonable outcomes because it results in infrastructure that will not meet actual future needs cost-effectively.[231] This, in turn, leads to expensive retrofits and reconstruction, and increases the need for otherwise avoidable new transmission rights of way that may be difficult, time delayed, and difficult to site. Historical examples exist of utilities initiating a review of multiple scenarios, identifying transmission solutions that best meet system needs across these scenarios, and building the indicated set of upgrades, the projects of which have exceeded even estimated benefits.[232]

Most planning processes limit the number and type of studied scenarios that are examined to known generator interconnections and retirements. 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."[233] Similarly, SPP only includes generation resources in its economic models if they meet a set of criteria that includes "an effective Generator Interconnection Agreement," unless SPP decides to grant a special case-by-case exemption.[234] As

[231] *Id.* at 28-29; 58-64.
[232] Examples include Texas' CREZ (begun in 2005), Minnesota's CapX2020 (begun in 2006), and California's RETI (begun in 2007). *See also*, Brattle-Grid Strategies Study at Sec. I, App. A.
[233] PJM, Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., Schedule 6, § 1.5.7(i)(iv), effective date September 17, 2010.
[234] SPP, Integrated Transmission Planning Manual, § 2.2.1.4, July 20, 2017.

a result, the 22,096 MW of wind currently on the SPP system has already surpassed the 2015 and 2017 plans' 10-year forecasts. Under-forecasting wind growth leads to chronic delays in transmission investment, contributing to persistent congestion and frustrating the ability of new cost-effective generation resources to participate in RTO markets. Additionally, it increases reliability risks as the existing system experiences undue stress due to the lack of investment. These processes fail to apply a core component of transmission planning process: to build infrastructure that connects the *future* resource mix to *future* load under *future* conditions.

MISO at least considers scenarios through its "futures" planning process.[235] However, until recently MISO's futures have woefully underestimated the pace of change across its system, thereby negating much of the potential benefits of this forward-looking approach. As part of this analysis, which is normally a 20-year lookout, MISO captures current trends including state and federal policies, utility IRPs and carbon reduction or clean energy commitments, corporate procurements of clean energy, and other trends to project a range of possible resource additions and subtractions based on cost inputs and other factors that go beyond known interconnections and retirements. For example, in 2021, MISO is focusing its regional 20-year planning on a future that assumes, among other things, the following: 85 percent state and utility goals met; 100 percent of IRPs met; and a 40 percent reduction in carbon emissions from 2005 levels.[236] MISO has also embarked on a long-term regional planning process that is looking more than 20 years out and will include more aggressive assumptions than those used in 2021, including 50 percent or more penetration of wind and solar resources, aggressive electrification assumptions, and an 80 percent reduction in carbon emissions. MISO has been very clear in stakeholder discussions that it is not

[235] https://www.misoenergy.org/planning/transmission-planning/futures-development/.
[236] https://cdn.misoenergy.org/20200427%20MTEP%20Futures%20Item%2002b%20Futures%20White%20Paper443656.pdf.

doing this to drive these systemic changes itself, but to be responsive to the stated direction of its utility members, consumers, and member-states. In 2021, MISO also completed its Renewable Integration Impact Analysis ("RIIA") study that carefully modeled futures with 30 percent, 40 percent and 50 percent renewable penetration to identify system needs as the system transitions to renewable energy resources.[237] The RIIA study is widely considered the type of study that must be routinely completed in the face of the changing generation portfolio. While MISO's updated approach is promising, it has yet to be fully implemented.[238] Furthermore, MISO's ability over the past decade to identify and approve transmission system investments necessary to meet future demand on its system has been no better than that of other RTOs.

Each planning region should be required to perform probabilistic planning to identify regional transmission infrastructure to provide low-cost electricity and accommodate state goals. To be fully informed, transmission planning stakeholder processes should be more diverse and inclusive, influencing scenario development and final determinations regarding what transmission projects will be constructed. To accomplish this, the Commission should require that planners develop scenarios through a transparent process which includes input from diverse stakeholders that represents a reasonable range of future conditions to ensure least-regrets planning that identifies transmission investments that perform well across a range of scenarios and provide protection from the risks of inaction.[239] The goal is to maximize the benefits and minimize the costs/risks of the inevitable changes that will occur across the system over the medium to long-term.

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[237] https://cdn.misoenergy.org/RIIA%20Executive%20Summary520053.pdf.
[238] Brattle-Grid Strategies Report at 13 n.29.
[239] *See* Brattle-Grid Strategies Report at 58-64; App. B, C.

Possible scenario drivers include, among other things: federal, state, and local goals, corporate and utility procurement targets, demand projections (including electrification, DER projections and EV charging technologies), economic growth, retirement projections, carbon reductions, generation types and locations, investments outside the planning process, interconnection queues, future weather/climate conditions – including extreme weather vulnerabilities, resource adequacy and reserve needs, and customer preferences.[240] Furthermore, transmission planners should consider scenarios compatible with emissions regulations (including greenhouse gas emissions regulations) that are likely to result in the retirement of polluting generation. A brief summary of some of the considerations that should be included in these scenarios follows.

Public policy. Transmission planners should be required to incorporate public policy into future resource mix projections. Order No. 1000 only requires that RTOs "consider" public policy,[241] and as a result, not all do this. For example, PJM does not include the consideration of public policy requirements in its economic planning forecast.[242]

Corporate and utility procurement targets. Consumer demand for economic, renewable resources will be met at a regional or national level, so the Commission should require all transmission owners to develop a process for estimating demand preferences from wholesale customers in their region. For example, MISO has recently incorporated utility and corporate procurement targets into its "futures" scenarios. MISO's MTEP21 includes 85 percent of the

[240] *Id.* at 59, App. B, C.
[241] Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities, Order No. 1000, 136 FERC ¶ 61,051, at P 203, July 21, 2011.
[242] PJM, Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., Schedule 6, § 1.5.9, effective date September 17, 2010.

utilities' plans and state plans, which has had the effect of increasing forecasted carbon reductions by 23 percent from the original assumption of a 40 percent carbon reduction by 2039.

Electrification. Electrification of the transportation and building sectors will greatly impact future system needs. Nine states and the District of Columbia have set targets of net zero economy-wide emissions by 2050 or sooner,[243] and building codes are likely to soon incentivize or require electrification. Brattle has estimated that $3-7 billion in annual transmission investments will be necessary to meet this increased demand between 2018 and 2030. This investment increases dramatically between 2031 and 2050, with an estimated $7-25 billion in additional necessary investments.[244]

The Commission should require all regions to explicitly account for additional load from electrification of both transportation and buildings and other infrastructure requirements, and should require planning under a variety of scenarios, particularly because it is difficult to predict the tipping point for the adoption of new technologies. For example, in MISO's LRTP process its most aggressive future assumes a 50 percent increase in demand by 2039, 40 percent of which is driven by electrification.[245] Without such estimates, actual needs will not be recognized in advance and decisions to build to meet demand will not occur.

2. *All potential values of transmission projects should be evaluated in an integrated rather than siloed fashion*

PIOs agree with the Commission that the fact that transmission needs driven by reliability, economic considerations, and public policy requirements are generally considered separately from

[243] https://www.nrdc.org/resources/nrdcs-8th-annual-energy-report-slow-and-steady-will-not-win-race?nrdcpreviewlink=rmmB6NM6zpiOTruhuObZJdH92bCOvmZTY1hx72xCSzQ#renewables.
[244] Dr. Jürgen Weiss, J. Michael Hagerty, and María Castañer, The Coming Electrification of the North American Economy, at 17, March 2019.
[245] https://cdn.misoenergy.org/20200427%20MTEP%20Futures%20Item%2002b%20Futures%20White%20Paper443656.pdf

one another fails to consider the suite of benefits that transmission facilities provide.[246] Failure to factor in and plan for the multiple potential values of transmission projects results in an uncoordinated overall planning approach, poorly targeted transmission investments, and fails to ensure the efficient expenditure of ratepayer dollars on projects that could advance multiple planning objectives.[247] As a result, it is inconsistent with the Commission's goal in Order No. 1000 to facilitate planning that results in more efficient and cost-effective investment decisions.[248]

Currently, most regions perform transmission planning in a manner that treats projects for reliability, economic efficiency, public policy, and generator interconnection purposes in separate silos.[249] Reliability planning, which is conducted 5- and 10-years out, has typically taken first priority and focuses on anticipating potential violations of reliability standards and planning projects which will insure against such violations.[250] Economic planning relates to planning to improve grid efficiencies and reduce congestion costs in the future, based on assumptions about load growth and generation prices.[251] Public policy planning refers to planning conducted to identify projects likely to be driven by public policies shaping the generation mix, such as renewable portfolio standards.[252] Finally, generator interconnection planning is not really systematic planning at all, but rather one-off planning studies done to support the interconnection needs of particular proposed generation assets.[253]

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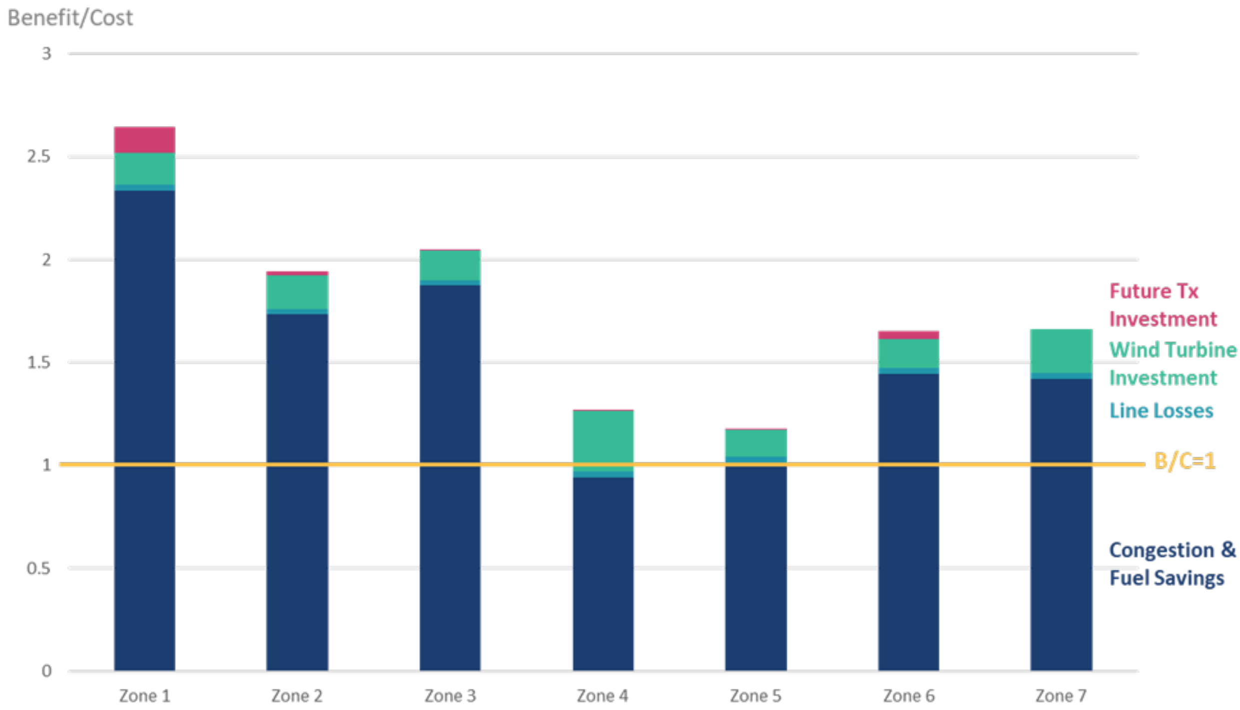
[246] ANOPR at ¶ 85.
[247] *See* Brattle-Grid Strategies Report *in passim.*
[248] Order No. 1000 at ¶ 46 ("It is therefore critical that the Commission act now to address deficiencies to ensure that more efficient or cost effective investments are made as the industry addresses its challenges").
[249] *See* Brattle-Grid Strategies Report at 31; Americans for a Clean Energy Grid, *Planning for the Future: FERC's Opportunity to Spur More Cost-Effective Transmission Infrastructure* at 29 (Jan. 2021), https://cleanenergygrid.org/wp-content/uploads/2021/01/ACEG_Planning-for-the-Future1.pdf.
[250] *See, e.g.*, PJM, PJM Manual 14B: PJM Region Transmission Planning Process, § 2.1.2, October 1, 2020.
[251] *Id*.
[252] https://www.energy.gov/sites/prod/files/2017/01/f34/Planning%20Electric%20Transmission%20Lines--A%20Review%20of%20Recent%20Regional%20Transmission%20Plans.pdf.
[253] *Id*.

Because these planning processes occur separately, a given transmission project is typically considered from the lens of only one of these categories, despite the fact that the project may offer benefits across several categories. For example, a project may offer economic benefits in the near term, but over the long term may also be necessary to avoid reliability violations and to meet public policy requirements. As is often said, "today's congestion problems are tomorrow's reliability problems." Moreover, the ability to assign values to these sometimes highly complex benefits is not only doable, it has and is being done.[254]

While MISO represents a historical example of integrated multi-value transmission planning through its multi-value project (MVP) process, it remains a good example of how pro-active planning can evaluate multiple benefits simultaneously on a system-wide basis. Projects approved through the MVP process meet one or more of the following goals: (1) reliably and economically enable regional public policy needs; (2) provide multiple types of regional economic value; or (3) provide a combination of regional reliability and economic value.[255] Benefits quantified pursuant to the MVP process include: (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 reduced on-peak transmission losses; (5) reduced renewable investment costs to meet public policy goals; and (6) reduced other future transmission investments.[256] Projects that were approved for inclusion in the MVP portfolio were incorporated into MISO's long-term transmission planning process, and the $6.6 billion spent on MVP projects from the 2011 cohort are now estimated to provide net-benefits of $7.3 to *$39 billion* over the next 20 to 40 years and across all MISO zones, as shown below:[257]

[254] Brattle-Grid Strategies Report at 30-58; App. B-D.
[255] MISO Tariff, Attachment FF.
[256] Brattle-Grid Strategies Report at 55.
[257] *Id.* at Fig. 8.

FIGURE 8. MISO MVP BENEFITS BY ZONE



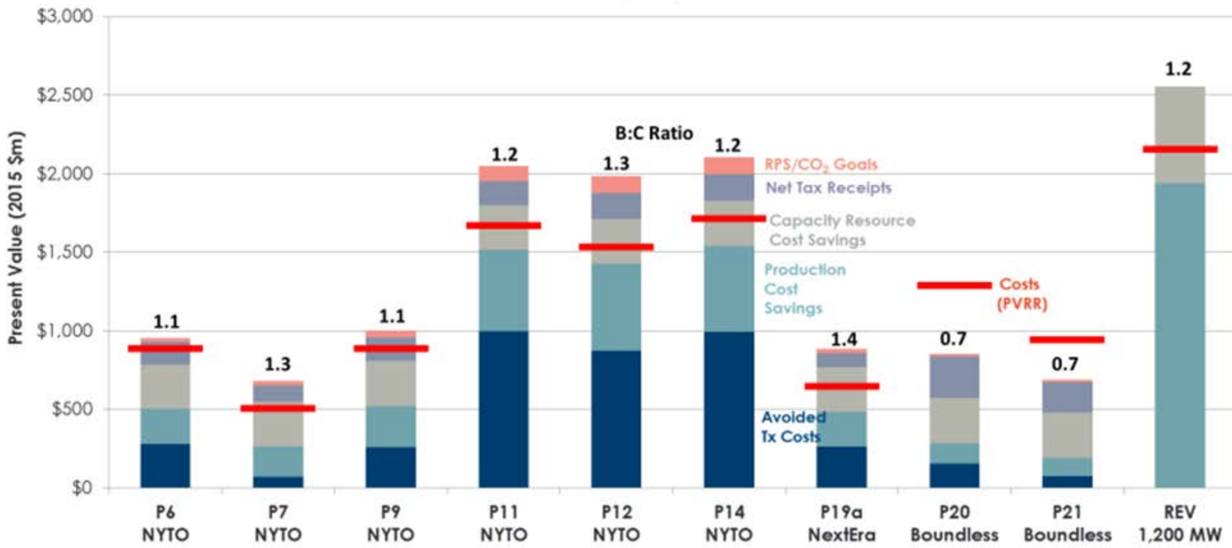
In 2021, MISO has begun implementing its Long-Range Transmission Planning (LRTP) process, which is similar to its MVP process and designed to assess the region's future transmission needs holistically in concert with utility and state plans to site new generation resources.

