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Planning and Development Pathways to Interregional Transmission

2025

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Preface

This report was prepared in connection with the National Transmission Planning (NTP) Study, which the U.S. Department of Energy's (DOE's) Grid Deployment Office led in partnership with National Renewable Energy Laboratory (NREL) and Pacific Northwest National Laboratory (PNNL) (GDO 2024a). The aim of the NTP Study was to identify transmission that will provide broad-scale benefits to electric customers, inform regional and interregional transmission planning processes, and identify interregional and national strategies to accelerate decarbonization while maintaining system reliability. The NTP Study report and resources are available at https://www.energy.gov/gdo/national-transmission-planning-study.

This report provides a high-level assessment of obstacles to deploying interregional transmission, along with a review of potential solutions to such challenges and system actors or organization types who might address each challenge and how. The aim of this report is to complement the NTP Study and other state, regional, and national grid modernization and reform efforts with a focused discussion of the barriers and potential solutions to developing interregional transmission that can unlock benefits otherwise out of reach. While this report does not identify any single silver bullet or make specific recommendations, it continues the ongoing conversation surrounding the Nation's energy transition by providing a survey of options that various actors across government and industry can pursue to modernize the grid to meet current and future needs.

There are three other companion reports under the NTP Study umbrella: the *Western Interconnection Baseline Study* (Western Baseline) report (Oikonomou et al. 2024); the *Interregional Renewable Energy Zones* (IREZ) report (Hurlburt et al. 2024); and the *Barriers and Opportunities To Realize the System Value of Interregional Transmission* (Barriers) report (Simeone and Rose 2024). The Western Baseline report serves as a comparative baseline for the scenario analysis conducted in the NTP Study, whereas the IREZ and Barriers reports are intended to raise options for achieving the benefits highlighted by the NTP Study. The Western Baseline report uses production cost modeling to compare a 2030 industry planning case of the Western Interconnection to a high renewables case with additional planned future transmission projects based on the best available data. The IREZ report assesses the potential for interregional renewable energy zone corridors to help spur regulatory and financial decision-making. The Barriers report identifies and examines how current market rules and operating practices may prevent existing transmission facilities from delivering maximum potential value across regions. The Barriers report also provides possible solutions, both incremental and transformative, to realize the full benefits of interregional transmission.

Acronyms and Abbreviations

Barriers	*Barriers and Opportunities To Realize the System Value of Interregional Transmission* (report)
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
CITAP	Coordinated Interagency Transmission Authorizations and Permits
CREPC	Committee on Regional Electric Power Cooperation
CREZ	Competitive Renewable Energy Zone
CSNP	Centralised Strategic Network Plan
DOE	U.S. Department of Energy
EIPC	Eastern Interconnection Planning Collaborative
ENTSO-E	European Network of Transmission System Operators for Electricity
ERCOT	Electric Reliability Council of Texas
ESIG	Energy Systems Integration Group
EU	European Union
FERC	Federal Energy Regulatory Commission
GDO	Grid Deployment Office
GW	Gigawatt(s)
HVDC	High-voltage direct current
IREZ	*Interregional Renewable Energy Zones* (report)
IRP	Integrated resource plan
ISO	Independent system operator
ISP	Integrated (transmission) system plan
JTIQ	Joint Targeted Interconnection Queue
kV	Kilovolt(s)
LRTP	Long-Range Transmission Planning
MISO	Midcontinent Independent System Operator
MVP	Multi-Value Projects
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
NTP	National Transmission Planning
NYISO	New York Independent System Operator, Inc.
Ofgem	Office of Gas and Electricity Markets (Great Britain)
OMS	Organization of MISO States
PJM	PJM Interconnection, L.L.C.
PMA	Power marketing administration
PNNL	Pacific Northwest National Laboratory

PTO	Participating transmission owner
RSC	SPP Regional State Committee
RTO	Regional transmission organization
SAA	PJM State Agreement Approach
SPP	Southwest Power Pool, Inc.
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council
WestTEC	Western Transmission Expansion Coalition
WRAP	Western Resource Adequacy Program

Executive Summary

The National Transmission Planning (NTP) Study (GDO 2024a), which was led by the U.S. Department of Energy's (DOE's) Grid Deployment Office in partnership with National Renewable Energy Laboratory (NREL) and Pacific Northwest National Laboratory (PNNL), demonstrates that interregional transmission can provide a wide range of benefits under a variety of potential future electric system scenarios, including reliability, resilience, economic, and decarbonization benefits. Long-term co-optimized generation and transmission scenarios simulated in the NTP Study suggest the electric grid will be less costly and more resilient if solutions include interregional transmission. Specifically, the NTP Study finds that improving interregional transmission can enhance grid reliability, particularly in response to extreme weather events, as it allows more resources to be shared across regions and energy to be moved from where it is available to where it is needed. The NTP Study also finds that a substantial expansion of the transmission system throughout the entire contiguous United States delivers the largest benefits to customers under various grid decarbonization scenarios and would save $270–$490 billion in system costs through 2050, with approximately $1.60 to $1.80 in system cost savings for every dollar spent on transmission (GDO 2024a).

Despite the potential for significant benefits, there are a variety of barriers to developing interregional transmission. This report is designed to supplement the technical findings in the multiyear NTP Study, with a qualitative assessment of obstacles to interregional transmission, and a high-level survey of potential solutions to such challenges. **This report provides state and federal decision-makers, transmission planners, and other industry participants with a survey of areas to explore to overcome existing barriers to planning and developing interregional transmission.**

Key Challenges for Planning and Deploying Interregional Transmission

Developers of new interregional transmission face many of the same barriers as those encountered by developers of regional or local transmission, only these challenges are exacerbated as interregional transmission projects tend to span greater distances over multiple jurisdictions and have higher overall costs and benefits. Interregional transmission developers also face unique technical challenges associated with dual-transmission system modeling, system-to-system operations, and lack of standardization of data and analysis methods.

Compounding the difficulties, there are no comprehensive, multi-value interregional transmission planning processes to identify and compare interregional transmission solutions to local or regional projects, and no organization or authority has clear responsibility for interregional planning. **For various reasons, incremental local transmission upgrades may preempt larger regional or interregional transmission projects that can potentially address multiple needs more cost-effectively.**

The authors of this report interviewed transmission system experts, planners, and developers in the United States; reviewed literature; and reviewed comments from Federal Energy Regulatory Commission (FERC) proceedings to understand the institutional and regulatory challenges to developing interregional transmission in the United States. Table ES-1 summarizes some of the challenges to interregional transmission development by challenge category.

Table ES-1 Summary of challenges to interregional transmission development

Challenge category	Challenge
Planning Challenges	• Lack of multi-value interregional planning that compares interregional solutions to potential regional and local projects • Lack of organization or authority clearly responsible for interregional planning • Lack of common methods and assumptions across planning regions for determining interregional transmission needs • Inconsistent benefits consideration, benefits calculation, and cost allocation methods between planning regions • Lack of generation and transmission co-optimized expansion planning
Operational Challenges	• Lack of co-optimization of interties along seams, leading to inefficient outcomes
Development Challenges	• Lack of incentives for incumbent utilities to build transmission outside their service territories • Complex and challenging siting and permitting requirements • Challenging financing and cost recovery
Merchant Challenges	• Different benefits and challenges associated with merchant project development • Lack of merchant HVDC* interconnection processes • Gap in how market operators value merchant interregional transmission

* High-voltage direct current

Strategies to Overcome Barriers to Interregional Transmission

This report identifies potential practices and approaches that states, federal entities, regional transmission organization (RTO)/independent system operators (ISOs), utilities, and other industry participants and decision-makers can consider to improve the likelihood that new, efficient interregional transmission is built. Table ES-2 provides a high-level list of approaches found in the literature and public proceedings, and collected through expert interviews, that could contribute to progress. Approaches are grouped by the entity type (state, federal, RTO/ISO/utility, or other industry players) that could implement the strategy. In this report, the authors present multiple pathways available to decision-makers to further the discussion and potentially advance interregional transmission. However, in listing the specific strategies in Table ES-2, PNNL and NREL do not specifically endorse one or more of those strategies.

Because the findings of the NTP Study indicate that increasing interregional transmission capability can result in meaningful consumer savings, reduced power outages during large-scale extreme weather events, and enhanced resilience for the U.S. electric system, interregional transmission planning and development is important as the Nation undertakes a once-in-a-lifetime effort to modernize the aging electric transmission system.

Table ES-2 Potential interregional transmission facilitation strategies

Category	Strategies
State-Led Options	• Collaborate with neighboring states on major projects that can benefit each state • Participate in (or create) multistate coordinating committees on energy policy • Create a state-specific transmission planning authority • Conduct state-level strategic transmission planning • Ensure adequate staffing and resources specific to transmission issues, including augmenting state research capabilities • Develop regulatory directives and expectations, including criteria for transmission projects intended to increase market access and provide additional economic benefits • Lead efforts to improve transmission planning transparency and early-stage stakeholder involvement • Institute competitive renewable energy zones
Federal Options	• Develop an interregional transmission planning framework • Identify interregional transmission planning principles • Explore opportunities to improve the integration of merchant projects • Develop broader and standardized cost-benefit metrics • Consider creating new entities, such as a national transmission planning organization • Continue to explore minimum interregional transfer capability requirements • Engage federal power market administrations • Continue to support siting and permitting activities
RTO/ISO and Utility-Led Options	• Go beyond minimum interregional coordination required by FERC • Develop joint operational and planning models with neighboring regions • Form national or multi-region planning organizations to conduct exploratory planning • Inform potential cost allocation approaches through joint regional data collection and common benefits metrics • Explore geographic partnerships that maximize the quantity and reliability of time-diversified renewable energy options • Increase the value of merchant interregional transmission by allowing excess capacity to be optimized by the RTO/ISO • Improve trading and address operational inefficiencies across existing interties • Work to quantify the resource adequacy value of interregional transmission
Industry Options	• Increase public engagement and awareness in advance of new projects • Establish tangible evidence of commercial interest • Consider public-private partnerships for interregional transmission projects • Develop studies and models showing multiple benefits across regions or proposed new projects

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1.0 Introduction

The National Transmission Planning (NTP) Study (GDO 2024a), led by the U.S. Department of Energy's (DOE's) Grid Deployment Office (GDO) in partnership with the National Renewable Energy Laboratory (NREL) and the Pacific Northwest National Laboratory (PNNL), was conducted to understand the transformation needed to ensure the U.S. electric system continues to reliably serve customers as the power sector evolves and transitions. The results of the NTP Study show that significantly more transmission needs to be built in the United States—roughly two to three times the current transmission system—to meet future demand growth, reliability requirements, and achieve existing and potential future public policy goals (such as decarbonizing the grid) (GDO 2024a). The NTP Study shows that the benefits of transmission expansion include enhanced grid reliability and resilience to extreme events, customer savings, and the ability to integrate new generation onto the grid. The NTP Study also finds that a substantial expansion of the transmission system throughout the entire contiguous United States delivers the largest benefits to customers under various future scenarios and would save $270–$490 billion in System Costs through 2050, with approximately $1.60 to $1.80 in system cost savings for every dollar spent on transmission. While the NTP Study conducts a nationwide optimization and assessment of transmission scenarios and the relative costs and benefits of different scenarios, it does not replace existing transmission planning processes or identify site-specific transmission lines. **This paper provides a bridge between the transmission planning scenarios featured in the NTP Study and the existing transmission planning and development processes in place in the United States and identifies potential paths forward to advance interregional transmission development.**

Given existing challenges to planning and developing interregional transmission in the United States today, this paper summarizes considerations and potential solutions to overcome those challenges. Many of the challenges and solutions shared in this paper have been described in other documents, but we summarize them in this paper to be considered alongside the NTP Study results.

