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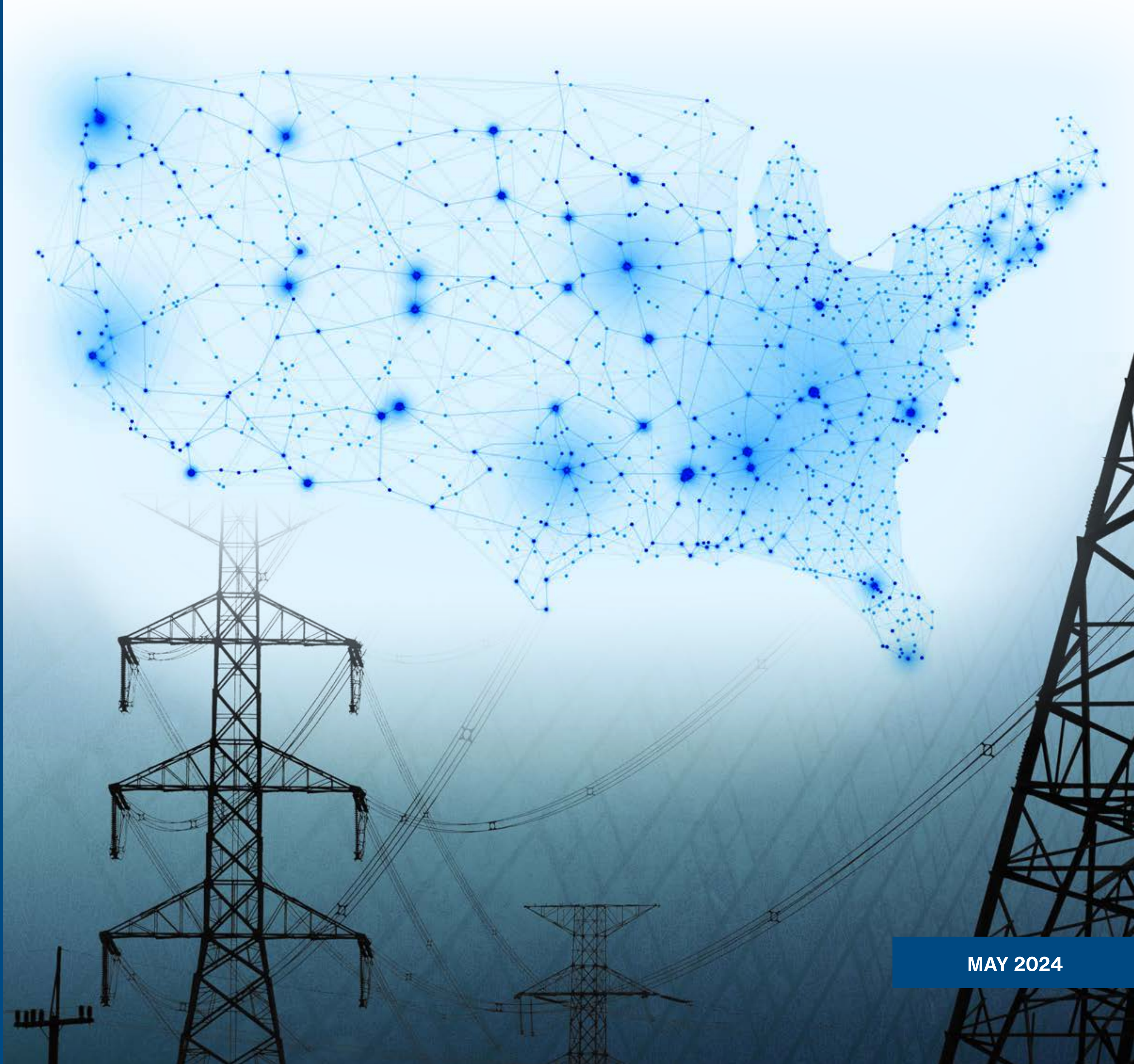
ENERGY FUTURES FINANCE FORUM

Modernizing the U.S. Electricity Grid for Resilience, Load Growth, the Clean Energy Transition, and Energy Security



MAY 2024

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Project Team

Jeff Brown . . . . *Managing Director, Energy Futures Finance Forum (EF³)*
Michael Downey . . *Deputy Director of Research*
Brennen Drysdale . . . . *Project Manager*
Sonia Griffen . . . . *Research Analyst*

Additional Contributors

Ernest J. Moniz . . . . *Chief Executive Officer and President*
Joseph S. Hezir . . . *Executive Vice President, Treasurer*
Melanie A. Kenderdine . . . . . . *Executive Vice President, Corporate Secretary*
Stephen D. Comello . . . *Senior Vice President, Strategic Initiatives; Co-Director, Energy Futures Finance Forum (EF³)*

Communications Team

David Ellis . . . . *Senior Vice President of Policy Strategy & Outreach*
Adrienne Young . *Senior Communications Lead*
Georgia Lyon . . . . *Communications Associate*
Ben Cunningham . . . . . . *Graphic Designer, MG Strategy + Design*

Copy Editing

Jane Hirt . . . . *M. Harris & Co.*
Nancy Watkins . . . . *M. Harris & Co.*

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Rob Gramlich	*Grid Strategies*
Kevin Nordt	*Dairyland Power Cooperative*
Sue Sheridan	*Coalition for Fair Transmission Policy*
Ted Thomas	*Energize Strategies*
Pamela Quinlan	*GQ New Energy Strategies*

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Foreword

This paper is produced within the Energy Futures Finance Forum (EF³), a program within the EFI Foundation focused on increasing the investment quality of decarbonization assets.

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Acronyms and Abbreviations

BCA	benefit-cost analysis
BCR	benefit-cost ratio
CAISO	California Independent System Operator
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
ICC	Illinois Commerce Commission
IIJA	Infrastructure Investment and Jobs Act
IRA	Inflation Reduction Act
ISO	independent system operator
LSE	load serving entity
LRTP	Long Range Transmission Planning
MISO	Midcontinent Independent System Operator
MVP	Multi-Value Projects (name for a MISO portfolio of regional transmission projects)
NERC	North American Electric Reliability Corporation
NOPR	notice of proposed rulemaking
NYISO	New York Independent System Operator
PJM	Pennsylvania-New Jersey-Maryland Interconnection
RTO	regional transmission organization
RP/CA	regional planning/cost allocation
SPP	Southwest Power Pool
VOLL	value of loss of load (estimate of economic harm caused per MWh of electricity curtailed to users)

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Executive Summary

The value of a reliable, resilient, and modern grid has never been clearer than it is today. The private sector in the United States knows how to build new electric generation, project-by-project. But the United States is failing to proactively build the wires that allow that new electric generation to reach customers.

Investments in manufacturing, data centers, and electrification of buildings, transportation, and industry are causing demand for electricity to spike after a decade of stagnation. States from across the political spectrum are recognizing that their ability to ensure timely and cost-effective access to power is a competitive advantage for attracting jobs and investment spurred by the Infrastructure Investment and Jobs Act (IIJA) and the Inflation Reduction Act (IRA).

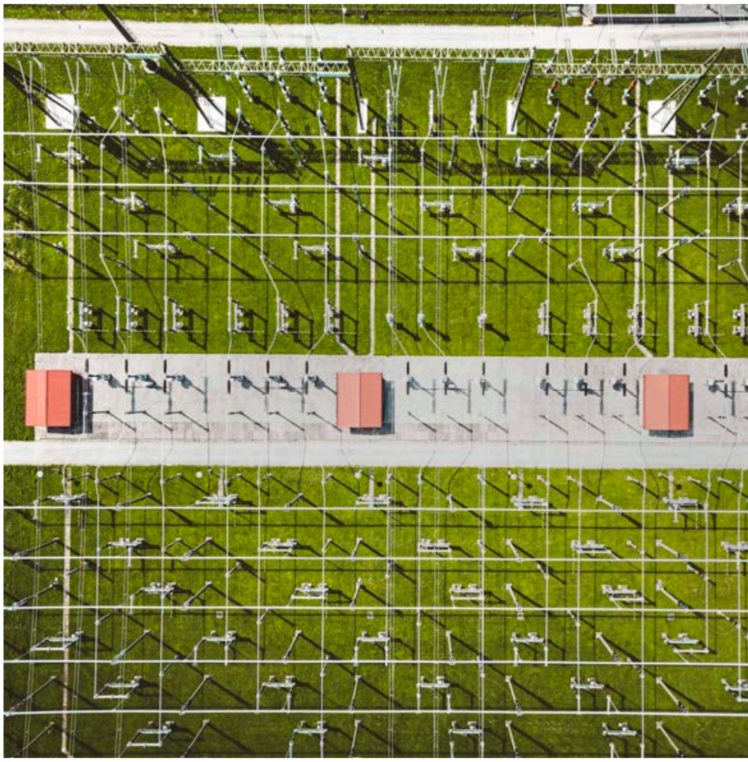
The United States electricity delivery system has struggled just to keep up with the repairs of its bulk transmission system. Even as states vie to attract industrial investments, they face intra- and inter-regional transmission system challenges that threaten not only economic growth but also the ability to meet the electricity needs of their residents, businesses, and public services.

This analysis targets one of the most serious financial roadblocks to ensuring access to reliable, affordable, and clean power: the inability to proactively maintain and expand transmission grid capacity to meet rapidly growing energy demand and enable a steady substitution of clean generation for high-emitting generation.

Why focus on transmission planning? Transmission must be planned to be built, and building transmission takes longer than building generation. New load that requires new power is growing today, but regional transmission typically takes at least a decade to build. New power capacity (including all kinds of generator technologies and storage systems) could deploy faster if transmission capital investments could be more quickly planned, agreed upon, and constructed by the nation's regional transmission system operators— particularly the large Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs).

The federal government has major roles to play, including reform of how transmission investments are planned and how the costs of those investments are allocated to ratepayers; financial assistance for transmission capital expenditure; and technical assistance. In all three roles—regulatory, financial, and technical—the federal government can help address the concerns of stakeholders who fear that as the nation addresses the urgent challenge of modernizing the grid, states without clean energy requirements or policies that accelerate electricity load growth may be called upon to subsidize the environmental and economic policy ambitions of other states.

A lack of transmission capacity slows the rapid deployment of new generation and reduces access to reliable, affordable, and clean power.



New generators want to connect to the grid; they wait years to do so. At more than 2,600 gigawatts (GW) of potential capacity, the interconnection queue is more than double the installed capacity of the entire existing U.S. bulk power system. Unfortunately, new generators must wait an average of five years from interconnection request to commercial operations.[1] The risk, expense, and delay of obtaining transmission service greatly increase the rate at which proposed clean energy projects fail.

While many projects are in the queue, financing them is getting harder because of time, uncertainty, and high interconnection costs. Projects often cannot secure financing until they have firm contractual assurance of the ability to transmit output to market. No grid access means no output delivered, which means no revenues earned, which means no source of funds to repay lenders and investors. Further, to connect to the grid, generators must shoulder ever-increasing costs for "network upgrades."[i] As a result, projects that are otherwise economic are unable to bear the interconnection costs and withdraw from the queue.

Connecting to the grid takes years and is expensive because the transmission system lacks spare capacity. A lack of sufficient investment in regional-scale high-voltage lines means that when new generators seek to connect to a regional grid, there is not enough existing transmission capacity currently available to reliably deliver the power to customers. Thus, new generators are forced to pay for network upgrades that may be located hundreds of miles from the generation site, vastly complicating the development process. Until those network upgrades are done, which can take years, new generation projects are stuck in limbo.

i Network upgrades are upgrades required to maintain the reliability of the grid at or beyond the point of interconnection for the generator.

The transmission system does not have spare capacity because planning efforts do not adequately account for future needs. Regions generally do not plan sufficiently far into the future–expert consensus suggests 20 years is appropriate–nor do they adequately account for the wide and varied benefits that transmission provides to ratepayers. Instead, regions typically plan only a few years ahead, evaluate projects individually rather than as portfolios, and compare only a few specific benefits against costs. Even among the regional transmission organizations that have had success, the successful practices are not implemented consistently.

Because of how transmission projects are planned, disagreements erupt over how to pay for projects. Analyses of costs and benefits that can stand up to scrutiny can result in project portfolios in which costs and benefits are equitably distributed, thereby enabling broader support for proposed projects. Unfortunately, because planning processes frequently lack transparent analytical rigor, stakeholders may challenge that planners failed to show that costs are commensurate with benefits, whether regionally or in particular parts of a given market. Such challenges often take the form of litigation to overturn entire plans as well as delays in siting and permitting projects deemed not to be in a particular jurisdiction's interest.

The economic and reliability benefits are often sufficient to justify investments in new capacity. Decarbonization is an added benefit. A decade of underinvestment in transmission capacity means that economic and reliability benefits, such as reduced congestion costs, access to lower cost generation, and mitigation of extreme weather events, outweigh the investment costs of new capacity. While additional transmission capacity certainly also provides decarbonization benefits, the economic and reliability benefits alone are sufficient to make the economic case for new capacity. The question is who pays for reliability and resilience within current rate structures?

The Federal Energy Regulatory Commission (FERC) has proposed a rule[2] (referred to as the "May 2022 NOPR") to improve regional electric transmission planning and cost allocation that incorporates many best practices. Its effectiveness will depend on the strength of the rule's requirements. The best practices included in FERC's proposed rule appear to have drawn heavily from recent regional precedents—successful and unsuccessful—for planning and implementing investments to meet transmission requirements over the long term. The proposed rule, however, can go further in requiring transmission planners to adopt successful practices.

Three major conclusions from this analysis should inform transmission planning and cost allocation:

1. **Long-term regional planning of transmission is crucial for ensuring access to reliable, affordable, and clean power.** Planning for future needs over a 20-year time horizon is a crucial component of conventional annual capital budgeting for reliability and congestion. It is not about adding new bureaucracy or top-down industrial policy.

