UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

REPLY COMMENTS OF PUBLIC INTEREST ORGANIZATIONS

NOVEMBER 30, 2021

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

I. There is Wide Consensus that FERC Must Comprehensively Reform Transmission Planning Processes

Ten years ago, the Commission responded to "changing conditions in the industry" to reform its transmission planning and cost allocation regulations to achieve "more efficient and cost-effective regional transmission planning."[2] Once again, we are at an inflection point where "shifts in the generation fleet increase the need for new transmission [and] the existing transmission system was not built to accommodate this shifting generation fleet."[3] Comments filed to the ANOPR show a wide consensus that Order No. 1000 is not meeting the needs of existing generation, much less anticipated future generation. In fact, over 100 parties support FERC making changes to its transmission planning rules to ensure proactive planning for the future resource mix. These entities represent a diverse mix of stakeholders including consumer groups,[4] utilities,[5] state

[1] Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, 176 FERC ¶ 61,024 (2021), 86 Fed. Reg. 40266 (July 27, 2021) (hereinafter "ANOPR").
[2] Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities, Order No. 1000, 136 FERC ¶ 61,051, at PP 81, 2, 3 (2011) (hereinafter "Order No. 1000").
[3] Order No. 1000 at P 46.
[4] *See, e.g.*, initial comments in Docket RM 21-17-000 of National Association of State Utility Consumer Advocates; Electricity Consumers Resource Council (ELCON), Iowa Office of Consumer Advocates; Office of the People's Counsel for the District of Columbia; Renewable Energy Buyers Alliance (REBA).
[5] *See, e.g.*, initial comments in Docket RM 21-17-000 of Edison Electric Institute (EEI), Ameren, AEP, AMP, Duke Energy, Duquesne Light, Entergy, Eversource, Exelon, National Grid, PG&E, PPL, PSEG, and Southern.

officials,[6] cooperative and municipal utilities,[7] and federal agencies.[8] It is rare to find such wide consensus across the entire power sector on a need for action. FERC must heed this call and reform its transmission planning regulations to meet the needs of the future grid.

A. Most Stakeholders Agree that the Transmission Planning Reforms in Order No. 1000 Have Failed to Materialize

As PIOs discussed in our initial comments, the benefits envisioned from the transmission planning reforms in Order No. 1000 have largely failed to materialize.[9] It is striking that most stakeholders, even those with vastly different underlying interests, agree on this point.[10] Among the stakeholders that argue that the Commission's transmission planning rules are insufficient are consumer groups, utilities, state officials, cooperative and municipal utilities, and federal agencies. To remedy these unjust and unreasonable outcomes, the Commission must act expeditiously to reform its rules concerning transmission planning, cost allocation and generator interconnection.

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[6] *See, e.g*, Initial comments in Docket RM 21-17-000 of National Association of Regulated Utility Commissioners (NARUC); Jay Inslee - State of Washington Governor; Arizona Corporation Commission; California PUC; Commonwealth of Massachusetts Department of Energy Resources; Maryland Energy Administration; Massachusetts Attorney General Maura Healey; Minnesota Department of Commerce; New England States Committee on Electricity; New York State PSC and NYSERDA; NJ Board of Public Utilities; North Carolina Utilities Commission Public Staff; Oklahoma Corporation Commissioner Dana L. Murphy; Oregon PUC; Organization of MISO States; Pennsylvania PUC; SPP Regional State Committee; State Agencies (Connecticut Attorney General, Connecticut Department of Energy and Environmental Protection, Connecticut Public Utilities Regulatory Authority, Connecticut Office of Consumer Counsel, Attorney General of the State of Delaware, DC Attorney General, Office of the Illinois Attorney General, Attorney General of Maryland, Maryland Office of People's Counsel, Maine Office of the Public Advocate, Massachusetts Attorney General, Attorney General of the State of Michigan, Minnesota Attorney General, New Jersey Board of Public Utilities, Oregon Attorney General, Pennsylvania Office of Consumer Advocate, Rhode Island Attorney General, Attorney General of Vermont).

[7] *See, e.g.*, initial comments of California Municipal Utilities Association; East Kentucky Power Cooperative; Massachusetts Municipal Wholesale Electric Company, New Hampshire Electric Cooperative, Connecticut Municipal Electric Energy Cooperative, and Vermont Public Power Supply Authority.

[8] *See, e.g.*, Initial comments in Docket RM 21-17-000 of U.S. Department of the Interior, U.S. Department of Energy ("DoE Comments").

[9] Comments of Public Interest Organizations, Docket RM 21-17-000, (Oct. 12, 2021) Accession No. 20211012-5519, at 7-12 (hereinafter "PIOs Initial Comments").

[10] *See* Grid Strategies, *Broad Support for Proactive Transmission Planning in FERC ANOPR Docket RM21-17* (Nov. 29, 2021) (listing 174 entities and 59 consumer organizations expressing support in this proceeding for proactive planning for the future resource mix).

Planning reforms should mandate scenario-based approaches to most effectively plan for likely future conditions. Understanding why Order No. 1000 failed is critical to improving it.

The comments in this record show that the current transmission and interconnection planning processes simply are not anticipating many future needs, fail to cost-effectively address what needs they do identify, and do not contain adequate protections against anticompetitive behavior. That means that consumers are paying for the wrong transmission, which is inherently unjust and unreasonable. Our comments below show that FERC must act expeditiously to reform its rules concerning the transmission planning process to set minimum requirements to effectively plan for anticipated future generation.

This proceeding is one of many in which there is overwhelming evidence that the existing rules, regulations, and practices affecting transmission planning have led to a system whose rates, charges, and classifications are unjust, unreasonable, unduly discriminatory and preferential.[11] State policies increasingly require load-serving entities to supply low-carbon power, creating a legal obligation for FERC to support these mandates through transmission.[12] At the same time, we are seeing widespread private investor shifts toward a decarbonized economy. Both of these forces are rooted firmly in consumer demand for zero-emission power, building, and transportation sectors and for greater control over their own contribution to these systems. Even absent policy support, the levelized cost of new-build wind and solar resources is becoming competitive with

[11] *See*, *e.g.*, Order No. 890, Preventing Undue Discrimination and Preference in Transmission Service, 72 Fed. Reg. 12,266, 12,318 (2007) ("Taken together, this lack of coordination, openness, and transparency results in opportunities for undue discrimination in transmission planning.").

[12] *See* 16 USC 824q(b)(4). FERC shall 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 the load-serving entities…." *See also* 16 U.S.C 824q(a)(3) (defining "service obligation" to include requirements created by state law).

traditional supply; this trend is likely to continue as renewable technologies increase in efficiency and scale.[13]

The result is plain to see in generation development: renewable resources now make up over 90% of PJM's interconnection queue and form the vast majority of interconnection requests in every PJM state.[14] In MISO, 64 GW (or 83%) of the resources in the interconnection queue are renewables[15] and 90% of ISO-NE's queue is carbon-free.[16] Despite this push toward a decarbonized electric sector, the transition to renewable generation, storage, and behind the meter resources is being threatened and potentially thwarted by those with control over the transmission system, all of whom benefit from transmission project redundancies and many of whom have vested interests in existing resources that would face increased competition from a properly functioning transmission planning regime.

As the Commission found in Order Nos. 888, 890, and 1000 – and as reflected in the FPA itself – anti-competitive forces in transmission access are endemic to the system and denial of open access to transmission starts at the planning level. The easiest way to deny access and prevent competition is for transmission owners to simply freeze an existing transmission system that is only designed to support existing resources and inadequate to accommodate the needs of alternative generation resources or new grid technologies. This is exactly what the last decade of overwhelming reliability-only predominantly right of first refusal (ROFR)-eligible local project

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[13] Lazard, *Levelized Cost of Energy, Levelized Cost of Storage, and Levelized Cost of Hydrogen* (Oct. 28, 2021), https://www.lazard.com/perspective/levelized-cost-of-energy-levelized-cost-of-storage-and-levelized-cost-of-hydrogen/.

[14] PJM, *PJM Interconnection Queue Status Update*, at 8-9 (Nov. 4, 2020), https://www.pjm.com/-/media/committees-groups/committees/pc/2020/20201104/20201104-pc-info-only-pjm-queue-status-update.ashx.

[15] MISO, *Storage project applications surpass Wind for the first time* (Sept. 15, 2021), https://www.misoenergy.org/about/media-center/2021-generator-interconnection-queue-applications-set-new-record/.

[16] ISO Newswire, *A queue and a curve: Signs in New England of a greener grid this Earth Day* (Apr. 22, 2021), https://isonewswire.com/2021/04/22/a-queue-and-a-curve-signs-in-new-england-of-a-greener-grid-this-earth-day/.

builds across the country[17] has achieved. But as transmission owners have successfully avoided achieving the spirit of Order No. 1000 over the last 10 years, the Commission's concerns that were once described as the "theoretical threat" of not being prepared to meet anticipated changes in generation coming from public policy requirements[18] are now fully realized present problems that not only result in unjust, unreasonable, and unduly discriminatory rates and practices, but are impairing the current and future reliability and resilience of the nation's electricity grid.

B. Comprehensive and System-wide Transmission Planning Reform is Necessary to Ensure Just and Reasonable Rates

The ANOPR asserts that "[e]nsuring just and reasonable rates as the resource mix changes, while maintaining grid reliability, remains the priority in the regional transmission planning and cost allocation and generator interconnection processes."[19] We couldn't agree more. But it isn't simply the dramatic shifts in the resource mix that require changes in how transmission is planned; FERC's planning rules must also ensure sufficient and reliable transmission in the face of increasingly extreme weather. The cost of not doing so is simply too high to bear. As FERC's own staff reports, at least 210 people died due to power losses during the extreme cold weather in February 2021 alone, which also caused between $80 and $130 billion in direct and indirect losses to the Texas economy.[20] These losses should not be unexpected – a study showed that the eastern

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[17] PIOs Initial Comments at 52-53 (citing Brattle-Grid Strategies Report at 15, Table 2). *See also id.* at iii, 2 (noting that "[w]hile the U.S. has recently been investing between $20 to $25 billion annually in improving the nation's transmission grid, most of this investment addresses individual local asset replacement needs, near-term reliability compliance, and generation-interconnection-related reliability needs without considering a comprehensive set of multiple regional needs and system-wide benefits. In MISO, for example, baseline reliability projects and other local projects approved through the annual regional transmission plan have grown dramatically since 2010 and have constituted 100% of approved transmission for the last three years and 80% since 2010").

[18] Order No. 1000 at PP 52-53.

[19] ANOPR at P 3.

[20] FERC - NERC - Regional Entity Status Report: The February 2021 Cold Weather Outages in Texas and the South Central United States, at 9-10 (Nov. 2021) (hereinafter "FERC-NERC Cold Weather Report").

states could each have saved $30-40 million for each GW of stronger transmission ties among themselves or to other regions during the Bomb Cyclone cold snap in 2017-2018.[21]

Several commenters opine that no action is necessary or that transmission reform efforts should focus first on targeted reforms to immediate problems, such as the undeniably backlogged interconnection queues.[22] But targeted enforcement or incremental transmission planning reforms will neither fix any of its broken elements nor meet the Commission's responsibility under FPA Section 206 to correct all the unlawful practices established as part of this record. Nothing short of comprehensive and system-wide transmission planning reform will effectively remedy the injustices that currently plague transmission planning across the country. The primary reason for this is that just and reasonable transmission planning that minimizes unnecessary and duplicative costs to consumers and maximizes competition for all resources must start with an interregional planning process that incorporates information from the local and regional levels – in short, everything in planning is interconnected and fixing interconnection queue problems is predicated on fixing regional planning and fixing regional planning also relies on joint interregional planning. Trying to tackle transmission planning by starting with any one of these pieces alone is destined to fail because the resulting processes won't reflect the reality of our energy future. In addition to unjustly leaving in place unlawful practices in any postponed areas, a piecemeal approach also presents a higher administrative burden for the Commission, stakeholders, and planning authorities, who will be locked in multiple cycles of technical conferences, rulemakings, compliance orders, and litigation that may ultimately conflict with one another.

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[21] Grid Strategies, LLC, *Transmission Makes the Power System Resilient to Extreme Weather*, at 2 (July 2021), https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf.
[22] *See, e.g.*, North Carolina Utilities Commission Initial Comments at 13-15; Pennsylvania Public Utility Commission Initial Comments, at 13-15.

Moreover, there is simply no time or justification for further delay. The record on the injustice of the transmission planning system extends back decades, as does the insufficiency of rules based on voluntary coordination and "consideration" of unspecified benefits.[23] The Commission tried to address transmission planning issues in 2016 through a Commissioner-led technical conference that discussed issues related to competitive transmission development.[24] The Commission sought and received hundreds of written comments following that technical conference. Yet no reforms were made. The Commission cannot allow that to happen again.

More importantly, it is now clear that the Commission faces a moral imperative to address the increasing number of deaths and crippling economic impacts to consumers attributable to the foreseeable impacts of extreme weather on system reliability and resiliency, the prevention of which will rely extensively on mandatory and effective interregional and regional transmission. Similarly, several state clean energy policy projects have already been unjustly delayed due to transmission planning failures and these delays will be compounded by the enormous volume of clean energy resources that are scheduled to come online in the next decade. The failure of transmission owners and planning authorities to accommodate state energy policies unjustly impinges on state authority over generation expressly granted to them under FPA Section 201.

At the November 15 Technical Conference, there was much discussion about the supposed tradeoff between mandatory requirements and flexibility. The idea that these concepts are incompatible with each other is a red herring. As Lauren Azar stated when asked about this issue at the conference, it can and should be a "yes/and" proposition.[25] Allowing flexibility often results

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[23] *See, e.g.,* Order No. 1000 at P 203 (requiring only "consideration" of public policy).
[24] FERC Notice of Technical Conference, Competitive Transmission Development Technical Conference, Docket No. AD16-18-000 (Mar. 17, 2016).
[25] November 15 Technical Conference, transcript forthcoming.

in a race to the bottom where if stakeholders cannot agree, the planning region does not to include it in its plan. Thus, as more fully discussed below, FERC must institute rules that establish minimum criteria for both the process and the substance of transmission planning, and put the industry on notice that projects arising from planning processes that do not meet FERC's standards lose their easy path to ratepayer-guaranteed returns. However, such mandatory rules would still respect regional differences because what ultimately goes into these plans will depend on what legal requirements exist in each region.

Finally, we recognize that some RTOs are currently evaluating changes to their transmission planning and stakeholder processes. FERC can set minimum enforceable requirements that are complimentary to these processes without disrupting them. In any event, FERC cannot wait to see if these processes result in meaningful reform before taking action to get transmission and interconnection planning right. It takes time for FERC to promulgate a rule, planning regions to submit compliance filings, and for those compliance filings to go into effect. Improving the reliability and resilience of the electric system simply cannot wait.

C. The Record in the ANOPR Provides Solutions to Form the Basis of a Holistic Transmission NOPR that Achieves Effective and Just Transmission Planning

The record in this proceeding provides clear solutions to form the basis of a holistic transmission NOPR that provides sufficient mandates to achieve effective, just, and non-discriminatory transmission planning while recognizing the differing needs across the nation's regions and localities. The following reforms should form the backbone of the Commission's transmission planning reforms:

1) Only transmission investments resulting from a planning process meeting strict criteria for independence and rigor should be presumed prudent and granted high returns on investment ("ROI"). Transmission investments made outside of adequate planning processes but seeking rate recovery should bear the burden of demonstrating prudence

and, if prudent, only be awarded an ROI appropriate with the lower risk and preferential financing available to a monopoly provider.

2) To be deemed independent, the body carrying out regional transmission planning should, at a minimum:
    a. Meet or exceed the independence criteria established for RTOs in Order Nos. 888 and 2000.
    b. Meet or exceed the stakeholder responsiveness criteria established for RTOs in Order No. 719.
    c. Have the technical capability to perform planning functions without reliance on assistance from incumbent transmission owners, and have unconditional access to all technical information required to perform those functions.
    d. Be free of conflicts of interest that arise from having transmission owners as clients or members.

3) To be deemed sufficiently rigorous to enjoy a presumption of prudence, a planning process should:
    a. Incorporate multiple futures scenarios encompassing at least the entire planning region.
    b. Use a planning horizon of at least 15 years.
    c. Plan to a minimum set of criteria, including anticipated future generation, existing and future constraints, asset age, and reasonably possible future weather scenarios using regionally applicable weather and climate projections.
    d. Utilize forecasts based on reasonable estimates of the type and location of anticipated future generation, storage, and new grid-enhancing technologies occurring over the planning horizon.
    e. Incorporate federal, state, and local policy goals and requirements; publicly-stated corporate and utility procurement targets and resource plans; reasonable estimates of market-based generation, electrification, energy efficiency, demand response, and distributed energy resources levels based on current trends.
    f. Place a value on reliability and resilience and incorporate extreme weather risks using probabilistic techniques.
    g. Fully consider all the costs and benefits of each possible project, without the 'siloing' common to current approaches and using an objective approach to measuring intangible and low-probability benefits.
    h. Result in a system-wide portfolio of projects that, taken as a whole, maximize expected value for ratepayers.
    i. Provide opportunities for and fully incorporate input from government agencies, the private sector, academia, and the general public.
    j. Be sufficiently transparent that capable third parties can verify and duplicate results.

4) Require planning regions to prepare joint interregional plans with common assumptions and methods. Each regional plan needs to evaluate the economic value of locating some generation in other regions, and the value of interregional transfers under

different reasonable scenarios including severe weather scenarios. All transmission planners must be required to determine whether any regional projects would obviate the need to replace aging assets or whether replacement of aging assets could be adjusted or optimized to address other transmission needs at the same time.

5) Allocate costs to all beneficiaries using objective criteria, following *ICC v FERC*[26] and other relevant case law. For policy-driven projects that do not otherwise meet cost-benefit criteria, it is reasonable for the sponsor of the policy to bear the costs in excess of expected benefits. Generators can and should pay for some of these costs given that they receive some benefit in terms of access, but they should not exclusively pay for transmission that benefits others.

6) Require transmission plans to be filed under Section 205 and regularly updated, perhaps every 3 years. Allow for public comment on plans similar to a state IRP proceeding and establish "best available data and forecasting methodologies" as the standard for review. Following this process, investments made following a FERC approved transmission plan are presumed prudent and earn a favorable ROI, possibly to include incentives.

PIOs discussed most of these reforms in detail in its initial comments. The comments below primarily serve to flesh out issues in response to discussions held during the September 15, 2021 Technical Conference or raised by other stakeholder comments in this docket.

II. Proposed Reforms

A. FERC Must Require Transmission Planning Entities to Plan for Local Transmission Needs in the Regional Transmission Planning Process

The current transmission planning rules result in transmission planning that is far too fragmented, producing mostly local transmission upgrades in lieu of meaningful regional or interregional transmission.[27] Order No. 1000's interregional requirements arose in part on the fact that, at the time, "[p]ublic utility transmission providers [were] under no affirmative obligation to develop a regional transmission plan that reflects the evaluation of whether alternative regional

[26] *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014); Illinois Commerce Comm'n v. Fed. Energy Regulatory Comm'n, 576 F.3d 470 (7th Cir. 2009) ("ICC v. FERC"); Illinois Commerce Comm'n v. Fed. Energy Regulatory Comm'n, 756 F.3d 556 (7th Cir. 2014) ("ICC II").

[27] *See* PIOs Initial Comments at 49.

solutions may be more efficient or cost-effective than solutions identified in local transmission planning processes."[28] To remedy this, Order No. 1000 adopted reforms that required "public utility transmission providers[29] to participate in a regional transmission planning process that evaluates transmission alternatives at the regional level that may resolve the transmission planning region's needs more efficiently and cost-effectively than alternatives identified by individual transmission planning entities in their local transmission planning processes."[30] However, as PIOs and many other commenters have pointed out, far too many local projects are approved without being subject to the regional transmission planning process, or simply 'stapled on' to a regional plan without meaningful review.[31] Initial comments from other parties echo this point. For example, the Michigan PSC asserts that "there is a glaring lack of transparency into how [local] projects are planned, prioritized, and scheduled, as well as what their final costs will be, and whether there may be more valuable or less-costly alternatives."[32] These practices are contrary to the goals and requirements of Order No. 1000 itself. Our initial comments provided evidence from a Brattle-Grid Strategies Report of the magnitude of the inefficiencies in the transmission planning processes, which we will not repeat here.[33]

Many commenters have provided examples of this problem, far more than we highlight here. For example, the California Public Utilities Commission ("CPUC") points out that California

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[28] Order No. 1000 at P 3.
[29] Hereinafter, "transmission planning entities."
[30] Order No. 1000 at P 6.
[31] PIOs Initial Comments at 45-46.
[32] Michigan PSC Initial Comments at 10.
[33] PIOs Initial Comments at 52-53 (citing Brattle-Grid Strategies Report at 15, Table 2). *See also id.* at iii, 2 (noting that:
"[w]hile the U.S. has recently been investing between $20 to $25 billion annually in improving the nation's transmission grid, most of this investment addresses individual local asset replacement needs, near-term reliability compliance, and generation-interconnection-related reliability needs without considering a comprehensive set of multiple regional needs and system-wide benefits. In MISO, for example, baseline reliability projects and other local projects approved through the annual regional transmission plan have grown dramatically since 2010 and have constituted 100% of approved transmission for the last three years and 80% since 2010").

utilities have prioritized investment to repair or replace transmission because they can build such projects without being subject to any oversight.[34] ELCON notes that FERC's current transmission planning rules have "led to perverse incentives for incumbents to keep projects small to avoid competition and transmission developers to avoid communication and data sharing in order to remain competitive."[35]

A handful of commenters argue that the Commission should continue to allow utilities to plan for local needs outside of a wider analysis of regional and interregional needs because of the need for local reliability; these often self-serving arguments are disingenuous at best.[36] Nobody is arguing that transmission should not be planned to meet local reliability needs. But the record shows that a planning sequence that addresses local reliability needs prior to and outside of the identification and evaluation of regional and interregional transmission needs stymies efficient, cost-effective, and transparent solutions that serve all needs.[37] For example, Union of Concerned Scientists ("UCS") provided concrete evidence that over a 4-year period, AEP proposed at least 10 individual transmission upgrades for the Columbus, OH area to PJM stakeholders.[38] This piecemeal approach to transmission upgrades obscured ways in which the regional transmission planning process could have produced a more efficient solution for the area. While UCS was unable to produce a more efficient or cost-effective solution when looking at alternatives to each individual proposal, we agree with UCS that "Order 1000, the laws of physics, and appropriate economic comparison dictate that the comparison would need to be based on the presentation of

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[34] CPUC Initial Comments at 2-3.
[35] ELCON Initial Comments at 11.
[36] *See, e.g.*, EEI Initial Comments at 6; AEP Initial Comments at 2; East Kentucky Power Cooperative Initial Comments at 2. *See also* State Agencies Reply Comments at 10-14.
[37] *See, e.g.*, CPUC Initial Comments at 4; PIOs Initial Comments at 11.
[38] UCS Initial Comments at 26-28.

all the costs of these eight or more line upgrades and the costs of an alternative that addresses as many of those upgrades as the physical conditions allow."[39] New York City similarly makes clear that planning for transmission by only looking at local or regional needs is insufficient because one project may meet regional needs but not solve local needs while another regional project could be the most efficient overall solution because it solves both regional and multiple local needs.[40]

Given the clear benefits of incorporating local needs into a wider level evaluation of transmission system needs, FERC must modify its transmission planning regulations to require regional transmission planning processes that plan for local transmission needs as part of the regional transmission planning process. And it must do so in a way that eliminates the loopholes that allow utilities to plan most transmission through opaque and balkanized local processes. This will produce more efficient and cost-effective transmission. In particular:

- Transmission owners must notify planners of expected needs to replace or conduct major maintenance on aging facilities with sufficient time for multiple planning cycles to evaluate alternatives to simple replacement. Proposals to replace or upgrade existing facilities (including upgrades under the guise of maintained) should be subject to the same cost-benefit analysis as any other project, and only approved if they are superior to other alternatives.

- Projects identified on the basis of data not available to regional planners, or alleged to be necessary to meet 'surprise' immediate reliability issues should be considered presumptively anticompetitive and earn non- remunerative ROIs.

- The sponsor of transmission projects that preempt projects identified in regional plans should bear the burden of demonstrating that the regional plan is unjust or unreasonable.

[39] *Id*. at 27-28.
[40] New York City Initial Comments at 19-20.

B. FERC Must Strengthen the Independent Planning Process Requirements and Incentives

One of the most important loopholes to close is the undue influence (if not effective control) transmission owners maintain over the transmission planning process. As set forth in PIOs' Initial Comments, to truly level the transmission planning playing field between RTO and non-RTO regions, FERC must align requirements and incentives for all transmission owners to proactively participate in the interregional and regional planning processes by strengthening independent planning requirements and requiring all regional planning entities to meet them.[41] In particular, PIOs proposed that FERC require RTOs to create a new planning-only membership category limited to transmission planning and information sharing. This would give RTOs authority to identify transmission needs, assess benefits, and recommend cost-recovery allocations for regionally planned projects but not section 205 rights over the transmission facilities owned by planning-only members.[42]

Bodies other than RTOs—e.g., some evolution of the WECC—could also serve as the independent regional planner, so long as they meet the same criteria for independence and planning processes. Indeed, regional planners need not be a membership organization of any kind. FERC has clear authority to order transmission owning utilities to provide sufficient information for a planner to do its job without any requirement the transmission owner 'join' anything. However, in order to ensure a level playing field between RTO and non-RTO planning processes, the Commission must incent participation in independent regional planning and ensure that transmission owners who do not cannot evade compliance with minimum transmission planning requirements necessary to ensure just, reasonable, and non-preferential rates and practices,

[41] PIO Initial Comments at 65-69.
[42] *Id.* at 68.

including by fundamentally increasing independent oversight of all planning processes and heightened prudence review of transmission cost recovery filings occurring outside of an independent regional plan.[43]

This call for increased independent planning requirements has been raised by the vast majority of stakeholders in this proceeding. In addition to the overwhelming support for requiring all regions to employ an Independent Transmission Monitor (discussed further below), many supporters of which would imbue it with an active role in planning,[44] the California PUC, California Department of Water Resources, Electricity Transmission Competition Coalition, Harvard Electricity Law Initiative, and LS Power all call for FERC to only presume as prudent those projects approved in an independently administered or competitive transmission planning process.[45] Pacific Gas & Electric urges the Commission to increase interregional planning by encouraging the development of RTO/ISOs in the West and the U.S. Department of Energy asks the Commission to consider incentives for new regional transmission facilities that would produce significant customer benefits.[46] The Pennsylvania PUC urges reconsidering eligibility for an RTO participation adder where supplemental projects are planned outside of the regional planning process.[47] In sum, there is widespread consensus that FERC must do more to create, monitor, and enforce structurally independent transmission planning across all planning regions.

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[43] *Id*.
[44] *See* Grid Strategies, "Broad Support for Proactive Transmission Planning in FERC ANOPR Docket RM21-17" (Nov. 29, 2021) (listing 174 entities and 59 consumer organizations expressing support in this proceeding for proactive planning for the future resource mix).
[45] CAPUC Initial Comments at 4; CA DWR Initial Comments at 18; Harvard Electricity Law Initiative Initial Comments at 49-50.
[46] Pacific Gas & Electric Initial Comments at 10; U.S. DOE Initial Comments at 32.
[47] PAPUC Initial Comments at 17-18.

C. FERC Must Mandate Holistic Interregional Planning Processes with Clear Minimum Criteria

Order No. 1000 found that effective interregional planning was necessary to ensure just, reasonable, and not unduly discriminatory rates.[48] However, experience has shown that, for all practical purposes, the interregional coordination process required by Order No. 1000 does not produce effective results. For many planning regions, this coordination process has essentially become a paper exercise, failed to identify much less implement needed projects,[49] and consequently has failed to alleviate unlawful rates and practices identified by the Commission as requiring an expeditious remedy over 10 years ago — the need for which has only grown more pressing since. As PIOs made clear in our initial comments, it is therefore not sufficient to simply reform the existing interregional coordination process. Nor would it be appropriate, as some suggest, to kick the interregional planning can down the road in favor of addressing smaller issues such as interconnection reform. Rather, FERC needs to create and mandate effective joint interregional *planning* requirements as in integral part of a single comprehensive and holistic transmission planning rule that incorporates the criteria below.[50]

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[48] Order No. 1000 at PP 8, 345, 350, 368-73. Of note, the Commission held that:

While we recognize that significant progress with respect to the development of open and transparent transmission planning processes has been made around the country, the existing transmission planning processes nevertheless do not adequately provide for the evaluation of proposed interregional transmission facilities or the identification of interregional transmission facilities that could address transmission needs more efficiently or cost-effectively than separate regional transmission facilities. Because such interregional transmission coordination helps to ensure that rates, terms, and conditions of jurisdictional service are just and reasonable and not unduly discriminatory or preferential by facilitating more efficient or cost-effective transmission infrastructure development, we conclude that the interregional transmission coordination reforms adopted in this Final Rule are necessary and should not be delayed.

Id. at P 370.

[49] PIO Comments at 45 (describing interregional planning process meetings in RTOs/regions).

[50] PIO Initial Comments at 99; *see also* ELCON Initial Comments at 11.

1. Interconnection queue woes must be addressed through comprehensive interregional and regional reforms, not the other way around.

Evidence throughout this docket establishes that effective interregional planning capitalizes on the enormous economies of scale and ability to address multiple benefits at once to drive far more cost-effective and robust transmission solutions across the grid than are currently generated from the primarily local and reliability-only driven planning that occurs today. Put another way, due to the failure of regions to proactively jointly plan and implement meaningful interregional transmission projects, consumers are currently unjustly and unreasonably facing enormous excess costs for a less reliable and inadequately-prepared grid. Because effective interregional planning incorporates the identification of regional and local needs to find opportunities to address multiple needs at once and usually with fewer projects, the sequence of transmission planning must be reversed to start with interregional planning. This is especially critical in a moment where historically unprecedented investments in transmission are necessary to meet *all* of the current transmission drivers—reliability, economic, and public policy—and where Congressional has directed billions of dollars be invested in building interregional transmission.[51] Given that large-scale transmission projects often take up to a decade to come online and many states have generation and electrification requirements that are expected to come online in that time frame, delaying interregional reform will not only thwart meeting these crucial needs, it will also simply perpetuate the injustice of the entire transmission planning process. Because what gets built at any level is dependent on what gets planned at every level, if the

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[51] *See* DOE Fact Sheet: *The Bipartisan Infrastructure Deal Will Deliver for American Workers, Families and Usher in the Clean Energy Future* (Nov. 9, 2021), https://www.energy.gov/articles/doe-fact-sheet-bipartisan-infrastructure-deal-will-deliver-american-workers-families-and-0.

Commission is to successfully reform transmission planning at all, it must issue a comprehensive and holistic transmission planning rule that addresses necessary reforms on every level.

a. The interconnection queue is the tail, not the dog

There has been some discussion in this docket questioning whether the Commission should first focus reform efforts around a smaller need of near-universal and immediate concern: interconnection queue backlogs. But the problems of the interconnection queue are merely a symptom of the failure to effectively plan transmission at the interregional and regional levels. Commenter Enel Green Power North America's (Enel) has submitted an excellent proposal for interconnection reform,[52] discussed further below in Section II.F.2. But it is critical to note that the developers who are the primary beneficiaries of interconnection queue reform have made clear that most interconnection problems stem from the fact that as currently structured, "generator interconnection and regional transmission planning processes proceed on largely separate tracks and there is little to no joint optimization of transmission projects that facilitate interconnections for new generation and transmission projects that meet the . . . [multiple] needs of system loads" and without which "there are no means to jointly assess the benefits and allocate the costs of transmission projects that yield benefits to both system loads and new generation."[53] Enel explicitly states that the success of their proposed interconnection queue reforms is predicated upon holistic transmission planning reform.[54] Piecemeal efforts to target generator interconnection outside of holistic transmission reform would thus not only fail to achieve the desired results, but would squander the significant investment made by all stakeholders to achieve

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[52] Comments of Enel North America, Docket No. RM21-17-000 (Oct 12, 2021) (hereinafter "Enel Initial Comments"), Accession No. 20211012-5505.
[53] *Id.* at Attach. A, at 3.
[54] Comments of Adam Stern, FERC Lead, Regulatory Affairs, Enel North America, Inc. – Panel 2, Docket No. RM21-17-000, at 3 (Nov. 16, 2021), Accession No. 20211123-4003.

necessary and lasting reform that would not only address generator interconnection woes, but would address unjust, unreasonable, and unduly discriminatory rates and practices system-wide.

b. Interregional and regional reforms are largely the same

One of the primary reasons for issuing a single and comprehensive transmission planning rule is that economies of scale exist in regulation as well. A comparison of recommended reforms for regional and interregional planning processes reveals that most of the necessary reforms on the interregional level mirror those on the regional level. As a result, including interregional planning reforms in the NOPR realizes far greater returns on a nominal extra investment. In particular, the identification of needs, assessments of benefits, and allocation of costs involve nearly identical minimum standards and nearly all of the same stakeholders.