This report is informed by interviews with or views expressed by industry experts, published reports and articles, and public comments in various regulatory proceedings. While the goal of this report is to provide an overview of the current state of discussion, there are undoubtedly additional options and issues that do not appear here. The authors hope this report provides a starting point for conversations at the state, regional, and national level that complement the formal conversations and proceedings at FERC and elsewhere.

2.0 Key Findings of the National Transmission Planning Study

The NTP Study was a multiyear effort that combined innovative methods with state-of-the-art industry practices demonstrating a forward-thinking approach to understanding the role and value of transmission in future power systems. The NTP Study sought to:

- Develop new national-grid-scale planning tools and methods that can be used by industry, especially when planning for interregional transmission capacity needs
- Identify potential transmission solutions that will provide broad-scale benefits to electric customers under a wide range of potential futures
- Inform planning processes for regional and interregional transmission
- Identify interregional and national strategies to maintain grid reliability as the grid transitions, including to a reliance on weather-dependent energy resources.

The key findings of the NTP Study are summarized by topic below (GDO 2024a):

- **Grid reliability**: Improving interregional transmission can enhance grid reliability as it allows more resources to be shared across regions and energy to be moved from where it is available to where it is needed. Interregional transmission can improve resilience to modeled extreme weather events.
- **Consumer savings**: A substantial expansion of the transmission system throughout the entire contiguous United States delivers the largest benefits to customers and would save the $270–$490 billion system-wide through 2050, with approximately $1.60 to $1.80 in savings in electric system costs for fuel, generation, and storage capacity, and other costs for every dollar spent on transmission from access to lower cost generation and more resource sharing for reliability.
- **Integrating new generation into the grid**: Expanded transmission enables the grid connection of new generation, balancing the variability of wind and solar resources and accommodating growing energy demands while maintaining system reliability and energy affordability.

The national planning perspective of the NTP Study provided a holistic examination of transmission, assuming regulatory and institutional barriers are overcome (GDO 2024a). This paper addresses planning and development barriers, some of which are regulatory and institutional, that can limit transmission development, particularly interregional transmission development. One way to use the NTP Study and this report is to consider the solutions described herein to help realize projects consistent with high-opportunity transmission (HOT) interfaces identified in the NTP Study. HOT interfaces represent common transmission transfer capacities between regions that are identified in 75 percent of 96 modeled scenarios considered in the NTP Study.

Figure 1 shows HOT interfaces between planning regions for two different types of transmission buildouts considered in the NTP Study: an alternating current (AC) transmission buildout and a multi-terminal (MT) high-voltage direct current (HVDC) buildout, both of which can be used to meet 90 percent by 2035 emissions targets for a mid-demand scenario.[1] Transmission projects

[1] The NTP Study modeled low, medium, and high demand scenarios. The mid-demand scenario assumes 2.0 percent/year growth in electricity demand.

that align with these HOT interfaces to increase transfer capacity could be strong candidates for further study and could serve as a starting point for states, planners, and developers interested in accelerated transmission expansion.

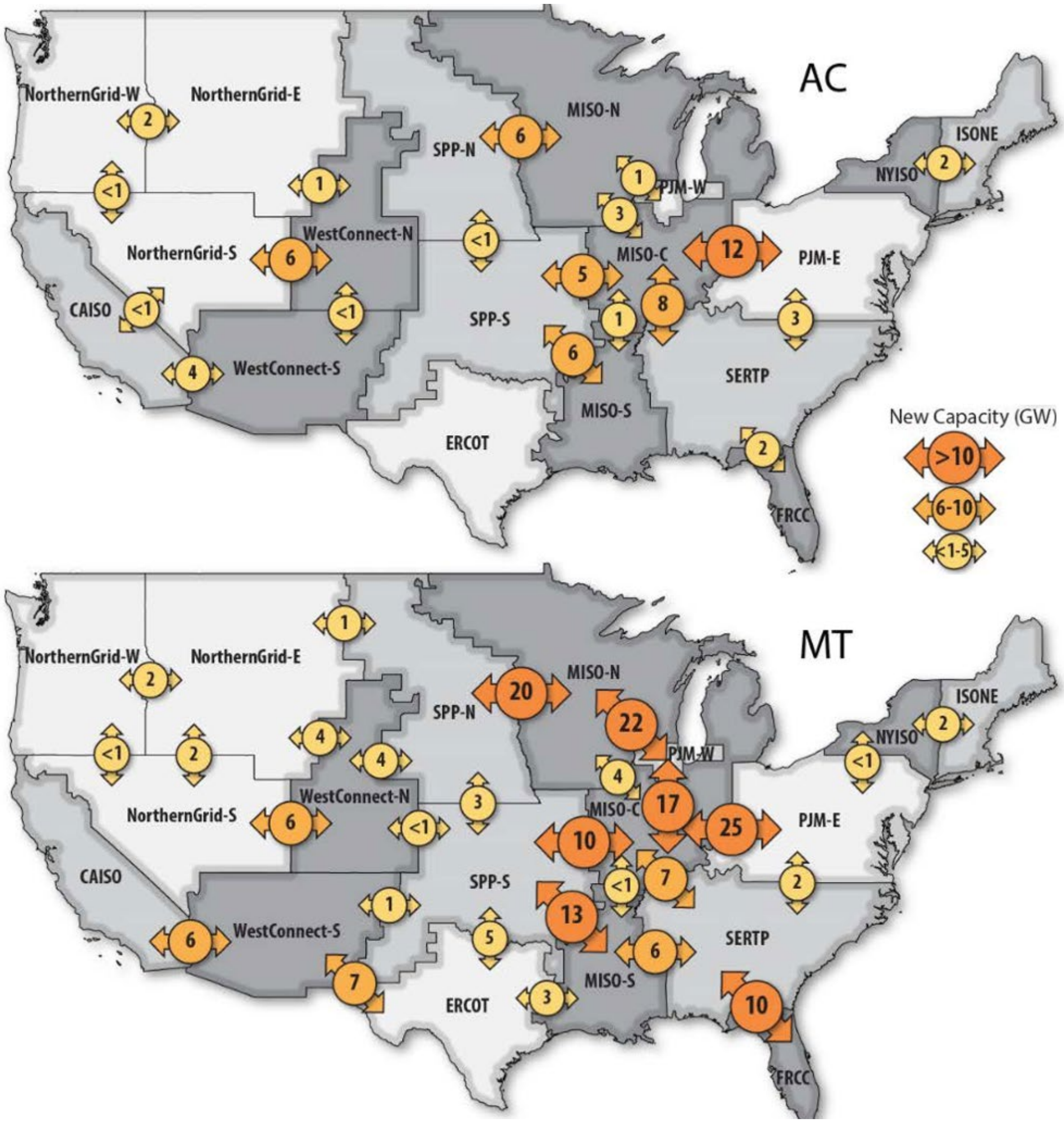

Figure 1 HOT interfaces identified in the NTP Study for achieving 90% by 2035 emissions reductions under mid-demand scenarios for AC or MT HVDC buildouts. For more details see: https://www.energy.gov/sites/default/files/2024-10/NationalTransmissionPlanningStudy-Chapter2.pdf

3.0 Factors that May Limit Interregional Transmission Development

There are a variety of factors that may limit interregional transmission planning and development. As context for the planning and deployment challenges described in this section, there are three general geographic scales of transmission projects:

- **Local transmission projects,** which are included in a utility's local transmission plan and involve lower-voltage projects solely within the service territory of that utility. This type of project comprises the majority of the transmission built in recent years and is not the focus of this report (Gramlich and Caspary 2021).
- **Regional transmission projects,** which are typically identified in regional transmission planning processes or by merchant transmission developers and span more than one utility service territory or state. FERC Order 1000—the last landmark transmission planning rule prior to Order 1920—requires designated FERC Order 1000 regions[2] to conduct regional transmission planning (FERC 2011). Figure 2 shows the FERC Order 1000 Transmission Planning Regions (FERC 2021a). Regional transmission planning processes, per FERC Order 1000, must evaluate whether transmission alternatives at the regional level may resolve the transmission planning region's needs more efficiently or cost-effectively than alternatives identified by individual utilities in their local transmission planning processes (FERC 2011).
- **Interregional transmission projects** are typically identified first in regional transmission plans and then through interregional coordination and span more than one transmission planning region. Merchant transmission developers also identify interregional projects outside of the regional planning process. FERC Order 1000 requires planning regions to engage in interregional coordination but stops short of requiring interregional planning (FERC 2011). FERC Order 1920 takes a similar approach, extending the FERC Order 1000 (FERC 2011) interregional transmission coordination requirements to the new long-term regional transmission planning process but again declining to require interregional planning (FERC 2024a).

The callout box in this section describes FERC Orders that are relevant to regional and interregional transmission planning.

[2] There are 12 transmission planning regions in the continental United States, 11 of which fall under the jurisdiction of FERC. One of the 12—the Electric Reliability Council of Texas (ERCOT)—falls under state jurisdiction (FERC 2021a). Of the 12 transmission planning regions, seven align with the footprint of a regional transmission organization (RTO) or independent system operator (ISO) that implements FERC's transmission planning rules. Some of the planning regions align with a single state, but most have a multistate footprint.

