Americans for a Clean Energy Grid

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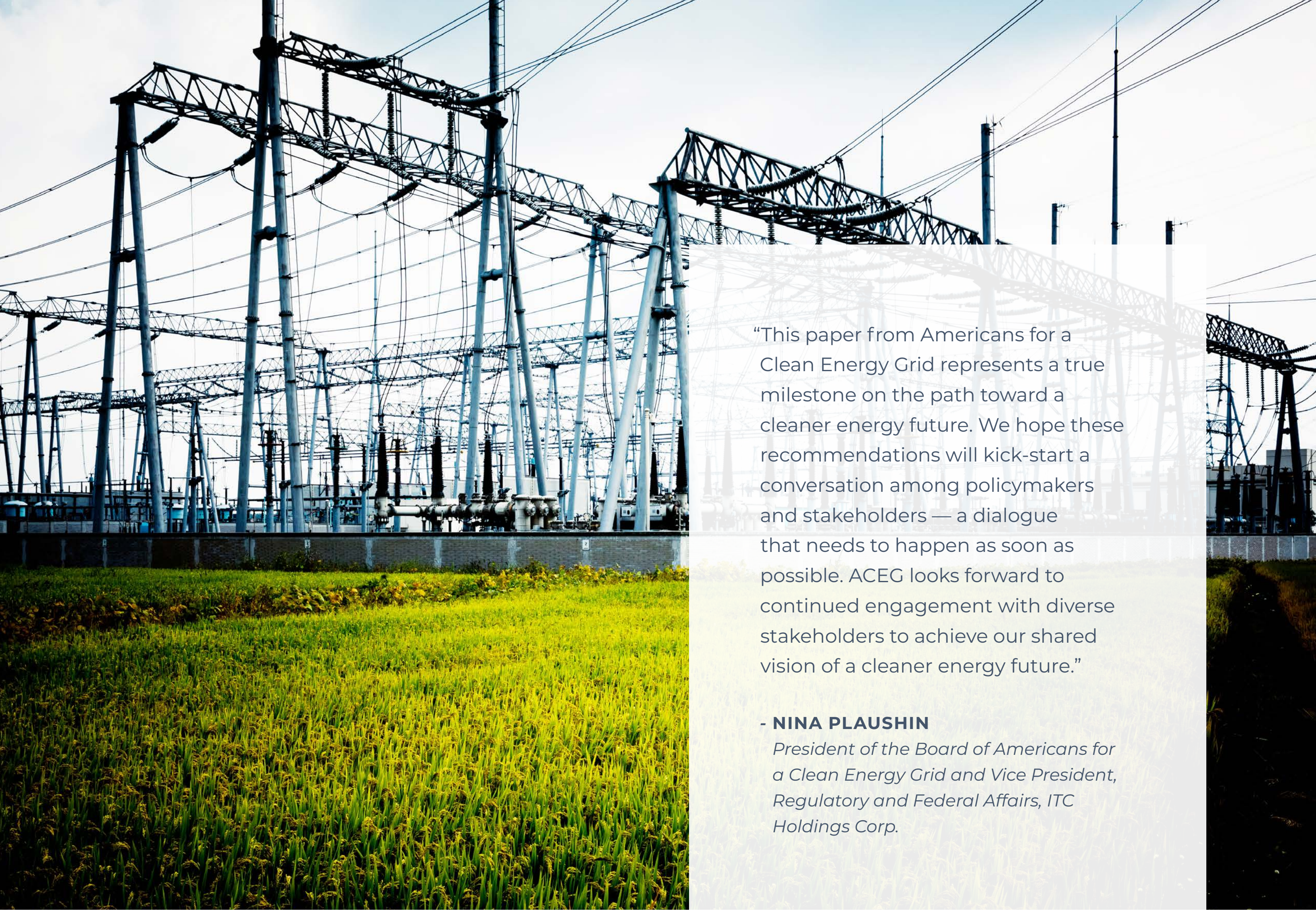
PLANNING FOR THE FUTURE

FERC'S OPPORTUNITY TO SPUR MORE COST-EFFECTIVE TRANSMISSION INFRASTRUCTURE



"This paper from Americans for a Clean Energy Grid represents a true milestone on the path toward a cleaner energy future. We hope these recommendations will kick-start a conversation among policymakers and stakeholders — a dialogue that needs to happen as soon as possible. ACEG looks forward to continued engagement with diverse stakeholders to achieve our shared vision of a cleaner energy future."

- **NINA PLAUSHIN**
President of the Board of Americans for a Clean Energy Grid and Vice President, Regulatory and Federal Affairs, ITC Holdings Corp.

REPORT AUTHORS

Rob Gramlich and Jay Caspary

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AC	Alternating Current
ACEG	Americans for a Clean Energy Grid
AEMO	Australian Energy Market Operator
BCA	Benefit-Cost Analysis
BRP	Baseline Reliability Projects
CAISO	California Independent System Operator
CLCPA	Climate Leadership and Community Protection Act
CREZ	Competitive Renewable Energy Zones
DC	Direct Current
DFAX	Distribution Factor
DPP	Definitive Planning Phase
EIA AEO	U.S. Energy Information Administration's Annual Energy Outlook
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
GET	Grid-Enhancing Technologies
GHG	Greenhouse Gases
GI	Generator Interconnection
GW	Gigawatt
HVDC	High Voltage Direct Current
IPP	Independent Power Producer
ISO	Independent System Operator
ISO-NE	ISO New England
ITP	Integrated Transmission Plan
LMP	Locational Marginal Price
LOLE	Loss of Load Expectation
MEP	Market Efficiency Projects
MISO	Midcontinent Independent System Operator
MIT	Massachusetts Institute of Technology
MTEP	MISO Transmission Expansion Plan
MVP	Multi-Value Projects
MW	Megawatt
MWh	Megawatt-hour
NERC	North American Electric Reliability Council
NIMBY	"Not In My Backyard"
NOAA	National Oceanic and Atmospheric Administration
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
PJM	PJM Interconnection
REBA	Renewable Energy Buyers Alliance
ROFR	Right of First Refusal
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Organization
SPP	Southwest Power Pool
TPL	Transmission Planning
TWh	Terawatt-hour
U.S. DOE	United States Department of Energy
U.S. EIA	United States Energy Information Agency
VER	Variable Energy Resources
VOLL	Value of Lost Load
WATT Coalition	Working for Advanced Transmission Technologies Coalition

I. Executive Summary

A. The time has come for the Federal Energy Regulatory Commission (FERC) to build on its previous orders and strengthen transmission planning through a new nationwide transmission planning and cost allocation rule

Over the last 25 years, four major FERC orders, No. 888, 2000, 890 and 1000, each made incremental progress building regional transmission infrastructure, moving the industry away from its past balkanized structure with relatively weak connections between utility systems towards a more reliable and efficient system allowing for more regional exchange of power. As we look to the future, much more regional and inter-regional power exchange will be needed for national energy security, reliability, resilience, cost-effectiveness, and economic competitiveness. A decade after Order No. 1000's issuance, the nation faces new challenges and it is clear that neither the current infrastructure nor the rules governing its development match this need.

Numerous studies, as well as the experiences of regional planning entities, demonstrate that more robust interregional infrastructure is needed to ensure system resilience and reliability, and would yield substantial consumer benefits and help ensure affordable rates for customers if built. The combination of an aging transmission system and a changing resource mix heighten the need for proactive planning of regional and inter-regional transmission infrastructure. While a large amount of transmission infrastructure built in the 1960s and 70s is due for replacement, simply rebuilding this infrastructure is inefficient in light of a changing resource mix and shifting demand patterns. By all accounts, wind and solar resources will become a much larger portion of the resource mix in the future, and electrification of transportation and buildings will substantially increase demand. These trends magnify the benefits of building large regional and inter-regional transmission infrastructure to connect resource rich areas with load centers.

For all of the best efforts of the Commission and regional planning authorities, the current set of transmission regulations have resulted in inadequate levels of infrastructure that have burdened the interconnection process with the task of planning new network facilities — a task that should instead take place in the planning process. Further, existing regulations have created a system that disproportionately yields projects that address only local needs, that address reliability without more broadly assessing other benefits, or that simply replace old retiring transmission assets with the same type and design despite the potential for larger projects to more cost effectively meet the same needs. While local projects, reliability projects, and asset replacements will continue to be necessary, there is an opportunity to make better use of valuable existing rights of way, install newer technologies as assets are replaced, provide greater transparency and guidance over transmission expenditures, and reconfigure the grid to vastly increase regional and inter-regional delivery capacity. This would improve the cost effectiveness of new transmission investments for customers, reducing congestion, and enhancing reliability.

To achieve these outcomes, the Commission should undertake a comprehensive rulemaking to reform planning, cost allocation, and review of transmission. Reforms designed to ensure adequate, cost-effective investment in transmission infrastructure takes place are necessary for rates to be "just and reasonable" and consistent with the Federal Power Act's requirements. The Commission has an obligation to find under Section 206 of the Federal Power Act that current tariffs are unjust and unreasonable, and must be replaced with new transmission planning, cost allocation, and review guidelines. Reforms to ensure that regional and interregional planning processes better assess future needs, evaluate a full range of solutions, and focus on increasing cost effectiveness of new infrastructure for customers are well within the Commission's statutory authority, and its mandate to identify and serve the interests of electricity consumers.

B. A new comprehensive FERC planning rule should establish basic guidelines for transmission planning processes to ensure they meet future needs

The Commission should build on its longstanding work to improve regional and interregional transmission planning. Beginning with an industry of separate vertically integrated utilities, with around 500 owners of transmission, FERC began to foster regional exchange of power in the mid-1990s. Order No. 888, issued in 1996, encouraged "Regional Transmission Groups"[1] and "Independent System Operators"[2] with transmission planning coordination functions.[3] Order No. 2000, issued in 1999, encouraged the voluntary formation of Regional Transmission Organizations with transmission planning as a core function, both for reliability and efficiency.[4] Order No. 890, issued in 2007, established a set of more specific transmission planning principles that help to facilitate stakehold-

1 The Commission's 1994 Regional Transmission Group Policy Statement was an important precursor to Order No. 888.

2 Throughout this paper, we refer to RTOs and ISOs together simply as "RTOs."

3 *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 75 FERC ¶ 61,080, April 24, 1996.

4 *Regional Transmission Organizations*, Order No. 2000, 89 FERC ¶ 61,285, December 20, 1999.

er input and help ensure a more efficient mix of transmission infrastructure. It requires transmission planning processes to be open and transparent, provide for coordination between entities through information exchange and other practices, and utilize economic planning studies to evaluate projects.[5] Order No. 1000, issued in 2011, built on these principles by enacting a series of reforms designed to "identify and evaluate transmission alternatives at the regional level that may resolve the region's needs more efficiently or cost-effectively than solutions identified in the local transmission plans of individual public utility transmission providers,"[6] and requiring greater interregional coordination. These signature orders, issued by bipartisan commissions led by Chairs from both parties, have all explicitly endeavored to bolster regional transmission infrastructure for reliability and efficiency of the overall power system.

We now have ample evidence to see that the current transmission planning regulations leave a large gap remaining between what is being done and what is needed to address current and future needs. Regions have taken a wide variety of approaches to implementing the orders, and their collective experience has yielded important lessons. The time has come to build on the experience from these four major FERC planning orders and to take another step in reforming the planning processes to ensure that they yield just and reasonable solutions. In particular, the time has come to apply those lessons to yield greater development of region-spanning and inter-regional transmission capacity, and a sharper focus on ensuring that new development is as cost effective as possible.

The Commission should undertake a rulemaking to provide greater specificity in how regional and interregional planning processes must be conducted, adding four new pillars to these planning processes to ensure that planning properly identifies infrastructure that best meets future needs:

1. ***A new FERC rule should require planning processes to rely upon the best available data and forecasting methodologies.***

Regional planning entities' implementation of Order No. 1000 has shown that many regions fall short in identifying transmission needs based on assessments of plausible futures that are as accurate as possible. Changes in the resource mix driven by public policies and utility resource plans, growth in electric vehicles and building heating, quantity and location of generation in interconnection queues, and other changes to electrici-

5 *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 18 CFR Parts 35 and 37, at PP 418-601, February 16, 2007.

6 *Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 78, July 21, 2011.

ty demand and supply are important factors for which information is publicly available. Failing to fully incorporate these factors into planning leads to unjust and unreasonable outcomes because it yields infrastructure that will not meet future needs as cost effectively as possible. Rather than focus on the status quo, planners should incorporate the best available information about changing system needs as they assemble plans. The Commission should require planning entities to evaluate needs based on a range of reasonable planning scenarios based on plausible futures that cover the full range of factors that are likely to influence future demand and resource mix. The Commission should also require transmission planners to account for project siting considerations and information about new technologies, and non-transmission alternatives that may be funded outside of the planning process as key inputs. In short, planning processes must be about the future in order to be deemed just and reasonable.

2. ***A new FERC rule should require planning authorities to consider all of the benefits of transmission together.***

Planning entities generally employ siloed planning processes that often only partially evaluate the benefits of transmission projects by classifying projects as "reliability," "public policy," or "economic" projects. This siloed approach leads to unjust and unreasonable outcomes by failing to consider the economies of scope, where transmission typically provides multiple benefits that span these artificial categories. While planning entities may continue to provide for cost allocations that appropriately reflect benefits, and provide individual assessments of lines for permitting purposes, the Commission should ensure that transmission needs and solutions are identified in a manner that recognizes all of the multiple benefits of all types of transmission projects.

3. ***A new FERC rule should require transmission planning entities to evaluate all available solutions, including new physical infrastructure options and grid-enhancing technologies, within regional transmission plans to more efficiently serve customers.***

Current approaches are unjust and unreasonable by failing to consider lower cost or better performing options, and should be changed to include them.

4. ***A new FERC rule should direct transmission planning entities to select a portfolio of solutions for each regional and interregional transmission plan that is likely to maximize aggregate net benefits.***

The Commission should direct all planning entities to engage in portfolio assessments and benefit-cost analysis, providing guidelines with regard to how they should do so.

To ensure consumers benefit from transmission plans, benefit-cost analysis should be performed using methods that address uncertainty by quantifying benefits and costs in a range of plausible future scenarios. All planning entities should be required to adhere to a minimum set of best practices that ensure that all benefits will be quantified across the full life of the applicable infrastructure. Innovations in the full and accurate quantifications of transmission-related benefits should be encouraged.

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

FERC Order No. 1000 policies on cost allocation are largely workable as long as the planning reforms discussed herein are accomplished. The current approach for transmission included in regional plans, as dictated in a set of court decisions, is that cost allocation should be roughly commensurate with benefits received. While the Commission should require all planning entities to better quantify the benefits of new transmission infrastructure, it should refrain from requiring that the costs of new infrastructure be allocated in a manner that matches these benefits based on overly narrow metric or with exacting precision on a project-by-project basis. Instead, it should continue to require that overall costs of the new transmission infrastructure be allocated in a manner roughly commensurate with benefits. Therefore, as the Commission carries out reforms to transmission regulation, it should largely adhere to the basic approach that it has taken on cost allocation in Order 1000. Since interconnection processes, as governed by policy decisions made in Order 2003, do not follow beneficiary pays and instead follow "participant funding," this inconsistency should be rectified by a new rule. Thus the rule would be updating some provisions of Order No. 2003 and the interconnection processes of public utilities, as well as Orders No. 890 and 1000 on planning provisions.

To minimize analysis and help ensure that costs are allocated in a stable and predictable way, the Commission should direct planning entities to allocate the costs of portfolios of projects as a group, rather than proceeding only on a project-by-project basis. And to ensure that costs are not significantly mismatched with benefits, it should provide that single metrics such as load flow analysis may not be the sole basis of cost allocation, instead directing planning entities to use methods that account for a broader range of benefits that projects bring the whole system. To avoid cost-shifting and process disruption, the rule should assign costs to loads whether or not their affiliated company remains in a Regional Transmission Organization (RTO). Finally, the Commission should clarify that planning entities may allocate a portion of total costs in the future to generators and customers who utilize the new transmission infrastructure.

D. The Commission should ensure transmission investment is as cost-effective as possible

Consumer interests must be central to transmission policy, as the Federal Power Act is a consumer protection statute first and foremost. In recent years, as aging assets have been replaced, spending on transmission has increased without always providing for a process for consumers to know whether the expenses are justified or the type of upgrade is cost-effective. The Commission should build on Orders No. 888, 2000, 890, and 1000 by enacting further reforms to governance and oversight processes to ensure that costs incurred benefit customers. Broadly, these reforms should (i) ensure that local and end-of-life projects are more carefully evaluated as part of regional planning processes, to determine whether needs may be more efficiently served by larger, regional, and interregional projects rather than simple replacements; (ii)

ensure there is cost transparency and oversight of transmission costs and that public utility transmission providers are appropriately incented to pursue a more optimal mix of transmission solutions; (iii) consider targeted forms of performance based rate making that can incent efficiency in project development, (iv) develop a more collaborative approach to transmission planning and ownership among utilities and (v) ensure that interregional and possibly national transmission infrastructure is more seamlessly facilitated.

In particular, the Commission should reform the interregional planning process to eliminate the multi-stage process that currently prevents interregional projects from being constructed. To do so, the Commission should consider the formation of new interregional planning boards that have full authority to make section 205 filings to FERC that select and allocate costs for interregional transmission projects. This could allow projects to proceed without separately securing the approval of each individual RTO board.

The Commission should also take on a greater role in overseeing transmission planning. The Commission should better incent public utility transmission providers to pursue a more optimal mix of projects. To do this the Commission should consider evaluating the cost-effectiveness of local transmission projects where there is evidence that a project addresses a need that could be met more efficiently by a regional or interregional project. The Commission should consider performance-based ratemaking techniques to reward transmission owners that pursue more cost-effective solutions. Finally, recognizing the critical role that states play in transmission planning, the Commission should consider requiring planning entities to grant state representatives an explicit governance role in the regional transmission planning process. The Commission should solicit comments from stakeholders on whether this step is appropriate and if so, what in particular the Commission should require with regard to governance reforms.

II. The Commission should replace current tariffs with planning requirements that will achieve just and reasonable rates

Reforms are necessary to meet Federal Power Act requirements of just and reasonable rates given new circumstances and demands on the grid. It has become clear that transmission investments need to be better targeted to the regional and inter-regional levels. Study after study shows substantial net benefits of such infrastructure, while broader trends in generator additions and retirements dictate that new regional and inter-regional infrastructure will be needed to integrate low-cost wind and solar generation into the system. Electrification of transportation and building end-uses will create a heightened need for new infrastructure. Market forces alone will not meet these needs. Transmission infrastructure's large economies of scale and scope make it a natural monopoly that is deployed most cost-effectively via a central coordinator.[7] As a large amount of transmission infrastructure is replaced in the coming decades, the Commission must seize the opportunity to ensure that it is built to cost-effectively meet the needs of the future system. And yet, current tariffs are failing to meet these needs.

A. Just and reasonable rates require plans that include more high voltage long distance transmission given future resource portfolios

As laid out in Appendix A, a number of studies have been conducted that demonstrate that significantly greater levels of transmission construction would yield substantial benefits to customers and enhance grid reliability.

These studies all point to the need for significant expansion of regional and inter-regional transmission infrastructure in order to create a reliable, efficient power system given reasonable projections of future needs.

7 William W. Hogan, *Transmission Investment Beneficiaries and Cost Allocation: New Zealand Electricity Authority Proposal*, at 1, February 1, 2020.

B. System threats require plans that provide greater resilience

Power systems are subject to an increasing variety and magnitude of threats. While reliability protocols have traditionally planned for reliable operation during and after system contingencies such as large generator or transmission line outages, there are other types of threats that result in the need for more robust regional and interregional transmission.

A recent report by national security experts noted: "Our electricity grid's resilience—its ability to withstand shocks, attacks and damages from natural events, systemic failures, cyber attack or extreme electromagnetic events, both natural and man-made—has emerged as a major concern for U.S. national security and a stable civilian society."[8] The report described large scale transmission as a solution: "Transmission buildout is critical to resilience as it can relieve line overloading—or "congestion" in industry jargon—on the existing system, lessening the compounding risks that come with a strained grid that could then be tested by an extreme weather event or an attack incident. Moreover, by enabling further development of renewable energy resources over wider geographic areas, well-planned transmission expansion can make targeted attacks on the grid more difficult to plan and carry out."[9]

When the Commission opened a proceeding about system resilience, grid operators and experts emphasized first and foremost the importance of robust regional and interregional transmission in protecting against modern threats. For example:

- NYISO: "[R]esiliency is closely linked to the importance of maintaining and expanding interregional interconnections, [and] the building out of a robust transmission system;"[10]
- ISO-NE: "The system's ability to withstand various transmission facility and generator contingencies and move power around without dependence on local resources under many operating conditions . . . results in a grid that is, as defined by the Commission, resilient."[11]
- PJM: "Robust long-term planning, including developing and incorporating resilience criteria into the [Regional Transmission Expansion Plan], can also help to protect the transmission system from threats to resilience."[12]

8 NCGR, *Grid Resilience: Priorities for the Next Administration*, at 1, 2020.

9 *Ibid.*, at 42.

10 *Response of the New York Independent System Operator, Inc.*, Docket No. AD18-7, at 4, March 9, 2018.

11 *Response of ISO New England Inc.*, Docket No. AD18-7, at 15, March 9, 2018.

12 *Comments and Responses of PJM Interconnection, L.L.C.*, Docket No. AD18-7, at 49, March 9, 2018.

- SPP: “The transmission infrastructure requirements that are identified through the [Integrated Transmission Plan (ITP)] process are intended to ensure that low cost generation is available to load, but the requirements also support resilience in that needs are identified beyond shorter term reliability needs. For example, the ITP identified the need for a number of 345 kV transmission lines connecting the panhandle of Texas to Oklahoma. These lines were identified as being economically beneficial for bringing low-cost, renewable energy to market, but their construction has also supported resilience by creating and strengthening alternate paths within SPP.”[13]
- Brattle Group analysts: “The power system can be vulnerable to disruptions originating at multiple levels, including events where a significant number of generating units experience unexpected outages. The transmission system provides an effective bulwark against threats to the generation fleet through the diversification of resources and multiple pathways for power to flow to distribution systems and ultimately customers. By providing customers access to generation resources with diverse geography, technology, and fuel sources, the transmission network buffers customers against extreme weather events that affect a specific geographic location or some external phenomenon (unavailability of fuel and physical or cyber-attacks) that affect only a portion of the generating units.”[14]

Similarly, a National Academies of Sciences study of power system resilience noted the need for planning improvements to protect against modern threats.[15] The report draws several conclusions that weigh toward enacting reforms to ensure that regional transmission plans improve system resilience:

- “[L]arge-scale physical destruction of key parts of the power system by terrorists is a real danger.”[16]
- “[T]he risks posed by cyber attacks are very real and could cause major disruptions in system operations.”[17]
- “The probability, intensity, and spatial distribution of many of the hazards that can disrupt the power system are changing. These changes are due in part to the consequences of ongoing climate change. Traditional measures, based on an assumption

13 *Comments of Southwest Power Pool, Inc. on Grid Resilience Issues*, Docket No. AD18-7, at 8, March 9, 2018.

14 Mark Chupka and Pearl Donohoo-Vallett, *Recognizing the Role of Transmission in Electric System Resilience*, at 3, May 9, 2018.

15 National Academies of Sciences, Engineering, and Medicine, *Enhancing the Resilience of the Nation’s Electricity System*, The National Academies Press, 2017.

16 *Ibid.*, at 64.

17 *Ibid.*

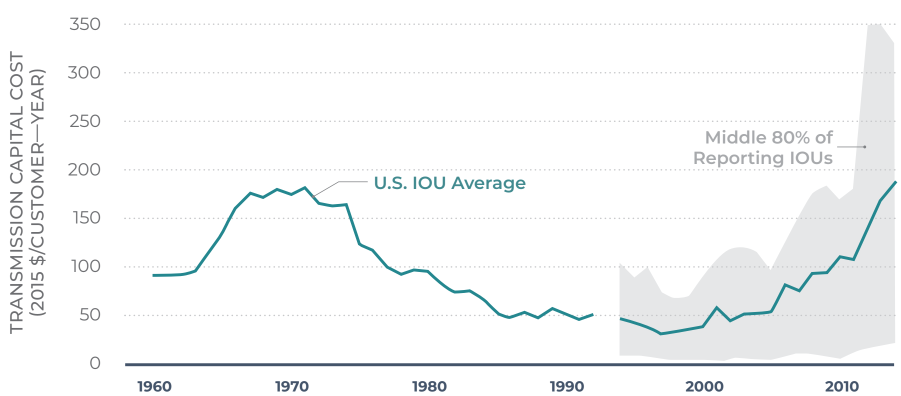
of statistical stationarity (e.g., 100-year flood), may need to be revised to produce measures that reflect the changing nature of some hazards."[18]

- "As the complexity and scale of the grid as a cyber-physical system continues to grow, there are opportunities to plan and design the system to reduce the criticality of individual components and to fail gracefully as opposed to catastrophically."[19]
- "In most cases, an electricity system that is designed, constructed, and operated solely on the basis of economic efficiency to meet standard reliability criteria will not be sufficiently resilient."[20]

C. The combination of an aging transmission system and a changing resource mix heighten the need for proactively planned transmission

The United States experienced a transmission construction boom in the 1960s and 70s, with the average annual investment cost of new transmission system capital infrastructure for U.S. Investor Owned Utilities climbing to nearly $200/customer-year at its peak during the late 1960s and early 70s before falling to less than $100/customer-year in the 1980s and 90s.[21]

FIGURE 1 Average Cost of Investment in New Transmission System Capital Infrastructure



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18 *Ibid.*, at 65.

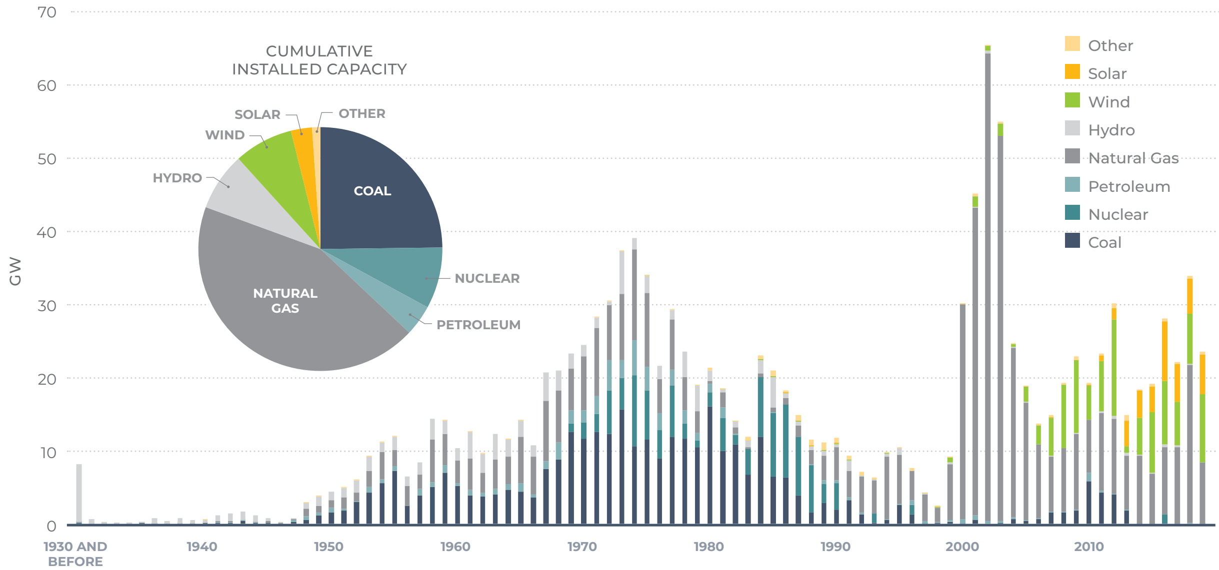
19 *Ibid.*, at 67.