2. **Transmission benefits ratepayers in a variety of ways, which should be accounted for when evaluating portfolios of projects.** Methodologies for quantifying those benefits should be analytically rigorous and analysis results must be transparent. This is particularly important if climate benefits are considered so that stakeholders who do not prioritize climate goals can trust that the non-climate benefits still exceed costs.

3. **Decisions about who pays for transmission can be simplified by integrating the planning process (i.e., identifying, evaluating, and selecting projects) and the cost allocation process (i.e., deciding how costs should be spread).** The cornerstone of planning is a comprehensive evaluation of the costs and benefits to participants and how those are distributed. Logically, a benefit-cost analysis cannot be performed conclusively if the method of assigning costs is indeterminate. The ideal scenario is one in which stakeholders reach a consensus *before evaluating and selecting potential projects* on the algorithm for how costs will be calculated and allocated sub-regionally once a portfolio of projects is selected.

   Consensus also should be sought on the methodologies for quantifying benefits and how those benefits will be attributed. This approach is termed an *ex ante* cost allocation and enables the cost allocation process to be tightly integrated with the planning process. In an *ex post* approach, cost allocation is up for discussion after "planning" (including after project selection and benefit-cost analysis is completed). Such a disjointed decision-making process is bound to fuel contentious debates among stakeholders, especially state regulators. *To advocate for a coordinated ex ante process is to advocate for the early involvement of state regulators—not for the disenfranchisement of state regulators.*

Recommendations to strengthen FERC's proposed rule and inform its implementation at the regional level:

The Energy Futures Finance Forum's (EF^3) recommendations aim to inform four specific audiences: FERC, the regional stakeholders involved in transmission planning, the U.S. Department of Energy (DOE), and Congress.

- **FERC: Recommendations to strengthen the transmission planning and cost allocation rule.** FERC's proposed rule includes many best practices that draw upon the real-world experience of ISOs and RTOs over the past decade—good and bad—and upon a wealth of expert techno-economic analyses addressing transmission planning/cost allocation. The four primary recommendations in this analysis build upon those components. (i) The recommendations support FERC's emphasis on requiring 20-year planning horizons and the consideration of portfolios of projects, incorporating known changes in the generation resource mix and customer demand. (ii) They call for requiring consideration of at least a minimum set of benefits with benefit-cost methodologies that are transparent and clearly distinguish between climate and non-climate benefits. (iii) *Ex ante* cost allocation methodologies should be published in transmission tariffs, and FERC should establish a backstop default methodology that regions can use if they are unable to reach consensus. (iv) Regarding methodologies, regions should be encouraged—even better, required—to evaluate benefits and costs not just regionally but also subregionally to ensure that costs and benefits are equitably distributed geographically. Without comprehensive subregional benefit-cost analysis, any ISO/RTO attempt to implement critically needed regional grid improvements is especially vulnerable to legal attack. Specifically, opponents will argue that costs have not been conclusively shown to be roughly commensurate with benefits across the ISO/RTO's footprint.

- **Regional transmission stakeholders: Recommendations to inform effective implementation of the final rule.** FERC's proposed reforms will spark debates about how to plan future transmission needs and how to evaluate costs and benefits. These recommendations propose that, where feasible, planning entities should coordinate 20-year load projections, resource planning, and transmission planning. Where such coordination is too logistically challenging—usually in multi-state markets where each state has its own resource planning timelines, requirements, regulations, etc.—those regions should at least publish assumptions, data, and methodologies used in developing future projections. The recommendations also call for large customers, particularly new customers with large data centers, to play a more active role in developing regional transmission tariffs.

- **Department of Energy: Recommendations for improving computational methods for long-term projections and enabling greater participation in planning processes.** FERC's proposed rule would require planners to develop 20-year projections of load, generation, and transmission that are highly complex, both methodologically and computationally. DOE has technical expertise within its own offices and in the National Laboratories that can help. Those experts could help ISOs/RTOs craft portfolios of transmission projects that are optimized and demonstrably equitable on a sub-regional basis. It is increasingly clear, based on ISO/RTO documents, that daunting computational issues exist in co-optimizing three types of interrelated models: (i) generation capacity expansion models (i.e., which generators are built), (ii) economic dispatch models (i.e., which generators are operated, when), and (iii) transmission system design/power flow models (i.e., how electricity reaches markets reliably). DOE's National Transmission Planning Study's mission includes tackling this triple challenge.

  The expanded use of the DOE Transmission Facilitation Program and Transmission Facility Financing Program can also play an important role in facilitating long-term regional transmission planning and cost allocation. The ability of DOE to contract for currently unallocated transmission capacity will help ensure that adequate reserve capacity is planned for the longer term. It also will avoid cost allocation issues that might otherwise arise over uncertainties in the projections of future requirements. DOE should assess the adequacy of existing funding for this program and seek additional funding as appropriate.

On a related note, these recommendations also encourage DOE to allocate funds made available through the IIJA and IRA to provide capacity funding to state and local agencies to participate in regional transmission planning and tariff-setting processes. Funding state and local participation is integral to establishing regional consensus that can streamline the regional planning/cost allocation process, including the establishment of *ex ante* cost allocation algorithms.

- **Congress: Recommendations for additional federal financial assistance.** Without some form of federal assistance, there are bound to be material effects on today's ratepayers as the U.S. seeks to build tomorrow's transmission system. The U.S. will be building transmission to accommodate future load growth and harden the system against increasingly catastrophic weather events—all in an environment of higher interest rates and commodity costs. Additional federal support could ameliorate the strain on ratepayers, whether through targeted grant programs or more broadly applicable Investment Tax Credits (ITC) for high-voltage regional transmission. Such support would fit in with a longstanding practice of the federal government supporting the buildout of infrastructure (especially interstate infrastructure) that provides widespread public benefits (e.g., economic development, reliability and resilience, environmental, clean energy transition, social equity).

  A transmission ITC would make transmission spending less daunting and risky for stakeholders, especially if it includes the "direct pay" provisions of the IRA. An ITC, which cuts capital cost by 30%, instantly boosts computed project benefit-cost ratios. The 30% ITC would apply to high-voltage regional lines that are included in regional plans (i.e., selected for cost allocation) and whose costs are allocated in a manner approved by FERC.

  Even for transmission project portfolios that can claim high benefit-cost ratios, costs tend to start immediately, whereas benefits grow over the 40- to 50-year life of a transmission line. Thus, this recommendation calls for additional funding for programs like the Transmission Facilitation Program and Transmission Facilities Financing Program. As noted above, these programs allow the federal government to absorb the "carrying cost" of major transmission capacity expansions until growing market demand absorbs excess capacity.

Introduction

The value of a reliable, resilient, and modern grid has never been clearer than it is today. The United States private sector knows how to build new electric generation, project-by-project. But the U.S. is failing to proactively build the wires that will allow that new generation to reach customers.

Why is high-capacity grid expansion of national importance?

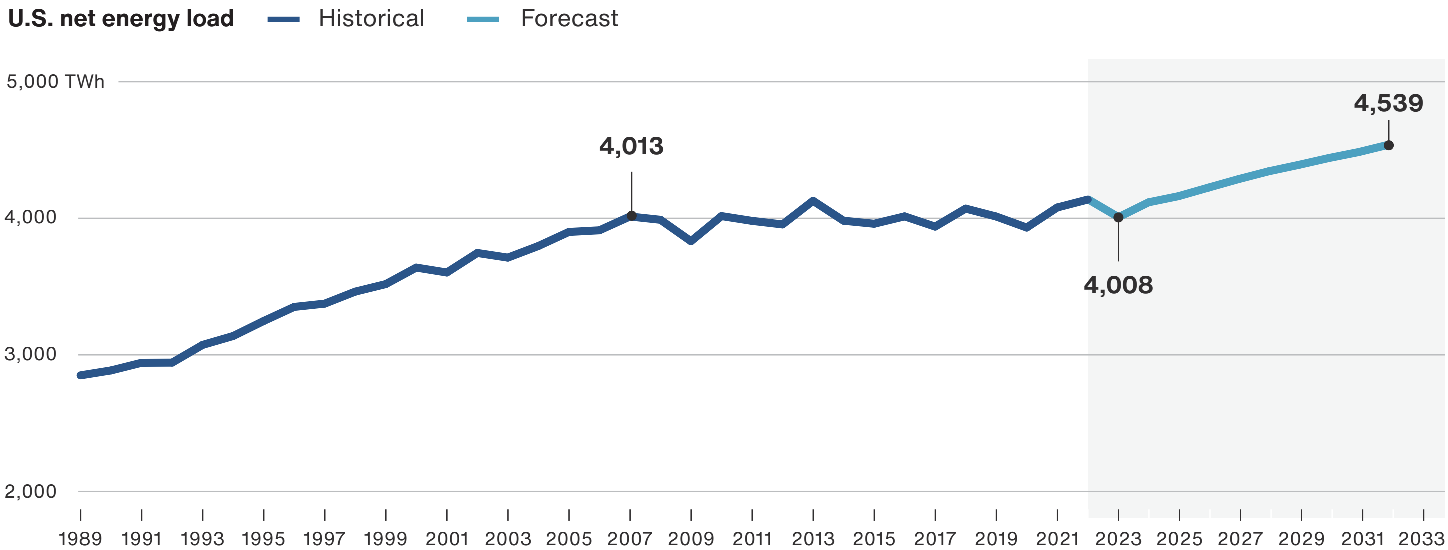
New investments are driving a major increase in demand for power. After more than a decade of stagnant growth in demand for power generation capacity, also known as load, utility forecasts suggest that the pace of load growth will double or even triple in the coming years.[3] This demand growth for electricity is driven by a proliferation of data centers, new investments in manufacturing, electrolytic hydrogen production, and electrification of buildings, transportation, and industry.

The North American Electric Reliability Corporation's (NERC) most recent forecasts show that the higher load growth rate will create a cumulative 500 terawatt-hours (TWh) of incremental electricity consumption over the next decade (**Figure 1**, next page).[4] To keep pace, new electricity generation roughly equal to current production by the state of Texas will need to connect to the grid.[5] Several commentators suggest that the NERC estimate may be relatively conservative.

"Vast swaths of the United States are at risk of running short of power as electricity-hungry data centers and clean-technology factories proliferate around the country, leaving utilities and regulators grasping for credible plans to expand the nation's creaking power grid." **— Washington Post, March 2024**

Figure 1: **NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION (NERC) HISTORICAL AND PROJECTED U.S. ELECTRICITY DEMAND**

NERC forecasts a growth in electricity demand after more than a decade of stagnant demand.



Source: Data from: NERC, (2023).

States from across the political spectrum are increasingly recognizing that the ability to ensure timely and cost-effective access to power is a competitive advantage for attracting jobs and investment spurred by federal legislation like the Infrastructure Investment and Jobs Act (IIJA) and the Inflation Reduction Act (IRA). In discussing efforts to attract electric vehicle manufacturers, Georgia's governor recently said: "Talking to the companies that we're recruiting, people that are looking to the state, they obviously want to produce with clean energy."[6]

However, the United States has struggled just to keep up with repairs of its bulk transmission system, let alone proactively investing to accommodate future demand. Indeed, even as states vie to attract major investments, they are grappling with growing challenges that threaten not only economic growth but also the ability to ensure access to reliable, affordable, and clean power.[7]

Customers face an increased risk of blackouts and brownouts, or lack of "resilience." Since the United States has not been reinforcing the grid to keep up with the challenges posed by ever-more-frequent weather emergencies, consequent blackouts and brownouts are more likely and more severe.

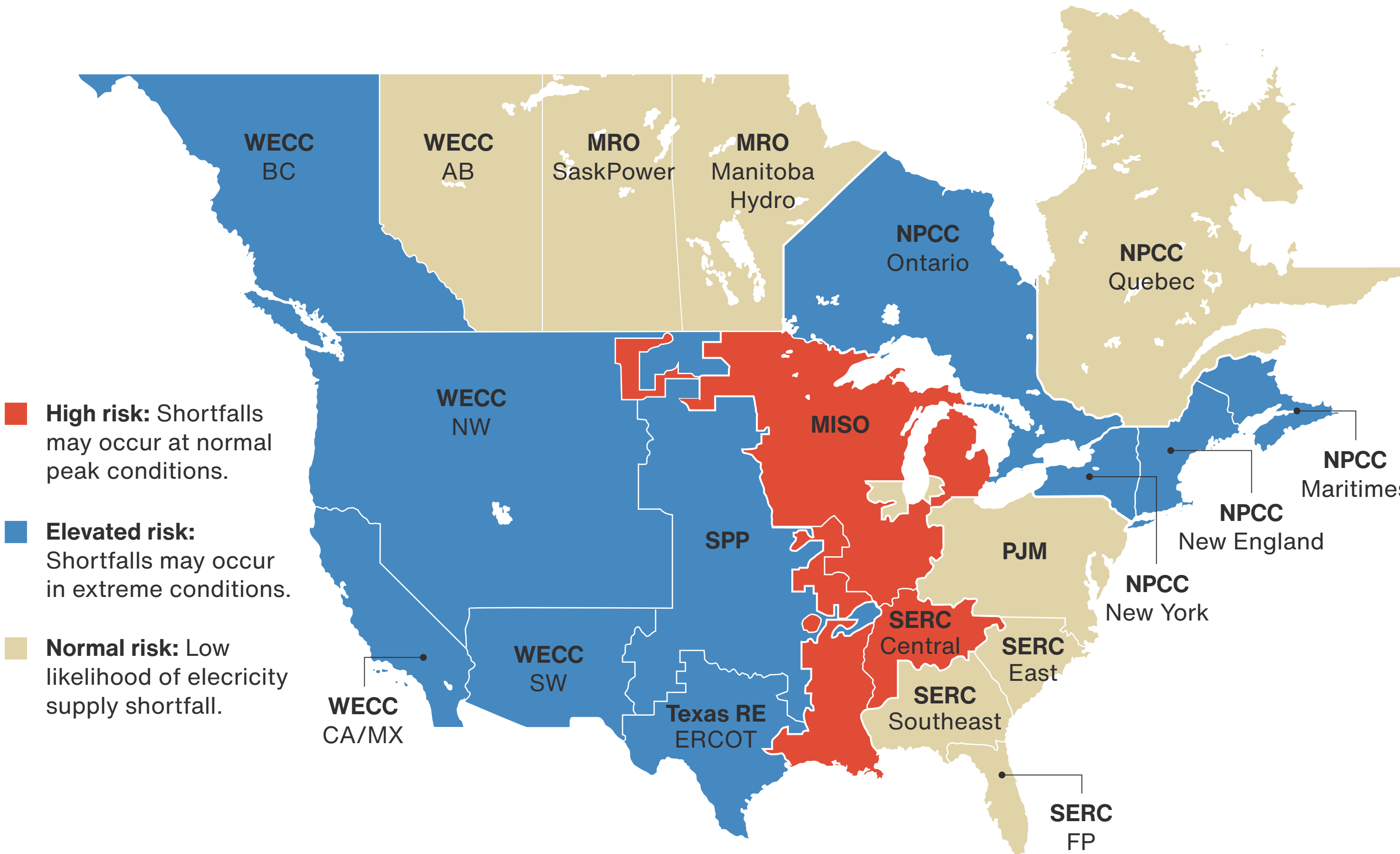
In a recent analysis, NERC designated whole swaths of the U.S. grid at "high risk" (i.e., blackouts and brownouts during normal peak conditions) or the less drastic "elevated risk" (**Figure 2**, next page).[8] During Winter Storm Uri in 2021, for example, more than a dozen military bases across the country had to close, with some losing power and water access.[9] Worse, the storm caused the deaths of at least 246 people, many of which could be attributed to a lack of access to power.[10]

Unpredicted loss of electricity due to a lack of grid resilience, as opposed to economic losses from run-of-the-mill "congestion,"[ii] can have a shockingly high cost to the U.S. economy.