In New York, NYISO has also implemented a multi-value, scenario-based regional transmission planning process pursuant to a mandate from the New York Public Service Commission ("NYPSC") in 2015.[258] The Public Policy Transmission Planning Process ("PPTPP") focuses on projects meeting public policy transmission needs that are suggested by market participants. After review and approval by the NYPSC, NYISO solicits solutions from market participants, which are evaluated on a multi-value basis that recognizes and quantifies the broad set of benefits the proposed solutions provide.[259] Pursuant to the PPTPP, seven portfolios of initially proposed projects and a suite of public policy resources (Reforming the Energy Vision or

[258] Brattle-Grid Strategies Report at 56.
[259] *Id.*

REV resources) were evaluated – seven of which were determined to provide net societal benefits, and two of which were ultimately approved:

FIGURE 9. SUMMARY OF NEW YORK SOCIETAL BENEFIT-COST ANALYSIS[260]



MISO MVP and NYISO PPTPP are far from the only examples prove that holistic regional planning efforts are not only possible, they have been done and their returns tend to exceed their estimates considerably. Holistic planning efforts have occurred fitfully across the grid:

[260] *Id.*

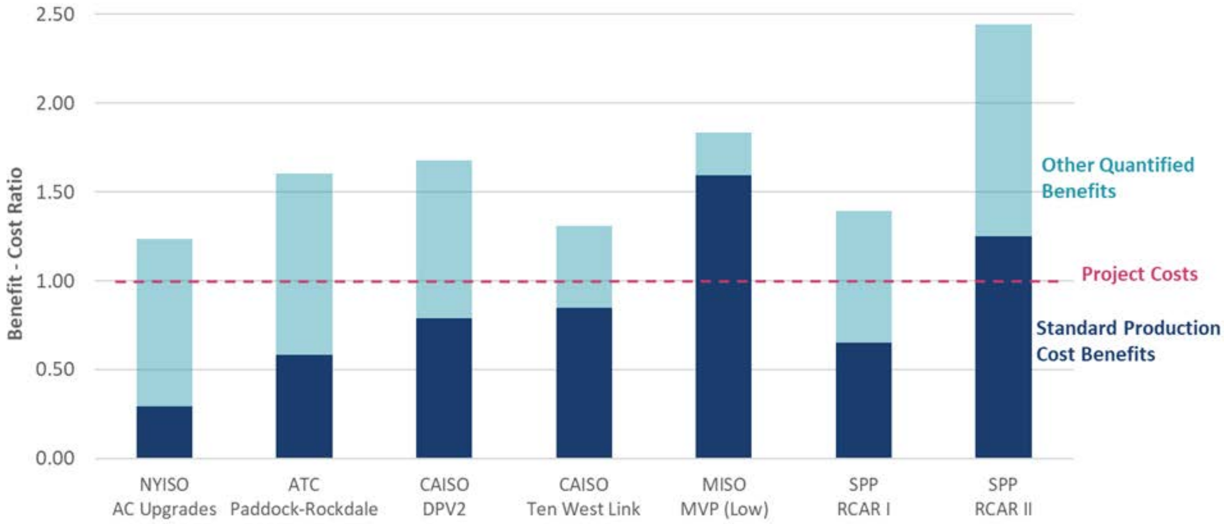
TABLE 7. EXAMPLES USING PROVEN EFFICIENT PLANNING METHODS[261]

	Proactive Planning	Multi-Benefit	Scenario-Based	Portfolio-Based	Interregional Transmission
CAISO TEAM (2004)[1]	✓	✓	✓		
ATC Paddock-Rockdale (2007)[2]	✓	✓	✓		
ERCOT CREZ (2008)[3]	✓			✓	
MISO RGOS (2010)[4]	✓	✓		✓	
EIPC (2010-2013)[5]	✓		✓	✓	✓
PJM renewable integration study (2014)[6]	✓		✓	✓	
NYISO PPTPP (2019)[7]	✓	✓	✓	✓	
ERCOT LTSA (2020)[8]	✓		✓		
SPP ITP Process (2020)[9]		✓		✓	
PJM Offshore Tx Study (2021)[10]	✓		✓	✓	
MISO RIIA (2021)[11]	✓	✓	✓	✓	
Australian Examples:					
- AEMO ISP (2020)[12]	✓	✓	✓	✓	✓
- Transgrid Energy Vision (2021)[13]	✓	✓	✓	✓	✓

Further, the benefit-cost ratios of transmission projects with vs. without a broad scope of benefits demonstrates the value that such holistic, integrated planning provides. An examination of multi-benefit planning conducted by NYISO, ATC, CAISO, MISO, and SPP have all found benefits that exceed costs once a more holistic evaluation of benefits is considered:[262]

[261] *Id.* at 70.
[262] *Id.* at 33.

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



FERC should require transmission planning regions to conduct transmission planning in a multi-value frame that considers all of the potential benefits of additional transmission infrastructure. As discussed above, FERC should require planners look for and consider *all* benefits from transmission projects, including, but not limited to mandatory consideration of the benefits of meeting public policy objectives, economic benefits, and mandatory inclusion of local reliability planning issues within the regional planning process. FERC should also require that the consideration of a broad range of benefits of transmission infrastructure in a region be conducted in a single integrated regional planning process that looks across the system-wide portfolio (including where that portfolio could cross into other regions), and not in separate, siloed processes.

3. *Ensure modeling is consistent between planning regions and that stakeholders have broader access to transmission models*

The ANOPR seeks comment on whether "reforms are needed regarding how the regional transmission planning and cost allocation processes model future scenarios to ensure that those scenarios incorporate sufficiently long-term and comprehensive forecasts of future transmission needs."[263] The ANOPR also asks if FERC should set minimum criteria for future transmission planning. The answer is a resounding yes.[264] Not only is reform needed on how transmission planning regions model, but the Commission must enact reforms that provide access to these models to interested persons. Lack of good data describing the transmission system is a barrier to effective planning. There are two fundamental problems here – the data itself and stakeholder access to it. The first problem is that each transmission planning region uses different models to identify transmission needs and uses different benefit metrics to assess those needs. This impedes interregional planning because the adjoining regions can't even agree on what the current system looks like, and makes it difficult for stakeholders to meaningfully participate in the transmission planning process because they need to understand multiple system models. Ideally, interregional planning would look at adjacent transmission planning regions as a whole to identify the most efficient and cost-effective solutions. However, various planning authorities each plan using their own model, including different futures scenarios and different benefit/cost metrics. This prevents any sort of holistic interregional planning, and reduces planners to "interregional coordination," where they essentially compare the results of their separate planning process to check for overlap.[265] To address interregional incompatibility and help resolve the triple hurdle barrier, the Commission should require compatible models of the current system, future scenarios, and benefits metrics across all interconnected planning regions.

RTO-led attempts to develop joint planning models have not been successful. SPP and MISO's attempt to evaluate interregional projects using a common model appears to have devolved into bickering.[266] The Commission approved SPP's and MISO's proposal to eliminate

[263] ANOPR at ¶¶ 46-53.
[264] PIOs address proposed minimum requirements in the previous section.
[265] See discussion of triple hurdle problem, *supra.*
[266] *See Midcontinent Independent System Operator, Inc., Southwest Power Pool, Inc.*, 168 FERC ¶ 61,018 at P 6.

the use of a joint regional model,[267] and the regions subsequently announced a joint study which will focus on better and collaborative plans to address generation interconnection needs.[268] One of the reasons SPP and MISO abandoned the joint interregional model was that "the use of a joint model results in evaluating potential interregional transmission projects with a different set of assumptions than each RTO uses in performing its individual regional transmission planning process."[269] There is no reason why adjoining transmission planning regions should use different assumptions of the underlying conditions of the grid or how to model the grid to develop transmission plans – either for regional or interregional transmission. FERC should require that transmission planning regions' planning methods are aligned such that a unified model can be compatible with each region's evaluation framework. Having adjoining transmission regions share a common understanding of the grid and model in a similar manner, even if their ultimate transmission needs differ, will help create a more robust and understandable transmission planning process. It will be easier to discern if interregional transmission lines can more cost effectively satisfy multiple regions' economic, reliability, and public policy needs while also allowing for easier stakeholder involvement in the transmission planning process.

As the experience in MISO and SPP demonstrates, it may be difficult for the planning regions themselves to create a compatible model of the current system, futures scenarios, and benefits metrics across all interconnected planning regions. The Department of Energy or the National Labs could provide technical support to this effort as a neutral third party.

The ANOPR also seeks comment on whether the current transmission planning process provides sufficient transparency for stakeholders to understand how best to obtain information and

[267] *Id*. ¶ 41.
[268] SPP, *MISO and SPP to Conduct Joint Study Targeting Interconnection Challenges*, September 14, 2020.
[269] *See Midcontinent Independent System Operator, Inc., Southwest Power Pool, Inc.*, 168 FERC ¶ 61,018 at P 7.

fully participate in the various processes.[270] The relates to the second data problem is that stakeholders, including the public, do not have access to the data on which transmission planners base their transmission planning decisions. Without such data, stakeholders attempting to participate in or evaluate the results of the regional planning processes often face insurmountable hurdles to simply understanding proposed projects, much less critically evaluating them or proposing reasonable alternatives. More ambitiously, entities such as merchant developers, states, the Department of Energy, or NGOs that might seek to propose new transmission facilities or review the results of the transmission planning process face difficulty accessing the data they need to do so. Independent generation developers often have little more than guesswork available to them for identifying promising project locations, which is often one of the root causes of interconnection queue backlogs. Requiring stakeholders to navigate varying rules of multiple transmission planning regions creates a further barrier to participating in the transmission planning process. This is particularly true for those who want to propose an interregional line and must understand and meet the varying requirements of more than one transmission planning region to access the information.

To remedy both of these problems with the current transmission planning processes, FERC should require the transmission planning regions to use a common model of the existing grid to plan for their transmission needs and provide all transmission modeling information that serves as the basis of the transmission planning process to FERC. FERC can then ensure access to those who need it. Such information should be at least sufficient for a stakeholder to use to independently understand the system and modelling to be able to propose new transmission or reproduce the results of the transmission planning process. The Commission has established the Office of Public

[270] ANOPR at ¶ 162.

Participation ("OPP") to assist the public with Commission proceedings. In summarizing the comments received by FERC on the creation of the OPP, MJ Bradly reported that commenters recommended that FERC use the OPP to reduce technical barriers to participate with RTOs and increase technical assistance at RTOs.[271] One way OPP could do this is to act as the clearinghouse for the public to access the data so that they can participate in, or evaluate the results of, the transmission planning process.

PIOs want to make clear that we are not talking about full unfettered public access to any such information. We recognize that some transmission planning data may be sensitive and fall under the definition of Critical Energy/Electric Infrastructure Information (CEII) and should be governed by the Commission's existing CEII regulations.[272] However, currently, such data is handled differently by different planning entities, making it harder to access and harder for the Commission to ensure that any CEII is kept secure.[273] The Commission's existing CEII regulations currently provide that any person who is a participant in a proceeding may request CEII, and generally can receive the information upon the execution of a signed protective agreement.[274] The same should be true of those seeking to participate in the transmission planning process, either by proposing regional or interregional transmission or by evaluating the results of the process. Thus, the Commission should modify its regulations to make clear that such treatment will also be afforded a person who wants to participate in, or evaluate the results of, the transmission planning process. Even if the Commission does not revise its regulations to explicitly provide for this

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[271] M.J. Bradley & Associates, Establishing the Federal Energy Regulatory Commission Office of Public Participation: A Review of Stakeholder Input at 26 (2021).
[272] 18 C.F.R § 388.113.
[273] For example, in MISO, you must be a market participant or member to access such information. Neither MISO's nor PJM's rules make clear how they will determine if the requestor has a legitimate need for the information. *See* MISO CEII Access Request Form, *available at* https://www.misoenergy.org/access-request/access-request-form; PJM CEII Access Request Form, *available at* https://www.pjm.com/library/request-access. This information is even more difficult, if not impossible, to access in non-RTO transmission planning regions.
[274] 18 C.F.R. § 113(g)(4).

treatment, it should make clear that a person needing such information to participate in or review the results of the transmission planning process has a particular need for the information pursuant to 18 C.F.R. § 388.113(g)(5).

Providing for a common model of the underlying grid and providing stakeholders who seek to participate in or evaluate the results of the transmission planning process with a clear way to access the data on which the transmission planning regions base their regional plans will help produce better plans. Transmission developers, both incumbent and merchant, will have a better way to analyze what effects their proposed transmission projects might have on the region and what benefits they might bring. Using a common model will make it easier for both transmission developers and planners to evaluate whether an interregional project can provide economic, reliability, and public policy benefits to two or more regions. These transmission developers will be able to tailor their projects to the actual needs of the system, without having to guess what those are. They will also be better able to estimate the costs to the system. Thus, the transmission proposed through the transmission planning process will more closely match the needs of the region, and the region can more efficiently evaluate the projects. It will also lower the barriers to entry for new developers, which will lead to a greater diversity of options and discipline anti-competitive behavior. This will lead to better overall transmission planning.

4. *Prioritize regional planning over local, and interregional over regional*

Current planning processes prioritize local projects over regional, and regional projects over interregional. This is most obvious in non-RTO regions. For example, SERTP simply bundles all local projects to build the base case used for regional planning. Subtler but similar procedures occur in RTOs. For example, even though PJM may be aware of upcoming local needs, it does not consider them in developing its regional transmission plan. Under PJM transmission owners' recently approved "end of life" provisions, PJM regional projects may only displace local projects if the regional project coincidentally addresses the local need, and even then only after consultation with the transmission owner responsible for the local need.[275] This is exacerbated by the surprisingly short lead time in which many local projects are identified. Following Order No. 1000, several RTOs saw a surge in so-called "immediate need" transmission projects which were exempted from regional planning and competitive procurement due to the short time before they were required to be in service.[276] Following FERC's disciplining of RTO immediate need procedures, the number of "end of life" projects increased, often with lead times difficult to reconcile with the many decades of service expected from transmission assets. The result is that transmission planning in recent years has been dominated by a hodgepodge of uncoordinated local projects. FERC has acknowledged concerns that these projects may be structured to avoid Order No. 1000 competitive procurement.[277]

This is the reverse of the order that would facilitate efficient, least-cost solutions. By virtue of their wider perspective, regional planners can consider local needs in their work. On the other hand, local planners lack the information needed to consider regional solutions, and in any event, are not tasked with doing so. Similarly, interregional planners, if they existed, would have access to a broader range of possible solutions and be able to consider cost saving measures that are simply invisible to regional planners.

FERC should act to correct this situation by coordinating local, regional and (potential) interregional planning such that (1) information about transmission needs is reported from local to regional to interregional planners in a timely enough manner that they can be acted on; and (2) planning cycles are aligned so interregional solutions are identified first and provide the base case

[275] PJM OATT Attachment M-3(d)2ii.
[276] *See* Ari Peskoe, *Is the Utility Syndicate Forever?* 42 Energy L.J. 1, 64-68 (2021).
[277] *Monongahela Power Co*., et al., 162 FERC ¶ 61,129 at 108.

for regional planning, which in turn provides the basis for local planning. This flow of information maximizes the opportunity to identify more efficient or cost-effective solutions and should minimize the portion of projects developed without competitive procurement.

As regional planning and (if it becomes a reality) interregional planning are both carried out through FERC-mandated processes, the Commission can correct the timing and information flow of those processes directly through a rulemaking. Local projects are not as amenable to direct regulation, as any effort by FERC to restrict their timing is likely to run afoul of transmission owners' section 205 filing rights. In a by now familiar refrain, we suggest that FERC's authority here is best exercised through policy statements on the treatment of rate recovery filings. FERC could make clear that local projects identified with insufficient time to be included in regional planning cycles should expect a lower ROI, both to reflect their lower risk[278] and, frankly, as a punitive measure. Going further, a consistent pattern of a transmission owner identifying needs in a way that avoids review by regional planners or competition could be taken as indication of possible anticompetitive behavior. The independent transmission monitors proposed in the ANOPR would appear to be ideally suited to monitor such activities and make appropriate referrals to the Office of Enforcement.