20 *Ibid.*, at 71.

21 Robert L. Fares and Carey W. King, *Trends in Transmission, Distribution, and Administration Costs for U.S. Investor Owned Electric Utilities*, at 8, August 2016.

This construction boom coincided with a wave of power plant construction that consisted largely of coal, nuclear, and some gas facilities.[22] Transmission integrated these power plants with the system, building an infrastructure network well suited to large, centrally located power plants.

FIGURE 2 **U.S. Electric Utility and Independent Power Producer Generating Capacity by Initial Operating Year[23]**



As this infrastructure ages, with transmission built in the 1960s now more than 50 years old, the system is facing a widespread need for maintenance, repair, and reconstruction. Yet as a second wave of transmission construction is playing out, new construction is too frequently focusing on simply rebuilding transmission infrastructure of the past, or addressing needs based on the current resource mix.

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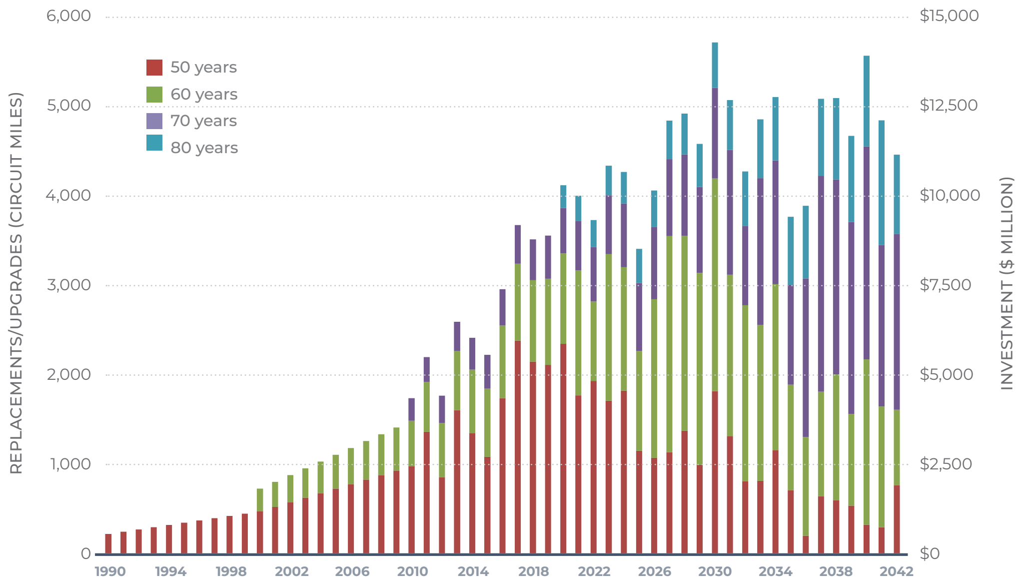
22 U.S. Energy Information Administration, *Most U.S. Nuclear Power Plants Were Built Between 1970 and 1990*, April 27, 2017.

23 U.S. Energy Information Administration, *Form 860*. Grid Strategies uses final 2019 data to aggregate electric generating units and their associated generating capacity by resource type and operating year.

FIGURE 3 **Projected Circuit Miles Replaced/Upgraded and Total Projected investment ($ million)**[24]

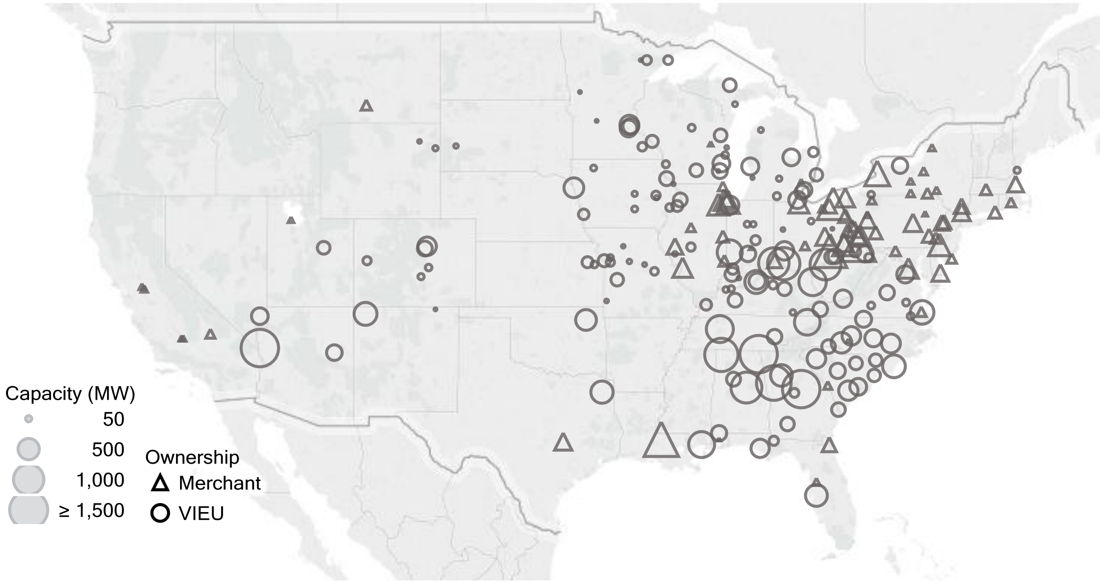


Such planning, blind to the retirement of aging generating plants and the forces shaping the future resource mix, is a recipe for a suboptimal infrastructure network that fails to meet future needs. As detailed in the U.S. Department of Energy's 2017 Staff Report to the Secretary on Electricity Markets and Reliability, a substantial portion of the nation's coal fleet has recently retired, and more coal plants and a significant number of nuclear plants are slated for retirement in the next 10 years.[25]

24 AEP, *Transmission's Future Today*, at 5, 2015, citing Johannes Pfeifenberger, Judy Chang, and John Tsoukalis, *Dynamics and Opportunities in Transmission Development*, December 2, 2014 (Assumes circuit mile costs equal to those of new lines).

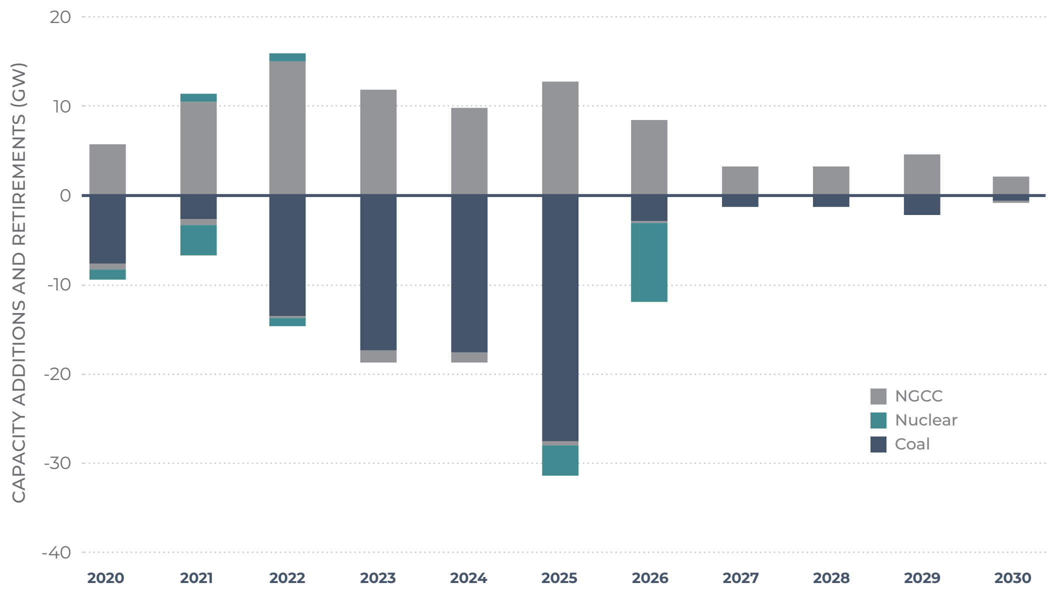
25 *See* U.S. Department of Energy, *Staff Report to the Secretary on Electricity Markets and Reliability*, August 2017.

FIGURE 4 **Location of Coal Retirements (2002-2016)**[26]



26 *Ibid.*, at 21.

FIGURE 5 Capacity Additions and Retirements from EIA Annual Energy Outlook (AEO) 2020 Reference Case[27]



At the same time, wind and solar resources are rapidly proliferating. Wind and solar energy costs have fallen 70 and 89 percent, respectively, in the last ten years, from 2009 through 2019.[28] A number of additional factors are spurring their deployment as well, including public policies and corporate and utility procurement targets, as shown in Figure 6 below.

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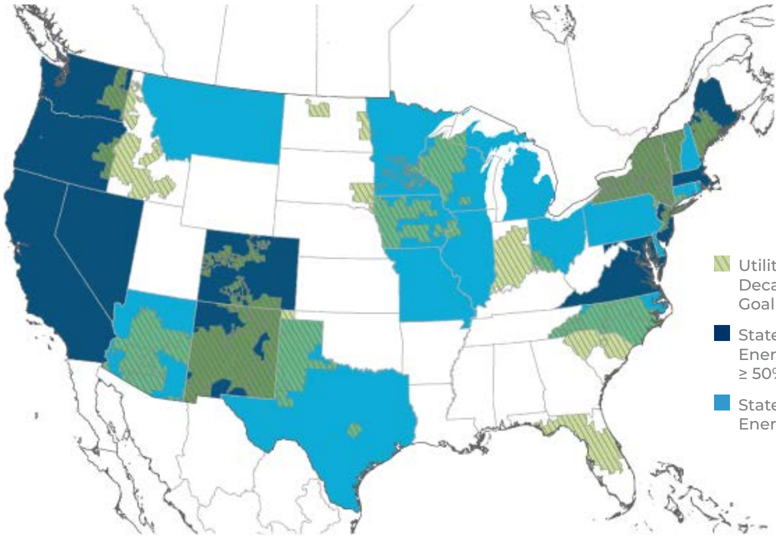
27 U.S. Energy Information Administration, *Annual Energy Outlook 2020*, Reference Table 9. Grid strategies uses EIA-projected electric generating capacity data to aggregate annual Coal, NGCC, and nuclear additions and retirements through 2030. The figure includes both "planned" and "unplanned" or projected additions and retirements.

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

FIGURE 6 **U.S. States with Clean Electricity Mandates & Utilities with Decarbonization Goals, 2020**[29]

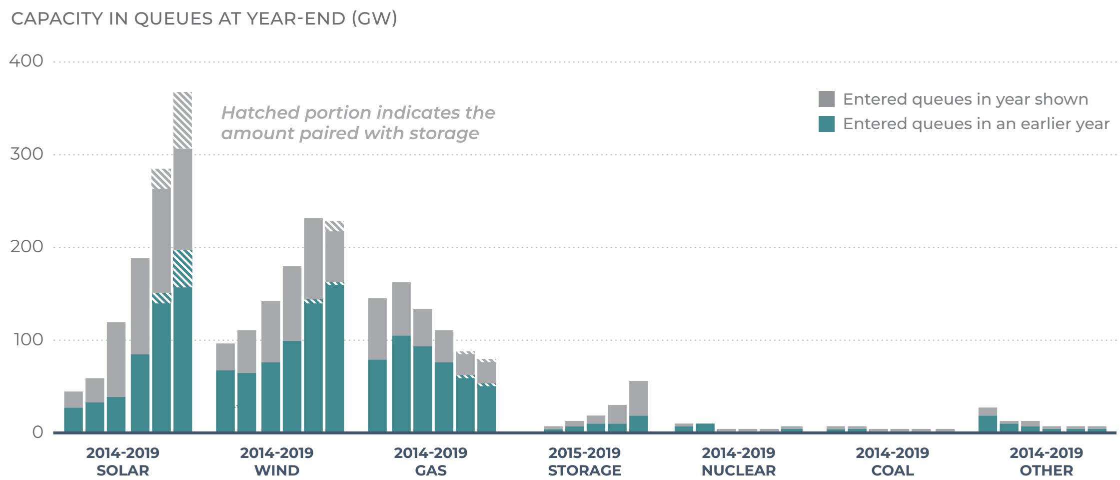


Source: WRI and Smart Electric Power Alliance. Updated on April 17, 2020

29 Lori Bird and Tyler Clevenger, *2019 Was a Watershed Year for Clean Energy Commitments from U.S. States and Utilities*, December 20, 2019.

Wind and solar resources make up the majority of resources in interconnection queues across the country.[30] There were 734 gigawatts (GW) of proposed generators waiting in interconnection queues nationwide at the end of 2019, almost 90% of which are renewable and storage resources as shown in Figure 7 below. 168 GW of solar and 64 GW of wind projects entered interconnection queues in 2019. The U.S. EIA forecasts that wind and solar will make up over 75% of new capacity additions in 2020,[31] and these resources will likely make up the lion's share of new additions for the foreseeable future.[32]

FIGURE 7 **Capacity in Queues at Year-End by Resource Type**



Source: Berkeley Lab review of interconnection queues ***Note: Not all of this capacity will be built***

Because the best locations for wind and solar resources are significantly different from those of retiring coal and nuclear resources, reconstructing the grid of the past is a poor match for future needs. Transmission has a long infrastructure life, so the infrastructure built today should be designed with the next 50 years in mind.

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

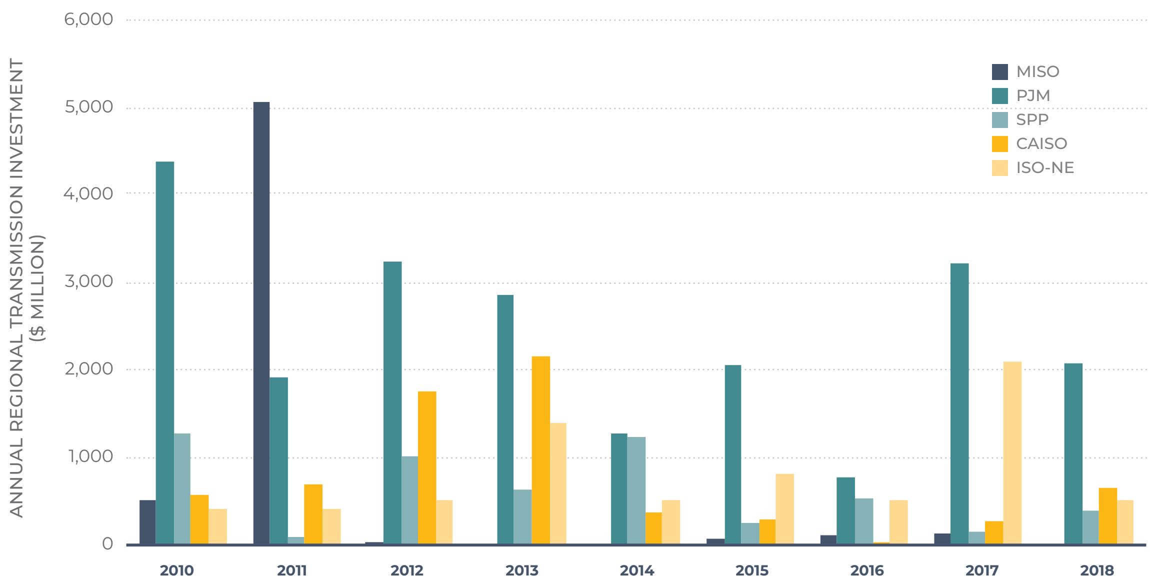
31 U.S. Energy Information Administration, *New Electric Generating Capacity in 2020 Will Come Primarily From Wind and Solar*, January 14, 2020.

32 *See*, e.g., U.S. Department of Energy, *Wind Vision: A New Era for Wind Power in the United States*, Figure 3-24 at 171, March 12, 2015.

D. The vast majority of new projects serve local needs or reconstruction of aging facilities, despite the large and growing need for bigger regional and inter-regional capacity

Despite the many benefits and economies of scale that regional and interregional transmission would bring, regional transmission investment (when excluding local transmission investments not subject to regional planning processes) has been stable or declining over the past decade.

FIGURE 8 Annual Regionally-Planned Transmission Investment in RTOs/ISOs ($ million)[33]



And while total annual transmission investment levels remain relatively robust, the majority of that investment has been in local transmission and low-voltage projects, planned without a full regional assessment that examines their cost-effectiveness relative to regional alternatives, or in regional infrastructure that is planned to meet reliability needs without assessing how to maximize other types of benefits, or that simply rebuilds or

33 Not all RTOs/ISOs provide regional transmission investment information. *See* Coalition of MISO Transmission Customers, Industrial Energy Consumers of America, and LS Power Midcontinent, LLC, *Section 206 Complaint and Request for Fast Track Processing*, at 31-32, January 21, 2020; PJM, *Project Statistics*, at 6, January 10, 2019; Lanny Nickell, *Transmission Investment in SPP*, at 5, July 15, 2019; CAISO, *ISO Board Approved Transmission Plans*, years 2012-2021 available under "Transmission planning and studies" section of webpage; CAISO, *2011-2012 Transmission Plan*, March 14, 2012; CAISO, *Briefing on 2010 Transmission Plan*, 2010; and ISO New-England, *Transmission*, accessed October 2020.

replaces existing infrastructure.[34] While utilities are understandably investing in local reliability upgrades when those needs are not addressed via regional and inter-regional infrastructure, this approach to transmission infrastructure investment results in higher total energy bills for customers than would result from more forward-looking, holistic transmission planning.

According to analysis by the Brattle Group, between 2013 and 2017, "about one-half of the approximately $70 billion of aggregate transmission investments by FERC-jurisdictional transmission owners in ISO/RTO regions [was] approved outside the regional planning processes or with limited ISO/RTO stakeholder engagement."[35] Further, the remaining transmission infrastructure that was included within regional transmission plans was skewed largely toward local projects, and projects built to meet near-term reliability needs. In addition, the Brattle Group analysts found that 97% of all transmission approved in their study period was not subject to a competitive selection process, either because it was built to address a near-term reliability need, upgraded existing infrastructure, or fell below RTO thresholds for competitive process, such as a specified voltage level.[36] Some RTOs do include RTO review of local projects,[37] but this is not consistent across Planning Authorities.

E. Generation interconnection processes are stretched to their breaking point

The lack of large regional transmission projects that connect resource rich areas with load centers has put the onus of building upgrades to interconnect wind and solar generators on generation interconnection processes. This has over-burdened them with a task they were never intended to perform: the job of planning the regional network in addition to the more local interconnection-related facilities.

Interconnection studies for individual generators (or groups of generators) are increasingly identifying costly regional upgrades and are projected to do so with greater fre-

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

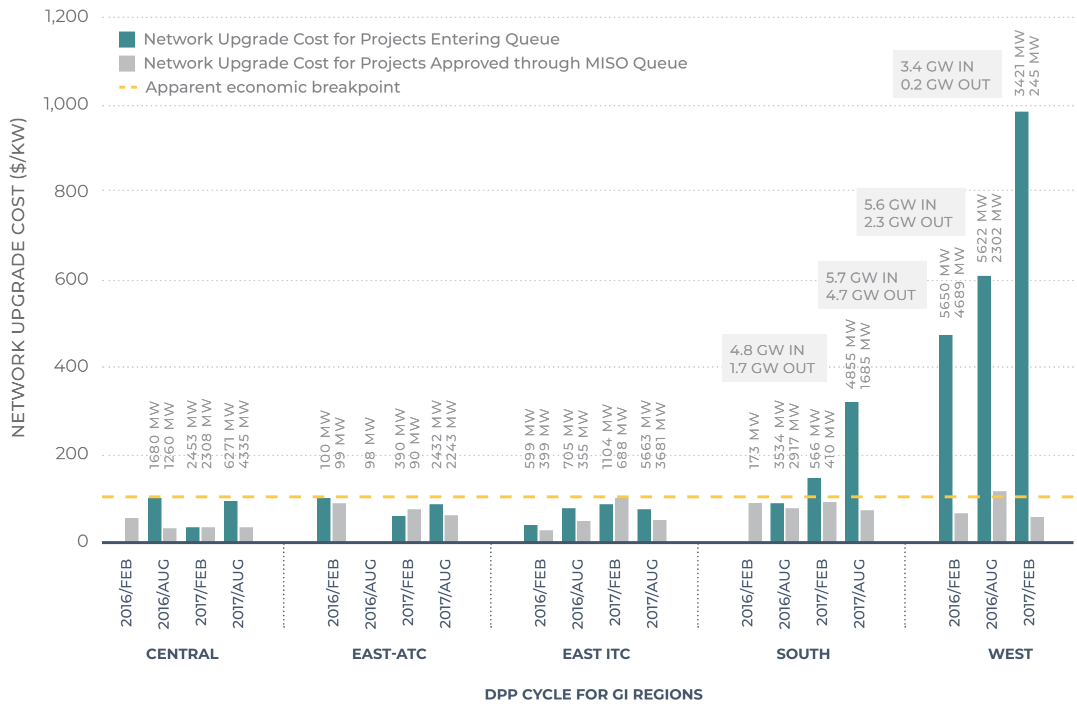
35 *Ibid.*, 6-7.

36 *Ibid.*, 17-20. *See also* MISO, *MTEP20 Appendix A - New Project List*, n.d., and PJM, *2019 Project Statistics*, at 3, May 12, 2020.

37 *See* MISO, *Business Practices Manual Transmission Planning*, BPM-020-r21, at 22, January 1, 2020. "In its role as the Planning Coordinator (PC), MISO will evaluate all bottom-up projects submitted by Transmission Owner(s) and validate that the projects represent prudent solutions to one or more identified Transmission Issues. In some situations, MISO, as the Planning Coordinator, may also recommend certain bottom-up projects if MISO analysis determines that additional expansion is necessary to comply with the NERC or regional reliability standards. Furthermore, MISO may also recommend alternative solutions to bottom-up projects submitted by Transmission Owner(s), and the expansion planning process will consider those alternative solutions along with the submitted bottom-up projects."

quency in the future. Costly system upgrades are not easily achieved by the interconnection process, which relies on participant funding — the practice of allocating project costs only to those who volunteer to pay them.[38] Interconnection costs are governed by Order No. 2003, which established the "at or beyond rule," pursuant to which the costs of facilities and equipment that lie between the generation source and the point of interconnection with the transmission network are born by the incoming generator.[39] While Order No. 2003 set a default rule that transmission owners would cover the cost of "network upgrades," (equipment "at or beyond" the point of interconnection), it gave RTOs "flexibility to customize . . . interconnection procedures and agreements to meet regional needs."[40] Some RTOs have since adopted methodologies that place the lion's share of network costs on the interconnecting generator.[41]

FIGURE 9 GI Network upgrade Costs ($/kW) for Recent MISO DPP Cycles[42]



38 *Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 715, July 21, 2011 (defining "participant funding").

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

40 *Ibid.*

41 For example, MISO adopted a methodology allocating 90 percent of even network upgrades above 345 kV to generation owners, and requiring generation owners to pay 100 percent of such costs for lines below 345 kV. *See Ibid.*

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

The system of funding major transmission upgrades through the generation interconnection process is ineffective for several reasons. First, large new transmission additions create broad-based regional benefits, so charging only interconnecting generators for this equipment requires them to fund infrastructure that others benefit from. This is the classic “free rider” problem in economics that makes it efficient to broadly allocate the cost of “public goods” like transmission, roads, water and sewer networks, etc. Second, it relies upon a study process that is highly unpredictable for participating generators, who do not know whether or not their interconnection request will require large upgrades. When studies reveal significant costs, generators tend to drop out of the process, necessitating restudies for all remaining generators and prompting delays (and potentially higher costs) for projects that are part of the same interconnection class year or further down in the interconnection queue. Third, there is a timing mismatch where transmission can take over five years, and it is not possible to know in advance which generation owners might want to connect at that point in the future. Finally, it misses opportunities to design new infrastructure in a more cost-effective fashion and of sufficient scale that maximizes all benefits of transmission, including reliability and economic benefits, and accommodates all likely new generation rather than just the particular generator(s) supporting the upgrades.

The current interconnection process simply does not work well when there is not adequate regional transmission capacity or a functioning mechanism to plan and pay for regional transmission. Without transmission planning reform that links the interconnection and transmission planning processes and eliminates the use of participant funding for significant system upgrades in the interconnection process, interconnection processes will become mired in ever-longer delays.[43]

43 Jay Caspary, Michael Goggin, Rob Gramlich, Jesse Schneider, *Disconnected: The Need for a New Generator Interconnection Policy*, January 2021.

III. FERC planning rule reforms

As the nation's resource mix evolves, the transmission system should be built to address future needs. Well-known commitments by major end use customers, utilities, cities, and states in support of net-zero or minimal carbon futures have not been adequately captured in grid planning scenarios. Information about the changing costs of different resource types are also widely recognized as driving significant system changes. Transmission plans can only yield reliable and efficient outcomes if they account for widely known trends and reasonable projections of future transmission needs. In short, plans should be about the future.

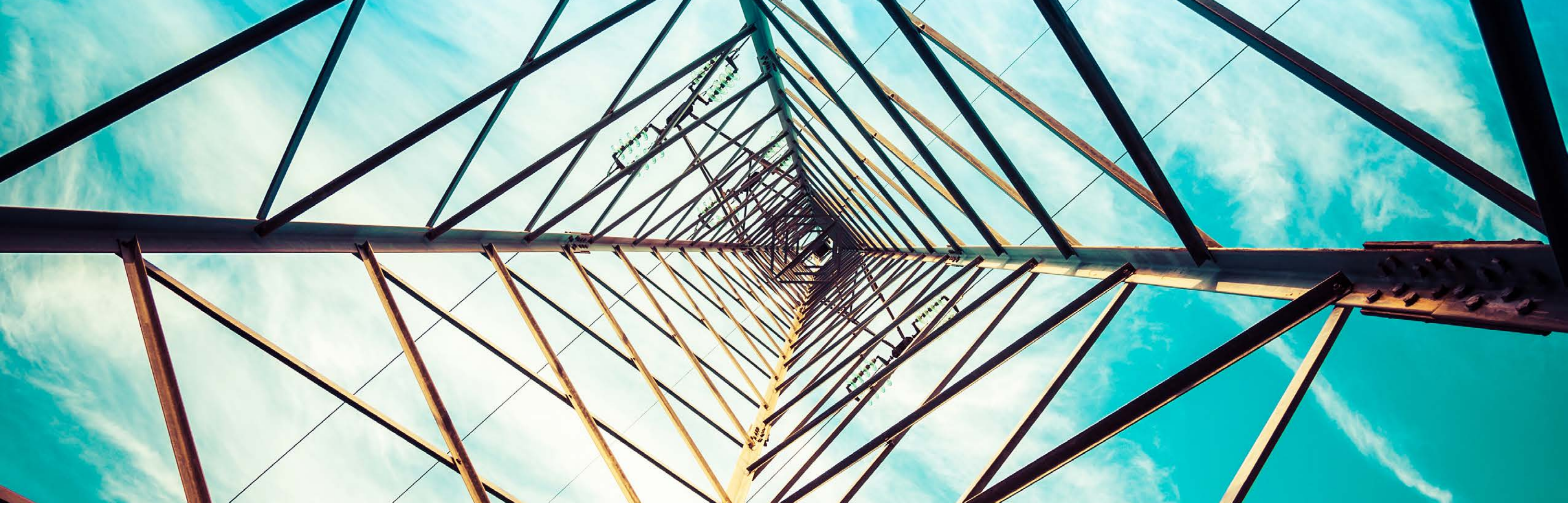
In most cases today, regional planning is limited to near term knowns and protecting firm service using scenarios which do not adequately incorporate likely future changes. In Appendix B, we describe and evaluate existing processes. In this section, we suggest reforms the Commission should enact to encourage better regional planning.