The Midcontinent Independent System Operator (MISO) estimates that the "value of loss of load" (VOLL) could be as high as $23,000 per megawatt-hour (MWh).[11,iii] For context, at that VOLL-per-MWh cost, a partial loss of California's grid, e.g., 10% of load for five hours, would be over $500 million.[12,iv] When entire states and regions experience catastrophic weather and full blackouts, the costs are vastly higher: the Texas Section of the American Society of Civil Engineers estimated Winter Storms Uri and Viola cost the economy $200 billion to $300 billion.[13]

Figure 2: **NERC'S 2024-2028 SUMMARY OF GEOGRAPHIC RISKS OF ELECTRICITY SUPPLY SHORTFALLS**

NERC reports: "The North American [bulk power system] is on the cust of large-scale growth, bringing reliability challenges and opportunities to a grid that was already amid unprecedented change."



Source: Adapted from North American Electric Reliability Corporation (2023).

ii Congestion happens when the electricity demand exceeds the capacity of the transmission infrastructure, leading to bottlenecks, potential service disruptions, and increased costs associated with managing grid stability.

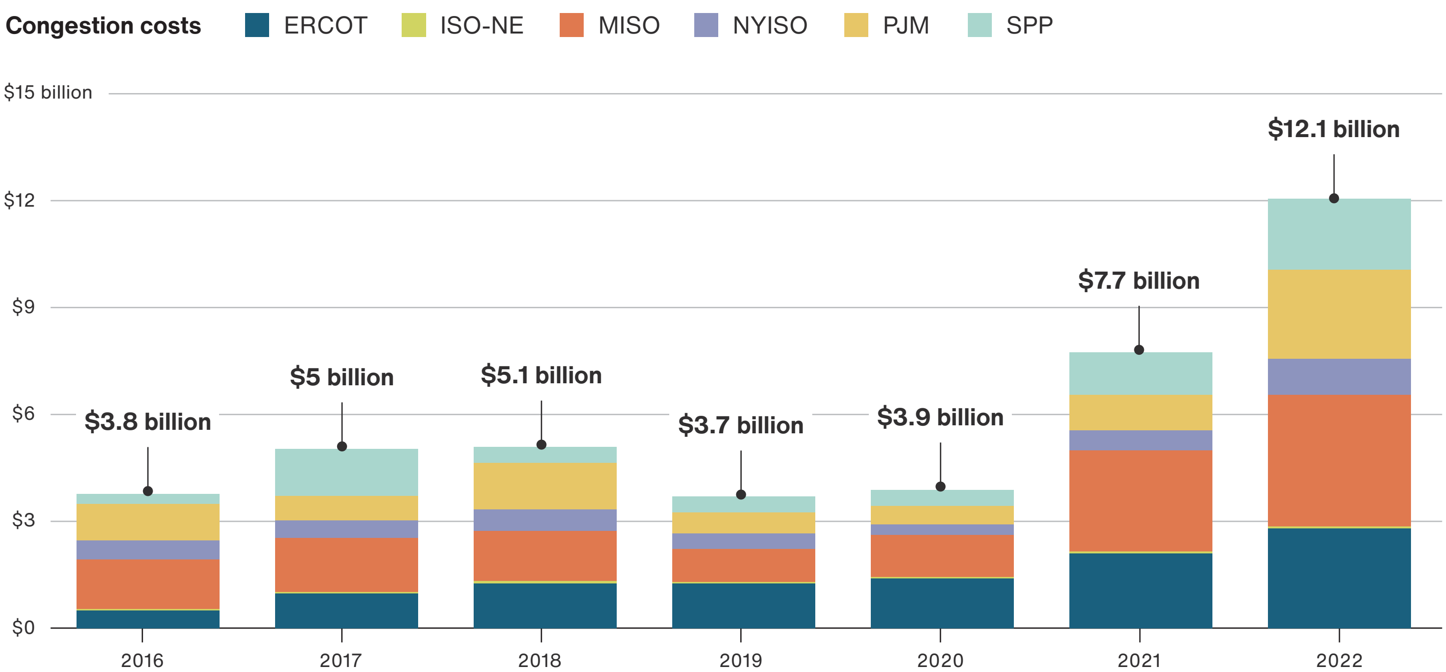
iii VOLL estimates the loss incurred by customers when electricity service is interrupted. So, if a business has a load of 1 MW and is cut off, losing $20,000 as a consequence, the VOLL is $20,000.

iv CAISO peak load is approximately 50,000 MW. 50,000 MW * 10% * $23,000/MWh * 5 hrs = $575,000,000.

Lack of grid capacity translates into higher customer bills. With the grid increasingly clogged, cheap energy is curtailed because transmission routes to customers are full, so more expensive—and often more carbon-intensive—generators must be used instead.[v] The result is an excess cost to ratepayers. In 2022, congestion costs across the country amounted to $25 billion, having risen around 56% in just one year (2021 to 2022, Figure 3).[14]

Figure 3: **TOTAL TRANSMISSION CONGESTION COSTS FOR REGIONAL TRANSMISSION ORGANIZATIONS (RTOs) AND INDEPENDENT SYSTEM OPERATORS (ISOs) FROM 2016 TO 2022**

Congestion cost increases have accelerated in recent years, including more than doubling in PJM Interconnection between 2021 and 2022.



Source: Data from: Richard Doying, et al. (2023).

Projects on the supply and demand side face multiyear timelines to connect to the grid.[15,16] Such delays make it much more challenging and expensive to secure private financing for new projects.

Strategies exist to moderately reduce the impacts of load growth and reliability challenges today. Such strategies include efficiency, energy storage, and grid-enhancing technologies (e.g., dynamic line ratings, advanced power flow controls). However, if new transmission capacity does not come online at scale and soon, such strategies will offer only minor improvements, considering the scale of the grid's challenges.

v Curtailment refers to the reduction of power production when the grid is stressed, and often refers to the reduction of renewable energy flowing onto the grid.

This analysis focuses on how regional transmission capacity is planned and paid for in U.S.-organized electricity markets.

The inability to proactively maintain and expand backbone high-voltage transmission grid capacity to reliably carry electricity from generation to customers blocks the successful development, financing, and construction of new electric generation. Without that generation, the United States cannot meet rapidly growing energy demand, replace aging plants, or gradually replace high-greenhouse gas (GHG) emitting generation with low GHG-emitting generation.

One of the most serious impediments—some experts say the *single most serious impediment*—to proactively maintaining and expanding the grid is called transmission regional planning and cost allocation (RP/CA). Broad RP/CA principles are set forth by the Federal Energy Regulatory Commission (FERC) and then operationalized by each transmission planning provider within its service footprint.

- The "regional planning" refers to how long-term plans for a portfolio of transmission projects are designed, evaluated, chosen for construction, and how some or all of those projects may be "selected" to have their costs recovered by region-wide transmission rates.

- The "cost allocation" portion is the actual transmission tariff by which the grid operators assign annual costs of projects selected for regional cost recovery utilities within their footprints.

- Taken together, these policies fall under the rubric of "Electric Regional Transmission Planning and Cost Allocation."

Experts believe today's policies are not incentivizing—and may be harming—grid expansion. FERC, in its May 2022 Notice of Proposed Rulemaking (NOPR)[vi] proposed comprehensive reforms, reforms that some parties believe go too far and that other parties believe should go much further. This study evaluates both sides of the issue.

Deficiencies in current RP/CA regimes are not the only problem transmission faces. Much of the federal debate surrounding grid modernization emphasizes permitting reform, a relatively easy policy lever to comprehend. However, if stakeholders of a transmission organization cannot even agree on how much capacity to add, where to add it, who benefits, and who should pay, a transmission line will never even get to the starting gate. A nonexistent transmission project does not need to begin finding rights-of-way or doing its environmental permitting analysis.

Further, RP/CA policies and their implementation are the focus of intense battles that will play a major role in determining outcomes such as where and how

vi Mentions of the "May 2022 NOPR" refer to FERC's "Notice of Proposed Rulemaking, Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, 179 FERC 61,028 (May 2022)" economic development will occur, the carbon intensity of the U.S. power sector, and increasingly the nation's ability to keep the lights on in the face of extreme weather.

This analysis leads EF^3 to agree with experts that federal RP/CA regulations, and the consequent policies/tariffs of regional grids, have impacts that far outweigh more prominent—though still critical—issues such as technology, economic feasibility of projects, or difficulty in obtaining permits/rights-of-way. Therefore, this analysis narrowly focuses on the RP/CA issues.

Specifically, this analysis focuses on finding policy solutions that can address today's lack of orderly, forward-looking regional planning and execution of scale-efficient transmission projects quickly enough to accommodate new types of generation and significantly growing loads.

This analysis aims to make current approaches to regional transmission planning and cost allocation more accessible and to inform ongoing FERC proceedings on the topic.

This analysis is especially timely because, for the past two years (i.e., 2022 to 2024) FERC has been developing a new rule that would update the existing FERC-mandated regime for RP/CA. It is possible that such a final rule could be released imminently.

While many know that the current system is failing and that the ramifications of such a rule will impact a range of sectors and all consumers, the technical, economic, and legal parameters of RP/CA are likely well understood by only a few hundred experts, lobbyists, lawyers, and regulators.

The goals of this analysis are to make this complex topic more accessible to a broader audience of policymakers, officials, public interest groups, industry, and financiers. We will therefore outline:

- Current gaps in high-capacity grid investment and the impact of those gaps on the electric industry and the broader U.S. industrial economy.
- The shortcomings of the current regime for RP/CA and the consequent over-reliance on the alternatives of the "generator interconnection process" and lower-capacity local utility-financed lines.
- The pros and cons of the draft FERC approach embodied in FERC's May 2022 Notice of Proposed Rulemaking (NOPR).
- Opportunities to strengthen FERC's approach, mobilize expert and fiscal resources from other federal actors, and develop better technoeconomic analytical tools for grid planning.

The U.S. Is Investing Billions of Dollars in Transmission Capacity but Very Little Goes Toward High-Voltage, Regional Lines

The United States is investing billions of dollars in transmission. But not enough of those investments support the backbone grid that is important for economic growth, reliability, resiliency, and the proliferation of low-cost clean energy.

With growing congestion, aging equipment, and increasing extreme weather events, the grid has difficulty transmitting even today's peak loads. The situation grows more perilous when load growth from new electricity-intensive industries such as large data centers is factored in. At the same time, industry and transportation are using more electricity to replace fossil fuels for power, heat, and propulsion.

According to FERC, though the United States has been spending $20 billion to $25 billion a year on transmission of all kinds, very little of that investment is going toward building up the "regional-scale" high-voltage, high-capacity lines that are the backbone of a stable grid (**Figure 4**, next page).[17,18,19]

Rather, the bulk of investment—up to 80% of the investment in examples cited by FERC—appears to be going into the local lower-voltage transmission and distribution lines that operate within individual utilities' service territories, as well as into the privately owned lines that tie new generators into the main grid.[20] By some counts, though reliable national figures are hard to compile, regional-scale high-voltage investment has been falling, rather than rising.[21]

Decades of underinvestment in regional-scale high-voltage lines means that when new generators seek to connect to a regional grid, there is not enough transmission capacity available to assure those new interconnectors of acceptable service, i.e., in reliably getting the power to customers. Thus, new generators are forced to pay for network upgrades[vii] that may be located hundreds of miles from the generation site, greatly complicating the development process. Until those network upgrades are done, which can take years, new generation projects are stuck in limbo.

The challenge can be described in terms of scale, multiyear timelines, and increasing costs. Total U.S. "nameplate generation capacity" as of year-end 2023 was 1,189 GW;

vii Network upgrades are upgrades required to maintain the reliability of the grid at or beyond the point of interconnection for the generator.