Critically, neighboring regions need to adopt minimum metrics, methodologies, and modeling to comply with both regional and interregional requirements. But if the Commission were to go forward with a proposed rule that continues to allow each region to develop its own benefits metrics and models, if and when the Commission gets around to issuing an interregional planning rule, such differences would have to be addressed so that planning between regions can more seamlessly align. This means that planning authorities will have already invested heavily in one rule change only to have the pendulum shift and have to start the process over again.[55] The Commission must not waste the enormous and precious resources that go into complying with a rule and must right size reform efforts the first time.

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[55] In the meantime, it is a near- if not absolute certainty that whatever course the Commission chooses will involve litigation, and the issuance of a comprehensive and holistic transmission planning rule will also promote judicial economy and administrative burdens for the Commission, the planning authorities, and all stakeholders.

2. There is broad consensus that interregional projects protect consumers from unnecessary and redundant transmission projects and will improve reliability and resiliency

As in Order No. 1000,[56] the record in this proceeding is replete with evidence that interregional transmission projects unlock the ability to maximize net consumer benefits.[57] In her pre-conference comments, Technical Conference panelist Dr. Debra Lew cited to studies demonstrating that "multi-regional transmission dramatically lowers the cost of clean electricity by reducing the amount of capacity that must be built and the operating and maintenance (O&M) costs of running the system."[58] At the conference, Dr. Lew asserted that, as a result, interregional transmission provides substantial net benefits to consumers, even though consumers may sometimes pay slightly more up front for large-scale transmission, because this is more than made up for by reduced generation and operations costs.[59] ELCON, which represents large industrial consumers, agrees with this premise and recognizes that planning for transmission over a larger footprint will ultimately benefit consumers, stating "consumers may prefer to pay for a single interregional project rather than paying piecemeal for dozens of local or regional projects whose combined cost far exceeds that of the interregional project."[60] Eversource similarly argues that

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[56] Order No. 1000 at P 368-371.

[57] *See, e.g.*, ELCON Initial Comments, Pre-Conference Comments of Dr. David J. Hurlbut, and Pre-Conference Comments of Dr. Debra Lew. *See also* The Brattle Group, A Roadmap to Improved Interregional Transmission Planning (Nov. 2021), at B1–B3 and App. B (hereinafter "Brattle Roadmap Report"), attached hereto as Exhibit A.

[58] Pre-Conference Comments of Dr. Debra Lew at 1-2 (citing A. Bloom et al., *Transmission Planning for 100% Clean Electricity*, Energy Systems Integration Group (Feb. 2021)); P. Brown and A. Botterud, *The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System*, Joule (2020), https://doi.org/10.1016/j.joule.2020.11.013; A. Bloom et al., *The Value of Increased HVDC Capacity Between Eastern and Western U.S. Grids: The Interconnections Seam Study*, in IEEE Transactions on Power Systems (Sept. 2021), doi: 10.1109/TPWRS.2021.3115092; Midcontinent Independent System Operator, *Renewable Integration Impact Assessment*, Carmel, IN (Feb. 2021); C. Clack, *100% Clean By 2050: What does it look like?*, ESIG Spring Technical Workshop (Mar. 2 2021), Keynote Address.; Brown and Botterud, 2020; A. L. F. Acevedo et al., *Design and Valuation of High-Capacity HVDC Macrogrid Transmission for the Continental US*, in IEEE Transactions on Power Systems, vol. 36, no. 4, pp. 2750-2760 (July 2021), doi: 10.1109/TPWRS.2020.2970865.

[59] November 15 Technical Conference, transcript forthcoming.

[60] ELCON Initial Comments at 12.

being able to "right-size" a project to serve multiple needs should reduce the overall costs to provide the needed infrastructure due to more efficient siting, engineering, and construction of facilities.[61] It also notes that this reduces the environmental impacts of transmission and the burden on abutting property owners and local communities by constructing efficiently and minimizing road and safety impacts from duplicative construction efforts. Finally, siting, engineering and construction are resource intensive, so co-optimizing projects reduces overall effort and increase the speed of development for needed transmission.

A broad coalition of commenters agrees that eliminating existing barriers to interregional transmission planning will also improve reliability and resiliency in the face of increasing extreme weather events and will maximize benefits across regions. For example, NARUC states that "[e]ffective planning should strive to quantify benefits associated with enhancing interregional import and export capabilities, given the likelihood of future extreme weather events and related energy shortages."[62] Eversource stated in its comments that "[i]n New England, and likely across the country, increasing interregional transmission capability and capacity will support improved resilience to climate change and extreme weather events."[63] AEP noted that the challenges of large-scale intermittent generation integration and extreme weather impacts can be addressed more efficiently across regions rather than each region planning for these impacts alone.[64] Commonwealth of Massachusetts Department of Energy Resources noted that "[p]lanning

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[61] Eversource Initial Comments at 10-11.
[62] NARUC Initial Comments at 19.
[63] Eversource comments at 18-19. *See*, *e.g.*, February 2021 Cold Weather Grid Operations: Preliminary Findings and Recommendations, FERC Docket No. AD21-28 (Sept. 23, 2021), https://www.ferc.gov/media/february-2021-cold-weather-grid-operations-preliminary-findings-and-recommendations-ppt.
[64] AEP Initial Comments at 21.

fundamentals should be applied to the interregional planning processes to allow for the identification of interregional projects that maximize net benefits across service territories."[65]

3. <u>The current interregional planning process makes it virtually impossible to reap these consumer and reliability benefits</u>

Barriers to interregional planning make it virtually impossible to maximize net consumer benefits. Based in part on surveys conducted with stakeholders from across the power sector, a new report by the brattle group examines the reasons for the lack of major interregional projects since order no. 1000 was issued.[66] Brattle found that barriers fall into three interrelated categories: (1) priorities, alignment, and understanding; (2) planning process and analytics; and (3) regulatory constraints. Within these categories, brattle summarized the barriers disclosed during the surveys in table 2 of its report, which is set forth below: [67]

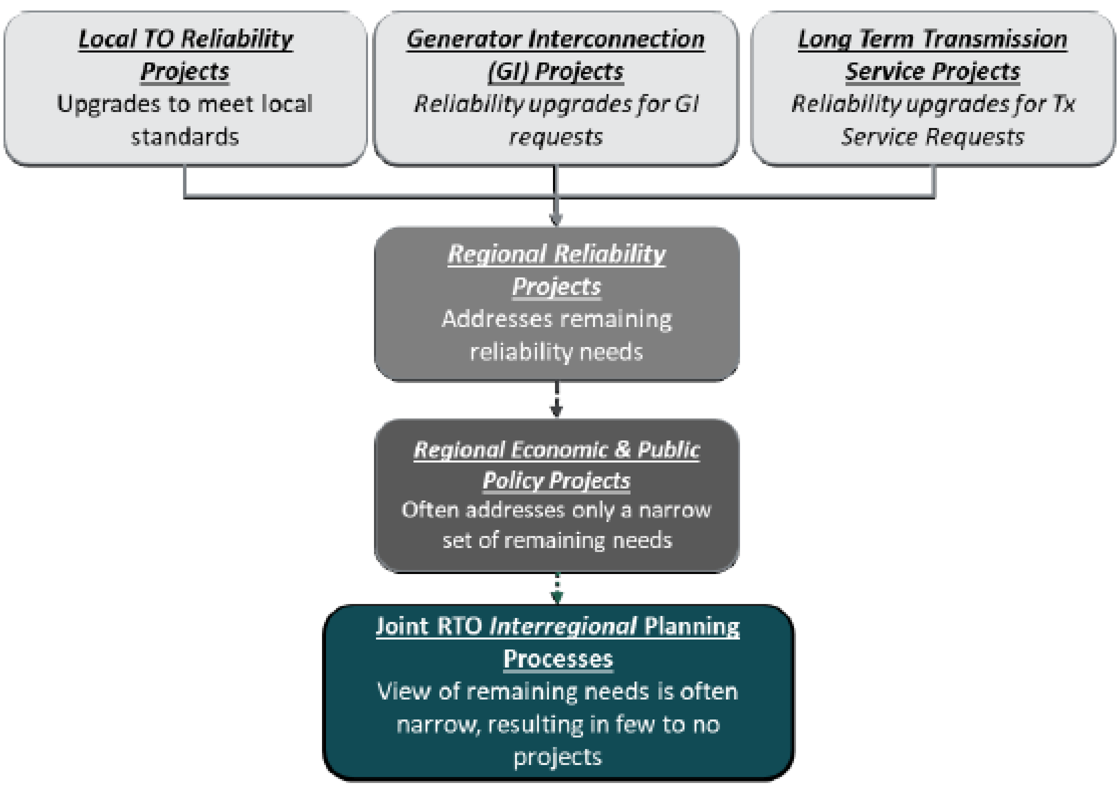
TABLE ES-1: SUMMARY OF BARRIERS TO INTERREGIONAL TRANSMISSION PLANNING AND DEVELOPMENT

A. Priorities, Alignment and Understanding	1. Insufficient leadership from RTOs and federal & state policymakers to prioritize interregional planning 2. Limited trust amongst states, RTOs, utilities, & customers 3. Limited understanding of transmission issues, benefits, & proposed solutions 4. Misaligned interests of RTOs, TOs, generators, & policymakers 5. States prioritize local interests, such as development of in-state renewables
B. Planning Process and Analytics	6. Benefit analyses are too narrow and often not consistent between regions 7. Lack of proactive planning for a full range of future scenarios 8. Sequencing of local, regional, and interregional planning 9. Cost allocation (too contentious or overly formulaic)
C. Regulatory Constraints	10. Overly-prescriptive tariffs and joint operating agreements 11. State need certification, permitting, and siting

[65] Commonwealth of Massachusetts Department of Energy Resources Initial Comments at 21.
[66] *See generally*, Brattle Roadmap Report,.
[67] *Id*. at B4, Table 2.

These barriers to interregional planning have created a gap in investments near and across market seams as regional planning authorities have shifted away from development along seams with neighboring regions and instead focus primarily on local and regional investments and generator interconnection requests. This shift is primarily a product of the existing transmission planning structure. Currently, transmission projects are separated into one of three separate silos that are generally addressed in the following sequence: (i) reliability and resilience needs driven by compliance with NERC and local reliability requirements; (ii) economic or market efficiency needs; and (iii) public policy needs, as shown in Figure 3 of the Brattle Roadmap Report below.[68]

FIGURE 3. PLANNING PROCESSES CURRENTLY USED IN RTOs TO IDENTIFY AND APPROVE TRANSMISSION PROJECTS



[68] *Id*. at B9.

Under the current structure of addressing local, then regional, then interregional needs, more than 90% of transmission projects are being driven by local and regional reliability-only projects that are implemented without a comparative assessment of economic costs and benefits.[69] This planning sequence also means that by the time all local and regional reliability-driven project and regional interconnection queue needs are addressed, there are few if any remaining needs that could be addressed more cost-effectively through interregional transmission. Additionally, these projects are approved before other needs and benefits that would come from larger solutions can even be considered and approved; as a consequence, there is little or no effort to find the most cost-effective solution to reliability-based projects.[70]

Commenters in this proceeding echo these findings. For example, Eversource notes that the regional transmission planning processes only considers the regional benefits of a proposed interregional project and ignores additional benefits associated with a project, "such as increased resource diversity, increased wholesale energy market competitiveness (i.e., reductions in market power), and improved resilience during extreme weather."[71]

As PIOs mentioned in our initial comments, a key problem in implementing interregional projects is attributable to the multistage approval process that requires a proposed solution to go through a coordinated interregional process as well as two separate regional approval processes, the so-called "triple hurdle" problem.[72] Because potential solutions must successfully meet three

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[69] *Id*..
[70] *Id.* at B10-B11.
[71] Eversource Initial Comments at 18.
[72] *See* PIO Initial Comments at 48 (noting that MISO and SPP have a joint planning committee responsible for carrying out a process that may arrive at identified solutions, at which point "each RTO considers the recommended inter-regional transmission solutions in its respective regional transmission planning process." Midcontinent Independent System Operator, Inc., Southwest Power Pool, Inc., 168 FERC ¶ 61,018, ¶ 2 (July 16, 2019)).

separate benefit-to-cost ratios, it is almost impossible for all three processes to result in one agreed upon solution, and thus nothing gets built. Several commenters, including the New Jersey Board of Public Utilities agree that the current process is outdated and ineffective, noting that "[i]nterregional planning, particularly across the PJM/New York seam, is effectively non-existent, constantly mired in litigation based on outdated Commission rules and cost allocation processes."[73] As a result, the existing interregional coordination process has essentially become a box checking exercise[74] that has produced no significant interregional projects since Order No. 1000 was issued. In non-RTO regions, there is no interregional activity to speak of at all.

4. Effective interregional planning requires comprehensive reform of the current transmission planning process

As in regional transmission planning, overcoming the barriers to interregional transmission will require similar comprehensive reforms. The Brattle Roadmap Report draws on stakeholder input as well as Brattle's decades of industry experience to identify key reforms that are necessary to make the interregional planning process effective.[75] These reforms include the items mentioned in Subsections II.C.3.a. – e. below.

a. Interregional system needs and solutions must be identified up front through a broader set of planning pathways

Primary among the necessary reforms for effective interregional planning is for FERC to reorder the sequence of planning and open multiple pathways for incorporating interregional transmission needs into the planning process. Informed in part by stakeholder input, the Brattle Roadmap Report identifies three potential pathways for effective identification of interregional

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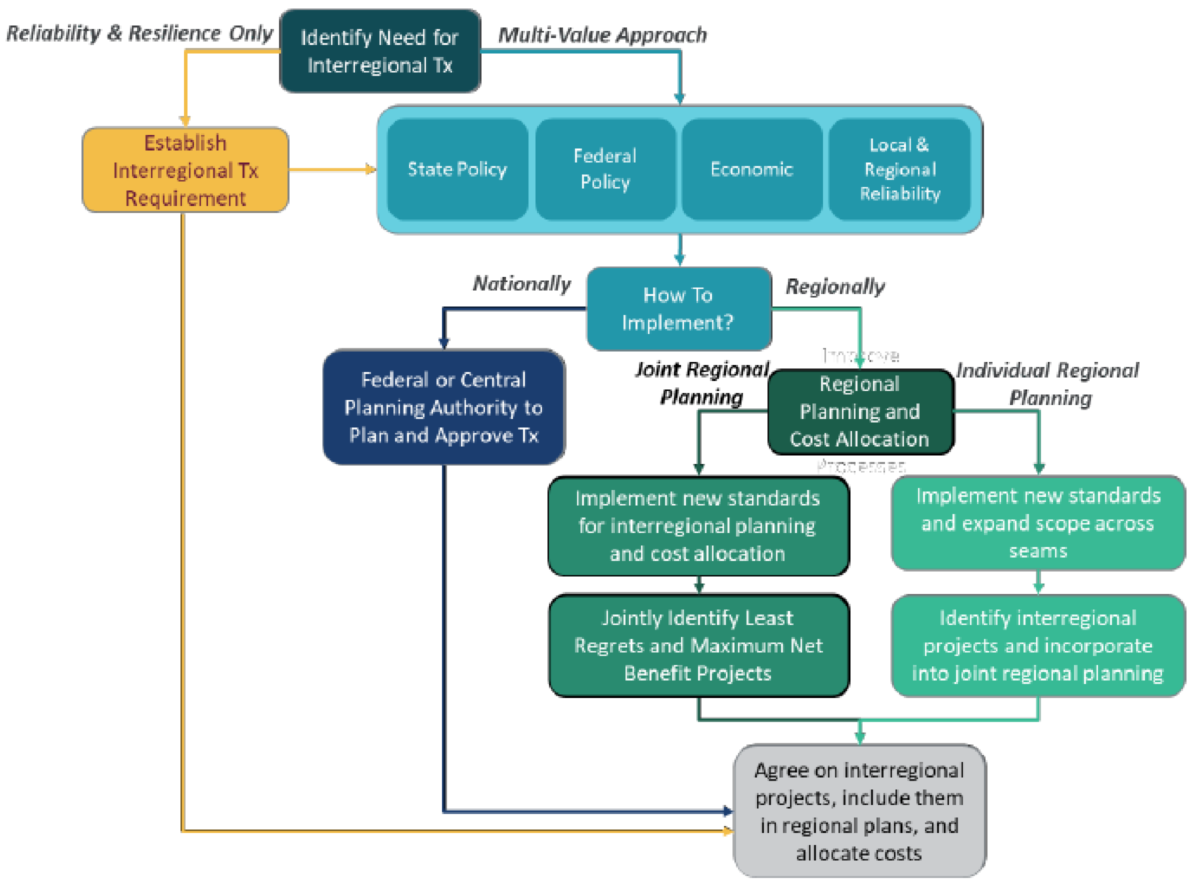
[73] New Jersey Board of Public Utilities Initial Comments at 3-4.
[74] PIO Comments at 45 (noting that the interregional coordination process for the Western Interconnect was reduced from an annual conference to single morning online session with report outs from three western planning regions with little time for stakeholder questions or input).
[75] Brattle Roadmap Report at B11-B13.

transmission needs as part of the planning process, as represented in Figure 4 from the Brattle Roadmap Report, shown below. [76]

FIGURE 4. PARALLEL PATHWAYS TO ESTABLISHING THE NEED FOR INTERREGIONAL TRANSMISSION



i. <u>FERC needs to incorporate interregional transmission solutions into mandatory reliability standards</u>

Several commenters highlighted that interregional transmission capacity plays a pivotal role in providing grid reliability and resiliency in the face of a changing generation landscape shifting to intermittent and weather-dependent resources and the increasing frequency of extreme weather systems with regional impacts that endure for days, weeks, or even seasons. For example,

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[76] *Id*. at 12, Figure 4.

the Kansas Corporation Commission ("KCC")—which has extensive experience with these issues—stressed that the ability to integrate intermittent resources and manage geographically dispersed generation is highly dependent upon the development of interregional transmission, but that despite best efforts to voluntarily address interregional planning, a variety of factors including parochial interests and differences in planning methodologies have and will continue to impede the identification and development of much-needed interregional projects.[77] KCC shared that its experience with Winter Storm Uri gave it an "acute appreciation for the substantial reliability and resiliency benefits" of import capacity, noting that while "benefits will mostly flow to large load centers and consumers of renewable energy resources, the KCC now believes cost allocation should consider the inherent reliability benefits to all regions of enhancing import-export capabilities during capacity shortfall events" and proposes requiring regions to identify and develop interregional projects that would equal at least 10% of each region's peak load.[78] PIOs agree with KCC and others on the call for a minimum interregional transfer capacity requirement as one of the key pieces of interregional transmission reform.

Commission staff's own analysis shows that during the severe cold weather event in February 2021, interregional transfer capability kept the catastrophic and deadly situation from being even worse.[79] It is no exaggeration to say that this interregional transfer capacity likely saved lives. The FERC-NERC Cold Weather Report states that:

> Unlike ERCOT, which can only import slightly more than 1,000 MW over its direct current ties, SPP and MISO imported power from other Balancing Authorities to make up for their increasing load levels and generation shortfalls, because the eastern part of the Eastern Interconnection did not have the same arctic weather conditions. Specifically, MISO was able to import large amounts of power from

[77] Kansas Corp. Comm. Initial Comments at 3, 7.
[78] *Id.* at 8, 11.
[79] FERC - NERC - Regional Entity Status Report: The February 2021 Cold Weather Outages in Texas and the South Central United States (Nov. 2021).

> neighbors to the east (e.g., PJM Interconnection, LLC), and SPP was able to transfer some of that power through MISO.[80]

The FERC-NERC Cold Weather Report also demonstrates in vivid and heartbreaking detail the deadly consequences caused by a lack of interregional planning, finding that at least 210 people died as a result of this extreme weather, that most died because of power outages, and that these outages caused direct and indirect economic losses of between $80 to $130 billion.[81] While Winter Storm Uri is a particularly consequential example of how important interregional transmission is to reliability, it is not the only one.[82]

Setting an actual reliability requirement could involve a number of different options. One potential pathway for addressing necessary interregional transmission is to direct NERC to incorporate interregional solutions into mandatory reliability requirements, as represented on the yellow path on the left side of Figure 4 above. Another option would be for the Commission to consult with relevant experts and stakeholders to establish a minimum interregional transfer capacity requirement. The Commission could also direct NERC to conduct such an analysis, perhaps in partnership with DOE and the National Labs.[83] The results of either process could then be incorporated into the NERC reliability standards. Another potential option is for regional planning authorities to develop policies requiring each region to meet a portion of its resource adequacy requirement from outside the region and demonstrate firm transfer capacity to deliver and accommodate those resources, as suggested by KCC. While PIOs believe that interregional

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[80] *Id.* at 14.
[81] *See id*. at 9 (citing Garrett Golding et al., *Cost of Texas' 2021 Deep Freeze Justifies Weatherization*, Dallas Fed Economics (Apr. 15, 2021), https://www.dallasfed.org/research/economics/2021/0415).
[82] *See, e.g.*, Brattle-Grid Strategies Report at 42-43; Brattle Roadmap Report at B24, B28; Grid Strategies, LLC, *Transmission Makes the Power System Resilient To Extreme Weather*, at 2, https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf.
[83] *See* 18 C.F.R § 39.11(a).

transmission adequacy must be mandatory, we believe that the Commission should hold a separate technical conference or paper hearing to determine how to best implement this requirement.

ii. Interregional planning is best conducted by a national planning authority

Another path for interregional planning is to have the process conducted by a national planning authority, represented in Figure 4 above in blue as the middle path. Because truly effective interregional transmission planning requires a level of independence and active cooperation between regions that runs counter to the structure and incentives of the existing planning authorities (especially those in non-RTO regions), PIOs continue to recommend that interregional planning be conducted by a new national planning authority with significant FERC and state participation.[84] We are not alone in calling for the creation of such an entity.[85] As the Brattle Group points out, federal oversight and broad stakeholder participation would "help ensure independence of the decision-making process" and mandatory participation by RTO and non-RTO regions would help level the transmission planning playing field between them.[86] "It would also provide a unique forum for states to participate, including through modernizing and aligning their siting processes, which would make successful development of interregional transmission far more likely."[87]

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[84] *See* PIO Initial Comments at 71-72.
[85] *See, e.g.*, Brattle Roadmap Report at B13, n. 12 ("ESIG's white paper, *Transmission Planning for 100% Clean Electricity* (2021): recommend[s] "that a national transmission planning authority be created to develop and implement an ongoing transmission planning process. . . that transcends regional and parochial interests. Such an organization will not obviate the need for regional planning, but should work with the regional planners and others to coordinate top-down and bottom-up needs and optimize solutions according to the national public interest."). *See also* Remarks of Allison Silverstein in FERC Docket AD21-13 (recommending a "National Electric Transmission Authority [that, among other functions, would] have the ability to work with federal agencies and states to identify preferred resource zones, find appropriate routes for new intra- and inter-regional lines to connect resource zones to loads, and use federal funds to help pay a portion of the costs of new backbone transmission.").
[86] Brattle Roadmap Report at B14.
[87] *Id*.

To implement such an approach, FERC could find that transmission rates are not just and reasonable without robust and independent interregional planning. FERC could then require public utility transmission providers to perform interregional planning through an independent entity. FERC has taken similar action in the past. For example, in Order No. 890, FERC directed public utilities, working through NERC, to modify available transfer capability-related standards.[88] FERC could take similar action here to require public utilities to work through an independent entity to plan interregional transmission. In conjunction with this action, FERC should also reverse its presumption that transmission expenses arising outside of any interregional independent planning processes are prudent and require public utilities to demonstrate that any such rates are prudent, as more fully described in PIO's Initial Comments.[89] Thus, FERC can implement this using both a carrot and a stick.

iii. <u>In the alternative, FERC can still facilitate interregional planning</u>

While a national planning authority would be optimal, there are other ways that the Commission could facilitate interregional planning. Many entities are capable of and willing to engage in interregional planning: through the national labs, the Department of Energy regularly conducts large-scale planning studies; *ad hoc* coalitions such as EIPC[90] look at interconnection-wide issues; and state governments may well have an interest in interregional planning.

The Commission can support and facilitate such activity in three ways:

1. As recommended by the Department of Energy in its comments, FERC needs to direct the regional planning entities to develop common models and methods, and to coordinate planning timelines.[91]

[88] *See* Order No. 890 at P 212.
[89] PIO Initial Comments at 61-65.
[90] The Eastern Interconnection Planning Collaborative. *See* https://eipconline.com/.
[91] *See* DoE Comments, responses to questions 4 (pp 12-15), and questions 20-23 (pp 32-35).

2. Acting through the Office of Public Participation, FERC can provide a pathway for interested organizations to demonstrate their *bona fides* and gain access to information, including CEII materials, needed to perform transmission studies.

3. Regional planners' stakeholder process should be the preferred means to provide input into transmission planning. However, in cases where regional planners are unable or unwilling to evaluate interregional projects that promise major benefits, the Commission can act either through *sua sponte* Section 206 or existing authority to order transmission connections.[92] Either of those paths give FERC more than ample authority to evaluate, and if appropriate, direct the solicitation and construction of interregional projects.

Ideally, such a process would be seldom used. Nonetheless, PIOs believe that in the absence of a national transmission planning authority, there must be some path for the Department of Energy and other entities of similar gravitas to fill the void and address matters of national infrastructure.

iv. Interregional planning by existing planning authorities must be restructured

Regardless of whether a national planning authority is established, regional planning must be reformed to prioritize the identification of interregional needs. As set forth in the multi-green pathway on the right side of Figure 4 above, planning processes need to be reformed to identify regional projects both on a top-down basis (as indicated in the dark green pathway) through planning processes conducted jointly by neighboring regions and through incorporation of bottom-up processes (as indicated in the light green pathway) where individual regional planning authorities integrate local and generation-related reliability needs into a multi-value regional transmission planning process by first looking across neighboring seams for interregional projects that can address multiple regional and local needs more cost-effectively than more incremental projects.[93]

[92] 16 U.S.C. 824a(b).
[93] Brattle Roadmap Report at B15-B16.

In both scenarios, the sequence and timing of planning analyses is critical, as is the need for mandatory reforms pertaining to the submission and transparency of information, the inclusion of stakeholders and states early in the process, and minimum standards for benefit and cost allocation criteria and methodology. Such reforms are necessary for planning authorities to shift away from a process driven primarily by addressing the urgent need of the moment, to proactively planning ahead for foreseeable system needs (including reliability needs and resource entry and exit) and meeting them through a broad evaluation of cost-effective solutions.[94]

b. Planning authorities need to proactively plan for future generation and load

Although all planners need to proactively plan for future generation and load, this is especially important at the interregional level, where projects routinely take 5-10 years to come to fruition. As with regional planning, to be effective, interregional planning must incorporate realistic long-term projections of the plausible future generation mix across the neighboring regions. It is at the interregional level that cost-effective solutions to meet multiple state policy objectives can be found, and where the potential development of renewable energy zones—which require holistic stakeholder and state participation to succeed—can be particularly beneficial. Further, the anticipated generation mix, public policy mandates, load profiles and load levels used in the planning models need to extend at least as far out as the time horizon of the relevant public policies, for example, meeting clean energy milestones by 2040 and 2050.[95] Additionally, planners need to focus not only how future generation and load will be impacted by the minimum requirements of any given public policy, but the potential maximum impacts of such policies as well as from the intersection between multiple public policies over time.

[94] *Id.*
[95] *Id.* at B7, n. 7.

c. Every transmission project must be analyzed on a multi-value, multi-driver basis

Like regional planning, interregional transmission planning must eliminate barriers that prevent reliability, economic, and public policy projects from being simultaneously and jointly planned and must instead require incorporate projects with multiple drivers and using multiple benefit values into interregional needs assessment—even when these drivers and values differ between regions. This is especially important in the interregional context, where interregional solutions provide significant benefits for each region, but the driver on each side of the seam may differ, such as where an interregional project may provide reliability benefits for one region but may meet public policy needs in another.[96] Additionally, barriers that prevent interregional projects from being considered due to different size and location thresholds in each neighboring region's transmission planning process must also be eliminated so that any cost-effective interregional project—such as a flow gate located in one region that addresses constrained flows in two or more regions—can go forward.[97] If minimum benefit-to-cost thresholds are utilized, they should not exceed 1.25, but lower thresholds should be acceptable if some of the benefits of interregional transmission projects are recognized qualitatively but have not been quantified.[98]

Especially critical to interregional planning is the standardization of metrics and methodologies. Simply put, regional entities cannot jointly plan if they are identifying needs, assessing benefits, and allocating costs using different criteria and methodology.[99] As PIOs and several other commenters have discussed, the Commission must set minimum standards expanding

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[96] *Id*. at B16-B18.
[97] *Id.*
[98] *Id.* at B27.
[99] Existing differences in benefits and cost allocation rules has proven to be one of the major barriers currently thwarting the identification of interregional project needs. *See* Brattle Roadmap Report at B18-B19, B23-B24, B25-B26.

the scope of transmission benefits that must be incorporated into transmission planning processes.[100] The Brattle Roadmap report proposes minimum criteria drawn from expanded multi-value benefits assessments that have been conducted across different RTOs and which are largely the same as those proposed for regional planning, set forth in Table 4 below.[101] To ensure that interregional projects can identify the most cost-effective solutions for all stakeholders, interregional planners also need to incorporate the full set of benefits provided by each region's

[100] *Id.* at 25, Table 4. Several parties discuss the necessity of expanding the scope of benefits used in transmission planning—*see, e.g.*, KCC Initial Comments at 8-9, LS Power Initial Comments at 41-48, Exelon Corp. Initial Comments at 12-14; ELCON Initial Comments at 6-8; EKPC Initial Comments at 4; Edison Electric Institute Initial Comments at 13-14; Massachusetts Dep't. of Energy Res. Initial Comments at 12, 16-17; Avengrid Initial Comments at 8-13; ITC Initial Comments at 5-6; Mass. Attorney Gen'l Initial Comments at 2-3; NARUC Initial Comments at 16-17, 52; National Grid Initial Comments at 7, 10, 13; New York City Initial Comments at 7-8, 15; NYTO Initial Comments at 14, 16; NextEra Initial Comments at 1-5; NYISO Initial Comments at 31; Office of the People's Counsel for the Dist. Of Columbia at 22-24, 27; SPP Initial Comments at 14.
[101] Brattle Roadmap Report at B22, Table 4.

local and regional transmission planning projects, since the goal of interregional transmission planning is to maximize economies of scale and resource conservation to deliver the most cost-effective transmission solutions system-wide.

Many commenters have stressed the need for flexibility to accommodate differences across regions, with which PIOs agree. But particularly in light of the pressing need for interregional

TABLE 4. ELECTRICITY SYSTEM BENEFITS OF TRANSMISSION INVESTMENTS

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

transmission to meet reliability, economic, and policy needs, "flexibility" cannot mean the ability to continue to do nothing. The Commission cannot continue to rely on the same broken process that includes no incentives to deliver different results. Rather, flexibility should be built into a mandatory process applicable to all planning authorities that drives outcomes meeting the particular interregional needs of the regions involved. For example, in addition to incorporation of minimum benefits that all regions must assess in identifying project needs, interregional planning authorities must also be required to jointly establish *additional* benefits metrics and cost allocation methodologies that pertain to region-specific issues (such as those related to particular state regulatory requirements) or are unique to particular interregional projects (such as the value of increased load and resource diversity).[102]

d. Planners must address uncertainties and high-stress grid conditions explicitly through scenario-based planning

Especially at the interregional level, near and long-term uncertainties must be explicitly considered as part of the transmission planning process. Because many if not most of the assets planned at the interregional level are larger projects with asset lives of fifty years or more, planning for such projects must identify needs and assess benefits on as long a time frame as possible. While long-term planning can introduce greater levels of uncertainty, contrary to the assertions of Potomac Economics,[103] experience thus far with effective long-term transmission planning has proven to be more cost-effective and less risky – not to mention less deadly – than the

[102] *Id*. at B26-B28.