A. Integrated transmission planning should consider all benefits of transmission together

Many regions have segregated transmission planning studies for economic, reliability, public policy, and generator interconnection (GI) transmission projects. As discussed further in Appendix B, regions have separate planning processes for "Reliability" and "Economic" projects, and many regions have additional processes for "Public Policy" projects. Requiring a transmission project to be categorized as only one type of project fails to recognize all of the values and benefits of a transmission investment.[44] This siloed approach fails to consider the economies of scope across different categories and results in more poorly targeted transmission investments are accordingly less value per dollar spent by customers relative to regions that have taken an integrated approach to planning a network that optimizes across all categories of benefits.

While some regions have a process for "Multi-Value" projects, recognizing the fact that a single project may bring many types of benefits, these processes are not regularly used.

44 For example, *see* Judy W. Chang, Johannes P. Pfeifenberger, and J. Michael Hagerty, *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments*, Appendix A, July 2013.



Rather than being the exception, they should be the norm. FERC should require regional planning entities, as a general course of practice, to plan projects in a multi-value frame that considers all of the different benefits they are capable of providing.

B. Transmission needs should be determined with the best available data and scenario-based forecasting methodologies

A primary reason that the regional planning process has yielded few projects is that the scenarios modeled at the regional level do not reflect a reasonable projection of future supply and demand. To remedy this, the Commission should direct regional planning entities to carry out regional planning using scenarios constructed according to the best available data and forecasting methodologies. While reliability planning processes must necessarily evaluate solutions according to projections of the status quo future system across a variety of time scales, the economic planning process should provide an overlay to this process that is based on a more realistic assessment of future system needs, including resource mix projections that incorporate the best available data on future market trends. These should include (i) technology costs, (ii) public policies, (iii) corporate and utility procurement targets, (iv) interconnection queues, (iv) investments outside the planning process in non-wires alternatives, and (v) retirement projections. Demand projections must include reasonable electrification projections, accounting for market trends as well as public policies that require or incentivize electrification of buildings and transportation end uses. Planning entities should formulate a variety of reasonable future resource and demand mixes, recognizing the uncertainty inherent in the planning processes, identifying transmission needs across a wide range of plausible scenarios.[45]

45 *See* Johannes Pfeifenberger, Judy Chang, and Akarsh Sheilendranath, *Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid*, Appendix B at B-1, April 2015; and Johannes Pfeifenberger and Judy Chang, *Well-Planned Electric Transmission Saves Customer Costs: Improved Transmission Planning is Key to the Transition to a Carbon Constrained Future*, Section V at 17, June 2016.

Formulating these planning scenarios is challenging insofar as it will require synthesizing a range of factors to project future generation and supply mixes. But by working with National Labs, states, and stakeholders to formulate reasonable assumptions, planning entities can greatly improve upon status quo approaches. To help guide regional planning entities, the Commission could encourage National Labs to focus on developing scenario analysis that can be used by regions, specifying that such projections are likely to constitute the best available data and forecasting methodologies.

1. *Plans should address needs according to reasonable estimates of the future resource mix*

Regional planning processes have tended to under-forecast the future mix of wind and solar. For example, in a 2019 planning assessment, SPP concluded that "[p]revious ITP assessments have been conservative in forecasting the amount of renewable generation expected to interconnect to the grid. When the studies were completed, installed amounts had nearly surpassed 10-year forecasts."[46] A variety of factors may contribute to this. Perhaps most significantly, planning processes may limit scenarios assessed to known generator interconnections and retirements, and fail to include new generation as part of the mix except insofar as needed to meet load growth.

For example, PJM's market efficiency planning process includes only facilities that have an "executed Interconnection Service Agreement or executed Interim Interconnection Service Agreement for which Interconnection Service Agreement is expected to be executed."[47] While PJM's methodology was adopted with the recognition that not all projects will come to fruition, protesting parties and the Market Monitor provided persuasive evidence that PJM's methodology will lead to inaccurate projections.[48] Likewise, SPP only includes generation resources in its economic models if they meet a set of criteria that includes "an effective Generator Interconnection Agreement," unless it grants a special case-by-case exemption.[49]

Such processes neglect the core function of the transmission planning process: to build infrastructure that connects the future resource mix to load. By default, generation that has secured interconnection agreements will have already agreed to pay for network upgrades necessary to integrate the generation. The generation that could benefit from

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46 SPP, *2019 Integrated Transmission Planning Assessment Report*, at 2, November 6, 2019.

47 PJM, *Amended and Restated Operating Agreement of PJM Interconnection*, L.L.C., Schedule 6, § 1.5.7(i)(iv), effective date September 17, 2010

48 *PJM Interconnection, L.L.C.*, 166 FERC ¶ 61,104, at PP 14-20, February 12, 2019.

49 SPP, *Integrated Transmission Planning Manual*, § 2.2.1.4, July 20, 2017.

transmission planning is necessarily the generation deeper in the queue. Generator retirements also should not be ignored, as they are a major factor impacting grid planning. In many cases, new resources of a different type will be installed at the same substation or zone where aging generators are being idled and retired. The lead time to install replacement resources has been reduced for inverter-based resources such as wind, solar and battery projects, so in many cases likely generator retirement may be a useful indicator of future resource mix locations. The recent announcements by many utilities in support of clean energy mandates and goals will require a significant amount of generator retirements that are not reflected in current long-range resource plans incorporated into regional planning assessments, and public policies can likewise cause generation retirements.

Rather than permitting status quo modeling that assesses only generation built to meet new load, the Commission should require regions to carry out economic planning processes according to more realistic projections of retirements, utilizing the best available information, including generation interconnection queues,[50] to predict the set of resources most likely to meet the needs currently served by existing generation that is likely to retire. The Midcontinent Independent System Operator's (MISO's) planning process provides a general template of how regions can conduct such a process. While its Regional Resource Forecasting model formulates the region's baseline scenario using only "existing generators and future generators with a filed Interconnection Agreement and in-service date prior to the point in time represented by the model," and reflects retirement only of "existing generators with approved Attachment Y [retirement] Notices,"[51] the model is then used as the basis for "Futures" assessments that project a range of resource additions and subtractions based on cost inputs and other factors.[52] In such analyses, a base case used for reliability assessments that contains only known resource retirements and additions should be given zero weight, reflecting the fact that a projection that relies solely on known resource retirements and additions has virtually zero probability of coming to pass.

Future resource mix projections should also be required to incorporate public policies. FERC should go beyond the Order 1000 requirement that regions simply "consider" public policy, and require that they incorporate it into a holistic assessment of transmission needs. While some regions incorporate state renewable portfolio standards into their

50 While interconnection queues will not perfectly match likely future generation, they are a data point that regional planning entities should critically evaluate along with other inputs.

51 SPP, *Integrated Transmission Planning Manual*, § 2.2.1.4, July 20, 2017

52 *See*, e.g., MISO, *MTEP19 Futures: Summary of Definitions, Uncertainty Variables, Resource Forecasts, Siting Process, and Siting Results*, n.d.

standard economic planning projections, not all regions do so.[53] Regions should account both for policies such as renewable portfolio or clean energy standards that encourage particular generation types, and also for emissions regulations that may cause the retirement of polluting resources, including federal, state, and local requirements. For example, NYISO incorporated peaker plant retirement scenarios into its most recent Comprehensive Reliability Plan, reflecting the likelihood that such plants would be impacted by state emissions regulations.[54] Local public policies are playing an increasing role in shaping the resource mix and should therefore be specifically accounted for by planning entities. Over "200 cities and counties have achieved or committed to 100 percent clean electricity," with the vast majority of these commitments having been made in the past three years.[55] With the increasing use of Community Choice Aggregation to enable such resource commitments, additional local commitments may become more likely in future years.

In addition, projections should reflect corporate and utility procurement targets. Incorporating such targets is necessary to accurately project future needs, which is required in order to ensure just and reasonable rates that reflect the right amount and type of infrastructure to serve those needs. Further, incorporating corporate and utility procurement targets will help facilitate an infrastructure mix that meets consumer preferences.

While MISO has recently proposed to incorporate corporate and utility procurement targets into its future planning scenarios,[56] most regions do not currently do so. Corporate procurement of renewables is a large and growing factor shaping future resource mix. Six utilities have adopted 100 percent clean energy or zero greenhouse gas emissions targets.[57] Corporations have signed power purchase agreements to procure over 21,000 megawatts of renewable capacity since 2018,[58] and will likely be seeking to procure thousands more in the coming years pursuant to renewable procurement targets. The Renewable Energy Buyers Alliance (REBA) has set a goal of catalyzing 60,000 megawatts of renewable energy projects by 2025.[59]

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53 For example, PJM does not include public policies within its standard economic planning forecast, instead requiring any transmission driven by public policy needs to be funded separately by states. PJM, *Amended and Restated Operating Agreement of PJM Interconnection*, L.L.C., Schedule 6, § 1.5.9, effective date September 17, 2010.

54 NYISO, *2019-2028 Comprehensive Reliability Plan*, at 14-29, 2019.

55 UCLA Luskin Center for Innovation, *Progress Toward 100% Clean Energy in Cities & States Across the U.S.*, at 10-11, November 2019.

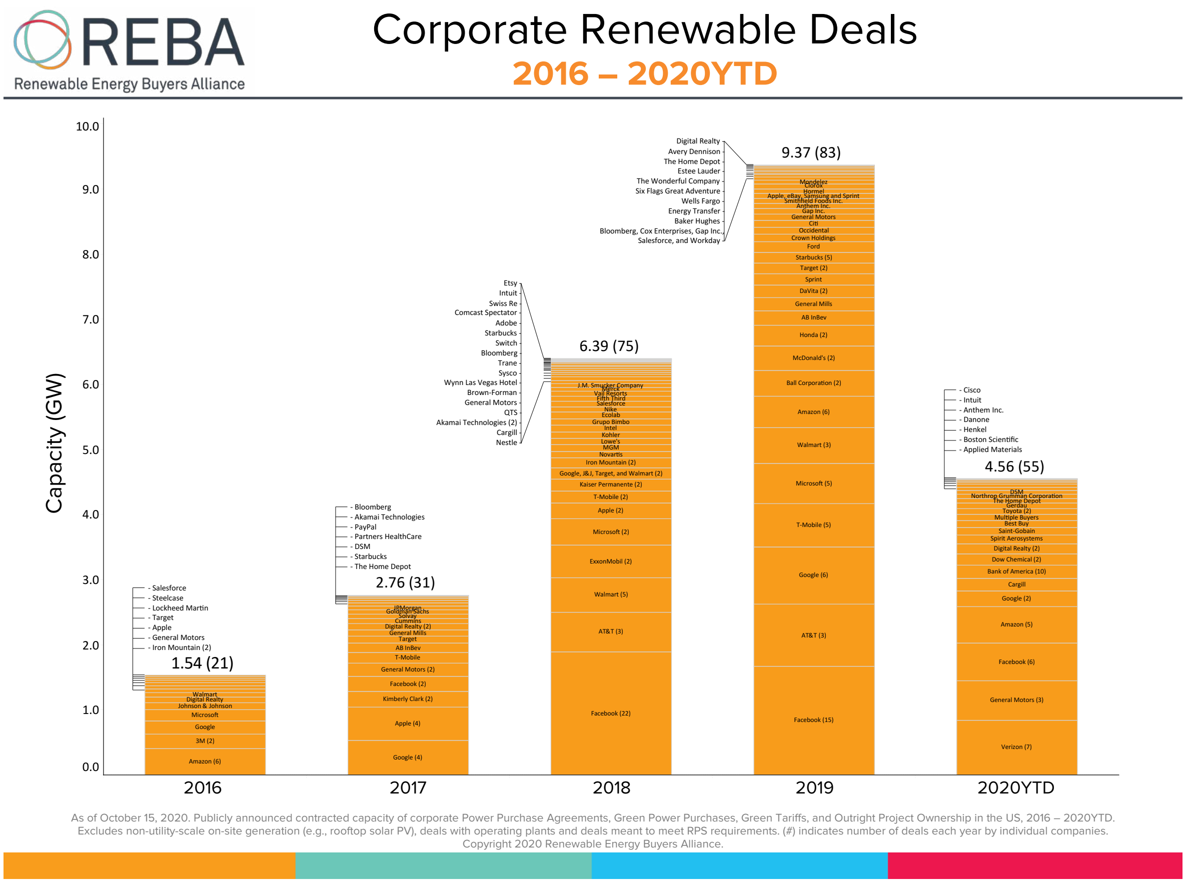
56 *See* MISO, *MISO Futures – Final*, Futures Siting Workshop, at 5, April 27, 2020, (incorporating utility and corporate procurement targets into Futures I and II).

57 UCLA Luskin Center for Innovation, *Progress Toward 100% Clean Energy in Cities & States Across the U.S.*, at 6, November 2019.

58 Renewable Energy Buyers Alliance, *REBA Deal Tracker*, accessed October 2020.

59 Renewable Energy Buyers Alliance, *Our Mission*, accessed Nov. 12, 2020. Corporate procurement goals can be more easily incorporated into regional transmission plans where companies have made time and location-specific commitments.

FIGURE 10 Corporate Renewable Deals (2016-2020)



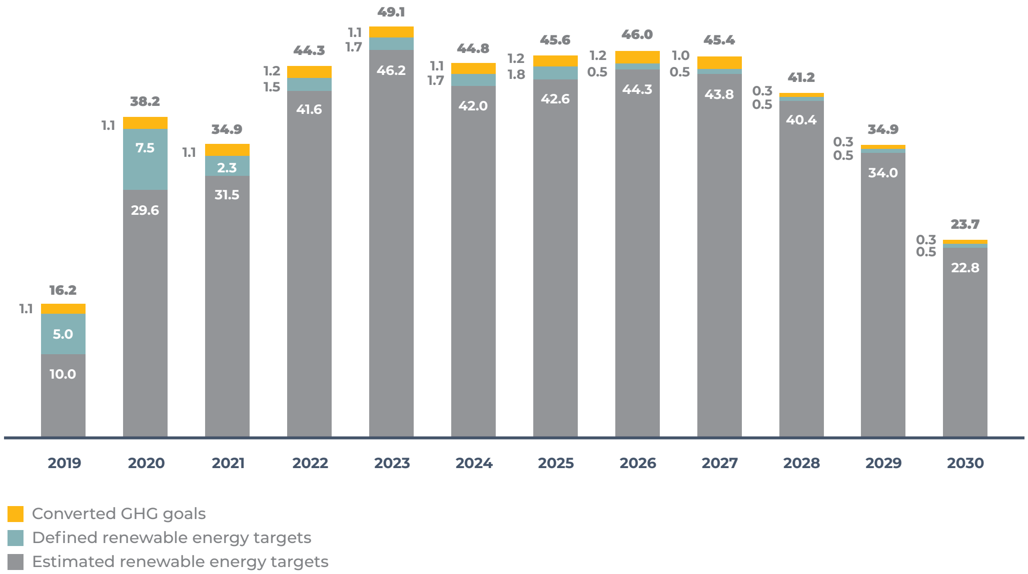
Credit: Renewable Energy Buyer's Alliance

Further, nearly half of Fortune 500 companies have set a greenhouse gas (GHG) reduction target.[60] Wood Mackenzie estimates that corporate and industrial renewable energy demand by the U.S. Fortune 1000 companies will be up to 85,000 megawatts by 2030.[61]

60 Nicolette Santos, David Gardiner and Associates, Nashville Carbon Competitiveness, at 7, September 2020.

61 Dan Shreve, Analysis of Commercial and Industrial Wind Energy Demand in the United States, at 5, August 2019.

FIGURE 11 Fortune 1000 Annual C&I Renewable Energy Procurement Requirements (TWh)



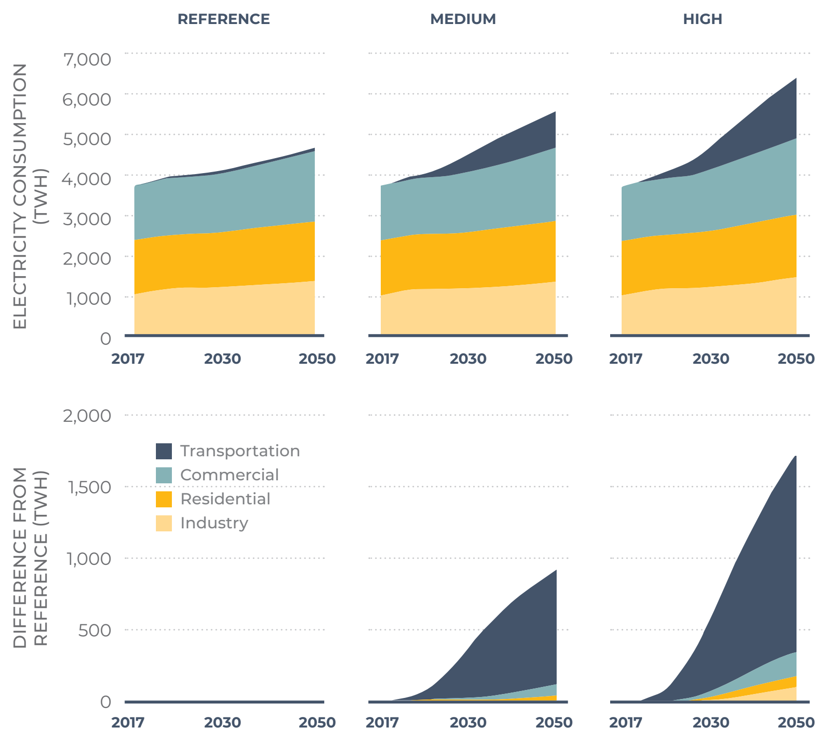
We are not aware of any reports that track total customer demand for particular resource types by region, so it is difficult to determine the extent to which such corporate targets will drive transmission planning needs. To fill this gap, the Commission should require regional planning entities to develop a process for estimating demand preferences from wholesale customers in their region. In sum, the Commission should require planning entities to plan for future resource mixes that respond to customers' preferences regarding supply sources, allocating costs appropriately, as described further in Section IV.

2. Plans should incorporate the effects of electrification on electricity demand

Electrification of transportation and buildings end-uses will have an enormous effect on future system needs. While regional transmission planning processes have made some strides forward to address this growing trend, they generally have not caught up to it and do not have adequate processes in place to ensure that demand projections will reflect reasonable electrification scenarios.

In its "medium electrification" case, which projects buildings and transportation electrification using only technology price forecasts and other factors without incorporating public policy, National Renewable Energy Laboratory (NREL) projects that transportation electrification will create nearly 1000 TWh of new demand in 2050, around a 25 percent increase from today's level, with building electrification more than making up for load reductions in the building sector caused by energy efficiency.[62]

FIGURE 12 Annual U.S. Electricity Consumption (top) and Difference from Reference (bottom)[63]



And national, state and local public policies will accelerate this trend. Recently passed state climate laws have included economy-wide emissions targets alongside generation sector requirements. For example, Maine's 2019 climate law requires the state to reduce GHG emissions to at least 80 percent below 1990 levels by 2050.[64] New York's Climate Leadership and Community Protection Act sets a target of net-zero emissions economy-wide by 2050.[65] In total, nine states and the District of Columbia have set targets of net zero economy-wide emissions by 2050 or sooner.[66]

62 Trieu Mai et al., *Electrification Futures Study: Scenarios of Electric Technology Adoption and Power Consumption for the United States*, at 60, 2018.

63 *Ibid.*, Figure 7.1 at 60.

64 *S.P. 550*, An Act to Establish the Maine Climate Change Council to Assist Maine to Mitigate, Prepare for and Adapt to Climate Change, 129th Maine Legislature, Legislative Document No. 1679, May 2, 2019.

65 *S. 6599*, An Act to Amend the Environmental Conservation Law, the Public Service Law, the Public Authorities Law, the Labor Law and the Community Risk and Resilience Act, in Relation to Establishing the New York State Climate Leadership and Community Protection Act, June 18, 2019.

66 John Podesta et al., *State Fact Sheet: A 100 Percent Clean Future*, Oct. 16, 2019.

Building codes are increasingly likely to incentivize or require electrification of some building segments, with the International Energy Conservation Code making its first ever electrification proposals for three features of its 2021 code.[67] New York City, the nation's largest local jurisdiction, has adopted a buildings efficiency standard that focuses on total building emissions and requires substantial reductions by 2030.[68] In California, "[m]ore than 50 cities and counties are considering requiring or encouraging all-electric new construction with local ordinances and zero-emission reach codes for buildings."[69] Furthermore, states and local jurisdictions also have a wide range of legal tools to electrify transportation fleets,[70] and are increasingly adopting plans to do so. For example, many states have adopted financial incentives for EV ownership, as well as incentives for EV charging infrastructure, often recoverable in rates.[71] California's governor recently signed an order banning sales of new gasoline cars by 2035.[72]

The Brattle Group analysts estimate that between $3 billion and $7 billion in annual incremental transmission investment will be need to meet increased demand caused by electrification between 2018 and 2030, with between $7 billion and $25 billion in annual incremental investment required between 2031 and 2050.[73]

In theory, reasonable electrification projections should already be guiding regional transmission planning processes, as they all include a load forecasting process to assess future demand.[74] In practice, however, load forecasting processes are not generally calibrated to capture the likelihood that electrification will drive a significant increase in future demand. Some regions, such as PJM, have begun to adjust their load forecasts to factor in electrification. PJM's forecast used for RTEP19 incorporates "an explicit adjustment for plug-in electric vehicle (PEV) charging in its peak and energy forecasts."[75] Building on these efforts, the Commission should require all regions to explicitly account for additional load from electrification of both transportation and buildings. Further, as with generation mix projections, it should require regions to plan according to a variety of scenarios. Scenario analysis is particularly appropriate with regard to electrification because, as Brattle analysts observe, "[t]he dynamics of electrification adoption, like the adoption of all new technologies, are likely to be characterized by hard to predict tipping points

67 *See* Stacey Hobart, *Electrification Nation?*, July 29, 2020.

68 *See* *Local Law No. 97 of 2019:* To amend the New York city charter and the administrative code of the city of New York, in relation to the commitment to achieve certain reductions in greenhouse gas emissions by 2050.

69 Sierra Club, *Building Electrification Action Plan for Climate Leaders*, at 7, December 2019.

70 *See* MJB&A, *Toolkit for Advanced Transportation Policies*, October 2018.

71 *See*, e.g., Center for Climate and Energy Solutions, *U.S. State Clean Vehicle Policies and Incentives*, last updated January 2019.

72 Lauren Sommer and Scott Neuman, *California Governor Signs Order Banning Sales Of New Gasoline Cars By 2035*, September 23, 2020.

73 Dr. Jürgen Weiss, J. Michael Hagerty, and María Castañer, *The Coming Electrification of the North American Economy*, at 17, March 2019.

74 *See*, e.g., PJM, *Regional Transmission Expansion Plan*, at 25, February 29, 2020, (describing PJM's load forecasting model).

75 PJM, *Regional Transmission Expansion Plan*, at 37, February 29, 2020.

that result in rapid and widespread changes in consumer preferences and exponential growth once a certain tipping point is reached."[76] For this reason, MISO's methodology, that uses electrification as an overlay to the load forecast included in its Futures assessment, is appropriate, beyond updating the underlying load forecast itself.

3. Plans should incorporate resilience and reliability

The National Commission on Grid Resilience, noting the national security risks and the benefits of large-scale transmission described above, recommended, "Order 1000 … failed to anticipate the need for inter-regional transmission over larger geographic scales between multiple grid regions in the wake of rising penetrations of renewable energy."[77] The report recommended "We agree with calls for reform, and specifically recommend that FERC strengthen requirements for interregional transmission planning, encourage longer term thinking about the value of larger lines (including high voltage direct current (HVDC) lines) and advanced technologies such as power flow controls and dynamic line ratings, and require RTOs/ISOs to assert leadership in planning processes and represent the public interest in doing so."[78] National security interests and expertise should be included in transmission planning processes.

4. Needs assessments should incorporate information on the use of non-wires options

Order No. 1000 rightly requires regional and inter-regional planning entities to "consider proposed non-transmission alternatives on a comparable basis."[79] Yet, because they are not currently given cost recovery in the transmission planning process, developers of such solutions, which include distributed energy resources such as energy efficiency, demand response, and energy storage, have little incentive to propose these solutions in the planning process. Therefore, the Commission should require regional planning entities to develop methods that assess the extent to which such solutions are likely to be able to cost-effectively reduce or replace the need for transmission solutions, without requiring them to be formally proposed. Such processes may consist of refinements to load forecasting analysis to account for the fact that solutions are more likely to be put forward in pockets with higher value, as well as linkages to state non-transmission solutions planning proceedings.

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76 Dr. Jürgen Weiss, J. Michael Hagerty, and María Castañer, *The Coming Electrification of the North American Economy*, at 6, March 2019.

77 NCGR, *Grid Resilience: Priorities for the Next Administration,* at 42, 2020.

78 *Ibid.*, at 42.

79 *Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 148, July 21, 2011.

Planning should also assess how strategically sited energy storage or advanced types of demand response deployed as transmission assets, included within state integrated resource plans, or likely to be built via competitive market forces, can serve as a complement to transmission expansion, allowing more efficient utilization of new transmission equipment. This includes benefits from storage charging when downstream transmission is congested and later discharging that energy when it is not, which is particularly advantageous for storage located in wind or solar producing areas. It also includes use of the fast charge and discharge response of storage devices to help accommodate system contingencies, instead of the current approach of leaving transmission capacity unutilized at all times so the system remains stable during flow conditions following a contingency.

5. ***Planning entities should incorporate input from states on siting***

Information from states will be critical to developing reasonable planning scenarios, considering the role states play with regard to the siting and permitting of transmission infrastructure. Reasonable planning scenarios should reflect siting constraints. The timing of the regional transmission planning processes means that the Commission should not reverse its determination in Order No. 1000-A "that it would be an impermissible barrier to entry to require, as part of the qualifica-

tion criteria, that a transmission developer demonstrate that it either has, or can obtain, state approvals necessary to operate in a state, including state public utility status and the right to eminent domain, to be eligible to propose a transmission facility."[80] But the Commission should go beyond Order No. 1000 in seeking ways to incorporate state input on siting and other related issues into the regional and interregional planning processes.

For example, the Commission can require regional planning entities to solicit input from states on siting considerations in advance, so that regional planning processes are designed with an eye toward state siting processes. Where states have broad siting priorities, such as prioritizing construction in existing corridors, that can be taken into account. Where particular projects have already obtained siting approval, or particular corridors have been designated by states, U.S. DOE,[81] or the Bureau of Land Management[82] as ripe for transmission development, regional planning entities can prioritize those projects or locations.

Because states have jurisdiction to set policies that control the mix of resources on the system, they will provide critical input to RTOs and other regional planning entities in constructing grid mix scenarios.

6. Planning scenarios and models should be consistent with operational practice

The scenarios and resulting models developed for planning efforts should reflect plausible and expected system conditions, including the realistic response those conditions would elicit from system operators.