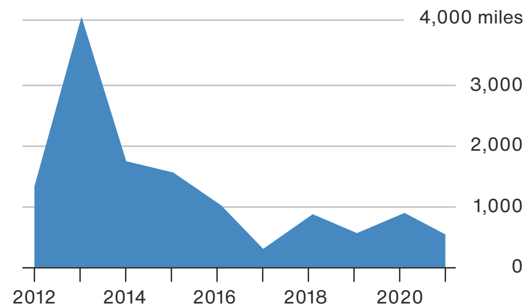
and the current interconnection backlog is more than twice that.[viii,22] By year-end 2023, Lawrence Berkeley National Laboratory estimated that the total waiting in the queue had risen to 2,600 GW.[23] Further, new generators seeking to sell power must wait an average of five years from interconnection request to commercial operations.[24] Finally, to connect to the grid, generators are asked to shoulder ever-increasing costs for "network upgrades." As a result, projects that are otherwise economic are unable to bear the interconnection costs and withdraw from the queue (**Figure 5**, next page).[25]

Figure 4: **TOTAL INVESTMENT IN TRANSMISSION CAPACITY (BOTH HIGH AND LOW VOLTAGE) IS RISING, YET THE NUMBER OF MILES OF NEW HIGH-VOLTAGE LINES (345kV AND ABOVE) IS DECLINING**

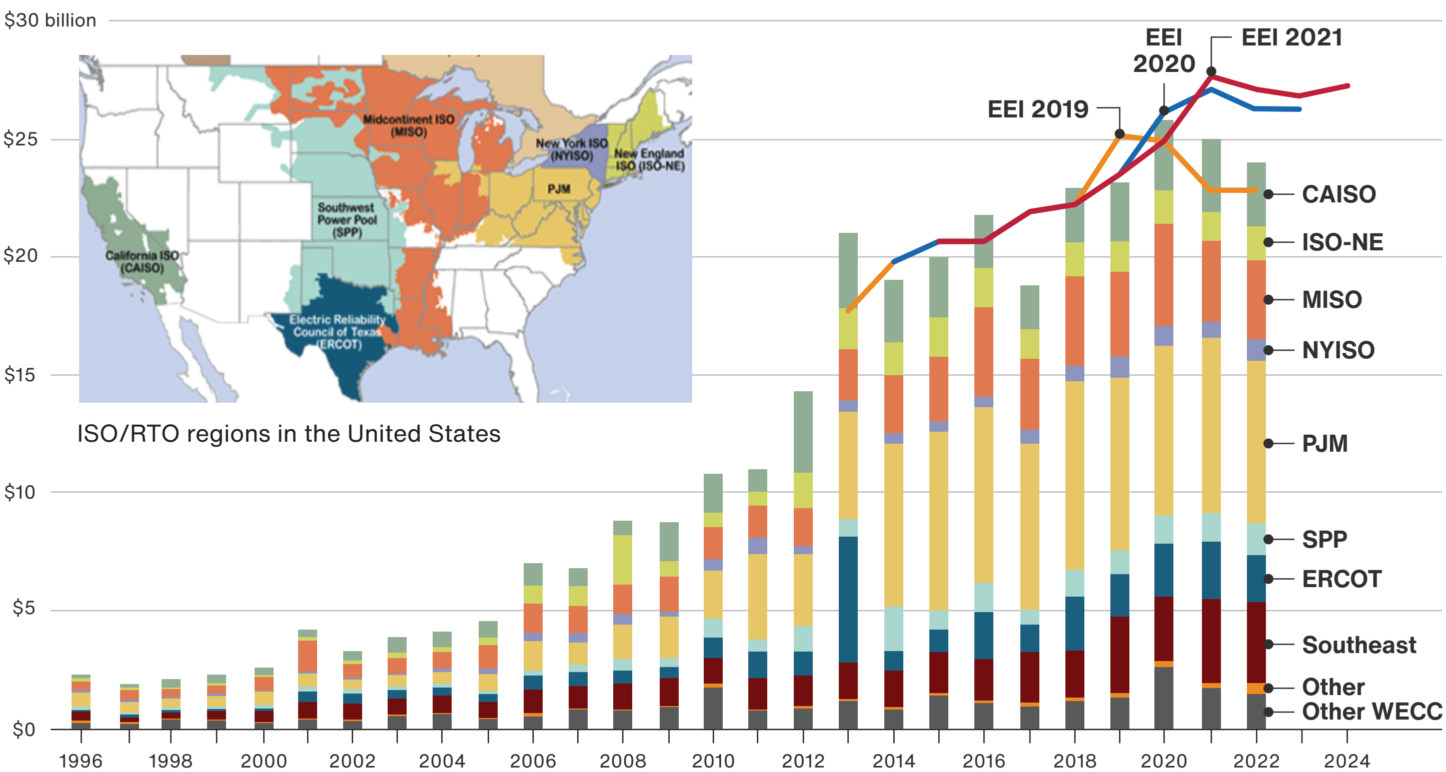
Recent annual transmission investments have reached $25 billion. According to the Brattle Group, however, more than 90% of those investments are for local, low-voltage projects rather than regional, high-voltage projects, which can be more cost-effective solutions.

NOTE: Does not include transmission investments of non-jurisdictional entities (e.g., BPA, TVA, WAPA, etc.)

Miles of new high-voltage (345kV+) lines completed



Annual transmission investment as reported to FERC by region

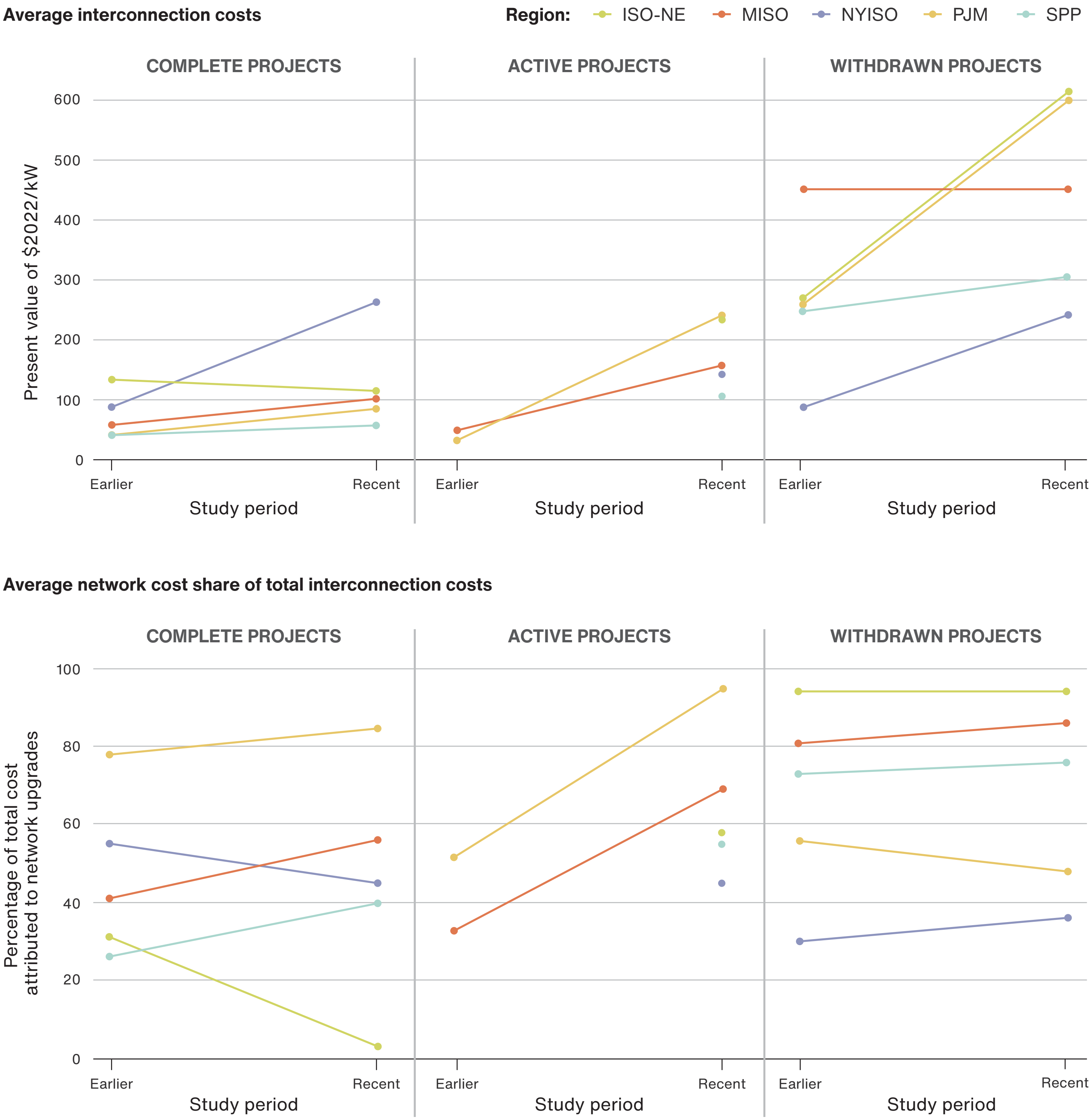


Sources: Department of Energy, ***Queued Up... But in Need of Transmission*** (2023); and **The Brattle Group** (2022).

viii Nameplate generation capacity refers to the maximum output a generator can produce under normal conditions.

Figure 5: **INTERCONNECTION COSTS FOR GENERATION PROJECTS HAVE BEEN RISING BECAUSE OF NETWORK UPGRADES**

The cost of network upgrades borne by new generators is increasing by dollar amount and as a percentage of total costs of interconnection in most ISOs/RTOs. "Earlier" periods generally include 2019 and earlier years, whereas "recent" periods generally reflect 2020–2022. The bottom right box of Figure 5 shows interconnection costs (including network upgrades) as a percent of the cost of the generation project itself for projects that were abandoned and left the queue—with costs of transmission nearly reaching the cost of generation in PJM (>90%), MISO (>80%), and Southwest Power Pool (SPP) (~75%)

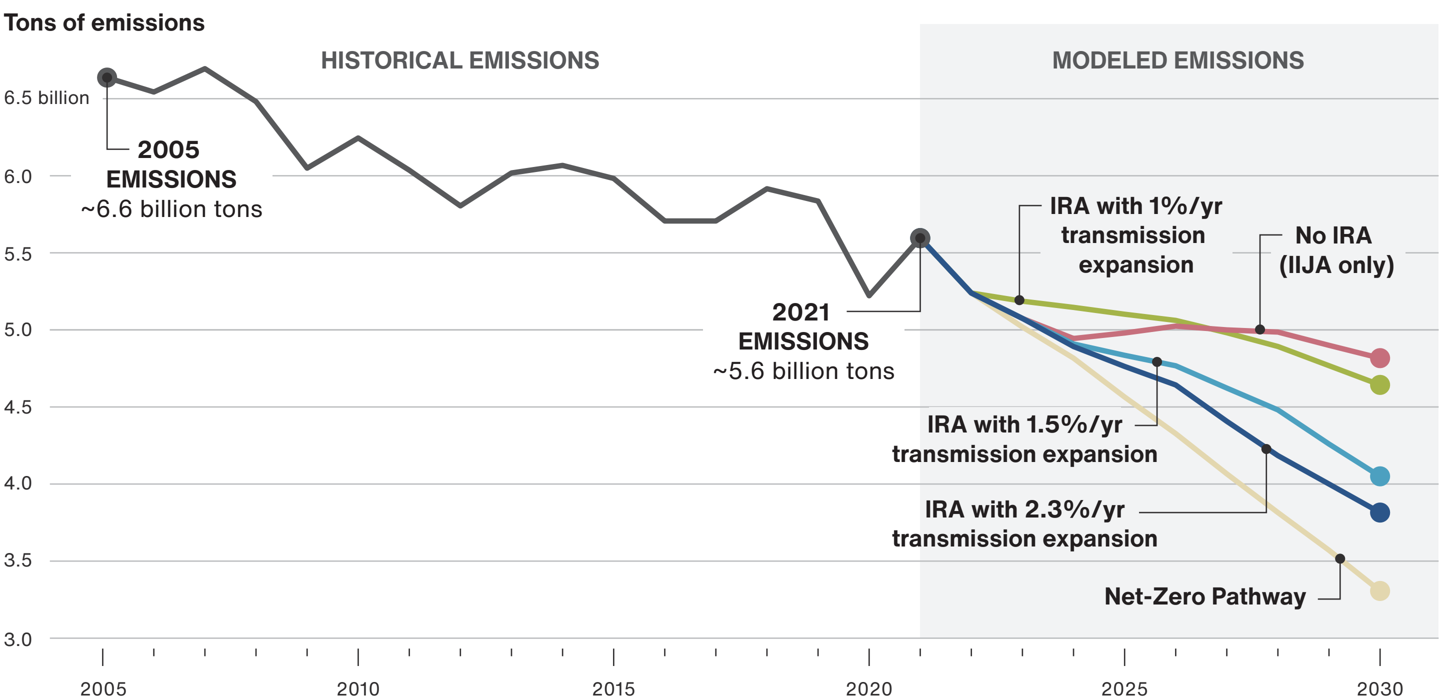


Source: Adapted from Joachim Seel, et al. (2023).

While the United States is barely keeping up with the minimum required regional grid improvements today, the future regional grid expansion capital expenditures may need to be three to four times bigger than they are now. A recent Princeton University paper shows that $415 billion in transmission capital investment is needed from 2023 to 2035 to achieve a net-zero pathway versus $164 billion in a business-as-usual case. This investment translates into 100,100 gigawatt (GW) miles of cumulative transmission built in a net-zero pathway versus 23,600 for business-as-usual (Figure 6).[ix,26] Results from the DOE Transmission Needs Study are similar: DOE identified a median need of 123,000 GW-miles by 2040 in its high load, high clean energy scenario.[27]

Figure 6: **IMPACT OF TRANSMISSION EXPANSION CONSTRAINTS ON MODELED NET U.S. GREENHOUSE GAS EMISSIONS (GHGs)**

Transmission expansion is a major determinant of whether IRA emissions reductions will be realized.



Source: Adapted from Jenkins, et al. (2023).