[103] *See* Comments of Potomac Economic, Ltd., Docket No. RM21-17-000, Accession No. 20211013-5052 (Oct. 13, 2021) at 2-4. Potomac Economics alleges without explanation of their terms or support for their conclusions that while "large and costly new transmission facilities are sometimes the most cost-effective transmission investments, smaller discrete projects to eliminate limiting elements are more often the most cost-effective means to facilitate higher regional transfer capability." *Id.* at 3. Consequently, they advise that planning after "congestion patterns emerge can lead to the most effective transmission upgrades." *Id.* at 3. They conclude (again, without support) that they "do not believe it is advisable to mandate long-term planning studies" and should instead focus on "near-term emerging trends that are less uncertain than these longer-term factors." *Id.* at 4. Although they admit that they "have not studied the MVP investments in MISO in detail," they express concern with the "congestion associated with growing wind output in the North zone [that has grown] sharply over the past 3 years." *Id.* They then assert that "[g]iven the billions that were invested in the MVP projects to facilitate the delivery of renewable energy to the system, using a larger share of these resources to target the key constraints that are currently limiting wind output in MISO the most would have produced sizable savings and been consistent with the objectives of the MVP projects." *Id.* But this fails to acknowledge that the MVP planning occurred over 10 years ago, and in no way looks at the overall cost-effectiveness of that effort. Nor does it examine the critical question of how much worse that congestion would currently be had the MVP planning effort not occurred. If anything, Potomac Economics' concerns regarding recently-emerging wind constraints proves the point that long-term planning should look not simply at minimum requirements but also at plausible maximum growth.

alternative.[104] Forecasting uncertainties have been mitigated through the use of well-proven scenario-based modeling that examines a number of plausible needs bookended by highly likely future scenarios on one end and less-likely-but-plausible scenarios on the other and choosing those "least regrets" projects that are estimated to be cost-effective across a number of scenarios.[105] Further, a robust transmission grid offers insurance value, and a proper economic analysis needs to assess *both* the possible losses from a project not proving to be fully cost-effective *and* the possible losses that customers may face due to an insufficiently robust transmission grid.[106] By implementing "least regrets" projects that result from scenario-based planning techniques that model for uncertainty and weight for sensitivity, the risk of an uneconomic outcome is quite low, especially when compared to the increasingly high costs of failing to adequately prepare for the current and clearly foreseeable dramatic shifts in generation, load, and reliability needs that the current transmission system cannot meet.[107] As Philip Moeller, Executive Vice President, Business Operations Group and Regulatory Affairs at EEI stated during the Technical Conference, there is no such thing as a stranded transmission asset, and the long-term benefits of well-planned

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[104] *See, e.g.*, Brattle-Grid Strategies Report at 1-12, App. A; Grid Strategies, LLC, *Transmission Makes the Power System Resilient to Extreme Weather*, at 2 (July 2021), https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf.

[105] Brattle Roadmap Report at B27-B29.

[106] *Id*. at B28-B29 (noting that in one scenario-based planning effort "the American Transmission Company evaluated seven plausible futures, spanning a wide range of long-term uncertainties. This analysis of multiple scenarios of plausible futures showed that the estimated benefits ranged widely across sets of plausible futures. While the project was projected to be clearly beneficial in most (but not all) futures, the analysis also showed that not investing in the $136 million project could leave customers up to $700 million worse off in two of seven plausible futures). Recognizing that benefits exceed costs in most of the seven futures, that benefits were projected to fall just short of covering project costs in only 2 futures, but that was because the project can avoid very-high-cost outcomes in another 2 of the 7 futures, the Wisconsin Public Service Commission unanimously approved the project." *Id.*

[107] *Id*. at 24-25. Scenario-based modeling techniques can successfully simulate and manage forecasting uncertainties *See also*, Pfeifenberger, *Transmission Planning and Benefit-Cost Analyses*, *prepared for FERC Staff*, April 29, 2021, at 16-19, 43, https://www.brattle.com/wp-content/uploads/2021/07/Transmission-Planning-and-Benefit-Cost-Analyses.pdf.

interregional transmission are not only economic but can literally mean the difference between life and death.[108]

Especially at the interregional level, the consideration of a variety of long-term uncertainties—such as industry structure, new technologies, fundamental policy changes, and other shifts in market fundamentals—is critical for developing robust transmission plans and investment strategies, valuing future investment options, and identifying least-regrets projects.[109] Currently, benefits analyses are undertaken primarily assuming normal system conditions that do not include systems stresses from extreme weather, price spikes, transmission outages, or unusual generation outages.[110] Similarly, projects assessing public policy benefits are often focused solely on base case scenarios using minimum requirements instead of maximum policy goals, or the plausible impacts from an interaction between different public policies and market forces.[111] For example, a variety of state policies have specific targets for a *minimum* required amount of offshore wind along the East Coast, which, along with existing projects in the interconnection queue, have been the primary drivers of transmission planning for offshore wind. Yet these analyses need to also plan for how other federal, state, and local policies, such as tightening emissions requirements, increased building and transportation sector electrification policies and market forces might ultimately increase the demand and/or need for additional offshore wind generation, which will in turn require additional transmission. Unfortunately, under the current interregional planning regime, the push to analyze the highly likely need for and substantial multiple potential benefits of a meshed, interregional connection between the offshore wind developments along the eastern

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[108] November 15 Technical Conference, transcript forthcoming.
[109] Brattle Roadmap Report at B27-B28.
[110] *Id.*
[111] *Id.*

seaboard has largely come from outside of existing regional planning authorities.[112] Requiring scenario-based interregional planning and implementation of least-regrets scenarios will prevent the kinds of excessive and potentially redundant expenditures that have resulted from the failure of regions to proactively and effectively plan for and implement interregional projects to meet foreseeable interregional needs.

As noted in the Brattle Roadmap Report and by others, good scenario-based planning also requires widespread stakeholder involvement: the successes realized by the MISO MVP and CREZ planning process relied in large part by the active participation of states, developers, and regional planning authorities (among others) to help ensure that the goals of the key parties were informing the process.[113] As part of implementing "least regrets" options, it is particularly important for planners to prioritize interregional projects that would avoid or delay the cost of (1) transmission upgrades needed to satisfy generation interconnection and transmission service requests; (2) transmission upgrades that would have to be planned now to address their already-known local and regional needs; and (3) transmission upgrades that likely would be needed in the future to meet local and regional needs (including the replacement of aging infrastructure).[114]

e. *Comprehensive transmission network portfolios must be used to address system needs and to allocate costs*[115]

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[112] *See* Comments of the Sustainable FERC Project, Natural Resources Defense Council, Americans for a Clean Energy Grid, American Clean Power Association, Sierra Club, Advanced Energy Economy, Union of Concerned Scientists, and New York Offshore Wind Alliance Concerning Possible Interregional Transmission Projects (July 2, 2021), https://sustainableferc.org/wp-content/uploads/2021/08/Clean-Energy-Advocates-Offshore-Wind-Interregional-Tx-Study-Request.pdf; Department of Energy, Atlantic Offshore Wind Transmission Literature Review and Gaps Analysis (Oct. 2021), https://www.energy.gov/sites/default/files/2021-10/atlantic-offshore-wind-transmission-literature-review-gaps-analysis.pdf.
[113] Brattle Roadmap Report at B25; Brattle-Grid Strategies, *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs,* at 24, 47-48 (Oct. 2021), https://www.brattle.com/wp-content/uploads/2021/10/2021-10-12-Brattle-GridStrategies-Transmission-Planning-Report_v2.pdf (hereinafter, "Brattle-Grid Strategies Report"); Department of Energy Initial Comments at 30; Dr. David J. Hurlbut November 15 Technical Conference, transcript forthcoming..
[114] Brattle Roadmap Report at B27.
[115] *Id*. at B8.

As with regional planning, in order to provide the flexibility to consider the variety of project drivers between and across regions and entities with differing needs while also providing the specificity necessary to build and allocate project costs, interregional planning must assess benefits and allocate costs across a comprehensive portfolio of projects, rather than on an individual project basis.[116] Portfolio-based planning also assists with cost allocation, as consideration of all benefits associated with a given project or suite of projects, evens out imbalances in cost allocations and the ability of parties who receive benefits of a different type than the one assessed and allocated will be reduced. For example, stakeholders that receive unallocated reliability benefits from transmission projects that are built and assessed only for economic purposes would no longer be allowed to occur, as they are now. Additionally, full visibility of overall benefits and beneficiaries makes it easier for planners to find cost allocation methodologies that are acceptable to stakeholders.

The Brattle Roadmap Report sets forth the following proposed list of minimum cost allocation standards for interregional planning that provide a flexible framework for meeting the cost-allocation requirements of Order No. 1000:[117]

- Costs allocated for a portfolio of interregional projects must be at least roughly commensurate with the total benefits that the portfolio provides to each region (rather than each individual project within the portfolio); no region shall be allocated costs without receiving benefits.

- Cost allocation methodologies, benefit assessments, and beneficiary identification must all be transparent.

- Different cost allocation methods may be applied to different types of needs addressed (e.g., reliability, economic, public policy, etc.) or different geographic portions of transmission facilities.

[116] *See, e.g.*, *id*. at B8, B34.
[117] Brattle Roadmap Report at B32-B33.

- Planners must utilize the quantified benefits in determining the cost allocation approach, while also recognizing non-monetized and non-quantified benefits, for portfolios of interregional projects in assessing the overall reasonableness of proposed cost allocations.

- The monetized total benefits of interregional projects for a given region must be at least equal to the avoided costs of achieving the same total benefits through local or regional upgrades.

- The total and types of benefits and cost allocations assessed for each region do not need to be the same.

- Project costs allocated to each regions need to be recovered via the existing cost allocation and recovery process of each region.

- Interregional and regional planning processes must use a common set of holistic criteria so that local and regional project needs can be incorporated into the interregional process and interregional solutions can be more easily evaluated by and allocated to individual regions.

- Cost allocation mechanisms must be pre-specified in advance, but must remain flexible enough to achieve cost allocations that recognize differences in project drivers and benefits across the regions. For example, cost allocation may specify that cost allocation to each region will be based on one or a combination of:

  - The share of total benefits received by each region as a proportion of the sum of the total benefits received for all projects

  - The share of the projects' physical location in each party's footprint (e.g., shares of circuit miles or investment dollars)

  - The share of each region's relative contribution to the need for a project (e.g., power flows that contribute to an upgrade)

  - The share of each region's projected or allocated usage of the projects' transmission capability (e.g., shares of increased flow-gate capacity)

- Planning processes must specify the financial mechanisms that allow for the actual sharing of project investment costs or annual project revenue requirements across boundaries such as physical ownership shares and financial transfers.

- Cost allocation based on physical ownership shares can be implemented through either physical ownership of individual project segments or co-ownership of the interregional or individual project sectors.

- Financial transfers between regions must correspond to the determined share of the projects' revenue requirements.

D. FERC Must Require Transmission Planning Entities to Incorporate Scenario-based Planning

It is no secret that transmission queues are clogged and can take increasingly long to get through. But the root cause of this problem is that the lack of proactive, multi-value, and scenario-based transmission planning for anticipated future generation and policy needs overburdens generators in the interconnection queue by making them solely responsible for network upgrades even when these upgrades provide multiple benefits to the grid. Many of the problems with the interconnection process will be alleviated if FERC requires better overall transmission planning that recognizes anticipated future generation. This does not mean that FERC is putting its thumb on the scale in favor of certain types of resources; rather, it merely requires transmission planning entities to recognize reality. To achieve this, FERC must set a cognizable standard to measure whether transmission planning entities are following the rule. In this section, we outline what these minimum requirements should be. We caution that, while there are ways to improve the interconnection process, doing so without also reforming the transmission planning process would be, at best, a half-measure.

Current processes do not consistently account for anticipated future generation or public policy requirements. Many commenters have pointed out that the anticipated future generation studied in the current transmission planning processes is not based on the reality of what generation is likely to show up. For example, at the first meeting of the Joint Federal-State Task Force on Electric Transmission, Chair Andrew French, Kansas Corporation Commission stated that future projections on renewable generation are not based on data or reality, but a consensus of what the stakeholders are willing to accept. He noted that in reality, more renewable generation seeks to interconnect to the system, so the transmission planning processes underestimate renewable penetration. Similarly, in its comments, SPP's MMU notes that historically the two futures studied by SPP in its transmission planning process have underperformed relative to the actual growth of renewables.[118]

As discussed in Section II, to remedy this, FERC must mandate that the transmission planning processes plan for transmission to serve the best available projection of the future. This must include sufficient transmission to meet known federal, state, and local policies because the government entities setting those policies have authority to take on risk on behalf of ratepayers or the general public. It must also include corporate and utility procurement targets and reasonable projections of future resources based on current trends. As Chair French stated at the Joint Task Force meeting, these state policies are indicative of demand for those resources and anything that indicates demand should be considered in planning process. Playing ostrich regarding anticipated future generation will result in a transmission plan that doesn't match the reality of the system.

PIOs recommend that the Commission require regional planners to plan based on future scenarios that use the best available data and forecasting methodologies. Several commenters assert that transmission planning entities should only assess reasonable future assumptions.[119] We agree, but believe that these commenters far too narrowly define what a reasonable future scenarios should look at. Such scenarios must include a variety of planning factors as discussed below. Such planning 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

[118] SPP MMU Initial Comments at 3.
[119] *See, e.g.*, Initial Comments of Entergy at 17.

Commission is permitted to "recognize[] that state and federal policies might affect the transmission market" and plan accordingly.[120]

Section 217(b)(4) of the FPA 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."[121] State electricity policies generally function by placing new service obligations on load-serving entities, placing them squarely within 217(b)'s scope of consideration. 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.[122]

1. <u>There is near unanimous consensus on the need for scenario planning</u>

Comments filed to the ANOPR show wide support for scenario-based planning, including a substantial number of filers who request that FERC mandate its use. Those commenters that fall short of requesting a mandate are generally supportive of its use and tend to accept that it will be required in one form or another. To the extent there is push-back at all, it appears to be limited to the scope and breadth of any requirement for or encouragement of scenario-based planning.

A wide range of entities representing a broad cross-section of the electricity industry expressed support for FERC requiring scenario-based planning. This includes, but is not limited

[120] South Carolina Public Service Authority v. FERC, 762 F.3d at 89 (D.C. Cir. 2014).
[121] 16 U.S.C. 824q(b)(4).
[122] 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).

to, Exelon Corporation,[123] Certain Transmission Dependent Utilities,[124] Electricity Consumers Resource Council,[125] Oregon Public Utility Commission,[126] New York Transmission Owners,[127] National Association of Regulatory Utility Commissioners,[128] and Edison Electric Institute.[129] Many of these comments supported the use of a minimum set of scenario-based planning standards, and some expressed a desire that any standards or requirements maintain a degree of flexibility to enable more local or regionally appropriate approaches.

A large number of commenters were supportive of scenario-based planning while refraining from making any affirmative statement calling for such planning to be mandatory. Like

[123] Initial Comments of Exelon Corporation, at 2-3, 11-19 ("The Commission therefore should require regions to proactively plan regional transmission based on future scenarios that consider policy drivers and other expected grid-related developments.").

[124] Initial Comments of Alliant Energy Corporate Services, Inc., Consumers Energy Company, and DTE Electric Company at 12 ("Requiring transmission providers to analyze the full range of realistic possible future scenarios as they evaluate proposed transmission solutions and non-transmission alternatives during long-range transmission planning would improve transmission providers' ability to solve for future anticipated generation growth and customer affordability. It also would grant an additional measure of transparency for stakeholders and metrics to assess how well the planning process anticipated actual outcomes, which could be used to enhance the process continually over time.").

[125] Initial Comments of the Electricity Consumers Resource Council (ELCON), at 4, 8-9 ("FERC stated the goal of the ANOPR is to consider reforms necessary at this time to ensure that rates for Commission-jurisdictional service are just and reasonable in light of changing conditions in the industry, as it understands its duties under Section 206 of the FPA. ELCON believes the best way to achieve that goal is to facilitate a broader and holistic planning process that incorporates probabilistic future scenarios to provide a roadmap of transmission development necessary to meet emerging challenges and opportunities") (footnotes omitted).

[126] Initial Comments of the Oregon Public Utility Commission, at 1, 9-10 ("The Oregon PUC urges FERC to upgrade its expectations for regional transmission planning . . . . Standards should require long-term scenario planning that identifies regional transmission needs and evaluates a range of solutions to those needs—much like a utility Integrated Resource Plan (IRP). Without robust, forward-looking planning that connects with states' goals for protecting utility ratepayers, promoting economic development, and addressing climate change, regulatory bodies lack a strong foundation for evaluating whether transmission investments are in the public interest and appropriate for cost recovery from retail ratepayers").

[127] Initial Comments of the New York Transmission Owners, at 8-14 ("In conclusion, the NYTOs support the ANOPR's goals of proactive, multi-value scenario modeling and recognize that further refinements to New York's transmission planning processes and modeling will likely be needed to integrate renewables and to maintain reliability") (footnotes omitted).

[128] Initial Comments of the National Association of Regulatory Commissioners, at 10-11 (including as one of its proposed reforms the adoption of scenario analysis).

[129] Initial Comments of the Edison Electric Institute, at 13-15, 24-6 ("While scenario planning should be incorporated into the long-term transmission planning, the Commission should continue to take a flexible approach and should not impose prescriptive regulations dictating how those scenarios are developed, particularly given significant regional differences") (footnotes omitted).

the above set of comments, this view is supported by actors representing a wide range of entities, including New England States Committee on Electricity,[130] R Street Institute,[131] East Kentucky Power Cooperative,[132] and the Organization for MISO States.[133] Comments from this group ranged from proposing certain scenario-based planning methodologies that FERC should consider, to cautioning against certain prescriptive elements that might take away from regional flexibility. Additionally, many RTOs and ISOs expressed support for scenario-based planning, indicating that they already include this to some extent in their operations, and requesting that any future requirements for scenario-based planning maintain enough flexibility to allow for regional circumstances while also not harming any current scenario-based planning processes that may be underway.[134]

In our review of scenario-based planning in the ANOPR comments, we did not encounter a single instance where a stakeholder sought the exclusion of scenario-based planning, although it is possible that we missed such a stance given the large number of comments. Of those comments

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[130] Initial Comments of the New England States Committee on Electricity (supportive of scenario-based planning while cautioning against prescribing certain inputs or assumptions).

[131] Initial Comments of the R Street Institute, at 5 ("Economic planning also requires the incorporation of all material and relevant anticipated future conditions, including changes in the nature and extent of the generation mix. The Commission could explore a requirement for hybrid transmission approaches that incorporates probabilistic approaches for risks (potential events with known probabilities) and scenario approaches for uncertainties (potential events with unknown probabilities).").

[132] Initial Comments of the East Kentucky Power Cooperative, Inc., at 4-8 (agreeing that scenario-based planning is important for ensuring future grid operations while cautioning that each region should be left to its own in determining how to use it.).

[133] Initial Comments of the Organization of MISO States, Inc., at 2 ("At a high level, MISO is already doing much of the scenario-based planning that the Commission seeks comment on . . . . The OMS supports this work . . . . Any future rule changes by FERC must preserve the ability of regions to develop regionally appropriate solutions to the issues raised in the ANOPR.").

[134] *See*, *e.g.*, Initial Comments of the California Independent System Operator Corporation, at 5-6, 47-8; Initial Comments of ISO New England Inc., at 20-23; and Comments of the Midcontinent Independent System Operator, Inc., at 41, 45, and 51.

that may be considered negative vis-à-vis scenario-based planning, such a negative view appears to have been limited to the possible "speculative" nature that any such scenarios may entail.[135]

From our review of the ANOPR comments, it appears that the vast majority of those comments that specifically address scenario-based planning either explicitly request FERC to mandate its use, or accept that FERC will either require or encourage it in some form or another. The implication of this is clear: the industry is ready to adopt scenario-based planning and is prepared for FERC to require its use.

2. <u>Scenario-based planning must incorporate a range of reasonable futures</u>

As discussed in more detail below, anticipated future generation must include: (1) 100% of the legally binding federal, state, and local climate and clean energy requirements, (2) corporate and utility procurement targets, (3) increased electrification levels based on existing trends, (4) energy efficiency, demand response, and distributed energy resources levels based on trends, (5) market-based generation trends, (6) capital-asset cost trends, capacity factors, and operations and maintenance costs based on current data, and (7) the need for reliability and resiliency in the face of extreme weather vulnerabilities and increased diversity of generation.

As PIOs noted in our initial comments, most planning regions, whether or not part of an RTO, fail to identify potential transmission needs based on reasonable futures that not only reflect known facts, but that also capture current trends and near-term risks that will necessitate transmission system investments, including transformational change in the generation portfolio, increased extreme weather and anticipated electrification of end uses.[136] Traditional planning is

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[135] *See, e.g.*, Comments of the Mississippi Public Service Commission and The Mississippi Public Utilities Staff, at 3-4 (warning against the use of unrealistic forecasts or speculations concerning future policy); and Comments of Potomac Economics, Ltd., at 4 (warning against the speculation of long term future possibilities while encouraging that planning focus on near-term emerging trends).
[136] PIOs Initial Comments at 77.

based on historical experience that is extrapolated into the future. Such an approach is ineffective when an industry is experiencing radical transformation given that the future is not simply an extension of the past. This is precisely what is happening currently in the electric industry. Scenario planning is an effective methodology during transformational change and has been used in the United States for at least a half century. Planning that fails to take these trends and risks into account leads to unjust and unreasonable outcomes because it results in infrastructure that will not meet actual future needs cost-effectively.

In scenario planning, plausible hypothetical futures (referred to as "Futures") are created based on how trends are bending towards the future. At the very least, two Futures are created that represent the opposite ends of the range of plausible Futures. On one end is a conservative Future not representing "business as usual" but instead representing a Future where the trends all cut in one direction. On the other end is an aggressive Future where the trends cut dramatically in the other direction, however still within the range of the "plausible." Of course, additional intermediary Futures can also be evaluated. Scenario planning is *not* attempting to predict the future but to identify a range of possible hypothetical future worlds. A single scenario is never selected at the end of the planning effort as the "correct" scenario. The Future will most likely be somewhere between the two bookended Futures and plans should be created understanding that fluidity and uncertainty.

3. <u>FERC must set mandatory baseline standards for use in the scenario planning process</u>

The Commission must establish mandatory baseline standards in planning regions used in developing future scenarios and ensure that the development of these scenarios includes a transparent process which includes input from diverse stakeholders that represents a plausible range of future conditions to ensure least-regrets planning.

PIOs urge the Commission to make these baseline standards mandatory for several reasons. First, ensuring the reasonable needs of load-serving entities (LSEs) requires that the scenario planning capture the trends driving the transformation in the electricity industry. Without recognizing those trends, the planning process will be unable to evaluate the most cost-effective solutions for the LSE's reasonable needs because these needs may be missed entirely in the analysis. It would be hard to establish just and reasonable rates when the analysis omits the primary drivers of what is shaping the industry's future. Second, some members of transmission planning regions have a financial incentive to object to regional and interregional transmission lines and, therefore, want to undermine the transmission planning processes that could identify a need for those lines. In other words, some members prefer costlier solutions because those solutions increase their ratebase. Third, regional planning processes are severely limited by members' ability to undermine those processes often, but not exclusively, by claiming the planning factors are arbitrary and not based on federal requirements. Having mandatory standards would eliminate that excuse. Fourth, RTOs are voluntary organizations whose members regularly threaten to leave the RTO unless they get their way. Members that would prefer costlier localized solutions over the less costly regional solutions—through threatening to leave—may bully their RTO into selecting the former rather than the latter. Finally, as seen with Order No. 1000, leaving certain planning criteria to the discretion of the transmission planning entities or requiring only that they "consider"[137] – not plan to meet – criteria results in transmission plans that, on the whole, do not actually incorporate those criteria. The result of this permissive language is that not all transmission planning regions actually plan for public policy needs.

[137] Order No. 1000 at P 203.

While FERC should require inclusion of specific planning factors, the values assigned to those factors will be established by the planning authorities in consultation with stakeholders. Such an approach provides assurance that planning authorities will be plan for the appropriate variables while simultaneously providing flexibility in how those factors are applied in the planning process. Such flexibility will ensure that regional differences are recognized and appreciated.

4. <u>These mandatory baseline standards should include certain planning factors</u>

A brief summary of what variables must be included in these scenarios follows.

- *100% of the legally binding federal, state, and local climate and clean energy requirements*: Transmission planners should be required to incorporate public policy requirements at the federal, state and local level into future resource mix projections.

- *Corporate and utility procurement targets, including utility goals approved in a state IRP or similar state/local proceeding*: Consumer demand for economic, renewable resources will be met at a regional or national level, so the Commission should require all transmission owners to develop a process for estimating demand preferences from wholesale customers in their region. Additionally, investor-owned utilities' promises to their shareholders regarding renewables or carbon goals should be included within planning factors. For example, MISO has recently incorporated utility and corporate procurement targets into its "futures" scenarios. MISO's MTEP21, in its most-conservative Future, includes 100 percent of utility IRPs and 85 percent of the non-binding, utilities' plans and state plans, which has had the effect of increasing forecasted carbon reductions by 23 percent from the original assumption of a 40 percent carbon reduction by 2039.[138] This information must include shareholder statements and SEC filings, integrated resource plans, power purchase agreements, known environmental regulations, and other relevant publicly available information.

- *Increased electrification levels based on existing trends on conversion from fossil fuels to electricity and incorporating the expected impact of state and federal incentives*: The Commission should require all regions to explicitly account for additional load from electrification of both transportation and buildings and other infrastructure requirements, and should require planning under a variety of scenarios, particularly because it is difficult to predict the tipping point for the adoption of new technologies. For example, in MISO's LRTP process its most aggressive future assumes a 50 percent increase in demand by 2039, 40 percent of

[138] *See* PIO Initial Comments at 80-81.

which is driven by electrification.[139] Without such estimates, actual needs will not be recognized in advance and decisions to build to meet demand will not occur.

- *Energy efficiency, demand response and distributed energy resources levels based on trends and incentives*: energy efficiency and demand response assumptions should also reflect any state and federal requirements.

- *Market-based generation trends particularly where renewable resources are concentrated*.

- *Capital-asset cost trends, capacity factors and operations and maintenance costs (e.g. fuel costs) based on current data*: if applicable, a learning rate should be applied, for example National Renewable Energy Lab's Annual Technology Basement (ATB).

- *Reflect need for reliability and resiliency in the face of extreme weather vulnerabilities and increased diversity of generation*.

In addition to the planning factors mentioned above, these mandatory standards should also include the following:

- Mandatory use of scenario planning with at least two Futures representing plausible bookends;

- Scenario planning should be conducted over a planning horizon of 10 and 20 years, if not longer;

- All models used with the scenario planning should include utilities' plans for new generation, new storage, new grid enhancing technologies and generation retirements for, at least 10 years out, or longer if available. FERC should mandate that utilities confidentially submit those plans to their planning authorities; and

- FERC should also require all planning authorities, when evaluating solution sets, to determine whether any regional projects would obviate the need to replace aging assets or whether replacement of aging assets could be adjusted or optimized to address other transmission needs at the same time.

E. FERC Must Increase Oversight of Transmission Planning

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[139] MISO Futures Whitepaper, MTEP21 (April 27, 2020), https://cdn.misoenergy.org/20200427%20MTEP%20Futures%20Item%2002b%20Futures%20White%20Paper443656.pdf.

PIO's initial comments emphasized the financial incentives transmission owners have to undermine or evade Order No. 1000's planning processes.[140] Numerous commenters agree.[141] Utilities desire to increase their ratebase, and the lack of effective oversight over transmission investments figure prominently in many initial comments. Allowing regulated utilities to decide on their own that their investments should be in ratebase is problematic in any context, but doubly so in the transmission planning context, as it not only imposes possibly unjust costs but also displaces more beneficial planning and investment.

We reiterate our belief that transmission planning reform will not be successful unless it addresses these conflicts of interest. Transmission Owners' near unanimous opposition to improved planning or oversight make clear that they will continue to subvert any planning regime so long as lucrative opportunities remain. In any event, no matter what reforms FERC puts in place, all utilities will have the right to make investments and file for cost recovery under Section 205.[142] For the sake of good regulatory practice and to align private incentives with desired planning outcomes, the Commission should base transmission planning reform on improved oversight and regulation:

1. *Restore prudence review of unplanned investments*. Local upgrades and replacement of existing facilities both have a place in efficient transmission investment. The Commission can ensure they find that place by expecting local upgrades to emerge from the regional planning process as part of a unified, efficient transmission investment plan. Local projects that have their origin in independent planning should be treated as presumptively prudent. On the other hand, when a transmission owner identifies a need for investment that is not obvious to independent planners, the burden logically rests on the transmission owner to demonstrate prudence.

[140] *See* PIO Initial Comments at 60-65.
[141] *See, e.g.*, Comments of the CA PUC at 2-3; Comments of the CA Dep't of Water Resources at 12; Comments of the NJ BPU at 2;
[142] See Atlantic City Elec. Co. v. FERC, 295 F.3d 1 (D.C. Cir. 2002).

2. *Lower the rate of return on unplanned investments, especially those with low risk*. We join NARUC[143] and others[144] in urging FERC to remove any ROI adders for transmission investments made outside independent planning. As discussed in greater length in our original comments, we also urge FERC to carefully review the components of the ROI for unplanned projects and consider if proposed equity returns and debt/equity ratio properly reflect their low risk and lack of competitive procurement. Finally, the Commission might consider a non-remunerative ROI at the sponsor's cost of debt for projects that have the appearance of being structured to evade regional planning.[145]

3. *Actively monitor for anticompetitive behavior*.

4. *The presumption of prudence and returns reflecting risk are appropriately reserved for independently planned projects*. Commercial reality and FERC's statutory authority to encourage transmission through incentives support preferential treatment for projects arising from independent planning. The prudence of those projects is a function of the integrity of the planning process. The potentially greater risk of projects identified based on system need rather than system owner's convenience likely, along with exposure to competition, justify a favorable ROI.

5. *Ensure independent planners are truly independent*. FERC should set strict criteria for entities seeking to fill the independent planner role. The independence and stakeholder participation criteria established for RTOs in Orders 888, 2000, and 719 provide a basis. In non-RTO regions, those criteria combined with assurances of no commercial relationships with transmission owners may be sufficient to ensure objective planning. In RTO regions, a complication arises that RTOs compete for members and are understandably averse to losing members. To avoid the conflicts of interest inherent in a membership model, we suggest that the Commission assign regional planning responsibilities on a purely geographic basis. Transmission planners would each be responsible for planning in their assigned region, with no membership requirements placed on the transmission owners in that region. Additionally, similar to FERC's standards of conduct rules for transmission and marketing function employees, an RTO's transmission planning activity should function independently from its business units focused on acquiring and retaining members.

Several of the above functions are well suited to participation from Independent Transmission Monitors (ITMs). In the context of unplanned transmission investments applying to FERC for rate recovery, ITMs could provide objective analysis to aid the Commission's decision-

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[143] NARUC Initial Comments at 59.
[144] *See, e.g.*, Comments of the NY PSC at 11; Comments of the PA PUC at 17.
[145] *See, e.g.*, 169 FERC ¶ 61,054 (Oct. 2019) (instituting Section 209 proceedings into whether "Immediate need reliability" provisions were used in an unduly preferential and discriminatory manner).

making, much like the role played by state commissions' staff in traditional rate cases. Much as Independent Market Monitors have unfettered access to market participants' relevant information, ITMs should have full visibility into transmission providers' planning and cost data. Such access would enable robust monitoring for anticompetitive behavior and ensure that regional planning is based on the same information as transmission owner's private planning. Finally, just as IMM's do for RTOs, ITMs can provide oversight to help ensure independent transmission planners remain truly independent.

F. FERC Must Improve Benefit-Cost Analysis and Cost Allocation

1. FERC must identify a minimum set of benefits that transmission planning entities must use in planning

Many commenters agree that the Commission must require the transmission planning entities to improve the cost-benefit analysis used for transmission planning and include the full suite of benefits in the process.[146] Other commenters assert that the costs and benefits taken into account in transmission planning should be real, tangible benefits.[147] We agree. However, we disagree with commenters that assert that the Commission should only look to a very narrow definition of benefits and costs in the transmission planning processes. Rather, there are a host of real, tangible, quantifiable benefits that the current transmission planning processes do not account

[146] *See, e.g.*, NextEra Initial Comments at 83; Commonwealth of Massachusetts Department of Energy Resources Initial Comments at 17; LS Power Supplemental Comments Specific To ANOPR Question 54 at 12; NYISO Initial Comments at 56-57; Pacific Gas and Electric Initial Comments at 8.
[147] *See, e.g.*, NARUC Initial Comments at 19; Comments of the Mississippi PSC and the Mississippi Public Utilities Staff at 4; Michigan PSC Initial Comments at 16; Organization of MISO States Initial Comments at 16; Entergy Initial Comments at 17.

for. FERC must modify its transmission planning regulations to identify a minimum set of benefits and costs that the transmission planning entities must use in planning both regional and interregional transmission.[148] This minimum set of benefits and costs must include *the full set of benefits* so that the transmission planning processes produce a more accurate benefit-cost analysis, provide more insightful comparisons, and avoid rejecting beneficial investments that would reduce system-wide costs. Leaving significant benefits on the table when identifying transmission will inherently produce unjust and unreasonable outcomes.