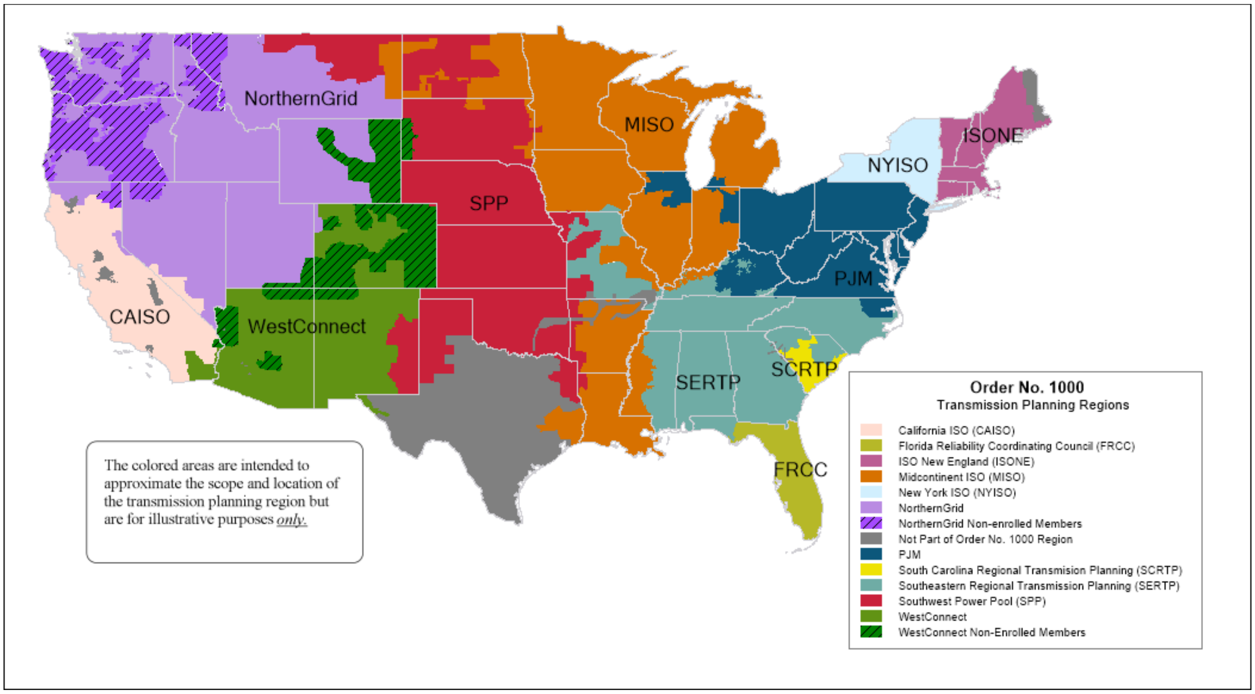

Figure 2 FERC Order 1000 Transmission Planning Regions (FERC 2021a)

FERC ORDERS RELEVANT TO REGIONAL AND INTERREGIONAL TRANSMISSION PLANNING

Regional and interregional transmission fall within the jurisdiction of FERC as part of its responsibility to regulate interstate transmission and wholesale electricity rates in interstate commerce. **FERC Order 888** from 1996 (FERC 2020) required open access to transmission systems and established minimum transmission planning requirements. **FERC Order 890** from 2007 (FERC 2007) required coordinated regional transmission planning and established key planning principles. **FERC Order 1000** from 2011 (FERC 2011) required transmission planning regions to develop regional transmission plans and required interregional coordination between these regions. Regional planning processes are required to evaluate transmission alternatives that can meet needs more efficiently or cost-effectively than projects identified in local transmission expansion plans. Transmission projects may address needs such as reliability, market efficiency (e.g., reduce congestion), public policy, or multiple needs. Order 1000 established certain cost allocation principles and requires methods to be put in place to allocate the cost of eligible new regional and interregional facilities (FERC 2011). Order 1000 requires planning regions to engage in interregional coordination but stops short of requiring interregional planning (FERC 2011). **FERC Order 1920**, issued in 2024, establishes certain long-term regional planning requirements that incorporate specific factors into future-looking scenarios and quantify specific types of benefits when evaluating potential transmission solutions (FERC 2024a). Order 1920 extends the Order 1000 interregional transmission coordination requirements to the new long-term regional transmission planning process (FERC 2024a). While FERC considered some of the topics described in this paper in the rulemaking proceeding that led to Order 1920, many were not addressed directly by the scope of Order 1920 and remain part of the ongoing application and evolution of the Nation’s transmission planning processes.

To identify barriers to successful interregional transmission planning and development as well as potential strategies to overcome these barriers, the authors reviewed research and industry reports and conducted interviews with transmission experts, transmission project developers, and regulatory experts. We also drew insights from written and verbal comments from industry leaders (i.e., planners, regulators, and policymakers) in various federal and regional contexts.

Some key limiting factors to interregional transmission development suggested by transmission stakeholders in various forums are described below.

3.1.1 Planning Challenges

- There is **a lack of comprehensive, multi-value interregional transmission planning processes to identify and compare interregional transmission solutions to local or regional projects** and there is **no planning organization or authority responsible for interregional transmission planning** (Pfeifenberger et al. 2021). Transmission planning regions plan to address their own reliability needs through their local and regional transmission planning processes. This is often done on a relatively near-term basis that makes it difficult to identify interregional transmission projects that can more optimally serve the reliability needs of multiple regions than separate, regional or local transmission projects. The long-term regional planning and interregional coordination required by FERC Order 1920 (FERC 2024a) may reduce this barrier to interregional projects, though the need to plan on a nearer-term basis to ensure reliability will continue and cannot be entirely overcome given the nature of reliability system planning. In some instances, local and regional reliability-based transmission projects will be essential to ensure reliability as they tend to develop more quickly than larger interregional transmission projects.

- There are **no common methodologies and assumptions for conducting planning and establishing interregional transmission needs**. While North American Electric Reliability Corporation (NERC) reliability standards are consistent across the country, NERC allows its Regional Entities to develop reliability standards that are region-specific. Each local transmission provider may develop its own planning criteria. Similarly, each transmission planning region may develop its own methodologies for identifying transmission needs. **This lack of common methodologies and assumptions for establishing transmission needs among transmission planning regions can inhibit the ability to analyze interregional transmission needs and identify the types of high-benefit interregional transmission projects consistent with the NTP Study findings**. In addition, regions may conduct planning activities under different timelines making it more difficult to coordinate across regions. Each transmission planning region must comply with specific interregional transmission coordination requirements from FERC. However, under FERC Order 1000, transmission planning regions are not required to fully align all elements of their interregional transmission coordination timelines, procedures, methods, and definitions with one another. For example, the details of interregional project identification, evaluation, selection, and cost allocation processes and criteria may be unique to each interregional coordination forum (FERC 2011).
- **Reliability-driven transmission projects generally do not undergo an analysis of broader economic and public policy benefits**. Reliability-driven projects can be approved without considering economic and public policy benefits (Pfeifenberger et al. 2021). This can lead to inefficient outcomes as reliability projects with lower total benefits and higher costs can be approved rather than alternative multi-value projects. **Incremental reliability-based transmission upgrades may, therefore, preempt larger regional or interregional transmission projects that can potentially address multiple needs more cost-effectively.**
- Currently, **regional transmission system models often do not include the latest transmission and generation plans or details of neighboring systems**, other than at the point of interconnection. This makes it difficult to model the system impacts of interregional transmission solutions in a meaningful way that helps determine how a proposed interregional transmission project can alleviate the need for proposed regional projects. In turn, this makes it difficult to assess the impacts and benefits of proposed interregional solutions. Since FERC Order 1000 requires interregional solutions to meet transmission needs in a more efficient or cost-effective manner than regional solutions to benefit from broad cost allocation (FERC 2011), incomplete identification of benefits may prevent interregional solutions from being meaningfully considered. In the West, the Western Electricity Coordinating Council (WECC) maintains a west-wide model of the system, and the Eastern Interconnection Planning Collaborative (EIPC) maintains an interconnection-wide model for the East. These models and data are inputs used in the regional transmission planning processes but they are not complete representations of each region's transmission system. However, there are initiatives to *develop* interconnection-wide base case power flow and dynamics models for use by transmission planning regions and other entities (ERAG 2023).
- Transmission planning regions **consider and calculate different benefits from region-to-region and have inconsistent cost allocation methods**. Transmission planning regions

do not have consistent processes and standards for determining cost-effectiveness. Some may characterize the various benefits of interregional transmission differently than others and have different preferences for how to allocate costs across each region. For example, some regions, such as the Florida Reliability Coordinating Council, do not use production cost savings in benefits characterizations. For those that do, production cost modeling methods and datasets vary by region. Methods to quantify reliability, resource adequacy, and resilience benefits are harder to agree on than production cost savings, and they may be included or excluded for planning purposes. When regions do consider similar benefits, they use different methods to quantify these benefits. **Without a consistent approach to characterizing and quantifying the resilience value of transmission, important solutions may remain out of reach, including solutions that are important to address transmission needs that arise during extreme weather events**. FERC Order 1920 mandates that transmission planning regions consider a specific set of benefits as part of evaluation of potential long-term regional transmission projects, which may help establish increased standardization among transmission planning regions (FERC 2024a). FERC Order 1920 also requires planners to conduct extreme event sensitivities for regional plan scenarios. That said, the details of how the benefits are calculated are left to the regions, meaning that in practice, significant differences may remain even after implementation of FERC Order 1920 (FERC 2024a).

- For some regions and transmission planning entities, **generation capacity expansion and transmission expansion planning processes are siloed, preventing the ability to co-optimize between generation and regional transmission solutions.** The result of not integrating these processes is an inability to understand tradeoffs between generation and transmission decisions, including the most cost-effective mix of new generation builds and new transmission capacity (ESIG 2022). It may become more critical to solve this lack of integration as variable renewable energy contribution and extreme weather events increase. For example, it may be important to consider how to co-optimize between local generation capacity expansion and geographically diverse regional and interregional transmission investments that can extend beyond weather systems.
- Planners' perspectives greatly vary in how they perceive the value of interregional transmission for resource adequacy. In some instances, **value calculations may not account for the resource adequacy value of interregional transmission** (Pfeifenberger et al. 2021). Some regional transmission organizations (RTOs)/independent system operators (ISOs) and utilities are concerned about reliability, cost, and equity problems that can emerge if interregional resource adequacy is used as a substitute for regional resource adequacy. In other cases, such as in the Midcontinent Independent System Operator (MISO) Long Range Transmission Planning projects, resource adequacy is one of the project benefits considered. Challenges related to valuing the resource adequacy benefits of interregional transmission include the following:
  - RTO/ISO resource adequacy simulations may not capture the full resource adequacy value of interties (Brattle 2024).
  - Provisions in capacity market rules (e.g., capacity import limits) to achieve resource adequacy requirements that are adopted by some RTOs/ISOs can create barriers for interregional transmission delivery of resource adequacy resources across seams (Simeone and Rose 2024).

3.1.2 Development Challenges

- There is a **disincentive for incumbent utilities to build transmission outside their existing service territories**. In general, cost allocation is easier for projects located within a single transmission service territory. In addition, most lower voltage projects that do not significantly increase transmission capacity and are within a single incumbent utility's service territory are not subject to competition from nonincumbent developers. Prior to FERC Order 1920, if an incumbent utility wanted to update an aging transmission line in its territory in a manner that would significantly increase capacity, the project might be subject to a competitive process. One result is that utilities avoid making significant capacity increases in their existing system to avoid competition from outsiders, creating a potential missed opportunity to enhance the transmission network. Order 1920 potentially eliminates this disincentive by giving incumbent utilities the right-of-first refusal to build upgrades to their existing system when they agree to "right-size" these equipment replacements (FERC 2024a). This policy change is aimed at reducing one barrier to maximizing the transmission capacity value of the existing system by "right-sizing" equipment replacement in existing rights-of-ways within a utility's service territory. However, this change might further focus utility development within their service area instead of expanding to regional and interregional development. Controversies associated with cost allocation to support regional and interregional project development where project benefits and beneficiaries must be identified to recover project costs may be another factor prompting utilities to focus within their own territory where costs are recovered from their own customers. As a result of these and other factors, incumbent transmission providers, who have significant expertise and experience in transmission expansion and have ready access to needed information within their service territories, may be inclined to focus more on local projects. In turn, the incentive to focus on local transmission projects may divert incumbent transmission owner attention from regional and interregional transmission opportunities.
- **Financing and cost recovery are challenging** for new interregional transmission. Financing may be challenging for interregional projects because interregional transmission projects are higher dollar cost projects than local or regional projects with greater risks associated with multi-jurisdiction permits and rights of way. Projects conceived through regional planning and interregional coordination must navigate cost allocation decisions for cost recovery, which are increasingly complex and controversial as the project costs and number of beneficiaries expand even though the value and cost-effectiveness also may increase. In addition, the failure of existing planning processes to result in new interregional lines has yielded more interregional projects being merchant developer projects. Merchant developers rely on market-based mechanisms to recover costs through sales of capacity at negotiated rates rather than regulated cost-of-service rates. Merchant projects generally have less certainty because they cannot allocate costs to a predefined customer base like a public utility can. Merchant developers assume all financial risks for their projects.
- **Transmission siting and permitting are complex and challenging**. Siting and permitting infrastructure are always challenging but even more so for a transmission project that crosses multiple states and regions. Not only is there a multitude of potential authorities with jurisdiction to issue needed permits, but each of these authorities may be required to make a separate finding of need for the project to comply with the relevant authorizing statute. A single interstate transmission project may fulfill different needs or deliver different types or levels of benefits to each respective state or to the region overall. The result can be years of protracted siting and permitting proceedings, sometimes resulting in a patchwork of time-bound permits along an interregional project's route. DOE has a variety of programs to support transmission siting and permitting, including the Coordinated Interagency

Transmission Authorization and Permits Program, Transmission Siting and Economic Development (TSED) Grant Program, the National Interest Electric Transmission Corridor Program, and others (GDO n.d.-a).