Integrating low-cost renewable generation into the grid provides widespread cost savings and consumer benefits. A 2017 study by The Brattle Group estimated that providing access to lower cost generation to meet renewable portfolio standards (RPS) and other clean energy needs through 2030 could create $30 billion to $70 billion in benefits to customers. Other studies have estimated that this number could be more than $100 billion.[28,29]

ix Gigawatt-mile refers to the energy transfer capability of one gigawatt of electricity across one mile in an electrical grid system.

A shortage of transmission capacity poses risks to developing, financing, and building generation and storage.

Shortfalls in transmission planning and cost allocation policies are impeding the development of new generation and storage projects. The challenges are especially acute for renewable resources that tend to be located far away from load centers and the existing grid.

When new decarbonized generation and storage projects (or any other new generator) seek early-stage and permanent financing, they often cannot secure financing until they have firm contractual assurance of the ability to transmit output to market. The fundamental credit underpinning of energy projects is the revenue stream generated by the sale of output based on long-term contracts with utilities or industry. No transmission means no output delivered, which means no revenues earned, which means no source of funds to repay lenders and investors.

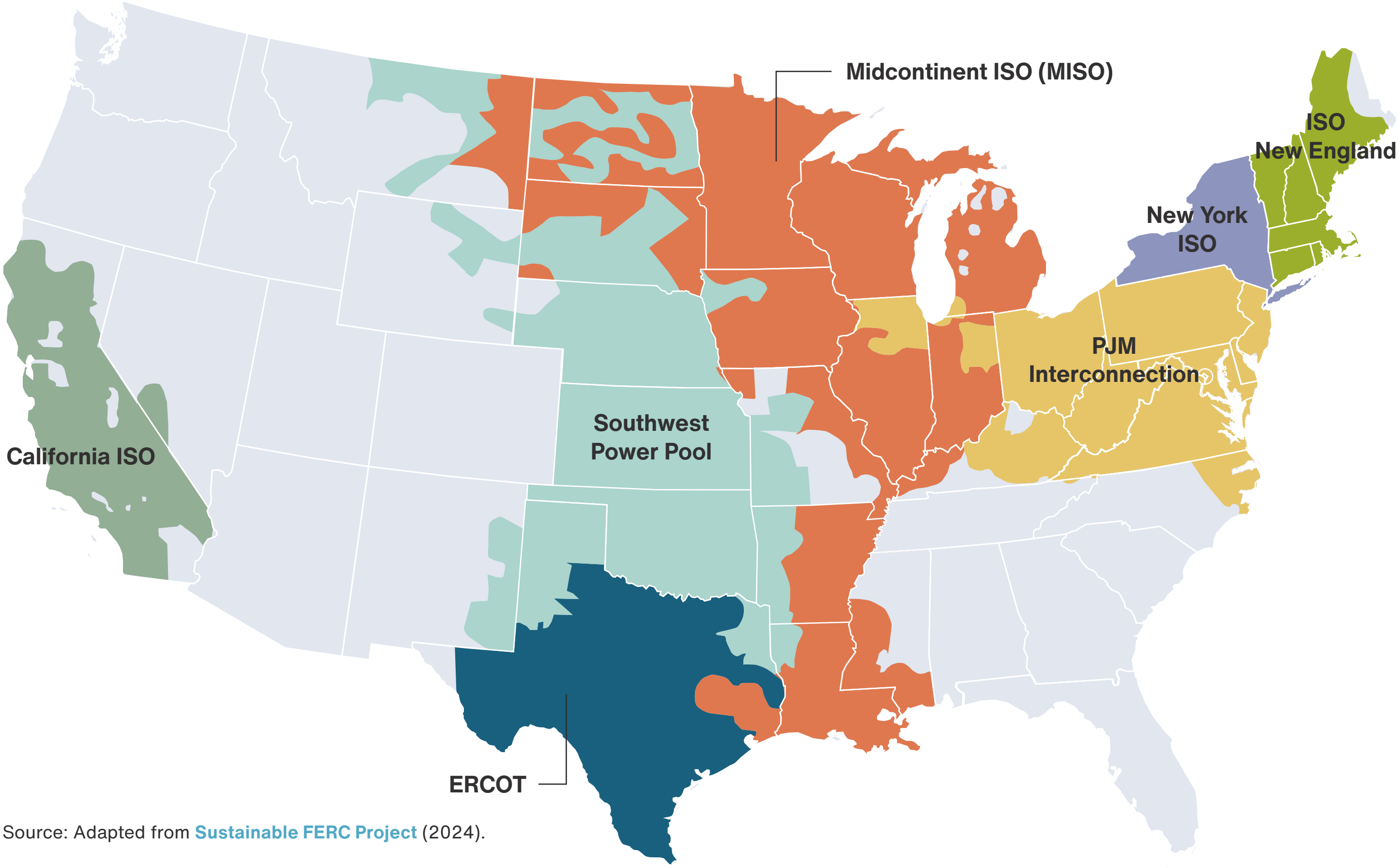
Long wait times and expensive upgrades to connect to the grid mean that most proposed projects do not reach commercial operations. In fact, among all projects requesting interconnection between 2000 and 2018, only 19% were in service as of the end of 2023.[30] The numbers are even lower for solar (14%) and battery (11%) projects. It should be noted, however, that many of the projects in the queue are likely speculative.

Two Pathways to Paying for Regional-Scale Transmission Network Upgrades

EF³'s analysis primarily concentrates on the challenges and promising precedents of RP/CA in the organized power markets in the U.S.[x] Within these regions, both the operation and planning of transmission and the operation of orderly wholesale electric markets are, for the most part, supervised by RTOs or ISOs (Figure 7).[31]

Figure 7: **MAP OF ISOs/RTOs IN THE CONTINENTAL UNITED STATES**

FERC-jurisdictional ISOs/RTOs plus non-jurisdictional ERCOT, which covers most of Texas. ERCOT refers to the Energy Reliability Council of Texas.



Source: Adapted from Sustainable FERC Project (2024).

x While many similar issues and opportunities are at play in non-ISO/RTO energy markets, including applicability of an upcoming transmission planning rule from FERC, they fell outside the scope of this analysis.

As discussed below, there are two alternative approaches under FERC regulations by which regional-scale upgrades of the main high- and medium-voltage backbone grid can take place.[xi]

Approach 1: A top-down regionally oriented transmission approach that proactively adds significant, resilient capacity in a cost-efficient manner. This approach uses the RP/CA system. The current RP/CA system evolved over the past 20 years, based on a synthesis of promising practices adopted by individual ISO/RTOs, some seminal federal appeals court cases, FERC's Order 1000 (from 2013 and still the law of the land), and now a proposed revision to Order 1000 (the May 2022 Notice of Proposed Rulemaking (NOPR)).

The goal in an ideal world, a goal that FERC forcefully articulated in the May 2022 NOPR, is for regional transmission authorities to plan well ahead of the need to engineer, permit, and build the transmission lines that will be needed in 10 to 20 years to meet expected changes in electricity demand and the generation mix. For high-voltage transmission project portfolios that create region-wide benefits, FERC is seeking to make the process of planning, selecting, and paying for transmission improvements a proactive and regionally-driven process. With region-wide needs in mind, those lines would be built at sufficient capacity to gain economies of scale and with a layout that provides robust alternative power flow paths to account for outages. Starting a decade ahead of when needs arise is critical because a large transmission line approved by an ISO/RTO in 2024 may take 5 to 10 years to be permitted and constructed, and even 15 to 20 years in some cases.[32,33]

For high-voltage transmission project portfolios that create region-wide benefits, FERC is seeking to make the process of planning, selecting, and paying for transmission improvements a proactive and regionally-driven process. With region-wide needs in mind, those lines would be built at sufficient capacity to gain economies of scale and with a layout that provides robust alternative paths to account for outages.

Generation projects that need to be deployed onto the grid to keep pace with increasing demand have a much shorter planning, approval, and construction timeline than transmission projects. A typical wind or solar project takes a year or two to permit and a year to build. A high-voltage transmission project that will serve new capacity from a new generation project would therefore need to start the planning process at least a decade ahead of when the generator seeks interconnection. In the

xi This is a simplified discussion of how transmission upgrades are made, since some desperately needed lines and/or opportunistic lines to reach cheap generation resources or to fix obvious spots of high congestion can be privately financed by consortia of generators and customers.

absence of such a “time-sequenced” grid buildout, and unless the project sponsor agrees to shoulder expensive network upgrades itself, the generation project might not have access to reliable, firm transmission service until eight or nine years after receiving generation project construction permits. Proactive and coordinated transmission planning and resource planning can therefore help address the timing and geographical mismatch between generation and transmission.

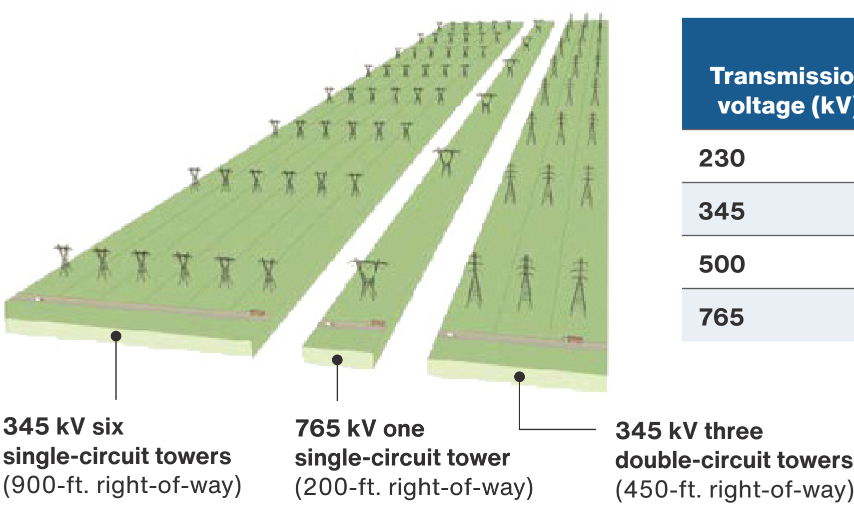
Planning for multiple drivers of transmission at once through “multi-value projects” can yield billions in cost savings for consumers. For example, Australia’s most recent multi-value transmission plan is projected to yield at least $17 billion in cost savings for consumers, and MISO’s most recent set of multi-value projects is projected to deliver more than $23 billion in cost savings.[34]

High-voltage transmission lowers the cost of delivering energy to consumers. For example, a 765 kV (or 5,000 MW) line can deliver 10 times as much energy as a 230 kV (or 500 MW) line at less than a quarter of the cost per unit of capacity (Figure 8).[35] Furthermore, a higher-voltage line does not necessarily take up more space than a lower-voltage line, which is important for reducing cumulative siting/permitting challenges for a regional grid expansion.[36]

A clear goal of the May 2022 NOPR is to reform planning and payment procedures for project portfolios that create region-wide benefits. Reform is clearly needed since FERC states that “[A]cross all the non-ISO/RTO regions, there has not yet been a single transmission facility selected in a regional transmission plan for purposes of cost allocation since implementation of Order No. 1000.”[37] Instead, most regional-scale lines—and not very many of them—are built under processes pre-dating Order 1000 or under a work-around called the “State Agreement Process. This process involves one or more states voluntarily taking financial responsibility for projects they particularly desire.

Figure 8: **ECONOMIES OF SCALE FROM HIGH-VOLTAGE TRANSMISSION**

High-voltage lines provide a significantly lower cost for each megawatt-hour of energy delivered than low-voltage lines.



Transmission voltage (kV)	Cost per mile ($/mile)	Capacity (MW)	Cost per unit of capacity ($/MW-mile)
230	$2.077 million	500	$5,460
345	$2.539 million	967	$2,850
500	$4.328 million	2,040	$1,450
765	$6.578 million	5,000	$1,320

Source: Adapted from Rob Gramlich and Jay Caspary (2021).

Approach 2: A bottom-up reactive, incremental generator interconnection approach based on waiting until groups of specific proposed generation projects are in advanced development and then forcing generators to bear the required network upgrade costs. This approach is formally codified in the various FERC rules governing "Generator Interconnection Procedures and Agreements," built upon the foundation of FERC's Order 2003 (of 2003). Order 2003 was updated last year with Order 2023. This approach, as practiced on the ground in most regions, effectively defers approving transmission lines until a concrete need crystallizes for that new transmission capacity based upon individual generation projects reaching advanced stages of development.

This reactive interconnection approach is based on a theory that transmission engineers employed by the grid operator can accurately identify the network upgrade capital costs "caused" by an individual generation project connecting to the grid if the generator desires transmission service of the same quality currently offered to incumbent grid users. Then, based on the rationale of "cost causality," it is fair to require the generator to raise funds to cover those costs and pay the grid operator to build the network upgrades. This approach ignores benefits received by other users around the region from the upgrades.

An overreliance on the reactive second approach to investing in transmission capacity leads to incremental, expensive upgrades.

In today's constrained grid, we find cohorts of 20 to 100 generation projects in one region, in one year, seeking assurance in 2024 of transmission availability—at a known cost—by 2026 at the end of their one- or two-year construction periods. However, with most ISO/RTO grids having little or no spare grid carrying capacity, new network upgrades across the entire regional grid—including the high-voltage backbone grid—may then urgently need to be executed to provide robust service to the new entrants.

The resulting generator-driven projects need to be executed *ad hoc* in a hurry, thus being unlikely to be the scale-efficient, well-designed, robust network that the RP/CA approach might have provided. Moreover, because these high-capacity upgrades are needed to serve many interconnecting and existing generators and will provide the entire region with more reliable and affordable power, the interconnecting generator has little incentive to pay the full cost of this public good.

How Is This Dual System Currently Performing?

The first system described above, a regional planning-based RP/CA regime, has not performed well since Order 1000 was issued in 2011. As a last resort, regional grid operators are falling back on the second approach based on generators bearing the cost of network upgrades to the main grid. The second system has shown that it is not an adequate alternative.