Historically, planning was focused on meeting peak demand, which necessitated most generating resources to be online and dispatched at high levels to meet the peak. With increased renewable generation, many times the most stringent transmission needs occur during periods with lower demand, when there can be significant flexibility to reschedule and redispatch resources, as not all of them are needed to meet demand under those conditions. However, planning models have tended to not account for this flexibility, and instead assume a certain fixed schedule and output of dispatchable thermal generation. These dispatch levels can be inconsistent with how these resources would behave under real system and market conditions in operations. As a result, the transmission system is modeled in planning as more burdened or with less capacity than it would have in operations under those same conditions. Planning models and power flow cases

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80 *Ibid.*, at P 441.

81 *See 16 U.S.C. § 824p.*

82 *See Energy Policy Act of 2005, § 368*, Pub. L. No. 109-58, H.R., August 8, 2005.

should reflect system conditions that are consistent with how the system is operated, including dispatching units using the same least-cost dispatch logic used to dispatch units in operations.

C. Transmission plans should construct the best feasible portfolios based on all available technologies, configurations, and options

Beyond carrying out planning according to reasonable scenarios projecting supply and demand mix, the Commission should also build on Order No. 1000's requirements to ensure that the scenarios modeled draw on all types of solutions to serve transmission needs, and include in plans all types of technologies and configurations.

1. Plans should consider and include all grid enhancing technologies

As a number of parties commented in the Commission's Notice of Proposed Rulemaking on transmission incentives, Grid Enhancing Technologies (GETs) should be included in the transmission planning process.[83] Dynamic Line Ratings, power flow control, topology optimization, and storage as transmission are "transmission assets," which can be directly included in plans, with costs recovered in RTO tariffs just like other transmission technologies. The American Public Power Association explains that regional processes for identifying solutions should "identify efficient and cost-effective GETs deployments (e.g., by ascertaining transmission paths with severe congestion that GETs might alleviate at a lower cost than alternatives)."[84] GETs should be modeled consistent with how they would be operated to deliver both reliability and economic benefits. These technologies often provide a great deal of flexibility that may be useful in a variety of potential system conditions. GETs are also generally modular (can be sized to the need) and mobile (can be physically moved to different points on the grid), which provides option value to any facility acquired.[85] These forms of optionality value should be incorporated into benefits assessments.

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83 *See*, e.g., *Comments of Transmission Access Policy Study Group*, Docket No. RM20-10, at 8-9, July 1, 2020 ("While the NOPR rightly does not propose the highly problematic shared-savings incentives, its proposed incentives for deployment of transmission technologies needlessly increase cost without addressing the real obstacles to deploying new technologies. A better approach would be to integrate advanced technologies into Order 890 and Order 1000 processes."); *Comments of Alliance Energy Corporate Services, Inc. and DTE Electric Company*, Docket No. RM20-10, at 35, July 1, 2020 ("The Commission should ensure that required transmission planning processes appropriately consider new technologies and alternative, non-transmission solutions.").

84 *Comments of the American Public Power Association*, Docket No. RM20-10, at 65, July 1, 2020.

85 Kerinia Cusick, Jon Wellinghoff, and Lorenzo Kristov, *Transmission Planning Protocol: Leveraging Technology to Optimize Existing Infrastructure*, August 2019.

Because the impacts of GETs are sometimes easier to measure in the shorter-term time frame (months to hours) rather than years, the Commission should consider whether an incremental step in the planning process may be appropriate that is particularly targeted at measuring ways in which GETs could improve operations of the existing system. At the same time, the inclusion of GETs in the long-term solution mix may frequently yield benefits, and may be used in conjunction with new infrastructure improvements to offer a more efficient solution than would otherwise be provided.

2. *Plans should consider options of non-traditional physical assets and configurations*

Future needs will likely call for more long-distance transfers of power across time zones and areas with asynchronous loads shapes. That factor along with the falling costs of High Voltage Direct Current (HVDC) will likely lead to more applications of HVDC into plans. Regional planners have not utilized HVDC much in recent decades, and it raises issues about control and operation that are different from current systems. Planners should address these opportunities and changes that may be needed.

New types of conductors, converters, transformers, and other assets provide potential reliability, resilience, and efficiency benefits that should be considered in transmission plans. For example, HVDC lines with Voltage Source Converters present opportunities for black starting whole regions with power from neighboring regions. Composite core transmission lines can deliver more and withstand more severe weather events than traditional conductors. All such options should be considered and incorporated as appropriate.

3. *Benefits of individual and merchant lines should be assessed in regional and inter-regional planning, whether or not they are not cost allocated*

Order No. 1000 does not require merchant transmission developers to participate in regional planning processes because they do not receive regional cost allocation.[86] It does, however, require merchant developers "to provide adequate information and data to allow public utility transmission providers in the transmission planning region to assess the potential reliability and operational impacts of the merchant transmission developer's proposed transmission facilities on other systems in the region," and allows merchant transmission developers to voluntarily participate in the regional transmission planning

86 *Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 163, July 21, 2011.

process.[87]

Assessing the benefits of merchant transmission development in regional transmission plans is appropriate because, even though such infrastructure does not receive regional cost allocation, it impacts the overall mix of solutions that may be built. Further, assessing the benefits and costs of merchant transmission solutions could help these projects secure state-level siting permits, by demonstrating the need for these projects. For this reason, the Commission should build on Order No. 1000's requirement for merchant developers to provide data to inform the regional transmission planning process[88] by directing planning entities to conduct planning scenarios that quantify the benefits of merchant projects. In addition to helping inform regional processes, this would help merchant developers drive projects forward by giving them some evidence of need that they could use in state permitting processes. Similarly, cost allocated lines that are assessed through portfolio benefits assessments should be studied for individual benefits upon request, for use in permitting proceedings.

D. FERC should direct planning entities to select infrastructure for inclusion in regional plans by maximizing net benefits of a portfolio

Once needs are assessed based on best available information, all benefits are considered together, and all technology and configuration options are considered, regional planning entities should be directed to select plans that maximize the net benefits of a portfolio of transmission investments.

The Commission should build on Order No. 1000 to provide greater direction and clarity about the wide range of benefit metrics regional planning entities should use to assess whether solutions are beneficial and should thus be included in the regional plan, directing planning entities to achieve just and reasonable rates by using Benefit-Cost Analysis (BCA). There will be many trade-offs between different options. Some investment options will be more costly in the near-term but carry much greater benefits over the long term. Some will be extremely low cost and fast to deploy with benefits that well exceed their costs, even though those benefits may not be as great as long-term large-scale options. In some cases, the options will be mutually exclusive and in other cases they will be complementary such that they could be done together. BCA provides a clear planning protocol that prioritizes among these potentially competing or complementary invest-

87 *Ibid.*, at PP 164-165.
88 *Ibid.*, at PP 163-165.

ments based on what would be most likely to result in just, reasonable, and not unduly discriminatory rates.[89]

1. *Pro-active holistic transmission planning to maximize net benefits is fully compatible with standard RTO market designs and competitive generation markets*

The six FERC-jurisdictional RTOs (ISO-NE, NYISO, PJM, MISO, SPP, and CAISO) as well as the ERCOT all use a form of bid-based security constrained economic dispatch with locational prices and financial transmission rights. The academic literature behind locational marginal price (LMP) design does not make the claim that the efficient level of transmission is achieved by relying only on voluntary investment. To the contrary, the leading economists and engineers were clear that planned investment is required to achieve efficiency. As perhaps the leading international expert and proponent of the LMP design, Dr. William Hogan of Harvard University, wrote recently:

> If there were no economies of scale and scope for transmission investment, electricity markets could follow the same competitive model for transmission where beneficiaries determine and pay for their own investments. Given the large economies of scale and scope, transmission is a natural monopoly and investment requires a central coordinator.[90]

Dr. Hogan explains the appropriate decision rule for transmission planning is Benefit-Cost Analysis: "A forward-looking cost-benefit analysis provides the gold standard for ensuring that transmission investments are efficient."[91] He continues to explain BCA as the only reasonable option for efficient grid planning:

> There is no other way of determining whether a grid investment is efficient. Whatever the purpose of the grid investment, it will only be efficient if the benefits it provides — for example, in terms of lower energy production costs or increased reliability — exceed the cost of the investment. No investment should proceed without being subject to a cost-benefit assessment which quantifies all benefits and costs.[92]

Some parties may prefer to rely only on voluntary investment and Financial Transmission Rights as the incentive for such investment, and some market participants would

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89 *See* generally Avi Zevin, *Regulating the Energy Transition: FERC and Cost-Benefit Analysis*, May 2020 (arguing that greater use of cost-benefit analysis will further the Commission's mission of cost-effectively serving customers).

90 William W. Hogan, *Transmission Investment Beneficiaries and Cost Allocation: New Zealand Electricity Authority Proposal*, at 1, February 1, 2020.

91 *Ibid.*

92 *Ibid.*, at 5.

probably fare better in that model. However, that is not efficient for consumers as Dr. Hogan's paper thoroughly describes. Relying only on voluntary investment by market participants does not work in theory because public goods are always under-provided when relying only on voluntary market participant investments. It does not work in practice either, as we have seen persistent congestion and a lack of infrastructure development as described in the first section.

Similarly Dr. Paul Joskow, the economist who initiated the movement towards competitive generation markets perhaps more than any other economist with his 1983 book Markets for Power,[93] has long recognized the natural monopoly and public goods aspects of transmission that do not lend themselves to a competitive structure for that sector. Instead he advocates for pro-active broad regional planning to achieve the efficient transmission network: "Barriers to expanding the needed inter-regional and internetwork transmission capacity are being addressed either too slowly or not at all."[94] During restructuring he advised the Commission:

> There are numerous reasons why we should not expect "the market" to produce transmission enhancements that meet reasonable economic and reliability goals. *Indeed, proceeding under the assumption that, at the present time, "the market" will provide needed transmission network enhancements is the road to ruin*. There is abundant evidence that market forces are drawing tens of thousands of megawatts *of new generating capacity* into the system. There is no evidence that market forces are drawing significant quantities of entrepreneurial investments in new transmission capacity. While third parties should be given the opportunity to propose market-based private initiatives to expand transmission capacity, incumbent transmission owners, in the context of a sound RTO/ISO planning process, must be relied upon to play a central role in expanding the transmission system.[95]

The arguments above from leading economists apply both to RTO structures as well as to transmission outside of RTO where traditional "contract path" transmission service is utilized. In either case, just and reasonable rates are also best achieved by pro-active holistic planning that maximizes net benefits.

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93 Paul L. Joskow and Richard Schmalensee, *Markets for Power*, MIT Press, November 1983.

94 Paul Joskow, *Transmission Capacity Expansion is Needed to Decarbonize the Electricity Sector Efficiently*, Joule 4, at 1-3, January 15, 2020.

95 *Comments of Professor Paul L. Joskow*, Docket RM 99-2, at v, August 16, 1999.

2. The Commission should direct planning entities to apply standard methods of incorporating uncertainty into BCA

BCA analysis of transmission portfolios will be shaped by the planning process, as the core of the analysis will be a forward-looking projection of benefits and costs across the scenarios examined. As recommended above, the Commission can ensure a wide range of benefits are accurately assessed by requiring incorporation of all factors likely to shape the future demand and supply mix, mandating consideration of all relevant technologies.

BCA can and should handle uncertainties, of which there are many in transmission. Fuel prices, load growth, load shapes, generation mix, and weather patterns can all change and lead to differing results on which transmission has benefits that exceed costs. Public policies may be expressed via actions such as Executive Orders that do not have the full force of statutes or regulations yet may nevertheless be likely to guide the transmission mix. Standard BCA uses the concept of "expected value" to address uncertainty. Expected value arrives at a single expected benefit number when considering two scenarios by multiplying the probability of the scenario times the value of it.

Certain scenarios significantly influence the expected value of transmission. For example, transmission enables existing power plants to be dispatched in real-time as fuel prices fluctuate or demand shifts. The value of transmission can be particularly high during extreme events, especially where they cause fuel prices and demand to spike while suppressing supply in localized region, making imports from other regions extremely valu-

able. For example, additional transmission would likely have yielded hundreds of millions of dollars in savings over a matter of days during recent Polar Vortex and Bomb Cyclone events.[96] Probabilistic transmission analysis will also become increasingly valuable as the penetration of variable renewable resources increases, which can make transmission ties extremely valuable during periods of regional renewable over-supply or shortage.

Transmission also creates optionality for new power plants to be built to take advantage of unexpected shifts in the economics of different energy sources. Over the last decade, transmission has not only allowed customers to benefit from the large cost reductions for wind and solar generation, but also the increased availability of low-cost shale natural gas in many regions where gas resources were not previously available. Because it takes much longer to plan, permit, and build transmission than generation, it is often not possible to wait for economic and policy shifts to occur before investing in the transmission needed to optimally respond to them.

SPP and Brattle Group analysts have documented the value of transmission for providing optionality to hedge against uncertainty in future fuel prices, the generation mix, and other factors.[97] Additional analysis has shown the optionality value of transmission to be very large and found that standard transmission planning methods greatly underestimates the value of transmission.

Plans that ignore important scenarios will produce inefficient outcomes. Analysis by Dr. Ben Hobbs and Francisco Espinoza from Johns Hopkins University shows that current transmission planning methods, which at best use several deterministic scenarios to highlight ranges of future outcomes for the power system, are "a weak tool for decisions under uncertainty" and "don't account for flexibility."[98] Relative to standard deterministic methods that do not account for uncertainty, probabilistic transmission planning methods that account for uncertainty by simultaneously evaluating a large number of possible scenarios result in both a larger and more optimal transmission build, potentially saving consumers tens or even hundreds of billions of dollars.[99]

Other recent analysis found that the consumer savings from use of such probabilistic (stochastic) tools in the Western U.S. "can be as much as or even exceed the cost of the

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96 Michael Goggin, *How Transmission Helped Keep the Lights on During the Polar Vortex*, February 14, 2019.

97 Johannes Pfeifenberger and Judy Chang, *Well-Planned Electric Transmission Saves Customer Costs: Improved Transmission Planning is Key to the Transition to a Carbon Constrained Future*, June 2016; and SPP, *The Value of Transmission*, January 26, 2016.

98 Francisco D. Munoz, Jean-Paul Watson, and Benjamin F. Hobbs, *Optimizing Your Options: Extracting the Full Economic Value of Transmission When Planning Under Uncertainty*, The Electricity Journal, Volume 28, Issue 5, at 26-38, June 2015; and Benjamin F. Hobbs, Francisco D. Munoz, Saamrat Kasina, and Jonathan Ho, *Assessing Transmission Investments under Uncertainty*, August 2013.

99 Francisco David Muñoz Espinoza, *Engineering-Economic Methods for Power Transmission Planning Under Uncertainty and Renewable Resource Policies*, at 102, January 2014.

recommended transmission facilities themselves."[100] The analysis "provide[s] evidence that the transmission recommendations of stochastic programming models are more robust to scenarios that haven't been considered than recommendations by deterministic models. That is, stochastic plans appear to make the network more adaptable in the face of all uncertainties, not just those that were included as specific scenarios."[101]

Transmission planning analysis often identifies certain scenarios where the value of transmission is extremely high even if it is not in the base case. But while many planning entities currently assess projects across a range of scenarios, they do not generally assign probabilities to these scenarios or clarify how the different scenario results factor into project selection. For the reasons above, BCA applied to transmission should consider scenarios and probabilities to arrive at expected value of transmission.

3. The Commission should provide a minimum set of benefits that must be included in any BCA analysis conducted by planning entities

Beyond ensuring that BCA is performed according to the reasonable likelihood of future scenarios, the Commission should also set a minimum standard for quantifying benefits and encourage planners to innovate and learn from one another's experience in quantifying benefits.

While many planning entities currently perform BCA analysis, none fully quantify the full range of benefits provided.[102] For example, SPP's benefit-cost methodology excludes transmission's benefits in lowering reliability margins, improving grid resilience to extreme weather, enabling more efficient operating practices and maintenance schedules, and enabling future markets.[103] To remedy these failures to accurately quantify benefits and provide a more consistent standard for judging projects, the Commission should mandate a minimum set of standards for quantifying benefits.

BCA should simultaneously evaluate all categories of benefits provided by transmission, instead of the siloed approach currently used in many regions. It should also include benefits that are not currently quantified in most regional transmission planning processes,

100 Jonathan L. Ho et al., *Planning Transmission for Uncertainty: Applications and Lessons for the Western Interconnection*, January 2016.

101 *Ibid*.

102 *See*, e.g., Burcin Unel, *A Path Forward for the Federal Energy Regulatory Commission: Near-Term Steps to Address Climate Change*, at 14-15, September 2020.

103 *See* Johannes Pfeifenberger, *Improving Transmission Planning: Benefits, Risks, and Cost Allocation*, at 12, November 6, 2019, (citing SPP, *Priority Projects Phase II Report*, February 2010, and SPP Metrics Task Force, *Benefits for the 2013 Regional Cost Allocation Review*, July 5, 2012).

but for which quantification methods exist.[104] As shown in the following table from SPP's report on the topic, transmission provides many benefits, though many are typically not quantified (listed as "N/Q"). BCA determines which options are efficient to pursue, taking all factors into account, and ensures that options that do not reduce rates in the long term are not chosen.

104 For example, *see* Judy W. Chang, Johannes P. Pfeifenberger, and J. Michael Hagerty, *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments*, Appendix A, July 2013; and Judy W. Chang et al., *Recommendations for Enhancing ERCOT's Long-Term Transmission Planning Process*, Appendix B, October 2013.

TABLE 1 **Projected Net Present Value (NPV) of SPP Transmission Projects Installed in 2012-14, Based on the First Year of SPP's Integrated Marketplace (Mar 2014 - Feb 2015)**[105]

BENEFIT CATEGORY	TRANSMISSION BENEFIT	NPV ($M)
Adjusted Production Cost Savings	Reduced production costs due to lower unit commitment, economic dispatch, and economically efficient transactions with neighboring systems	10,442*
1. Additional Production Cost Savings **	a. Impact of generation outages and A/S unit designations	INCLUDED
	b. Reduced transmission energy losses	INCLUDED
	c. Reduced congestion due to transmission outages	INCLUDED
	d. Mitigation of extreme events and system contingencies	PARTIAL
	e. Mitigation of weather and load uncertainty	PARTIAL
	f. Reduced cost due to imperfect foresight of real-time system conditions	INCLUDED
	g. Reduced cost of cycling power plants	PARTIAL
	h. Reduced amounts and costs of operating reserves and other ancillary services	PARTIAL
	i. Mitigation of reliability-must-run (RMR) conditions	N/Q
	j. More realistic "Day 1" market representation	N/Q
2. Reliability and Resource Adequacy Benefits	a. Avoided/deferred reliability projects	105
	b. Reduced loss of load probability or c. reduced planning reserve margin (2% assumed)	1,354
	c. Mandated reliability projects	2,166
3. Generation Capacity Cost Savings	a. Capacity cost benefits from reduced peak energy losses	171
	b. Deferred generation capacity investments	N/Q
	c. Access to lower-cost generation resources	PARTIAL
4. Market Benefits	a. increased competition	N/Q
	b. Increased market liquidity	N/Q
5. Other Benefits	a. storm hardening	N/Q
	b. fuel diversity	N/Q
	c. flexibility	N/Q
	d. reducing the costs of future transmission needs	N/Q
	e. wheeling revenues	1,133
	f. HVDC operational benefits	N /A
6. Environmental Benefits	a. Reduced emissions of air pollutants	N/Q
	b. Improved utilization of transmission corridors	
7. Public Policy Benefits	a. Optimal wind development	1,283
8. Employment and Economic Development Benefits	b. Other benefits of meeting public policy goals	N/Q
	Increased employment and economic activity; Increased tax revenues	N/Q
	TOTAL	**16,670 +**

105 SPP, *The Value of Transmission*, Appendix B, January 26, 2016.

To address these gaps, and similar gaps in other planning regions, the Commission should require all planning entities to at least:

- Fully capture production cost savings, including many categories in traditional analyses (reduced transmission energy losses, reduced congestion due to transmission outages, reduced cost of cycling power plants, etc.);[106]
- Consider the extent to which the transmission project can avoid the need to replace aging facilities in the future, as NYISO did in its assessment of a recently approved public policy project;[107] and
- Fully capture the reliability value of transmission infrastructure, including (i) avoided/deferred reliability projects, (ii) reduced expected unserved energy or reduced planning reserve margin, (iii) reduced capacity needs from reduced losses at times when the grid is stressed, (iv) enabling market access to less costly capacity resources, (v), improved reserves sharing, and (vi) increased voltage support.

Because methodologies for assessing benefits are likely to improve over time, criteria adopted by the Commission should establish a floor, but not a ceiling for benefits to be considered.

4. BCA should include reliability and resilience factors

BCA can handle "reliability" and "resilience" factors as well as production costs and more measurable economic factors. Of course, transmission that is strictly required for compliance with reliability standards will be incorporated into plans. Beyond what is required, however, are reliability and resilience benefits associated with any given transmission investment option. Reliability and resilience values can be quantified, measured, and monetized.[108] It will matter, for example, whether a scenario results in 1% of load being shed for a short period of time versus all load for an extended period. Therefore "loss of load probability" (percent chance of load loss) will be less useful than "expected unserved energy" (expected MWhs of load lost). BCA using expected values can take into account real-world instances like what we have recently witnessed with cold snap conditions and generator outages leading to maximum possible transfers of power from one region to

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106 The Brattle Group report provides a set of best practices on benefits to include in analyses, as well as an overview describing how different RTOs capture different benefits, but all leave certain benefit categories out of their analysis. *See* Johannes Pfeifenberger, *Improving Transmission Planning: Benefits, Risks, and Cost Allocation*, at 12-13, November 6, 2019.

107 *See* NYISO, *AC Transmission Public Policy Transmission Plan*, at 3, April 8, 2019, (assessing "quantitative and qualitative metrics include the project's capital cost, cost per MW, expandability, operability, performance, property rights and routing, schedule, metrics identified by the NYPSC (e.g., replacement of aging infrastructure), and other metrics (e.g., production cost savings, Location Based Marginal Pricing ("LBMP") savings, Installed Capacity ("ICAP") savings, and emissions savings").

108 *See* Burcin Unel and Avi Zevin, *Toward Resilience: Defining, Measuring, and Monetizing Resilience in the Electricity System*, August 1, 2018.

the next. Even if that is expected to happen a few times over the life of a transmission investment, it can justify the investment. Planners can quantify expected value using the principle of expected loss of load (LOLE) times value of lost load (VOLL), as with the treatment of uncertainty described above. But as explained further below, there is no legal requirement to fully quantify all or most components of benefits. The economic principle can be followed regardless of how much quantification is performed, as the best way to achieve just and reasonable rates.

5. BCA should incorporate social benefits if public policies include them

Where applicable, regional planning entities should also include societal benefits as reflected by public policies. For example, the New York System Operator already applies a "Social Cost of Carbon" sensitivity to its analyses of public policy projects,[109] reflecting New York State's public policies that place a negative value on carbon emissions.[110] The Commission should require planning entities to build this approach wherever the applicable public policymakers have put a value on emissions, using that value as the base case for all planning scenarios across applicable market nodes, rather than using it merely as a sensitivity and only for public policy projects.[111] To the extent that different public policy requirements are in place across a region, planning entities can apply different values at different market nodes.

6. BCA time frames should reflect the full life of the transmission assets

Standard BCA is performed over the life of assets. This is intuitive to traditional transmission planners. For example, the Pacific direct current (DC) Intertie is a key part of the Western power system 50 years after its dedication.[112] It is obvious that if today's common approach of assessing benefits over 10 to 15 years were applied, such important infrastructure would never have been built. The Commission should direct planning entities to assess benefits across the full useful life of transmission infrastructure, which is generally over 40 years.[113] Despite transmission's long asset life, regional planning entities often carry out benefit-cost analysis using a much shorter forecast period. Because the benefits tend to grow over time (often faster than the relevant discount rate) but regulated

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109 *See*, e.g., NYISO, *AC Transmission Public Policy Transmission Plan*, at 20-22, April 8, 2019.

110 For example, the New York Public Service Commission's Benefit-cost Analysis framework factors in the social cost of carbon. *See Order Establishing the Benefit Cost Analysis Framework*, Case 14-M-0101, January 21, 2016.

111 Where incorporating quantified social benefits is not supported by the relevant public policies, it is nevertheless critical that supply, demand, and congestion created by those policies factor into other components of the benefits analysis.

112 Bonneville Power Administration, *Direct current line still hot after 40 years*, May 26, 2010.

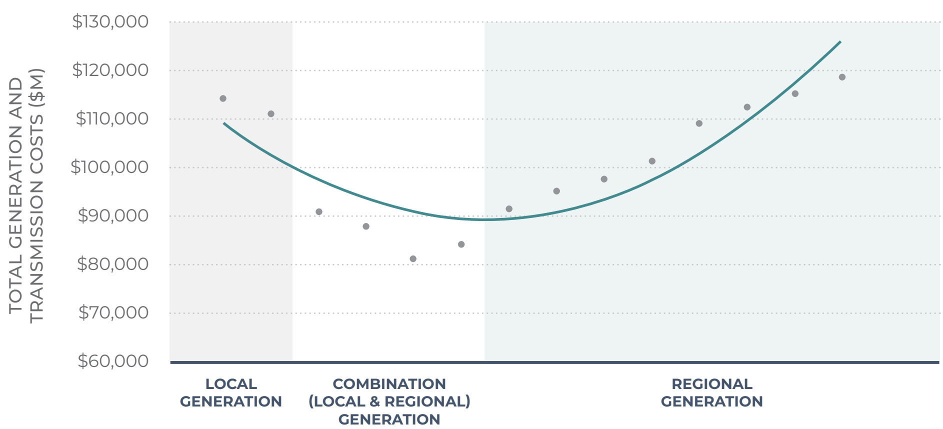
113 Union of Concerned Scientists, *Average Life Expectancy of Select Infrastructure Types and Potential Climate-Related Vulnerabilities*, n.d.

cost of transmission declines over time as assets are depreciated, BCA horizons that do not cover the life of the asset will understate benefit-to-cost ratios. For example, PJM's market efficiency planning process assesses benefits across only a 15-year planning period.[114]

7. BCA should include the trade-off the consumer benefits of local vs remote resources

In selecting projects to maximize net benefits, the Commission should direct planning entities to co-optimize transmission investments with generation expansion planning, particularly renewable resources needed to meet public policy requirements, to minimize the total cost of generation plus transmission. This was the cornerstone of MISO's approach in its Regional Generation Outlet Study and Multi-Value Projects (MVP) analysis, as shown in the MISO chart below.[115]

FIGURE 13 **MISO "Bathtub" Curve of Optimal Local vs Remote/Regional Generation**



8. BCA Assessments should include full portfolios

Consistent with the recommendation above of incorporating multiple benefits together, BCA should be performed on the full portfolio of transmission projects. Assessing the full portfolio accounts for instances where some options will be mutually exclusive and others will be additive—the latter will show up with greater benefits than the former as it should. BCA on the portfolio will also account for trade-offs between smaller speedier

114 *See* PJM, *PJM Manual 14B: PJM Region Transmission Planning Process*, Attachment E at 108, October 1, 2020.

115 MISO, *MTEP17 MVP Triennial Review*, at 31, September 2017.

technology and grid operations investments versus larger longer-term options. If each transmission line or investment were assessed separately, these interactions would be ignored and net benefits would be misleading. Assessing the benefit of a portfolio of transmission assets will also facilitate cost allocation as discussed further below.