3.1.3 Operational Challenges

- **Operational limitations for interregional transactions can inhibit realizing the value of both existing and potential future interregional transmission** (Simeone and Rose 2024). Different rules or procedures used between neighboring systems can cause trading barriers or inefficiencies. Reducing these issues can improve the efficiency of interregional transmission infrastructure and system-to-system trading. Examples of operational barriers and inefficiencies include uneconomic flows (where power flows from areas of higher prices to areas of lower prices), problems with market-to-market scheduling rules (high transaction fees, inaccurate price forecasts), differences between physical and pricing interchange points, and operation of market-to-market flowgates (jointly operated transmission facilities). Maximizing the value of interregional transmission for both existing and potential new lines—as identified in the NTP Study—requires minimizing inefficiencies potentially caused by these operational issues. To learn more about these issues, refer to the NTP Study companion report, *Barriers and Opportunities to Realize the System Value of Interregional Transmission* (Barriers; Simeone and Rose 2024).

3.1.4 Merchant-Related Challenges

- **Merchant projects face different benefits and challenges associated with project development**. Most of the interregional transmission projects that have advanced to date have come not from traditional regulated utilities or the regional planning and interregional coordination processes, but from merchant transmission developers. The merchant development model differs from the incumbent utility model in that it relies on obtaining individual customer commitments (from generation resources or load-serving utilities) to take capacity on the line rather than inclusion in a local or regional transmission plan, and it is thus typically a step removed from the ongoing system planning and cost allocation conducted by utilities and transmission planning regions, including RTOs and ISOs (FERC 2011). Consequently, the inception stage for merchant transmission projects can bypass the conventional transmission planning process challenges, such as establishing transmission needs noted above, allowing them to emerge independently. At the same time, merchant transmission development comes with its own set of challenges, including complications associated with not being afforded public utility status, potential inefficiencies of being planned outside a more comprehensive planning process, and potential conflicts with regional projects selected by transmission planning regions. While many merchant transmission projects appear to align with underlying economic trends described in the NTP Study and previous studies, nearly all interregional merchant transmission projects have experienced delay, and many have been canceled altogether due to obstacles in permitting or transmission development. While all transmission projects can encounter delays with siting and permitting, merchant developers may face additional obstacles because they are not public utilities (Eto 2016, FERC 2022, Hale 2023, and Reed 2021). State public utility commissions or other state siting authorities often require designation as a public utility under state law before awarding a certificate of public convenience or necessity to a project, which is required to operate within the state or to exercise eminent domain (Hoecker and Smith 2014). These certificates are only awarded to projects that are deemed to be in the public interest. However, restricting private non-public-utility developers from receiving award of these certificates can prevent many projects in the public interest from being realized.

- There is a **lack of merchant HVDC transmission interconnection processes**. Some merchant transmission developers point out that many transmission providers simply do not have tariffs and interconnection processes specifically for connecting merchant HVDC interregional transmission projects (Invenergy 2022). Some developers report that as new HVDC projects have been proposed to regional transmission planners, new processes have to be developed. Without interconnection processes these new merchant HVDC projects have to navigate the generation interconnection queue process, which may result in significant development delays if backlogged. To complicate matters further, there are many different types and configurations of merchant HVDC transmission, and the lack of an HVDC transmission interconnection process disproportionately harms merchant HVDC transmission that does not have associated generation but may still be required to use the generation interconnection queue. Interconnection queue backlog motivated FERC to issue Order 2023 (FERC 2023)[3] to reduce the delays associated with generator interconnection. Meanwhile, if realized, new merchant HVDC transmission capacity can facilitate new generation supply into congested areas and facilitate the interconnection of new resources. Merchant developers have pushed for a technical conference at FERC on merchant transmission, but to date, this has not happened (Invenergy 2022). There are also unique issues with HVDC interconnection, such as single-source contingency or injection limits established by system operators. These limits may prevent multiple offshore projects from sharing transmission that injects into the grid at a single point of interconnection or otherwise limit the size of HVDC projects if they are determined to be the most severe single contingency to the AC grid (DOE BOEM 2024; Pfeifenberger et al. 2023).
- **Gaps in how market operators use and value merchant interregional transmission can reduce the system value of these resources**, creating an opportunity cost and making these projects harder to develop. Some merchant transmission facilities are financially supported by subscriber-customers—typically interconnected generation projects that need transmission to deliver electricity to load—who are charged negotiated, market-based rates and afforded priority access. These projects are required to make unused capacity available at owner-determined rates but are not required to provide open access or to make unused capacity available to market operators for co-optimization (Pfeifenberger et al. 2023). Allowing market operators to operate merchant lines and optimizing unused capacity can be complicated under existing compensation structures (e.g., transmission access charges), because these charges are used to recover costs for projects developed through regional planning.

Table 1 provides a summary of the key challenges identified in this section.

[3] FERC Order 2023 was issued in July 2023 (with rehearing issued in May 2024) and seeks to improve the process for new generators to connect to the grid.

Table 1 Summary of challenges to interregional transmission development

Challenge category	Challenge
Planning Challenges	• Lack of multi-value interregional planning that compares interregional solutions to potential regional and local projects • Lack of organization or authority responsible for interregional planning • Lack of common methods and assumptions across planning regions for determining interregional transmission needs • Inconsistent benefits consideration, benefits calculation, and cost allocation methods between regions • Lack of generation and transmission co-optimized expansion planning
Operational Challenges	• Lack of co-optimization of interties along seams, leading to inefficient outcomes
Development Challenges	• Lack of incentives for incumbent utilities to build transmission outside their service territories • Complex and challenging siting and permitting requirements • Challenging financing and cost recovery
Merchant Challenges	• Different benefits and challenges associated with merchant project development • Lack of merchant HVDC interconnection process • Gap in how market operators value merchant interregional transmission

Although many challenges to developing interregional transmission exist, the next section describes potential strategies available to states, federal entities, RTOs/ISOs, and industry actors that wish to advance interregional transmission development to capture benefits associated with interregional transmission, such as reliability and cost savings.

4.0 Potential Considerations for Advancing Interregional Transmission Development

The NTP Study showed that interregional transmission can be an effective way to meet new reliability challenges, address cost and resource constraints, and achieve clean energy goals. Importantly, there is a wide range of actors that can contribute to advancing its deployment. In preparing this report, **the authors encountered three high-level perspectives** on how to overcome the challenges of the lack of interregional transmission planning and development. These perspectives are listed below.

- **States can take a leadership role:** Some experts argue that the potential benefits to states and the public warrant enhanced multistate collaboration and leadership on interregional transmission planning and cost allocation.
- **The federal government can play more of a role:** Others suggest the potential benefits to the Nation justify the creation of new federal institutions and/or rules for interregional transmission planning, oversight, and cost allocation, going beyond FERC's current rules and requirements.
- **RTOs/ISOs and industry players can do more, but in general, existing processes are sufficient with a few modifications:** Some believe the current regional planning and interregional coordination paradigm might not be perfect, but it is working well enough and can work better with voluntary actions by RTOs and utilities and active engagement by all relevant parties.

The following sections outline potential actions that can be taken by states, the federal government, RTO/ISOs and utilities, and other industry players such as project developers. Information presented in this section was informed by interviews with or views expressed by industry experts, published reports and articles, and public comments in various regulatory proceedings. The actions described below are grouped by state-led solutions, federal actions, RTO/ISO and utility actions, and potential industry-led actions. Some of these actions are addressed in part by FERC Order 1920 (FERC 2024a) and are included here for completeness and given implementation uncertainty.

This report presents multiple pathways available to decision makers to potentially advance interregional transmission without specifically endorsing any of these views.

4.1 State-Led Actions to Advance Interregional Transmission

States play a key role in transmission development and can play an important role in advancing interregional transmission expansion. They are uniquely positioned to find infrastructure solutions that work for their citizens and advance state policies, and they are largely in control of siting and permitting. For many state agencies, however, **limited staffing and budgetary resources are constraints that inhibit active participation in transmission planning processes** and require careful prioritization between transmission and other energy issues. In addition, because state utility regulators are required to look out for the public interest of their state, they may be reluctant to support interregional transmission solutions where benefits are shared across states in varying degrees, for fear that customers in their state would be subsidizing benefits accruing to customers in other states. This is often referred to as the "free rider problem," and it's a consistent concern with interregional transmission projects.

While interregional transmission planning is generally within the purview of the federal government, due to interstate commerce, state jurisdiction includes siting and permitting on non-federal land, and may include resource planning. Thus, it is important that state and federal organizations coordinate on interregional transmission planning and development. State–federal collaboration can be a practical path for both levels of government to meet new policy and reliability challenges. FERC and the National Association of Regulatory Utility Commissioners (NARUC) acknowledged the potential benefits of coordinated federalism when they created the Joint Federal-State Task Force on Electric Transmission in 2021.[4] As FERC explained,

> Federal and state regulators each have authority over transmission-related issues, meaning that transmission developers must successfully navigate different federal and state regulatory processes. In addition, the development of new transmission infrastructure often affects numerous different priorities of federal and state regulators (e.g., reliability, customer protection, environmental considerations). As a result, the area is ripe for greater federal-state coordination and cooperation (FERC 2021b).

Studying and determining the state public interest in interregional transmission can involve state utility regulators as well as governors, legislators, and state energy offices. Utility regulators and other state decision-makers can play a role in requiring or encouraging local utilities and relevant RTOs/ISOs to explore new infrastructure strategies, including coordination across jurisdictional lines.