There have been a few isolated examples of success in major high-voltage grid expansions based on long-term regional planning. In these instances, grid operators (i.e., ISO/RTOs) decided that a resilient, robust grid benefits all parties, and that delay would harm all ratepayers. Grid operators therefore concluded that it was entirely fair to proportionally spread the cost of new regional transmission improvements across the entire customer base because of the widespread benefits. Examples of these (some of which precede or are contemporaneous with Order 1000) are:

- **ERCOT's Competitive Renewable Energy Zones** (CREZ, dating from 2005), whose costs are allocated across ratepayers based on maximum coincident demand at each meter.

- **MISO's Multi-Value Projects** (MVP, dating from 2011), including the most recent Long-Range Transmission Planning (LRTP) projects, are portfolios of projects built across MISO's Midwest region. The costs are allocated uniformly across utilities in MISO Midwest based on their share of energy consumed.

- **SPP's Highways and Byways** (originally dating from 2010), which formulaically allocates transmission project costs between SPP and local areas depending on the voltage of the line, i.e., high-voltage allocated SPP-wide, medium-voltage split, and low-voltage allocated to local areas.

Beyond these promising RP/CA precedents within a few transmission regions, progress has been poor. The few successes have not been repeated in other ISO/RTOs. Even among the ISO/RTOs that have had successes, the practices have not been implemented consistently.[38,39] Especially in a divided political environment, many attempts by ISOs to manage and justify simplified cost allocation methods have hit speedbumps at FERC and in federal courts overseeing FERC approval of ISO actions.

As described earlier, the alternative system was not designed to substitute for proper RP/CA, particularly for high-capacity upgrades that provide multiple benefits while interconnecting several location-constrained renewable resources with short construction timelines.

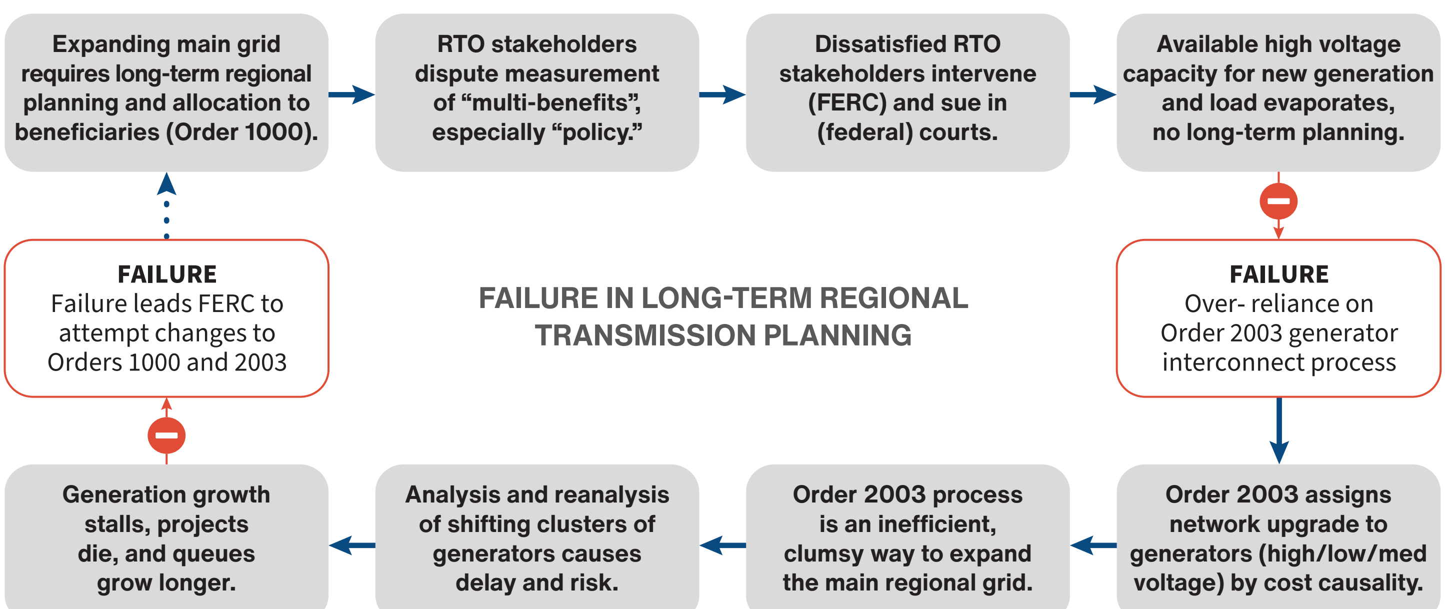
While simple in theory for a single generator, the cost causality analysis required by the second approach is confounded when it faces large numbers of applicants simultaneously. That is, sizable cohorts of would-be interconnecting generators in the same area in the same year seek to gain contractual assurance of an uninterrupted ability to deliver their electricity to customers.

Even when ISO/RTOs try to speed the process by analyzing 50 or 100 would-be interconnectors in a so-called "cluster study," it is extremely difficult to reliably determine each such interconnector's *pro rata* share of a variety of network capacity upgrades scattered across the ISO/RTO's territory.

The types of needed backbone investments tend to benefit a wide range of users, if not all users, across the region, so it is nearly impossible to attribute the benefits to one interconnecting generator. Or if planners try, the costs assigned just to that one generator or set of generators are prohibitive for the project to proceed. Further, with most ISO/RTO grids having little or no spare carrying capacity, new network upgrades across the entire regional grid—including the high-voltage backbone grid—may need to be executed to provide robust service to the new entrants.

Ultimately the RP/CA process fails first, and the attempt to pay for needed network upgrades via the fallback generator "cost causality" process flounders in turn. The queue of interconnectors grows longer. The grid creaks and sometimes breaks as it seeks to operate with almost no margin for error. Figure 9 shows a simplified flowchart of the failure points.

Figure 9: **IMPETUS FOR REFORM: TODAY'S SPIRAL OF FAILURE IN LONG-TERM REGIONAL TRANSMISSION PLANNING IS CREATING OVER-RELIANCE ON LARGE GENERATOR INTERCONNECTION PROCEDURES**



Source: Analyzed based off data from May 2022 NOPR at paragraph 36.

Ultimately, this spiral of transmission planning and cost allocation conflict and failure is at the heart of FERC's now three-year old attempt to improve the situation via changes in FERC regulations.

In the May 2022 NOPR, FERC articulated a clear commitment to move beyond the RP/CA system originally set forth in Order 1000, which has not been formally revisited since 2011. Thus, the May 2022 NOPR reflects a decade's worth of trial and error as FERC jurisdictional and non-jurisdictional transmission organizations have struggled to keep up with the evolving needs of the grid.

FERC was clear in its proposed rule as to the extremity of the problem and as to the need for decisive action. The agency has historically sought to avoid being over-prescriptive and has been sensitive to the desires of state regulators to avoid overbuilding transmission capacity. However, in the May 2022 NOPR, FERC signaled that it was considering much more top-down prescriptive action.

FERC's Ability to Enact Bolder Top-down Direction

FERC's proposed rule includes a compilation of reforms that experts believe will ameliorate current problems plaguing transmission planning efforts, backed up by a solid rulemaking record. But some will question whether FERC has the statutory authority to prescribe and direct jurisdictional transmission organizations to enact those reforms, as opposed to simply making suggestions and recommendations.

Courts have upheld FERC's authority to prescribe robust planning methodologies, though skeptics argue for a more limited approach.

There is a school of thought that would say FERC has the statutory authority, reinforced by a long string of judicial precedents, to be far more prescriptive and directive than it has been over the past decade.

That school of thought builds on FERC's fundamental responsibility and fundamental power under Section 206(a) of the Federal Power Act. Under Section 206(a), if FERC finds that rates and charges of a jurisdictional utility, or any "rule, regulation [or] practice" affecting rates and charges are "unjust, unreasonable, unduly discriminatory or preferential," then FERC has the right to determine a "just and reasonable" substitute and order that substitute to be implemented.

Adherents to this school of thought point to judicial precedents upholding FERC's right to prescribe regional planning methodologies. For instance, after FERC promulgated Order 1000 on Regional Planning and Cost Allocation, a group of petitioners in *South Carolina Public Service Authority v. FERC* challenged that FERC had overstepped its authority. The petitioners argued "that FERC's authority is limited to regulating voluntary planning efforts and [did] not extend to requiring the new regional planning arrangements mandated by Order 1000."[40]

The D.C. Circuit supported FERC by finding that transmission planning, or failure to engage in transmission planning, falls within the category of practices that affect rates. The court then found that FERC has the power to prescribe planning procedures that are more likely to result in just and reasonable rates and charges. The court also found that "the Commission reasonably determined that regional planning must include consideration of transmission needs driven by public policy requirements."[41]

An opposing school of thought, as articulated in Commissioner Danly's dissent to the May 2022 NOPR, reads Federal Power Act Section 206(a) in a far more limited way. Commissioner Danly stated that for FERC to lawfully impose "mandatory, pervasive, and invasive 'reforms,'" such as those contemplated, "FERC must find that the current planning processes are so unacceptable that the existing system essentially must be scrapped," and that "we must also have record evidence that the replacement rate–the final rule to follow the NOPR–is just and reasonable." He also expressed a clear preference for regions finding their own solutions: "In my view, if an RTO or public utility wants to 'enhance' its regional planning, it can figure out how to do so."[42]

These opponents would be considerably more comfortable with FERC remaining in a reactive role, waiting for transmission providers to bring their proposed regimes to FERC one-by-one, with FERC then accepting or rejecting them individually. FERC would be kept in the passive position of rejecting RP/CA regimes that FERC views as ineffective but prohibited from clearly stating the principles that transmission providers can follow to avoid such a rejection.[43]

With the current composition of the U.S. Supreme Court, opponents may find comfort in the court's increasing reliance on the "major questions doctrine." While never used explicitly in a major opinion, this doctrine suggests that in issues of major national significance, agencies may need to be granted clear statutory authority by Congress rather than relying on interpretations of more general delegated authorities.[44] Through this lens, they may argue that prior legal decisions should be revisited to ensure that regulations are supported by clear congressional authorities.

Legal precedents regarding ISO/RTO planning regimes have evolved.

As stated in the introduction, the current RP/CA system evolved over the last 20 years, based on a synthesis of promising practices adopted by individual ISO/RTOs, some seminal federal appeals court cases, FERC's Order 1000 (from 2011 and still the law of the land), subsequent court cases, and now proposed reforms in the May 2022 NOPR.

ISO/RTOs themselves generated many of the RP/CA regimes that made progress constructing high-voltage regional lines in the decade preceding the adoption of Order 1000:

- MISO's 2011 Multi-Value Project was an early example of reaching a political consensus to develop a regional plan that used a benefit-cost analysis including a wide variety of transmission benefit types (e.g., reliability, congestion relief, lower duplication in construction of generation reserves, and electricity cost savings).

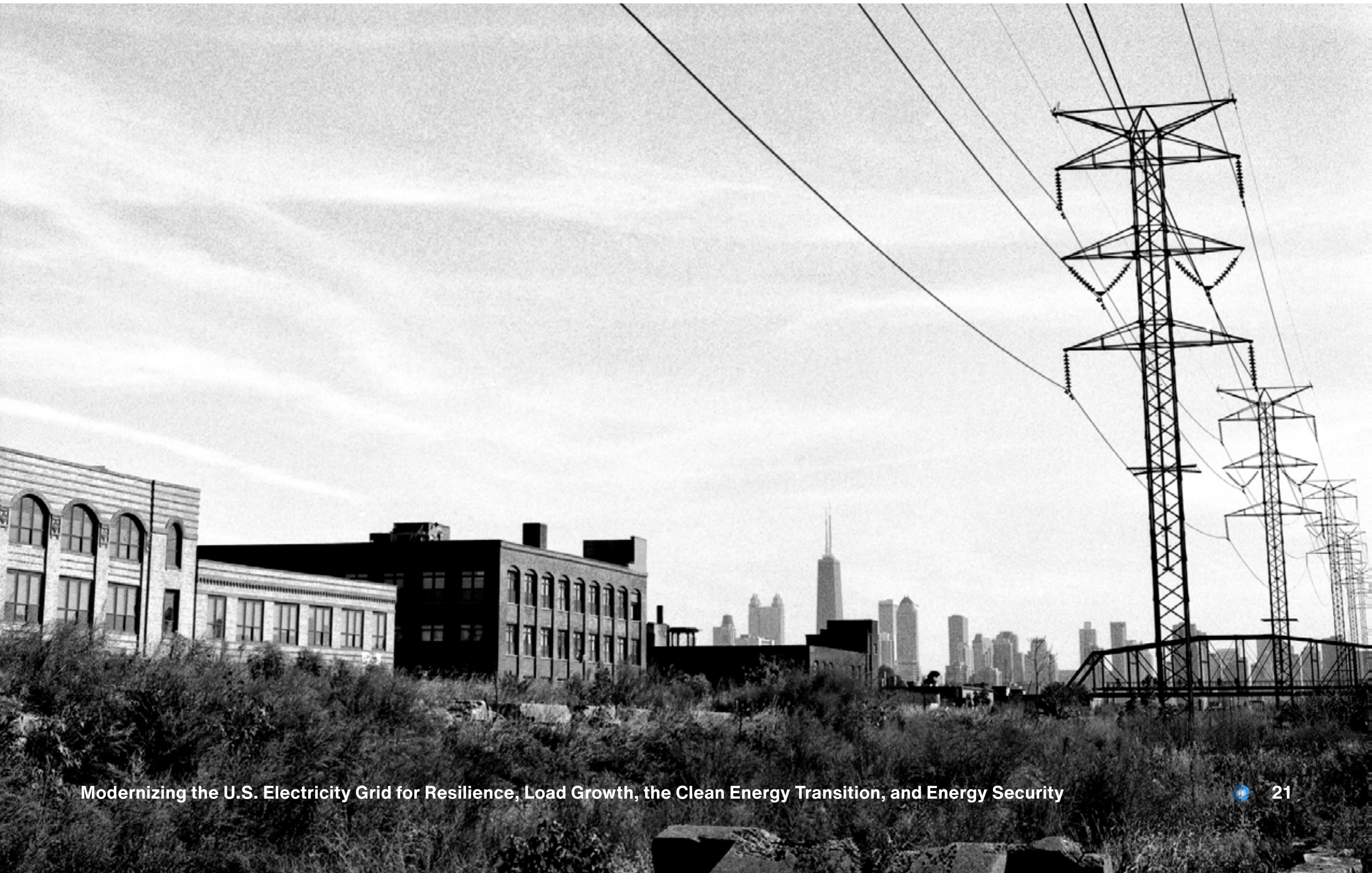
- SPP's Highways and Byways program was an early example of a simplified scheme for determining which types of projects would be 100% regionally allocated (i.e., those above 345 kV) and what the pro rata method of assigning cost would be (i.e., based on peak loads of SPP's various load serving entities (LSEs)).