Proper benefit analysis is the foundation of just cost allocation. Multiple commenters express concerns that cost allocation of projects not result in one set of consumers footing the bill for others' preferences.[149] We agree. Although PIOs may disagree with some on the value of environmental benefits, that is ultimately a question for legislatures. Properly designed cost allocation is perfectly capable of equitably assigning costs, even in the case where value is partially determined by policy decisions that may vary across the system. We believe that our proposed cost allocation framework[150] offers a comprehensive approach to integrate multiple —and often differing—policy, market, and reliability benefits without imposing unintended cross-subsidies.

In our initial comments, PIOs provided evidence that there are significant quantifiable benefits that should be taken into account in transmission planning.[151] Many commenters agreed and provided examples of the types of benefits that can be quantified. For example, a 2013 Brattle Group study provided an extensive list of transmission benefits that can be quantified.[152] NYISO

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148 *See* NARUC Initial Comments at 19 ("Effective planning should strive to quantify benefits associated with enhancing interregional import and export capabilities, given the likelihood of future extreme weather events and related energy shortages.")
149 *See, e.g.*, Comments of the Michigan PSC at 17; Comments of the North Dakota PSC at 3-4.
150 PIO Initial Comments at 125-129.
151 *See* PIO Initial Comments, Exhibit A: Brattle, Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs at 33, Fig. 5.
152 Brattle, The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments (2013).

stated that it quantifies additional economic benefits which it provides to its LSEs as information. These include changes to generator payments, installed capacity costs, Transmission Congestion Contract revenues, Ancillary Services costs, emissions costs, fuel and load forecast uncertainty and energy deliverability.[153] LS Power points to the CREZ process in ERCOT to show that "properly identifying the benefits of renewable energy integration, including production cost benefits, can support significant transmission expansion."[154] This shows that such benefits are quantifiable.

Further, the transmission planning process must incorporate the value of resilience in mitigating the impacts on extreme weather on the transmission system. After each major extreme weather event, numerous studies are done to quantify the effect of the event.[155] For example, a study showed that the eastern states could each have waved $30-40 million for each GW of stronger transmission ties among themselves or to other regions during the Bomb Cyclone cold snap in 2017-2018.[156] The Commission cannot allow transmission planning entities to ignore such benefits when creating a transmission plan.

Thus, the record in this proceeding supports FERC modifying its transmission planning regulations to identify a minimum set of benefits and costs that the transmission planning entities must use in planning both regional and interregional transmission. As detailed further in PIO's Initial Comments and the Brattle study attached thereto as Exhibit A, such minimum benefits should include, among other things,: lower line losses and operating reserves, greater reliability

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[153] NYISO Initial Comments at 11.
[154] LS Power Initial Comments at 12.
[155] *See, e.g.*, FERC-NERC Cold Weather Report at 9-10; Grid Strategies, LLC, *Transmission Makes the Power System Resilient To Extreme Weather*, at 2, https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf.
[156] Grid Strategies, LLC, *Transmission Makes the Power System Resilient To Extreme Weather*, at 2, https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf.

and resilience, greater resource adequacy through reduced planning reserves and higher capacity value, and market benefits.[157]

2. <u>FERC must reform cost allocation process for generator interconnection</u>

As PIOs explained in our initial comments, the current lack of proactive, multi-value, and scenario-based planning for anticipated future generation and policy needs has created a situation where we are planning an integrated and shared network largely through the generator interconnection process, and that having to bear the full costs of such upgrades forces many generation developers to withdraw their interconnection requests, resulting in inefficient outcomes and higher system-wide costs.[158] Until recently, these interconnection charges for new renewable resources typically comprised a small fraction of total project costs, but these charges have risen dramatically in recent years and now can comprise a significant percentage of overall project costs.[159]

As we discuss above, many of the problems with the interconnection process will be alleviated if FERC requires better overall transmission planning that recognizes anticipated future generation. Planning for anticipated future generation in the transmission planning process can ensure a robust transmission system paid for by all of the beneficiaries of that transmission. Once these broader needs are planned for in the transmission planning process, the interconnection process need only study the very limited needs of an interconnecting generator (or cluster of generators). Interconnecting facilities will no longer be saddled with costs resulting from gross underinvestment in the transmission system. Thus, while PIOs caution that undertaking only

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[157] *See* PIO Initial Comments, Exhibit A: Brattle, Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs at 33 and Table 5.
[158] PIO Initial Comments at 17-18.
[159] *Id*.

reforms to the interconnection process would be, at best, a half-measure, we also believe the record in this proceeding provides innovative funding models that FERC should consider in reforming generator interconnection.

FERC must require all beneficiaries to pay for transmission even if the primary motivation was some other purpose for another entity, following *ICC v. FERC*[160] and other relevant case law. This must include transmission that results from the generator interconnection process. Generators can and should pay for some of these costs given that they receive some benefit in terms of access, but they should not exclusively pay for transmission that benefits others. Enel's Initial Comments point out that the current interconnection processes identify and assign network upgrades to interconnection customers "that are hundreds of miles or even 1000+ miles away, even when these [interconnection customers] bear negligible responsibility for the upgrade."[161] This does not comport with the "roughly commensurate" standard for allocating the costs of transmission articulated by the Seventh Circuit in *ICC v. FERC*. Thus, FERC must modify the transmission planning and interconnection process to set out rules that distinguish what upgrade costs should be paid by the interconnecting resource and which should be paid by load.

We support Enel's proposal that the Commission could use Transfer Distribution Factor (TDF) to show direct causes causation. Enel provides more detail in its initial comments, but TDF measures the percentage of the electricity produced by a generator which travels on a given transmission facility.[162] We agree that this is a good metric to determine network upgrades local to an interconnection customer's project for which it should be responsible. Enel notes that

[160] *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014); *Illinois Commerce Comm'n v. FERC*, 576 F.3d 470 (7th Cir. 2009); *Illinois Commerce Comm'n v. FERC*, 756 F.3d 556 (7th Cir. 2014).
[161] Enel Initial Comments at 3, Appendix B.
[162] *Id*. at 6.

transmission providers currently use TDF in interconnection planning, so they will be familiar with the calculation. However, as shown in Enel's Initial Comments, transmission providers use far too low a threshold for TDF to be useful. Thus, we support Enel's proposal that the Commission set a common TDF threshold of 20% to assign network upgrade costs to interconnection customers.

Enel's initial comments also provide a useful roadmap to consolidate generation interconnection, transmission service, and regional transmission planning studies. From a process standpoint, Enel proposes that:

> If multiple similarly located generators enter the same regional planning process and are expected to have overlapping generation profiles (e.g., common fuel types), [transmission providers] could study those generators in a tandem study at the beginning of the regional process to identify any new transmission constraints caused by the combination of the two plants. Common upgrades that [transmission providers] identify in the initial screening study could be shared between the generators to reduce cost allocation to each, and if the combined study identifies new upgrades that are cost effective for mitigating congestion and curtailment concerns, the generators could opt to share those costs and/or reduce sizes in some proportionate amount. Stakeholders could create rules requiring these additional upgrades if the total cost of upgrades in the combined study did not result in a net cost increase to the interconnection customers. While this additional study is not necessary to implement, it is one possible solution to a frequently asked question about this proposal.[163]

Ultimately, while we believe that reforming the transmission planning and cost allocation processes will go a long way to fixing the problems with interconnection, we continue to believe that FERC must require all beneficiaries to pay for transmission even if that transmission is planned through the interconnection process.

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[163] *Id*. at 12.

III. The Commission Should Not Reinstate a Federal Right of First Refusal

A number of transmission owners blame competitive transmission planning for fostering a climate in which transmission operators see transmission as a zero-sum game and will no longer collaborate on regional solutions to transmission problems.[164] They argue that if the Commission would restore the federal ROFR, transmission owners would "once again be free to collaborate and develop the best projects to meet regional needs."[165] While this is a nice sounding goal, it harkens back to a past that simply did not exist. In Order No. 1000, the Commission stated:

> The need for additional transmission facilities is being driven, in large part, by changes in the generation mix. … These shifts in the generation fleet increase the need for new transmission. Additionally, the existing transmission system was not built to accommodate this shifting generation fleet. … The record in this proceeding and the reports cited above confirm that additional, and potentially significant, investment in new transmission facilities will be required in the future to meet reliability needs and integrate new sources of generation. It is therefore critical that the Commission act now to address deficiencies to ensure that more efficient or cost-effective investments are made as the industry addresses its challenges.[166]

This sounds eerily familiar. The Commission cannot be swayed by arguments that use rose colored glasses to assert that if only FERC had not implemented transmission reform, more transmission could have been built. The record in Order No. 1000 showed a clear need for transmission reform, and we should not go back now.

Further, the Commission should be wary of arguments of some transmission owners that if given the opportunity, they will be more willing to cooperate and build necessary regional and interregional transmission. The record of the last decade establishes otherwise. At every opportunity, transmission owners have worked to ensure that local projects under their control and upon which they could receive a guaranteed return would be built, rather than more cost effective

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[164] *See, e.g.*, PPL Initial Comments, PJM TOs Initial Comments, MISO Transmission Owners at 26.
[165] PPL Initial Comments at 22.
[166] Order No. 1000 at PP 45-46.

regional or interregional projects. Nothing in Order No. 1000 prohibited transmission owners from proposing regional or interregional transmission projects that were mutually beneficial—which was the whole goal of Order No. 1000—but they chose not to do so. We strongly agree with the NYTOs that "competitive processes should be leveraged to address regional transmission needs ... where they will provide the most value to customers and enable the timely construction of needed projects."[167] The NYTOs highlight that over the past several years, NYISO has undertaken several competitive solicitations to develop major efficient and cost-effective transmission projects in response to New York public policy requirements to relieve or avoid constraints on the bulk transmission system to access existing and future renewable resources.[168] The NYISO transmission planning process was able to produce two major projects that were competitively bid to meet New York public policy requirements: Western New York to address congestion-constrained hydro resources and AC Transmission to add flows between upstate and downstate New York.[169] NYISO is currently conducting a third solicitation for transmission to allow the delivery of offshore wind required by the New York's Climate Leadership and Community Protection Act.[170] NYISO's planning processes shows that competitive processes work.

The Commission should not allow specious arguments about a past that did not exist to rewrite the history of what led to Order No. 1000 or to blind it to the fact that competition works. As it did in Order No. 1000, the Commission must find that allowing incumbent transmission owners to further skirt the goals of competition will just slow down planning for needed transmission.

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[167] NYTOs Initial Comments at 15.
[168] *Id*. at 4.
[169] *Id*. at 11-12.
[170] *Id*.

IV. Conclusion

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

Dated: November 30, 2021.

Respectfully submitted,

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CERTIFICATE OF SERVICE

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

Dated: November 30, 2021.

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EXHIBIT A

Pfeifenberger et al., *A Roadmap to Improved Interregional Transmission Planning*, The Brattle Group (Nov. 30, 2021)

A Roadmap to Improved Interregional Transmission Planning

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- Pfeifenberger *et al.*, Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs, The Brattle Group and Grid Strategies, October 2021.
- Pfeifenberger, Transmission Planning and Benefit-Cost Analyses, April 29, 2021.
- Goggin, *Transmission Makes the Power System Resilient to Extreme Weather*, prepared for ACORE, July 2021.
- Gramlich and Caspary, *Planning for the Future: FERC's Opportunity to Spur More Cost-Effective Transmission Infrastructure,* January 2021.
- Pfeifenberger, Ruiz, Horn, *The Value of Diversifying Uncertain Renewable Generation through the Transmission System*, published by Boston University's Institute for Sustainable Energy, September 1, 2020.
- Pfeifenberger and Chang, *Well-Planned Electric Transmission Saves Customer Costs: Improved Transmission Planning is Key to the Transition to a Carbon-Constrained Future*, prepared for WIRES May 2016.
- Pfeifenberger, Chang, and Sheilendranath, *Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid*, prepared for WIRES, April 2015.
- Chang, Pfeifenberger, Hagerty, *The Benefits of Electric Transmission Identifying and Analyzing the Value of Investments*, prepared for WIRES, July 2013.
- Pfeifenberger and Hou, Seams Cost Allocation: A Flexible Framework to Support Interregional Transmission Planning, on behalf of SPP RSC, April 2012.

This report reflects the analyses and opinions of the authors and not necessarily those of The Brattle Group's clients or other consultants.

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Appendix A: Barriers to Interregional Transmission (Survey)

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Executive Summary

Most stakeholders in the electric power industry today agree that expanding interregional transmission capability can deliver cost savings to customers, particularly as the grid transitions to cleaner generation resources. In the recent Federal Energy Regulatory Commission (FERC) Advance Notice of Proposed Rulemaking (ANOPR),[1] at least 32 comments referenced interregional transmission and most of them favored improving interregional planning processes.

Numerous studies have confirmed the significant benefits of expanding interregional transmission in North America, demonstrating that building new interregional transmission projects can lower overall costs, help diversify and integrate renewable resources more cost effectively, and reduce the risk of high-cost outcomes and power outages during extreme weather events. Moreover, interregional transmission benefits range far beyond just delivering renewable resources to load zones and include reliability, resiliency, market efficiency, and resource adequacy benefits. This means there are often substantial costs and risks to *not* expanding interregional transmission. Several recent events, including the 2021 winter storm Uri, emphasize the very large potential (but thus far unrealized) reliability benefits and cost savings that interregional transmission can provide. These events show that the lack of sufficient interregional transmission imposes great risks and can lead to tremendously high costs.

In spite of this near-consensus that the benefits and value of expanding interregional transmission capabilities often exceed its costs (thereby reducing overall system costs), virtually no major interregional transmission projects have been built in the U.S. over the last decades. To understand why cost-effective interregional transmission projects do not get built, we surveyed stakeholders from 18 different organizations across the industry, including RTOs, state and federal policymakers and regulators, large customers, industry and environmental groups, and utilities. These stakeholder interviews identified numerous barriers to interregional transmission planning and project development that fall into three interrelated categories as shown in Table ES-1: (A) Priorities, Alignment, and Understanding, (B) Planning Processes and Analytics, and (C) Regulatory Constraints.

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

TABLE ES-1: SUMMARY OF BARRIERS TO INTERREGIONAL TRANSMISSION PLANNING AND DEVELOPMENT

A. Priorities, Alignment and Understanding	1. Insufficient leadership from RTOs and federal & state policymakers to prioritize interregional planning 2. Limited trust amongst states, RTOs, utilities, & customers 3. Limited understanding of transmission issues, benefits, & proposed solutions 4. Misaligned interests of RTOs, TOs, generators, & policymakers 5. States prioritize local interests, such as development of in-state renewables
B. Planning Process and Analytics	6. Benefit analyses are too narrow and often not consistent between regions 7. Lack of proactive planning for a full range of future scenarios 8. Sequencing of local, regional, and interregional planning 9. Cost allocation (too contentious or overly formulaic)
C. Regulatory Constraints	10. Overly-prescriptive tariffs and joint operating agreements 11. State need certification, permitting, and siting

While we provide preliminary recommendations to address the barriers in categories A and C, this report focuses primarily on the second set of barriers and develops a "roadmap" of recommendations to improve interregional planning processes and analytics. Improved processes and analytics are prerequisites for addressing the other barriers. However, recognizing that it will require federal and state policy makers and planning authorities to prioritize interregional issues, we also offer our initial thoughts on what the role of these authorities should be in addressing at least some of the identified barriers, implementing the recommended planning process improvements, and addressing the associated regulatory constraints.

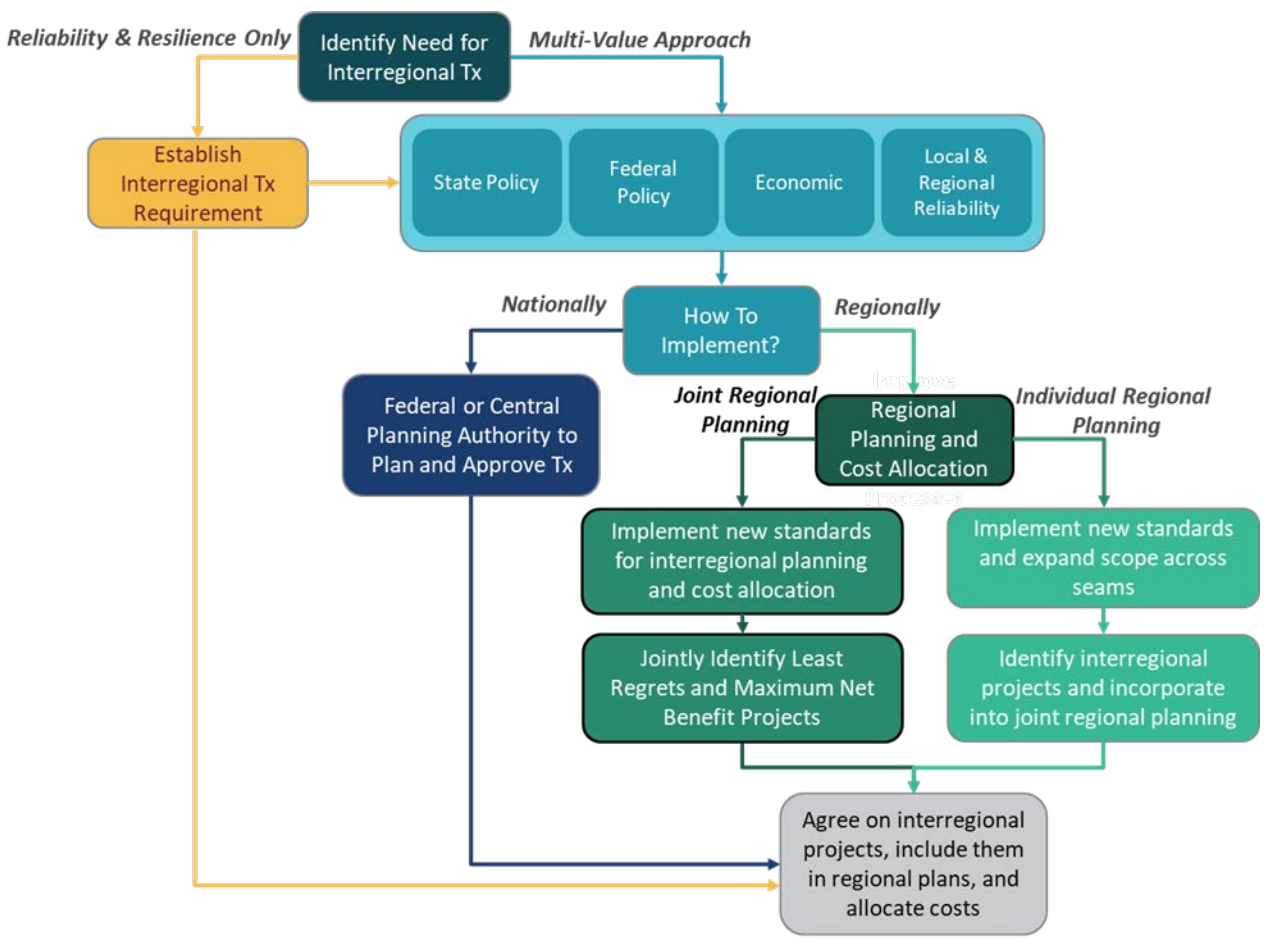
Addressing planning-process-related barriers to interregional transmission starts with improving the **determination of interregional transmission needs** and the sequencing of how those needs are addressed through transmission solutions. Currently, interregional transmission needs are determined only through regions' joint interregional planning processes that often are too narrowly defined to be able to identify interregional transmission needs and cost-effective solutions to these needs. Meanwhile, compartmentalized generator interconnection and local and regional reliability planning processes yield mostly incremental solutions to individual (and often near-term) needs that result in inefficient outcomes with higher system-wide costs. Not only has this process resulted in piecemeal upgrades primarily at the local and regional level (and often are solely reliability-driven without considering other needs), but the approved projects also pre-empt more cost effective regional and interregional transmission investment that could proactively and simultaneously address a broader set of future reliability, economic, and public policy needs.

We propose minimum standards to enhance the joint interregional planning processes and discuss three additional interregional planning pathways to more proactively and effectively determine the need for interregional transmission and solutions that can reduce system-wide costs. The combination of these four planning pathways will be more effective in identifying interregional needs and cost-effective interregional projects.

As illustrated in Figure ES-1 below, the four parallel pathways to determining and addressing interregional transmission needs are:

- Develop new reliability and resilience standards that would establish minimum interregional transfer capabilities
- Create a new federal or other central planning authority that would identify economic and public policy needs, including those driven by new state or federal policies
- Enhance the current joint interregional planning processes to take a broader view of interregional project needs and benefits
- Improve individual regional planning processes to prioritize the identification of interregional projects that could more cost-effectively and proactively solve regional needs (including generation interconnection needs) than available regional solutions and specify the process for proposing such solutions to the neighboring region

FIGURE ES-1: PARALLEL PATHWAYS TO ESTABLISHING THE NEED FOR INTERREGIONAL TRANSMISSION



We further address the narrow and inconsistent **benefit analyses** of the current interregional planning processes and develop standards based on proven practices to improve benefit analyses for interregional projects. The analyses used in transmission planning to measure the economic benefits of new projects today rely primarily on narrowly-applied production cost simulations to determine whether the cost savings offered by a transmission project exceed the project's costs. Other transmission-related economic benefits often are either not considered by the regional planning authority or not quantified because they lack the metrics and tools to estimate those benefits. Interregional transmission planning is especially challenging given the tendency of joint planning efforts to evaluate interregional projects based only on the smaller subset of benefits that are common to the planning processes of each of the respective regions involved. Yet, a complete assessment of the wide range of benefits provided by interregional projects is essential to both cost allocation and state permitting.

Lastly, we discuss the contentious and overly formulaic **cost allocation** processes that often exist. A successful approach to cost allocation will need to be sufficiently flexible to accommodate projects that address different types of interregional needs (*e.g.*, reliability, economic, and public policy projects) across different types of neighboring regions and entities (*e.g.*, RTO and non-RTO regions, FERC-jurisdictional, and non-jurisdictional entities); but they will also need to be specific enough to be actionable without being overly restrictive and formulaic. To achieve this balance, cost allocation agreements should include guidelines or illustrations of how benefit metrics would be applied. For example, the cost allocation guidelines might specify that the costs of an interregional transmission project should be allocated based on the share of monetized benefits, *i.e.*, in proportion to the present value of project benefits received by each region. Alternatively, if the regions agree, the guidelines could allow for the cost allocation for some interregional projects to be based on more qualitative, non-monetized benefits and cost causation ratios.

Building on industry experience of the last decade and our October 2021 report,[2] we further offer the following proven principles and recommendations for effective transmission planning processes as the starting point for better regional and improved interregional planning:

1. **Proactively plan for future generation and load** by incorporating realistic long-term projections of the anticipated generation mix, public policy mandates, load levels, and load profiles; integrate generation interconnection and local reliability planning processes into broader regional and interregional transmission planning to ensure the most cost-effective solutions can identified and not be pre-empted by less-efficient incremental solutions;
2. **Approach every transmission project as a multi-value project**, able to address multiple drivers and multiple needs, which may differ across the regions, and account for the full range of transmission

[2] Pfeifenberger *et al.*, Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs, The Brattle Group and Grid Strategies, October 2021.

projects' benefits to comprehensively identify investments that can more cost-effectively address all categories of needs and benefits;

3. **Address uncertainties and high-stress grid conditions explicitly through scenario-based planning** that takes into account a broad range of plausible (but uncertain) long-term futures as well as real-world system conditions, including challenging and extreme events; employ "least regrets" planning methodology to reduce the risks of an uncertain future and avoid under- or over-building transmission;
4. **Use comprehensive transmission network portfolios** to address system needs and cost allocation more efficiently and less contentiously than a project-by-project approach; in particular, cost allocation should be based on the broad range of transmission-related benefits and, where possible for the entire portfolio of projects rather than individual projects, to take advantage of more stable and wide-spread benefits associated with recognizing multiple transmission-related values for entire portfolios of projects; and
5. **Jointly plan across neighboring interregional systems** to recognize regional interdependence, increase system resilience, and take full advantage of interregional scale economics and geographic diversification benefits.

However, as our stakeholder survey indicates, **interregional transmission planning and cost allocation creates unique challenges that go beyond the five principles mentioned above**. These additional challenges are addressed through proposed specific standards and principles for interregional needs determination, benefits quantification, and cost allocation developed as discussed in Sections II, IV and V of this roadmap report. We conclude the discussion of these interregional transmission planning topics—need determination, benefits quantification, and cost allocation—with recommended "key action items" for five major stakeholders: FERC, federal policy makers, state policymakers and regulators, regional planning authorities, and transmission owners.

I. Benefits of and Barriers to Interregional Transmission

Interregional transmission projects can provide significant cost savings and reliability benefits for customers and ensure the lowest cost outcomes as the grid transitions to clean resources. Numerous studies have shown that interregional transmission reduces costs, lowers electricity costs to customers, and reduces the risk of high-cost outcomes and power outages during extreme weather events and challenging market conditions (see Table 1 and Appendix A). While many of the national studies simulate various clean-energy futures, the benefits of interregional transmission go beyond transporting clean energy to load. Benefits also include resource and load diversification, increased system reliability and resilience, and wholesale power market benefits.

Table 1 summarizes a select group of recent studies that have analyzed the benefits of interregional transmission. For example, one such study found that an additional 1,000 MW of transmission capacity into Texas during winter storm Uri would have fully paid for itself over the course of the four-day event. The same study found that 1,000 MW of additional transmission capacity between MISO and PJM would have earned $100 million during the same short period of time.

Despite the net benefits of expanded interregional transmission estimated in these studies, they have failed to yield interregional transmission projects.[3] However, any beneficial expansion of interregional transmission capabilities identified in these national studies would also have to be confirmed as a need (that requires addressing) through the transmission planning processes of the respective regional planning authorities, which include the ISOs and RTOs, local transmission owners, as well as the various states' transmission siting and permitting agencies.

[3] These studies have not been successful in motivating improved interregional planning or actual transmission project developments because (1) many studies tend to analyze aspirational clean energy targets (*e.g.*, 100% by 2050) not the actual policies for the next 10−15 years; (2) the studies do not produce specific transmission projects; (3) the studies fail to identify how benefits and costs are distributed across jurisdictions; (4) there has not been an analysis of the state-by-state economic impact and job creation from interregional transmission development; and (5) most studies do not propose solutions to address the barriers to planning processes and to the development of new interregional transmission projects.

TABLE 1. SUMMARY OF SELECT RECENT INTERREGIONAL TRANSMISSION STUDIES

Study	Region	Findings
Grid Strategies Transmission Resilience Study (2021)	Various	During 2021 winter storm Uri, a gigawatt of transmission between Texas and the Southeastern U.S. could have saved lives and nearly $1 billion
NREL North American Renewable Integration Study (2021)	U.S., Canada, Mexico	Increasing international electricity trade can provide $10–$30 billion in net benefits Interregional transmission expansion achieves up to $180 billion in net benefits
MIT Value of Interregional Coordination (2021)	U.S. Nation-Wide	National coordination of transmission and clean-energy requirements reduces the cost of decarbonizing by almost 50% compared to no coordination between states The lowest-cost scenario builds almost 400 TW-km of transmission; including roughly 100 TW-km of DC capacity between the interconnections and over 200 TW-km of interregional AC capacity No individual state is better off implementing decarbonization alone compared to national coordination of generation and transmission investment Low storage and solar costs still result in significant cost-effective interregional transmission
Princeton Net Zero America Study (2021)	Nation-Wide	Achieving net-zero emissions by 2050 requires 700–1,400 TW-km of new transmission (two to five times the existing amount) Investment in transmission needed ranges $2–$4 trillion dollars by 2050
U.C. Berkeley 90% by 2035 (2020)	National-Wide	The only national study that suggest relatively little interregional transmission would be needed to achieve 90% clean electricity. However, the study's simulation approach does not utilize more granular and well-established methods to properly value interregional transmission.
Vibrant Clean Energy Interconnection Study (2020)	Eastern Interconnection	40 to 90 TW-km of transmission is built by 2050 to meet climate goals Transmission development can create 1–2 million jobs in the coming decades, more than wind, storage, or distributed solar development Transmission reduces electricity bills by $60–$90 per MWh
NREL Seams Study (2020)	Eastern & Western Interconnections	Major new ties between interconnections saves $4.5–$29 billion over a 35 year period

In the recent Federal Energy Regulatory Commission (FERC) Advance Notice of Proposed Rulemaking (ANOPR),[4] at least 32 comments referenced interregional transmission and most favored improved interregional planning processes, which include the following examples:

- *American Electric Power Service Corp.*: "The Commission should address planning for high-voltage interregional transmission projects, establishing system needs and common assumptions, which may include minimum interregional transfer capability requirements and resource adequacy standards, to encourage interregional transmission development."
- *Arizona Corporation Commission*: "Requiring either a joint planning process or coordination among neighboring regions would be beneficial to the Western Interconnection."
- *Commonwealth of Massachusetts Department of Energy Resources*: "Planning fundamentals should be applied to the interregional planning processes to allow for the identification of interregional projects that maximize net benefits across service territories."
- *New Jersey Board of Public Utilities*: "Interregional planning, particularly across the PJM/New York seam, is effectively non-existent, constantly mired in litigation based on outdated Commission rules and cost allocation processes."

FERC Order 1000 encouraged the regional planning authorities to coordinate interregional transmission planning but did not mandate the development of interregional transmission plans. Today, a decade after FERC Order 1000 was enacted, interregional transmission planning processes remain largely ineffective[5]—without any major interregional transmission projects having been approved in the U.S. since Order 1000 was implemented.

To better understand the reasons that prevent the development of cost-effective interregional projects from being realized through existing planning processes, we surveyed stakeholders from 18 different organizations across the industry, including RTOs, state and federal policymakers and regulators, large customers, industry and environmental groups, and utilities. We asked the stakeholders to provide their views about the benefits of interregional projects, the existing barriers to interregional transmission planning, and the potential solutions for improving interregional planning.

The stakeholder interviews consistently identified numerous barriers to interregional transmission planning and project development that fall broadly into the three interrelated categories shown in Figure 1: (A) Priorities, Alignment, and Understanding, (B) Planning Processes and Analytics, and (C) Regulatory Constraints. Table 2 lists the specific barriers identified in each of these three categories and additional details on each are presented in Appendix A.

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4 Building for the Future through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, 176 FERC ¶ 61,024 (2021).

5 See Pfeifenberger, Chang, and Sheilendranath, Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid, Prepared for WIRES, April 2015, p. 31 and Pfeifenberger, Transmission Planning and Benefit-Cost Analyses, Presented to FERC Staff, April 29, 2021, p. 3.

FIGURE 1: CATEGORIES OF BARRIERS TO INTERREGIONAL TRANSMISSION PLANNING AND DEVELOPMENT

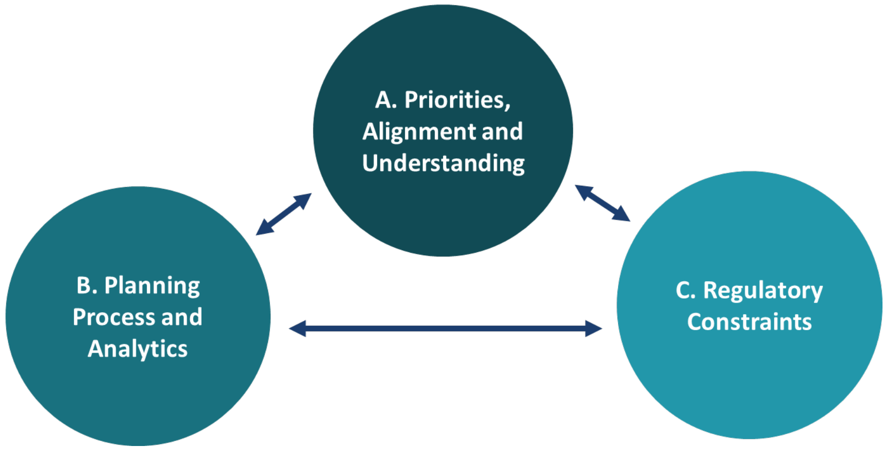

TABLE 2. SUMMARY OF BARRIERS TO INTERREGIONAL TRANSMISSION PLANNING AND DEVELOPMENT

A. Priorities, Alignment and Understanding	1. Insufficient leadership from RTOs and federal & state policymakers to prioritize interregional planning 2. Limited trust amongst states, RTOs, utilities, & customers 3. Limited understanding of transmission issues, benefits, & proposed solutions 4. Misaligned interests of RTOs, TOs, generators, & policymakers 5. States prioritize local interests, such as development of in-state renewables
B. Planning Process and Analytics	6. Benefit analyses are too narrow and often not consistent between regions 7. Lack of proactive planning for a full range of future scenarios 8. Sequencing of local, regional, and interregional planning 9. Cost allocation (too contentious or overly formulaic)
C. Regulatory Constraints	10. Overly-prescriptive tariffs and joint operating agreements 11. State certification, permitting, and siting requirements

This whitepaper provides a roadmap for addressing primarily the second category of barriers: improving interregional planning processes and analytics. However, as these groups of barriers are interrelated and making progress in improving interregional transmission development will require addressing the barriers in each of the three categories, we offer some initial thoughts on what the role of different entities could be in addressing the identified barriers. Even if much-improved interregional planning and analytical processes were to be designed, those improvements are unlikely to be implemented and actionable without efforts to address the other barriers: understanding interregional transmission benefits, planning prioritization, stakeholder alignment, and regulatory constraints.