Below is an overview of potential state leadership actions to encourage regional and interregional transmission development through planning and policy, and transparency and capacity building:

4.1.1 Planning and Policy Options

- **Implement or encourage state-to-state collaboration.** State officials, including governors, state energy offices, and public utility commissions, can coordinate with counterparts in other states in their region and beyond on planning, resource adequacy, innovative cost recovery agreements, and standardizing siting and permitting information requirements to enable better information sharing and improved efficiencies. This can help address capacity and staffing challenges. States can also utilize multistate coordination committees. States can create or participate in cross-state regulatory/policy organizations and work with neighboring states' public utility commissions and state energy offices on transmission planning, options analysis, and decision-making. These collaborations, sustained over time, can help build trust between organizations and staff, and states can work together to understand issues and tradeoffs. In addition to the information, coordination, and planning options, there is a need for a collaborative framework for decision-making and cost allocation. Some examples of states coordinating around both general energy policy and specific issues of concern include the following:
  - **MISO Multi-Value Projects (MVPs) and Long-Range Transmission Planning (LRTP)** – The MISO LRTP process and the associated cost allocation methodology was spurred by a collaboration of governors of Midwest states interested in meeting state's renewable portfolio standards and addressing delays in connecting new renewable energy to the grid (UMTDI 2010). In 2007, the Midwest Governors Association called for increasing collaborative regional transmission planning and siting to enable future

[4] The Joint Federal-State Task Force on Electric Transmission has been disbanded and replaced by a Federal-State Current Issues Collaborative between NARUC and FERC.

development of renewable electricity generation. This action was a catalyst for expanded regional transmission planning in MISO. MISO developed a new type of project, the MVP, and associated project criteria through a process initiated in 2007 and culminated in an MVP transmission plan consisting of 17 projects that the MISO Board of Directors approved in 2011. In July 2022, MISO approved a second set of 18 projects spanning nine states, referred to as Tranche 1. In December 2024, MISO's Board is scheduled to finalize the LRTP tranche 2.1, which as of September 2024 included 24 projects totaling $21.8 billion and a new 765 kilovolt (kV) backbone across the Midwest (MISO 2024a). MISO also published a business case metrics methodology whitepaper with tranche 2 to show how the projects were evaluated (MISO 2024b). The support from the Organization of MISO States (OMS) for regional coordination and long-range transmission planning has been critical in the recent progress made on the MISO MVP and LRTP processes and associated projects. OMS developed a set of cost allocation principles for projects developed through MISO LRTP, for example (MISO n.d.[a]).

- **The Northeast States Collaborative on Interregional Transmission** – In June 2023, a collection of eight Northeastern states proposed a new model of interregional planning supported by DOE technical expertise. The Northeastern States Collaborative on Interregional Transmission has since grown to 10 states, including state officials from Massachusetts, Connecticut, Maine, Vermont, New York, New Jersey, Rhode Island, New Hampshire, Maryland, and Delaware. In July 2024, these states formalized their collaboration through a memorandum of understanding to explore regional and interregional transmission facilities, including both on- and offshore options. The Northeast States Collaborative is a forum convened outside existing processes and across FERC Order 1000 interregional coordination transmission planning regions to assist with planning and increase interconnectivity. In this collaboration model, the three RTOs representing the regions (i.e., PJM Interconnection, L.L.C. [PJM]; ISO New England, Inc.; and New York Independent System Operator, Inc. [NYISO]) have been invited to participate as technical support.
- **The Western Resource Adequacy Program and Western Transmission Expansion Coalition** – The Western Resource Adequacy Program (WRAP) is an example of a multistate, interregional collaboration on resource adequacy. Although WRAP is primarily a mechanism for generation resource sharing between regions, its modeling protocols include transmission-constrained zones to help determine the degree to which interzonal transfers can help meet planning reserve margins (Western Power Pool 2023b). The Western Transmission Expansion Coalition (WestTEC) was established with the goal of providing holistic transmission planning across the Western United States and hopes to develop an actionable transmission plan to address regional and interregional needs. The group grew out of a request from the Bonneville Power Administration and released a concept paper in October 2023 (Western Power Pool 2023a). DOE's Grid Deployment Office funded the Western Power Pool to complete a planning analysis for WestTEC through the Wholesale Electricity Market Studies and Engagement Program (GDO n.d.-b).
- **Committee on Regional Electric Power Cooperation (CREPC)** – CREPC comprises a state energy office official and a state utility regulatory commissioner from each of the western states and Canadian provinces. CREPC was established in 1982 as a joint committee between the Western Interstate Energy Board and the Western Conference of Public Service Commissioners. CREPC focuses on electric power system policy issues that require regional cooperation in the West. CREPC engages with the regional

energy institutions in the West and provides an education forum on the issues involving regional cooperation (CREPC 2022).

- **Create state transmission planning entities.** A state may create its own transmission authority to evaluate options and help identify, fund, and/or develop both in-state and interregional transmission. For example, Colorado created the Colorado Electric Transmission Authority (CETA) to establish intrastate transmission corridors and operate storage and transmission infrastructure to enable state utilities to connect to and participate in regional markets (Colorado General Assembly 2021). CETA explored in-state and interstate projects to meet the state's transmission needs in its 2024 transmission capacity expansion study (CETA 2024a). State transmission planning entities can look beyond individual utility plans to identify and implement options that benefit the state. They can also collaborate with transmission authorities in other states. State transmission planning entities also offer a state governmental body that can apply for certain types of federal funding to advance transmission without concern about prejudging eventual siting and permitting applications from specific transmission projects. States that have created energy infrastructure entities include Colorado, Idaho, New Mexico, North Dakota, and Wyoming. New Mexico created its Renewable Energy Transmission Authority to plan, finance, develop, and acquire high-voltage transmission lines and storage projects to promote economic development. In January 2023, the New Mexico Renewable Energy Transmission Authority entered into a joint agreement with Invenergy Transmission to advance a new 400-mile transmission line to move up to 4 gigawatts (GW) of energy from New Mexico to the Four Corners region (Invenergy 2023).
- **Conduct state strategic planning.** States can conduct strategic electricity planning, including transmission planning, at the state level. States that are home to two or more large transmission utilities can require coordinated long-term resource and transmission development plans. These studies can identify in-state resources, projected demand at major load centers, preferred corridors for transmission within the state, and transmission connections with neighboring states and regions. The Arizona Corporation Commission staff members conduct a biennial transmission assessment that combines and reviews the 10-year plans of every transmission utility in the state (ACCS and ESTA 2021). In collaboration with the California Public Utilities Commission and the California Energy Commission, CAISO developed California's first 20-year transmission outlook in May 2022 to provide a longer-term view of transmission needed to reliably meet the state's clean energy goals (CAISO 2022a). Figure 2 shows the resource areas and interregional transmission CAISO studied. State outlooks can provide a basis for coordination between states and can provide a framework from which to explore and develop projects in an organized rather than piecemeal way. NTP Study results, including the HOT interfaces shown in Figure 1, can help inform long-term state plans or outlooks.

Figure 3 Resource areas and interregional connections in CAISO's 20-year plan (CAISO 2022a)

- **Institute regulatory directives and expectations.** In states with vertically integrated and regulated utilities, state regulators can require utilities to collaborate on interstate transmission or to consider interregional options. For example, this can occur through a state regulatory directive in an integrated resource plan (IRP) filing. Information from large-scale studies, including the HOT interfaces and other aspects of the NTP Study, can provide a foundation for state utility regulators to understand interregional options and the potential benefits of those options. Regulators can require utilities to meaningfully consider interstate, interregional, and collaborative transmission solutions and compare costs and benefits to local solutions.
- **Reevaluate transmission value through market participation.** In some states, state regulators can indicate support for interstate transmission through IRP dockets. Often transmission approved by state regulatory utility commissions for cost recovery is developed in response to direct reliability needs or to meet a policy objective in their state. However, with greater integration of regional wholesale energy markets, regulators may consider criteria for approving transmission projects that enable lower-cost transactions and other economic benefits to states. Insofar as nonmarket areas begin to incorporate greater coordination—for example, through imbalance markets, day-ahead markets, etc.—the market efficiency benefits of interregional transmission may deserve greater attention. For

instance, at a recent 2022 CAISO stakeholder symposium, a panel of Western regional transmission experts opined that the role of markets needs to become a much more robust part of transmission discussions and planning in the West (CAISO 2022b). In some cases, states can study transmission coordination in the context of larger questions, as Oregon and Colorado did in their studies of the benefits and challenges of RTO membership (Oregon State Legislature 2021).

- **Institute Competitive Renewable Energy Zones.** Texas pioneered the Competitive Renewable Energy Zone (CREZ) approach in 2005. ERCOT and the Public Utility Commission of Texas designated competitive renewable energy zones, which are geographic areas with a high concentration of cost-effective renewable energy potential and strong interest from developers. Then a transmission plan was developed to deliver renewable power from the CREZ to customers. This propelled Texas to become the Nation's leading state for wind power. Several states have since adapted the CREZ model, and a companion effort in the NTP Study applies lessons from Texas to several potential interregional renewable energy zones throughout the United States (Hurlbut et al. 2024).

4.1.2 Transparency and Capacity Building

- **Initiate state-led efforts to improve transparency in the transmission planning process and increase early-stage stakeholder engagement**. States can take a leadership role in implementing efforts to identify and engage stakeholders early in the planning phase, rather than waiting until the siting phase. States can develop principles of engagement as the Colorado Electric Transmission Authority has done (CETA 2024b). States can identify and engage affected communities (e.g., Tribal, energy communities, environmental justice communities, etc.) to ensure their inclusion in both the planning and site selection processes. States can also assist with plain language and multilingual communications targeted to reach specific communities that may be important because of potential benefits/impacts or historical/cultural concerns. This increased stakeholder engagement may be further aided by FERC Order 1920 (FERC 2024a) requirements for enhanced transparency and greater stakeholder engagement in the local transmission planning portion of the regional transmission planning process. This issue of engagement by the public and interested parties is described in greater detail in Section 5.
- **Ensure adequate staffing and resources**. Increasing transmission-specific funding and staffing levels for state public utility commissions, state energy offices, and other state energy decision-making bodies can enable them to move more efficiently and engage more actively in transmission planning. Some states have begun to ramp up the staffing and resources needed to exert a more active influence within transmission planning processes and in related forums. Massachusetts, for example, recently established a new executive office called the Federal and Regional Energy Affairs office within the Executive Office of Energy and Environmental Affairs to engage with regional and federal energy issues (Commonwealth of Massachusetts n.d.).
- **Augment state research capabilities.** Many public utility commissions and state energy offices are resource-constrained in terms of workforce, as noted above. States can engage DOE and the national labs or consultants to provide analysis to support evaluating transmission alternatives. For example, grants for siting and permitting activities, including support for analysis of alternatives and enhanced public and community engagement, have been awarded through DOE's Transmission Siting and Economic Development Grant Program (GDO n.d.-c). DOE's Transmission Acceleration Grants Program assists states and

Tribal entities with planning, siting, or permitting process reforms and capacity building (GDO n.d.-c). DOE provided support to Western states to study the impacts of regional coordination models ranging from expanded day-ahead energy markets to a West-wide RTO, including sensitivities on the effect of transmission expansion (Energy Strategies 2021). The body of relevant research is well-developed and captures a wide geographic perspective, such that it can support state analysis and decision-making. For example, the intent of the NTP Study is to provide objective analysis to support state collaboration on regional and interregional transmission planning strategies.

The examples above comprise a non-exhaustive list that states can use to lead in advancing interregional transmission solutions.