9. BCA assessments should not only be quantitative

While the Commission should require a robust approach to quantifying transmission benefits, not all benefits and costs can be quantified or boiled down to a dollar figure. Some pros and cons that may be attributed to different options will be inherently subjective. While the common metrics described above will be useful when comparing various options, and can provide clearer guidance and an objective recipe for decision-making, they cannot possibly address all of the relevant considerations that should be weighed in transmission planning, so regional entities will require some flexibility to prioritize certain projects over others due to qualitative criteria. “The sensible way to deal with uncertainty about some aspects of a benefit or a cost is to quantify what can be quantified, to array and rank nonquantifiable factors, and to proceed as far as possible.”[116]

Legal requirements do not require full quantification. Where the rubber meets the road in assigning costs to beneficiaries, as described in Section IV of this report, the legal standard is that the assignment be “roughly commensurate” with beneficiaries, not that every electron be assigned to every individual customer. At the upstream planning stage of the process, before we reach the cost allocation stage, that same “roughly commensurate” standard can be applied. What is important is the conceptual framework of maximizing net benefits of a portfolio.

10. Resource diversity value and the value of transmission to mitigate operational uncertainty can and should be quantified in the benefits assessment

An increasing set of benefits have been quantified, and can and should be quantified and incorporated into benefits assessments. Recently a study was issued by the Boston University Institute for Sustainable Energy quantifying the benefits of transmission from connecting wind energy from different wind regions, given the uncertainties of wind output in the day ahead time frame.[117] Since the correlation of wind output decreases significantly with distance, there is a steadier supply of zero variable cost energy when

116 Edward M. Gramlich, *A Guide to Benefit-Cost Analysis,* 2nd edition, at 5, Waveland Press, 1988.

117 Kai Van Horn, Pablo Ruiz, and Johannes Pfeifenberger, *The Value of Diversifying Uncertain Renewable Generation Through the Transmission System*, October 2020.

different wind sites are connected to each other, reducing system dispatch costs.

11. The BCA decision rule should be to maximize net benefits

The Commission should require planning entities to adopt a general objective of maximizing net benefits from the various portfolio options considered. Maximizing net benefits accounts for the differing scales of different options. For example, a set of larger more expensive lines will have much higher costs but potentially much larger benefits than a smaller cheaper portfolio. Maximizing net benefits leads to the greatest benefits to consumers over the long run. Maximizing net benefits is more appropriate than a benefit-cost ratio because, as in the example above, a high ratio could yield lower net benefits to consumers. "The last step is reasonably clear...find the program that maximizes net benefits...do not even get tempted to show benefit-cost ratios — they can just get you into trouble."[118] Once again, full quantification is not required. What is important is the conceptual framework.

Order No. 1000 provides that where regional planning entities use a benefit-cost analysis threshold to evaluate projects, "such a threshold may not include a ratio of benefits to costs that exceeds 1.25 unless the transmission planning region or public utility transmission provider justifies and the Commission approves a greater ratio."[119] In accordance with this rule, many regional planning entities rely upon benefit-cost thresholds of 1.25. This approach, by its nature, will deny projects the opportunity to proceed even where they would provide net benefits. This is exacerbated by the fact that many difficult-to-quantify benefits of transmission may not be quantified. Thus, a project may yield significant net benefits even where its official BCA score is 1 or lower. Of course, when maximizing net benefits, the BCA ratio for any portfolio that performs better than a no-investment option will necessarily exceed 1.0, so a BCA ratio of 1.0 can also be a guideline but is not separately needed as a standard.

E. Planning methods should be made compatible across regions to enable inter-regional transmission

While Order No. 1000 attempted to address inter-regional coordination and planning, designing and implementing projects to address needs across transmission planning re-

118 Edward M. Gramlich, *A Guide to Benefit-Cost Analysis,* 2nd edition, at 230, Waveland Press, 1988.

119 *Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 586, July 21, 2011.

gions remains extremely challenging. No significant inter-regional transmission project has been approved. This lack of approval of any significant inter-regional projects under Order No. 1000 combined with studies finding that such projects would yield significant consumer benefits if built,[120] demonstrate need for inter-regional planning reform.

Inter-regional projects face a "triple hurdle" in that they must not only be selected via the inter-regional process, but also must gain approval from each respective RTO. This "triple hurdle" is the heart of the challenge in inter-regional planning. To address this barrier, the Commission should at a minimum require compatible benefits metrics, and study approaches between neighboring regions in approving interregional projects, and mandate that these metrics seek to maximize net benefits on an inter-regional, not regional basis. As part of this exercise in aligning the regional planning processes, the Commission should require all regions to treat inter-regional projects as multi-value projects, rather than placing them in siloes according to the benefits they create (which creates a risk that the siloes used for a given project by each region will not match). Aligning regional approval processes in this manner would help to address the challenge inter-regional projects face in being subject to different metrics and approval standards in the different RTOs from which they must obtain approval.

SPP and MISO have recently attempted to address the barrier of unaligned regional processes by seeking to limit the extent to which the coordinated interregional process must rely upon a single model, recognizing neighboring RTOs have different assumptions underlying their transmission planning processes, and a single model cannot possibly match the assumptions used by both RTOs.[121] The Commission approved SPP's and MISO's proposal to eliminate the use of a single regional model,[122] and the regions have now announced a new joint study which will focus on better and collaborative plans to address generation interconnection needs initially,[123] which presumably will be able to be fed through different modeling assumptions in each region. But while this may facilitate more review of inter-regional projects between SPP and MISO by each respective RTO board without excluding benefits due to a mismatch of approach between regions, a more direct approach is to ensure that the RTO planning methods are aligned such that a unified model can be compatible with each region's evaluation framework.

120 Scott Madden projects, based on enacted clean energy standards and corporate and utility clean energy procurement policies, that "many regions are projected to have adequate or excess renewable supply compared with 'headline' clean energy demand," whereas other regions, including California, New York, and New England, will have a need for additional supply which could be served by import from other regions. Scott Madden, *Informing the Transmission Discussion: A Look at Renewables Integration and Resilience Issues for Power Transmission in Selected Regions of the United States*, at 17, January 2020.

121 *Midcontinent Independent System Operator, Inc., Southwest Power Pool, Inc.*, 168 FERC ¶ 61,018, at P 7, July 16, 2019.

122 *Ibid*., at P 41.

123 SPP, *MISO and SPP to Conduct Joint Study Targeting Interconnection Challenges*, September 14, 2020.

Adopting the minimum guidelines for planning and benefit-cost analysis we have recommended in this section for all regions will make it easier for regions to find alignment in inter-regional project evaluation processes. Beyond establishing this minimum set of guidelines, the Commission should also enable and encourage regions to incorporate additional benefits including in neighboring regional methodologies, as well as incorporate additional benefits that may be unique to interregional projects.[124] As Brattle Group analysts recommend, each seams entity should be given "the option, but not the obligation, to consider some or all of the benefits and metrics used by the other seams entity even if these benefits and metrics are not currently used in the entity's internal transmission planning process."[125] Further, seams entities may "agree to develop metrics to capture any [unique] seams-related benefits."[126]

Regions can update their planning processes with an eye toward inter-regional compatibility such that the primary changes they need to make that are particular to inter-regional review relate to evaluating such projects by maximizing inter-regional benefits as opposed to maximizing benefits solely within the region's borders. The Commission should require the method established to provide that all projects capable of providing net benefits are eligible for inclusion in an interregional plan, disallowing exclusions for projects of arbitrary voltage levels or sizes that currently exist in some interregional planning processes. Interregional planning processes should be conducted at annual intervals, and include a process for ensuring that projects included in the plans are not duplicative of projects being approved within regional planning processes.

124 *See* Johannes P. Pfeifenberger and Delphine Hou, *Seams Cost Allocation: A Flexible Framework to Support Interregional Transmission Planning*, at 53, April 2012 (recommending a set of principles for quantifying benefits of seams projects).

125 *Ibid.*

126 *Ibid.*

IV. Cost allocation

As the Commission recognized in Order Nos. 890 and 1000, "knowing how the costs of transmission facilities [will] be allocated is critical to the development of new infrastructure because transmission providers and customers cannot be expected to support the construction of new transmission unless they understand who will pay the associated costs."[127] The Commission made significant progress in clarifying cost allocation issues in Order No. 1000, requiring public utility transmission providers to establish regional and interregional cost allocation methodologies that meet a set of six principles established by the Commission, but allowing cost allocation methodologies to vary by project type.[128] Very different approaches to regional cost allocation have been deployed in compliance with Order No. 1000, and several have evolved with time to align beneficiaries and cost assignments. Others, such as MISO-planned reliability projects, have moved away from regional cost allocation to avoid competitive processes.[129] And the generator interconnection process marches to a different drummer altogether, using "participant funding;" these differences should be remedied.

With a few limited exceptions described further below, the Commission should continue to use beneficiary pays principles for cost allocation, as they appropriately straddle the need to provide clarity to stakeholders, while at the same time providing planning entities with flexibility to develop methodologies supported by a broad range of stakeholders given region-specific circumstances that affect the distribution of benefits for regional transmission projects. The Commission can facilitate more cost-effective transmission development by refining the application of its cost allocation principles, while adhering to the same general framework it has already applied. Any changes should be applied prospectively only, and not undermine previous cost allocation agreements on operating or approved projects.

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127 *Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 496, July 21, 2011. (citing Order No. 890, at P 557).

128 *Ibid*., at PP 558-750.

129 Johannes P. Pfeifenberger et al., *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value*, at 20, April 2019

A. The Commission should continue to require that costs of regional and interregional transmission projects be allocated in a manner roughly commensurate with their benefits

The cornerstone of cost allocation should continue to be that public utility transmission providers must provide for processes by which costs are allocated fairly — in a way that is at least roughly commensurate with the benefits. This standard is the first principle articulated by the Commission in Order No. 1000,[130] is well-supported by economic theory,[131] and has also been required by the courts. As the U.S. Court of Appeals for the Seventh Circuit articulated in *Illinois Commerce Commission v. FERC*, to approve a cost allocation methodology, the Commission must have "an articulable and plausible reason to believe that the benefits are at least roughly commensurate" with how the costs are allocated.[132] This principle dictates not only that the Commission may not approve regionally allocated costs without reasons to believe benefits are allocated regionally, but also that it may not approve cost recovery only from local customers where benefits are regional.[133] The Commission should continue to adhere to this approach, which provides flexibility to planning entities and fulfills the Commission's duty under the Federal Power Act to ensure just and reasonable and not unduly discriminatory rates.

While Order No. 1000 declined to prescribe "a particular definition of 'benefits' or 'beneficiaries,'"[134] we recommend that the Commission provide a minimum standard for a broad set of benefits to be included within benefit-cost analysis, as discussed in Section III.D of this paper. Importantly, we recommend a robust benefit-cost methodology that includes what used to be considered "difficult to quantify" benefits. While planners can use benefit-cost analyses to help allocate costs, as described below, the ability to allocate a particular benefit must not be used as a constraint to reduce the scope of benefit-cost assessment. "Benefits that can be allocated readily or accurately tend to be only a subset of readily-quantifiable benefits," so "[r]elying on allocated benefits to assess individual projects would result in rejection of many desirable projects."[135]

Beneficiary-pays principles can be implemented using benefit-cost analysis, despite the challenge of tracing all benefits to beneficiaries. William Hogan explains that where "to-

130 *See Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at PP 622-629, July 21, 2011.

131 *See*, e.g., William W. Hogan, *A Primer on Transmission Benefits and Cost Allocation*, Economics of Energy & Environmental Policy, Volume 7, Issue 1, March 2018.

132 *Illinois Commerce Commission v. FERC*, 576 F.3d 470, 477 (7th Cir. 2009).

133 *See Old Dominion Electric Coop. v. FERC*, 898 F.3d 1254, 1261 (2018).

134 *See Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 624, July 21, 2011.

135 *Ibid.*

tal quantifiable benefits exceed the transmission investment cost, then allocating in proportion to the quantifiable benefits would be consistent with efficient investments."[136] And where "easily quantifiable benefits are less than the investment cost, but the subjective estimate is that total benefits are greater . . . a simple rule would be to allocate the costs equal to and according to the quantifiable benefits . . . and then allocate the residual costs . . . according to the regulator's subjective distribution of benefits," which may be distributed evenly across the region, for example.[137] Similarly, Brattle Group analysts explain that a 2-step approach can be used that first determines whether projects are beneficial overall, and next evaluates "how the cost of a portfolio of beneficial projects should be allocated based on distribution of benefits."[138] In this manner, benefit-cost analyses used to guide planning decisions will not be artificially constrained to benefits that can easily be allocated, but will nevertheless serve as the core input to cost allocation decisions.

To provide certainty to market participants, costs should continue to be allocated based on ex ante analysis.[139] Allocating costs to beneficiaries, when the benefits can be measured and beneficiaries can be identified, improves economic efficiency. Transmission is sometimes a complement to other resources and sometimes a substitute. When generation, demand response, or storage closer to load is more economic than transmission, then it should not be discouraged by fully socialized transmission cost allocation without any attempt to determine beneficiaries.[140] Argentina used a governance model of stakeholder support levels to find appropriate cost allocation alignment, which could be a model.[141] State involvement will be important as representatives of load interests.

At the same time, the Commission should retain a degree of flexibility with regard to how costs are allocated. The legal standard under the Federal Power Act does not require a

136 William W. Hogan, *A Primer on Transmission Benefits and Cost Allocation*, Economics of Energy & Environmental Policy, Volume 7, Issue 1, at 39, March 2018.

137 *Ibid*.

138 Johannes Pfeifenberger, *Improving Transmission Planning: Benefits, Risks, and Cost Allocation*, at 28, November 6, 2019.

139 *See Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 499, July 21, 2011 (finding "that the lack of clear ex ante cost allocation methods" prior to Order No. 1000's enactment "may be impairing the ability of public utility transmission providers to implement more efficient or cost-effective solutions); William W. Hogan, *Transmission Investment Beneficiaries and Cost Allocation: New Zealand Electricity Authority Proposal*, at 4, February 1, 2020 ("A cost-benefit evaluation should be done before the investment decision.").

140 William W. Hogan, *A Primer on Transmission Benefits and Cost Allocation*, Economics of Energy & Environmental Policy, Volume 7, Issue 1, at 39, March 2018.

141 Stephen C. Littlechild, and Carlos J. Skerk, *Transmission Expansion in Argentina 2: The Fourth Line Revisited*, Energy Economics, 30(4), at 1385–1419, July 2008.

precise tracing of benefits to costs,[142] and the Commission should clarify in a new planning rule that even though benefits may be quantified via benefit-cost analysis, they need not be precisely traced to beneficiaries in cost allocation. There are good reasons to refrain from an overly prescriptive approach.

For example, regions may provide for methodologies that do not precisely quantify all benefits so as to provide for greater administrative simplicity. There is a trade-off between relying on analysis to identify the beneficiaries of projects (which inherently cannot be done until a particular project or set of projects have been proposed and evaluated by the relevant planning entity), and setting rules that provide a high degree of clarity at the outset as to how costs will be allocated. As the Commission found in Order No. 1000, "the lack of clear ex ante cost allocation methods that identify beneficiaries of proposed regional and interregional transmission facilities may be impairing the ability of public utility transmission providers to implement more efficient or cost-effective transmission solutions identified during the transmission planning process."[143]

Methods such as postage stamp cost allocation (allocating costs equally to all customers in a region) for certain facilities benefitting entire regions can provide for clear rules on allocation of costs prior to any such analysis, and FERC should continue to permit them to be used where processes are in place to ensure they result in costs being allocated in a manner roughly commensurate to beneficiaries. The imprecise nature of analytical techniques used to apportion project benefits may weigh toward the adoption of techniques such as postage stamp cost allocation that set a clear formula at the outset that is not dependent on precise modeling. As the Commission observed in Order No. 1000, there are cases where "the distribution of benefits associated with a class or group of transmission facilities is likely to vary considerably over the long depreciation life of the transmission facilities amid changing power flows, fuel prices, population patters, and local economic considerations," for which such methods are particularly appropriate.[144] While the courts have rejected postage stamp allocation where there is no reason to believe that the approach would allocate costs in a manner roughly commensurate to benefits,[145] it passes

142 *See South Carolina Public Service Authority v. FERC*, 762 F.3d, 41, at 88 ("We recognize that feasibility concerns play a role in approving rates, such that the Commission is not bound to reject any rate mechanism that tracks the cost-causation principle less than perfectly."). As the U.S. Court of Appeals for the Seventh Circuit has articulated, the Commission need not "calculate benefits to the last penny, or for that matter to the last million or ten million or perhaps hundred million dollars." *Illinois Commerce Commission v. FERC*, 576 F.3d 470, 477 (7th Cir. 2009).

143 *Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 496, July 21, 2011.

144 *Ibid.,* at P 605.

145 *See Illinois Commerce Commission v. FERC*, 576 F.3d 470, 477 (7th Cir. 2009) (noting that the Commission may not use the presumption that "new transmission lines benefit the entire network" to overcome its "duty of 'comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party'"); and *Illinois Commerce Commission v. FERC*, 756 F.3d 556 (7th Cir. 2014) (same).

legal muster where the Commission does have reason to believe this is so.[146] SPP's transmission planning and cost allocation methods provides an example of such approach, allocating the costs of "highway" projects on a postage stamp basis, but SPP is periodically conducting a review that assesses net benefits across SPP's various load zones to ensure that benefits are reasonably distributed — such as, for example, that there is a "Balanced Portfolio" of projects[147] — and reallocating costs to the extent that a given zone does not receive sufficient benefits.[148]

The success of MISO's MVP portfolio similarly demonstrates the benefits of a simple cost allocation approach where the portfolio of projects approved provides reason to believe that it will yield benefits roughly commensurate with the largely postage-stamp allocation of costs. FERC approved the MVP portfolio despite the fact that MISO did not "determine the costs and benefits of the projects subregion by subregion and utility by utility."[149] While MISO now estimates subregional benefits, such an analysis could initially have bogged down MISO's approval of the portfolio, which MISO now projects to create average monthly benefits between $4.23 and $5.13 for the average residential customers over the next 40-year period, as compared to only $1.50 per month in average costs.[150]

B. The Commission should encourage portfolio-based cost allocation

The Commission should require planning entities to provide for a cost allocation process that groups projects together to prevent the need for a multitude of time-consuming project-specific cost-allocation studies and provide for more durable results that engender stakeholder support. Conducting cost allocation at the portfolio level makes sense because "[b]enefits of a portfolio of projects will tend to be more stable and distributed more evenly."[151] The MISO MVP experience again demonstrates the value of allocating costs for a portfolio of projects together, rather than doing so one-by-one. By simultaneously pursuing 17 projects distributed across the region's geographic footprint,[152] the MISO MVP portfolio provided stakeholders with confidence that benefits would accrue to all load across the region. MISO's periodic analyses of the portfolio shows that this is in

146 *See Illinois Commerce Commission v. FERC*, 721 F.3d 764 (7th Cir. 2013) (upholding FERC orders approving postage stamp cost allocation for a portfolio of projects); *Illinois Commerce Commission v. FERC*, 756 F.3d 556, 562 (7th Cir. 2014) (explaining that MISO's allocation of the costs of MISO's MVP portfolio on a postage stamp basis was appropriate because "[t]here was evidence that the lines would not yield highly disparate benefits to the utilities asked to contribute to their costs").

147 *See* SPP, *Open Access Transmission Tariff*, Sixth Revised Volume No. 1, Attachment O § IV, effective date: July 26, 2010.

148 *Ibid*., at Attachment J § IV.

149 *Illinois Commerce Commission v. FERC*, 721 F.3d 764, 774 (7th Cir. 2013), ICC II at 774.

150 MISO, *MTEP19*, at 7, n.d.

151 Johannes Pfeifenberger, *Improving Transmission Planning: Benefits, Risks, and Cost Allocation*, at 28, November 6, 2019.

152 *See* MISO, *Multi Value Project Portfolio: Results and Analyses*, January 10, 2012.

fact the case, with significant net benefits accruing across every local resource zone over which costs were apportioned.[153] Likewise, SPP's portfolio approach allows for a simple approach to cost allocation that nevertheless ensures benefits accrue to every load zone. And portfolio planning also underlies the use of cluster studies for interconnection which has been an improvement over project-by-project processes, as multiple projects and the transmission that they share are considered together. Portfolio planning expands those efficiencies to consider all the transmission needed for multiple purposes, not just interconnection.

A portfolio-based approach more accurately captures the benefits of proposed transmission infrastructure because one project's benefits depend on the future system as a whole, including the presence of other projects. By grouping together all projects that will be approved in a single planning period (e.g. annually), planning entities can capture these interactive effects in any benefit-cost studies that may then also be used to support cost allocation.

As we have described above, we recommend the Commission require planning entities to carry out scenario-based planning analysis that refrain from grouping projects into siloes by project type, and that instead models projects together, recognizing their multiple values and using reliability constraints as binding inputs. This modeling process lends itself to a planning process by which the costs of projects within the portfolio are allocated together. While needs may nevertheless arise for individual projects to be cost allocated outside of this general process, we recommend that the Commission recommend planning entities use a portfolio approach as a baseline.

The Commission should explicitly provide guidance against the use of load flow analysis techniques as the sole basis for cost allocation, in favor of an economically-driven approach that relies upon a broader conception of total benefits that recognizes the value of projects in the portfolio that address reliability needs alongside other benefits. This would guard against cases such as the Artificial Island development, where "PJM reported that only 10% of the estimated benefits would appear in [the] Delmarva region, but these customers would bear 90% of the costs,"[154] and the Commission ultimately found on rehearing that PJM's load-flow based distribution factor (DFAX) analysis was an unjust and unreasonable mechanism for allocating the costs of a stability-related reliability issue.[155]

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153 *See* MISO, *MTEP17 MVP Triennial Review*, at 8, September 2017.

154 *Ibid.*

155 *PJM Interconnection, L.L.C. and Certain Transmission Owners Designated,* Order Granting Rehearing and Establishing Paper Hearing Procedures, 164 FERC ¶ 61,035, at P 41, July 19, 2018.

Because a portfolio of projects will necessarily provide a wide range of different benefits, any cost allocation methodology must ensure that the sum total of these benefits is allocated in a roughly commensurate fashion. Approaches such as SPP's meet this standard because, while they rely on simplified postage stamp allocation, they include a mechanism that ensures that the approach yields the fair apportionment of costs based on benefit-cost analysis that incorporates many types of benefits. Techniques based solely on load-flow analysis fail for this purpose because they do not account for both reliability and other benefits and, therefore, may bear little relationship to the total value of benefits received.

Portfolio plans and cost allocation should be performed on a regular schedule to maximize the economies of scale and scope of considering all the projects together. However, it may also be appropriate to pursue occasional project-based plans and cost allocation in between larger less frequent portfolio plans.

C. The Commission should remedy the inconsistency with the "participant funding" approach in interconnection processes while clarifying that generators and customers who derive particularized benefits from transmission upgrades can be relied upon to a limited extent to fund new transmission infrastructure, where applicable, as part of a broader cost allocation formula

"Participant funding" is an "approach to cost allocation, in which the costs of a new transmission facility are allocated *only* to entities that volunteer to bear those costs."[156] Interconnection processes are allowed to rely on participant funding, based on the interconnection policies established by the Commission going back to Order No. 2003 issued in that year. Since interconnecting generators are often being asked to pay for network facilities that benefit other generators and other loads all around the region, the Commission should make sure that its policies remedy this inconsistency and disallow full participant funding on interconnecting generators.

At the same time, the Commission should clarify that regional cost allocation methods may, where appropriate, require limited contributions by project participants as they use the facilities in the future. In transmission planning which operates as a completely separate process from interconnection, Order No. 1000 prohibits participant funding from being used as a regional or interregional cost allocation method.[157] But while the Com-

156 *Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 715, July 21, 2011 (emphasis added).

157 *Ibid.*, at PP 723-729.

mission was appropriately fearful "that reliance on participant funding as a regional or interregional cost allocation method increases the incentive of any individual beneficiary to defer investment in the hopes that other beneficiaries will value a transmission project enough to fund its development,"[158] we recommend that the Commission clarify that this prohibition allows for approaches to cost allocation by which project participants pay for a limited portion but not all of the costs of a project.

As discussed in Section III.B, we recommend that the Commission require planning entities to formulate reasonable scenarios that include corporate and utility resource procurement targets. But while a scenario-based approach is the best way to plan for an uncertain future by covering a range of plausible futures, it raises the possible objection that, depending on cost allocation methodology, there may be a probability that infrastructure development could burden non-beneficiaries with the costs for achieving corporate and utility procurement targets more appropriately borne by the entities setting those targets.

To allow for appropriate cost allocation in such cases, the Commission should provide that where the evidence supports such an approach, planning entities may require particular customers and generators that derive unique benefits from the infrastructure to fund it to a limited extent. The Commission should set a specified limit on the portion of project costs that can be recovered in this manner for regional projects (e.g. 10 percent) to prevent the problems seen under participant funding schemes. Participant funding as the sole mechanism for cost recovery has proven to be problematic because it is akin to charging the next car to enter a congested highway for the cost of building a new lane. This approach is subject to the free rider problem because the entity being charged has an incentive to pull out of the process and attempt to enter once someone else has picked up the charge, and it is unfair because the new infrastructure will create system wide benefits. But requiring direct beneficiaries to fund upgrades (e.g., on a joint basis), when used to a more limited extent, could be effective. Just as tolls can prove to be an effective highway financing mechanism, assessing a charge that is truly proportional to the benefit an entity gets could help facilitate the construction of net beneficial transmission infrastructure. CAISO has a Location Constrained Resource Interconnection provision in its tariff that follows this approach.[159] Planning entities could establish models that initially assign costs to load serving entities, allowing them to get paid back as projects using the infrastructure enter the system, drawing lessons from experiences such

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158 *Ibid.*, at P 723.

159 *See California Independent System Operator Corporation*, Order Granting Petition for Declaratory Order, 119 FERC ¶ 61,061, April 2007; and Bracewell LLP, *FERC Tailors Transmission to Connect Renewables*, May 1, 2007.

as the CAISO Tehachapi trunkline, where current wholesale RTO customers financed the line but are being paid back over time as generators interconnect.[160]

This type of cost allocation formula will not be necessary in all cases where a corporate or utility procurement target drives transmission needs. Facilitating corporate procurement targets may reduce total costs for regional customers by adding load or low-cost generation to the region and thereby reducing the proportion of regional costs that other customers must bear. Similarly, interconnecting electric vehicle charging equipment could benefit the system as a whole by increasing total (off-peak) system load. But it may prove to be a useful arrow in the regional cost allocation quiver in cases where an entity's procurement goal creates costs appropriately borne by that customer alone.

D. The Commission should provide more specific cost allocation requirements for inter-regional projects

Finding alignment on cost allocation for inter-regional projects is especially challenging given the potentially disparate approaches that regions may take for projects that fall solely within their borders, as well as the risk that one region could seek to impose costs on a neighboring region through this process. To address this challenge, the Commission should require regions to adopt unified cost-allocation processes for projects at their respective seams, and provide specific guardrails around the cost allocation approaches that may be used for such projects. The Commission should require that the cost allocation processes be a beneficiary pays methodology that relies on a quantified assessment of benefits and costs for every inter-regional project portfolio. To facilitate interregional cooperation and collaboration, the Commission could specify that the primary mechanism for cost allocation for seams projects should be to allocate seams project costs based on monetized benefits,[161] while allowing regions flexibility to agree on alternate cost allocation mechanisms to modify this baseline rule. Brattle Group analysts Hannes Pfeifenberger and Delphine Hou outline a number of potential cost allocation mechanisms that may facilitate interregional agreement in *Seams Cost Allocation: A Flexible Framework to Support Interregional Transmission Planning, including allocation according to contribution to the need, usage share of the project, or allocating costs based*

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160 *See* Pedro J. Pizarro, *Transmission Planning and Development: Examples and Lessons*, at 17, February 25, 2010; CAISO, *Memorandum re: Decision on Tehachapi Project*, at 6, fn. 3 January 18, 2007 (explaining how generators would pay a pro-rata share to the extent the Tehachapi improvements are characterized as bulk transfer gen-tie lines, with customers in SCE's service territory paying the costs of the network upgrade portions of the project).