A rational, timely flow of information and coordination of planning cycles appears to be one of the most straightforward ways to improve transmission planning efficiency, cost-effectiveness, and competitiveness. Imposing such reform is well within FERC's power, and should be conserved as one of the no-regrets reforms within the scope of the ANOPR.

[278] Indeed, MISO and its transmission owners have argued that excluding projects from competition reduces the risk of delay and that local projects "can be implemented quickly." MISO and MISO Transmission Owners Tariff Filing Transmittal Letter, FERC Docket No. ER19-1124, Feb. 19, 2019 at 20 and 33.

5. *FERC should require meaningful evaluation of storage and other grid enhancing technologies*

The ANOPR sought comment on whether and how Grid-Enhancing Technologies (GETs) should be accounted for in determining what transmission is needed.[279] The ANOPR also asked if there is the potential for GETs not only to increase the capacity, efficiency, and reliability of transmission facilities, but, in so doing, also to reduce the cost of interconnection-related network upgrades. Specifically, the Commission asked whether it should require that transmission providers consider GETs in interconnection studies to assess whether their deployment can more cost-effectively facilitate interconnections.[280]

PIOs recommend that FERC require, as part of regional and inter-regional planning, comprehensive evaluation of GETs, including storage as transmission, dynamic line ratings, and topology optimization software. The potential impact of doing so is significant. One recent study estimates that comprehensive incorporation of GETs into the grid could double the amount of renewable energy that could be interconnected without new large-scale transmission lines by 2025.[281]

This is an area in which Commission regulatory action is necessary because public utilities lack sufficiently aligned incentives to pursue the savings possible through GETs. As the Brattle Group has observed, public utilities tend to underinvest in GETs because 1) utilities' performance is measured in terms of meeting minimum reliability thresholds, not improving efficiency; 2) congestion costs from inefficient transmission infrastructure are simply passed on to other market

[279] ANOPR at ¶ 48.
[280] *Id.* ¶ 158
[281] WATT Coalition Report, p. 9-10 https://watt-transmission.org/wp-content/uploads/2021/02/Brattle__Unlocking-the-Queue-with-Grid-Enhancing-Technologies__Final-Report_Public-Version.pdf90.pdf.

participants; and 3) utilities derive profits from capital investments in transmission assets that using more efficient GETs solutions could avoid.[282]

The Commission has previously recognized the value of such technologies. In Order No. 890-A, the Commission stated that "advanced technologies . . . must be treated comparably where appropriate in the transmission planning process and, thus, the transmission provider's consideration of solutions should be technology neutral."[283] In Order No. 1000, the Commission required "comparable consideration of transmission and non-transmission alternatives in the regional transmission planning process[.]"[284] In 2019, the Commission convened a technical conference to gather information about how the Commission could facilitate the deployment of GETs.[285] In 2020, the Commission approved the use of storage as transmission in MISO[286] and initiated a rulemaking to develop rules for RTO deployment of dynamic line ratings.[287]

Yet GETs have not yet been effectively integrated into transmission planning. In Order No. 1000, the Commission declined to set forth "minimum requirements governing which non-transmission alternatives should be considered or the appropriate metrics to measure non-transmission alternatives against transmission alternatives," leaving such matters to "the stake-holders and the public utility transmission providers participating in the regional transmission planning process."[288] As numerous advocates have observed, this approach has not worked to

[282] Tsuchida et al., *Improving Transmission Operation with Advanced Technologies: A Review of Deployment Experience and Analysis of Incentives*, p. 21 at https://brattlefiles.blob.core.windows.net/files/16634_improving_transmission_operating_with_advanced_technologies.pdf.
[283] Order No. 890-A at ¶ 3009.
[284] Order No. 1000 at ¶ 49,869.
[285] Notice of Workshop, Docket No. AD19-19-000, Document Accession #: 20190909-3021.
[286] 172 FERC ¶ 61,132.
[287] https://elibrary.ferc.gov/eLibrary/docinfo?document_id=14908647.
[288] Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities, Order No. 1000, 136 FERC ¶ 61,051, at P 49,869.

ensure detailed consideration of GETs.[289] As a result, the Commission should build on Order No. 1000 to require planners to incorporate comprehensive consideration of GETs. While the Commission need not fully prescribe the metrics to be used, planners should be required to show that they have incorporated GETs into their planning process where they are cost-effective.[290] The Commission should also consider requiring entities proposing a transmission project to include in their submittal analysis of non-wires alternatives to the proposed project.[291]

A broad range of technologies can serve as GETs, but one of the most important such technologies is storage. The Commission has recognized the role of storage as a transmission asset on numerous occasions.[292] Notably, after conducting a technical conference to study the incorporation of storage as a transmission asset into transmission planning in MISO,[293] the Commission approved MISO tariff language effecting such incorporation and providing for full cost recovery on an equal footing with traditional wires solutions.[294] Given the information gathered in the process of the Commission's consideration of storage as transmission in MISO, the Commission is well situated to put forth nationwide transmission planning reforms that require

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[289] *See* Americans for a Clean Energy Grid, *Planning for the Future: FERC's Opportunity to Spur More Cost-Effective Transmission Infrastructure* (Jan. 2021), https://cleanenergygrid.org/wp-content/uploads/2021/01/ACEG_Planning-for-the-Future1.pdf; Shelley Welton, *Non-Transmission Alternatives* 39 Harvard Env. L. Rev. 458, 482, https://harvardelr.com/wp-content/uploads/sites/12/2015/07/Welton-39-HELR-457.pdf; Scott Hempling, *Non-Transmission Alternatives: FERC's "Comparable Consideration" Needs Correction* 7 (May 2013), https://www.scotthemplinglaw.com/files/pdf/ppr_nta_comparable_consideration_0513.pdf.

[290] *See* Americans for a Clean Energy Grid, *Planning for the Future: FERC's Opportunity to Spur More Cost-Effective Transmission Infrastructure* (Jan. 2021), Shelley Welton, *Non-Transmission Alternatives* 39 Harvard Env. L. Rev. 458, https://harvardelr.com/wp-content/uploads/sites/12/2015/07/Welton-39-HELR-457.pdf Welton.

[291] Shelley Welton, *Non-Transmission Alternatives* 39 Harvard Env. L. Rev. 458, https://harvardelr.com/wp-content/uploads/sites/12/2015/07/Welton-39-HELR-457.pdf.

[292] Western Grid Development, LLC, 130 FERC ¶ 61,056, 61,327, 61,333 (2010); 172 FERC P 61132 (F.E.R.C.). This recognition is consistent with the Energy Policy Act, which directed the Commission to encourage the deployment of storage as an "advanced transmission technology." Pub. L. No. 109-58 § 1223 (2005), 119 Stat. 953-54 (codified at 42 U.S.C. § 16422).

[293] https://www.federalregister.gov/documents/2020/05/07/2020-09751/midcontinent-independent-system-operator-inc-supplemental-notice-of-technical-conference.

[294] 172 FERC ¶ 61,132.

detailed consideration of storage in the transmission planning process on equal terms to transmission, including cost-recovery.

However, even if the Commission is disinclined to require cost-recovery for storage as a transmission asset at this time, it can take other steps that help unlock the value of storage as a transmission asset for the grid. One such step is clarifying pro-forma OATT language and interconnection processes to make use of storage proposed by generation developers for the purpose of reducing possible transmission upgrade needs for a generation project, without requiring that transmission revenues be provided to such generation-plus-storage owners. Examples of existing authority or practices relevant to using generator-owned storage to address transmission needs are:

> a) *reactive power*: Interconnection studies make use of the ability of a proposed generator to provide or absorb reactive power. The Commission can order transmission analysis of interconnections to allow for the proposed storage to absorb or provide power.
>
> b) *redispatch*: OATT language that describes redispatch of generation can be applied to the operation of storage: "To the extent the ISO determines that the reliability of the system can be maintained by redispatching resources, the ISO will initiate procedures pursuant to Section II.22 of this OATT to redispatch the appropriate resources and the Transmission Customers' own resources on a least-cost basis without regard to the ownership of such resources."[295]

Additionally, the Commission can and should require the incorporation of storage and other GETs into transmission planning even if cost-recovery is not allowed. Although this may raise a funding issue, it would nevertheless offer important benefits.[296] First, analysis demonstrating the superior cost-effectiveness of GETs could help stimulate fresh thinking and political will to resolve this issue at the Commission level. Second, an analysis showing GETs to be cost-effective could

[295] ISO-NE OATT.
[296] Shelley Welton, *Non-Transmission Alternatives* 39 Harvard Env. L. Rev. 458, 508, https://harvardelr.com/wp-content/uploads/sites/12/2015/07/Welton-39-HELR-457.pdf.

also prompt interested states to coordinate cost-sharing for such an alternative amongst themselves.[297]

Due to the record developed through consideration of MISO's storage as transmission tariff, storage is well positioned for deepened and comprehensive incorporation into transmission planning processes. However, other GETs, such as dynamic line ratings and topology optimization software, should also be considered as part of the planning process. For the same reasons discussed above, even if cost-recovery is not mandated for such technologies at this time, their incorporation into planning requirements can generate useful data to inform further steps.

6. *Create effective interregional planning*

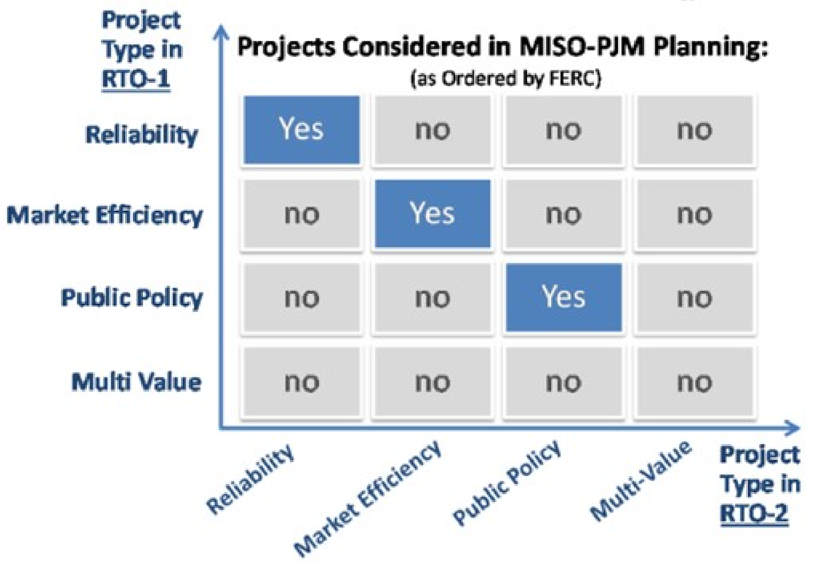
The ANOPR raises the question of whether reforms to the current interregional transmission coordination process, including potentially requiring interregional transmission planning, are needed and whether such reforms are consistent with the Commission's authority under section 206 of the FPA.[298] Reforms to how interregional transmission is planned are critical to ensuring the energy transition is successful. It is not sufficient to just reform the interregional coordination process as created in Order No. 1000. Rather, FERC needs to create an effective interregional transmission *planning* process.

Like regional planning, joint interregional planning has significant benefits but suffers from similar barriers.[299] Existing 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.[300] As illustrated below, these types of interregional planning processes may exclude the evaluation of projects where the needs

[297] *Id*.
[298] ANOPR at ¶ 62.
[299] Brattle-Grid Strategies Report at 66.
[300] *Id*.

differ between the regions, thus eliminating from consideration many valuable interregional projects:

FIGURE 13. SOME INTERREGIONAL PLANNING PROCESSES DO NOT ALLOW FOR THE EVALUATION OF PROJECTS THAT ADDRESS DIFFERENT NEEDS IN EACH RTO[301]



However, by limiting projects only to those that address the same types of needs in both regions, the planning process inadvertently excludes any interregional projects that would, for example, address reliability needs in one region but address market efficiency or public policy needs in the neighboring region.[302] Additionally, differences in each region's planning rules can lead to rejection of projects that might be similar but categorized differently. More often than not, however, a transmission project will provide multiple types of benefits and these benefits may differ across regions, such as where the development of wind generation resources provides an economic opportunity in one region but serves the public policy needs in the region where it is

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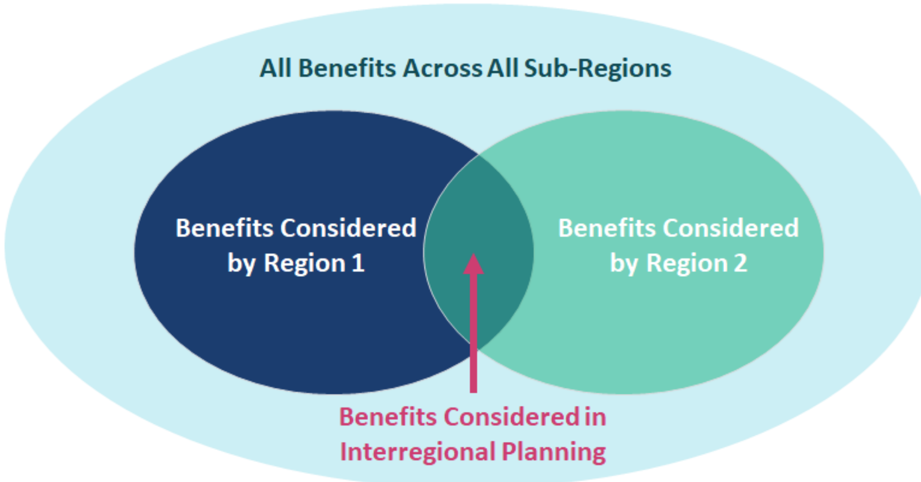
[301] *Id.* at 67. For a summary of the PJM-MISO interregional planning process, see Appendix C of Pfeifenberger, et al., *Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid*, Prepared for WIRES Group, April 2015 at https://brattlefiles.blob.core.windows.net/files/5950_toward_more_effective_transmission_planning_addressing_the_costs_and_risks_of_an_insufficiently_flexible_electricity_grid.pdf.
[302] Brattle-Grid Strategies Report at 67.

delivered.[303] As a result, only the least common denominator of benefits makes it through for consideration as shown below:[304]



The current lack of uniform criteria and requirement for multivalue planning across the neighboring regions leads to missed opportunities to build lower-cost or higher-value transmission projects that could provide greater benefits and reduce the overall costs and risks to customers in both regions.[305]

In the United States, there are two major schools of thought on interregional transmission that are so different as to appear to be describing separate countries. On one hand, an ever-growing body of studies from academia and the national labs identify vast potential savings from major interregional lines (Figure 14).[306] On the other hand, RTO interregional planning groups generally find little to no need for new interregional transmission (Figure 15). Academic studies admittedly are based on an idealized world, but the diametrically opposed findings suggest problems greater than can be explained away as oversimplification.