The single most important court precedent was the 2009 *Illinois Commerce Commission (ICC) v. FERC* case, in which the ICC sued FERC for approving a PJM regional allocation scheme.[45] PJM's regime was facially neutral (lines 500kV and above were cost allocated pro rata across PJM's LSEs), but the ICC believed it was unfair to Illinois ratepayers since no 500kV lines were in use or were planned in Illinois. The case established three main principles:

1. The Court of Appeals did not demand that FERC develop a regulatory record that showed perfect precision and fairness in aligning LSE financial burdens with LSE benefits received (in keeping with an earlier decision in Sithe/Independence Power Partners, L.P. v. FERC).[46]

2. The Court did demand that FERC must develop a record of analysis (provided by proponents and opponents of an ISO/RTO planning/allocation regime) that adequately demonstrated that the approved regional regime allocated benefits in a manner roughly commensurate with costs.

3. The Court in effect ruled that even though PJM's regime appeared to be neutral, based on an objective quantitative standard (i.e., "500 kV+ lines to be regionally allocated") FERC's approval of PJM's regime was unsound because FERC had not considered clear evidence that PJM's regime had unfair results. In this case the Midwest states on the far western edge of PJM, such as Illinois and Ohio, used lines with a maximum voltage of 345 kV.



DOE Has Undertaken Initiatives that Can Support Regional Transmission Planning and Cost Allocation

DOE has significant technical expertise within its own offices and in the National Laboratories to support effective planning and cost allocation. Many of its ongoing initiatives can serve as inputs to regional transmission planning efforts and help mitigate cost allocation disputes. Some of DOE's most relevant initiatives that are currently underway include:

- Through the **$2.5 billion Transmission Facilitation Program**, authorized by the IIJA, DOE uses several financing tools to improve financial stability for eligible large transmission projects.[xii] These tools are: (i) capacity contracts where DOE serves as the "anchor customer" to buy up to 50% of planned line rating for up to 40 years (and subsequently recover the costs), (ii) loans from DOE, and (iii) DOE participation in public-private partnerships within a National Interest Electric Transmission Corridor (NIETC).[xiii] The Transmission Facilitation Program is intended to improve the business case for projects that would not be built without the support of this funding, despite providing a range of benefits. DOE has already committed $1.3 billion for three transmission projects across six states.[47]

- The **$2 billion Transmission Facility Financing program**, authorized by the IRA, is a direct loan program for transmission projects located in a National Interest Electric Corridor (NIETCs). This program will similarly improve the business case for transmission projects deemed to be in the national interest.[48]

- The **National Transmission Needs Study** assesses current and near-term future regional and interregional transmission needs to inform regional and interregional planning. Previously called the Transmission Congestion Study, the Transmission Needs Study now examines near-term future constraints in addition to historical data.[49]

- The **National Transmission Planning (NTP) Study** identifies high-priority national transmission solutions. This study is centered on a long-term planning horizon and is a collaboration between state, regional, and federal entities,

xii Eligible projects are (i) new lines that transmit at least 1,000 MW, project upgrades where the upgrade transmits at least 500 MW, or (iii) constructs a transmission line to connect isolated microgrid to the grid in Alaska, Hawaii, or U.S. territories.

xiii NIETCs are high-priority geographic area designated by the Secretary of Energy where the development of transmission would advance national interests including reducing costs to consumers, reducing capacity constraints, and advancing policy goals. DOE designates NIETCs based upon a four-phase process, including establishing discretionary factors that will guide designation.

and uses a range of models and public engagement to inform its analysis. A study conducted by the National Renewable Energy Laboratory (NREL) identified the benefits of using an interregional renewable energy zones (IREZ) approach to transmission buildout; in other words, the construction of long-distance, high-voltage transmission lines connecting the biggest load centers to valuable renewable energy resources could achieve cost savings, reliability, and decarbonization.[50] The NTP Study is intended to inform state,[xiv] regional, and interregional planning processes and will be used to prioritize DOE funding including the Transmission Facilitation Program as the nation shifts to a more forward-looking and proactive investment approach.[51]

The previous sections addressed important background topics including (i) the massive interconnection backlog, (ii) underinvestment in regional high-voltage transmission, (iii) the dual regimes of investment (regional planning vs. generator-driven), (iv) FERC's power to change the situation under statute and existing case law, and (v) current DOE initiatives that can facilitate more effective regional transmission planning and ease cost allocation debates.

Next, the analysis will build upon those background topics with a focus on:

- Examples of best practices for RP/CA in multi-state ISO/RTOs before the release of the May 2022 NOPR as well as some respected transmission experts' analyses on how FERC's RP/CA regime could be improved

- How FERC's proposed solutions relate to best practices from some ISO/RTO actors and the technoeconomic recommendations of national transmission experts

- The broad outline of FERC's proposed solutions in the May 2022 NOPR, which are giving rise to a final rule imminently

- How effective planning (following best practices) can mitigate cost allocation disputes

- The relative degrees of prescriptiveness of these detailed parameters, i.e., when FERC proposed to *require* specific actions versus when FERC proposed to *advise* and *recommend* specific actions in its May 2022 NOPR

- EF^3's conclusions and recommendations for FERC action

- Other possible regional and federal actions that would complement FERC's final rule in bolstering more rapid investment in the grid

xiv The IREZ report by NREL notes that "states will ultimately take the lead in deciding whether to pursue IREZ development." and an upcoming Regulatory Pathways report as part of the NTP Study series will be written for state decision-makers with the goal of providing knowledge of the benefits of the NTP Study's national scenarios.

Experts' Review of Needed Reforms and Key ISO/RTO Precedents, Prior to the Proposed FERC Rule

FERC did not develop its approach for the May 2022 NOPR in a vacuum. Rather, FERC's list of best practices draws heavily from recent regional precedents—successful and unsuccessful—for planning and implementing transmission investments to meet transmission requirements over a long-term horizon. One example is MISO's Multi-Value Projects, particularly its most recent Long Range Transmission Plan Tranche 1 initiative (a roughly $10.3 billion investment in transmission across the MISO region), with early contours of a $23 billion Tranche 2 announced March 15, 2024.[52]

Since 2020, several transmission experts have published analyses on how the ISO/RTO planning/allocation process could be improved. FERC cited these sources in support of its May 2022 NOPR,[xv] including numerous citations from work by Grid Strategies (Rob Gramlich and Jay Caspary)[53] and The Brattle Group (Johannes Pfeifenberger et al.).[54] **Figure 10** summarizes what could be termed "the emerging expert consensus" approach.

Figure 10: **CONSENSUS BEST PRACTICE BASED ON REGIONAL PRECEDENTS AND EXPERT RESEARCH**

PLANNING COMPONENTS

1. PARAMETERS — Time frame and assumptions about future → **2. EVALUATION** — Benefits vs. costs. All or some benefits? Single project vs. portfolio? → **3. SELECTION** — If selected for allocation, will costs to LSEs be roughly commensurate to benefits? → **ALLOCATION** — Is allocation method simple *ex ante* or a contentious *ex post* renegotiation?

Long-term planning	Evaluation	Selection	Allocation
Much longer-term **probabilistic scenario planning** vs. reactive reliability and economic upgrades. Construct *before* network upgrades needed to connect large generators. **Incorporate load growth and legally enforceable changes in resource mix.**	**Multi-benefit:** Count all benefits that are reasonably measurable or forecastable. **Portfolio:** Do it on a portfolio basis. More defensible economically and more astute politically.	Select based upon **regional portfolio** Benefit-Cost Analysis (BCA). NPV (Net Present Value) of *multi-benefits* vs. NPV of costs. **Subregional BCA** to demonstrate that costs are commensurate to benefits.	If the "selection" step's **subregional BCA** denominator utilizes cost **NPV to subregions**—based upon a pre-agreed, *ex ante* allocation method that demonstrates costs are commensurate with benefits—then the allocation is bulletproof (see MISO LRTP).

Source: This graphic draws heavily on papers done singly or jointly by Rob Gramlich (Grid Strategies) and Johannes Pfeifenberger (Brattle).

xv One of the most comprehensive is: Johannes Pfeifenberger et al., *Transmission Planning for the 21st Century: Proven Practices That Increase Value and Reduce Costs*, The Brattle Group and Grid Strategies, October 2021.

1. Planning parameters: Long-term planning is essential and is complementary to existing, routine short-term planning.

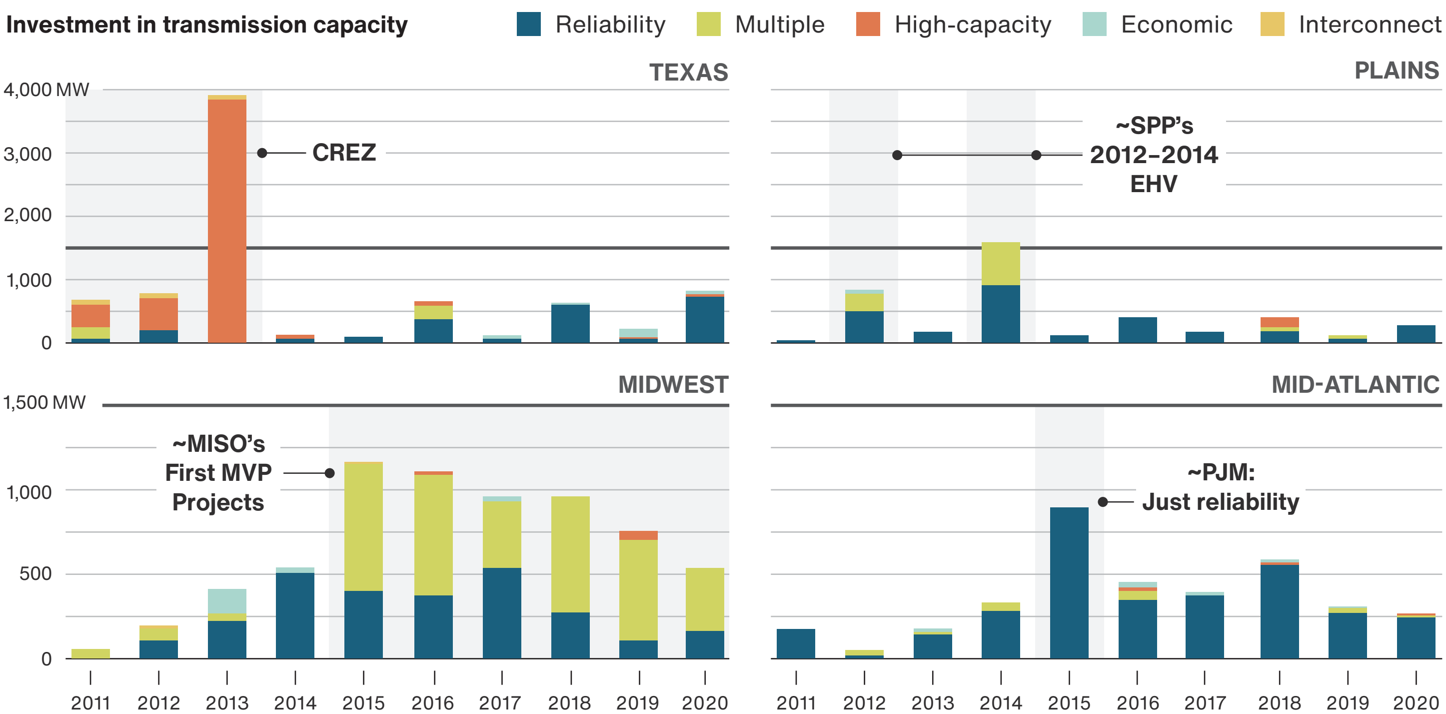
Large grid buildouts tend to happen in laboriously assembled portfolios every 5 to 10 years, if they happen at all. Some regions have done a better job building transmission for "knowable" market changes that will occur despite not knowing precisely where those changes will occur, rather than planning largely for short-term reliability purposes (Figure 11).[55]

The expert consensus is that long-term plans need to be developed on a regular basis, not sporadically. The plans should look far enough in the future to design an orderly layout (a.k.a. "topology") of new lines that provide room to connect generation of the type and at the location likely to be demanded, while providing alternative routes for electricity to flow during times of system crisis.[56]

ERCOT, SPP, and MISO each had a burst of "high-capacity" or "multiple [value/benefit]" projects in either the 2011 to 2014 time frame or, in MISO's case, 2015 to 2020 but authorized in 2011. However, these efforts were not necessarily followed by long-term/high-capacity construction projects in later years. Meanwhile, virtually all of PJM's focus has been on "reliability" projects that address near-term violations of NERC standards.

Figure 11: **DRIVERS OF GRID BUILDOUT IN ERCOT, SPP, MISO, AND PJM OVER TIME**

ERCOT's Competitive Renewable Energy Zone (CREZ) initiative, SPP's 2021–2014 Extra High Voltage (EHV) projects, and MISO's Multi-Value Projects were all long-term planning initiatives outside of normal planning processes that built high-capacity and multi-benefit portfolios of transmission projects. However, these large buildouts have not occurred on a continuous basis.