161 *See* Johannes P. Pfeifenberger and Delphine Hou, *Seams Cost Allocation: A Flexible Framework to Support Interregional Transmission Planning*, at 61, April 2012 (recommending such a mechanism as the first of several potential cost allocation mechanisms for Seams projects).

on the project's physical location.[162]

E. The Commission should assign costs to loads regardless of the utility's choice of whether to be an RTO member

When costs are allocated to voluntary members of Regional Transmission Organizations, those utilities can shift costs and disrupt the transmission planning process by resigning from the RTO. FERC should prevent RTO members from using this power to choose whether to be an RTO member to game the process once it becomes apparent that they may be assigned costs. Without rules put in place by the Commission, threats to leave the RTO in response to particular planning decisions may be a hindrance to efficient and reliable transmission development. Accordingly, the Commission should put a rule in place that allocates costs to regardless of such choices. For example, it may put in place a rule that assigns costs to TOs based on their planning region membership at the beginning of the planning cycle, thus preventing RTO exit from avoiding a specific cost that may become apparent during the planning process.

162 *Ibid.*

V. Ensuring cost-effectiveness

A. The Commission should ensure sufficiently broad geographic scope of planning authorities and consider requiring the formation of inter-regional planning boards with full authority to propose filings to FERC that select and cost allocate inter-regional projects

Much of the system need is interregional, connecting areas addressed by separate planning entities. Since these "regional" planning entities are really "sub-regional" and do not cover the full geographic breadth of the transmission system, the Commission should consider structural reforms to broaden transmission planning.

The Commission should consider collapsing sub-regional planning entities into larger Planning Authorities. For example, in the West, there are four Planning Authorities as shown in the map below, while the region really operates as one interconnected grid. The large load centers in the state of California cause the state to import 30 percent of its power from other parts of the region. Collapsing the four regions into one could make transmission planning more optimal.

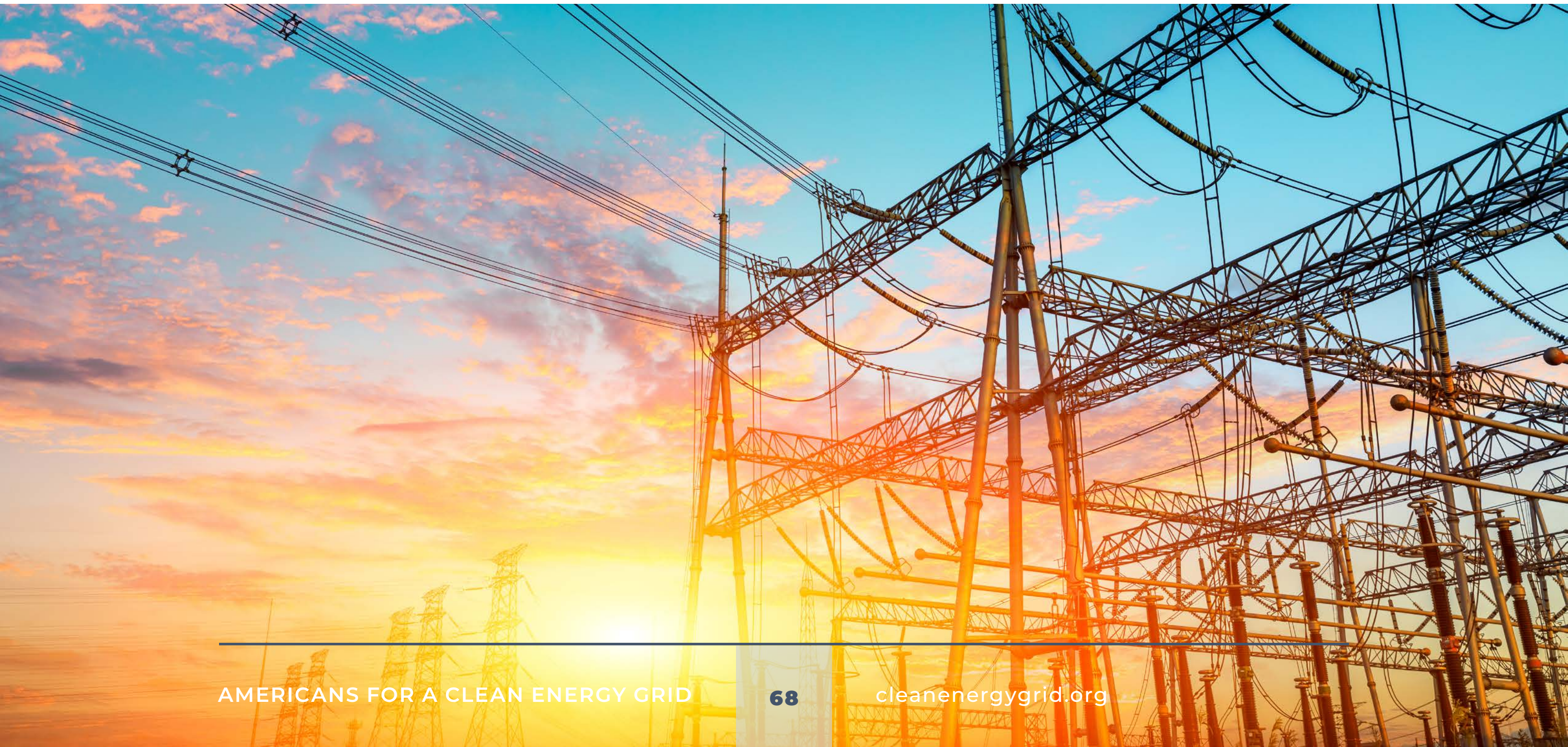
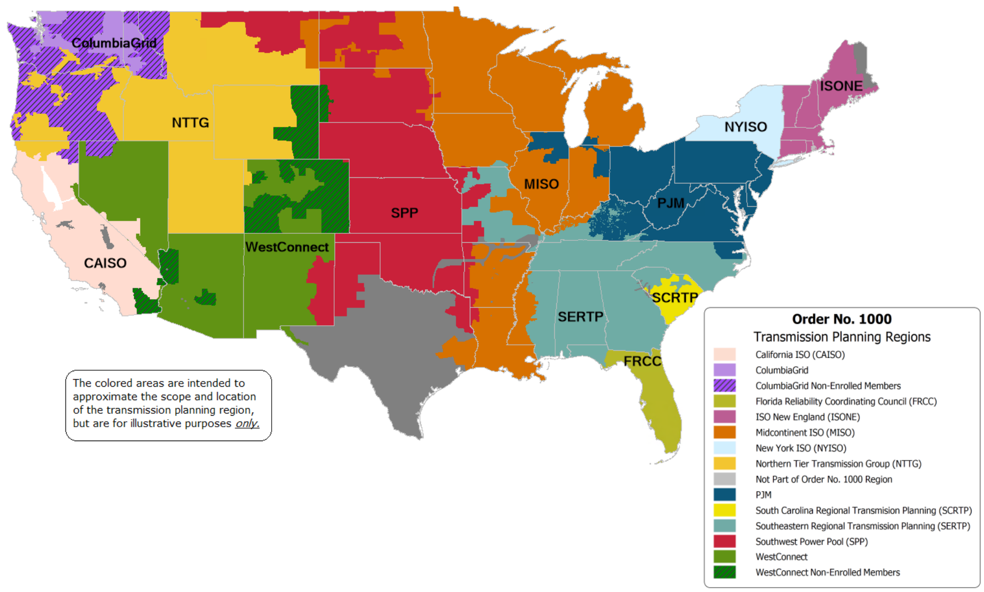


FIGURE 14 Planning Authority Regions[163]



The Commission should also consider unifying inter-regional planning into a single process whereby a single entity composed of representatives of the applicable RTOs identifies transmission needs and solutions, selects projects and quantifies their benefits and costs, and allocates costs in a manner roughly commensurate with benefits. Doing so would completely eliminate the "triple hurdle."

The Commission could accomplish this reform by requiring the applicable regional planning entities (consistent with Order No. 1000's geographic criteria) to establish a process for the creation of joint regional boards that have full authority to independently approve projects and allocate costs across both regions.

In the event the Commission requires the establishment of such boards, it should require the planning and benefit-cost analysis processes established by such interregional planning boards to adhere to the same minimum requirements set forth in Section III, with the additional requirement that the interregional planning process must consider benefits and costs across both regions or the applicable group of regions (for multi-region planning boards).

163 FERC, *Order No. 1000 Transmission Planning Regions*, n.d.

B. FERC should take on a greater role in ensuring new transmission investment is as cost-effective as possible

More balance is needed between the bottom up and top-down planning processes, such that plans conducted by regional planning entities identify more opportunities to address transmission needs in a more cost-effective manner, and local utility plans are altered where needs are served more effectively by regional solutions.

1. The Commission should more carefully evaluate local projects that serve needs that could be addressed more cost-effectively by regional facilities

One step to remedy this imbalance would be a set of reforms designed to provide greater transparency surrounding local transmission planning and end-of-life asset management, better evaluate whether regional projects can more efficiently serve needs being met by local projects or project replacements, and closer evaluation of local projects where there is reason to believe a more efficient regional solution exists.

Order No. 890 requires "each public utility transmission provider to have a coordinated, open, and transparent regional transmission planning process,"[164] and Order No. 1000 requires every such transmission provider to "participate in a regional transmission planning process that produces a regional transmission plan and that complies with the transmission planning principles of Order No. 890."[165] Further, Order No. 1000 requires identification of "alternative transmission solutions that might meet the needs of the transmission planning region more efficiently or cost-effectively than solutions identified by individual public utility transmission providers in their local transmission planning process."[166] The examination required under Order No. 1000 is supposed to assess regional solutions that address all types of transmission needs, including "transmission facilities needed to meet reliability requirements, address economic considerations, and/or meet transmission needs driven by Public Policy Requirements."[167]

Yet, despite these requirements, as described above, implementation of Order No. 1000 in many regions has yielded a flood of local projects that are either entirely exempt from the regional process, or that remain uninfluenced by it. For example, while the PJM Board approved $1.27 in baseline transmission investment,[168] it has approved nearly three times that amount — $3.5 billion — in "supplemental" projects.[169] As PJM explains, "Supplemental projects are identified and developed by transmission owners to address local reliability needs, including customer service and load growth, equipment material condition, operational performance and risk, and infrastructure resilience."[170] PJM reviews them to "evaluate their impact on the regional transmission system,"[171] and provides for a stakeholder process that allows for limited input,[172] but they are not subject to Board approval.[173]

There is often no close review of local projects via any other process. Despite Section 205 of the Federal Power Act's explicit language that "the burden of proof to show that the increased rate or charge is just and reasonable shall be upon the public utility," the Commission has implemented a policy that "presumes that all [transmission] expenditures

164 *Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 1, July 21, 2011.

165 *Ibid.*, at P 146.

166 *Ibid.*, at P 148.

167 *Ibid.*

168 PJM, *Regional Transmission Expansion Plan*, at 4, February 29, 2020.

169 *Ibid.*, at 50.

170 *Ibid.*, at 4.

171 *Ibid.*

172 *Ibid.*, at 49.

173 Ibid. Further, regional transmission planning processes are yielding a mix of increasingly local projects even for infrastructure that is approved as part of regional transmission plans. *See*, e.g., Ibid., at 4. As discussed in **Section III.B**, this result is driven to a significant extent by the fact that processes used to identify regional solutions often do not base needs on the best available data and forecasting methodologies, and do not include all project benefits in their assessments of regional solutions.

are prudent."[174] Given this burden shifting, cases where costs are "disallowed and excluded from the revenue requirement . . . are rare."[175] As Dr. Paul Joskow puts it, "[f]or all intents and purposes the FERC [transmission] regulatory process is a model of cost pass-through regulation with little scrutiny of costs."[176] As noted above, some RTOs do include RTO review of local projects,[177] but this is not consistent across Planning Authorities.

Failing to proactively review the cost-effectiveness of transmission investments even where there are reasons to believe alternatives would be more appropriate has potentially tremendous costs. Utilities have an incentive to add capital assets to their rate base, so as with all regulated industries, the basic economic regulatory structure should provide for scrutiny of investments by any entity holding a license to serve as the public utility. The current approach also likely squanders valuable rights-of-way. End-of-life replacements, maintenance expenditures, and local projects by their nature utilize existing rights-of-way controlled by utilities. Upgrading and up-sizing this infrastructure in many cases will make better use of these rights-of-way, which should be fully leveraged given the challenges associated with siting transmission infrastructure. Finally, even if the investments turn out to be necessary and appropriate, the current process engenders mistrust by consumers. Many consumer and state interests have become skeptical of transmission costs being added to their bills, at a time when certain types of transmission expenditures are sorely needed.

The Commission can remedy this failure in two ways. First, it should directly require that all regional transmission planning processes better address the potential to improve upon end-of-life planning decisions by (i) requiring transmission owners to notify the regional planning entity of aging infrastructure needs far in advance of the end of an asset's life (e.g. 10 years), unless there are circumstances that prevent early notification, and (ii) requiring such projects to be approved via regional planning processes through which they may be assessed against alternatives identified by region-wide top down planning processes and assessed for benefits beyond the immediate need for repair or replacement. While some regions currently classify end-of-life projects as asset maintenance not subject to regional transmission planning processes,[178] as explained in Section VI.B.2

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174 *Potomac-Appalachian Transmission Highline, LLC, PJM Interconnection, L.L.C.*, 158 FERC ¶ 61,050, at P 100, January 19, 2017; *see also Iroquois Gas Transmission System, L.P.*, 87 FERC ¶ 61,295, 62,168, June 17, 1999 ("As a matter of procedural practice to ensure that rate cases are manageable, the Commission does not require regulated entities to 'demonstrate in their cases-in-chief that all expenditures were prudent unless the Commission's filing requirements, policy, or precedent otherwise require.' There is, in effect, a presumption of prudence which can be rebutted at hearing whenever another party 'creates serious doubt as to the prudence of an expenditure.'").

175 Paul L. Joskow, *Competition for Electric Transmission projects in the U.S.: FERC Order 1000*, at 13, March 2019.

176 *Ibid.*

177 *See* MISO, *Business Practices Manual Transmission Planning*, BPM-020-r21, at 22, January 1, 2020.

178 *See*, e.g., *PJM Interconnection, L.L.C.*, 172 FERC ¶ 61,136, at P 85, August 11, 2020 (holding that regional planning requirements do not apply to "Asset Management Projects" in PJM, a category that includes end-of-life transmission infrastructure replacements).

below, the Commission has authority to reform the planning process to require more fulsome consideration of these needs via regional planning. The MISO approach noted above may be a good model for this component of the rule.

Second, the Commission should consider proactively evaluating the cost-effectiveness of local projects and end-of-life project replacements where there is reason to believe that the same needs could have been addressed more cost-effectively by a regional solution.[179] Reason to doubt the cost-effectiveness of an investment will exist where (a) scenario analysis conducted by a regional planning entity demonstrates that the need could be addressed more effectively by a regional solution; or (b) the regional planning process does not include a step that effectively examines the ability of regional solutions to more efficiently address the need.

In taking this step, the Commission should carefully calibrate the scope of projects subject to review. The Commission's current presumption of prudence for all projects is designed to ensure the administrability of rate cases,[180] and any revision to this review policy must be done according to a plan that anticipates the additional responsibilities such a change in approach would vest with the Commission. To ensure that review is aimed narrowly at the set of circumstances where the failure to interface between local and regional planning produces the most acute problems, and is carried out in the most efficient manner possible, the Commission should request input from stakeholders on how to design its criteria for review, as well as procedure for examining the prudence of such projects. For example, projects below a certain kilovolt threshold may be very unlikely to interact with regional needs, and thus should be automatically exempt from any shifting of the review burden.

Beyond incorporating such criteria at a high level into a new planning rule, the Commission could provide further guidance while retaining a degree of flexibility in implementation by issuing a policy statement explaining the scope of its new process for scrutinizing applicable local projects.[181]

179 Ari Peskoe has proposed a broader shifting of the burden of proving projects are prudent, suggesting that the Commission reverse the burden for any local project that is not incorporated into a planning process conducted by an independent entity. As Ari Peskoe discusses in his forthcoming paper, the Commission has ample authority to reverse the presumption of prudence, and could likely even directly require that local transmission planning be conducted by independent entities. *See* Ari Peskoe, Is the Utility Transmission Syndicate Forever?, forthcoming 2021.

180 *Ibid.*

181 *Ibid. (suggesting a policy statement guide FERC prudence review of transmission investments).*

2. ***The Commission should consider performance-based ratemaking techniques to incentivize more cost-effective transmission development***

Beyond the threshold determination whether these expenditures are prudent, the Commission should assess whether and how rates may be adjusted in response to planning deficiencies. For example, there may be circumstances where a local upgrade becomes prudent to address a reliability concern, but the transmission owner's failure to appropriately examine alternatives means that the solution is not as efficient or cost-effective as it could or should have been. In such circumstances, it may be appropriate to reduce or eliminate the transmission owner's return on equity. Conversely, it may be appropriate to reward transmission owners that establish particularly effective mechanisms for identifying cost-effective regional solutions, through incentives such as shared savings mechanisms. The Commission is currently considering incentives including performance-based incentives in a rulemaking proceeding, RM20-10. Depending on how that rulemaking proceeds, there could be overlap with the recommendations in this paper.

As Dr. Paul Joskow explains, the "conventional incentive/performance based regulation mechanisms," that the Commission could theoretically apply are distinct from the "financial incentives for transmission investments meeting several specified goals."[182] The incentive mechanisms prescribed by Section 219 of the Federal Power Act are "not the kind of cost control and operating performance incentives that would normally be an important part of a performance-based incentive regulation tool kit. Rather, the incentive scheme is basically cost of service regulation with higher returns to take certain actions that advance FERC Policies."[183] But while Section 219 provides additional authority for the Commission to implement certain types of incentives, it does not constrain the Commission's ratemaking authority under Sections 205 and 206, which could be employed to apply more conventional performance-based regulation to ensure just and reasonable rates.

One performance-based option would be to adopt something like an 80/20 rule for regional/interregional projects. If a project goes over its budget, the transmission owner only recovers 20 percent of the overage. If it goes underbudget, the transmission owner recovers 80 percent of the variance, and customers get the rest.

Another option is the shared savings congestion reduction proposal by Americans for a Clean Energy Grid (ACEG), the Working for Advanced Transmission Technologies (WATT)

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182 Paul L. Joskow, *Competition for Electric Transmission projects in the U.S.: FERC Order 1000*, at 13, March 2019.

183 *Ibid.*, at 14. *See also Economic Regulation and its Reform: What Have We Learned?* (Nancy Rose, ed.), "Incentive Regulation in Theory and Practice: Electric Distribution and Transmission Networks," Chapter 5, University of Chicago Press, 2014.

Coalition and other entities in the Commission's incentive proceeding.[184]

A third performance-based option is the Australian Energy Market Operator (AEMO) where for everyday operations and maintenance work, there is a scheme called Service Target Performance Incentive Scheme that gives utilities an incentive payment to reduce impact on the market.[185]

C. Re-establish a more collaborative approach to transmission ownership and allow RTOs more flexibility to regionally cost allocate infrastructure that has not been selected via competitive processes

Beyond the lack of efficiency between local and regional projects, another factor that in some circumstances has contributed to regional processes yielding fewer large multi-benefit projects than they otherwise could have is the perverse incentive unintentionally created by Order No. 1000's requirement that regional planning processes provide "a nonincumbent transmission developer" with "the same eligibility as an incumbent transmission developer to use a regional cost allocation method."[186]

Some regions, such as NYISO and CAISO, have successfully conducted competitive solicitations to meet regional needs, with significant stakeholder support. In other regions, however, Order No. 1000's elimination of rights of first refusal for regionally cost allocated projects has degraded the necessary planning collaboration to pursue regional projects in favor of local projects. MISO provides a stark example of the manner in which the Commission's well-intentioned push toward a more competitive framework may have had unintended consequences. The MVP portfolio approach was a collaborative effort among utilities negotiated prior to Order No. 1000. The region has since failed to assemble a comparable portfolio of large multi-benefit projects. Instead, responding to their incentives, incumbent investor owned utilities have primarily pursued local baseline reliability and other transmission projects that are subject to utility rights of first refusal.[187] In the most recent MISO Transmission Expansion Plan (MTEP), for example, nearly all projects were local and not subject to competition.[188] In former Commissioner Tony Clark's view "FERC's insistence that even one penny of regional cost allocation ended an incumbent transmis-

184 *WATT Coalition Initial Comments*, Inquiry Regarding the Commission's Transmission Electric Incentives Policy, Docket No. PL19-3, June 26, 2019.

185 Australian Energy Regulator, *Service Target Performance Incentive Scheme*, December 2015.

186 *Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 332, July 21, 2011.

187 *MISO Transmission Owners v. FERC*, 819 F.3d 329 (7th Cir. 2016) (FERC permissibly exempted local baseline reliability projects from bar on rights of first refusal).

188 MISO, *MTEP19*, at 17, n.d.

sion owner's federal right of first refusal caused a series of cost allocation methodologies that previously had garnered widespread acceptance to fall apart."[189] In promulgating and affirming Order No. 1000 on rehearing, the Commission concluded that subjecting transmission projects proposed by incumbent utilities to competition was justified in order to provide for planning practices likely to yield just and reasonable rates, and to ensure those practices are not unduly discriminatory.[190] FERC concluded that "the inclusion of a federal right of first refusal, can have the effect of limiting the identification and evaluation of potential solutions to regional transmission needs," which "in turn can directly increase the cost of new transmission development that is recovered from jurisdictional customers through rates."[191] And it reasoned that "federal rights of first refusal create opportunities for undue discrimination and preferential treatment against nonincumbent transmission developers within existing regional transmission planning processes."[192]

The evidence gathered since Order No. 1000's enactment, however, has demonstrated that these conclusions are dependent upon particular regional circumstances. Economic theory suggests that competition will deliver savings in structurally competitive sectors,[193] and comparisons of costs of competitive processes versus those of non-competitive processes have been put forward to demonstrate the benefits of competition.[194] But the transmission sector, unlike generation, is not structurally competitive. There are still large economies of scale and network externalities where all projects impact flows on the broad network, so it better fits the standard economic model of "natural monopoly," for which the standard public policy prescription is to allow monopoly entities to invest as long as a regulator is overseeing the quality and price of service. As stated fifty years ago in the classic work on the economics of regulation by Alfred Kahn "[a]s long as the tendency prevails for unit costs to decline with an increasing volume of business, because of economies of scale internal to the firm, it is more efficient, other things being equal, to have one supplier than several."[195] As a practical matter, the distortion of incumbent utili-

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189 Tony Clark, *Order No. 1000 at the Crossroads: Reflections on the Rule and Its Future*, at 10, April 2018.

190 *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000-A, 139 FERC ¶ 61,132, at PP 357-363, May 17, 2012.

191 *Ibid.*, at P 358.

192 *Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 286, July 21, 2011; *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000-A, 139 FERC ¶ 61,132, at PP 363, May 17, 2012 (affirming in relevant part).

193 *See*, e.g. J Paul L. Joskow, *Competition for Electric Transmission projects in the U.S.: FERC Order 1000*, March 2019; Burcin Unel, *A Path Forward for the Federal Energy Regulatory Commission Near-Term Steps to Address Climate Change*, at 13-14, September 2020.

194 *See* Johannes P. Pfeifenberger et al., *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value*, at 5, April 2019. Estimating the potential benefits of competition for transmission projects is difficult and different experts have come to conflicting conclusions. *See also* Paul L. Joskow, *Competition for Electric Transmission projects in the U.S.: FERC Order 1000*, March 2019; Concentric Energy Advisors *Building New Transmission Experience To-Date Does Not Support Expanding Solicitations*, June 2019.

195 Alfred Kahn, *The Economics of Regulation: Principles and Institutions*, at 125/II, MIT Press, June 1988.

ty incentives that has been created by subjecting regional projects to competition while continuing to insulate local projects from competitive pressures has yielded and will likely continue to yield a suboptimal mix of new projects skewed toward local projects that is likely to yield unjust and unreasonable rates for customers. Brattle analysts observe that "[i]n some developers' views, subjecting regionally-planned projects to competition has discouraged transmission companies from suggesting potentially valuable regional projects, anticipating that the projects would need to go through competitive processes and thus could be delayed."[196] Further, as Judge Posner observed in MISO Transmission Owners v. FERC, "competition is [not] an unmixed blessing. It can result in costly duplication, and in politicking aimed at courting favor with [the regional planning entity] or FERC."[197]

Even if transmission competition were a theoretically optimal solution, it is not clear that voluntary RTOs are an administratively workable means of achieving it. Voluntary RTOs are not government regulators; they are more like associations of companies when it comes to transmission planning. They cannot be expected to choose among their members or effectively apply cost regulation to them. As Dr. Paul Joskow stated, "a competitive bidding program for new transmission links allows competing transmission developers effectively to propose alternative regulatory cost recovery formulas for determining annual revenue requirements... However, ISO's are not economic regulators in the traditional sense and have neither the expertise nor authority to adopt transmission ratemaking procedures."[198] Experience demonstrates that given RTOs' institutional structure — they are not cost regulators — a planning process that relies upon the RTO to mediate a competitive process for some projects and not others may often yield a suboptimal asset mix.

We are not arguing that competition for transmission cannot work or has not. It appears to have been successful in certain areas such as with ERCOT Competitive Renewable Energy Zones (CREZ) lines and in the U.K. where government agencies run the solicitation, and in NYISO and CAISO where utility participation in the ISO is effectively mandatory. It could also potentially work if the federal government oversaw a process for granting rights to projects from competing bidders. We are only observing that there are factors that in many cases have and should be expected to inhibit its effective use by voluntary RTOs in cases where incumbent transmission owners develop projects.

We also note the long history of success in the electric industry with joint ownership by utilities of regional network facilities. There are many forms of joint ownership in various

196 *See* Johannes P. Pfeifenberger et al., *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value*, at 21-22, April 2019.

197 *MISO Transmission Owners v. FERC*, 819 F.3d 329 (7th Cir. 2016).

198 *See* Paul L. Joskow, *Competition for Electric Transmission projects in the U.S.: FERC Order 1000*, at 2, March 2019.

regions. This collaborative approach has worked in many instances to pool the benefits and share the costs of regionally beneficial transmission.[199]

Regional circumstances may also dictate that incumbent utilities are not similarly situated with other developers, due to their unique ability to design a portfolio of local and regional transmission projects that together best serves customers. In many regions utilities are vertically integrated and subject to integrated resource planning processes at the state level that position incumbents uniquely to develop holistic solutions that will leverage generation, demand adjustments, and transmission solutions to serve future resource mixes and facilitate public policies. And siting concerns may have different effects in different regions, depend on the approach states take to these issues. In some cases, states will prioritize low-impact projects and siting constraints will dictate that only viable near-term opportunities for grid expansion is on scarce and valuable existing rights of way that utilities own. State input into the planning process may also identify occasions where, given the challenge of siting new projects that may be particularly acute in some regions, limiting competition may be a catalyst for new development because it limits the number of developers that may stir up "not in my backyard" or "NIMBY" opposition via project development activities.