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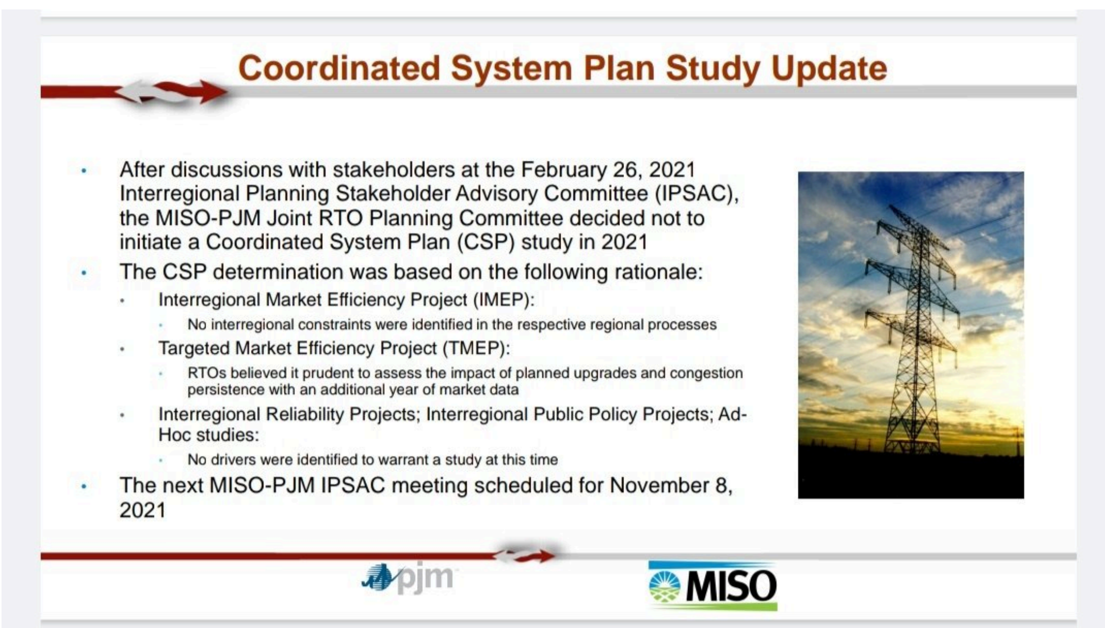
[303] *Id.*
[304] *Id.* at 68.
[305] *Id.* at 67.
[306] *See, e.g.*, Rob Gramlich & Jay Caspary, *Planning for the Future: FERC's Opportunity to Spur More Cost-Effective Transmission Infrastructure*, ACEG, Appendix A (January 2021).

FIGURE 14: REPRESENTATIVE NEW TRANSMISSION BUILD FROM AN ACADEMIC TRANSMISSION STUDY.[307] THE PICTURED TRANSMISSION INVESTMENTS ARE REPORTED AS HAVING A 202% BENEFIT-TO-COST RATIO UNDER A BASE CASE SCENARIO WITH NO NEW CLEAN ENERGY POLICIES.

FIGURE 15: REPRESENTATIVE CONCLUSION FROM RTO REGIONAL PLANNING ANNUAL PROCESS.[308]



[307] A. Bloom *et. al., The Value of Increased HVDC Capacity Between Eastern and Western U.S. Grids: The Interconnections Seam Study*, p. 6.
[308] PJM/MISO, *Interregional Planning Update* (August 2021), *available at* https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/pjm-miso-joint-common/2021/20210824/20210824-item-03-interregional-planning-update.ashx.

One way academic studies simplify their modeling is by assuming what might be called "frictionless planning," where the most economically efficient transmission investments are quickly identified. As we argue above, current interregional planning approaches are far from this ideal.

Adopting a minimum set of guidelines for planning and benefit-cost analysis for all planning regions will make it easier to align interregional project evaluation processes. Beyond establishing a minimum set of guidelines, the Commission should require transmission planning regions to study benefits to neighboring regions, as well as incorporate additional benefits that may be unique to interregional projects.[309] As Brattle Group has recommended, each seams entity should be mandated 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.[310] Further, seams entities should develop metrics to capture any unique seams-related benefits.[311]

Planning regions should be required to update their planning processes to be compatible with interregional planning such that they should evaluate inter-regional projects by maximizing interregional benefits as opposed to maximizing benefits solely within the region's borders. The Commission should disallow exclusions for projects of arbitrary voltage levels or sizes that currently exist in some interregional planning processes.[312] Finally, interregional planning processes should be conducted at annual intervals, and include a process for ensuring that inter-regional projects are not duplicative of projects being approved within regional planning processes.

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[309] *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).
[310] *See id.*
[311] *See id.*
[312] MISO and SPP interregional planning processes do not include projects under 345 kV.

Cost allocation for interregional projects is especially challenging given that regions have different approaches to cost-allocation for projects that are within their borders, and because of the risk that one region may seek to unfairly impose costs on a neighboring region through this process. To address these issues, the Commission should require that all planning regions adopt unified cost-allocation processes for projects at their respective seams and require that the cost-allocation process be a "beneficiary pays" methodology that relies on a quantified assessment of benefits and costs for every inter-regional project portfolio. The Brattle Group has outlined a number of potential cost allocation mechanisms that may facilitate interregional agreement, including allocation according to contribution to the need, usage share of the project, or allocating costs based on the project's physical location.[313]

7. *Reform the process for planning and funding network upgrades through generator interconnection*

The ANOPR seeks comment on whether FERC needs to improve the coordination between the regional transmission planning and cost allocation and generator interconnection processes.[314] The current lack of proactive, multi-value, and scenario-based planning for future generation and policy needs has created a situation where we are planning an integrated and shared network through the generator interconnection, local upgrade, and reliability planning processes. Having to bear the full costs of such upgrades forces many generation developers to withdraw their interconnection requests, resulting in inefficient outcomes and higher system-wide costs. Without reform to the transmission planning process that links interconnection with transmission planning, projects stalled in interconnection queues will continue to face ever-longer delays and consumers will face ever increasing costs.

[313] *See* Johannes P. Pfeifenberger and Delphine Hou, *Seams Cost Allocation: A Flexible Framework to Support Interregional Transmission Planning*, at 61, April 2012.
[314] ANOPR at ¶ 65.

As a January 2021 report by Grid Strategies demonstrates, the current approach of identifying and funding network upgrades through the generator interconnection process is becoming unworkable as costs and queue backlogs increase. This report shows that recent network upgrade costs are 2 to 5 times higher now that the existing transmission capacity has been fully subscribed in most regions of the country.[315] The report cites data showing that the identified upgrade costs for recent entrants into the interconnection queue in western MISO now exceed $750/kW.[316] By 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.[317]

Importantly, the current process leads to a higher-cost solution for achieving state clean energy policies, which unreasonably increases overall electricity costs for consumers.[318] This is confirmed by RTOs' own studies. Under PJM's current queue-based generation interconnection study process, its feasibility and system impact studies for interconnection requests totaling 15.5 GW of offshore wind along the PJM territory coastline estimated $6.4 billion in total PJM network upgrade costs.[319] By contrast, a proactive region-wide study conducted by PJM in July 2021 that evaluated onshore transmission investment needs to connect a cumulative 17 GW of offshore wind generation to its footprint, which included offshore wind resource interconnection needs of

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[315] 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.
[316] For example, the average cost for wind projects in MISO's August 2017 Definitive Planning Phase 2, West was $756/kW.
[317] 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.
[318] Brattle-Grid Report at 5.
[319] *Id*. at 4.

multiple states' offshore wind plans, estimated only $3.2 billion in onshore network upgrade expenditures — less than half the costs.[320]

Until recently, these interconnection charges for new renewable resources typically comprised a small fraction of total project costs.[321] However, because of insufficient transmission buildout, in recent years these costs have risen dramatically; interconnection charges now can comprise a significant percentage of total project costs.[322] In most regions, new network capacity is needed for almost all projects in interconnection queues. The 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. For example, interconnecting wind projects in MISO historically incurred interconnection costs of $0.85 per megawatt hour (MWh) or $66 per kilowatt (kW), but new wind projects face interconnection costs that are nearly five times higher, at $4.05/MWh or $317/kW, or about 23 percent of the capital cost of building a wind project.[323] New solar projects in MISO South have even higher upgrade costs. A 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.[324] Similar increasing network upgrade cost assignments are 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.[325] However, upgrade costs for newly

[320] *Id*., *citing* PJM, Offshore Transmission Study Group Phase 1 Results, presented to Independent State Agencies Committee (ISAC), July 29, 2021.
[321] *See Americans for a Clean Energy Grid*, *Disconnected: The Need for a New Generation Interconnection Policy* 13-16 (Dec. 2020), *citing* 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.
[322] *Id*. at 6.
[323] *Id*.
[324] MISO, Final MISO DPP 2019 Cycle 1 South Area Study Phase I Report, at 8-15, July 16, 2020.
[325] *Americans for a Clean Energy Grid*, *Disconnected: The Need for a New Generation Interconnection Policy* at 14, *citing* 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.

proposed wind and solar projects, have risen to \$0.69/MWh and \$3.66/MWh, respectively, or \$54/kW and \$131.90/ kW, respectively, more than a 100 percent increase.[326]

The high cost of interconnection is increasing the rate at which generators drop out of the interconnection queue. A recent study by Sustainable FERC found that between January 2016 and July 2020, 245 clean energy projects in advanced stages of the MISO generator interconnection process chose to withdraw from the queue.[327] Interviews with the owners of these projects indicates that network upgrade costs were the primary reason for withdrawing.[328] Worse still, queue dropout rates appear to be rising. 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. The projects that dropped out, some of which had power purchase agreements in place,[329] each faced transmission upgrade costs ranging from tens to hundreds of millions of dollars.[330] As mentioned, long-term solutions to this problem require changes that fundamentally reform the regional and inter-regional transmission planning process to require proactive and forward-looking transmission planning. Planning for future generation in the transmission planning process can ensure a robust transmission system paid for by all of the beneficiaries of that transmission. Once these broader needs are planned for in the transmission planning process, the interconnection process need only study the very limited needs of an interconnecting generator (or cluster of generators). Interconnecting facilities will no

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[326] *Id*.

[327] Sustainable FERC, New Interactive Map Shows Clean Energy Projects Withdrawn from MISO Queue at https://sustainableferc.org/wp-content/uploads/2020/08/MISO-Queue-Map-and-Analysis-2PageReport-8-26-20-2.pdf.

[328] *Americans for a Clean Energy Grid, Disconnected: The Need for a New Generation Interconnection Policy* at 17.

[329] 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.

[330] *Americans for a Clean Energy Grid, Disconnected: The Need for a New Generation Interconnection Policy* at 17, *citing* Peder Mewis and Kelley Welf, *Clarion Call! Success has Brought Us to the Limits of the Current Transmission System*, November 12, 2019.

longer need to pay for what amounts to underinvestment in the transmission system. Fewer will drop out of the queue, and the interconnection process will be more efficient and quick.

Several interesting funding models that attempt to proactively address this issue have emerged from PJM's Interconnection Policy Workshops, where stakeholders have discussed possible alternatives to participant funding.[331] One option would change planning criteria to treat a defined set of network upgrades as baseline transmission upgrades that would advance in the PJM regional planning process.[332] Under this approach, these projects would be subject to the competitive planning process on the basis of a certain amount of projects impacting a particular facility or on a cost-per-MW threshold and be paid for under existing cost allocation rules. Another option would implement the State Agreement Approach (SAA) authorized under Order No. 1000 by a state or states voluntarily taking responsibility for funding network upgrades based on their renewable portfolio goals.[333] Under this approach, network upgrades that exceed a certain dollar threshold would be sent to a state or state to underwrite. Generators that would impact these upgrades would reimburse the state under the terms and conditions of the SAA. New Jersey has incorporated the state's offshore wind public policy goals into PJM's regional transmission planning process through the SAA.[334] Pursuant to this approach, New Jersey is able to determine whether a coordinated approach to transmission planning can lead to more cost-effective transmission solutions. The state has the option to select one or more of the proposed projects, but is not required to do so. A third option would apply a subscription model, pursuant to which PJM

[331] *See* Ken Seiler, *Cost Allocation Today and Possible Alternatives: Review of Options Discussed to Date*, Interconnection Policy Workshop: Session 3 July 22, 2021, https://www.pjm.com/-/media/committees-groups/committees/pc/2021/20210722-workshop-3/20210722-item-03-interconnection-policy-reforms-overview-presentation.ashx.
[332] *See id.*, slide 7.
[333] *See id.*, slide 6. *See also State Voluntary Agreements to Plan and Pay for Transmission Facilities*, 175 FERC ¶ 61,225 (2021).
[334] *See* https://www.nj.gov/bpu/pdf/boardorders/2020/20201118/8D%20-%20ORDER%20Offshore%20Wind%20Transmission.pdf.

would examine the level of commercial interest before developing a multi-interconnection network upgrade.[335] Under this approach, PJM would study whether a large-scale network upgrade would be advantageous and would post identified areas of the system and would seek "subscribers" in the form of interconnection requests looking to use the line. Once a certain subscription threshold was met, the upgrade would advance through the planning process, and all costs associated with the upgrade would be paid by subscribing projects.

D. INTEGRATE STATE AND LOCAL OUTREACH EARLY IN THE PLANNING PROCESS

The FPA leaves transmission siting to the states, but that is not the end of the preemption analysis. A siting law that completely undermines regional planning is preempted under the Supremacy Clause. That does not mean FERC is commandeering authority over siting. States have enormous discretion to create siting laws that accommodate their own idiosyncratic preferences, and that would not change. They cannot use siting laws to completely prevent FERC from exercising its own statutory obligations over the FPA.

This ANOPR presents opportunities for the Commission to work with states and RTOs/ISOs to make transmission siting more coordinated, efficient, cost-effective, and equitable through increased coordination between regional and local transmission planning processes. There are also significant opportunities for the Commission to facilitate improved stakeholder engagement processes in transmission siting, including a heightened focus on environmental justice and equitable considerations. While the ANOPR seeks comment on whether a regional-state committee or other organized body of state officials could help develop and evaluate regional planning assumptions,[336] we believe that the Commission's Office of Public Participation is well

[335] Ken Seiler, *Cost Allocation Today and Possible Alternatives: Review of Options Discussed to Date*, Interconnection Policy Workshop: Session 3 July 22, 2021, slide 11.
[336] ANOPR at ¶¶ 64, 176-77.

positioned to play a leading role in ensuring that stakeholder concerns are heard early and are meaningfully addressed, and to develop principles and guidelines that strike an appropriate balance between addressing stakeholder concerns while also ensuring that transmission can be built at a speed and scope commensurate with the need to rapidly expand the transmission system and decarbonize the grid within the next 15 years, consistent with the United States' goal of reaching 100 percent carbon-free electricity by 2035.[337] The recently established Joint Federal-State Task Force on Electric Transmission can also play a key role in increasing federal and state coordination and cooperation on transmission planning and development.

1. *Improved coordination at the federal, regional, and state levels can facilitate more efficient and cost-effective transmission planning and development*

In several places, the ANOPR seeks comment on the role of states in transmission planning and development.[338] Transmission siting challenges are pervasive throughout the country. However, some states' siting processes are more efficient than others, resulting in a shorter project development time and lower costs. It can take as many as 5-10 years to plan, develop, and build a transmission project, which means that some transmission projects take twice as long to be completed as others. There is an urgent need to rapidly expand transmission infrastructure to accelerate the interconnection of renewable generation facilities and the interstate and interregional transfer of electricity, and to facilitate the decarbonization of the electricity grid. These steps are critical to meet the goals of carbon-free electricity by 2035 and net-zero emissions economy-wide by 2050, and to avoid the worst impacts of climate change, as highlighted in the Intergovernmental

[337] https://www.whitehouse.gov/briefing-room/statements-releases/2021/04/22/fact-sheet-president-biden-sets-2030-greenhouse-gas-pollution-reduction-target-aimed-at-creating-good-paying-union-jobs-and-securing-u-s-leadership-on-clean-energy-technologies/.
[338] *See, e.g.*, ANOPR at ¶¶ 51-52, 176-77,

Panel on Climate Change's ("IPCC") Sixth Assessment Report.[339] Transmission projects that take many years to complete significantly hinder these efforts. At the same time, it is important that people impacted by transmission projects, including environmental justice populations, have access to, and meaningful input on transmission planning processes. Increased coordination between regional and local transmission planning entities could accelerate project development, by helping decision makers understand local planning needs and issues, and implement best practices from other jurisdictions, while meaningfully considering stakeholder input and avoiding mistakes that have hindered or prevented proposed transmission projects from being built.