4.2 Federal Actions to Support Interregional Transmission

Different parts of the federal government are making significant strides to support new transmission development in the country. FERC has taken many actions related to transmission planning. See the call-out box in Section 3 for summaries of key FERC orders. The following are some of the many actions taken by DOE in addition to the DOE-led NTP Study already described:

- 2023 National Transmission Needs Study (GDO n.d.-d), which is an assessment of current and near-term transmission needs in the United States through 2040 based on publicly available information, existing data, and reports.
- DOE financial programs, including the Transmission Facilitation Program (GDO n.d.-e), the Transmission Facility Financing direct loan program (GDO n.d.-f), the Grid Resilience and Innovation Partnerships competitive grant program (GDO n.d.-g), and the Title 17 Innovative Clean Energy Financing Program (Loan Programs Office n.d.).
- DOE programs on transmission siting and permitting, including the Transmission Siting and Economic Development competitive grant program (GDO n.d.-c), the Transmission Acceleration Grants program (GDO n.d.-c), the Coordinated Interagency Transmission Authorizations and Permits (CITAP) program (GDO n.d.-h), and the National Interest Electric Transmission Corridor program (GDO n.d.-i).
- Multi-regional offshore wind studies, including the Atlantic Offshore Wind Transmission Study (GDO n.d.-j) and the West Coast Offshore Wind Transmission Study (GDO n.d.-k), which seek to inform planners of value, cost, and challenges that are likely to be seen in the emergence of the offshore transmission opportunity.

This section describes actions that federal entities can initiate to help overcome barriers to interregional transmission development. **These options are not recommendations by the authors of this paper**, but rather, they are options that have been identified by others based on interviews, literature, and comments in public forums, and they are put forward to advance the discussion. These options are generally related to planning and policy actions.

4.2.1 Planning and policy actions

- **Improve Interregional Transmission Coordination and Planning.** Interregional transmission coordination requirements currently lack the same rigor as regional transmission planning. Commenters in FERC dockets and in other contexts have put forward suggestions to move beyond or expand on existing requirements. Some of these suggestions are enumerated here:

- **Institute interregional transmission planning requirements or frameworks** and clearly specify conditions and circumstances that would trigger joint planning efforts. Planning regions can be required to conduct joint assessments of proposed interregional transmission facilities from the perspective of their joint footprint or from an interconnection-wide perspective. They can also be required to develop or adapt planning models for consistency and comparability to facilitate interregional planning. Development of interregional planning models that can accurately and consistently represent neighboring systems and system interactions has proven important in recent interregional planning efforts. The MISO-Southwest Power Pool (SPP) Joint Targeted Interconnection Queue (JTIQ) study process led to the JTIQ portfolio of five transmission projects across seven Midwest states (Iowa, Kansas, North Dakota, Nebraska, Minnesota, Michigan, South Dakota) meant to relieve interconnection queue delays associated with system needs that were preventing interconnection of new generation. SPP, MISO, and their stakeholders worked together to develop the study and approach to cost allocation. SPP and MISO used their own generation and transmission planning processes and models, but they coordinated closely with each other (MISO and SPP 2022).
- **Identify interregional planning principles** that transmission planners in neighboring transmission planning regions can consider, and encourage planners to develop their own processes based on those principles tailored to meet regional needs.
- **Increase focus on processes for merchant interregional transmission developers**. Hold technical conferences to explore challenges and opportunities associated with HVDC merchant transmission development and pursue avenues for more formal consideration of merchant projects in RTO and ISO processes.
- Consider a **cap-and-floor mechanism** for HVDC grid connections between regions to provide minimum revenue certainty to developers and a pathway for customers to benefit from revenue in excess of the cap. In a cap-and-floor mechanism, developer revenues are subject to minimum and maximum thresholds. If developers earn revenues above a threshold, returns above the threshold accrue to customers according to established cost allocation methods. If revenues are below the lower threshold, revenues are 'topped up' to the floor level by utilities via a pass-through to customers (Ofgem 2021). The Office of Gas and Electricity Markets (Ofgem), the energy regulator for Great Britain, rolled out a cap-and-floor mechanism to new electricity interconnectors in April 2014 to incentivize the timely delivery of more interconnections, which led to a significant increase in interconnections (Ofgem 2021).

- **Consider Developing Broader and Standardized Cost-Benefit Metrics.** DOE can develop improved methods for evaluating the benefits and costs of large-scale transmission, as well as other technologies, such as grid-enhancing technologies and non-wires alternatives. The methodology could embody a multi-value approach with clear methods, metrics, and definitions. In Europe, the European Network of Transmission System Operators for Electricity (ENTSO-e), an association of 39 transmission system operators from 35 countries that develops a pan-European, 10-year network development plan, developed a comprehensive, uniform benefit-cost analysis framework, which greatly facilitates interregional planning (ENTSO-E 2024a). FERC Order 1920 requires the consideration of seven different types of potential benefits categories from transmission facilities planned through long-term regional transmission planning: avoided reliability facilities, reduced loss of load probability or reduced planning reserve margin, production cost savings, reduced transmission losses, reduced congestion due to transmission outages, mitigation of extreme weather events or unexpected system conditions, and capacity cost benefit from reduced peak energy losses (FERC 2024a). While the benefits categories will be consistent across regions to comply with Order 1920, the methods that regions use to quantify these benefits may not be consistent. Moreover, FERC did not require regions to consider these same benefits categories for transmission facilities planned through nearer-term Order 1000 regional planning for reliability, market efficiency, and public policy projects. Last, many of the benefits categories only look at system-related benefits, whereas transmission facilities may also deliver non-system benefits (e.g., avoided emissions, job creation) that can be considered.

For example, MISO LRTP tranche 1 projects used the MVP methodology and criteria and considered eight different benefit category metrics (Gramlich 2022). The primary benefits of the LRTP tranche 1 projects were congestion and fuel savings and avoided capital cost of local resources, but additional benefits considered include avoided investment in transmission, resource adequacy savings, avoided risk of load shedding, and decarbonization benefits (MISO 2022). The MISO MVP tranche 1 process also includes an ex-post review process to determine whether benefits are realized. With extensive transmission value metrics, coordination of methodologies is necessary to avoid disagreements on the calculations. In conversations and filings, some parties caution against overly stringent and burdensome cost-benefit thresholds that can bog down planning.

- **Consider a National/Multiregional Planning Organization.** Under one suggested approach, the federal government could create or require the creation of a new national or multiregional planning organization to conduct national or multiregional transmission planning. This could be similar to the European Network of Transmission System Operators for Electricity (ENTSO-E) in Europe, which is an association of 39 transmission system operators from 35 countries required to develop a pan-European, 10-year network development plan that serves to identify transmission projects of common interest that qualify for expedited permitting, enhanced stakeholder engagement, and project development funding (European Commission n.d.). This new entity could develop new standards for interregional planning and cost allocation and then identify least regrets and maximum net benefit projects, which RTOs/ISOs would implement. Organizations such as the Energy Systems Integration Group (ESIG) have proposed developing a National Transmission Planning Authority (ESIG n.d.). The current extent of national planning is limited to the triennial National Transmission Needs Study required under Section 216(a) of the Federal Power Act. The Needs Study evaluates current and future national transmission capacity constraints and congestion, but it does not identify specific transmission solutions to address those needs (FERC 2024c). See the National Planning Box for national planning examples from Australia and Great Britan.
- **Continue to Explore Minimum Interregional Transfer Capability Requirements** for emerging grid needs. Many commenters suggested in response to FERC's Notice of Proposed Rulemaking that preceded issuance of Order 1920 (FERC 2022b) that the federal government develop a standard methodology to determine minimum interregional transfer capability between regions (CAISO 2022c). In December 2022, in Docket AD23-3, FERC staff convened a two-day workshop to consider how to establish minimum requirements for interregional transfer capability for grid operators (FERC 2022a). In response to direction from Congress in the Fiscal Responsibility Act (U.S. Congress 2023), NERC conducted a study of the total transfer capability between transmission planning regions, and provided recommendations for additions to strengthen reliability (NERC 2023a). NERC's analysis found that transfer capability is not a static metric; rather it varies by season, system conditions, and by region, and can vary widely across the United States, ranging from 1% to

92% of peak load (NERC 2024). In the November 2024 report, NERC recommends adding 35,000 MW of interregional transfer capacity to address grid resilience needs and enable electrification and load growth (Walton 2024). The NTP Study also identifies opportunities to expand interregional transfer capability to achieve economic gains, above and beyond the reliability focus of the NERC study (GDO 2024a).

- **Engage Power Marketing Administrations (PMAs).** Many of the possible federal actions catalogued in this section would involve FERC, but other potential federal actors can be the PMAs, such as the Western Area Power Administration (WAPA) or the Bonneville Power Administration (BPA). According to their statutory authorities, PMAs market the power from federal hydropower facilities to certain customers. Three of the four PMAs also own and operate high-voltage transmission lines: BPA, WAPA, and the Southwestern Power Administration. PMA statutory authority, in some cases, allows for partnerships with other transmission owners, such as BPA's agreement with NorthWestern Energy and other utilities on the 500 kV Colstrip line in Montana and WAPA's partnership with five other utilities on the 500 kV Navajo Transmission System in Arizona. In addition, WAPA has $3.25 billion in borrowing authority to support strategic transmission development across its service territory through its Transmission Infrastructure Program. PMAs may be able to use their authority and funding mechanisms to advance beneficial interregional transmission across their service territories.
- **Continue to Support Siting and Permitting Efficiencies**. Through its CITAP Program, DOE acts as the lead agency to coordinate required federal authorizations and related environmental reviews for qualifying electric transmission facilities. Whereas each federal agency historically led its own permitting processes and procedures for these facilities, DOE will now function as the lead point of contact and coordinate between developers and participating federal agencies. Federal agencies will still make their own statutorily required decisions, but DOE's coordination will accelerate the permitting process where federal agencies are involved. Through the Transmission Siting and Economic Development grant program, DOE can help facilitate siting and permitting of transmission projects at the state and local level with grants to support siting and permitting authorities as well as economic development activities in communities hosting transmission projects.

NATIONAL PLANNING APPROACHES

The **Australian Energy Market Operator** operates a national energy market comprising five regions in south and southeastern Australia (AEMC n.d.). A rapid transition from coal-fired power plants toward variable renewable energy has increased focus on transmission, with the introduction in 2021 of a "whole-of-system" integrated (transmission) system plan (ISP) (AEMO 2023). The ISP includes both a 20- and 50-year planning horizon and incorporates renewable energy zones. The plan includes five different plausible future scenarios and identifies technical power system requirements stemming from new generation and grid technologies. Plans also evaluate the impacts of coupled sectors (e.g., natural gas, transportation, hydrogen). The ISP modeling starts with inputs, assumptions, and scenario(s) data, then runs a capacity expansion model that co-optimizes transmission and generation. The results of a capacity expansion model are run through a time sequential model to optimize for hourly and 30-minute dispatch before being rerun through the capacity expansion and time sequence models in an iterative process. These results are tested against technical engineering and power system requirements before a final collection of candidate development plans are produced. Candidate development plans are scored considering a host of cost-benefit tests (AER 2020) including:

- An expansive set of net market benefits—meaning the difference between total system costs with and without the candidate plan—weighted by the perceived likelihood of the future scenario occurring.
- A least–worst regrets test that measures regrets defined as excess investment in unneeded assets or underinvestment in needed assets through forgone net market benefits.
- The insurance and option value achieved through flexibility, for example, by staging the overall size or timing of projects.
- A sensitivity analysis of key variables (e.g., discount rates, natural gas prices).
- The highest-scoring candidate plan becomes the Optimal Development Path. To implement the plan, local transmission network providers explore potential variations to projects identified in the Optimal Development Path, then submit project development plans to the Australian Energy Market Operator for review to confirm alignment with the ISP (AEMO 2024). Then, the transmission providers apply to the Australian Energy Regulator for prudence review and approval to develop.