Regardless, it is clear that Order No. 1000's removal of the right-of-first-refusal has had the unintended consequence of undermining regional transmission planning in some cases. Given this evidence, the Commission can reasonably conclude that a rule relaxing the broad requirement for a competitive process to be used to yield any project that gets regional cost allocation is appropriate and upholds the Commission's duties under Sections 205 and 206 of the Federal Power Act.

This approach, coupled with closer and more robust evaluation of whether regional projects can more efficiently serve local needs, as described in Section V.B above, will allow regional planning entities flexibility to find regionally appropriate solutions that will rebalance transmission portfolios in favor of a project mix that will best serve customers. In MISO, comprised almost exclusively of vertically integrated utilities, a compliance approach that centers on reinstituting a right of first refusal may be warranted. At the same time, in ISO-NE, which has experienced a similar project skew with not "a single competitive transmission project bid, selected or completed" "more than eight years after the Commission issued Order 1000,"[200] it is possible that a different approach may be war-

199 APPA, *Joint Ownership of Transmission*, February 2009.

200 *Comments of William Tong, Attorney General for the State of Connecticut, Maura Healey, Massachusetts Attorney General, Connecticut Department of Energy and Environmental Protection, Connecticut Office of Consumer Counsel and Maine Office for the Public Advocate*, Docket No. EL19-90, at 9, January 24, 2020.

ranted. Rather than reinstituting a right of first refusal, the region could prevent a skew towards local projects by better incorporating local project needs and end-of-asset-life planning into the regional process, and relying upon the Commission applying greater scrutiny to local projects for which regional planning suggests a better alternative is available. These are hypotheticals. We do not necessarily predict that the evidence will play out in this manner in these regions, but we raise these examples simply to illustrate the point that by taking a region-by-region or even context specific approach to rights of first refusal, the Commission may achieve better results across all regions.

D. The Commission should consider requiring regional planning entities to grant states a governance role in regional transmission planning

States play a central role in transmission planning that is only becoming more critical. States are the arbiters of the transmission siting process, and have a role in overseeing utilities' transmission and distribution plans as retail regulators. State involvement was critical to the successful regional transmission plans that have occurred, including MISO MVPs and SPP Priority Projects. Further, as discussed above, state public policies are playing an increasingly large role in shaping the future demand and supply mix.

Beyond standard regulatory processes, state legislation is sometimes specifically directed at transmission planning. For example, New York's Accelerated Renewable Energy Growth and Community Benefit Act calls for the New York Department of Public Service, in consultation with NYISO, the state's utilities, and other state agencies, to carry out a comprehensive power grid study at regular intervals that examines both local transmission and distribution and bulk transmission system improvements needed to reach the state's ambitious climate goals enshrined in the Climate Leadership and Community Protection Act.[201] The Act also grants the New York Power Authority, acting by itself or in collaboration with other parties, special rights to construct transmission projects found to be needed to be "completed expeditiously to meet the Climate Leadership and Community Protection Act (CLCPA) targets."[202] Other states, such as New Mexico, have transmission authorities to help plan and finance transmission that serves state energy policy goals.[203] In the wake of Order No. 1000, several states, including Minnesota, North Dakota, South Dakota, Nebraska, and Oklahoma, have enacted their own laws instituting a right

201 *See New York Accelerated Renewable Energy Growth and Community Benefit Act*, Chapter XVIII, Title 19 of NYCRR Part 900, §900-2.18 (State power grid study and program to achieve CLCPA targets).

202 *Ibid.*

203 *See* https://nmreta.com/.

of first refusal for incumbent utilities at the state level.[204] The dismissal of a challenge to Minnesota's right of first refusal law was recently affirmed by the U.S. Court of Appeals for the Eighth Circuit.[205]

Given the central importance of states to transmission planning, the Commission should consider initiating governance changes to regional planning entities so as to give states a more significant role in regional transmission planning. Some regions already give states a special role on transmission cost allocation issues.[206] And special state roles in resource adequacy are common in RTO tariffs and governing documents, another area where states have a unique statutory role.[207] For example, SPP's bylaws provide that the Regional State Committee will "determine the approach for resource adequacy across the entire region," and transmission cost allocation policy for the region.[208] The Commission should gather input from stakeholders regarding whether it would be appropriate to require governance changes of regional planning entities to incorporate a state role, and if so, what changes should be required or encouraged. Recognizing the differences in governance between RTO and non-RTO regions, the Commission should seek input on whether and how this should vary according to a region's characteristics on this dimension.

In single state transmission planning regions, the benefits of integrating states into the governance of regional transmission planning processes could be particularly acute. But larger regions will likely also see significant benefits by giving regional state committees a special governance role.

Beyond considering requiring regional planning entities to grant states a governance role in transmission planning decisions, the Commission could also facilitate better integration between the regional planning process and state proceedings by using Section 209 of the Federal Power Act to convene joint boards. Such a board could be used, for example, if one or more states demonstrate interest in aligning their transmission siting process with the regional planning process of the relevant regional planning entity(ies).

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204 *See LSP Transmission Holdings, LLC v. Sieben*, 954 F.3d 1018, 1024 n. 3 (8th Cir. 2020), (citing N.D. Cent. Code § 49-09-02.2, S.D. Codified Laws § 49-32-20, Neb. Rev. Stat.§ 70-1028, 17 Okla. Stat. § 292).

205 *Ibid*., at 1031.

206 *See* SPP, *Governing Documents Tariff, Bylaws*, First Revised Volume No. 4, at 67, effective date: August 5, 2010, (giving the Regional State Committee authority over certain transmission cost allocation issues).

207 For a discussion of resource adequacy governance provisions in multi-state RTOs, *see* Jennifer Chen and Gabrielle Murnan, *State Participation in Resource Adequacy Decisions in Multistate Regional Transmission Organizations*, March 2019.

208 SPP, *Governing Documents Tariff, Bylaws*, First Revised Volume No. 4, at 67, effective date: August 5, 2010; *Southwest Power Pool*, 106 FERC ¶ 61,110, at P 220, February 10, 2004 ("The RSC should . . . determine the approach for resource adequacy across the entire region."); *Southwest Power Pool, Inc.*, 109 FERC ¶ 61,010, at P 93, October 1, 2004, ("We reject arguments that the RSC is infringing on SPP's own section 205 filing rights.").

E. Produce plans on a regular schedule

To ensure effective planning that is updated to evolving circumstances, the Commission should require regular updates, such as every two years.

F. Produce plans in operations time frame

A FERC planning rule should provide for planning in different time frames. Congestion on the system is widespread and costs consumers roughly $6.1 billion per year.[209] Yet if one only looks at the system a year or two ahead of time, much of that congestion does not exist. That is because congestion is often a function of planned transmission line outages that are not known in that time frame. Transmission planning should include an operational time frame component. Looking out two or three months ahead when planned outages are known allows fast deployment of Grid-Enhancing Technologies to reduce or resolve that congestion.

209 Jesse Schneider, *Transmission Congestion Costs in the U.S. RTOs*, August 14, 2019 (updated November 12, 2020).

VI. The Commission has authority to carry out these reforms

Broadly speaking, to issue a new planning rule under Section 206 of the Federal Power Act, the Commission must find based on substantial evidence that existing planning practices are not just and reasonable or are unduly discriminatory. Evidence of challenges that have persisted despite the progress made under Orders No. 890 and 1000 clears this bar with room to spare. As discussed in Appendix A, numerous studies demonstrate that large, high-voltage transmission infrastructure would yield significant net benefits. Yet regional planning processes are largely not approving such infrastructure, instead yielding locally focused projects that in many cases are likely not as cost-effective as regional or interregional solutions could be. This has overburdened interconnection processes, which are becoming clogged and unworkable. These factors all demonstrate the need for broad planning reforms.

At a more granular level, the Commission has ample authority to adopt the specific solutions we have suggested in this report, as discussed further below.

A. Planning

1. The Commission can require regions to plan based on the best available data and forecasting methodologies

We recommend that the Commission require regions to plan based on reasonable future scenarios that use the best available data and forecasting methodologies. Such planning, which requires the incorporation of not only factors such as resource cost curves, but also public policies as well as corporate and utility procurement targets, falls under FERC's standard power to require planning to be conducted using reasonably available information, just as FERC requires RTOs establish capacity requirements based on their projections of load that is influenced by state energy efficiency policies and other factors. The Commission is permitted to "recognize[] that state and federal policies might affect the transmission market" and plan accordingly.[210]

210 *South Carolina Public Service Authority v. FERC*, 762 F.3d at 89 (D.C. Cir. 2014).

Section 217(b)(4) of the Federal Power Act also supports a requirement to plan based on the best available data and forecasting methodologies, and to include public policies and utility and corporate renewable procurement goals within planning scenarios. It requires the Commission to exercise its authority "in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of load-serving entities."[211] Load serving entities' service obligations will be more accurately predicted by the best available forecasting methodologies, and will naturally depend upon both public policies and the resource preferences of their customers.[212]

2. The Commission can require regional planning entities to approve transmission plans that maximize net benefits

The Commission can also require regional planning entities to approve transmission plans that maximize net benefits using the same general authority it relied upon in promulgating Order No. 1000. Like Order No. 1000, such a requirement focuses on "process" and is "not intended to dictate substantive outcomes."[213] While establishing minimum standards for benefit-cost analysis is a more detailed requirement than requirements such as Order No. 1000's directive that any threshold regional planning entities apply for benefit-cost analysis must be no lower than 1.25, it likewise does not dictate that public utility transmission providers build any particular infrastructure and instead simply mandates that they follow a series of prescribed steps designed to yield just and reasonable rates. As with Order No. 1000, "[t]he substance of a regional transmission plan and any subsequent formation of agreements to construct or operate regional transmission facilities" would "remain within the discretion of the decision-makers in each planning region."[214]

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211 *16 U.S.C. 824q(b)(4)*.

212 As the Commission explained in Order No. 1000-A, "many, if not all, of the Public Policy Requirements will likely impose legal obligations on load-serving entities." *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000-A, 139 FERC ¶ 61,132, at P 175, May 17, 2012.

213 *South Carolina Public Service Authority v. FERC*, 762 F.3d at 58 (D.C. Cir. 2014), (quoting Order No. 1000-A, at P 188, 77 Fed. Reg. at 32,215).

214 *Ibid*.

B. Governance, oversight, and formation of new planning entities

1. *The Commission can require regions to form joint inter-regional planning boards that have full authority to propose FPA section 205 filings that select projects and allocate their costs, and form a new planning entity to assess national transmission opportunities*

In considering the establishment of joint inter-regional planning boards that hold full authority to select and dictate cost allocation methodologies for projects included within an inter-regional plan, the Commission could rely on the same authority it used in Order No. 1000 to require regional planning to be conducted even in non-RTO regions.

As the D.C. Circuit explained in upholding Order No. 888 and Order No. 1000, Section 202(a) of the Federal Power Act's reference to voluntary coordination and Section 202(b) and 211's grant of authority to order interconnection and wheeling do not limit the ability of the Commission to compel rules for planning new facilities that remedy unjust, unreasonable, and discriminatory behavior under Section 206.[215] Here, as was the case in Order No. 1000, the evidence demonstrates that existing transmission planning practices are unjust, unreasonable, and unduly discriminatory with respect to interregional planning because they have not resulted in the approval of a single inter-regional project, despite a large amount of evidence suggesting that such projects would yield net benefits.

The Commission may explore different potential organizational structures for such interregional planning boards. One option may be to require the formation of new, independent entities. While such entities would not themselves be "public utilities" under the Federal Power Act, the Commission could nevertheless require transmission owners in the relevant regions to file agreements governing each interregional board with the Commission. As the Commission explained in its policy statement governing Regional Transmission Groups (similar entities that did not themselves operate transmission but governed transmission planning and operations by member entities), "under section 205(c) of the Federal Power Act (FPA), public utilities must file with the Commission the classifications, practices, and regulations affecting rates and charges for any transmission or sale subject to the Commission's jurisdiction, together with all contracts which in any manner affect or relate to such rates, charges, classifications and services."[216] Thus,

215 *See Transmission Access Policy Study Group v. FERC*, 225 F.3d 667, 686 (D.C. Cir. 2000) ("Otter Tail does not constrain FERC from mandating open access where it finds circumstances of undue discrimination to exist."); *South Carolina Public Service Authority v. FERC*, 762 F.3d at 61 (2014), ("To the extent the court in Central Iowa interpreted Section 202(a) to mean that 'Congress intended coordination and interconnection arrangements be left to the 'voluntary' action of the utilities,' there is nothing to suggest that the court purported to interpret the meaning of 'coordination' in regard to the planning of future facilities.").

216 *Policy Statement Regarding Regional Transmission Groups*, 58 Fed. Reg. 41,626, August 5, 1993.

an agreement governing such an interregional planning board, like a Regional Transmission Group Agreement "that in any manner affects or relates to jurisdictional transmission rates or services," would need to "be approved or accepted by [the] Commission as just, reasonable, and not unduly discriminatory or preferential under [section 205 of] the FPA."[217]

Another option may be to refrain from establishing new, independent organizations and instead dictate that relevant RTO agreements and utility tariffs provide for the participation in such a board and designation to such board full, binding authority to select and cost allocate projects in a manner that cannot be subsequently second guessed by the relevant individual RTO boards or utilities.

2. The Commission can enhance the transparency of transmission planning

Currently, the planning regions possess and report disparate information[218] on transmission needs and investments. Some regions do not publish cost information for approved projects, which limits the ability of stakeholders to assess such projects.[219] Further, there is no centralized place that tracks the costs of transmission projects "planned by the local transmission owners that are not subject to full ISO/RTO regional planning review."[220]

Building on Order No. 890's transparency requirements, the Commission could require more specific minimum data transparency standards as part of a new rule, drawing on the examples set by leading regions such as MISO and SPP, which "currently maintain . . . transparent cost recording and tracking processes for projects approved through their regional planning processes."[221] As Brattle Group analysts have recommended, the Commission should require that regional planning entities at minimum "have a detailed project tracking mechanism that consistently document[s] project cost estimates at various stages of the project, particularly when the project needs are first identified and at the completion of the projects."[222]

217 *Ibid.*

218 Johannes P. Pfeifenberger et al., *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value*, at 24, April 2019.

219 *Ibid.*, at 23-26 (describing data reporting practices, noting that their "analysis was not able to cover NYISO, which does not publish cost information on approved projects").

220 *Ibid.*, at 26.

221 *Ibid.*

222 *Ibid.*, at 24.

3. *The Commission can require regional transmission plans to incorporate end-of-life project planning*

The Commission could mandate end-of-life project planning be considered as part of the regional planning process by reasoning that such planning must be conducted in order to design new transmission facilities where appropriate. Regulating this planning process can be articulated as a requirement to plan *new* projects, without requiring coordination of existing facilities.

Opponents of Order No. 1000 argued that the Commission exceeded its authority in mandating regional transmission planning, as opposed to simply regulating *voluntary* planning arrangements.[223] Section 202(a) of the Federal Power Act "empower[s] and direct[s]" the Commission "to divide the country into regional districts for the voluntary interconnection and coordination of facilities."[224] But in upholding Order No. 1000, the Court of Appeals for the District of Columbia Circuit agreed with the Commission that Section 202(a)'s reference to voluntary coordination does not preclude mandatory planning activities. Rather, the voluntary coordination referred to in Section 202(a) applies only to the operation of existing facilities, not to the planning of new facilities, which "'occurs before [facilities] can be interconnected.'"[225]

We recommend that the Commission explicitly include end-of-life planning decisions within the scope of its new planning rule. While it is true that end-of-life infrastructure replacements are currently classified as asset maintenance in some regions,[226] the Federal Power Act provides the Commission with discretion to reclassify such projects as new construction. The Federal Power Act does not specify what constitutes a "facility" with regard to section 202(a)'s language governing "voluntary interconnection and coordination of facilities"; an interpretation by the Commission that rebuilding all or a significant part of an existing facility constitutes the creation of a new facility rather than maintenance of an existing one is reasonable and not arbitrary and capricious,[227] and would constitute the same type of interpretation that was upheld in *South Carolina Public Service Authority v. FERC* as permissibly distinguishing between planning new facilities and regulating the coordination of existing ones.[228] The Commission, without requiring a transmission owner to engage in any involuntary coordination of an existing facility while it is being

223 *See South Carolina Public Service Authority v. FERC*, 762 F.3d, 41, 55-64 (D.C. Cir. 2014).

224 *16 U.S.C. § 824a(a)* (emphasis added).

225 *South Carolina Public Service Authority v. FERC*, 762 F.3d at 59 (D.C. Cir. 2014). (quoting Order No. 1000, at P 124, 77 Fed. Reg. at 32,206).

226 *See,* e.g., *PJM Interconnection, L.L.C.*, 172 FERC ¶ 61,136, at P 85, August 11, 2020, (holding that regional planning requirements do not apply to "Asset Management Projects" in PJM, a category that includes end-of-life transmission infrastructure replacements).

227 *See Chevron U.S.A. Inc. v. Natural Resources Defense Council, Inc.*, 467 U.S. 837 (1984) (holding that where a statute is "silent or ambiguous on [a] specific issue," courts must defer to an agency's reasonable interpretation).

228 *See South Carolina Public Service Authority v. FERC*, 762 F.3d at 59.

planned, can nevertheless establish rules with regard to whether a new facility should be built in its place that more efficiently meets regional needs.

The Commission can provide guidance dictating that when expenditures exceed a certain threshold, they no longer constitute 'maintenance' activities that are excluded from regional transmission planning.[229] The Commission can reason that rules that classify "asset management" activities as maintenance, even where those activities involve replacement of all or most of a given existing facility,[230] create an inappropriate incentive for utilities to reconstruct existing lines even where other alternatives are more efficient, and is not compelled by the text of the Federal Power Act.

To the extent that the Commission's directive in this area conflicts with existing RTO operating agreements concerning which facilities are subject to regional planning, the Commission can argue that the *Mobile-Sierra* doctrine does not apply, just as it did not apply with regard to the Commission's mandate that Rights-of-First-Refusal be removed from tariffs governing regional planning processes.[231] In upholding the Commission's Right of First Refusal (ROFR) removal mandate, the D.C. Circuit reasoned that *Mobile-Sierra* did not apply because the contractual terms altered by the Commission's directive were "arrived at by horizontal competitors with a common interest to exclude any future competition."[232] The same is true here. Transmission Owners' decision not to give PJM control over end-of-life planning decisions was one made by horizontal competitors to exclude such projects from future competition, and is not reflective of arm's length bargaining that could be expected to arrive at a competitive result.

4. The Commission can apply greater oversight to local transmission plans

The Commission has authority to evaluate local transmission projects where appropriate to ensure the same needs cannot be more cost-effectively met via regional and interre-

229 In many cases, this would require broadening the scope of planning tariffs and agreements. For example, FERC recently held that PJM's Consolidated Transmission Owner's Agreement (CTOA) requires a project to "expand" or "enhance" the PJM grid for planning to be transferred to PJM. *See* *PJM Interconnection, L.L.C.*, 172 FERC ¶ 61,136, at P 83, August 11, 2020. In adopting new criteria to distinguish infrastructure maintenance from grid upgrades, the Commission should gather input from stakeholders regarding how to define the threshold dividing these activities (e.g. whether as an absolute dollar amount or as a percentage of an existing facility, how to define the scope of a facility for purposes of this rule, etc.).

230 *See*, e.g., *Ibid.*, at P 85 (finding that PJM's proposal to designate replacement projects as "asset management" projects exempt from Order No. 890's requirements is just and reasonable). *See also* Johannes P. Pfeifenberger et al., *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value*, April 2019.

231 *See* *Oklahoma Gas and Electric Co. v. FERC*, 827 F.3d 75 (D.C. Cir. 2016).

232 *Ibid.*, at 80 (D.C. Cir. 2016).

gional infrastructure.[233] Evaluating the cost-effectiveness of such projects would be more consistent with Section 205 of the Federal Power Act, which places the "burden of proof" on the filing party.[234]

To prevent such a change in the burden of proof for some projects from overburdening the Commission's capacity to administer rate cases, the Commission could issue policy guidance regarding its scope and process for review.

5. The Commission can take a case-by-case approach to approving regional planning tariffs that reinstitute a right of first refusal

While the Commission was justified in mandating the removal of rights of first refusal from regional transmission planning tariffs, as discussed in Section V.D, evidence in implementing Order No. 1000 warrants a change in position by the Commission.

In determining that in some circumstances a new tariff proposal that contains a right of first refusal may yield just and reasonable rates, the Commission can point to the manner in which a mismatch in rights of first refusal at the regional and local level has led to a skewed, non-optimal project mix. At the same time, the Commission could approve a regional transmission plan that continues to omit a right of first refusal if the evidence dictates that inclusion of end-of-life project decisions within such a plan, coupled with a process for evaluating whether a regional project more efficiently serves a local need, creates incentives that will prevent the project skew we have seen in the past.

As explained in Section V.D, the Commission can also point to the experience in implementing Order No. 1000 as demonstrating that in certain circumstances, different treatment between incumbent transmission owners and non-incumbents is justified and not "undue discrimination," recognizing the role incumbents play in operating the local system, and in some regions, participating in integrated resource planning processes at the state level.

233 Existing Commission precedent applies a presumption of prudence to local transmission plans. *See Potomac-Appalachian Transmission Highline, LLC PJM Interconnection, L.L.C.*, 158 FERC ¶ 61,050, at P 100, January 19, 2017; *see also Iroquois Gas Transmission System, L.P.*, 87 FERC ¶ 61,295, 62,168, June 17, 1999, ("As a matter of procedural practice to ensure that rate cases are manageable, the Commission does not require regulated entities to 'demonstrate in their cases-in-chief that all expenditures were prudent unless the Commission's filing requirements, policy, or precedent otherwise require.' There is, in effect, a presumption of prudence which can be rebutted at hearing whenever another party 'creates serious doubt as to the prudence of an expenditure.'"). Nevertheless, the Commission could appropriately reason that such a presumption is not appropriate where evidence suggests that a regional transmission solution may more efficiently meet the same need.

234 *16 U.S.C. § 824d(e)*; *see* Ari Peskoe, Is the Utility Transmission Syndicate Forever?, forthcoming 2021.

Appendix A

EVIDENCE OF THE NEED FOR LARGE REGIONAL AND INTERREGIONAL TRANSMISSION

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

- A study by leading grid experts at the National Oceanic and Atmospheric Administration (NOAA), found that moving away from a regionally divided network to a national network of HVDC transmission can save consumers up to $47 billion annually while integrating 523 GWs of wind and 371 GWs of solar onto the grid.[235]
- The NREL *Interconnections Seam Study* shows that significant transmission expansion and the creation of a national network will be essential in incorporating high levels of renewable resources, all the while returning more than $2.50 for every dollar invested.[236] The study found a need for 40-60 million MW-miles of alternating current (AC) and up to 63 million MW-miles of direct current (DC) transmission for one scenario. The U.S. has approximately 150 million MW-miles in operation today.
- A study by ScottMadden Management Consultants on behalf of WIRES concluded, "as more states, utilities, and other companies are mandating or committing to clean energy targets and agendas, it will not be possible to meet those goals without additional transmission to connect desired resources to load. Similarly, the current transmission system will need further expansion and hardening beyond the traditional focus on meeting reliability needs if the system is to be adequately designed and constructed to withstand and timely recover from disruptive or low probability, high-impact events affecting the resilience of the bulk power system."[237]
- Dr. Paul Joskow of MIT has reviewed transmission planning needs and concluded that "[s]ubstantial investment in new transmission capacity will be needed to allow wind and solar generators to develop projects where the most attractive natural

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

236 Aaron Bloom, *Interconnections Seam Study*, August 2018.

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

wind and solar resources are located. Barriers to expanding the needed inter-regional and internetwork transmission capacity are being addressed either too slowly or not at all."[238]

- The Commission itself recently reviewed transmission needs and barriers and "found that high voltage transmission, as individual lines or as an overlay, can improve reliability by allowing utilities to share generating resources, enhance the stability of the existing transmission system, aid with restoration and recovery after an event, and improve frequency response and ancillary services throughout the existing system."[239]

- A study of the Eastern Interconnection for the state of Minnesota found that scenarios with interstate transmission expansion can introduce annual savings to Minnesota consumers of up to $2.8 billion, with an annual savings for Minnesotan households of up to $1,165 per year.[240]

- Analysts at The Brattle Group estimate that providing access to areas with lower cost generation to meet Renewable Portfolio Standards (RPS) and clean energy needs through 2030 could create $30-70 billion in benefits for customers, and multiple studies have identified potential benefits of over $100 billion.[241]

- The Princeton University Net Zero America study of a low carbon economy found "[h]igh voltage transmission capacity expands ~60% by 2030 and triples through 2050 to connect wind and solar facilities to demand; total capital invested in transmission is $360 billion through 2030 and $2.4 trillion by 2050."[242]

- A study by MIT scientists found that inter-state coordination and transmission expansion reduces the cost of zero-carbon electricity by up to 46% compared to a state-by-state approach.[243] To achieve these cost reductions the study found a need for approximately doubling transmission capacity, and "[e]ven in the ''5x transmission cost'' case there are substantial transmission additions."[244]

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238 Paul Joskow, *Transmission Capacity Expansion is Needed to Decarbonize the Electricity Sector Efficiently*, Joule 4, at 1-3, January 15, 2020.

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

240 Vibrant Clean Energy, *Minnesota's Smarter Grid*, July 31, 2018.

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

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

243 Patrick R. Brown and Audun Botterud, *The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System*, Joule, December 11, 2020.

244 *Ibid., at 12.*

- A recent study to compare the “flexibility cost-benefits of geographic aggregation, renewable overgeneration, storage, and flexible electric vehicle charging,” as “pathways to a fully renewable electricity system” found that “[g]eographic aggregation provides the largest flexibility benefit with ~5–50% cost savings.[245] The study found that “With a major expansion of long-distance transmission interconnection to smooth renewable energy variation across the continent, curtailment falls to negligible levels” at a 60% renewable penetration, from 5% in the case without transmission. In the 80% renewable case, transmission reduced curtailment from 12% to 5%.”[246]

- The Brattle Group analysts find that “$30–90 billion dollars of incremental transmission investments will be necessary in the U.S. by 2030 to meet the changing needs of the system due to electrification, with an additional $200–600 billion needed from 2030 to 2050.”[247]

- Analysis conducted for MISO found that significant transmission expansion was economical under all future scenarios, with the largest transmission expansion needed in Minnesota, the Dakotas, and Iowa. In the carbon reduction case, transmission provided $3.8 billion in annual savings, reducing total power system costs by 5.3%.[248] MISO’s Renewable Integration Impact Assessment conducted a diverse set of power system studies examining up to 50% Variable Energy Resources (VER) (570GW VER) in the eastern interconnection. Within the MISO footprint, this included the following transmission expansion: 590 circuit-miles of 345kV and below, 820 circuit-miles of 500kV, 2040 circuit-miles of 765kV and 640 circuit-miles of HVDC.[249]

- Brattle group analysts, on behalf of WIRES, demonstrate that transmission expansion creates trading opportunities across existing regional and interregional constraints. The report finds, using existing wholesale power price differences between SPP and the Northwestern U.S., that “adding 1,000 MW of transmission capability would create approximately $3 billion in economic benefits on a present value basis.”[250]

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

246 *Ibid*.

247 Dr. Jürgen Weiss, J. Michael Hagerty, and María Castañer, *The Coming Electrification of the North American Economy*, at ii, March 2019.