The Commission could facilitate coordination between regional and local transmission planning entities in a number of ways. For instance, as discussed in the ANOPR,[340] it could establish an independent transmission monitor within each region to, among other things, review transmission-related spending and identify inefficiencies between local and regional transmission planning processes. The Commission could also establish a mechanism for state oversight of the regional transmission planning process, for example through a state review committee that could, among other things, evaluate whether needs identified in a local transmission plan could be better met through the regional planning process.[341] Further, the Commission could require transmission providers to coordinate with states and local entities to identify geographic zones with the potential for the development of significant amounts of renewable resources and plan transmission to facilitate the integration of renewable resources in those zones.[342]

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[339] IPCC, 2021: Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change, Cambridge University Press, https://www.ipcc.ch/report/ar6/wg1/downloads/report/IPCC_AR6_WGI_Full_Report.pdf.
[340] ANOPR at ¶¶ 163-75.
[341] For example, see the Regional State Committee (RSC) in the Southwest Power Pool (SPP), https://spp.org/stakeholder-groups/organizational-groups/regional-state-committee. *See also* ANOPR at P 177.
[342] For example, see the Competitive Renewable Energy Zones (CREZ) in Electric Reliability Council of Texas (ERCOT), http://www.ercot.com/committee/crez, and Multi-Value Projects (MVPs) in the Midcontinent

As the Commission recognizes, potential transmission reforms "may require greater interregional or state-regional coordination to be fully realized in a just, reasonable and not unduly discriminatory or preferential manner."[343] Increasing coordination among neighboring regions by requiring them to participate in a joint regional planning process, rather than separate parallel processes, could reduce or eliminate current inefficiencies in the multi-step process of selecting and developing interregional transmission projects. It is appropriate and consistent with the Commission's authority under section 206 of the FPA for the Commission to consider the presence and location of renewable resource geographic zones during the interregional planning process because such areas with plentiful, low-cost renewable resources have bearing on "the cost of the production or transmission of electric energy by means of facilities under the jurisdiction of the Commission."[344]

Better coordination between regional and local transmission planning processes can increase efficiency and develop more cost-effective solutions. As the Commission suggests, this should include efforts "to more clearly identify the lines of regulatory authority and oversight between states and federal authorities with regard to regional and local transmission facilities to ensure appropriate vetting of transmission infrastructure."[345] Delineating the boundaries of state and federal authority over transmission planning and identifying areas of concurrent jurisdiction would help clarify the process for many interested stakeholders, including potentially affected communities, and would aid in identifying existing inefficiencies or redundancies that may increase costs and should be mitigated or eliminated.

Independent System Operator (MISO), https://www.misoenergy.org/planning/planning/multi-value-projects-mvps/#t=10&p=0&s=&sd=.
[343] ANOPR at ¶ 46.
[344] 16 U.S.C. § 824e(d).
[345] ANOPR at ¶ 8.

The recently established Joint Federal-State Task Force on Electric Transmission[346] should play a key role in identifying opportunities to improve federal and state coordination, while also considering interregional and regional aspects of transmission planning. Topics the Task Force may address include several topics that could contribute to improved coordination and cooperation directly between states, and between states and the Commission. Determining how to strike an appropriate balance between states' priorities, and between state and federal priorities (such as reliability, consumer protection, equity and environmental justice, and the protection of natural resources, communities, and the environment) will be an important topic for the Task Force to consider, particularly in "Exploring potential bases for one or more states to use FERC-jurisdictional transmission planning processes to advance their policy goals, including multistate goals; [and] Exploring opportunities for states to voluntarily coordinate in order to identify, plan, and develop regional transmission solutions."[347] In situations where neighboring states have different policy goals and competing priorities, the Task Force can play an important role in addressing these conflicts and identifying a path forward. Regional meetings of the Task Force, with an opportunity for all state commissioners in the region to attend, could be especially useful in addressing this situation.

2. *Meaningful stakeholder engagement in transmission planning is critical to facilitate effectual and equitable transmission siting.*

The ANOPR seeks comment on whether the Commission should require additional stakeholder input into the transmission planning processes and provide sufficient opportunities for stakeholders to assess the reasonableness of the results and provide input on future modifications to the planning process.[348] The states have primary jurisdiction over transmission siting and

[346] *Joint Federal-State Task Force on Electric Transmission*, 175 FERC ¶ 61,224 (2021).
[347] *Id.*
[348] ANOPR at ¶¶ 52, 60.

determine how to address issues such as protection of natural resources, equity, and environmental justice in their siting decisions. However, the Commission's Office of Public Participation (OPP) can and should play a critical role in transmission siting by working with the states to develop and implement robust stakeholder engagement processes that can be used both in regional transmission planning and local transmission planning.

Some states are more advanced in their efforts to integrate robust stakeholder engagement into their planning and permitting processes, which should include consideration of equity and may require targeted outreach to environmental justice populations. Stakeholder engagement early in the transmission siting process is critical to identify community concerns about potential siting locations, and to begin assessing potential solutions to these concerns. For example, the CapX2020 project in the Upper Midwest, which resulted in nearly 800 miles of new transmission lines across four states worth over $2 billion, has been highlighted as a successful example of collaborative planning and meaningful stakeholder outreach.[349] Eleven utilities in four states participated in the process, and there was a sustained commitment to stakeholder outreach and engagement from the very beginning. The project has enabled a significant increase in wind generation in Great Plains states served by the new transmission lines.[350]

Avoiding comprehensive stakeholder engagement in transmission siting may reduce costs and save time initially, but a failure to meaningfully consult with affected communities and other interested stakeholders is likely to cost more and cause delays and problems later in the process, through public protests, litigation, legislative action, negative press, or other actions in opposition

[349] Frank Jossi, Utility Dive, *Utilities say CapX2020 transmission project prompting wind energy growth* (Nov. 30, 2017) (quoting a University of Minnesota report stating that "They engaged to an unparalleled degree with landowners, town, city, and county administrators, state utility commissioners, legislatures, and regulators throughout the planning process to bring a new era of transparency and civic engagement to transmission planning, citing, and construction of new high-voltage transmission lines.").
[350] *Id.*

to the planned siting location. For example, New England has struggled to expand transmission in recent years due to public opposition and siting issues. The Northern Pass transmission project, which was first proposed in 2011, and later submitted as a proposal in response to a clean energy procurement in Massachusetts, would have delivered over 1,000 MW of Canadian hydropower into New England, but was rejected by the New Hampshire siting committee in 2018.[351] The following year, the New Hampshire Supreme Court upheld the committee's decision, and the project was withdrawn.[352] A parallel proposal, the New England Clean Energy Connect transmission line, was selected by Massachusetts after the Northern Pass project failed to obtain its siting approval, and will bring 1,200 MW of Canadian hydropower from Quebec to Maine, and ultimately to Massachusetts.[353] However, this project has faced intense public opposition and numerous siting challenges.[354] Construction has already begun on the transmission corridor, but litigation and an upcoming referendum on the project have called its future into question.[355] In contrast, another transmission project that connected Canadian hydropower to Minnesota, dubbed the Great Northern Transmission Line, prioritized early and meaningful stakeholder engagement, which helped the project receive necessary permits in less than three years and begin operating within six years.[356]

Some RTOs have planning bodies that are ostensibly designed to facilitate public engagement and solicit public input into regional transmission planning processes, but even where these bodies exist, they may not provide meaningful access to transmission planning processes or

[351] David Brooks, Concord Monitor, *Eversource gives up on Northern Pass hydropower project* (July 26, 2019), https://www.concordmonitor.com/northern-pass-eversource-hydroquebec-27284387.
[352] *Id.*
[353] Scott Van Voorhis, Utility Dive, *An ideal marriage? The battle to match US clean energy demand with excess Canadian hydropower* (Aug. 16, 2021), https://www.utilitydive.com/news/an-ideal-marriage-the-battle-to-match-us-clean-energy-demand-with-excess-c/603600/.
[354] *Id.*
[355] *Id.*
[356] *Id.*

produce meaningful outcomes for stakeholders impacted by proposed transmission infrastructure improvements or additions. For instance, ISO-NE's Planning Advisory Committee (PAC) is a public forum designed to consider and assess regional transmission planning proposals and developments.[357] Though it is open to the public, materials are often not available to the public for security reasons and, even when the planning materials are available, they are often highly technical and thus inaccessible to the average member of the public. In addition, meetings of the PAC happen during the day on weekdays, making the meetings inaccessible to many. Given the lack of accessibility, it is difficult for stakeholders to meaningfully engage and influence the PAC. The New England states recently issued a report outlining recommendations for improving consideration of equity and environmental justice in regional transmission planning at ISO-NE, including that the PAC issue supplemental meeting materials that describe the major infrastructure agenda items briefly in non-technical language, and that ISO-NE's Regional System Plan include a supplement that explains the primary findings and project list in non-technical language.[358]

We encourage the Commission to work with states to develop guiding principles that strike an appropriate balance between states' jurisdiction over transmission siting, including considerations of equity and environmental justice and protection of natural resources, and federal jurisdiction over interstate and interregional transmission planning. The OPP can and should promote greater consistency and predictability in the transmission siting process by developing recommended best practices for stakeholder outreach. States that already have strong and effective stakeholder engagement processes could contribute their best practices to the OPP recommendations; states that do not could benefit from other states' experiences and a uniform set

[357] ISO-NE Planning Advisory Committee, https://www.iso-ne.com/committees/planning/planning-advisory/.
[358] New England States Committee on Electricity, "New England Energy Vision Statement, Report to Governors – Advancing the Vision," June 2021, https://newenglandenergyvision.files.wordpress.com/2021/06/advancing-the-vision-report-to-governors-2.pdf, at 22.

of minimum recommendations. All states would have the flexibility to tailor the OPP's recommendations as needed to account for local conditions.

Stakeholder engagement best practices should include both procedural and substantive equity and environmental justice considerations. Stakeholder engagement processes should be open, accessible and transparent to the public. For instance, communications with the public should be in plain language and explain how transmission planning and decisions may impact stakeholders, in particular environmental justice communities, communities of color, low-income communities and frontline and fenceline communities, and planning officials should hold public meetings at multiple times, including evenings and weekends, and at multiple venues, including via different forms of virtual media. These meetings should occur early in the transmission planning process so that stakeholder input can be meaningfully used by the transmission planners. Engagement processes should enable diverse and meaningful public participation. For instance, planning processes should be designed and equipped to solicit and receive public participation relating to alternatives to projects undergoing consideration, including, as applicable, non-wires alternatives, and relating to project benefit packages. Further, planning officials should engage in early and ongoing outreach and communication with members of the public that may be affected by planning decisions, with an emphasis on environmental justice communities, communities of color, low-income communities, and frontline and fence line communities.

3. *Federal permitting and approval of transmission projects should be better coordinated and expedited*

The Commission should work with relevant federal agencies to consider developing a coordinated, expedited, and concurrent review process for transmission infrastructure projects[359]

[359] At the state level, New York's Office of Renewable Energy Siting was established to "Streamline and expedite the siting of major renewable energy projects and associated transmission facilities to help achieve the State's clean

that require federal permits or approvals.[360] This process should build on the existing legal framework for creating national interest electric transmission corridors.[361] That framework outlines coordination among federal agencies on the development of such corridors, including designation by the Department of Energy of such corridors in "geographic areas experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers,"[362] permitting by the Commission for the construction of electric transmission facilities within such corridors,[363] and coordination of other federal authorizations for transmission facilities.[364] The Commission should pursue increased coordination among federal agencies for interstate and interregional transmission infrastructure under this existing statutory framework. The Commission should also support efforts to develop a "Grid Authority" proposed as part of the Biden administration's infrastructure bill, to be housed in the Department of Energy and to oversee power infrastructure upgrades, including the development of thousands of miles of transmission lines.[365]

In addition to advancing coordination among federal agencies, other options for reducing delays often associated with developing transmission infrastructure—and resulting delays in relieving transmission congestion and unlocking renewable energy resources—include a process for fast-tracking generator interconnection for facilities that have firmly committed to connecting to new regional transmission facilities. As the Commission points out, the timeline for transmission

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energy and climate goals, while maintaining the State's strong environmental and public participation standards." New York Office of Renewable Energy Siting, https://ores.ny.gov/.

[360] *E.g.*, Section 404 permits from the Army Corps of Engineers under the Clean Water Act, Presidential Permits from the Department of Energy for projects crossing international borders.

[361] 16 U.S.C. § 824p; 10 C.F.R. § 900.4.

[362] 16 U.S.C. § 824p(a).

[363] 16 U.S.C. § 824p(b).

[364] 16 U.S.C. § 824p(h).

[365] https://www.whitehouse.gov/briefing-room/statements-releases/2021/06/24/fact-sheet-president-biden-announces-support-for-the-bipartisan-infrastructure-framework/.

facility permitting and construction often exceeds that of the generator interconnection and construction process, but a faster interconnection process would nonetheless be beneficial.

E. BENEFIT COST ANALYSIS AND COST ALLOCATION SHOULD BE REFORMED

The ANOPR asks multiple question about calculating the benefits and costs of transmission for transmission planning and cost allocation.[366] In multiple regions, planners calculate the benefits of transmission narrowly and often consider distinct needs in separate processes. Regional planning typically begins by running a model to determine whether the region has violated any NERC reliability requirements. Planners apply NERC Transmission Planning Performance Requirements (known as TPL standards) to identify any long-term reliability issues. TPL standards require transmission planners to evaluate the long-term reliability issues in the region.[367]

Typically, only after a regional planner identifies the region's reliability needs does it consider economic and policy needs. As part of this process, planners are supposed to consider future scenarios, which presumably involves considering how the resource mix and electric demand could change in the future. Reliability projects are usually selected on the basis of cost. Economic and policy projects are based on the benefit-to-cost ratio.[368] Planners quantify the expected benefits of a proposed project and compare those benefits to the costs of building the transmission line. Those projects that create the most sizable benefits compared to their costs are chosen, and regulators often require a benefit-to-cost ratio of 1.25— meaning that the benefits of a new transmission line should be 25% greater than the costs of building it.[369]

[366] *See, e.g.,* ANOPR at ¶¶ 39, 48, 53.
[367] FERC, Report on Barriers and Opportunities for High Voltage Transmission 25 (June 2020).
[368] *See* Johannes Pfeiffenberger, *Improving Transmission Planning*, The Brattle Group (Nov.6, 2019), https://brattlefiles.blob.core.windows.net/files/17555_improving_transmission_planning_-_benefits_risks_and_cost_allocation.pdf.
[369] *See id*.

The problem is that many RTOs calculate the benefits of transmission narrowly. Most RTOs rely on the Adjusted Production Cost (APC) to calculate the benefits of transmission.[370] APC compares the costs of operating a generation fleet with and without the proposed transmission upgrade.[371] APC allows the RTO to identify the monetary savings of operating under normal conditions. Doing so, however, excludes substantial reliability and climate benefits, including the fact that a diversified and geographically diffuse resource mix can better withstand extreme weather events, the ability of grid operators to respond to transmission outages, and the climate benefits of increasing renewables benefits. These are all quantifiable benefits, but in many cases, RTOs do not count them when calculating the benefits of proposed transmission upgrades.

FERC must ensure that planning regions calculate all of the benefits and costs in determining what transmission is included in a regional plan and how to cost allocate that transmission. Below PIOs lay out recommendation on how to better perform the benefit cost analysis.

1. *Expand and standardize benefit metrics and cost-benefit accounting*

Transmission projects have many benefits. A consistent framework for evaluating those benefits is critical to ensure that the transmission planning processes identify the right suite of projects given the realities of the current system and future resources, that transmission development supports both the public interest and reasonable rates, and to provide a basis for cost allocation. This is particularly important for projects that receive cost-of-service treatment, as rigorous benefit analysis is the primary safeguard against misallocation of ratepayer funds. To identify solutions that result in lower overall consumer costs, planning needs to consider the

[370] *See* MISO, Adjusted Production Cost Calculator White Paper, https://cdn.misoenergy.org//MISO%20APC%20Calculation%20Methodology125160.pdf.
[371] *See id*.

multiple values offered by transmission investments, irrespective of whether the primary driver of transmission infrastructure is based on reliability, public policy, or economic needs.[372] Current procedures for reviewing projects requesting cost-of-service rates may lead to unjust, unreasonable, or unduly discriminatory rates because the planning processes that approve them do not consider all benefits.

Unfortunately, the Brattle Report explains, 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.[373] 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. Similarly, 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. As Brattle explains, 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.[374] The Commission should require planning authorities to use consistent benefit metrics that reasonably reflect all benefits of considered projects.