In **Great Britain**, the Office of Gas and Electricity Markets (Ofgem) is moving toward whole transmission system planning at the regional and national level by requiring the development of a new Centralized Strategic Network Plan (CSNP) (Ofgem 2023). In a December 2023 decision, Ofgem established that the first CSNP will be an independently developed, coordinated transmission plan initially focused on onshore, offshore, and cross-border transmission needs to achieve the government's net-zero carbon goal by 2050 (Ofgem 2023). The first CSNP must be filed in 2026 (Ofgem 2023). The CSNP will be informed by a strategic spatial energy plan that maps government policy goals and forecasts supply and demand by location and includes Future Energy Scenarios. The CSNP will include both short- and long-term plans. The short-term (10-year) plan is updated annually and must identify baseline needs projects for near-term development. The long-term plan (25-year) must be updated every 5 years and will be used to encourage transmission owner engagement with supply chain companies and capital investment planning (Ofgem 2023). Ofgem is establishing a new entity to produce the Future Energy Scenarios, strategic spatial energy plan, and CSNP, called the Future System Operator (Ofgem 2022). The Future System Operator will be a publicly owned, expert, impartial system operator and planner with responsibilities across both the natural gas and power systems. The Future System Operator will be regulated by the government with the goals of balancing the tradeoffs between achieving net-zero carbon; maintaining the security of the energy supply; and ensuring an efficient, coordinated, and economical power and gas system (Ofgem n.d.)

4.3 RTO/ISO and Utility Voluntary Actions to Support Interregional Transmission

RTOs/ISOs, non-RTO/ISO transmission planning regions, and utility transmission planners (referred to in this section as transmission planners) can take voluntary actions—either on their own or in response to requests from states and stakeholders—to enable more interregional transmission. While it is possible for transmission planners to pursue these actions, in some cases, there may be financial, political, or other factors that discourage pursuing modified planning practices without a regulatory mandate. Nonetheless, some potential voluntary actions at the transmission planner level can include, for example, the following:

4.3.1 Planning and Policy Options

- **Go beyond the minimum interregional coordination required by FERC**. Transmission planners are not bound to limit themselves to the minimum interregional coordination requirements of FERC. Some regional planning entities may be reluctant to participate in interregional planning because interregional planning is not part of their tariffs; only coordination is required. However, FERC Order 1000 sets a floor rather than a ceiling, and FERC encourages planning organizations to go beyond minimum requirements. Transmission planners can proactively work with neighboring systems or regions to develop an analytical interregional transmission planning framework and conduct exploratory long-range interregional transmission planning. Transmission planners can work together and consider combinations of generation and regional and interregional transmission solutions.
- **Voluntarily establish a national or multiregional planning organization or process**. Transmission planners could voluntarily establish a national planning organization or national planning process. In the European Union (EU), ENTSO-E is a professional organization of regulated entities—with 39 transmission system operator members—with certain legal mandates that include coordinating the planning and development of infrastructure at the EU level, including the 10-year network development plan (ENTSO-E 2024b). Although ENTSO-E's 10-year, EU-wide network development plan is mandatory, it demonstrates a collaborative model that is carried out by the transmission system operators. Transmission planners can work together to fill this role in the United States. Transmission planners would still be required to comply with FERC requirements and would need FERC approval to deviate from existing requirements.
- **Work more closely with other regional planners to explore projects** that provide benefits to all regions. Examples of proactive coordination within and across regions include the MISO LRTP and MVP processes; the MISO and SPP JTIQ projects (MISO and SPP 2023) described in Section 4.2.1 of this report; and the Boardman to Hemingway transmission line, which is a multistate project and partnership between PacifiCorp and Idaho Power. In November 2018, the OMS and SPP Regional State Committee (RSC) Liaison Committee performed a study and released a white paper identifying the barriers to more efficient seam operations and transmission planning between SPP and MISO (MISO and SPP 2022). This report was released in advance of the formal JTIQ effort, from which specific regional and interregional transmission projects were identified.
- Work with neighboring systems and regions to **develop detailed operational and planning models** that demonstrate the value of interregional transmission under a variety of conditions. Transmission planners can work together proactively to develop joint models that evaluate interregional projects. The November 2018 OMS and SPP RSC Liaison Committee white paper identified modeling issues as "one of the main complications that arose when

performing a Coordinated System Plan" (MISO and SPP 2018). Modeling challenges included differences in the SPP and MISO regional models, agreeing to joint modeling assumptions, and inconsistent results between the combined model and regional-specific models due to the different assumptions (MISO and SPP 2018). With time and attention, transmission planners can overcome these challenges, as MISO and SPP have done with the JTIQ projects.

- Work with other systems or regions to gather data and develop common benefit metrics to **inform potential cost allocation approaches**. As part of coordination, transmission planners can work together on common cost allocation approaches and, where appropriate, make methodology proposals to FERC and to affected states. FERC Order 1920 developed a common set of benefits categories that must be considered for transmission facilities planned through long-term regional transmission planning, but there is no requirement for consistency in methods for calculating those benefits across planning regions or transmission providers (FERC 2024a). Instead, the rule requires transmission providers to include in their tariffs a general description of how they will measure each of the seven benefits. The rule also requires transmission providers to file one or more *ex ante* cost allocation methods—established in the tariff prior to conducting long-term transmission planning—for long-term regional transmission facilities. But the rule also allows transmission providers to include in their tariffs a "State Agreement Process," through which states in the region can determine a cost allocation method for a specific long-term regional transmission facility that differs from the *ex ante* cost allocation method in their tariffs.
- As described above under state-led solutions, transmission planners can **engage in more geographic partnerships to maximize the quantity and reliability of time-diversified renewable energy** opportunities. Transmission planners can work together and with states to identify renewable energy zones and then work to develop new transmission to deliver power from identified zones to customers, similar to the Texas CREZ approach. The IREZ companion report to the NTP Study seeks to apply lessons from Texas to a number of interregional renewable energy zones throughout the country (Hurlbut et al. 2024). Transmission planners can work together and build on the IREZ analysis from the NTP Study.
- **Develop pathways to optimize the value of merchant transmission facilities in RTO/ISOs.** Although NYISO and MISO are taking steps in this direction, CAISO is the only RTO/ISO in the United States that co-optimizes merchant transmission and generation dispatch in nodal day-ahead and real-time markets (Pfeifenberger, et al. 2023a; Brattle Group 2020). Some states like California forecast increased reliance on imported variable energy resources to meet public policy goals while maintaining reliability. Often, these variable energy generation resources can be delivered by merchant HVDC lines. However, the traditional CAISO transmission planning process was proving to be a barrier to these merchant lines. To address this, CAISO developed the subscriber participating transmission owner (PTO) model that, among other things, allows merchant interregional transmission facilities to be operationally controlled by CAISO and facilitates the delivery of external resources. TransWest Express is now a subscriber PTO in CAISO, with the subscriber PTO model approved by FERC in 2023 (FERC 2023c). TransWest Express is a merchant project that is currently under construction and will bring energy from Wyoming to California, Nevada, and Arizona (Transwest 2024). It was proposed to realize the economic and clean energy benefits demonstrated in previous analyses conducted by WECC (2011) and NREL (Corbus et al. 2014). Project developers worked closely with the Bureau of Land Management and WAPA on the project. Stakeholders could work with RTOs/ISOs to

develop similar participation models that allow for optimization of available merchant transmission capacity.

- **Improve trading across existing interties**. To realize the full benefit of potential new transmission lines that may result from activities mentioned in the previous bullets, it may be necessary for system operators like utilities and RTO/ISOs to improve trading and the use of existing interties. Doing so would allow transmission operators to increase the economic efficiency of existing transmission and realize greater economic benefits of potential future lines. An October 2023 Brattle Group report points out that, per market monitors in PJM and MISO, power flows were inconsistent with price differences 48 percent of the year in PJM and 40 percent of the year in MISO (Pfeifenberger et al. 2023b). This means that, in each case, power is flowing from higher-price markets to lower-priced markets nearly half the time. RTOs/ISOs can address this by following recommendations of market monitors (where applicable), by improving coordinated transaction scheduling and market-to-market congestion coordination programs, or by exploring intertie optimization. A companion paper to this report, the Barriers report, focuses on improving the efficiency and utilization of existing interregional transmission assets (Simeone and Rose 2024).
- **Work to quantify the resource adequacy contribution of interregional transmission** and improve interregional transmission operations or contracts to optimize use of transmission during stressful grid conditions. Interties can provide resource adequacy benefits via geographically diverse generation profiles, peak load diversity, and enhanced transfer capacity between regions. By calculating the effective load-carrying capability of interregional transmission and giving it access to capacity markets, RTOs/ISOs can help incentivize interregional transmission development, ensure revenue adequacy for interregional transmission, and help their member utilities manage risk. Improving the efficiency of interregional transmission operations can increase confidence in the ability of interregional transmission to deliver resource adequacy benefits during extreme events.

4.3.2 Engagement and Coordination

- Transmission planners can **increase public engagement in the early stages of project development**. For example, transmission planners can proactively seek greater consumer advocate representation in transmission planning processes, as consumer advocates are often the only stakeholders representing residential customer interests at this stage. Transmission planners can also require transmission project developers to perform minimum public outreach activities to potentially affected communities prior to including projects in the regional or interregional transmission plans. This subject is addressed further in Section 5 of this report.
- **Work more closely with state regulators and policymakers** to explore the connections between policy-related transmission needs and other related opportunities. FERC Order 1920 requires transmission planning regions to incorporate specific factors into long-term future scenarios that are related to current and potential future policies and to solicit input on these policy-based factors from states and stakeholders (FERC 2024a). An example of how state input has been incorporated in the past is PJM’s agreement with the New Jersey Board of Public Utilities through a State Agreement Approach (SAA). New Jersey increased its state offshore wind goal from 7.6 GW by 2035 to 11 GW by 2040 (NJ DEP 2024). To facilitate meeting this goal, New Jersey asked PJM to incorporate New Jersey’s offshore wind goals into PJM’s regional transmission planning process as part of an SAA. PJM agreed to include policy-related transmission in its plan based on the SAA agreement with the New Jersey Board of Public Utilities. The costs of the proposed public policy projects

under the SAA are recovered from the customers in the states proposing the projects (State of New Jersey 2020).

There are many voluntary actions that transmission planners can take to advance enhanced regional and interregional transmission planning. States and stakeholders can encourage transmission planners to take these actions, and where necessary, seek FERC approval for new approaches.