Implementing improved planning processes requires a better understanding of the holistic value of transmission, how to fairly allocate costs, and how to overcome institutional barriers by all parties involves in transmission planning. Because interregional transmission projects are a critical part of present and future reliability in the face of increasing extreme weather patterns and also offer considerable economies of scale that can obviate the need for more costly and siloed regional and local projects, regulatory frameworks also need to be modified to incent interregional projects and require joint interregional planning that analyzes and incorporates least regrets projects at the outset of the regional planning process. To promote alignment of interests between regions, promote better understanding of the value of such projects, fairly apportion costs, minimize the burdens on directly impacted communities and consumers, and garner necessary support for such efforts, the interregional planning process must include relevant federal, state, and local policymakers and a broad representation of stakeholder interests and perspectives. Similarly, addressing the identified regulatory constraints will require evaluating and updating RTO tariffs and agreements, federal regulatory policies, and transmission-related state policies to improve the determination of transmission needs, cost-allocation, and permitting processes.

The remainder of this roadmap report discusses the current interregional transmission planning processes and analytical approaches, ways to improve these processes, and supporting analytics to increase their ability to identify cost-effective interregional transmission projects, quantify their benefits, and allocate project costs so they are roughly commensurate with the identified benefits. Recognizing that it will require leadership from federal and state policymakers and planning organizations to prioritize interregional issues, we offer our initial thoughts on what the role of these entities may be in addressing the identified barriers, implementing the recommended planning process improvements, and addressing the associated regulatory constraints. The report concludes with a brief case study that demonstrates how several elements of the proposed roadmap were successfully applied by a group of transmission providers in Louisiana to identify and approve a cost-effective seams project that faced several of the interregional barriers identified by stakeholders.

II. Improving Interregional Planning Processes and Analytics

Interregional transmission planning processes and analytical frameworks currently used by neighboring regions are mostly ineffective in advancing interregional transmission development. The barriers to interregional planning have created a gap of transmission investments near and across market seams.

Our interviews with stakeholders explored existing barriers and the adverse impacts they have on the development of interregional transmission projects. For example, RTO planners noted that they have shifted transmission development away from their border, or “seam,” with neighboring regions to increase the benefits that accrue internally to their region and the likelihood of winning approval for such development. Stakeholders also noted that this shift has narrowed what is even considered for development and RTOs would identify very different regional system needs and transmission upgrades if they studied a broader regional footprint and measured benefits for areas beyond their own RTO's boundaries. These stakeholder observations highlight the importance of standardizing how transmission planners analyze system-wide needs, benefits, and costs under different future transmission scenarios to ensure that interregional transmission needs can be identified and economies of scale can be captured.

Consistent with the findings of our stakeholder interviews, addressing interregional transmission barriers requires:

- Updating the sequencing of planning processes for generation interconnection needs, local transmission needs, and regional reliability, economic, and public policy needs to enable establishing a need for interregional transmission projects
- Quantifying a broader set of transmission-related benefits in support of the project need
- Implementing more proactive planning for a full range of future scenarios to recognize and understand uncertainties in project needs and benefits to identify "least-regrets" projects
- Improving cost-allocation methods based on a better understanding of project benefits and uncertainties

Addressing these identified barriers requires improving every phase of interregional planning processes, as illustrated in Figure 2 below, starting with (1) initial needs assessment and project identification, (2) benefits analysis to determine an identified project's cost-effectiveness, and (3) project cost recovery based on the cost-allocation approach. Developing a more effective approach to interregional planning will consequently require addressing the barriers at each step of the planning process.

FIGURE 2: TRANSMISSION PLANNING PROCESS

A successful interregional planning process needs to:

- Allow for interregional system needs and solutions to be identified through a broader set of planning pathways
- Accommodate projects that simultaneously serve a range of system needs, often offering different types of benefits to each region
- Ensure that a broad set of benefits are considered in any benefit-cost analyses

- Analyze the benefits for scenarios that represent the likely range of plausible futures
- Define clear cost allocation methodologies that provide sufficient guidance for planners, regulators, and stakeholders and ensure that cost recovery for portfolios of approved projects is roughly commensurate with the projected benefits of the projects

Industry experience with proven planning and cost-allocation processes points to several core principles for improving transmission planning processes, including the processes utilized for interregional transmission planning. As we have pointed out in a recent report,[6] in order to be effective, transmission planning processes need to:

1. **Proactively plan for future generation and load** by incorporating realistic long-term projections of the anticipated generation mix, public policy mandates, load levels, and load profiles;[7] integrate generation interconnection and local reliability planning processes into broader regional and interregional transmission planning to ensure the most cost-effective solutions can be identified and not be pre-empted by less-efficient incremental solutions;
2. **Approach every transmission project as a multi-value project**, able to address multiple drivers and multiple needs, which may differ across the regions, and account for the full range of transmission projects' benefits to comprehensively identify investments that can more cost-effectively address all categories of needs and benefits;

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[6] Pfeifenberger, *et al.*, Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs, The Brattle Group and Grid Strategies, October 2021.

[7] ANOPR comments have also addressed the appropriate timeframe over which transmission should be planned. There is almost universal agreement that the time horizon needs to be at least as long as the planning and development timeframes of major transmission projects, which often is a decade (if not more). However, while this approach would allow for the approval of projects that could realistically be completed before a specified need for the project first arises, such a "first-needs-based" approach will not be able to identify the most cost-effective solutions to address the multiple needs that a transmission project can address (and the benefits it would provide) over the course of its useful life.

For example, while a limited upgrade to a 230 kV transmission facility may address a specific reliability or generation-interconnection need within the next 10 years, a larger-scale 345 kV transmission investment may be more cost effective because it can address multiple needs that would likely arise in the decade(s) after the initial reliability need has to be addressed. For example, in addition to addressing the most pressing reliability need, the 345 kV upgrade may offer a lower-cost solution for longer-term generation interconnection needs, additionally reduce congestion and renewable curtailments over its lifespan, and address multiple reliability needs that would also have to be addressed in the future.

To capture these opportunities for addressing multiple future transmission needs at lower cost, projections for the anticipated generation mix, public policy mandates, load levels, and load profiles used in planning models should cover at least the time horizon of public policies (*e.g.*, the next 20 years for 2040 clean-energy mandates or the next 30 years for 2050 goals). Importantly, however, to reasonably compare a transmission investment's cost and benefits, the horizon of the benefit-cost analysis needs to cover (at least approximately) the cost-recovery lifespan of the transmission asset. If planning models only extend 20 years into the future, estimated benefits should be extrapolated beyond the 20 years (even if just indexed with inflation) to cover the remaining cost-recovery lifespan of the transmission asset. Otherwise the benefit-cost ratio of the investment will tend to be understated because benefits tend to grow over time (*e.g.*, with fuel costs and more stringent clean-energy and emissions standard) while project costs (*i.e.*, transmission revenue requirements) will tend to decline over time as the asset is depreciated.

For a discussion of using scenario-based planning to address long-term uncertainties, see pages 58-64 of Pfeifenberger, *et al.*, Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs, The Brattle Group and Grid Strategies, October 2021.

3. **Address uncertainties and high-stress grid conditions explicitly through scenario-based planning** that manages uncertainty by evaluating a broad range of plausible long-term futures as well as real-world system conditions, including challenging and extreme events and choosing "least regrets" options that prevent either over- or under-building transmission;
4. **Use comprehensive transmission network portfolios** to address system needs and cost allocation more efficiently and less contentiously than a project-by-project approach; in particular, cost allocation methodologies need to account for the more stable and wide-spread benefits associated with recognizing multiple transmission-related values for entire portfolios of projects; and
5. **Jointly plan across neighboring interregional systems** to recognize regional interdependence, increase system resilience, and take full advantage of interregional scale economics and geographic diversification benefits.

As highlighted by our stakeholder interviews, however, the planning and cost allocation of interregional transmission creates unique challenges that go beyond the above principles. The following sections outline a roadmap for overcoming the key barriers to effective interregional transmission planning.

III. Identifying Interregional Transmission Needs

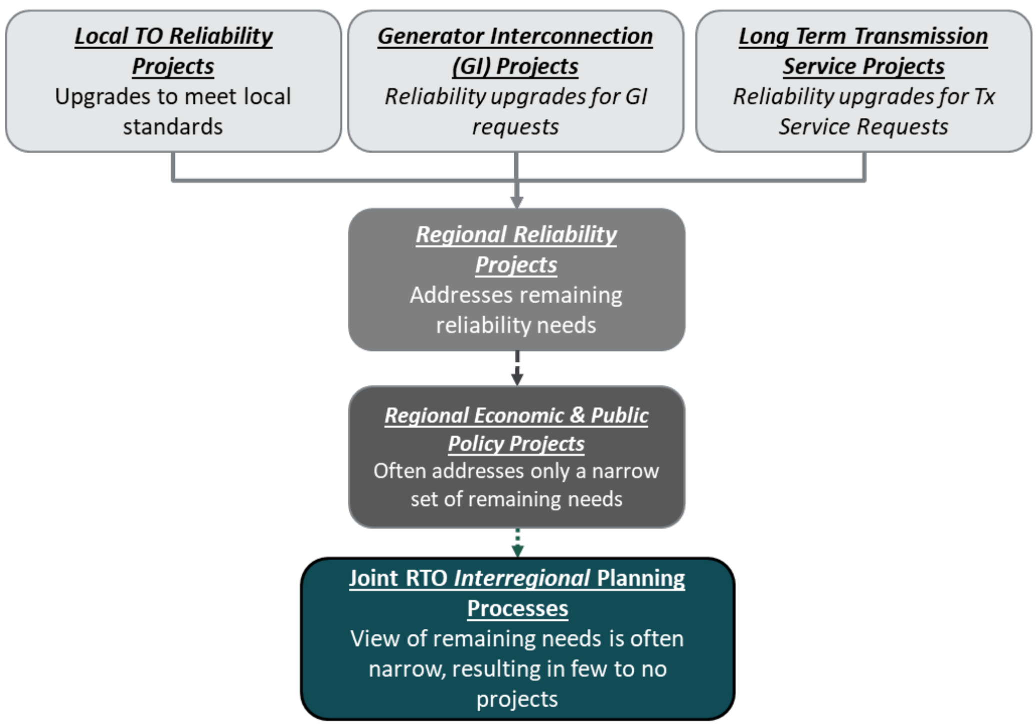
One of the main barriers hindering the ability to create an effective planning framework is the limited view currently taken to establish interregional project needs. In the transmission-planning context, "need" refers to projected problems for the transmission grid that can be addressed cost-effectively through a proposed solution. Defining a clear need that can be addressed through interregional transmission is essential for identifying cost-effective interregional projects during the planning process and for establishing that the projects are necessary and in the public interest during the RTO and state-level approval processes.

A. Limitations of Current Transmission Planning Processes

Currently, the needs for transmission projects are primarily placed into one of three separate buckets: (i) reliability and resilience driven needs, (ii) economic or market efficiency needs, and (iii) public policy needs. Reliability and resilience needs refer to system inadequacies that can trigger a violation of applicable reliability criteria if left unaddressed. Reliability needs, which represent the large majority of planned transmission projects in most regions, are identified as RTOs' plans for compliance with NERC and local reliability standards. Economic or market-efficiency needs generally refer to the cost savings that transmission upgrades can provide by reducing congestion, allowing the delivery of lower-cost power to load, and offering other grid- and generation-related benefits that reduce system-wide costs. Finally, public policy needs refer to the infrastructure required to cost-effectively meet the policy requirements of local, state, or federal governments—often clean-energy policies that require the integration of renewable energy resources.

The current transmission planning processes vary by region, but generally follow the process illustrated in Figure 3 below. The large majority of a region's transmission projects approved through the current planning processes are transmission upgrades to ensure compliance with the reliability needs set out by NERC and local utilities' reliability standards and are driven by: (1) local utility reliability planning, (2) generator interconnection requests, and (3) long-term transmission service requests—as shown by the first row of Figure 3.

FIGURE 3. PLANNING PROCESSES CURRENTLY USED IN RTOs TO IDENTIFY AND APPROVE TRANSMISSION PROJECTS



Once transmission projects based on these specific reliability needs are identified, most of the remaining projects are approved to address additional regional reliability needs. Together the local and regional reliability projects of the first and second row of Figure 3 account for the large majority (*I.e.*, more than 90%) of the approximately $25 billion/year of national transmission investments.[8] None of these

8 *See* slide 1 of Pfeifenberger, Transmission—The Great Enabler: Recognizing Multiple Benefits in Transmission Planning, ESIG Fall Workshop, October 28, 2021.

reliability-driven projects involve any assessment of economic cost and benefits—which also means these investments add transmission costs but are not made with the objective to find the most cost-effective solutions from a total system-wide costs and electricity rates perspective. Only after these reliability needs are addressed are regional economic and public policy needs evaluated in most of the regional planning processes.

This sequencing leads to inefficient outcomes, as it results in incremental transmission upgrades that preempt larger regional or interregional projects, particularly those that could preemptively address the multiple needs more cost-effectively than the projects selected through the current (incremental, primarily reliability-focused) planning processes.

To the extent interregional planning efforts have been conducted under the current processes, it is generally based on a narrow view of economic benefits (often limited to traditional production cost savings) and without a consistent consideration of public policy needs. While there have been instances of successful planning of major regional transmission projections to address regional economic and public policy projects—such as CAISO's Location Constrained Resource Interconnection (LCRI) project, SPP's Integrated Transmission Planning (ITP) projects, MISO's portfolio of Multi Value Projects (MVP), ERCOT Competitive Renewable Energy Zones transmission, New York's Public Policy Transmission projects, and the New Jersey BPU's current efforts related to offshore wind integration[9]—these projects often account for only a small share of total transmission investments and do not address interregional needs. While existing planning regimes include some interregional coordination opportunities, they are generally ineffective and have produced only a few minor interregional transmission projects to date. This outcome in large part relates to the sequence of how the different needs are addressed—leaving few needs that could be addressed more cost-effectively through interregional transmission projects—and to an overly narrow assessment of interregional transmission needs and benefits.

In short, while there are many multi-regional and national studies that have identified many benefits from increasing interregional transmission capability as discussed above, the existing sequencing of transmission planning processes have not identified such interregional needs. As a result, very few interregional projects have ever been identified and approved under these processes.

Consistent with this general description of current transmission planning processes, our interviews with stakeholders have similarly identified (and confirmed) various reasons for why the current planning processes fail to identify transmission needs, particularly when focused on *interregional* needs:

- First, since each planning region has to ensure that its own system meets all applicable reliability standards, all of these reliability needs are addressed at the local and regional level. ***Almost by definition, there is no reliability need for interregional transmission projects left to address***.

[9] *See* Pfeifenberger, *et al.*, Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs, October 2021.

- Second, many regional planning processes do not account for multiple drivers of the overall need for interregional transmission projects, which means that these ***processes are not set up to identify interregional transmission project solutions that can simultaneously and more cost-effectively address multiple regional and interregional needs***.
- Third, the scope of regional planning processes tends to be too narrowly focused in the consideration of transmission-related benefits and their geographic scope, typically quantifying only a subset of transmission-related economic and public policy benefits and considering only benefits that accrue to that particular region ***without considering the broader set of interregional benefits***. This means quantified benefits are frequently understated and even "regional" projects near the region's seams often fail to meet applicable benefit-cost thresholds for regional market-efficiency and public policy needs simply because the planning process ignores the benefits that accrue on the other side of the seam.
- Finally, ***local and regional reliability needs*** tend to be addressed quickly and projects are ***often approved before*** larger, proactive, and potentially ***more cost-effective interregional solutions can be considered*** and approved in a sufficiently timely manner.[10]

B. Multiple Pathways to Establishing Interregional Transmission Needs

Joint regional planning processes by neighboring regions currently are the primary pathway to identify interregional transmission needs and determine the benefits of candidate interregional transmission projects that could address these needs. Based on stakeholder input and our own experience with interregional transmission processes, we recommend reforms to joint interregional planning processes and identify additional pathways that could be implemented in parallel to establish the need for interregional transmission projects.

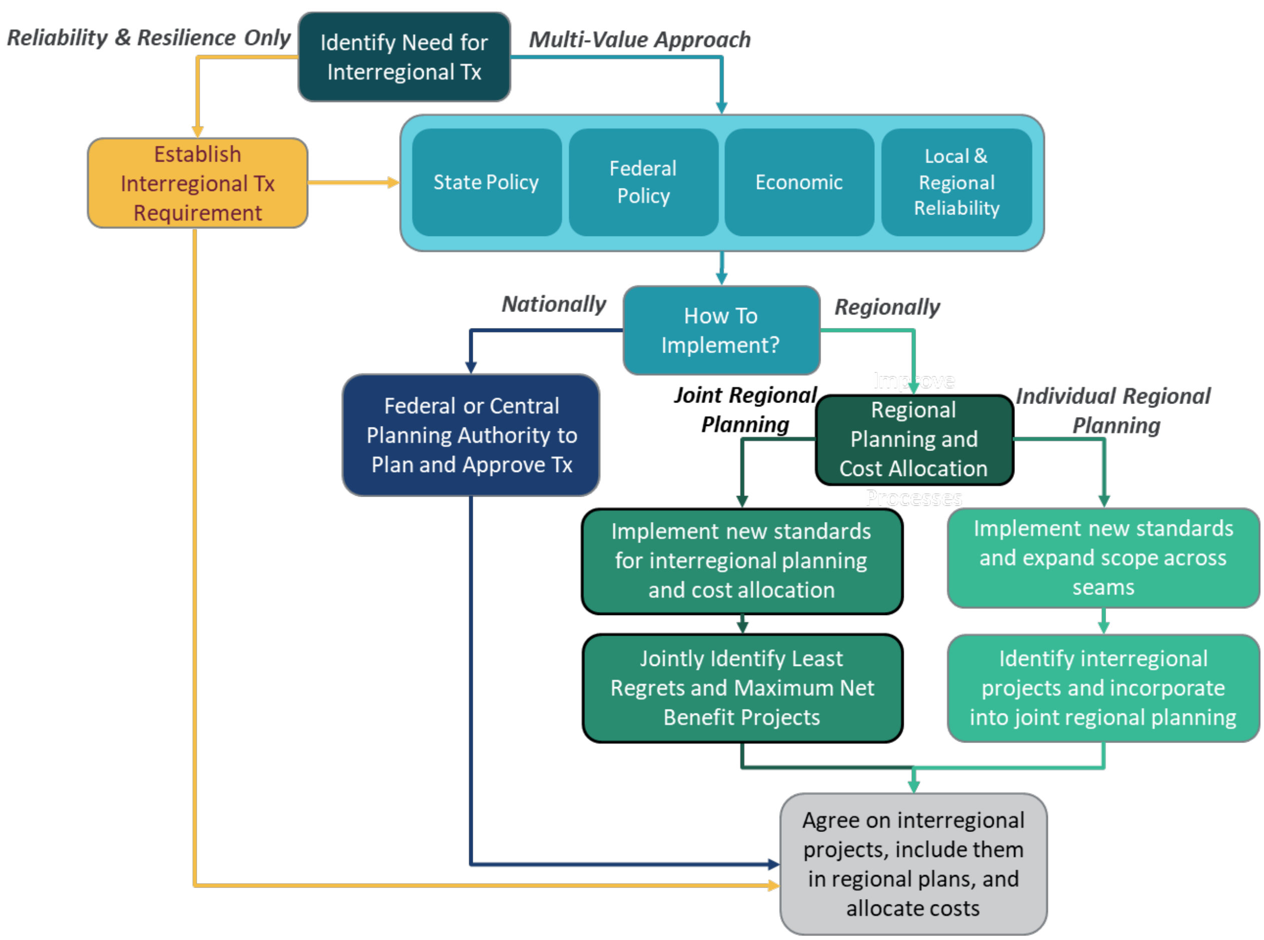
These recommendations are summarized in Figure 4 and include determining interregional transmission needs through several parallel planning pathways that can be pursued simultaneously:

- New reliability and resilience standards that would establish minimum interregional transfer capabilities, possibly implemented through NERC
- A new federal or central planning authority that would identify economic and public policy needs, including those driven by new state or federal policies, and has the authority to ensure projects are evaluated, permitted and sited, and ultimately built

[10] As we explain further below, reliability needs that are located along the seam with neighboring regions and, thus, might provide (different types of) benefits on both sides of the seam should be incorporated into the existing RTO process for identifying interregional needs and cost effective solutions.

- Enhanced joint interregional planning processes that would take a broader and proactive view of interregional project needs and benefits
- Improved individual regional planning processes that would allow the identification of interregional projects that could more cost effectively meet regional needs than available regional solutions and provide benefits to the neighboring system (and would specify the process for proposing such solutions to the neighboring region)

FIGURE 4. PARALLEL PATHWAYS TO ESTABLISHING THE NEED FOR INTERREGIONAL TRANSMISSION



Notes: "GI" refers to generator interconnection.

Improving and pursuing these interregional planning pathways will be increasingly important to assure resource diversity and cost-effective outcomes in a higher-renewable-generation power grid. For example, the experience in Germany shows that as renewable generation shares increase, the need for additional interregional transmission to help diversify renewable generation patterns increases as well. Germany recently approved a fourth major new high-capacity transmission line to more completely and cost-effectively integrate its southern region (with surplus distributed solar generation during sunny days and import needs when the sun is down) and its northern region (with surplus offshore wind generation during wind-rich periods and import needs during low-wind period).[11]

1. A New NERC Interregional Reliability & Resilience Standard

As shown in the left branch of Figure 4, one future pathway to determine the need for interregional transmission could be created through new reliability and resilience standards that aim to improve regional reliability and resilience through minimum interregional transfer capabilities. If designed correctly, and possibly implemented through NERC, they would require interregional transmission expansion where there is insufficient transfer capability between regions.

The increasing frequency of extreme weather events across the U.S.—most recently in the summer of 2020 and in February 2021—have certainly highlighted the key role that the interregional transmission system plays under extreme weather conditions and the ability to avoid outages and very-high-cost outcomes.[12] In response to those geographically-large weather events, FERC needs to direct NERC to incorporate additional reliability and resilience standards related to interregional transfer capability going forward. If it does, NERC will need to determine whether standards related to interregional transfer capability should be created and, if so, how planning regions would need to adjust their transmission-related reliability and resilience standards. System planning authorities would then need to determine how much additional interregional transfer capability is necessary to meet those standards.[13]

2. A New Federal or Central Planning Authority

Without a reliability or resilience need determined by new NERC interregional transfer capability requirements, interregional projects would primarily be driven by evaluating economic, reliability, and public policy requirements.[14] Economic and public policy needs can be driven by new state or federal

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11 *See* [*Fourth North-South Power Line Required in Germany*](), Clean Energy Wire, August 7, 2019.

12 In the past 12 months, major blackouts occurred in California and the Northwest in August 2020 due to an extreme heat wave across the Western U.S. and in Texas and the Midwest in February 2021 due to extreme cold weather conditions. Similar events occurred during the winter of 2014 and 2015 due to "polar vortex" events that affected the East Coast.

For a discussion of the benefit that additional interregional transmission would have provided during these extreme weather events, see Goggin, *Transmission Makes the Power System Resilient to Extreme Weather*, prepared for ACORE, July 2021, showing that The report shows that 1,000 MW of additional transmission capacity between Texas and its neighboring power regions would have provided nearly USD $1 billion dollars of value over just a few days during Winter Storm Uri.

13 For example, the European Union has set interregional interconnection targets such that each country has in place transmission interties that allow at least 10% of the electricity produced by its power plants to be transported across its borders to neighboring countries. See: https://ec.europa.eu/energy/topics/infrastructure/electricity-interconnection-targets_en

14 As we explain below, local and regional reliability needs located along the seam with neighboring regions should also be incorporated into the existing regional planning processes to evaluate if they, in combination with other regional and interregional needs, could be addressed more cost effectively through interregional transmission solutions.

policies. As has been proposed elsewhere,[15] the planning of interregional transmission projects to address any such state or federal needs could be undertaken either by a new federal planning authority—particularly in concert with any new federal clean-energy and transmission infrastructure investment legislation—or by a centralized, multi-regional planning authority established by the states. Figure 4 above shows this second pathway in blue.

At either the federal or interregional level, policymakers will need to determine whether such a new national or multi-regional planning authority would be housed at or authorized by FERC, the Department of Energy, or another agency. This new planning authority would need to consider several key issues, including (1) whether to address both federal and state policy objectives in addition to reliability, market efficiency, and broader economic objectives, (2) how to interface with states and RTOs, (3) whether it would primarily establish interregional needs that would then be addressed by the regions, or whether it would also identify cost-effective solutions for these needs, and (4) how costs of interregional planning and projects should be allocated across the regions or nationally.

Developing a federal planning process that can take a broader view of long-term interregional transmission needs and benefits than the existing RTO processes is worth considering, especially if the planning regions are unable or unwilling to lead this effort and adequately adapt their existing planning processes to address the transmission needs associated with the ongoing industry transition. The benefit of this approach would be that it would ensure the coverage of and participation from both RTO and non-RTO regions. It would also provide a unique forum for states to participate, including through modernizing and aligning their siting processes, which would make successful development of interregional transmission far more likely. Federal oversight and broader stakeholder participation would also help ensure independence of the decision-making process.

3. Improved Interregional and Regional Planning Processes

As shown with the two green pathways in the right half of Figure 4 above, existing regional (often RTO-administered) transmission planning processes could be improved through both (1) a top-down basis (dark green pathway) by mandating that the existing interregional planning efforts (conducted jointly by the neighboring regional planning authorities) produce and implement interregional transmission plans; and (2) a bottom-up basis (light green pathway) through expanded regional planning by the individual

[15] For example, see ESIG's white paper, Transmission Planning for 100% Clean Electricity (2021): recommending "that a national transmission planning authority be created to develop and implement an ongoing transmission planning process. The United States needs an organization with the authority and responsibility to conduct national-level planning that transcends regional and parochial interests. Such an organization will not obviate the need for regional planning, but should work with the regional planners and others to coordinate top-down and bottom-up needs and optimize solutions according to the national public interest." *See also* Remarks of Allison Silverstein in FERC Docket AD21-13, recommending a "National Electric Transmission Authority [that, among other functions, would] have the ability to work with federal agencies and states to identify preferred resource zones, find appropriate routes for new intra- and inter-regional lines to connect resource zones to loads, and use federal funds to help pay a portion of the costs of new backbone transmission."

RTO and non-RTO regions so they are able to identify interregional transmission solutions that can cost-effectively address regional needs.

Expanding the scope of the individual regional planning processes to also consider interregional needs on a bottom-up basis would fill a crucial gap that currently exists between the existing joint interregional planning processes meant to identify valuable interregional transmission projects and the individual regional planning processes that do not consider whether interregional solutions could address their regional needs more cost-effectively. This gap in the existing regional planning processes can lead to an inability to identify beneficial interregional projects before less cost-effective regional solutions are approved and implemented—thereby preempting the opportunity to implement interregional projects that could more cost-effectively address multiple other needs on either side of the region's boundary.

A bottom-up approach under which individual regional planning authorities could identify interregional needs and solutions through their regional planning efforts would reduce barriers related to the sequencing of transmission planning for interregional needs, regional needs, generation interconnection requests, transmission service requests, and local transmission needs. The regional planning processes could be modified to (1) integrate addressing local and generation-related reliability needs into multi-value regional transmission planning and (2) include in that multi-value needs assessment an evaluation of whether interregional projects can address multiple needs near and across their seam more cost effectively than the incremental projects that address only a specific regional need.[16]

Simultaneously, the (top-down) joint interregional planning processes would need to be improved to more effectively identify whether interregional solutions would be more cost-effective than already-identified regional projects, in part by being able to address a wider range of needs for both of the neighboring regions. However, due to the near-term needs for some regional reliability projects (*e.g.* due the unexpected retirement of a generating plant), such an interregional assessment would either (a)

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[16] For example, NYISO has integrated consideration of aging facilities replacement into its public policy planning process. By doing so, NYISO determined that replacements of aging transmission infrastructure nearing its end of life could be avoided by major regional AC system upgrades. The avoided costs of the facilities replacements are considered as a benefit that partially covers the cost of the larger regional upgrade that also addresses public policy needs. *See* Newell, *et al.*, *Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades*, September 15, 2015.

Similar opportunities exist for integrating incremental transmission upgrades associated with generation interconnection needs into the regional and interregional planning process. For example, Enel recently presented a proposed approach under which generation-interconnection upgrades would be limited to narrow local needs at the interconnection point, while larger network upgrades are considered through a single, integrated regional transmission planning process. *See Plugging In: A Roadmap for Modernizing & Integrating Interconnection and Transmission Planning*, Enel Green Power, Working Paper, 2021. This approach of reducing the scope of generation-interconnection driven upgrades so regional network upgrades can be planned more holistically has already been used successfully in the United Kingdom for over a decade now. The "Connect and Manage" regime allows all new generation to apply for an accelerated connection based solely on the time taken to complete their local 'enabling works', with wider network reinforcement carried out after they have been connected through the regional transmission planning process. This process has dramatically reduced generation interconnection timelines by five years on average while allowing regional planning processes to more holistically identify the most cost-effective network upgrades. See, for example, Crouch, *Report on the enduring 'Connect and Manage' grid access regime,* Ofgem letter to The Rt Hon Andrea Leadsom MP Minister of State Department of Energy & Climate, December 14, 2015.

need to occur quickly, so that more cost-effective interregional solutions can be identified before the regional project is built; or (b) identify potential interregional needs and solutions ahead of time, such that they can be considered by the individual regions when developing projects to address a specific regional need. To the extent possible, however, planning processes should be more pro-active to, whenever possible, avoid outcomes in which predictable needs are ignored until they have to be addressed urgently, without sufficient time for a broader evaluation of cost-effective solutions through the regional and interregional planning processes.

As a part of an individual region's bottom-up approach to identifying interregional needs, each region would have to analyze its individual system needs by considering benefits that accrue to an expanded footprint that includes (all or portions of) neighboring regions. RTO planners noted during our stakeholder interviews that they already include neighboring markets in their planning models but only quantify benefits of possible transmission upgrades for their own footprint. Considering project benefits to the broader system would provide regional planners an additional opportunity to identify projects with interregional benefits that they could then propose as an interregional project to the neighboring region.

C. Improving Needs Assessment in Interregional Planning Processes

We recommend that the current interregional planning processes for identifying interregional needs—jointly conducted by neighboring planning regions—be modified in three ways to avoid the barriers that stakeholders identified in the current processes. Regional planning authorities should:

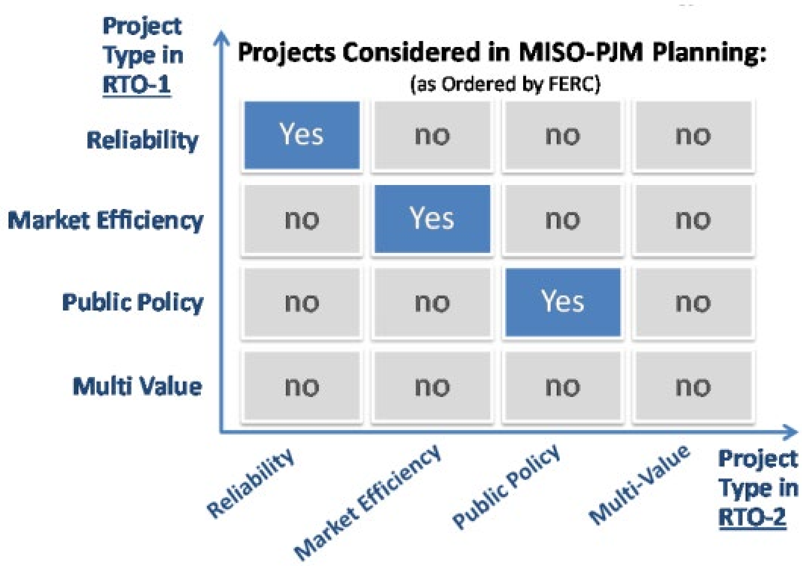
- Consider multiple drivers of need for interregional projects
- Remove any requirements that interregional projects address the same need for each of the neighboring regions
- Eliminate minimum size thresholds for interregional projects (if any), including those based on the voltage or cost

Some of the existing joint interregional planning processes (such as the PJM-MISO interregional planning process) allow only for the evaluation of transmission needs that are of the same type (*i.e.*, reliability, market efficiency, or public policy) in both regions. As illustrated in Figure 5,[17] these types of interregional planning processes thus may not allow for the evaluation of needs that differ across the regions, which can disqualify many valuable interregional projects from consideration.