Transmission planning can be improved by developing a set of consistent benefit metrics that apply to all planning regions. In the context of regional planning, FERC can build on Order No. 1000 by mandating that these metrics be used to compare proposed projects. The Commission could also develop a new policy of using these same metrics to evaluate the prudence of

[372] Brattle-Grid Strategies Report at 3.
[373] *Id*. at 31.
[374] *Id*.

transmission owner-directed investments. Also, the Commission should require that benefits be quantified over the asset life of the project rather than just the first 20 (or less) years of service. Such a consistent framework would ensure rates are just and reasonable by ensuring all projects are evaluated on a comparable and transparent basis and that all projects are evaluated by the same criteria regardless of the sponsor.

Benefit-Cost Analyses (BCAs) can be used to demonstrate that transmission investments are efficient and thus that these investments are just and reasonable. The Commission should provide a minimum set of factors to be evaluated in regional planning processes and in rate filings for other projects seeking cost-of-service rates. These factors could include the following:

Economic: Reduction in the cost of power through reduction of transmission congestion and greater access to low-cost supplies. Such an estimate will necessarily require an “expected value” approach considering a range of future fuel prices and demand patterns. The Commission may also wish to place a value on reduction (or increase) in electricity price sensitivities resulting from greater geographic and fuel source diversity.

Resource adequacy and reliability: Reduction in the cost of meeting resource adequacy and reliability standards by allowing imports to replace more expensive local generation, by lowering required reserve margins (or other planning targets) through increased diversity benefits, by increasing the ELCC (or similar measure) of planned and existing generation through increased geographic diversity of renewable resources, by lowering fuel security risks by reducing dependencies on vulnerable elements of the natural gas or other fuel distribution systems, by enabling greater reserves sharing, and by resolving existing or forecast transmission contingency issues.

Resiliency: Improved ability of the system to maintain service in the event of disruptions, reduction in the frequency or severity of service interruptions, and shortened recovery time after interruptions. Whatever framework the Commission arrives at, transmission's ability to provide resiliency benefits should be evaluated consistently with other means of mitigating risks. Because future contingencies are unknown, resiliency benefits will likely be estimated on a probabilistic basis. In developing these measures, the Commission should remain mindful that the past may not be an accurate guide to the frequency of future extreme weather events and their associated power system disruptions. Additionally, the cost of power system disruptions is likely to grow at or faster than the overall economy, which suggests that the Commission consider if an alternative discount rate should be used for valuing resiliency improvements.

Public policy: Transmission planners must ensure sufficient transmission to meet known state or federal policies. This must include anticipated future generation. The resources to meet these state policies will be built—this is simple fact. To limit the transmission planning studies to looking only at generation in the interconnection queue with a completed facilities study in lieu of what is clearly planned for is short sighted and ill-advised. Playing ostrich regarding expected future generation in the transmission plan will result in a transmission plan that doesn't match the reality of the system.

Beyond establishing a minimum set of guidelines, the Commission should encourage regions to incorporate additional benefits, including those in neighboring regional methodologies, as well as incorporate additional benefits that may be unique to interregional projects.[375] As the Brattle Group has recommended, each seams entity should be given the option to consider some

[375] *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).

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.[376] Further, seams entities may "agree to develop metrics to capture any [unique] seams-related benefits."[377]

2. *Public utilities should be required to incorporate climate vulnerabilities into their transmission planning practices*[378]

FERC should act to reform the transmission planning process for the additional reason that reforming transmission is crucial to creating grid resilience in the face of climate disruption. As highlighted in PIO's comments in response to the Commission's Technical Conference on Climate Change, FERC can and should promulgate rules to require public utilities to assess climate vulnerabilities and incorporate the results of those assessments into their transmission planning practices. Midwestern regional experiences with polar vortexes over the past seven years underscore the importance of improved transmission planning to a more robust grid: a recent report from the American Council on Renewable Energy examining the causes of the service disruption during the February 2021 Winter Storm that stretched down to Texas concluded that "[e]ach additional 1 GigaWatt (GW) of transmission ties between the Texas power grid (ERCOT) and the Southwestern U.S. could have saved nearly $1 billion, while keeping the heat on for hundreds of thousands of Texans."[379] It concluded similarly that the other regional operators impacted by the winter storm, SPP and the MISO each could have saved over $100 million as well "with an additional 1 GW of transmission ties to power systems to the east."[380] And this phenomenon is not limited to cold weather spells in the Midwest: the report projected that additional transmission

[376] *See id*.
[377] *See id.*
[378] "It does not do to leave a live dragon out of your calculations, if you live near him." J.R.R. Tolkien, The Hobbit, or There and Back Again.
[379] Michael Goggin, Grid Strategies LLC, Transmission Makes the Power System Resilient to Extreme Weather, at 3 (Feb. 2021), *available at* https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf.
[380] *Id.*

could have saved tens of millions of dollars for the Texas heat wave in August 2019 (for ERCOT), and cold snaps in the Northeast from 2014 and 2017-18 (for the Northeastern RTOs).[381] Increased climate disruption, which will almost certainly continue, has created additional urgency in the effort to improve the transmission planning process. As discussed at FERC's Climate Change technical conference earlier this year, FERC should not allow transmission planning entities to plan transmission to remediate the effects of climate change in ways that that exacerbate or contribute to its effects.[382]

3. *FERC should consider how to incorporate costs and benefits defined by fiat into transmission analysis*

Following long-standing cost causation principles, transmission costs are allocated generally according to the benefits parties receive from the facility.[383] Benefits from transmission are have generally been financial, with some consideration given to less tangible benefits such as reliably.[384]

Recent years have seen the emergence of benefits relevant to the electric industry that are defined by fiat. As a case in point, consider the Clean Energy Standard (CES) currently under discussion in Congress. To simplify, the CES would assess a charge or award a payment to utilities based on their attainment of clean energy targets. Should Congress enact the CES, we argue that it would be binding on FERC, and transmission benefit cost analysis would be required to consider it, both for project threshold tests and for cost allocation purposes. In the case of the CES, the contemplated benefit is monetary and the beneficiaries clearly identified, so this would be a

[381] *Id.*
[382] Romany Webb, Associate Research Scholar/Senior Fellow at the Sabin Center for Climate Change Law, Columbia University Law School (FERC Technical Conference to Discuss Climate Change, Extreme Weather, & Electric System Reliability June 1 Tr. at 95, ln. 3-11).
[383] *See, e.g.*, *Illinois Commerce Com'n v. F.E.R.C*, 576 F.3d 470 (7th Cir. 2009).
[384] *Id.* at 477, agreeing that FERC may allocate costs based in part on reliability benefits, so long as a reasoned attempt it made to quantify the benefit and allocate costs proportionately.

straightforward matter, or at least no less straightforward than any other transmission benefit analysis.

However, other fiat benefits may not be so clear cut. Executive Order 13,990[385] states "It is essential that agencies capture the full costs of greenhouse gas emissions as accurately as possible…," identifies the Social Cost of Carbon ("SCC") and other greenhouse gasses as a key metric, and declares that "[a]n accurate social cost is essential for agencies to accurately determine the social benefits of reducing greenhouse gas ("GHG") emissions when conducting cost-benefit analyses of regulatory and other actions." To our knowledge, it is not settled if Executive Orders are binding upon FERC,[386] and FERC docket PL18-1, considering among other matters how to incorporate greenhouse gas concerns into pipeline permitting, is pending. Thus, inclusion of greenhouse gas costs and benefit in transmission analysis is not yet ripe for consideration but may soon be.

Nonetheless, the issue raises questions that it would be prudent for the Commission to engage in anticipation of near future need. As a key enabling technology for all forms of electricity production—both carbon dense and carbon free—transmission projects have potential GHG impacts far beyond the simple construction of the facility. The GHG impacts of transmission facilities appear amenable to analysis using similar tools transmission planners currently use to estimate economic effects, but ensuring that GHG social costs (or benefits from GHG reductions) are counted but not double-counted in the face of a multitude of federal, state, and private incentives for GHG reduction. The nature of GHG effects on climate makes benefits extremely diffuse. Arguably, every ratepayer enjoys a share of the benefits from any GHG reduction. Thus,

[385] *Protecting Public Health and the Environment and Restoring Science To Tackle the Climate Crisis*, 86 FR 7037 (January 20, 2021).
[386] *See Sierra Club et. al. v. FERC,* D.C. Cir. No. 16-1329 (2017), fn 5.

we submit that FERC should adopt rules that account for GHG analysis in transmission planning processes. FERC should consider the following issues when developing such rules:

- Should transmission planners be required to estimate the greenhouse gas impacts of proposed projects alongside traditional economic metrics?
- What are the considerations in determining if, and how much of, the GHG costs or benefits of a transmission project are captured through other policy tools, and how much residual cost/benefit should be ascribed?
- How should the benefits of transmission projects that reduce GHGs be reckoned so that costs may be allocated proportionately?
- If the cost allocation of transmission GHG benefits is to be allocated more broadly than traditional transmission benefits, are any new mechanisms needed?

A second set of issues arises from states' increasing role in environmental regulation. Acting in their role as retail ratemakers, environmental regulators, or under other authorities, states are increasingly creating fiat benefits valuing clean energy, specific technologies, or greenhouse gas reductions. The Commission's current approach to transmission projects built to support these public policies simply allocates all costs of those projects to the sponsoring state. We believe this approach is unreasonably crude, and would not pass judicial review under the standards articulated in the two *Illinois v. FERC* cases.[387]

Just as any other transmission project, many projects planned to meet public policy goals will produce reliability and economic benefits outside of the state that enacted the public policy. To the extent others share in the benefits, they should also share in the costs. We suggest that traditional benefits (cost savings and reliability) that accrue to transmission customers in states

[387] *See Illinois Commerce Comm'n v. F.E.R.C*, 576 F.3d 470 (7th Cir. 2009); *Illinois Commerce Comm'n v. Fed. Energy Regulatory Comm'n*, 756 F.3d 556 (7th Cir. 2014).

other than the sponsoring state(s) be valued, and cost allocated to those transmission customers appropriately. This is a variant on the usual cost allocation problem, as rather than finding a just and reasonable allocation of known costs, it requires the Commission to determine the just and reasonable charges for a given benefit. Based on the common threshold that transmission projects must meet a 1.25 to 1 benefit-cost ratio to be deemed prudent, we suggest that the Commission consider determining a conservative benefit-cost ratio such as 1.5 to 1 and allocate costs to beneficiaries based on that ratio. Under a 1.5 to 1 ratio, regions not sponsoring a public policy project would be allocated costs equal to 66% of their expected benefit. Recipients of traditional benefits in the sponsoring state(s) would receive identical treatment. Residual project costs after traditional benefits are accounted for should be borne by the state that enacted the public policy.

No doubt some opposed to particular state policies will argue that this is somehow requiring one state to bear the costs of another state's decisions. We disagree. Our proposed policy does nothing more or less than treat public policy transmission projects comparably to other transmission projects. The fiat benefits of a public policy project are only of value within the jurisdiction creating them, but that does not justify allowing residents of other jurisdictions to free-ride on the traditional benefits. To treat public policy projects otherwise is unduly discriminatory, and arguably allows states to impede interstate commerce for the purposes of protecting favored local interests.

4. *FERC should find that current practices of allocating network upgrade costs on a "but for" basis is unjust and unreasonable*

The ANOPR seeks comment on the existing participant funding approach to interconnection-related network upgrades.[388] The current lack of proactive, multi-value, and scenario-based planning for future generation and policy needs overburdens generators in the

[388] ANOPR at ¶¶ 71, 100-58.

interconnection queue by making them solely responsible for network upgrades even when these upgrades provide multiple benefits to the grid.[389] As Brattle notes, a recent ICF study showed that generation developers bear the entire cost of regional network upgrades required to interconnect generators, even though these upgrades often provide broad system-wide benefits.[390] It is important to emphasize that these upgrades are not limited to direct interconnection costs that allow these resources to access the grid. As the ICF study notes, given the fact that the power grid is currently over-subscribed, customers are being allocated the full cost of "adding new lanes to the highway and are increasingly responsible for building new highways."[391]

RTOs currently allocate most, if not all, network upgrade costs to the interconnecting resource. For example, under MISO's cost allocation process, developers are responsible for 90% of the cost of network upgrade projects rated 345 kV and higher, with the remaining 10% allocated regionally on a postage stamp basis. Developers are responsible for all the costs for network upgrades rated below 345 kV. In SPP, the entire cost of network upgrades is assigned directly to generators. Like in all planning regions, SPP's cost allocation fails to consider potential regional economic benefits from these network upgrades.

Many network upgrades provide quantifiable system-wide benefits. For example, in the ICF study referenced above, researchers evaluated the economic benefits of twelve network upgrade projects assigned through the MISO and SPP generation interconnection process from 2014-2020.[392] Calculating only the Adjusted Production Cost (APC) savings to the shared system,

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[389] Brattle Report at 3-4.

[390] *See id*. at 4, *citing* 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.

[391] *See* ICF Resources, *Just & Reasonable? Transmission Upgrades Charged to Interconnecting Generators Are Delivering System-Wide Benefits* at 3.

[392] ICF initially screened 230 network upgrades spanning four DISIS studies (2014 – 2017) for SPP and 433 network upgrades spanning four DPP studies (2016 – 2020) for MISO. Informed by a range of factors, including

ten of the twelve network upgrades assessed in the study provided positive APC benefits, and six of the nine network upgrades modeled where 70% or greater of the same or similarly placed generator interconnection capacity was matched with RTO planning models resulted in significant benefits—with a range of \$59M to \$335M in benefits to the shared system.[393] On average, the network upgrades enabled 12 TWh of additional renewable output in MISO and nearly 7 TWh of additional renewable output in SPP. The network upgrades also eased existing chokepoints in SPP and MISO.[394]

Unfortunately, these limited benefits are not considered when determining who should pay for network upgrades. 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. Given these identified regional benefits, allocating 100% of the network upgrade costs using the "but for" test does not ensure that all beneficiaries pay costs that are roughly commensurate to the benefits they receive, violating the "beneficiary pays" principle and leading to an unjust and unreasonable outcome. Network upgrades sponsored by interconnection customers are unduly discriminated against because they receive less favorable cost allocation than other similarly situated upgrades.

This is essentially the same problem as discussed in the previous section,[395] where all costs of a transmission project are allocated to whoever caused the project to be built, without regard for the benefits to others. We suggest the same solution: determine benefits using a standardized set of metrics, charge beneficiaries based on a conservative benefit-cost ratio so they are comfortably

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voltage class, location of the upgrades, and level of generation interconnection capacity that were allocated the network upgrades, and in consultation with MISO and SPP staff, the screened network upgrades across both RTOs were shortlisted to six network upgrades in each RTO. *See* ICF Resources, *Just & Reasonable? Transmission Upgrades Charged to Interconnecting Generators Are Delivering System-Wide Benefits* at 3.

393 *Id*. at 4-5.

394 *Id*. at 7.

395 *See* p. 126, *supra.*

better off than they would be without the project, then assign residual costs to the interconnection customer.

VII. CONCLUSION

PIOs appreciate the opportunity to provide these initial comments on the Commission's timely and important ANOPR and ask that the Commission consider the recommendations made herein in this rulemaking.

Dated: October 12, 2021.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that the foregoing has been served in accordance with 18 C.F.R. § 385.2010 upon each party designated on the official service lists in these proceedings listed above, by email.

Dated: October 12, 2021.

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EXHIBIT A

The Brattle Group, *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs* (Oct. 2021)

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

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NOTICE

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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.

The report reflects the analyses and opinions of the authors and does not necessarily reflect those of The Brattle Group's or Grid Strategies' clients or other consultants. There are no third party beneficiaries with respect to this report, and neither the Brattle Group nor Grid Strategies accepts any liability to any third party in respect of the contents of this report or any actions taken or decisions made as a consequence of the information set forth herein.

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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.

[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

[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

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[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.