248 Vibrant Clean Energy, *MISO High Penetration Renewable Energy Study for 2050*, at 23-24, January 2016.

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

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

- In its HVDC Network Concept study, MISO estimates that expanding east-to-west and north-to-south transmission interties can generate investment cost savings of approximately $38 billion through load diversity benefits that would reduce nation-wide generation capacity needs by 36,000 MW.[251]

- A study prepared for the Eastern Interconnection States Planning Council, National Association of Regulatory Utility Commissioners, and the Department of Energy estimates that $50–110 billion of interregional transmission will be needed over the next 20 years to cost-effectively support new generation investment. A co-optimized, anticipatory transmission planning process is estimated to reduce total generation costs by $150 billion, compared to a traditional transmission planning approach, and would generate approximately $90 billion in overall system-wide savings.[252]

- SPP found that a portfolio of transmission projects constructed in the region between 2012 and 2014 at a cost of $3.4 billion is estimated to generate upwards of $12 billion in net benefits over the next 40 years. The net present value is expected to total over $16.6 billion over the 40-year period, resulting in a benefit-to-cost ratio of 3.5.[253]

- MISO estimates that its 17 Multi-Value Projects (MVPs), approved in 2011, will generate between $7.3 to $39 billion in net benefits over the next 20 to 40 years, which will result in a total cost-benefit ratio of between 1.8 to 3.1. Typical residential households could realize an estimated $4.23 to $5.13 in monthly benefits over the 40-year period.[254]

- A study conducted by the Eastern Interconnection Planning Collaborative on the need for interregional transmission projects to meet national environmental goals found that an efficient interregional transmission planning approach to meet a 25% nation-wide RPS standard would reduce generation costs by $163–197 billion compared to traditional planning approaches.[255] Phase 2 of the study found that the transmission investment necessary to support the generation and the environmental compliance scenarios associated with these savings ranges from $67 to $98

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251 MISO, *HVDC Network Concept*, at 3, January 7, 2014.

252 Andrew Liu et al., *Co-optimization of Transmission and Other Supply Resources*, September 2013.

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

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

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

billion.[256] These results indicate that the combination of interregional environmental policy compliance and interregional transmission may offer net savings of up to $100 billion.

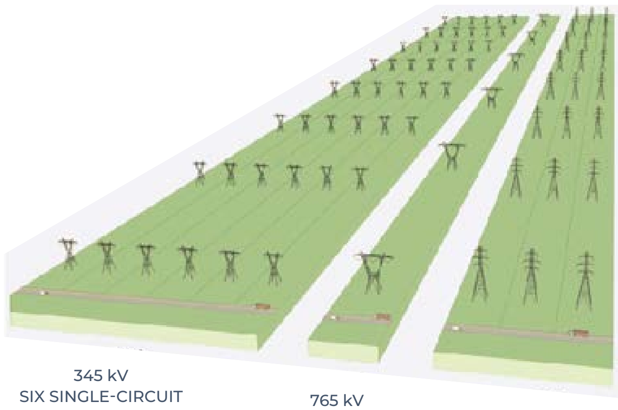
- A study comparing pro-active planning to reactive planning found significant benefits to pro-active planning because it is able to co-optimize generation and transmission. "Transmission planning has traditionally followed a "generation first" or "reactive" logic, in which network reinforcements are planned to accommodate assumed generation build-outs. The emergence of renewables has revealed deficiencies in this approach, in that it ignores the interdependence of transmission and generation investments. For instance, grid investments can provide access to higher quality renewables and thus affect plant siting. Disregarding this complementarity increases costs. In theory, this can be corrected by "proactive" transmission planning, which anticipates how generation investment responds by co-optimizing transmission and generation investments. We evaluate the potential usefulness of co-optimization by applying a mixed-integer linear programming formulation to a 24-bus stakeholder-developed representation of the U.S. Eastern Interconnection. We estimate cost savings from co-optimization compared to both reactive planning and an approach that iterates between generation and transmission investment optimization. These savings turn out to be comparable in magnitude to the amount of incremental transmission investment."[257]
- There are extremely large economies of scale in transmission, such that building at the appropriate scale achieves lower costs for each Megawatt-hour delivered. The chart below shows the much lower cost for larger conductor sizes.[258]

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

257 Evangelia Spyrou, Jonathan L. Ho, Benjamin F. Hobbs, Randell M. Johnson, and James D. McCalley, *What Are the Benefits of Co-Optimizing Transmission and Generation Investment? Eastern Interconnection Case Study*. IEEE Transactions on Power Systems 32 (6): 4265–77, January 27, 2017.

258 *Fabricators & Manufacturers Association, International*.

FIGURE 15 Lower Transmission Cost per MW-Mile for Larger Conductors



TRANSMISSION VOLTAGE (KV)	COST PER MILE ($/MILE)	CAPACITY (MW)	COST PER UNIT OF CAPACITY ($/MW-MILE)
230	$2.077 million	500	$5,460
345	$2.539 million	967	$2,850
500	$4.328 million	2,040	$1,450
765	$6.578 million	5,000	$1,320

Customer and reliability benefits from an increase in transmission construction have also been noted in studies focused on networks outside of the U.S. that have the same fundamental physics and economics at work.

- The "European e-Highway 2050" study found that interregional transmission investments allow for the integration of lower-cost, region-wide renewable resources, which reduce the cost of achieving a low-carbon electricity sector. Additionally, in high-renewable generation scenarios, interregional transmission investments are found to be highly cost effective with a payback period of just one year.[259]

- A study conducted by McKinsey & Company analysts found that, in Europe, the most cost-effective way to reach 40% to 45% renewable generation targets in 2050 requires doubling existing region-wide transmission capabilities by 2020 and quadrupling transmission capabilities by 2050. Germany, in particular, would need to significantly expand its interregional transmission capabilities to facilitate Europe-wide resource planning coordination.[260]

- Achieving Europe's overall renewable energy policy objectives, according to a report prepared for the Directorate General for Energy of the European Commission, finds

259 E-Highway 2050, Modular Development Plan of the Pan-European Transmission System 2050, *D2.3 System Simulations Analysis and Overlay-Grid Development*, April 16, 2015.

260 McKinsey & Company, *Transformation of Europe's power system until 2050Including specific considerations for Germany*, October 2010.

the most cost-effective path to achieving Europe's renewable energy policy objectives involves a substantial expansion of transmission networks, which composes 15% to 20% of total investment needs in all scenarios. A delay or lack of regional and interregional transmission was found to increase overall system-wide costs as well as increase levels of price volatility within regional markets.[261]

261 DNV GL - Energy, *Integration of Renewable Energy in Europe*, June 12, 2014.

Appendix B

HIGH LEVEL OVERVIEW AND ASSESSMENT OF CURRENT PLANNING APPROACHES

In most cases today, regional planning is limited to near term knowns and protecting firm service using scenarios which do not adequately incorporate likely future changes. Below, we summarize existing processes and their infirmities.

Order Nos. 890 and 1000 require a regional planning process in all areas of the country, extending transmission planning regions beyond ISO and RTOs. In almost all non-RTO areas, the participating utilities' individual transmission plans are consolidated to create a baseline regional reliability plan which is used to evaluate other proposals for both regional transmission needs and solutions. In these transmission planning regions, analysis of opportunities to expand beyond the baseline regional reliability plan are seldom robust, and as a result few projects have resulted from the regional planning process in non-RTO areas.

RTOs tend to have more robust regional planning processes than non-RTO regional planning entities. These RTO planning processes consist of at least two main steps: (1) a regional reliability assessment that identifies projects to meet reliability needs; and (2) a process designed to identify projects that will enhance the regional economic efficiency of the transmission system. They also carry out separate "tariff services" processes to develop transmission pursuant to customer load additions, transmission service requests, or generator interconnection requests. Infrastructure built pursuant to these tariff services processes is incorporated into regional transmission plans, but not driven by them. In addition, tariff service processes result in minimal system upgrades to provide the requested service, with little or no consideration of optimal long-term plans. Regions vary in the degree to which local projects, as well as upgrades and maintenance of existing infrastructure, are included in the regional reliability planning process or instead pursued according to separate local planning processes that later feed into the regional needs assessment. They also vary in the extent to which they have a separate process designed to identify projects to serve public policy goals, or projects driven by both economics and policy.

A. Reliability planning

Utilities have always focused on providing reliable service to customers as the top priority. Reliability planning processes, as their name suggests, tend to focus solely on meeting reliability standards and identifying projects based on their ability to address projected violations of reliability standards.[262] North American Electric Reliability Corporation (NERC) reliability criteria have evolved to establish system performance requirements to address thermal, voltage and stability needs of a secure bulk power system. Regional plans incorporate not only NERC criteria, but also regional and local criteria. Criteria have traditionally focused on deterministic needs of the bulk power system to evaluate system performance during system peak conditions, light load, and other planning scenarios.

Reliability planning processes begin with a baseline reliability assessment that identifies the ability of local and regional transmission infrastructure to meet reliability criteria. For example, MISO's baseline reliability study examines all infrastructure rated 100 kV and above, carrying out "power-flow models reflective of two-year out, five-year out, and ten-year out system conditions in accordance with NERC Transmision Planning (TPL) standards,"[263] as well as a variety of other studies such as a load deliverability analysis to assess system performance across relatively-near term conditions.[264]

RTOs then assess reliability according to a range of future scenarios that project system resource mix and demand across a longer time horizon. For example, MISO annually develops "Futures" to project various potential system resource mix and demand scenarios, which are used as an input into the reliability planning process.[265] The process for developing such future scenarios varies widely by region. Some regions, such as MISO and SPP, incorporate state renewable portfolio standards into their future grid mix scenarios.[266] Others, such as PJM, do not.[267] Efforts are underway in many regions to complement deterministic assessments with probabilistic techniques, which are paramount to manage the allocation of limited capital to the best system improvements given the variable na-

262 *See*, e.g., PJM, *PJM Manual 14B: PJM Region Transmission Planning Process*, § 2.1.2, October 1, 2020.

263 MISO, *Business Practices Manual Transmission Planning*, § 4.3.3, effective date: May 1, 2020.

264 *Ibid.*, § 4.5.1.

265 *Ibid.*, at § 4.4.2.5 ("It is necessary that the transmission plan is developed to be effective under the range of Futures studied. Therefore, the proposed transmission plan will be tested under each of the agreed upon Future for economic results (e.g. benefit-to-cost ratios, etc.), reliability performance (e.g., NERC standards, etc.), and public policy performance (e.g. compliance with RPS mandates, etc.).

266 *See*, e.g., Ibid., at § 4.3.3.2 ("[S]ufficient renewable generation will be modeled to meet renewable portfolio standard mandates effective during the applicable planning horizon."); SPP, *Integrated Transmission Planning Manual*, § 2.2.1.3, July 20, 2017, (requiring renewable resource targets set by state renewable portfolio standard requirements to "be met in each of the study years").

267 *See* PJM, *Amended and Restated Operating Agreement of PJM Interconnection, L.L.C.*, Schedule 6, § 1.5.7, effective date September 17, 2010.

ture of new renewable resources and loads, plus uncertainties regarding key variables. [268]

B. Local projects and maintenance activities

Transmission owners have an obligation to serve and must maintain assets, including those that have been placed under the operational control and authority of an RTO. Regions vary in how they conduct planning of local assets and maintenance activities based on the degree of control that has been given to the RTO. The Commission held in 2018 that Order No. 890 does not require Transmission owners "to allow the RTO to do to all planning for local or Supplemental Projects."[269] In many regions, such as PJM, transmission owners carry out separate local planning processes, which address a wide range of transmission needs, including upgrades and maintenance of existing infrastructure.[270] These local processes act as an input to regional plans, but are not subject to approval by the regional planning entity and there is often minimal coordination between the local and regional planning process to facilitate modification of local projects in response to the development of regional solutions. Other regions, such as SPP, have a very close degree of coordination between local and regional planning. With the exception of Southwestern Public Service Company, all transmission owners in SPP carry out their transmission planning via a process that is fully integrated (i.e. not separate from) SPP's regional planning process, with SPP collecting local planning criteria from each transmission owner in accordance with its tariff.[271]

Local planning processes may address not only local planning criteria but also project upgrades and replacements. Most RTOs have long-standing processes which exempt end of life projects from the full rigors of the regional planning process and allow incumbent TOs to rebuild, replace or upgrade select assets as they approach the end of their useful life.[272] Non-RTO regions have processes which are more opaque or non-existent, leaving end-of-life project planning entirely to local planning processes that are not subject to the transparency requirements of the regional planning process. In such local planning processes, the opportunity to leverage project upgrades to meet needs beyond the immediate reliability issue may or may not be considered, but are not assessed in the con-

268 *See,* e.g., ISO New-England, *Transmission Planning Assumptions*, September 6, 2017; PJM, *PJM Manual 14B: PJM Region Transmission Planning Process*, § 2.7.2, October 1, 2020; and MISO, *Planning Models Used by MISO*, April 24, 2018.

269 *Monongahela Power Company et al.*, Order on Rehearing and Compliance, 164 FERC ¶ 61,217, at P 13, September 26, 2018.

270 *See* PJM, *PJM Manual 14B: PJM Region Transmission Planning Process*, § 1.1, October 1, 2020 (providing an overview of the PJM transmission planning process).

271 SPP, *Integrated Transmission Planning Manual*, § 4.2.6, July 20, 2017.

272 *See* Johannes P. Pfeifenberger et al., *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value*, at 20, April 2019. (noting that all RTOs examined exempt certain upgrade projects from competitive solicitation processes).

text of larger regional needs. Local projects must be coordinated with regional planning entities in advance of being placed in-service per NERC standards, but process simply checks for operational issues, not economic efficiency.

Local projects exempt from regional cost allocation can address a wide range of needs. PJM's supplemental project planning process, for example, may identify any "need associated with a transmission expansion or enhancement not required to comply with the PJM reliability, operational performance, FERC Form No. 715 or economic criteria.[273] MISO's "Other" projects, which comprised the majority of projects included in MTEP19, are driven by a variety of needs including reliability, age and condition, load growth, and other planning needs.[274]

Overall, the dividing line between what constitutes a "local" versus a regional project is murky, and varies significantly by region, as does the extent of interfacing between the local and regional planning processes. Generally speaking, four related factors contribute to whether a project is local or regional: (i) the project's voltage – with low voltage projects being local and higher voltage being more regional in nature; (ii) whether the project is built to address a local transmission owner's reliability criteria, regional or NERC criteria, or to provide economic or public policy benefits; (iii) whether the project involves maintenance or replacement of a transmission owner's system; and (iv) whether the project creates regional benefits.[275] Further, as discussed above, whether a project is "local" or "regional" has different consequences across different regions, as some regions will include local projects within a regional plan but not allocate costs regionally, whereas other regions will simply exclude such projects from regional plans entirely.

C. Economic, public policy, and multi-value planning processes

Regional planning entities are required to study potential transmission expansion projects to reduce congestion and improve grid efficiencies.[276] To do so, RTOs engage in an economic planning process. Economic planning is based on futures which reflect baseline assumptions for key variables like load growth, natural gas prices, resource additions that include projects which are expected to be approved and installed.

273 PJM, *PJM Manual 14B: PJM Region Transmission Planning Process*, § 1.4.1.5, October 1, 2020.

274 MISO, *MTEP19*, at 16, n.d. (showing that 43% of "Other" projects were driven by reliability, 27% by age and condition, 26% by load growth, and 4% by other needs).

275 The D.C. Circuit recently held that if a project creates regional benefits, its costs cannot be allocated solely to the local zone, even where the project is driven solely by local reliability planning criteria. *See Old Dominion Electric Cooperative v. FERC*, 898 F.3d 1254, 1260-64 (D.C. Cir. 2018).

276 *Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 147, July 21, 2011.

RTOs vary in how they establish the future scenarios, as well as in the planning horizon assessed. Some regions, such as MISO, use the same future scenarios to inform both reliability and economic planning processes,[277] whereas others like PJM vary the assumptions used at the economic planning stage.[278] Generally speaking, the generation and demand profiles used by regions for purposes of economic planning processes reflect known retirements and interconnections rather than reasonable projections of future retirement and interconnection scenarios, with a few limited exceptions.[279] For example, PJM's planning processes include new generation sensitivities in its transmission modeling process only "[w]hen the PJM load in the RTEP model exceeds the sum of the available in-service generation plus generation with an executed [Interconnection Service Agreement]," and they do so by simply "including queued generation that has received an Impact Study" rather than conducting more sophisticated analysis.[280]

While economic planning processes are primarily designed to reduce congestion rather than solve reliability challenges, reliability and economics are interrelated. In many cases, today's economic upgrade addresses tomorrow's reliability need. Economic projects can displace reliability solutions, as long as they pass the same parameters that are being considered for the reliability portfolio. Some planning regions have taken the positive step of using market efficiency planning processes to determine if proposed reliability-based enhancements could have economic benefits if accelerated, or yield greater benefits if modified.[281] But no economic planning process accounts for the full range of reliability benefits that can be provided by economically planned projects.

Beyond this core economic planning process, many regions also have a particularized process to identify projects driven by public policies, or projects driven by a range of factors, including reliability, economic efficiency, and public policies. Needs are assessed according to a range of different metrics, which in many regions depend on the project pathway chosen. Project pathways may be dependent on relatively arbitrary buckets or artificially restrict the potential benefits of solutions to be provided to address transmission needs. For example, MISO has separate processes for Market Efficiency Projects and Multi-Value Projects, despite the fact that in theory Market Efficiency Projects are identified according to a process that incorporates both public policy and reliability needs. Market Efficiency Projects must meet a specified set of cost savings metrics with a BCA ratio

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277 MISO, *Business Practices Manual Transmission Planning*, § 4.4.2.5, effective date: May 1, 2020, (explaining that economic transmission planning solutions are examined according to performance in the "Futures" selected).

278 *See* PJM, *PJM Manual 14B: PJM Region Transmission Planning Process*, § 1.3.2, October 1, 2020.

279 MISO's "Futures" process includes a more robust scenario assessment.

280 PJM, *PJM Manual 14B: PJM Region Transmission Planning Process*, Attachment B.4 Scenario Planning Procedure, October 1, 2020.

281 *See*, e.g., PJM, *Regional Transmission Expansion Plan*, at 61, February 29, 2020.

of at least 1.25,[282] whereas Multi-Value Projects must meet one of three criteria that involve (1) reliably and economically delivering energy in support of a state policy mandate; (2) providing multiple types of economic value across multiple pricing zones for a BCA of 1.0 or higher; or (3) address a projected violation of a reliability standard and have a total project BCA of 1.0 or higher.[283] The MISO planning rules are not clear when one project pathway will be pursued to identify solutions versus another, or how exactly identifying transmission needs differs under each process. Neither MISO nor other Planning Authorities have begun Multi-Value processes in the last ten years. This structure of including several different project pathways with a lack of clarity around when each pathway is used is common among RTOs.

D. Inter-regional planning

Order No. 1000 expanded the planning requirements of Order No. 890 to require regional planning entities to establish procedures with each of its neighboring regional planning entities within existing interconnections for the purposes of coordinating and sharing regional plans to identify potential transmission solutions that are more efficient and effective than separate regional solutions to each region's needs.[284] Order No. 1000 specifies that this coordination process must include "a formal procedure to identify and jointly evaluate interregional transmission facilities."[285] It also requires "each public utility transmission provider to develop procedures by which differences in data, models, assumptions, transmission planning horizons, and criteria used to study a proposed interregional transmission project can be identified and resolved for purposes of joint evaluation."[286]

While Joint Operating Agreements have been in place for years, the focus has been for model and data exchanges to support operations, not efficient planning. A key challenge in implementing Order No. 1000 has been that the agreements between regional planning entities have a multi-stage process on interregional project approvals that requires any proposed solution to not only emerge from the coordinated interregional process, but also separately secure approvals from each RTO individually. For example, MISO and SPP have a joint planning committee responsible for carrying out a process that may arrive at identified solutions, at which point "each RTO considers the recommended interregional

282 *See* MISO, *Business Practices Manual Transmission Planning*, § 7.4.2, effective date: May 1, 2020.

283 MISO, *Tariff - Attachment FF*, §§ II.C.1, II.C.2, and II.C.3, effective date: August 11, 2020.

284 *Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at PP 374-481, July 21, 2011.

285 *Ibid.*, at P 435.

286 *Midcontinent Independent System Operator, Inc., Southwest Power Pool, Inc.*, 168 FERC ¶ 61,018, at P 5, July 16, 2019.

transmission solutions in its respective regional transmission planning process."[287] For a project to be approved it must first "be vetted through both RTO regional processes and approved by each RTO's Board of Directors."[288] Recent reforms have collapsed one stage between these RTOs it is still unlikely for the separate processes to find the same project result from their analyses.

E. Project selection for reliability, economic, public policy, multi-value, and inter-regional projects

Order No. 1000 eliminated the Right of First Refusal for utilities to build regionally and inter-regionally cost-allocated projects. In implementing this directive, the goal of planning entities, at least in theory, is to identify and select the best performing portfolio of projects according to the regional metrics, and approve those projects for regional cost allocation. All regions approach this task by first conducting the reliability and economic needs assessments described above. Some regions follow this by defining with particularity the types of infrastructure that can meet these needs, then using a competitive solicitation process to select projects.[289] Other regions use a "sponsorship model," where transmission providers are invited to propose projects that meet the needs.[290]

In practice, however, competitive solicitation is seldom used. The Commission has approved exclusions for reliability projects if those projects are needed in a short time frame, reasoning that the 6-18 months required to conduct a solicitation makes competition an inappropriate mechanism to select projects to meet those needs.[291] Regions also exclude projects from competition based on voltage level and/or total cost, with lower voltage or smaller sized local projects not subject to competition.[292] The voltage and size thresholds vary widely by region.[293] For example, MISO requires economic efficiency projects selected by competition to have a minimum voltage level of 230kV and $5 million in total costs,[294] while ISO-NE only applies a voltage threshold of less than 100 kV.[295]

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287 *Ibid.*, at P 2.

288 *Ibid.*, at P 3.

289 Joseph H. Eto and Giulia Gallo, *Regional Transmission Planning: A Review of Practices Following FERC Order Nos. 890 and 1000*, at 5-6, November 2017.

290 *Ibid.*, at 5.

291 See Johannes P. Pfeifenberger et al., Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value, at 20, April 2019.

292 *Ibid.*

293 *Ibid.*

294 MISO, *Tariff - Attachment FF*, § II.B, effective date: August 11, 2020.

295 *See* Johannes P. Pfeifenberger et al., *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value*, at 20, April 2019.

These exclusions, along with state Right of First Refusal laws, contributed to the outcome of only 3% of total RTO-region transmission investments being competitively selected between 2013 and 2017, according to the Brattle Group analysis.[296] As Order No. 1000 requires regional cost allocation for regionally beneficial projects that are planned with a long lead time, the lack of competitively selected projects shows that very few projects are being planned with regional needs in mind.

Rather, the dominant trend has been of regional plans composed almost entirely of projects that (i) address local needs and are not designed to provide greater regional economic efficiency or address public policy needs, and (ii) projects built to replace existing infrastructure, executed with short lead time in advance of the reliability need being addressed and accordingly, often without assessing potential synergies with broader regional needs and leveraging the opportunity to build larger or differently designed infrastructure utilizing the right-of-way to more cost-effectively address more regional needs.

MISO's MVP Portfolio included within MTEP11, and SPP's Priority Projects portfolio, approved in 2010, are the two main exceptions to this trend, but both occurred prior to the passage of Order No. 1000.[297] Accordingly, Order No. 1000's requirement for competitive selection did not apply and those broad portfolios consisted of solutions identified by regional planners and implemented by incumbent utilities.

296 *Ibid*., at 18.

297 SPP's 2010 Priority Projects portfolio was spurred by the Synergistic Planning Project Team (SPPT) report which outlined a new transmission planning process as well as a new cost allocation methodology, both of which were ultimately approved. SPP, *SPP Priority Projects Phase II Report*, February 2010. The portfolio consisted of 6 projects including three double-circuit, high capacity 345kV backbone projects in western SPP be approved to address benefit projected Generation Interconnection and Aggregate Transmission Service Study processes, address known and anticipated congestion patterns and also to better integrate the west and east portions of the SPP transmission system. Construction of these projects was projected to result in large local economic benefits.

MISO provides a paradigmatic example of the near exclusive reliance on locally planned projects and projects exclusively focused on reliability since Order No. 1000 was implemented:

TABLE 2 MISO MTEP Investment by Project Type[298]

YEAR	BASELINE RELIABILITY PROJECTS (BRP) ($ MILLION)	MARKET EFFICIENCY PROJECTS (MEP) ($ MILLION)	MULTI-VALUE PROJECTS (MVP) ($ MILLION)	OTHER (LOCAL) ($ MILLION)
2010	94	-	510	575
2011	424	-	5,100	681
2012	468	15	-	744
2013	372	-	-	1,100
2014	270	-	-	1,500
2015	1,200	67	-	1,380
2016	691	108	-	1,750
2017	957	130	-	1,400
2018	709	-	-	2,300
2019	836	-	-	2,800

Likewise, in PJM, about two thirds of projects were Supplemental Projects planned outside the regional process, 75 percent of which were driven by end-of-life planning decisions.[299]

F. Overall assessment of the current approach

The lack of regionally planned projects should not be taken as evidence that such planning would not yield benefits. Experience with MISO's MVP portfolio and SPP's priority projects portfolio has shown that, where proactive planning has been utilized, the resulting projects have been highly beneficial with total benefits approximately three times

298 Coalition of MISO Transmission Customers, Industrial Energy Consumers of America, and LS Power Midcontinent, LLC, *Section 206 Complaint and Request for Fast Track Processing*, at 31-32, January 21, 2020.

299 Paul L. Joskow, *Competition for Electric Transmission projects in the U.S.: FERC Order 1000*, March 2019; and Mohammad Reza Hesamzadeh, Juan Rosellon, and Ingo Vogelsang, *Transmission Network Investment in Liberalized Power Markets*, Springer 2020. *See also* PJM Interconnection, L.L.C., *Affidavit of Johannes P. Pfeifenberger and John Michael Hagerty on Behalf of LS Power*, Docket No. ER20-2308, at 7, July 23, 2020.

larger than costs.[300]

And as discussed in Appendix A, studies from National Labs and other sources suggest that benefits of more regionally planned projects would greatly exceed costs, and the backlog of projects in the interconnection queue suggest that more transmission planned to resource rich regions would eliminate costly delays and provide customers with access to lower cost supply.

Rather than reflecting their lack of net benefits, the lack of proactively planned projects is the result of shortcomings in regional planning processes, cost allocation, governance and oversight. Regional planning processes suffer from four primary deficiencies. First, many regional plans identify transmission needs through a siloed process that considers reliability, economic, and public policy benefits separately, rather than looking at all needs holistically. Second, in identifying transmission needs, regional planning entities generally rely upon modeling that does not accurately forecast future supply mixes or electricity demand. Third, regional processes used for identifying solutions to transmission needs do not include the full range of technologies available to serve needs. Fourth, benefit-cost analyses applied to regional transmission projects generally do not accurately reflect the full range of project benefits or select the option that maximizes aggregate net benefits to consumers.

By remedying these deficiencies, together with overcoming shortcomings in cost allocation, governance, and oversight processes discussed in Sections IV and V, the Commission can create a process through which regional planning processes more cost-effectively meet future needs and result in just and reasonable rates.

300 MISO now projects to create average monthly benefits between $4.23 and $5.13 for the average residential customers over the next 40-year period, as compared to only $1.50 per month in average costs. MISO, *MTEP19*, at 7, n.d. SPP found $3.4 billion in transmission upgrades it installed between 2012 and 2014 created over $16 billion in gross savings – 3.5 times greater than the cost of the transmission upgrades. SPP, *The Value of Transmission*, January 26, 2016.