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

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

FIGURE 5. SOME INTERREGIONAL PLANNING PROCESSES DO NOT ALLOW FOR THE EVALUATION OF PROJECTS THAT ADDRESS DIFFERENT NEEDS IN EACH REGION



To address this barrier, joint interregional planning processes should universally consider multiple drivers of need for identifying interregional projects. While only a reliability need may exist on one side of a seam, only market efficiency or public policy needs may exist on the other side. However, multiple needs and benefits are equally likely to exist on either side of the seam. Without recognizing that many transmission investments can address multiple needs, the industry will not be able to move beyond incremental solutions based on addressing reliability needs, leaving much unexplored value on the table, and increasing the overall costs and risks to customers and the power system as a whole. This means that interregional planning processes should encourage regional planning authorities to address their own regional needs through interregional projects if doing so is more cost effective overall.

Even where multi-value or multi-driver planning is possible under the currently-used interregional planning processes, interregional transmission projects may not be able to qualify under these processes due to different size and location thresholds used by neighboring regions in their regional and interregional planning processes. For example, interregional planning processes may exclude any upgrades below certain voltage levels (*e.g.*, 230 kV) or impose minimum project cost thresholds, which may eliminate from consideration any lower voltage or smaller projects even if they could cost-effectively address interregional needs.[18] Based on the definition of interregional transmission assets in FERC Order 1000, some of the current interregional planning processes may also exclude from consideration any projects that are physically located within a single region, even if the projects (such as an upgrade to a shared flow gate) would also address the needs of neighboring regions. This limitation, however, is no longer present in the PJM-MISO and MISO-SPP joint interregional planning process, which specifically allow for the consideration projects (such as upgrades to shared flow gates) that are located entirely within one of the regions but address needs in both regions.[19]

D. Proposed Improvements for Determining Interregional Transmission Needs

As illustrated in the pathways chart (Figure 4) above, improving the interregional planning processes to identify interregional transmission needs will require the following changes.

Add new pathways for interregional needs assessment: The process for identifying the need for interregional upgrades to the transmission system and/or identifying problems that interregional upgrades could resolve should be expanded to include additional pathways as outlined in Figure 4 above. The additional pathways could include (1) NERC establishing interregional reliability and resilience standards, (2) a federal planning authority or state-administered regional planning authorities identifying interregional economic and policy needs, and/or (3) individual regions identifying interregional needs through their existing regional planning process.

Expand options for interregional needs identification: The existing joint interregional planning processes should be improved to allow individual regions to identify and present interregional transmission projects for consideration by the other region, including for further evaluation through the joint interregional planning process. This would require interregional planning processes to clearly define how individual regions (or stakeholders within those regions) can identify interregional needs and nominate projects for consideration during the joint planning process.

Apply a multi-driver framework to identify interregional transmission needs: Interregional planning processes need to be expanded to allow for the identification of multiple drivers of needs and to be flexible enough to accommodate projects that address different needs in different regions (*e.g.*,

18 SPP has attempted to approach interregional planning more broadly and include reliability, economic, and public policy projects at all voltage levels. In contrast, MISO applies a narrower perspective and proposed limiting interregional planning solely to “market efficiency projects” at a voltage level of 230 kV or above.

19 SPP-MISO and MISO-PJM Joint Operating Agreements available here: https://www.misoenergy.org/planning/interregional-coodination/

reliability needs in one region but public policy needs in the other). This will require expanding the needs identification process beyond the current narrow approach of identifying reliability, economic, or policy needs. Instead, the full set of interregional needs across the neighboring regions should be considered as a whole to determine whether certain projects may be able to address one or more needs across both regions.

Reduce project qualification thresholds: Regional planning authorities should eliminate the use of minimum-size thresholds based on voltage level, total cost, or total benefits for interregional planning as even small projects might offer benefits that significantly exceed their costs. The definition of an interregional project should include both projects that physically cross the seam (as interregional projects are currently defined in Order 1000) or that are physically located within one region but can address the needs of and provide clear benefits to both regions. Examples of the latter type of interregionally-beneficial projects are upgrades to shared flow-gates that are located whole in one region but also constrain flows of the neighboring region.

E. Key Stakeholder Action Items

To implement the suggested improvements to interregional planning and needs assessment, planners and policymakers need to pursue the following action items:

FERC:

- Require regional planning authorities to amend their joint interregional planning processes to identify interregional transmission needs based on a scenario-based, multi-driver, multi-value analysis.
- Mandate that interregional planning processes develop a procedure for individual regions to incorporate interregional solutions into the standardized regional planning processes.
- Require multi-driver analysis of interregionally-beneficial projects regardless of size or project location.
- Update NERC reliability and resilience standards to require necessary levels of interregional transfer capability.

Federal Policymakers:

- Develop a multi-regional planning process and consider establishing a federal planning authority (possibly under FERC or DOE) for identifying federal policy-related needs for increased transfer capability between regions, especially needs associated with meeting federal clean energy and decarbonization objectives.

State Policymakers and Regulators:

- Support alternative pathways for interregional planning efforts that can more cost-effectively support state policy goals.
- Consider whether multi-state regional planning authorities are necessary for identifying policy-related needs for increased transfer capability between states and regions in the absence of a federal planning process.

Regional Planning Authorities:

- Implement new standards for interregional needs identification
- Work with joint/interregional planning authority bodies to adopt multi-driver needs determinations (consistent with implementing proven methods that quantify a broad range of transmission benefits and develop portfolio-based cost allocation methods that allocate costs commensurate with benefits).
- Incorporate into interregional transmission planning processes a procedure for proactively identifying when interregional solutions address multiple needs in a more cost effective manner.
- Commence regional planning analysis across a larger footprint that includes neighboring regions to identify interregional solutions that more cost-effectively address regional needs and implement those as part of the interregional planning process.

Transmission Owners

- Support planning authorities in their efforts to identify interregional transmission needs

IV. Quantifying the Full Benefits of Interregional Transmission

Most economic analyses used in transmission planning rely primarily on traditional applications of production cost simulations to determine whether the production cost savings offered by a transmission project exceed the project's costs. These production cost savings, adjusted for wholesale purchases and sales (or imports and exports), are mostly composed of fuel cost savings. Other transmission-related benefits are either not considered by regional planners or they lack the metrics and tools to quantify those benefits. Interregional benefits analyses are additionally challenging since the models, tools, and benefits metrics used by neighboring planning regions typically are not well-aligned.

Stakeholders highlighted in our interviews that the narrow scope of benefits that are currently included in regional planning processes is a significant barrier to identifying and approving both regional and interregional transmission projects. They also noted that the narrow scope of benefits quantified creates barriers in cost allocation (which we address further in the next section) since costs can only be allocated to individual regions if the benefits are recognized by the planning authorities and stakeholders of those regions.

In some planning regions, the analysis of economic benefits has expanded well beyond production cost savings for at least a subset of transmission projects evaluated within the regional planning process. For example, as shown in Table 3 below, when MISO planned its portfolio of Multi-Value Projects a decade ago, it considered reduced operations reserves, reduced planning reserves, reduced transmission losses, reduced renewable generation investment costs, and reduced future transmission investment costs in its benefits analysis in addition to the standard production cost savings. Table 3 below summarizes the experience with expanded benefits analysis employed by SPP, CAISO, and NYISO for certain transmission projects. To be effective, analysis and quantification of a broader set of transmission-related benefits must also be applied to interregional planning efforts.

TABLE 3: EXAMPLES OF EXPANDED TRANSMISSION BENEFITS ANALYSIS

SPP **2016 RCAR, 2013 MTF**	**MISO** **2011 MVP ANALYSIS**	**CAISO** **2007 TEAM ANALYSIS OF DPV2 PROJECT**	**NYISO** **2015 PPTN STUDY OF AC UPGRADES**
Quantified 1. **production cost savings** value of reduced emissions reduced AS costs 2. avoided transmission project costs 3. reduced transmission losses capacity benefit energy cost benefit 4. lower transmission outage costs 5. value of reliability projects 6. value of meeting policy goals 7. Increased wheeling revenues	**Quantified** 1. production cost savings 2. reduced operating reserves 3. reduced planning reserves 4. reduced transmission losses 5. reduced renewable generation investment costs 6. reduced future transmission investment costs	**Quantified** 1. production cost savings and reduced energy prices from both a societal and customer perspective 2. mitigation of market power 3. insurance value for high-impact low-probability events 4. capacity benefits due to reduced generation investment costs 5. operational benefits (RMR) 6. reduced transmission losses* 7. emissions benefit	**Quantified** 1. production cost savings (includes savings not captured by normalized simulations) 2. capacity resource cost savings 3. reduced refurbishment costs for aging transmission 4. reduced costs of achieving renewable & climate goals
Not Quantified 8. reduced cost of extreme events 9. reduced reserve margin 10. reduced loss of load probability 11. increased competition/liquidity 12. improved congestion hedging 13. mitigation of uncertainty 14. reduced plant cycling costs 15. societal economic benefits	**Not Quantified** 7. enhanced generation policy flexibility 8. increased system robustness 9. decreased nat. gas price risk 10. decreased CO_2 emissions 11. decreased wind volatility 12. increased local investment and job creation	**Not Quantified** 8. facilitation of the retirement of aging power plants 9. encouraging fuel diversity 10. improved reserve sharing 11. increased voltage support	**Not Quantified** 5. protection against extreme market conditions 6. increased competition and liquidity 7. storm hardening and resilience 8. expandability benefits

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

A consolidated summary of the benefits of transmission investments that have been considered and quantified by RTOs and others in transmission benefits assessments are listed in Table 4 below.[20] The wide range of benefits that can be quantified but often are not included in the analysis of economic and public policy transmission projects include reduced system losses, the value of increased system reliability (or reduced reserve margin requirements), access to lower-cost conventional and renewable generation, and increased wholesale-market competition, among others.

TABLE 4. ELECTRICITY SYSTEM BENEFITS OF TRANSMISSION INVESTMENTS

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

Most regional planning processes that are focused mostly on traditional production cost savings are not taking advantage of available industry experience and well-tested practices in quantifying an expanded

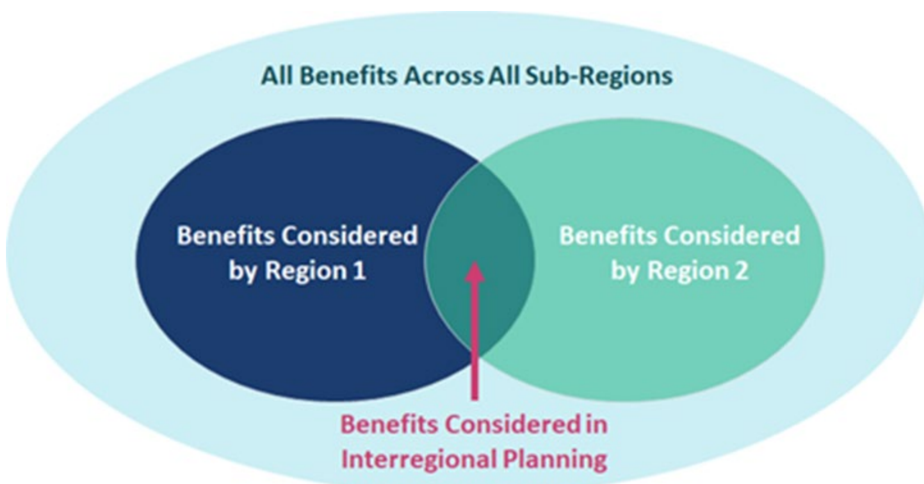
[20] Pfeifenberger *et al.*, Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs, October 2021. This report also summarizes proven industry experience with a wide range of benefit metrics for the evaluation of transmission projects and documents the approaches taken and well-tested practices for quantifying the benefits associated with these metrics. A good discussion of benefit metrics and methods for quantifying them is also presented in SPP, *Regional Cost Allocation Review Report for RCAR II*, July 11, 2016 (Section 6) and SPP Metrics Task Force, *Benefits for the 2013 Regional Cost Allocation Review*, July, 5 2012.

set of transmission-related benefits. The benefit-cost assessment of regional and interregional planning processes thus needs to expand beyond focusing solely on the traditionally-quantified production cost savings to a more holistic view of benefits that accurately reflect the benefits of proposed transmission projects.

Despite the significant experience in quantifying a broader set of benefits across the industry, several stakeholders, especially state policymakers and customers, were not familiar with other regions' experience with considering and quantifying many of these benefits. As a result, the full set of benefits is not typically considered in most regional transmission planning processes.

Interregional transmission planning is especially challenging given the tendency of neighboring regions to evaluate interregional projects based only on the subset of benefits that are common to the planning processes of each of the respective regions involved. In some cases, the respective regions reviewing an interregional project might have agreed for project evaluation to use only the subset of criteria and benefit metrics that are common to both regions. However, such an approach tends to disadvantage interregional projects because the jointly agreed-upon criteria and metrics generally will tend to represent the least common denominator subset of the criteria and metrics used in the adjoining regions. Worse, as shown in Figure 6, the range of benefits considered for interregional projects tends be more limited than even the narrow scope of benefits considered in intra-regional planning processes.

FIGURE 6. THE "LEAST COMMON DENOMINATOR" CHALLENGE OF BENEFIT-COST ANALYSIS FOR INTERREGIONAL PROJECTS



Similarly, current interregional planning processes do not recognize the unique benefits often offered by an expanded interregional transmission system, which include increased load and resource diversity and the geographic diversification of load and renewable generation variability and forecasting uncertainty.[21]

Current benefit analyses of regional planning processes tend to over-rely on "base case" projections, with a focus on current trends and associated needs. The utility industry faces considerable uncertainties on both a near- and long-term basis. These uncertainties should be considered explicitly in transmission planning. A base case planning approach does not recognize the value of transmission investments to address challenges and high-cost outcomes in futures that deviate from the business as usual case, such as increased environmental regulations or market rule changes, higher natural gas and emissions prices, substantive shifts in generation or load, or infrequent but extreme weather conditions. The consideration of near-term uncertainties—such as uncertainties in loads, volatility in fuel prices, and transmission and generation outages—is important because the value of the transmission infrastructure is generally disproportionately concentrated in periods of more challenging, or extreme, market conditions. As the high economic costs and lost lives due to extended power outages during winter storm Uri demonstrated most recently, insufficient interregional transmission and being exposed to plausible risks can be extremely costly.

The consideration of long-term uncertainties—such as industry structure, new technologies, fundamental policy changes, and other shifts in market fundamentals—is important for developing robust transmission plans and investment strategies, valuing future investment options, and identifying least-regrets projects. A least regrets planning approach, however, needs to consider *both* (1) the possible regret that a project may not be cost effective in a particular future; *and* (2) the possible regret that customers may face excessive costs due to an insufficiently robust transmission grid in other futures.[22]

Another recent example of system planners failing to adequately consider the implications of insufficient expansion of interregional transfer capability to address extreme market conditions is the August 2020 blackouts in California. The final root cause analysis released by California policymakers concluded that "transmission constraints ultimately limited the amount of physical transfer capability into the CAISO footprint" and "more energy was available in the north than could be physically delivered."[23] CAISO had similarly concluded after the 2000−01 California power crisis that the crisis and

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

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

23 CAISO, CPUC, and CEC, *Final Root Cause Analysis Report: Mid-August 2020 Extreme Heat Wave*, January 13, 2021, p. 48.

its extremely high costs could have been avoided if more interregional transmission capability had been available to the state.[24]

An important limitation to accurately quantifying the total benefits of transmission is caused by the fact that most planning analyses of economic benefits are undertaken only for normal system conditions that do not include challenging events such as cold snaps, heat waves, fuel price spikes, transmission outages, or unusual generation outages.[25] It is important, however, to quantify the benefits of avoiding high-cost outcomes during such challenging economic, weather, and system conditions that could occur in every possible future over the long life of the investment. Ignoring these situations means that, without the investment, the costs and risks imposed on consumers and other market participants will tend to be much higher than typically estimated. Even in cases where a broader set of future scenarios are developed for transmission planning, system planners and stakeholders often still tend to focus primarily on the base case for driving transmission needs.

A major limitation identified by stakeholders to developing future scenarios is the lack of input from the states on how they plan on achieving their policy goals, especially those related to clean energy. This is particularly important since states often have specific goals for local renewable energy resource development that are not well articulated or challenging to incorporate into regional and interregional planning processes. One of the key drivers of the MISO MVP process was that state representatives were requesting that MISO evaluate transmission solutions that could cost-effectively meet the region's combined state-level renewable portfolio standards by integrating a combination of local and regional renewable resources. A high-level outlook of how states wish to pursue meeting their goals, or a more detailed set of scenarios, would greatly improve the ability of regions to plan their future system without having to develop a specific portfolio of resources to do so.

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

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

[25] For example, SCE analyzed the benefits of the Palo Verde to Devers 2 (PVD2) under a range of system conditions that significantly increased the value of the project. Similarly, ERCOT considered a range of load and natural gas price sensitivities in its evaluation of the Houston Import project. For a summary of these approaches, see Appendix A and Appendix B of Pfeifenberger, Chang, Sheilendranath, Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid, Prepared for WIRES Group, April 2015.

scenarios of future market conditions, this adds to the challenge of approving even very valuable projects.

A. Proposed Improvements for Quantifying Project Benefits

We offer the following recommendation for consideration by planners and policymakers when evaluating the merits of transmission projects.

Establish minimum standards for improved benefits analysis: Developing a set of minimum standards for interregional planning processes would set the stage for analyzing a broader set of benefits and metrics. Two regions involved in a joint interregional planning process do not need to rely on the same exact set of benefits and costs may ultimately differ because the project beneficiaries in each region may differ—but in order to identify interregional project needs, parties need to be planning on the same page.[26]

Our recommended principles and minimum standards for determining the benefits of interregional transmission projects are:

1. Interregional projects (either as single projects or a group of projects) may offer combinations of different types of benefits and cost-effectively address multiple needs;
2. It is possible that entirely different sets of needs are addressed in and benefits accrue to each region from a particular interregional project;
3. The benefits and metrics used for the evaluation of interregional projects by each region needs to include the full set of benefits and metrics considered in each region's local and regional transmission planning process;
4. Each region needs to have the flexibility to include, in addition to the full set of benefit metrics used for its regional planning effort, some or all of the benefits and metrics used by the other region even if these benefits and metrics are not currently used in the region's internal transmission planning process;
5. The regions need to recognize that interregional projects may offer unique benefits beyond those currently considered in either region's internal transmission planning process. If deemed significant, the regions need to develop metrics to capture any such additional interregional-related benefits;

[26] These guiding principles have been updated from similar principles developed in a 2012 report on interregional planning and cost allocation. *See* Pfeifenberger and Hou, Seams Cost Allocation: A Flexible Framework to Support Interregional Transmission Planning, prepared for SPP Regional State Committee, April 2012. The report includes several case studies illustrating the application of these principles and includes proposed changes to the SPP Joint Operating Agreement (JOA) with neighboring planning authorities, which would be necessary to implement these principles.

6. The regions need to recognize that additional benefits may be documented as more experience is gained with the planning and evaluation of interregional projects. If deemed significant, the regions need to develop metrics to capture any such additional interregional-related benefits;
7. The regions must prioritize interregional projects that would avoid or delay the cost of (1) transmission upgrades needed to satisfy generation interconnection and transmission service requests; (2) transmission upgrades that would have to be planned now to address their already-known local and regional needs; and (3) transmission upgrades that likely would be needed in the future to meet local and regional needs (including the replacement of aging infrastructure); and
8. If minimum benefit-to-cost thresholds are utilized, they should not exceed 1.25. Lower thresholds should be acceptable if some of the benefits of interregional transmission projects are recognized qualitatively but have not been quantified.

More specifically, we further recommend that the scope of benefit-cost analyses of interregional transmission projects include the following:

Capture unique interregional benefits: Interregional planning processes need to recognize that projects might offer additional benefits beyond those currently considered in either region's internal transmission planning process, such as incremental wheeling revenues or benefits from increased reserve sharing capability. Planning processes must define a comprehensive but flexible set of project evaluation criteria and benefit metrics. Regions should also recognize that interregional projects might serve to avoid or delay the cost of other upgrades, such as projects included in each region's existing plans, or upgrades that might be needed in the future to meet local or regional needs, or to satisfy generation interconnection or transmission service requests.

Consider all regional benefits: To avoid a least-common-denominator approach to interregional planning, each of the neighboring regions, at a minimum, should evaluate its share of an interregional project's benefits by considering all types of benefits that are used in the region's internal transmission planning process. Doing so will ensure that the total benefits considered in the interregional planning process are at least equal to the sum of the benefits that each regional planning authority would determine for a regional project in its own footprint. In this way, benefits and metrics considered in interregional planning would at least be consistent with the reliability, operational, public policy, and economic benefits considered in the individual regions, even if these benefits are not defined and measured the same way in each region. Interregional planning processes must also recognize that interregional projects might offer unique benefits beyond those currently considered in either region's internal transmission planning process, such as incremental wheeling revenues that could offset some portion of the costs associated with the transmission project or benefits from increased reserve sharing capability.

Address uncertainties and long-term benefits: The analytical approaches applied to interregional planning must (1) be proactive by considering all base case future generation required to address public policy needs and (2) look beyond base cases or business-as-usual cases and explicitly consider a broader range of plausible market conditions, system contingencies, and public policy environments. Gaining buy-in from stakeholders on the approach for developing alternative scenarios and specific assumptions is critical to stakeholders supporting the results of the study.[27] Doing so will better capture the short- and long-term flexibility benefits and insurance value that a more robust interregional transmission infrastructure can offer in terms of shielding customers from high-cost outcomes. Stakeholders should urge planners to expand least regrets transmission planning from (1) identifying only those projects that are beneficial under most circumstances to (2) also considering the potential regrettable circumstances that could result in very high-cost outcomes because of inadequate infrastructure.[28]

The high-cost regret of not having sufficient infrastructure has been illustrated during the 2021 winter storm Uri, an where additional 1,000 MW of interregional regional transmission between Texas and neighboring regions could have provided over a $1 billion of value in only four days, which would have been sufficient to cover the entire cost of the additional transmission.[29] This example shows that the cost of not having built more transmission must be considered in least regrets planning as it can be extremely high. Another example includes the 2000-2001 California Power Crisis, where a previously considered transmission upgrade ("Path 15") that was rejected based on limited need could have reduced customer costs by over $200 million in only December 2000 had it been in service.[30] Given the project's ultimate $250 million cost and the fact that the crisis lasted into the first quarter of 2001, the line would have paid for itself in just one year.

Alternatively, in evaluating the Paddock-Rockdale Project, the American Transmission Company evaluated seven plausible futures, spanning a wide range of long-term uncertainties. This analysis of multiple scenarios of plausible futures showed that the estimated benefits ranged widely across sets of plausible futures. While the project was projected to be clearly beneficial in most (but not all) futures, the analysis also showed that not investing in the $136 million project could leave customers up to $700

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[27] Chang, Pfeifenberger, Newell, Tsuchida, Hagerty, Recommendations for Enhancing ERCOT's Long-Term Transmission Planning Process, Prepared for ERCOT, October 2013, pp. 62–64.

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

This report provides a number of examples of how transmission benefits vary across different plausible futures and uncertainties. For example, a planning analysis of the Paddock-Rockdale transmission project in Wisconsin evaluated the long-term benefits of the project under seven plausible futures. These results show that the estimated benefits can span a wide range when different future scenarios are considered: while the project's benefits fall short of its costs in one of the seven futures, not investing in the project with a cost of $138 million would potentially leave customers $700 million worse off in two of the seven futures evaluated. *Id.* at 17.

Similarly, a scenario-based analysis by CAISO showed that a transmission project with an annual cost of $70 million is not only cost effective in all of the evaluated cases with an average benefit-cost ratio of 1.4, but also eliminates a 10% chance that customers would be exposed to $300 million to $750 million in higher annual costs without the project. *Id.* at 14–17.

[29] Caspary, *et al.*, Disconnected: The Need for a New Generator Interconnection Policy, prepared for Americans for a Clean Energy Grid (ACORE), January 2021.

[30] California ISO, 2001, "Path 15 Upgrade Cost Analysis Study," February 16, 2001.

million worse off in two of seven plausible futures.[31] Recognizing that benefits exceed costs in most of the seven futures, that benefits were projected to fall just short of covering project costs in only two futures, but because the project can avoid very-high-cost outcomes in another 2 of the 7 futures, the Wisconsin Public Service Commission unanimously approved the project.

These examples show that a robust transmission grid offers insurance value. And stated in insurance terms: planners and policy makers must move from focusing solely on the cost of insurance and the regret of having bought it and not needed it (*I.e.*, one type of "regret") to also analyzing the potentially very high cost of not having insurance when it is needed (*I.e.*, include the "regret" of not having bought it).[32]

Prohibit more stringent cost-benefit thresholds: The benefit-to-cost thresholds to interregional projects must be no more stringent than those applied within each region. Since interregional projects are projects that regions evaluate jointly, a single joint benefit-to-cost threshold should be sufficient. If the regions jointly find that a certain interregional project or portfolio of projects offers benefits in excess of costs, the participating regions need to agree on a cost allocation such that each region enjoys a share of the overall benefits that exceeds its share of the costs. Having a single benefit-to-cost threshold for the participating regions would help avoid reaching different conclusions simply because the thresholds are different in the participating regions. If minimum benefit-to-cost thresholds are utilized, they must not exceed the regional thresholds. However, if some of the benefits of interregional transmission projects are recognized only qualitatively but are not quantified, reduced benefit-cost thresholds (such as 1.0) should be acceptable to account for this.

B. Key Stakeholder Action Items

To implement the suggested improvements to capture the full range of benefits in planning, we propose the following action items for key planners and policy makers:

FERC:

- Reform transmission planning requirements to capture the wide-range of benefits of transmission investments and the need for transmission planning processes to account for those benefits
- Require planning authorities to incorporate a wide-range of transmission benefits across and implement least-regrets in planning processes
- Require transmission planning processes to proactively incorporate both short- and long-term uncertainty through scenario-based planning using a broad range of plausible futures to capture

31 Pfeifenberger, *et al.*, *Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid*, prepared for WIRES, April 2015.

32 *See* Trabish, 3 serious failures in transmission planning and how to fix them, Utility Dive, May 4, 2015.

long-term uncertainties and sensitivities that can capture short-term uncertainties and challenges, such as high-cost weather events and market conditions

State Policymakers and Regulators

- Engage with RTOs and non-RTO regional planning authorities to modify the approach to analyzing benefits
- Develop scenarios for regions to consider in interregional planning efforts, including with future resource mixes that achieve existing state policy mandates and plausible new future policy goals

Regional Planning Authorities

- Work with neighboring regions to develop and implement interregional planning reforms, including a shared set of benefit metrics and methodologies used for in both regions
- Expand capabilities to analyze a wide-range of benefits of interregional transmission projects

Transmission Owners

- Empower stakeholders and consumers in developing a more inclusive set of benefit metrics
- Allow planning authorities to consider the value of avoided local reliability and regional projects when analyzing the benefits of larger interregional projects

V. Establishing a Flexible Interregional Cost Allocation Framework

Cost allocation across regional boundaries is perhaps the biggest hurdle for successful development of interregional projects. Customers and transmission owners are unwilling to bear the costs for individual transmission projects that they feel do not provide tangible benefits to them and their customers. However, one of the fundamental causes of the challenges created in the cost allocation process is that the benefits of interregional projects or portfolios of projects often are well-articulated, documented with sufficient detail, and quantified such that the entities who would have to pay for the new transmission are willing to support the project.

Even if the approach to estimating the overall benefits of interregional transmission projects is adequate, the lack of sufficiently detailed, actionable, but flexible principles and guidelines for cost allocation creates a significant barrier to interregional planning. This barrier can be further magnified if cost allocation is not aligned with project ownership interests and the assignment of transmission rights, and is determined on a project-by-project basis.[33]

A key function of any successful cost allocation framework is the clear articulation of project evaluation criteria and benefit metrics. As described in the previous section, benefits can include meeting policy goals, avoided costs, and achieving other system improvements and savings. The specified metrics may capture these benefits in either monetary or non-monetary terms. FERC's six cost allocation principles defined under Order 1000 provide a good starting point, but these do not provide enough guidance to be actionable by themselves.

Generally, there are six cost allocation methods and recovery mechanisms that have been considered at the regional level:

1. *License plate:* each utility recovers the costs of its own transmission investments usually located within its footprint.
2. *Beneficiary pays:* Various formulas that allocate costs of transmission investments to individual TOs that benefit from a project, even if the project is not owned by the beneficiaries. TOs then recover allocated costs in their License Plate tariffs from own customers.
3. *Postage stamp:* transmission costs are recovered uniformly from all loads in a defined market area (*e.g.*, RTO-wide in ERCOT and CAISO). In some cases (*e.g.*, SPP, MISO, PJM) the costs of certain project types are allocated uniformly to TOs, who then recover these allocated costs in their License Plate tariffs.
4. *Direct assignment:* transmission costs associated with generation interconnection or other transmission service requests are fully or partially assigned to the requesting entity. (Innovative variance: CAISO's Location Constrained Resource Interconnection (LCRI) policy that offer up-front system-wide funding, with pro-rata interconnection costs that later charged back to generators as the interconnect).
5. *Merchant cost recovery:* the project sponsors recover the cost of the investment outside regulated tariffs (*e.g.*, via negotiated rates with specific customers); largely applies to DC lines where transmission use can be controlled.
6. *Co-ownership:* benefitting transmission owners co-own the facility, with each recovering costs through rate base treatment; this "one operator shared transmission ownership and rights" model has been employed for the CAPX2020 transmission upgrades by Minnesota utilities and is often used in WECC.

[33] Many transmission owners prefer owning (and earning a return on ratebase) the transmission facilities whose costs are recovered from their customers. They tend to be more reluctant to recover from their customers the costs of transmission owned by others. They will also have a strong preference for obtaining physical or financial rights to the transmission capabilities of facilities they have to pay for.

A successful approach to cost allocation at the interregional level will need to be flexible enough to accommodate different types of interregional projects (*e.g.*, reliability, economic, and public policy projects) for different types of neighboring regions and entities (*e.g.*, RTO and non-RTO regions, FERC-jurisdictional, and non-jurisdictional entities) and specific enough to be actionable without being overly restrictive and formulaic. To achieve this balance, cost allocation needs to be completed for a portfolio of interregional and regional projects rather than a single project[34] and cost allocation agreements must include guidelines for how benefit metrics will be applied to support cost allocation. For example, cost allocation guidelines might specify that the costs of interregional transmission projects should be allocated based on the share of monetized benefits, in proportion to the present values of project benefits received by each entity. Alternatively, the guidelines could allow for cost allocation to be based on more qualitative, non-monetized benefits and cost-causation ratios. As documented by the approval of portfolio-based regional cost allocation framework in MISO and SPP shows, FERC Order 1000 does not require that the cost of each project is allocated strictly based on its benefits as long as the cost allocation for a portfolio of projects is roughly commensurate with overall benefits.

As more experience with the cost allocation of interregional projects is gained, planning regions may pre-specify cost allocation options. These pre-specified formulaic cost allocations would be based on specific metrics for the evaluation of interregional projects and a pre-specified cost allocation methodology that formulaically relies on these benefits and metrics. Projects that do not fit the pre-specified options would be considered under the more flexible cost allocation principles.

A. Proposed Improvements for Interregional Cost Allocation

We propose for further consideration by transmission planners and policymakers the following minimum standards, cost allocation mechanisms, and payment mechanisms for interregional transmission projects.

Minimum Standards: Rather than resolve interregional cost allocation formulaically or on a case-by-case approach, we recommend the inclusion of a core set of minimum standards to serve as the overarching framework for developing transmission cost allocation for interregional projects. Integrating the cost allocation requirements of FERC Order 1000, we propose the following principles and requirements:

1. Costs allocated for a portfolio of interregional projects must be at least roughly commensurate with the total benefits that the portfolio provides to each region; neither region shall be allocated cost without receiving benefits.

[34] As explained below, this is because a portfolio-based cost allocation approach has the advantage that the portfolio-wide benefits will be more evenly distributed, which allows for less complex cost allocation approaches while still ensuring that the sum of costs allocated is roughly commensurate with the sum of benefits received.