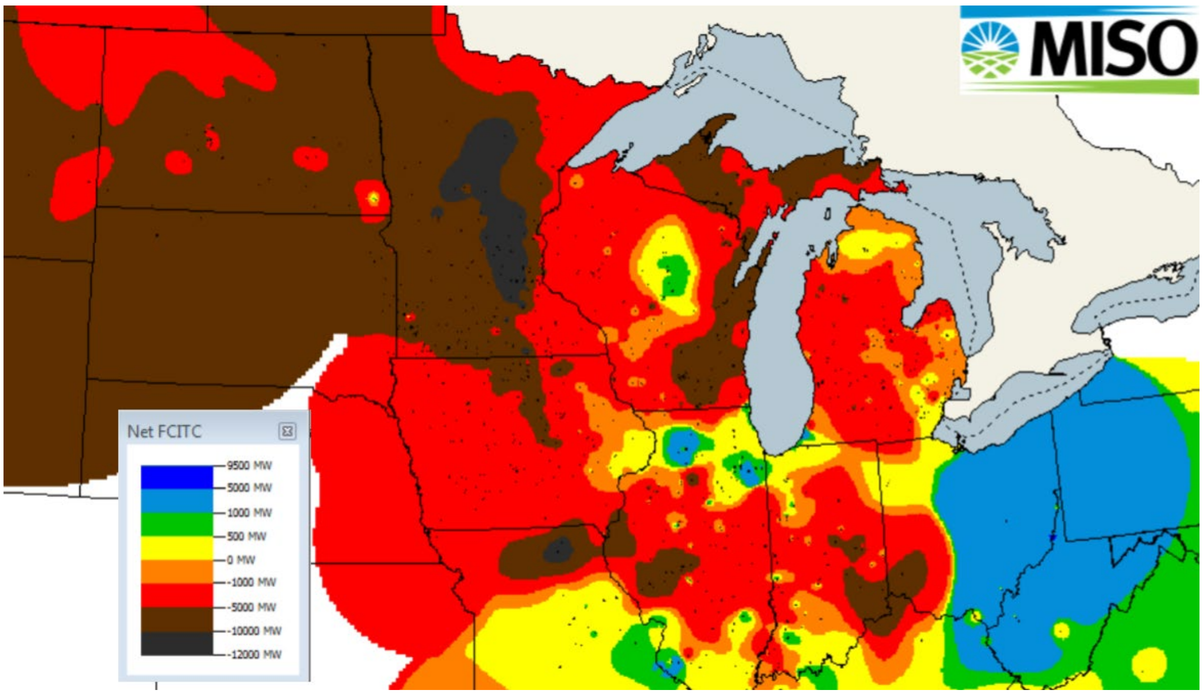
[14] The MVP lines cost $6.57 billion, per MISO, *Regionally Cost Allocated Project Reporting Analysis, MVP Project Status July 2021*, and were designed to interconnect 15,949 MW of wind, per MISO, *MTEP17 MVP Triennial Review: A 2017 review of the public policy, economic, and qualitative benefits of 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

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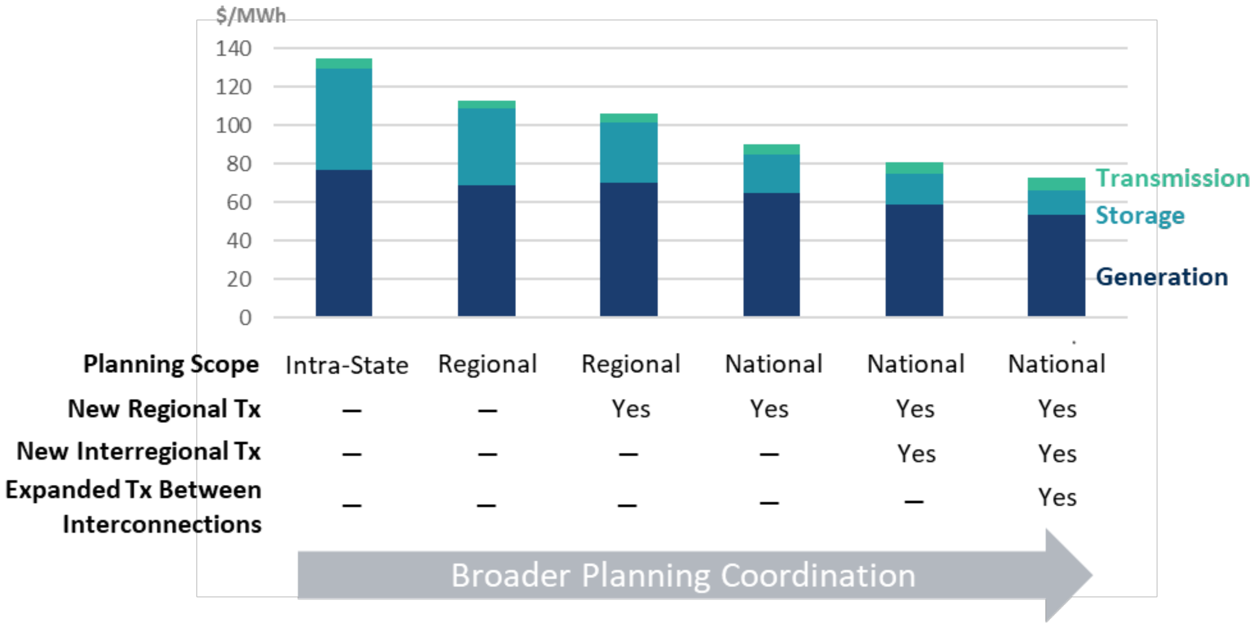
[25] P. R. Brown and A. Botterud, "*The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System*," *Joule*, Vol. 5, No. 1, p115–134, January 20, 2021.

[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 <u>multi-value</u> 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 <u>scenario-based</u> 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 <u>portfolio-based</u> 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 <u>joint interregional</u> 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

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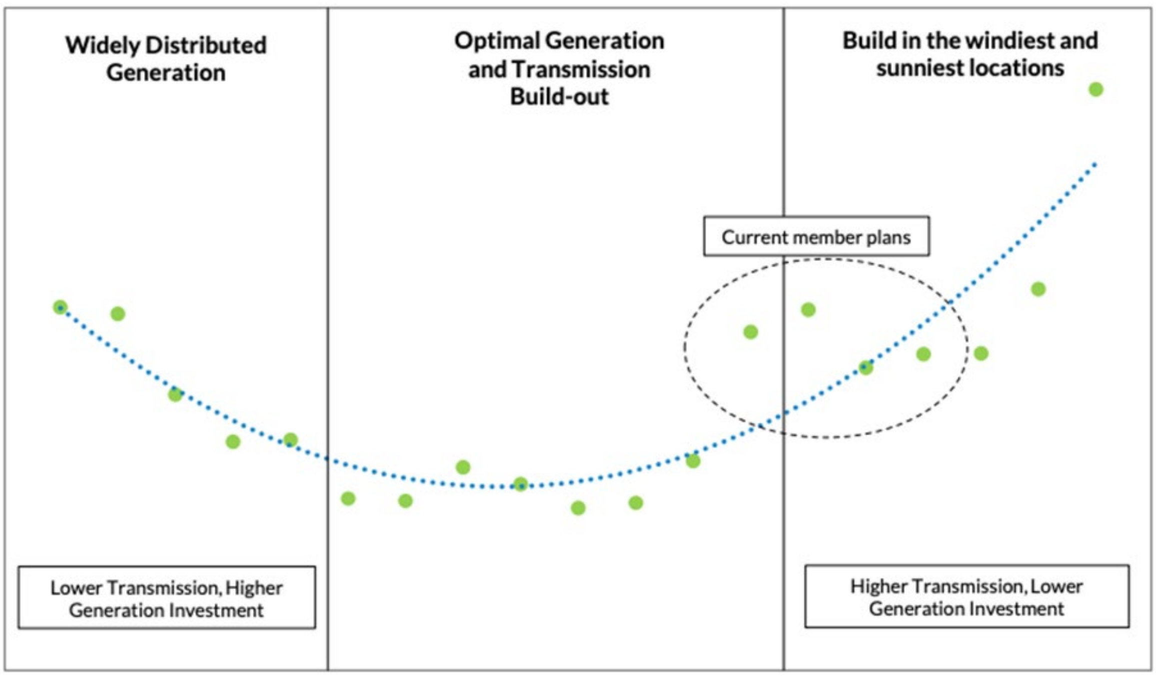
71 Midwest ISO (MISO), *RGOS: RGOS: Regional Generation Outlet Study*, November 19, 2010.

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

[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.

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[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.

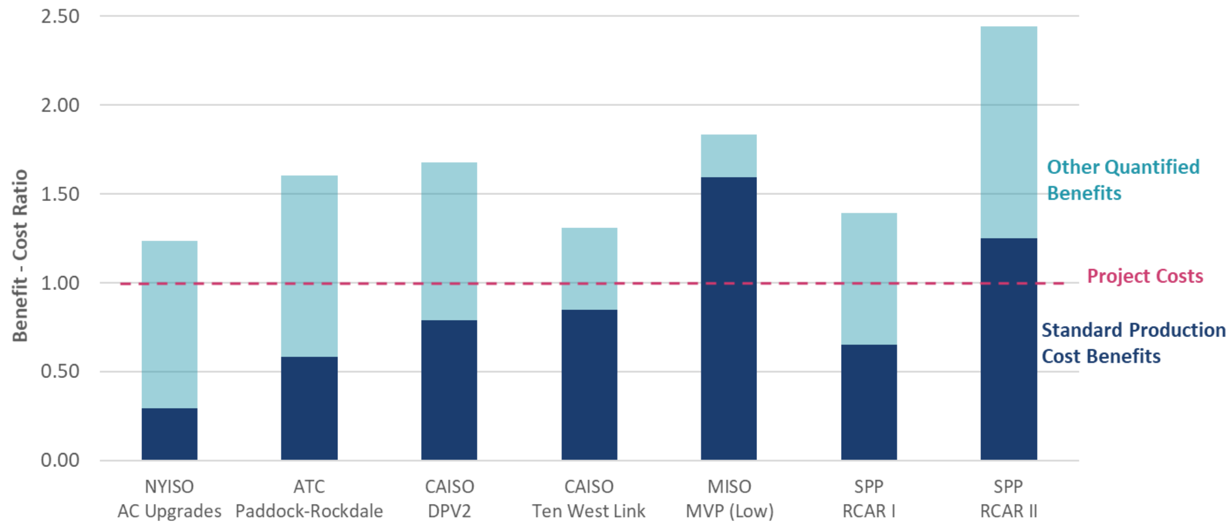
While not all proposed transmission investments provide benefits that exceed project costs, overlooking benefits because traditional tools and processes do not automatically capture these benefits leads to the premature rejection of valuable projects and underinvestment in transmission infrastructure. 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

[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.

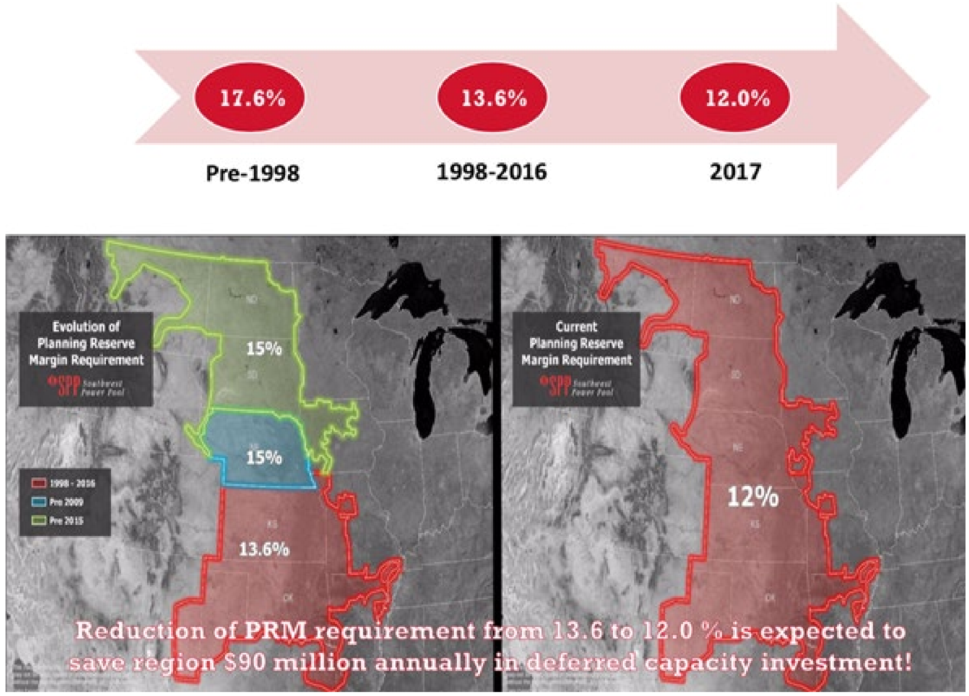
[92] Public Service Commission (PSC) of Wisconsin (WI), *Order*, re Investigation on the Commission's Own Motion to Review the 18 Percent Planning Reserve Margin Requirement, Docket 5-EI-141, PSC REF#:102692, dated October 9, 2008, received October 11, 2008, p 5. Two other changes that contributed to 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

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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.

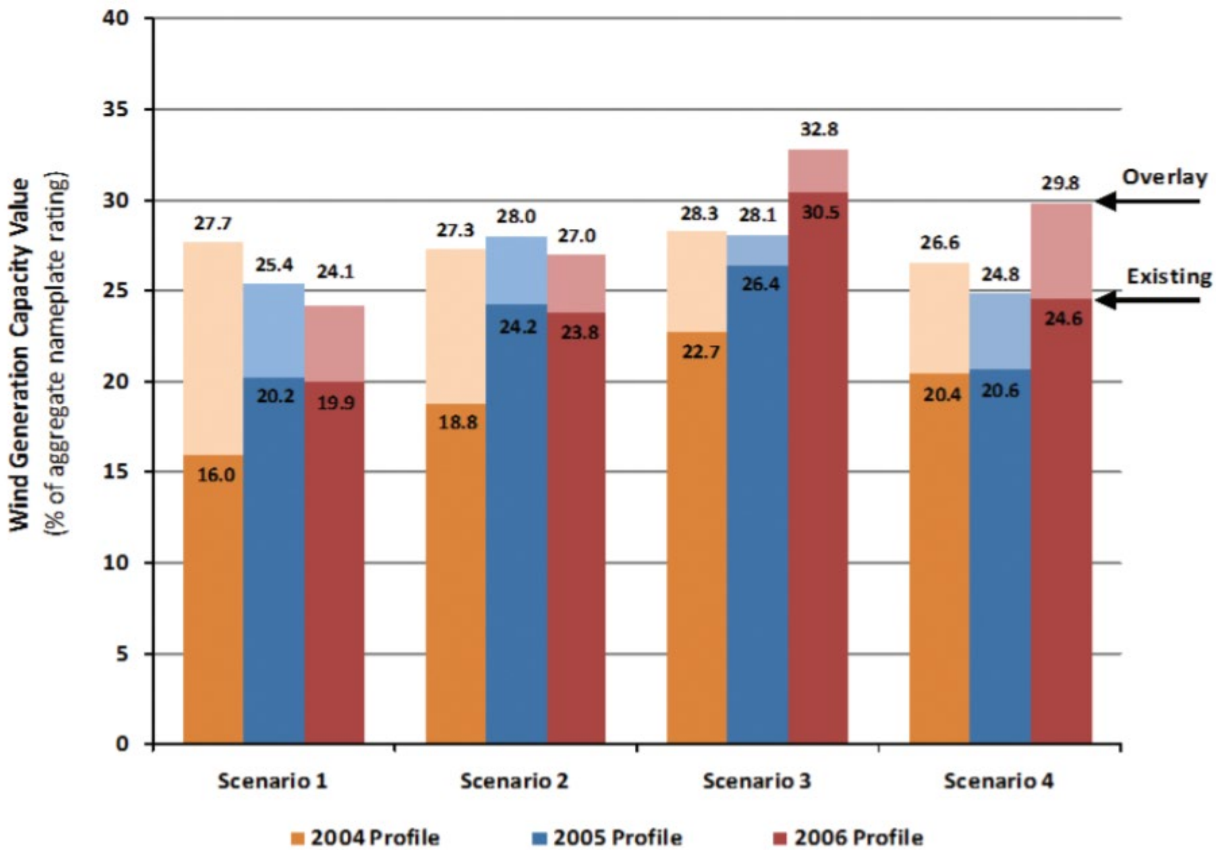
Transmission can increase the capacity value of existing resources, particularly wind and solar resources due to their geographic diversity. Higher capacity values reduce system (generation plus transmission) costs and increase net benefits. In the chart below from the Eastern Wind Integration and Transmission 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]

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[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

[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.