4.4 Industry Actions That Can Advance Interregional Transmission

Project developers and other industry stakeholders can take several actions to help advance interregional transmission planning and development. Developers can consider the actions listed below. In addition, state decision-makers can encourage project developers and other industry actors to take such steps through incentives, requirements, and other measures.

- **Increase public engagement and awareness in advance of new projects.** Consult with potentially affected stakeholders, including Tribes and communities earlier in the planning and development processes, rather than waiting until transmission routes have been selected and siting and permitting are underway.
- Load-serving entities and transmission developers can **establish tangible evidence of commercial interest in energy and capacity** from interregional transmission projects. This is consistent with the Texas CREZ approach. Tangible evidence of commercial interest can support regional planners and state and federal regulators as they consider and advance transmission projects, including interregional transmission.
- **Consider public–private partnerships for interregional transmission projects.** Project developers can explore public–private partnerships between industry; federal, Tribal, and state governments; and other interested entities. Through the Transmission Facilitation Program, DOE operates a revolving fund program that can support such initiatives. Through the Transmission Facilitation Program, DOE can serve as an “anchor customer” for up to 50 percent of the capacity of a new large-scale transmission line. Transmission developers can repurchase the capacity from DOE later when the financial risk has been reduced. DOE can also enter into public–private partnerships for transmission development needed to accommodate electricity demand across states or planning regions. In establishing the Transmission Facilitation Program, Congress directed DOE to prioritize projects that contribute to interregional transmission capacity, when evaluating proposals (GDO n.d.-a).
- **Develop studies and models showing multiple benefits across regions or proposed new projects**. Just as the NTP Study demonstrated the benefits of scenarios that included increased interregional transmission, industry participants, including the Brattle Group (Hagerty, Pfeifenberger, and Bennett 2021), ESIG (n.d.), and Power from the Prairie (2023), are developing models or aggregating results from past studies that demonstrate the benefits of interregional transmission projects. In some cases, developers share this information in RTO/ISO proceedings, comments at FERC, and other public forums. Access to data and system models and lack of established methodologies may be limiting factors to modeling benefits in sufficient detail to be considered alongside incumbent utility proposed projects.

5.0 Opportunities to Increase and Broaden Engagement by the Public and Interested Parties

Increased and improved public engagement is one approach that can advance the development of transmission, including interregional transmission, because engagement has the potential to result in increased public buy-in that can help a project move forward. Public participation and engagement vary by jurisdiction; however, in most instances, nonexpert public participation in transmission planning has been compartmentalized into specific siting issues after a project has been identified. Planning and origination activities are typically less accessible to Tribes, local communities, public interest groups, and public representatives. Additional barriers to participation exist due to lack of awareness of the planning processes; membership costs and requirements to participate in planning forums; insufficient technical knowledge; lack of public materials in nonexpert language; as well as time and/or bandwidth for an individual, Tribe, or organization to dedicate to the process. Interregional transmission is not unique in facing the challenge of robust public engagement, but the challenge is amplified for large projects that cross multiple jurisdictions and regions. As a result, public engagement for interregional transmission may require more concerted efforts by a larger range of parties.

While certain stakeholder bodies and circumscribed processes exist in all FERC Order 1000 transmission planning regions for stakeholder engagement (FERC 2011), many additional opportunities exist to increase and diversify engagement in transmission planning processes. FERC Order 1920 increases opportunities for improved oversight of local transmission planning and enhanced engagement in long-term regional planning processes (FERC 2024a). Many of these enhanced transparency, oversight, and engagement opportunities focus on increasing state involvement in the planning process. The rule also recognized that energy equity and environmental justice laws and regulations that impact long-term planning can be potential factors considered in the development of long-term future planning scenarios. Planners and developers can include more types of interested parties—such as potentially affected Tribes/communities or advocates representing the electricity customers who are charged for the projects—early on in planning processes and in preparation for choosing site locations. Doing so may inform site selection, reduce impacts, and identify more benefits that can be provided cost-effectively. FERC Order 1977, issued in May 2024, updates FERC’s existing regulations governing permit applications for siting transmission. It includes a voluntary code of conduct to demonstrate good faith efforts to engage with affected landowners and a requirement to develop an Environmental Justice Public Engagement Plan and Tribal Engagement Plan as part of a Project Participation Plan (FERC 2024b).

The following list of potential options can increase stakeholder engagement while seeking to address environmental justice and energy equity.

- Transmission planners can **go beyond minimum requirements and proactively solicit input during early planning phases**, subject to confidentiality requirements that may apply, for example, to commercially sensitive business proposals. Tribes can be included in this early outreach. Input from such parties can potentially inform planning scenarios. This can help achieve buy-in on the results of the study and ultimately help avoid siting pitfalls. Interested parties can help identify risk scenarios and least-regrets options.
- Transmission planners **can seek input from stakeholders and other interested parties in developing a more inclusive set of benefit metrics**, perhaps beyond the new metrics required in FERC Order 1920 (FERC 2024a), and expanding benefits metrics applicable to

projects in shorter-term planning cycles. This can include those that recognize and respect the policies and needs of multiple states.

- Transmission planners can **more proactively engage traditionally disadvantaged and marginalized communities and those who have disproportionately borne the brunt of impacts from past energy infrastructure.** These and similar community concerns are not current considerations in many transmission planning processes, though they may be considered in siting and permitting processes, which comes long after planning and therefore can create a disjunction that is hard to remedy. In addition, FERC Order 1920 allows for energy equity and environmental justice laws and regulations to potentially be incorporated into long-term planning scenarios (FERC 2024a). Additional actions to facilitate early involvement are beyond the scope of this report, but it is a common theme that emerges in the literature.
- Transmission planners and state and federal regulators can **learn from and adapt participant engagement best practices**. For example, in Europe, the market regulator requires utilities to adopt the AA1000 Stakeholder Engagement Standard, which is an internationally recognized framework for stakeholder engagement excellence. The market regulator also allows for financial incentives for planners who conduct robust stakeholder engagement (Ofgem 2018).
- **Improve compensation packages and community benefits approaches** to encourage and compensate Tribes, individuals, community organizations, and public interest groups with varying perspectives to participate in transmission planning proceedings, including coordinated interregional transmission planning. Improve compensation packages and community benefits offered to landowners and communities affected by the siting of lines, beyond values typically established via eminent domain proceedings (Haugen 2013). Examples of compensation include direct bonus payments, per pole or per mile, with additional compensation to vulnerable communities affected by the line (Berry 2013). A programmatic example is DOE's Transmission Siting and Economic Development grant program, which can provide tangible economic development benefits to communities that host or are affected by transmission. Strengthening other community benefits and stakeholder engagement processes can also play an important role, particularly stakeholder engagement that results in community benefits agreements that are directly responsive to the needs of the relevant community. DOE, GridWorks, the Midwestern Governors Association, and other energy experts across the country are developing tools and best practices to improve stakeholder engagement and to strengthen community benefits plans (GDO n.d.-b; Gridworks.org 2024; Pfeifenberger 2023). These can be a resource for developers, state regulators, and others.
- **States can initiate their own engagement processes,** initially outside the formal transmission planning forums, to identify needs and coordinate on goals and approaches. CETA developed principles of community engagement to foster a transparent, credible, and open public engagement process in Colorado. The principles address the following categories: information sharing, communication, community benefits, and accountability (CETA 2024b). The principles of community engagement were adopted by the CETA board of directors. For interregional transmission projects, states may find additional benefit from coordination and communication across jurisdictions. States may benefit from sharing plain language and multilingual public informational materials.

Because of the scale of interregional transmission, early and comprehensive public engagement by transmission planners and developers may be necessary. Planners and developers can make targeted efforts to engage parties who will be affected but who may not traditionally be involved in planning and development processes.

6.0 Conclusion

The NTP Study revealed there are many benefits to increasing interregional transmission across the United States. For example, improving interregional transmission can enhance grid reliability, particularly in response to extreme weather events, as it allows more resources to be shared across regions and energy to be moved from where it is available to where it is needed. However, in practice, there are many barriers to realizing new interregional transmission projects.

Critically, the lack of a regulatory requirement to plan for interregional transmission serves as a barrier to transmission system operators being able to identify beneficial projects to potentially support. Merchant transmission projects conceived outside the utility planning processes face unique barriers as non-utility developers with assets that system operators may undervalue. The developers of new interregional transmission facilities face many of the same barriers as those encountered by developers of regional or local transmission projects, only these challenges are exacerbated as interregional projects tend to span greater distances over multiple jurisdictions and have higher overall costs (and benefits). Interregional transmission projects also face unique technical challenges associated with dual-transmission system modeling, system-to-system operations, and lack of standardization of data and analysis methods.

FERC Order 1920 will advance regional transmission planning processes by requiring long-term planning with multiple future scenarios and with expanded benefits categories (FERC 2024a). Even with this recent reform, many opportunities remain to improve upon the processes for planning, permitting, and funding the development of interregional transmission to increase project success rates. This report identifies a non-exhaustive list of these potential opportunities through literature review and interviews with industry experts. These opportunities are presented for educational purposes without endorsement from PNNL or NREL. These opportunities are presented by category, including actions that can be taken by states, federal regulators, RTOs/ISOs, or members of the utility industry interested in advancing interregional transmission. These actions are summarized in the table below.

Table 2 Potential interregional transmission facilitation strategies

Category	Strategies
State-Led Options	• Collaborate with neighboring states on major projects that can benefit each state • Participate in (or create) multistate coordinating committees on energy policy • Create a state-specific transmission planning authority • Conduct state-level strategic transmission planning • Ensure adequate staffing and resources specific to transmission issues, including augmenting state research capabilities • Develop regulatory directives and expectations, including criteria for transmission projects intended to increase market access and provide additional economic benefits • Lead efforts to improve transmission planning transparency and early-stage stakeholder involvement • Institute competitive renewable energy zones
Federal Options	• Develop an interregional transmission planning framework • Identify interregional transmission planning principles • Explore opportunities to improve the integration of merchant projects • Develop broader and standardized cost-benefit metrics • Consider creating new entities, such as a national transmission planning organization • Continue to explore minimum interregional transfer capability requirements • Engage federal power market administrations • Continue to support siting and permitting activities
RTO/ISO* and Utility-Led Options	• Go beyond minimum interregional coordination required by FERC • Develop joint operational and planning models with neighboring regions • Form national or multi-region planning organizations to conduct exploratory planning • Inform potential cost allocation approaches through joint regional data collection and common benefits metrics • Explore geographic partnerships that maximize the quantity and reliability of time-diversified renewable energy options • Increase the value of merchant interregional transmission by allowing excess capacity to be optimized by the RTO/ISO • Improve trading and address operational inefficiencies across existing interties • Work to quantify the resource adequacy value of interregional transmission
Industry Options	• Increase public engagement and awareness in advance of new projects • Establish tangible evidence of commercial interest • Consider public-private partnerships for interregional transmission projects • Develop studies and models showing multiple benefits across regions or proposed new projects

Some of the options identified to advance interregional transmission development may require changes to existing laws or regulations, but voluntary actions are also available and may avoid the need to establish new requirements. We acknowledge that all actions may still be complex undertakings. Development of new research, models, methods, data, and other technical requirements may be resource-intensive to support; however, the effort may be justified given the compelling reliability, resilience, cost savings, and other benefits made possible through interregional transmission, as presented by the NTP Study.

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