2. Cost allocation methodologies and identification of benefits and beneficiaries must be transparent.
3. Different cost allocation methods may be applied to different types of needs addressed (*e.g.*, reliability, economic, or public policy needs) or different portions of transmission facilities.
4. Regions must utilize the quantified and, if possible, monetized benefits in determining the cost allocation approach (but they must also recognize non-monetized and non-quantified benefits) for portfolios of interregional projects in assessing overall reasonableness of proposed cost allocations.
5. The monetized reliability, load serving, and/or public policy benefits of interregional projects should be at least equal to the avoided cost of achieving the same total benefits through local or regional upgrades.
6. The monetized benefits and share of costs allocated to each region should be sufficient to support the interregional projects' approval through each region's internal planning process.
7. Project costs allocated to each region should be recovered via the existing local and regional cost allocation and recovery process of each region.

Several of the above interregional cost allocation standards simply implement Order 1000 requirements. However, standards Nos. 1, 4, 5, and 7 go beyond Order 1000 requirements. For example, the proposed standards No. 1 and No. 4 would apply cost allocation to portfolios of projects rather than individual projects. The portfolio-based cost allocation approach has the advantage that portfolio-wide benefits will tend to be more broadly and more evenly distributed, which allows for less complex cost allocation approaches while still ensuring that the sum of costs allocated is roughly commensurate with the sum of benefits received.[35] Proposed standard No. 4 reflects the expectation that cost allocations be based mostly on quantifiable benefits and thus requires that regions attempt to quantify and monetize the identified benefits based on the metrics provided. It also states, however, that non-monetized and non-quantified benefits must still be considered at least qualitatively in the regions' assessment of the overall reasonableness of any proposed cost allocations. Standard No. 5 provides an approach for estimating the reliability, load serving, public policy, and other similar benefits of interregional projects by proposing that the monetized value of such benefits be at least equal to the avoided cost of achieving the same benefits through cost-effective local or regional transmission solutions. And standard No. 7 goes beyond Order 1000 requirements by specifically addressing fairness concerns related to the potentially different scope of benefits that the proposed framework defines for different regions.

Standard No. 6 requires that the monetized benefits of an interregional project, when compared to its allocated costs, are sufficient to support the project's approval based on the criteria that are used in

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

each region's internal transmission planning process. This means even if one region were to utilize different definitions of project benefits, the project will still be beneficial to the region considering both its share of benefits as well as its share of costs. While it is still possible that a region realizing a broader scope of benefits would end up with a larger share of allocated costs, the region would not be asked to approve an interregional project at terms that are any less attractive than the terms that would be considered for local and regional projects in the region's internal planning process. To successfully improve interregional planning, however, regions will thus have to improve the flexibility of their regional planning processes such that they are able to use a full set of holistic criteria to evaluate transmission-related benefits across a set of future scenarios that reasonably span long-term uncertainties. Commonality of the suite of benefits being evaluated, even if the applicable benefits or ultimate values differ across regions, is necessary to prevent one region's failure to quantify many of the benefits of transmission projects in its regional planning process to be compounded into a failure to support and commensurately share the costs of valuable interregional transmission projects altogether.[36]

Cost allocation mechanisms: Interregional planning processes must pre-specify cost allocation mechanisms but ensure they remain flexible enough to achieve cost allocations that recognize differences in project drivers and benefits across the regions. For example, the planning process may specify that cost allocation to each region should be based on one or a combination of:

- The share of the projects' total benefits received by each region as a proportion of the sum of the regions' total benefits received consistent with specified principles and benefit metrics.
- If non-monetary ratios are reasonably proxies for shares of received benefits or are roughly proportionate to benefits received, cost allocation can also be based on:
  - The share of projects' physical location in each Party's footprint (*e.g.*, shares of circuit miles or investment dollars).
  - The share of each region's relative contribution to the need for a project (*e.g.*, power flows that contribute to a reliability-driven upgrade).
  - The share of each region's projected or allocated usage of the interregional projects' transmission capability (*e.g.*, shares of increased flow-gate capacity).

Regions must explain their cost allocation framework through concrete (even if illustrative) examples that consider key variables, such as the size and type of project.

Payment mechanisms: Planning processes should specify the financial mechanisms that allow for the actual sharing of project investment costs or annual project revenue requirements across the regions' boundaries. We propose as a starting point the consideration of two types of payment mechanisms: (1) physical ownership shares; and (2) financial transfers. To facilitate the implementation of cost

[36] A FERC requirement that all transmission planning regions consider a similarly broad set of transmission-related benefits would reduce perception that unfair cost allocations result from regions' different scope of quantified benefits.

allocation mechanisms, we recommend that, to the extent feasible and practical, an entity sharing the cost of interregional projects should also receive physical or financial rights for a commensurate share of the project's added transmission capability (*e.g.*, financial transmission rights or a share of increased flow gate capability).

Cost allocation based on physical ownership shares can be implemented through either (1) physical ownership of individual project segments or (2) co-ownership of the interregional or individual project segments. In either case, ownership of individual project segments would be assigned so that the investment and operating cost of each owned portion of the project is consistent with the determined cost allocations. Co-ownership of interregional projects or individual project segments may be necessary where the project cannot be divided into fully-owned segments or if a proposed project or project segment is entirely within the service territory of only one of the regions. In other words, different shares of the interregional project would be allocated to existing or new transmission owners within each of the two regions. The transmission owners would then simply recover the cost of their portion of the project as they would recover the cost of any other regional or local transmission project.

If the interregional project is developed by a single corporate entity, the company could form a transmission-owning subsidiary in each of the neighboring regions, each of which would recover the costs associated with its ownership share of the interregional project through the respective existing regional or local cost recovery options.

Where ownership-based allocation of project costs is neither feasible nor practical, cost allocation can be implemented through financial transfers from one region to the other. These payments would correspond to the determined share of the interregional project's revenue requirements. The revenue requirements associated with payments to the neighboring regions would be recovered consistent with the cost recovery of the revenue requirements of local and regional projects in the transmission owner's regional footprint. We recommend that such payments be implemented in conjunction with the assignment of physical or financial rights for a commensurate share of the project's added transmission capability.

B. Key Stakeholder Action Items

To implement the suggested improvements to capture the full range of benefits in planning, we propose that transmission planners and policy makers take the following actions:

FERC:

- Establish new cost allocation minimum standards and procedures for regional planning authorities to implement
- Permit the development of innovative and flexible cost allocation approaches that align with those guidelines

- Confirm that reasonableness of cost allocation will be based where possible on benefits from a portfolio of transmission projects rather than based on the benefits of each individual project

Federal Policy Makers

- Consider federal funding or federal guidelines for cost allocation of interregional transmission projects

State Policymakers and Regulators

- Propose and support innovative, flexible, and portfolio-based cost allocation for interregional public policy projects

Regional Planning Authorities

- Work with neighboring regions to develop and implement better processes for interregional planning, including a cost allocation method that is sufficiently flexible and can be implemented in both regions

Transmission Owners

- Utilize regional stakeholder processes to advocate for more effective, innovative, flexible, and portfolio-based cost allocation mechanisms
- Empower stakeholders and consumers in developing a cost allocation approach

VI. Case Study of Successful Multi-Area Transmission Planning and Cost Allocation

The following case study, based on an earlier report on interregional planning and cost allocation prepared for the SPP Regional State Committee (and presented in Appendix C to this report), illustrates how the proposed improvements to the determination of interregional needs, the quantification of benefits, and the cost allocation mechanism can overcome existing barriers to yield valuable interregional transmission projects.

The Acadian Load Pocket (ALP) Project developed in 2009 addressed transmission needs along the seam between three separate transmission service providers in Louisiana. While not specifically an interregional project in nature, the challenges encountered in developing the ALP transmission project and the approach to cost allocation are helpful in informing the current efforts to develop a more robust interregional planning and cost allocation framework.

The ALP Project is a helpful case study because: (1) it is a seams project involving multiple transmission providers; (2) it provides both reliability and economic benefits to the sponsors; (3) the reliability and economic benefits differ significantly for each of the sponsors; (4) cost allocation was implemented by aligning its benefits through physical ownership of newly constructed facilities; (5) there was strong public utility commission involvement; and (6) the project has already been approved.

There are at least six important "lessons learned" from the ALP Project case study:

- **First**, there was general agreement that the various problems identified by the transmission service providers created a need that had to be addressed and that a seams solution could provide both individual and joint benefits.
- **Second**, it was recognized that needs and drivers were different for the parties involved. The ALP Project provided both reliability and economic benefits, which accrued to parties differently.
- **Third**, transmission planning and cost allocation was jointly considered so that a solution and its associated costs produced equitable results. Cost allocation was determined by considering the approximate magnitude of the reliability and economic benefits to each party involved, while also considering the geographic location of the future facilities and operational flexibility, rather than a strict formulaic matching of costs and benefits.
- **Fourth**, cost allocation via transmission ownership (not financial transfers) was easier to accomplish. Especially for non-market regions and utilities, financial transfers may not even be possible or prove difficult to implement. For the ALP Project, each entity shared costs by building, owning, and maintaining a different segment of the buildout.
- **Fifth**, each entity is responsible for recovering approved ALP Project-related costs through its own transmission tariff.
- **And finally**, participation by the Public Service Commission helped facilitate the process.

Appendix A: Barriers to Interregional Transmission

The Barriers to Interregional Transmission

A SURVEY OF POLICY MAKERS, REGULATORS, TRANSMISSION PLANNERS, TRANSMISSION DEVELOPERS, TRADE GROUPS, AND CUSTOMERS

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Barriers Preventing Beneficial Interregional Transmission

Interregional transmission (between separately-operated regions of the grid) can provide large cost savings and reliability benefits

- Numerous studies have shown that **interregional transmission reduces costs, lowers electricity costs to customers, and reduces the risk of high-cost outcomes and power outages**
- These benefits of interregional transmission go beyond transporting clean energy to load. They also include resource and load diversification, reliability, and other wholesale power market benefits
- Yet, the benefits shown in many **studies have failed to yield any interregional transmission** projects for a variety of reasons

Barriers to the planning and development of interregional transmission prevent these benefits from being realized

A survey of policy makers, regulators, transmission planners, transmission developers, trade groups, and customers identified three categories of such barriers:

1. Insufficient **leadership, alignment, and understanding** on interregional matters yields little support for the development of interregional transmission projects
2. Narrow, overly-formulaic, and misaligned **planning processes and analyses** have limited the "needs" identified, benefits calculated, projects considered, and the design of acceptable cost allocations
3. Significant **regulatory constraints** have stifled development, including overly-prescriptive tariffs and state permitting processes

All stakeholders interviewed agree that interregional transmission barriers need to be addressed. We are now in the process of developing a detailed roadmap to address these barriers

The Need for and Benefits of Interregional Transmission

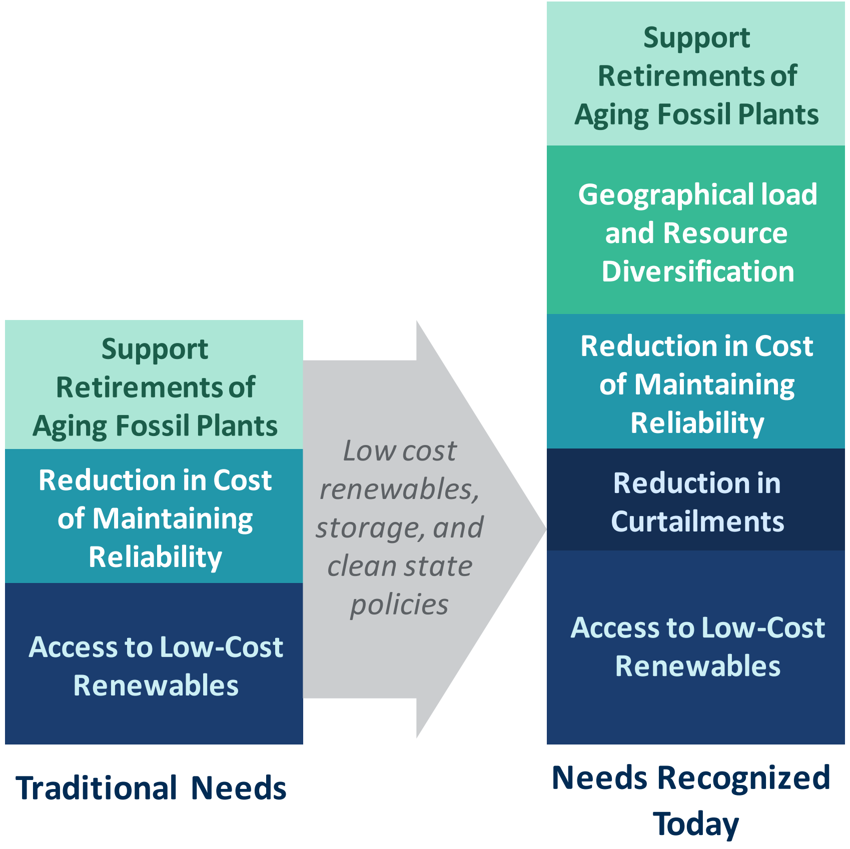
STUDIES SHOW LARGE BENEFITS BUT DO NOT RESULT IN NEW TRANSMISSION DEVELOPMENT

The Need for and Value Proposition of Interregional Transmission

Existing studies highlight how interregional transmission can provide significant benefits as the grid transitions to clean resources

- **The value proposition (increased reliability, reduced costs, risk mitigation) of interregional transmission defines the "need" for the approval these projects**
- In the last ten years, numerous studies have looked at a wide range of grid transition scenarios—including a "continuation of recent trend" view in which coal is gradually being replaced by renewables to reduce emissions
  - In all instances, **building new interregional transmission reduces overall system costs and reduces emissions** while reducing risk and helping to maintain or increase reliability
- The **need for interregional transmission has evolved** as renewable costs have declined and state clean-energy and decarbonization policies have become more ambitious. It has shifted from transporting (mostly) low-cost wind to load centers to include a broader set of benefits: **interregional transmission improves reliability and protects customers from high-cost outcomes**
- While there is some substitutability between solar, storage, and transmission, the **declining cost of solar and storage has not changed the conclusion that interregional transmission reduces costs**
- The development of **interregional transmission and lower electricity rates also create jobs**; potentially more than many local-only renewables policies
- Particularly as shares of weather-correlated renewable generation increases, **robust interregional transmission** is needed to ensure that the geographic scale of the grid exceeds **the size of typical weather systems**

Evolution of Transmission Needs



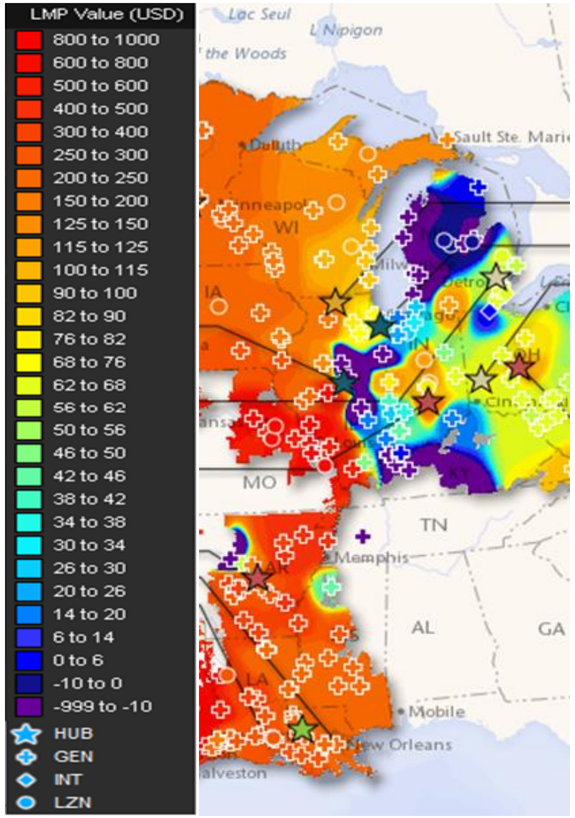
Summary of Recent Interregional Transmission Studies

Study	Region	Findings
NREL North American Renewable Integration Study (2021)	U.S., Canada, Mexico	• Increasing trade between countries can provide $10-30 billion in net benefits • **Interregional transmission expansion achieves up to $180 billion in net benefits**
MIT Value of Interregional Coordination (2021)	Nation-Wide	• National coordination of **reduces the cost of decarbonizing by almost 50% compared to no coordination between states** • The lowest-cost scenario builds almost 400 TW-km of transmission; including **roughly 100 TW-km of DC capacity between the interconnections** and over 200 TW-km of interregional AC capacity • **No individual state is better off implementing decarbonization alone** compared to national coordination of generation and transmission investment • Low storage and solar costs still result in significant cost effective interregional transmission
Princeton Net Zero America Study (2021)	Nation-Wide	• Achieving net-zero emissions by 2050 requires **700-1,400 TW-km of new transmission** • Investment in transmission needed ranges **$2-4 trillion dollars by 2050**
U.C. Berkeley 90% by 2035 (2020)	Nation-Wide	• The only national study that suggest relatively little interregional transmission would be needed to achieve 90% clean electricity. However, the study's simulation approach does not utilize more granular and well-established methods to properly value interregional transmission.
Vibrant Clean Energy Interconnection Study (2020)	Eastern Interconnect	• **40 to 90 TW-km of transmission is built by 2050** to meet climate goals • Transmission development can create **1-2 million jobs in the coming decades**, more than wind, storage, or distributed solar development • Transmission **reduces electricity bills by $60-90 per MWh**
Wind Energy Foundation Study (2018)	ERCOT, MISO, PJM, and SPP	• Transmission planners are not incorporating this rising tide of voluntary corporate renewable energy demand into plans to build new transmission
NREL Seams Study (2017)	Eastern and Western Interconnects	• Major new ties between interconnections **saves $4.5-$29 billion** over a 35 year period

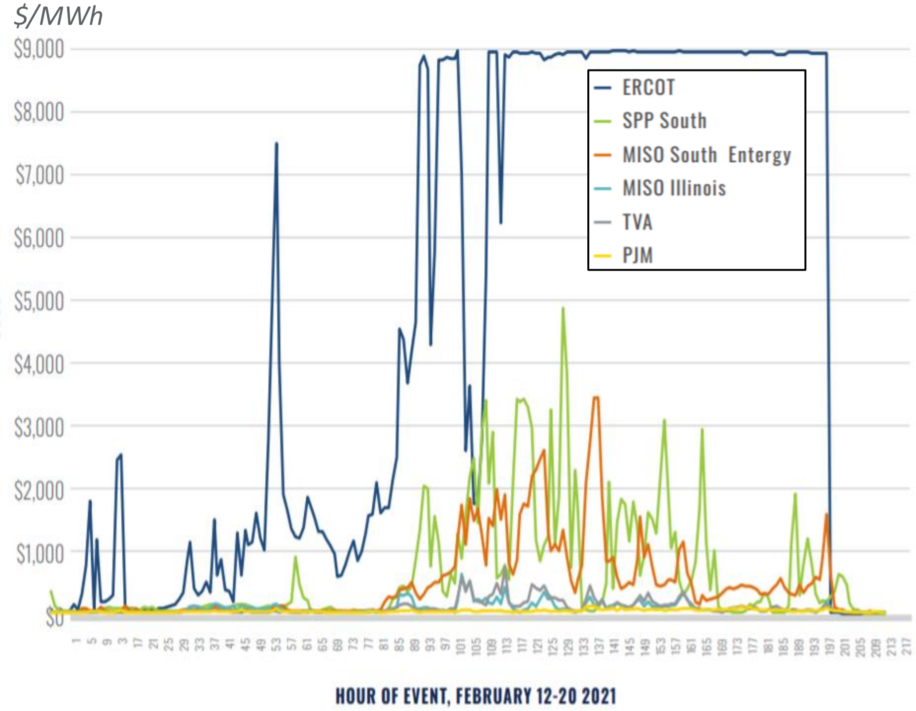
Case Study: Winter Storm Uri

Transmission constraints led to substantial price separations. An additional GW of transmission into Texas would have fully paid for itself over the course of the four-day event (Goggin, 2021).

LMPs on Feb 15th, 2021 at 7:45-7:55



Electricity Price Differences Between Regions During Uri



Savings per GW of Additional Interregional Transmission Capability
($ millions)

ERCOT – TVA	$993
SPP South – PJM	$129
SPP South – MISO IL	$122
SPP South – TVA	$120
SPP S – MISO S (Entergy Texas)	$110
MISO S-N (Entergy Texas - IL)	$85
MISO S (Entergy Texas) – TVA	$82

Limitations of Existing National Studies

Although existing studies demonstrate the cost reductions offered by interregional transmission, they have not been successful in motivating improved interregional planning or actual transmission project developments. The reasons include:

- Many studies **tend to analyze aspirational clean energy targets (e.g., 90% by 2035 or 100% by 2050)** not the actual policies and mandates applicable for the next 10-15 years
  - By not modeling actual state or federal policies, clean-energy mandates, and renewable technology preferences, the studies cannot demonstrate a compelling "need" to policy makers, regulators, and permitting agencies
- The studies are **not transmission planning studies** that produce specific transmission projects that can be developed to deliver the identified benefits and they do not support a need for specific projects
  - The results of these studies do not connect with RTO planning processes and needs identification,
  - The studies typically do not consider how to recover ("allocate") transmission costs
- Studies **fail to identify how benefits and costs are distributed** across utility service areas, states, or RTO/ISO under different scenarios, as would be necessary to gain support and develop feasible cost recovery options
- There has not been **an analysis of the state-by-state economic impact and job creation** from interregional transmission development, reduced electricity prices, and shifts in the locations of clean-energy investment
- Most studies do not **propose actionable solutions** to address the many barriers to planning processes and to the development of new interregional transmission projects

National Studies are Not a Substitute for Transmission Planning

While national studies indicate the economic benefits of new regional and interregional transmission, they do not analyze the transmission grid in sufficient detail to yield actionable interregional transmission plans (and cannot substitute for interregional transmission planning)

- Various “macro grid” studies show how much transmission capacity might be cost effective between certain regions, but they fail to:
  - Consider existing **transmission planning criteria** (e.g., reliability, stability, size of largest contingencies)
  - Pinpoint **specific locations on the power system** where transmission projects could interconnect to achieve cost reductions (studies typically only indicate which regions would benefit from more transfer capacity)
  - **Identify a list of actionable individual transmission projects (or manageable portfolios of projects)** and quantify project-specific benefits needed by regional planning authorities and transmission developers to obtain approvals for individual projects
  - **“Connect” to RTO/ISO and TO planning processes** that can approve actual projects for development
  - **Consider actual project costs and cost allocations** (including the costs of necessary local upgrades)

Detailed interregional transmission studies that include RTOs/ISOs are needed to identify specific projects that meet all planning criteria and are cost-effective overall and to the individual regions

Regional Studies do Not Adequately Consider Interregional Needs

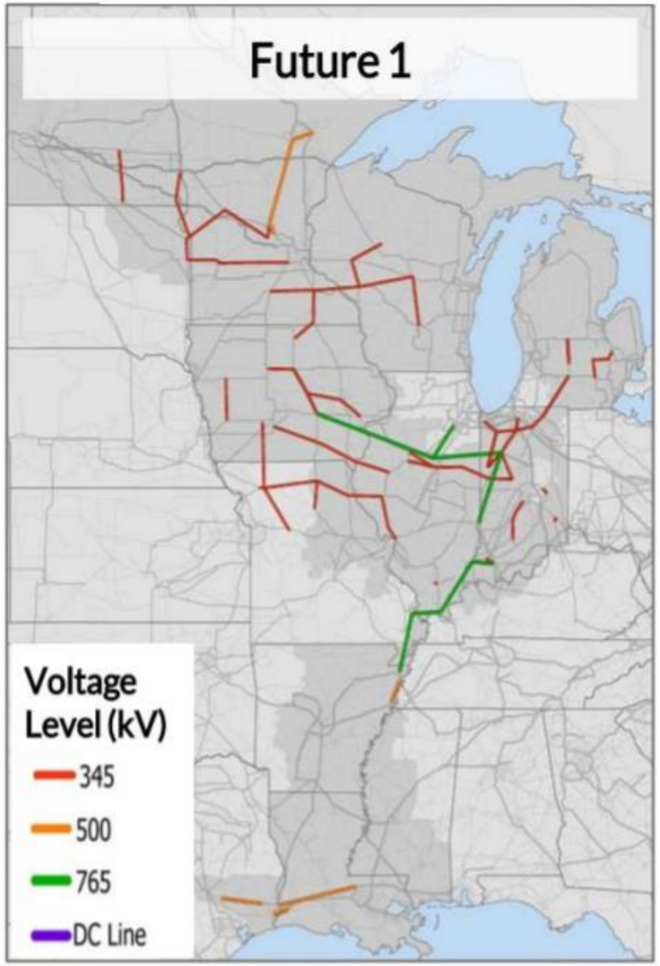
Example: MISO's new Renewable Integration Impact Assessment (RIIA) improves regional planning (over most similar efforts) by:

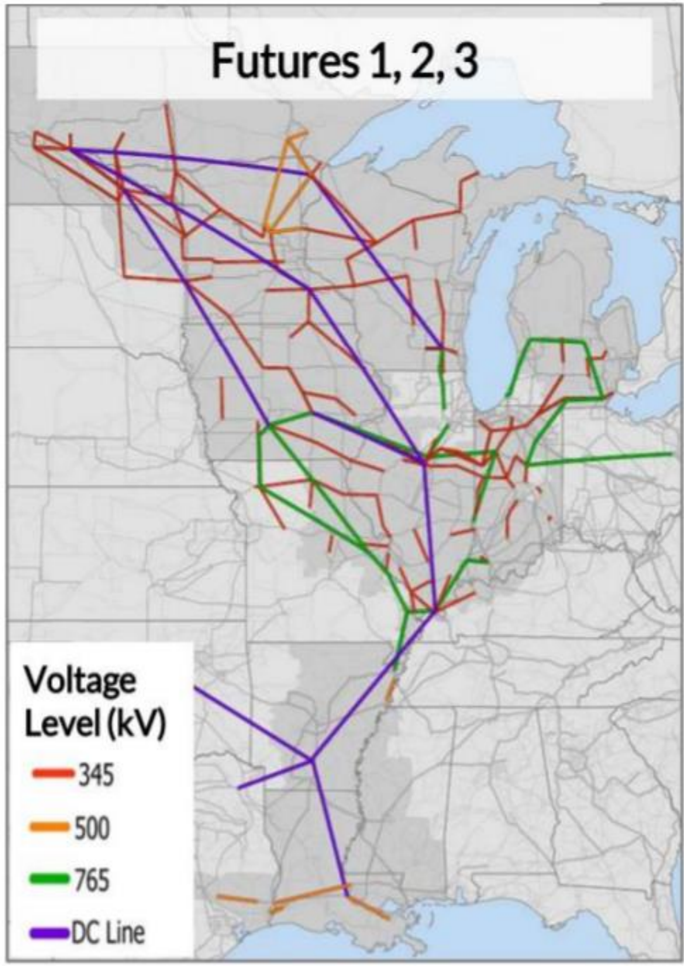
- Establishing the need to proactively study policy goals and reliability goals simultaneously
- Considering multiple economic benefits across a diverse set future scenarios

However, the study does not meaningfully address interregional opportunities:

- Despite modeling five regions in addition to MISO, the study did not adequately consider interregional transmission (see figures)
- Recommends a "least-regret" transmission plan, which is not the "optimal" transmission plan (and does not address possibility of regrets from inadequate transmission)
- Even if "optimal" for MISO, it's likely far from optimal for the broader regional grid

MISO's projected scope of transmission expansion needs





Source: MISO LRTP Roadmap, March 2021.

Stakeholder Perspectives on Barriers to Interregional Transmission

A SURVEY OF POLICY MAKERS, REGULATORS, TRANSMISSION PLANNERS, TRANSMISSION DEVELOPERS, INDUSTRY AND ENVIRONMENTAL GROUPS, AND CUSTOMERS

Stakeholder Survey on Interregional Transmission

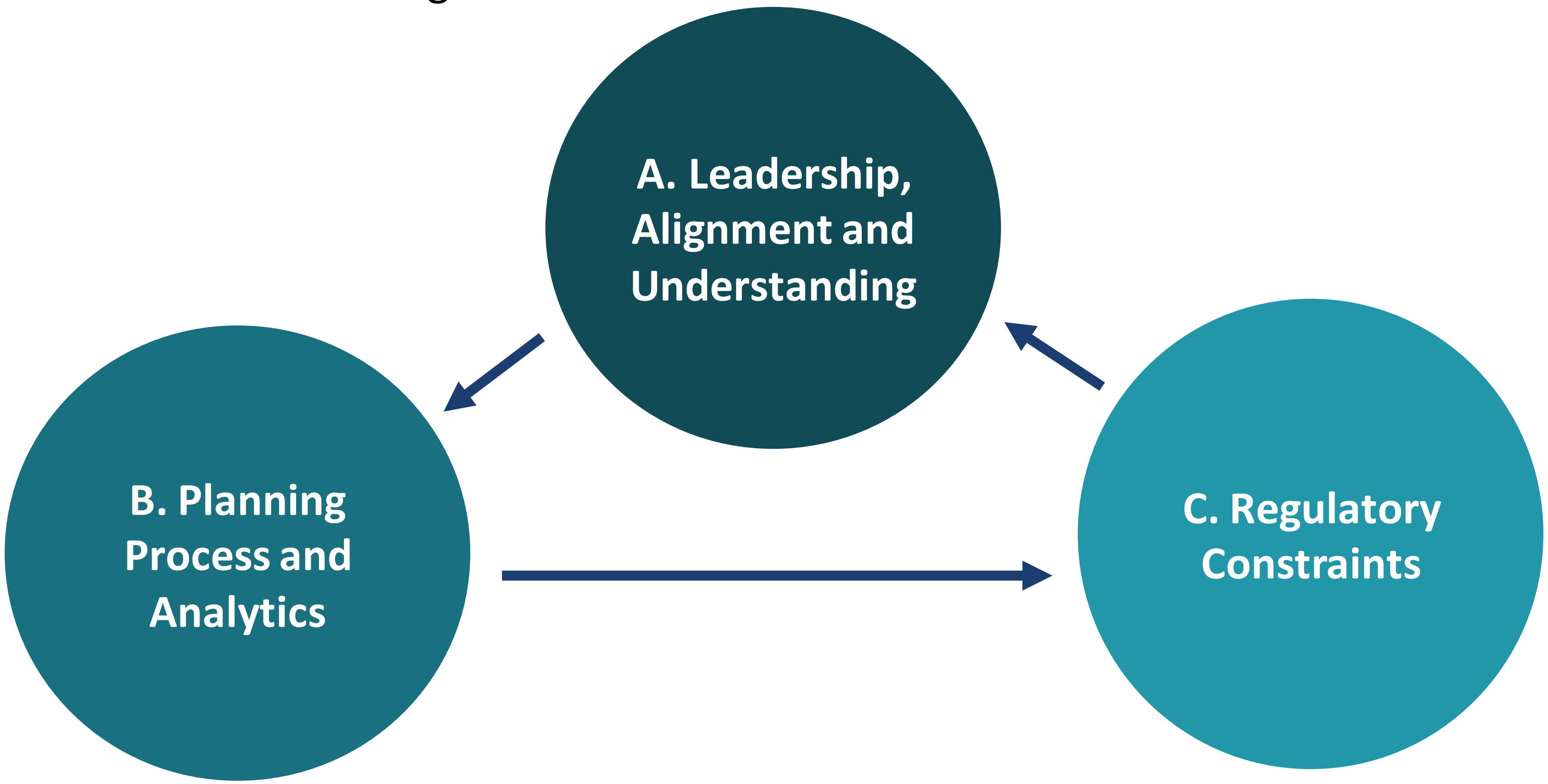
- We surveyed stakeholders from **18 different organizations** across in the industry on their views about interregional transmission planning
- Topics covered in the interviews included:
  - **Benefits of Interregional Projects:** What are the primary benefits or interregional projects to your region? What are the risks of investments or insufficient investments in interregional projects?
  - **Barriers to Interregional Planning:** What are the primary barriers to realizing planning? Are some of these barriers specific to the individual RTOs and seams?
  - **Potential Solutions for Interregional Planning**: What should be done to make interregional planning more effective? To what extent are effective improvements broadly applicable or specific to the individual RTOs and seams?
- See slides 19-20 for a summary of stakeholder comments

Stakeholder Groups Interviewed

- RTO Planners
- State Policy-makers & Regulators
- Large Customers
- Industry and Environmental Groups
- Utilities and Transmission Owners
- Federal Policy-makers & Regulators

Three Categories of Interregional Transmission Barriers

The stakeholders (ranging from RTOs, industry, trade groups, regulators, customers, to policy makers) consistently identified barriers to interregional transmission planning and project development that fall into three interrelated categories:



Identified Barriers to Interregional Transmission

A. Leadership, Alignment and Understanding	1. Insufficient leadership from RTOs and federal & state policy makers to prioritize interregional planning 2. Limited trust amongst states, RTOs, utilities, & customers 3. Limited understanding of transmission issues, benefits & proposed solutions 4. Misaligned interests of RTOs, TOs, generators & policymakers 5. States prioritize local interests, such as development of in-state renewables
B. Planning Process and Analytics	6. Benefit analyses are too narrow, and often not consistent between regions 7. Lack of proactive planning for a full range of future scenarios 8. Sequencing of local, regional, and interregional planning 9. Cost allocation (too contentious or overly formulaic)
C. Regulatory Constraints	10. Overly-prescriptive tariffs and joint operating agreements 11. State need certification, permitting, and siting

A. Leadership, Alignment, and Understanding

1. **Lack of aligned leadership from federal, state & RTO policy makers**
   - FERC:
     - Interregional planning neither required nor prioritized
     - No effort to identify and share industry best practices
     - Some RTOs constrained by overly-specific FERC tariffs
   - States:
     - Limited involvement in RTO planning to date
     - Demands for better planning lack specificity
     - States prioritize local issues above regional needs
   - RTOs:
     - Interregional planning has not been a priority, often due to of a lack of federal and state policy direction
     - Focused instead on reliability projects
2. **Mistrust amongst states, RTOs & utilities**
   - States and customers concerned that utilities and RTOs have their interests in mind
   - Even engaged states often have limited influence into RTO processes
3. **Limited understanding of transmission issues, benefits, and proposed solutions**
   - Limited communication across key players
   - Benefits perceived to be uncertain, changing, intangible; cost/risk of insufficient transmission not well appreciated
   - States have limited technical capabilities and resources to engage in RTO processes
   - Perceived limited benefits from rising transmission costs results in rate-increase fatigue
   - Few opportunities to educate stakeholders on analyses
4. **Misaligned interests of RTOs, TOs, generators, and policymakers**
   - Generation vs transmission concerns
   - Competitive transmission and cost sharing
   - Perception of winners and losers from price effects of transmission
5. **State preference for local renewables**
   - Focus on in-state resources to meet clean energy goals

B. Planning Process and Analytics

6. **Benefit analysis too narrow**
   - Silo-ed planning with narrow set of benefit metrics; no opportunity for interregional multi-value projects
   - Limited experience with quantifying a broader range of benefits results in inability to demonstrate "needs"
   - Regions consider different scopes of benefits
   - Scope of RTO analyses limited only to their footprint (which cannot identify valuable projects with interregional benefits)
   - RTO coordination challenges reduce the scope of benefits and future scenarios considered (even below the limited scope of regional analyses)
7. **Lack of proactive planning for a full range of future scenarios**
   - Over-emphasis on base case (and business as usual) scenarios
   - Too focused on near-term outlook and needs
   - Does not adequately cover sufficiently wide range of future market conditions (to capture risk-mitigation and option value of transmission)
8. **Sequencing of local, regional, and interregional planning**
   - Challenges to fit interregional planning into sequencing of regional planning, generation interconnection requests, transmission service requests, and local transmission needs
   - Makes it difficult to identify more valuable interregional solutions that also address reliability needs in a timely manner
9. **Contentious cost allocation**
   - No pre-determined cost allocation or no flexibility to consider a wider set of benefits and solutions
   - Cost allocation considered too early; should look at total benefits of individual projects first
   - Project-by-project allocations more contentious than portfolio-based allocations (with more stable and widely-distributed benefits)
   - False precision of formulaic approaches does not align costs with wide range of changing benefits

C. Regulatory Constraints

10. Overly-prescriptive tariffs and joint operating agreements

- Some RTOs feel constrained by their prescriptive FERC tariff and JOAs that limit a broader view of interregional planning
- Interregional planning processes are too narrow and disconnected between regions to establish compelling needs (different benefits analyzed by each region and no consideration of benefits from other regions in project approval)
- Planning processes often do not consider interregional solutions to address reliability needs on a timely manner
- Results in “lowest-common denominator” approach to interregional planning

11. State need certification, permitting, and siting

- Multi-state projects must receive approvals from each state (often based on different standards of project “need”)
- State regulators and policymakers often do not fully recognize the complete range of benefits to their state from interstate transmission (economic stimulus and development, reduced power prices, lowest-cost achievement of state public policy goals, meeting customers’ clean energy preferences)

Interregional Barriers Identified by Interviewed Stakeholders

Barrier	RTO Planners	State Policymakers & Regulators	Large Customers	Industry & Environmental Groups	Federal Policymakers & Regulators	Utilities & Transmission Owners
1. Lack of aligned leadership		✓	✓	✓	✓	✓
2. Mistrust among players		✓	✓		✓	✓
3. Limited understanding	✓	✓	✓	✓		✓
4. Misaligned interests	✓	✓	✓	✓		✓
5. State local preferences	✓	✓	✓	✓	✓	✓
6. Benefits analysis to narrow	✓	✓	✓	✓	✓	✓
7. Lack of proactive planning				✓	✓	✓
8. Planning sequence	✓			✓	✓	✓
9. Cost allocation	✓	✓		✓	✓	✓
10. Tariffs and JOAs	✓			✓		
11. State needs, siting, permitting	✓			✓	✓	

Next Steps: Addressing the Identified Barriers

To improve interregional transmission planning and project development will require a coordinated effort by industry stakeholders to address each of the identified barriers

- To align **leadership**, build **alignment**, and improve **understanding** of the complex set of barriers and transmission-related benefits will require a coordinated outreach to federal and state policy makers by a group of stakeholders that represent a broad range of interests and perspectives
- Improving RTO **planning processes and analyses** will require implementing already-available industry experience and best practices to quantify a broad range of transmission-related benefits, consider a wider range of scenarios, and improve the sequencing of regional and interregional planning processes
- Addressing the identified **regulatory constraints** will require evaluating and updating RTO tariffs and agreements, federal regulatory policies, and transmission-related state policies to improve planning, cost-allocation, and permitting processes

We are now in the process of developing a detailed roadmap to address these barriers

Summary of Responses by Stakeholder Group

Reports on Transmission Planning

Stakeholder Feedback by Stakeholder Type

Stakeholders	Key Points
RTO Planners	• Lack of consensus on benefits; need to expand benefits, including from capacity savings; take a total cost approach • Limited by overly prescriptive tariffs and JOAs that specify planning process; utility interests are a major barrier • Better to take the view of solving problems than to analyze limited scope of benefits • Expand view of benefits to both customers *and* generators • A single interregional planning entity would be better than joint planning • Already model other systems; should plan for upgrades across a wider footprint and bring ideas to the table • Need increased state involvement and align interests/objectives; states need education on transmission issues/benefits; MGA letter not actionable • Need to communicate to states the value of a mix of local resources and out-of-state resources in terms of economic impacts • Lack coordination between regional and interregional planning; sequencing of planning is a challenge • Customers tired of spending on transmission; utilities are not in a strong position to push for more investment • Not clear that federal policy changes will resolve issues • Get RTO CEOs together to prioritize these issues, come to consensus on best approaches
State Policymakers & Regulators	• Significant trust issue between states, utilities, and RTOs; lack confidence that RTOs and utilities have their interests in mind • Costs rising without clear benefits to customers; utilities and RTOs just want more infrastructure, need to be more forthcoming • States lack resources to participate in technical analysis, but “can’t be passive any longer” • Transmission planning seen as a complex process with unclear benefits to customers • Need RTOs and utilities meeting with state Governor offices to open lines of communications on key issues, benefits of transmission, and potential downside of focusing only on in-state resources • Challenging to get states to commit to future goals and resources; uncertainty in future resources is a barrier; • Lack awareness of what has worked in other regions in terms of benefits considered, look-back analysis of benefits • Don’t want FERC to be heavy handed, instead should be a mediator/enabler between parties • Hopeful that recent changes in RTO processes will result in better outcome • Cost allocation process is too contentious, especially when there are inequities in benefits for several stakeholders and for portfolio projects
Large Customers	• Shifting to a more local/regional view of renewable energy, especially to meet sustainability or clean energy targets • Benefits of increased transmission are pretty obvious to them for reducing costs of clean energy resources and providing option value • Trust between utilities and customers has eroded, customers want to rebuild with more engagement and data transparency • Need leadership to get out of the current planning paradigm; could come from FERC or RTO boards • Meeting with RTO board members to identify key issues and need to drive change • RTOs lack the authority to do the right planning; cost allocation, siting, and permitting remain a key barriers • States need to understand tradeoff of transmission vs generation costs; and risks of not building out the system

Summary of Stakeholder Feedback

Stakeholders	Key Points
Industry & Environmental Groups	• Limited view of benefits; highlight to stakeholders that a lot of cost effective transmission is being left on the table • Find high-value, small interregional projects to use as examples • RTOs timid in projecting new resources; not comfortable adding non-firm resources; need to use more scenario analysis • FERC is pretty limited in its ability to impose additional requirements on RTOs • Hope new FERC will prioritize Tx planning, impose more requirements for planning, and resolve cost allocation • Getting state policymakers on board is crucial; need to shift conversation away from wind imports towards value of exports • RTOs plan for their internal benefits, modify projects to maximize their benefits; creates DMZ between RTOs • Waiting to see what comes out of new approach by RTOs in terms of benefits and identifying solutions
Federal Policymakers & Regulators	• Limited by lack of national energy policy, FERC backstop siting, antiquated Federal Power Act; NERC may be pathway to create reliability need for interregional transmissions, but uncertain how effective and expedited that process can be • Federalism isn't working here; won't work if states can veto projects • Focused on reviewing and building on existing interregional processes • Expect FERC to review Order 1000; can tweaks tariffs to allow for broader view of benefits • Utilities have overbuilt their local system and increased transmission costs • RTOs are showing limited leadership in resolving issues • States may need to develop their own transmission planning body to identify policy needs
Utilities and Transmission Owners	• States are focused on local resources and clean jobs; need to re-frame benefits for the states; make it a win for states • Thinking too small; different projects will result if you remove RTO borders from studies; but macrogrids don't get us anywhere • Limited scope of benefits; interregional benefits too diffuse and considered uncertain; make benefits more tangible • Hard to get consensus across RTOs when they use different models, assumptions, and benefits • FERC should be more prescriptive, require interregional planning, share best practices • Most customers primarily concerned about increasing transmission rates • Identify and communicate smaller-scale and highly beneficial interregional projects to get the ball rolling • Federal backstop siting worked for gas pipelines, could it work for electric transmission? • Need to think about what is in it for local utilities, otherwise they will remain a barrier • Utilities need to do more to sell benefits of transmission to PUCs and customers • Cost allocation remains a key barrier; should consider cost allocation of a portfolio of projects instead of project-by-project

Brattle Group Reports on Transmission Planning

Well-Planned Electric Transmission Saves Customer Costs:
Improved Transmission Planning is Key to the Transition to a Carbon-Constrained Future

Link: https://bit.ly/3dnKrxe

PREPARED FOR

WIRES

PREPARED BY

Judy W. Chang
Johannes P. Pfeifenberger

May 2016

THE Brattle GROUP

Toward More Effective Transmission Planning:
Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid

PREPARED FOR

WIRES

PREPARED BY

Johannes P. Pfeifenberger
Judy W. Chang
Akarsh Sheilendranath

April 2015

Link: https://bit.ly/2GU4h7w

The Brattle Group

Link: https://bit.ly/3jS0PsB

The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments

July 2013

Judy W. Chang
Johannes P. Pfeifenberger
J. Michael Hagerty

Link: https://bit.ly/2KaFLAk

BU
Boston University Institute for Sustainable Energy

The Value of Diversifying Uncertain Renewable Generation through the Transmission System

September • 2020

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

Link: Brattle Grid Strategies

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Jesse Schneider

OCTOBER 2021

Brattle

GRID STRATEGIES LLC

Documents proven approaches to quantifying various benefits

Additional Reading on Transmission

Pfeifenberger et al, Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs, Brattle-Grid Strategies, October 2021.

Pfeifenberger, Transmission Options for Offshore Wind Generation, NYSERDA webinar, May 12, 2021.

Pfeifenberger, Transmission Planning and Benefit-Cost Analyses, presentation to FERC Staff, April 29, 2021.

Pfeifenberger et al, Initial Report on the New York Power Grid Study, prepared for NYPSC, January 19, 2021.

Pfeifenberger, "Transmission Cost Allocation: Principles, Methodologies, and Recommendations," prepared for OMS, Nov 16, 2020.

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

Pfeifenberger, Newell, Graf and Spokas, "Offshore Wind Transmission: An Analysis of Options for New York", prepared for Anbaric, August 2020.

Pfeifenberger, Newell, and Graf, "Offshore Transmission in New England: The Benefits of a Better-Planned Grid," prepared for Anbaric, May 2020.

Tsuchida and Ruiz, "Innovation in Transmission Operation with Advanced Technologies," T&D World, December 19, 2019.

Pfeifenberger, "Cost Savings Offered by Competition in Electric Transmission," Power Markets Today Webinar, December 11, 2019.

Pfeifenberger, "Improving Transmission Planning: Benefits, Risks, and Cost Allocation," MGA-OMS Ninth Annual Transmission Summit, Nov 6, 2019.

Chang, Pfeifenberger, Sheilendranath, Hagerty, Levin, and Jiang, "Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value," April 2019. "Response to Concentric Energy Advisors' Report on Competitive Transmission," August 2019.

Ruiz, "Transmission Topology Optimization: Application in Operations, Markets, and Planning Decision Making," May 2019.

Chang and Pfeifenberger, "Well-Planned Electric Transmission Saves Customer Costs: Improved Transmission Planning is Key to the Transition to a Carbon-Constrained Future," WIRES and The Brattle Group, June 2016.

Newell et al. "Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades," on behalf of NYISO and DPS Staff, September 15, 2015.

Pfeifenberger, Chang, and Sheilendranath, "Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid," WIRES and The Brattle Group, April 2015.

Chang, Pfeifenberger, Hagerty, "The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments," on behalf of WIRES, July 2013.

Chang, Pfeifenberger, Newell, Tsuchida, Hagerty, "Recommendations for Enhancing ERCOT's Long-Term Transmission Planning Process," October 2013.

Pfeifenberger and Hou, "Seams Cost Allocation: A Flexible Framework to Support Interregional Transmission Planning," on behalf of SPP, April 2012.

Pfeifenberger, Hou, "Employment and Economic Benefits of Transmission Infrastructure Investment in the U.S. and Canada," on behalf of WIRES, May 2011.

Appendix B: Studies Documenting the Benefits of 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 interregional transmission expansion is needed for this to happen. This evidence includes:

- A study by leading grid experts at the National Oceanic and Atmospheric Administration (NOAA) found that moving away from a regionally divided network to a national network of HVDC transmission can save consumers up to $47 billion annually while integrating 523 GWs of wind and 371 GWs of solar onto the grid.[37]
- 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.[38] 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 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.[39] To achieve these cost reductions the study found a need for approximately doubling transmission capacity, and "[e]ven in the ''5× transmission cost'' case there are substantial transmission additions."[40]
- A study by Vibrant Clean Energy found that lower storage costs (and to some extent lower solar costs) reduce the optimal amount of transmission investments, but even studies with very low storage and solar costs find that it is cost effective to add significant new interregional transmission.[41] Moreover, storage raises utilization of interregional transmission lines, using the lines during low-renewable production hours.
- Dr. Paul Joskow of MIT has reviewed transmission planning needs and concluded that "[s]ubstantial investment in new transmission capacity will be needed to allow wind and solar generators to develop projects where the most attractive natural wind and solar resources are located. Barriers to

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37 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.

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

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

40 *Id.*, at 12.

41 Clack, C., *et al.*, *Consumer, Employment, and Environmental Benefits of Electricity Transmission Expansion in the Eastern U.S.*, Vibrant Clean Energy, October 2020

expanding the needed inter-regional and internetwork transmission capacity are being addressed either too slowly or not at all."[42]

- 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."[43]
- 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.[44] 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%.[45]
- The Brattle Group analysts, on behalf of WIRES, demonstrate that transmission expansion creates trading opportunities across existing regional and interregional constraints. The report finds, using existing wholesale power price differences between SPP and the Northwestern U.S., that "adding 1,000 MW of transmission capability would create approximately $3 billion in economic benefits on a present value basis."[46]
- 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.[47]
- 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.[48]

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

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

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

[45] *Ibid*.

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

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

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

- 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.[49]
- Phase 2 of the Eastern Interconnection Planning Collaborative study found that the transmission investment necessary to support the generation and the environmental compliance scenarios associated with these savings ranges from $67 to $98 billion.[50] These results indicate that the combination of interregional environmental policy compliance and interregional transmission may offer net savings of up to $100 billion.
- Recent experience in Germany shows that as renewable generation shares increase, the need for additional interregional transmission to help diversify renewable generation patterns increases as well. Germany recently approved a fourth major new transmission line interconnection to more completely and cost-effectively integrate its southern region (with surplus distributed solar generation during sunny days and import needs when the sun is down) and its norther region (with surplus offshore wind generation during wind-rich periods and import needs during low-wind periods).

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

[50] 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.

Appendix C: Case Study of Multi-Area Transmission Planning and Cost Allocation

Case Study: The Acadiana Load Pocket Project

To help develop a cost allocation framework for SPP's Regional State Committee in 2012,[51] we reviewed SPP's prior experience with a "seams project"—the Acadiana Load Pocket ("ALP") Project. This Appendix C is taken from pages 34-41 of the SPP RSC report. Additional discussions of the ALP Project and other interregional transmission planning and cost allocation case studies are presented in Section XII of the SPP RSC report.

The approximately $200 million ALP Project is a series of new transmission lines and substations jointly developed by three transmission system operators—Cleco Power ("Cleco"), Lafayette Utilities System ("LUS"), and Entergy Gulf States Louisiana ("EGSL")—to address a variety of reliability and economic considerations related to serving a load pocket in south-central Louisiana.

While the ALP Project does not involve RTO seams, it specifically addresses transmission needs along the seam between three individual transmission service providers. The challenges encountered in developing the project and the associated cost allocation proved to be helpful in our effort to develop the proposed interregional planning and cost allocation framework. Specifically, the ALP Project is a helpful case study because: (1) it is a seams project involving multiple transmission providers; (2) it provides both reliability and economic benefits to the sponsors; (3) the reliability and economic benefits differ significantly for each of the sponsors; (4) cost allocation was implemented by aligning it with physical ownership of newly constructed facilities; (5) there was strong public utility commission involvement; and (6) the project has already been approved.

The ALP is defined as the electrical loads south of U.S. Highway 190 to the Gulf of Mexico, west of the Atchafalaya Basin, and east of the City of Jennings as shown in Figure C-1 below.[52] The loads within the ALP area include Cleco, LUS, EGSL, South Louisiana Electric Cooperative Association, South Louisiana

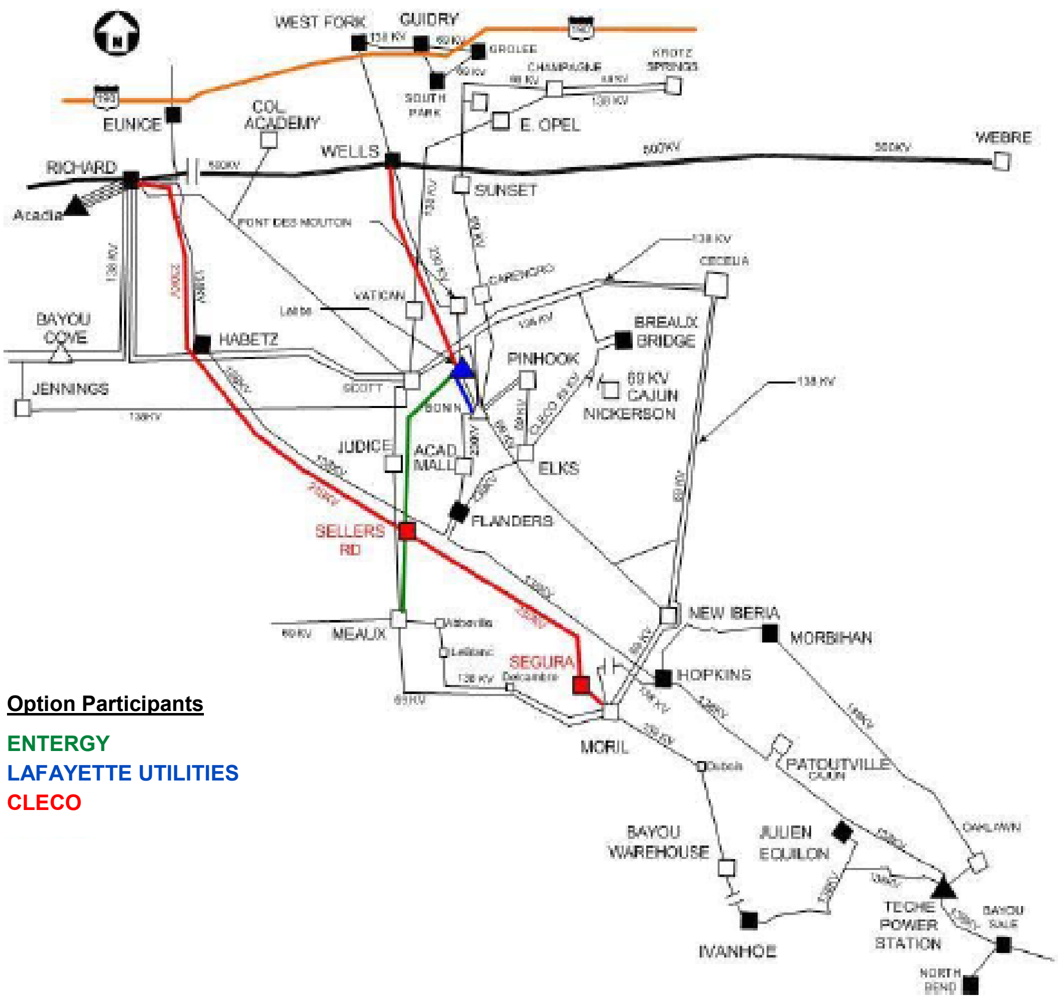
[51] Pfeifenberger and Hou, Seams Cost Allocation: A Flexible Framework to Support Interregional Transmission Planning, prepared for SPP Regional State Committee, April 2012 (SPP RSC report).

[52] Cleco Power LLC, Louisiana Public Service Commission Docket No. U-30689, "Direct Testimony of Terry John Whitmore," July 14, 2008, p. 4 ("Whitmore Testimony, 7/14/08").

Electric Membership Corporation, and Louisiana Energy and Power Authority.[53] In 2008, load was approximately 1,700 MW while total generation capacity was only 965 MW.[54]

The ALP region had been experiencing several problems, including an increase in transmission loading relief ("TLR") procedures to curtail non-firm service, an over-reliance on inefficient generating units needed for voltage support, disconnects between modeling assumptions and actual operational limits, a lack of operational flexibility in the load pocket, and limitations to accommodate additional transmission service.

FIGURE C-1. ACADIANA LOAD POCKET PROJECT



Sources and notes: Southwest Power Pool, Inc., "Cleco, Entergy, and Lafayette Utilities System to improve electric service in South Louisiana through joint transmission project," January 19, 2009.

53 *Ibid.*, p. 4.

54 *Ibid.*, Exhibit TJW-2, p 1 and p. 5.

The ALP area had been experiencing reliability problems since the early 2000s and a new substation was completed in 2005 to alleviate some of the TLR procedures that forced the curtailment of non-firm transmission service and relied on more expensive generation within the load pocket.[55] Despite the new substation, conditions within ALP continued to worsen and a joint study effort, including SPP as the Independent Coordinator of Transmission ("ICT") for Entergy, identified the following major issues within the ALP:

- **Increase in TLR procedures and their severity** — Between November 2006 and November 2007, SPP reliability coordinators initiated 125 TLR procedures, primarily on EGSL's lines for the loss of Cleco's or LUS's lines. The TLR procedures included both firm and non-firm curtailments for importing energy from external generators and required re-dispatch of Cleco's Teche and LUS's Bonin Power plants (discussed below).[56]
- **Over-reliance on inefficient units** — Because of import constraints, two plants within ALP, Cleco's Teche Power plant and LUS's Bonin Power plant, were required to be online during moderate to high load conditions.[57] The Teche plants are described as "old, less efficient steam turbines" with units 1, 2, and 3 placed in service in 1953, 1956, and 1971, respectively.[58] Cleco's Teche Unit 3 is the **single largest generation contingency** in ALP[59] and provides both **load-serving capability** and **voltage support,** which may complicate any scheduled maintenance and cause reliability concerns if the unit was to be offline for an extended period of time.[60] If a solution such as the ALP Project was implemented, estimated fuel savings to Cleco would be $144.2 million between 2010 and 2016 and $905.6 million between 2010 and 2039.[61] LUS may also realize economic benefits such as fuel cost savings and increased generation flexibility.[62]
- **Disconnects between planning model assumptions and operation**—
  - Long-term modeling of flows versus operational realities — In the long-term model, only firm network resources were dispatched and confirmed long-term firm transmission transactions are modeled to meet each control area's load. However, the increase in more efficient merchant generation with short-term economic power sales causes a deviation in modeled power flows and actual use of the transmission system.[63] The result

55 Whitmore Testimony, 7/14/08, p. 7 and p. 11.

56 *Ibid.*, p. 12.

57 *Ibid.*, p. 10.

58 *Ibid.,* p. 5.

59 *Ibid.,* p. 10.

60 *Ibid.,* p. 13.

61 *Ibid.,* p. 25.

62 *Ibid.,* p. 19.

63 Whitmore Testimony, 7/14/08*,* p. 7.

was that the long-term model did not accurately capture how heavily the transmission system was being used to import into ALP.

- Natural gas prices — Unforeseen increases in natural gas prices caused economic dispatch to favor imported energy, putting stress on the existing transmission system which was not designed for such significant reliance on imports.[64]
- Power flow model correction — A smaller conductor used to expeditiously replace lines damaged by Hurricane Lili in 2002 was incorrectly recorded in the power flow model and caused a fault, forcing lines out of service.[65]

- **Lack of operational flexibility** — Increased reliance on imports means that it was more difficult to obtain scheduled outages on the transmission system to perform routine maintenance.[66]

In 2008, a joint study facilitated by SPP identified several upgrade options, one of which was the ALP Project, comprised of a reliability component to address TLRs and related concerns and an additional economic component as shown in Table C-1 below.

While the reliability component addressed historical and current reliability concerns, the economic component was deemed valuable to the parties to create optionality by allowing the removal of must-run status for older units and increased operational flexibility.

64 *Ibid.,* p. 9.

65 *Ibid.*, p. 9.

66 *Ibid.*, p. 10.

TABLE C-1. ALP PROJECT COMPONENTS, BENEFITS, AND ESTIMATED COSTS

Component	Benefits	Total Est. Cost ($ million)
Reliability Component (Responsible Entity):		**$71.9**
• New 230 kV line from Labbe - Bonin (LUS) • 500/230 kV auto transformer at Wells (Cleco) • New 230 kV line from Wells - Labbe (Cleco/LUS) • New 230 kV line from Labbe - Meaux (EGSL) • 230/138 kV auto transformer at Meaux (Cleco)	• Relieves Entergy TLR procedures (allows for increased economic import) • Accommodates load growth and improves load serving capability[67]	Allocated roughly based on load ratio share and then matched with component ownership
Economic Component (Responsible Entity):		**$128.1**
• 500/230 kV auto transformer at Richard (Cleco/EGSL) • New 230 kV line from Richard - Sellers Road (Cleco) • New 230 kV substation at Sellers Road to connect Labbe-Meaux and Richard - Sellers Road (Cleco) • New 230 kV substation at Segura near Moril (Cleco) • New 230 kV line from Sellers Road - Segura (Cleco) • 230/138 kV auto transformer at Segura (Cleco) • New 138 kV line from Segura - Moril (Cleco)	• Allows removal of must-run designation for Cleco's Teche and LUS's Bonin • Economic benefits largely to Cleco (est. fuel cost savings of $906 million 2010-2039) • Additional generation dispatch flexibility and potential fuel cost savings for LUS •	Approx. 70% allocated to Cleco (with smaller shares to EGSL and LUS) and then matched with component ownership
Total Estimated Cost *(as of 2008)*		**$200.0**

Sources and notes: Components from: Cleco Power LLC, Louisiana Public Service Commission Docket No. U-30689, "Direct Testimony of Terry John Whitmore," July 14, 2008. Benefits from: Cleco Power LLC, Louisiana Public Service Commission Docket No. U-30689, "Direct Testimony of Terry John Whitmore," July 14, 2008 and Entergy Gulf States Louisiana, L.L.C. and Entergy Louisiana, LLC, Louisiana Public Service Commission Docket No. U-31196, "Direct Testimony of Mark F. McCulla," November 13, 2009. Cost estimates from: Southwest Power Pool, Inc., Cleco Power - Lafayette Utilities System-SPP/SPPICT-Entergy Joint Transmission Planning Study, "Reliability and Economic Study for the 2008 Transmission Expansion Plan of the Acadiana Area Load Pocket," October 2008.

Cost allocation was developed by first determining which portion of the entire project addressed reliability concerns and which portion addressed economic needs. For the reliability component, cost allocation was based on an adjusted load ratio share of Cleco, LUS, and EGSL as a proxy of received reliability benefits. (The adjustment was made to account for additional loads that each utility served

[67] *Ibid.*, p. 19.

under contract, using projected 2012 load.) The adjusted load ratio shares as applied to the estimated reliability component costs are shown in column [2] in Table C-2.

TABLE C-2. ALP PROJECT RELIABILITY COMPONENT BY ADJUSTED LOAD RATIO SHARE

			Allocated ALP Project Reliability Component Cost ($ Million)		
Sponsor	Adj. Projected 2012 Load (MW)	Adj. Load Ratio Share (%)	Based on Adj. Load Ratio Share	Based on Ownership	Based on Revised Estimates
	[1]	[2]	[3]	[4]	[5]
EGSL	877	47%	$33.6	n/a	n/a
Cleco	732	39%	$28.0	$26.6	$30.1
LUS	270	14%	$10.3	n/a	n/a
Total	**1,879**	**100%**	**$71.9**		

Sources and notes:

[1]: Cleco Power LLC, Louisiana Public Service Commission Docket No. U-30689, "Direct Testimony of Terry John Whitmore," July 14, 2008, pp. 21-22.

[2]: Percentage of each utility's projected load as a share of total.

[3]: [1] x [2].

[4]: Cleco Power LLC, Louisiana Public Service Commission Docket No. U-30689, "Direct Testimony of Terry John Whitmore," July 14, 2008, p. 22.

[5]: Cleco Power LLC, Louisiana Public Service Commission Docket No. U-30689, Subdocket A, "Direct Testimony of Terry John Whitmore," November 4, 2008, p. 6.

According to filings made on behalf of Cleco, the $28.0 million share of the reliability component (as shown in column [3] of Table C-2 above) was approximately aligned with the $26.6 million direct cost of constructing and owning the new transmission components interconnected to the Cleco system (as shown in column [4]). Therefore, in the first iteration of the Memorandum of Understanding ("MOU"), Cleco assumed $26.6 million in reliability-related ALP Project costs. In an updated MOU, Cleco and LUS each slightly expanded their projected buildouts with Cleco's total estimated reliability costs increasing by $3.5 million to $30.1 million (as shown in column [5]). Despite this revision, the underlying allocation did not change. In fact, the MOU is structured so that each utility is individually responsible for components of the ALP Project in a way that is roughly commensurate with benefits received. For the economic component, Cleco is the main beneficiary and therefore will own and construct the majority of those facilities at a total estimated cost of $87.1 million.[68]

There are at least five important lessons learned from the ALP Project case study, as summarized by SPP Staff.[69] First, there was general agreement that the various problems identified in the ALP had to be

[68] Whitmore Testimony, 7/14/08, p. 23.

[69] Kelley, David, SPP Seams Steering Committee, "Acadiana Load Pocket," memo to Seams Cost Allocation Task Force ("SCATF"), September 12, 2011.

addressed and that **a seams solution could provide both individual and joint benefits**. Second, it was recognized that **needs and drivers were different for the parties involved**. The ALP Project provided both reliability and economic benefits, which accrued to parties differently. Third, **transmission planning and cost allocation was jointly considered** so that a solution and its associated costs produced equitable results. Fourth, **cost allocation via transmission ownership, not financial transfers, was easier to accomplish**. Especially for non-market regions and utilities, financial transfers may not even be possible or prove difficult to implement. For the ALP Project, each seams entity shared costs by building, owning, and maintaining a segment of the buildout. Similarly, each entity was responsible for recovering approved ALP Project-related costs through its own transmission tariff. Parties were also able to agree to the **approximate magnitudes of contribution rather than a strict matching of costs to benefits**. Cost allocation was determined by considering the approximate magnitude of the reliability and economic benefits to each party involved while also considering the geographic location of the future facilities and operational flexibility. And finally, **strong state-level participation** via Commissioner Jimmy Field of the Louisiana Public Service Commission and the ICT staff helped facilitate the process.