[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]

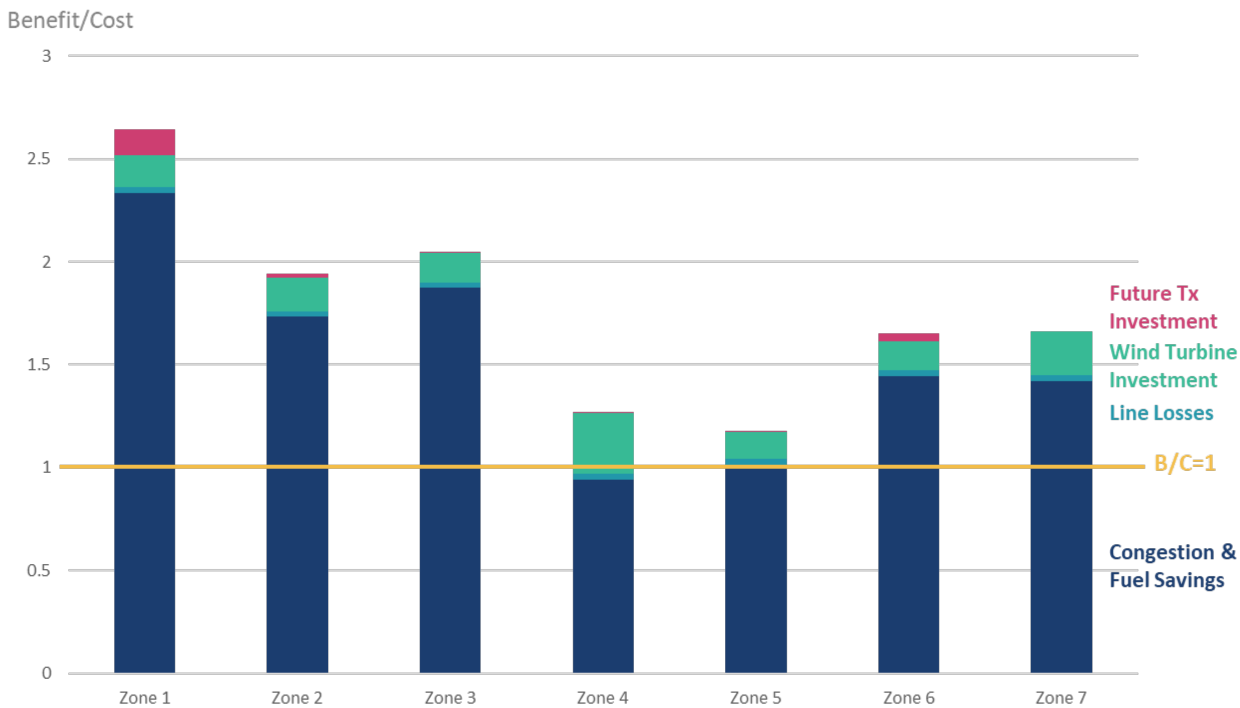
2. MISO Multi Value Projects (MVP)

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

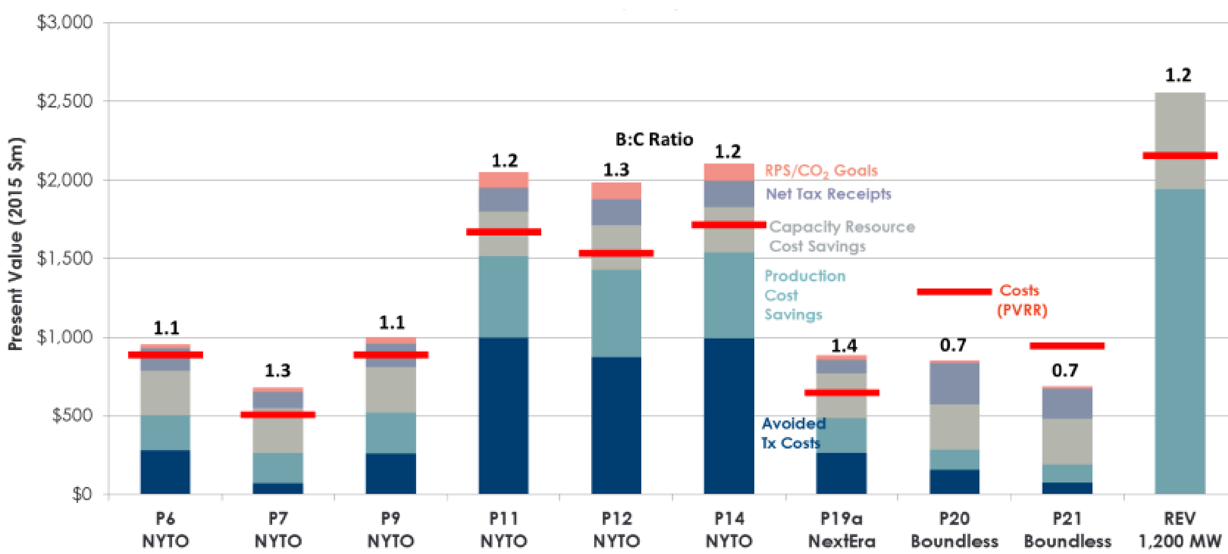
In New York, NYISO implemented a multi-value "public policy" transmission planning process after the New York Public Service Commission (PSC) mandated that approach in 2015. Prior, the existing approach for identifying "economic" projects through the NYISO Congestion Assessment and Resource Integration 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)

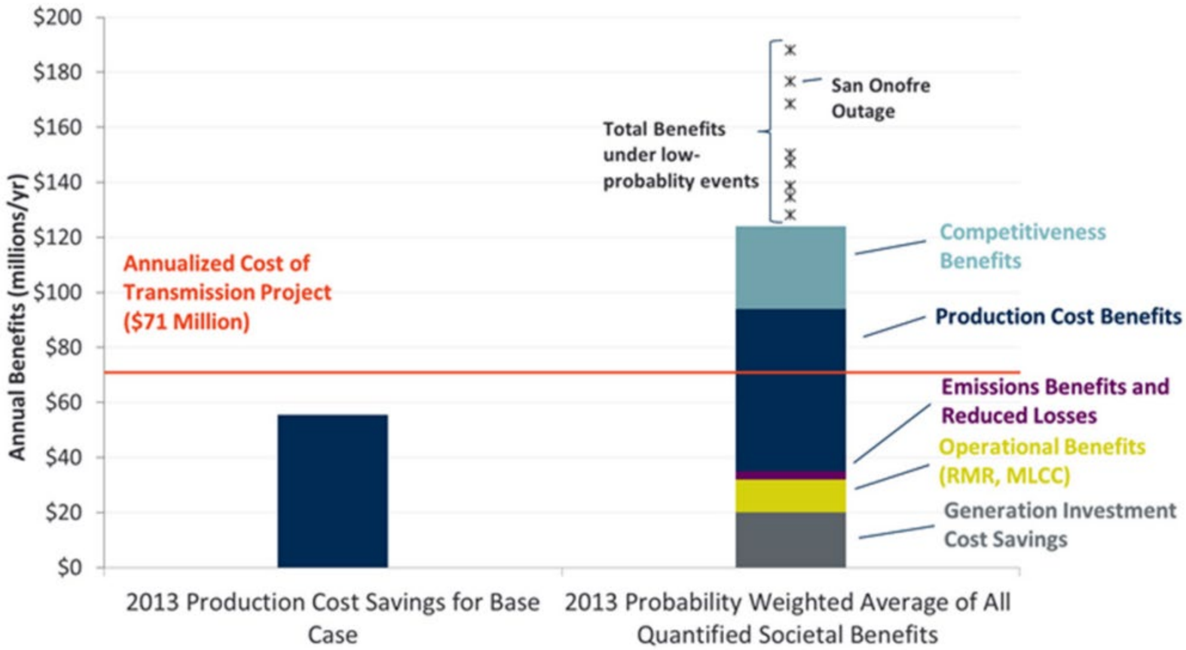
CAISO has occasionally utilized its TEAM approach in its transmission planning effort, which considers multiple benefits.[127] When initially evaluating CAISO's Palo Verde-Devers 2 (PVD2) line, the California Public Utility Commission (CPUC) relied on results from the TEAM approach.[128] Quantified benefits 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

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[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.

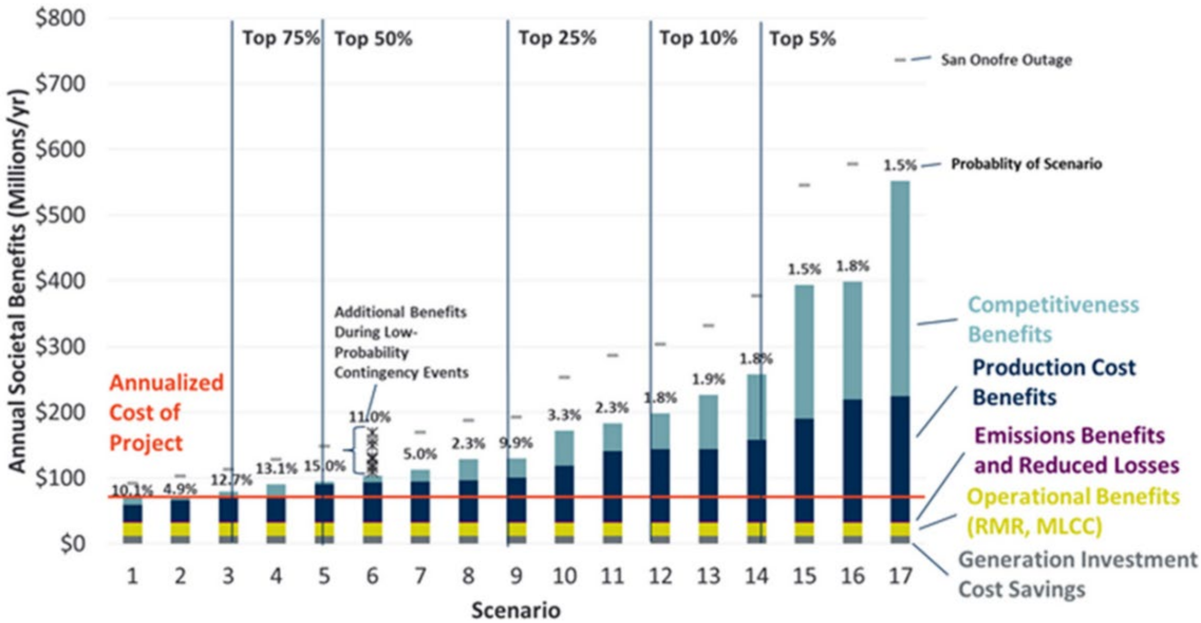
[134] ERCOT, *2014 Long-Term System Assessment for the ERCOT Region*, December, 2014; Chang, Pfiefenberger and Hagerty (The Brattle Group), *Stakeholder-Driven Scenario Development for the ERCOT 2014 Long-Term System Assessment*, September 30, 2014.

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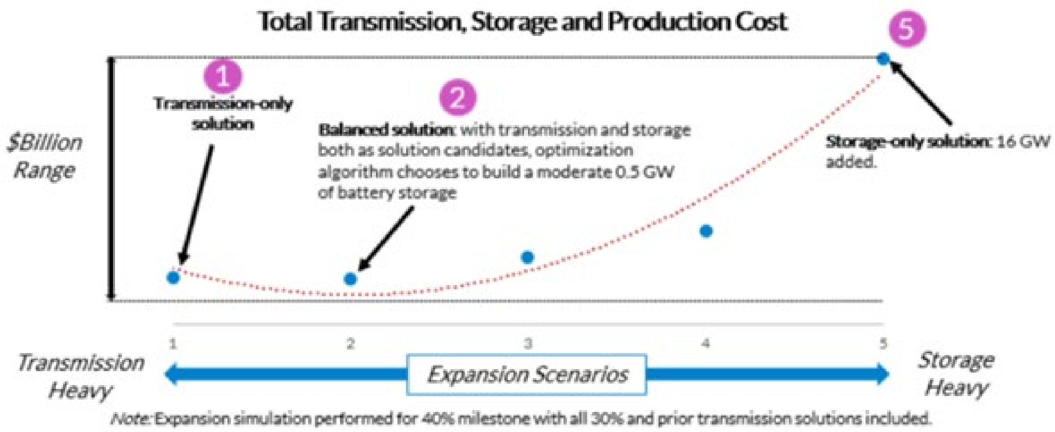
136 J. Frayer, E. Wang, R. Wang, *et al.*(London Economics International, Inc.), *How Does Electric Transmission Benefit You?: Identifying and Measuring the Life-Cycle Benefits of Infrastructure Investment*, A WIRES report, January 8, 2018, p 46.

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

[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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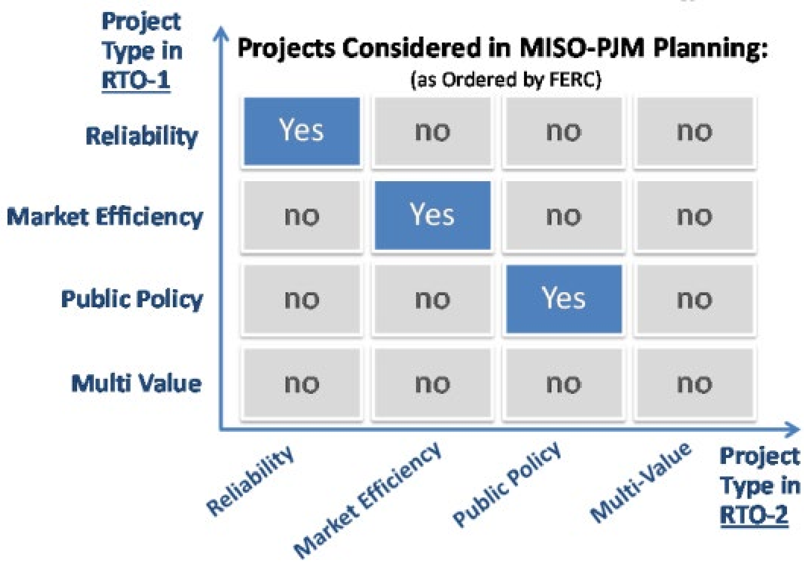
[141] This approach is widely used for infrastructure costs, such as roads or distribution systems. The portfolio-based approach has also been applied, for example, by SPP for the highway-byway cost allocation of projects approved through its Integrated Transmission Planning (ITP) process and MISO for 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

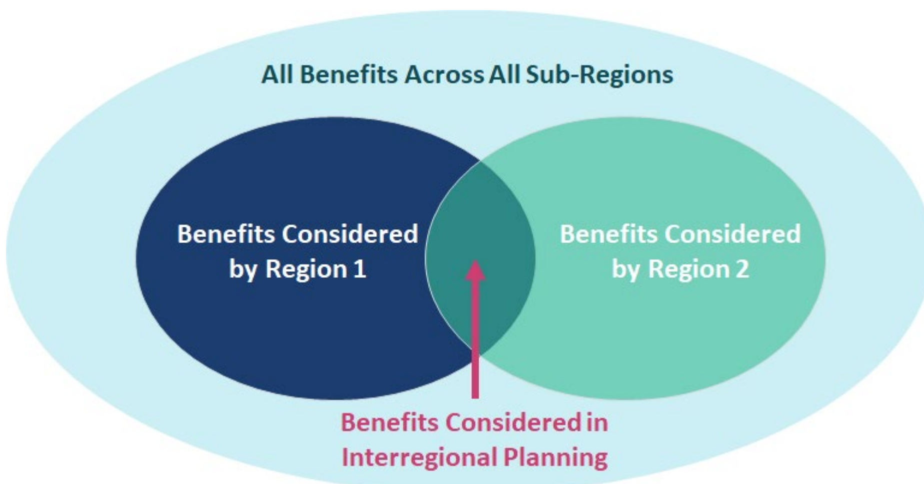


By focusing only on projects that address reliability, market efficiency, or public policy needs in both regions, the planning process inadvertently excludes any interregional projects that, for example, would address reliability needs in one region but address market efficiency or public policy needs 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;

[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.

[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.

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[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)