Note: Scales differ, with thicker, darker line highlighting MW capacity of lines built at 1,500 MW. Source: Department of Energy, ***National Transmission Needs Study***, (October 2023).

2. Planning evaluation: An equitable, geographically distributed portfolio of projects, with benefits evaluated as a portfolio (regionally and subregionally).

The experts' views on best practices for the "evaluation" stage have been evolving along four dimensions:

1. Examining a geographically distributed portfolio of transmission projects is both essential for the creation of a robust grid over a large region and politically advantageous in distributing benefits widely.

2. Examining multiple benefit types over multiple decades in a benefit-cost analysis is also essential to fully understanding the business case for the proposed transmission investment.

3. Given the lack of consensus across states on the importance of reducing GHG emissions, it is important to be able to demonstrate that the prospective business proposition does not depend on the benefit of GHG reduction on a regional basis.

4. When possible, ISO/RTOs should perform retrospective re-analysis to bolster public confidence that benefits and costs generally align with predictions and that they are equitably distributed.

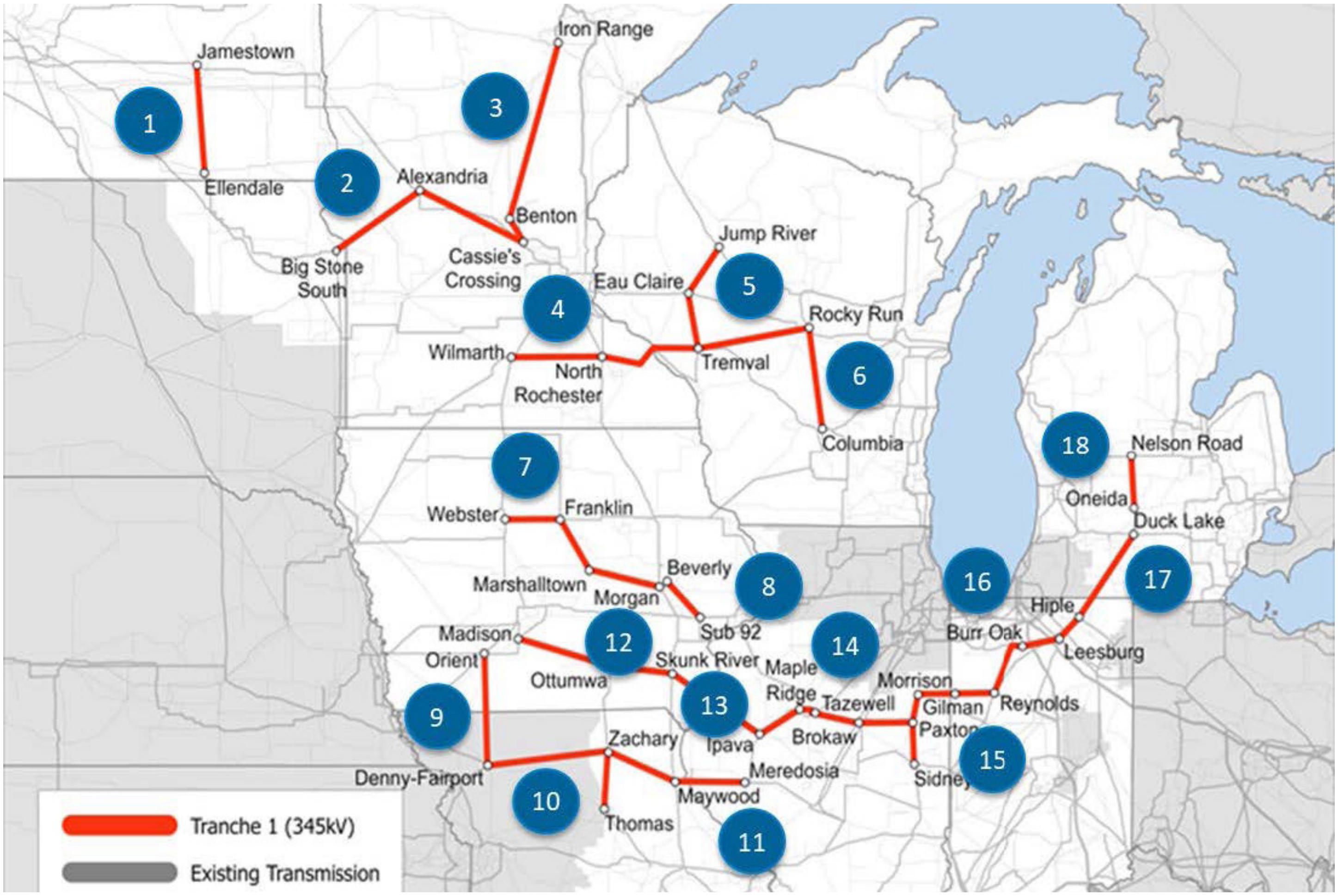
Geographically spread portfolios of projects may be more astute economically and politically.

It is impossible to precisely predict the location of future generators, though areas with high-quality resources that are suitable for development are known in advance. Furthermore, many risks to the grid include extreme weather events that affect customers across the entire grid, thus requiring regional solutions. Without a geographically distributed portfolio, an ISO/RTO is challenged to demonstrate that "costs are roughly commensurate with benefits" across those ISO/RTOs subregions.

A politically and economically reasonable approach for building regional consensus, therefore, is to widely spread jobs, reliability improvements, and economic benefits via a geographically distributed project portfolio (**Figure 12**, next page).

Figure 12: **GEOGRAPHIC DISPERSION OF MISO LRTP TRANCHE 1 $10 BILLION OF PROJECTS**

Transmission lines in MISO's LRTP Tranche 1 are distributed across the region, allowing for the benefits to be spread.



Source: **MISO Energy** (2022).

Multiple benefits should be examined across the portfolio of projects.

MISO's recent (2022) Long Range Transmission Plan Tranche 1 used a multi-value/portfolio approach to planning that builds upon the original MISO Multi-Value Projects portfolio of 2011. In terms of precedents for the evaluation phase of planning, MISO's approach demonstrates (i) the importance of multi-benefit evaluation across a portfolio of projects and (ii) that decarbonization benefits do not make or break the benefit-cost threshold.

In MISO's LRTP Tranche 1 initiative, no single benefit is dominant or alone could justify the suite of projects (**Figure 13**, next page).[57] Note that the benefits and costs have a high and low range, which is good practice given the uncertainties involved in predicting the future investment landscape. Outside of the decarbonization benefit, the main benefits are non-ideological and technology-neutral.

- Congestion and fuel savings ($13.1 billion to $19.9 billion of total benefits) are enhanced by the ability to deliver new zero-marginal-cost renewable energy. States with renewable portfolio standards help pay to build some of the renewables, and by building the transmission necessary to interconnect these low-cost resources, consumers receive cheaper electricity in return.

- The avoided capital cost of local resources is $17.5 billion. It reflects an estimated value of being able to optimize new generation locations via new transmission.[xvi]

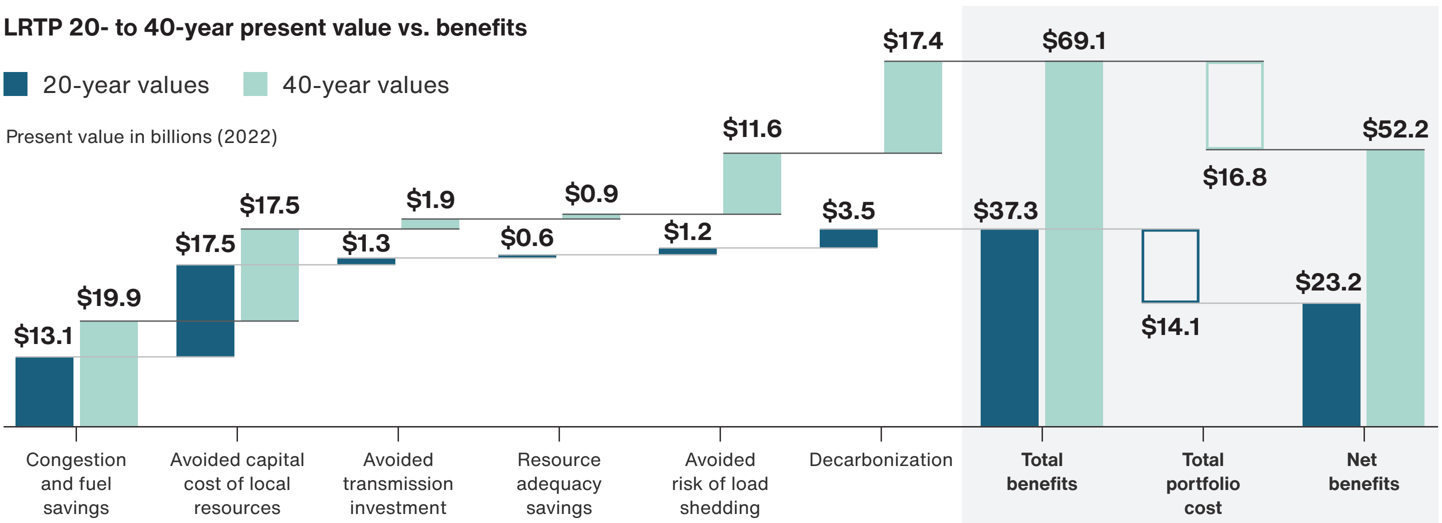
- Avoided transmission investment ($1.3 billion to $1.9 billion) and resource adequacy savings ($0.6 billion to $0.9 billion) are more modest.

- Similarly, avoided risk of load shedding (i.e., resilience to extreme weather) benefits the entire grid and can be a big factor, though the value of load loss (VOLL) estimates are unusually wide because of uncertainty in the value of avoiding a grid catastrophe ($3,500 to $23,000 per MWh).

- The pure "decarbonization" benefit ranges from $3.5 billion[xvii] to $17.4 billion,[xviii] which is 9% to 25% of total benefits. Given the high value of the non-GHG benefits, the value placed on CO_2 doesn't drive the benefit proposition.

Figure 13: **MISO LRTP TRANCHE 1 REGIONAL PORTFOLIO BENEFITS OUTWEIGH COSTS**

MISO's benefit-cost analysis shows net benefits of $23.2 billion to $52.2 billion when using 20- to 40-year present value benefits at a discount rate of 6.9%. 20 years represents MISO's planning horizon, while high-capacity transmission lines remain for 40 or more years.



Source: Adapted from MISO Energy (2022).

xvi The ability to optimize new generation locations is a critical benefit but is difficult to calculate and attribute to type of generation or location of beneficiary. This challenge is covered in more detail in the recommendations section.

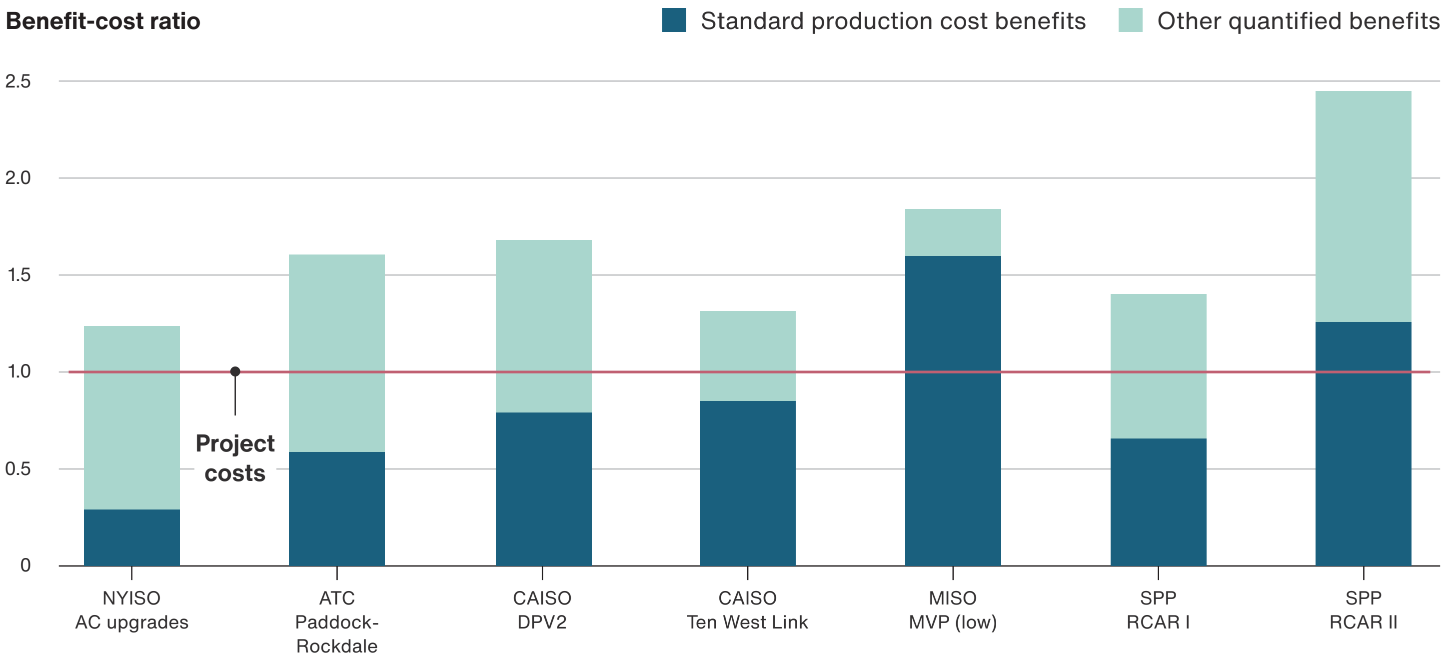
xvii The minimum benefit is calculated over 20 years (the duration for which multi-value projects plan) and assumes a $12.55/t starting CO_2 price.

xviii The maximum benefit is calculated over 40 years (the lifespan of high-voltage lines is often around 50 years, however) and assumes a $49/t starting CO_2 price.

The calculation of multiple benefits has been essential for the approval of most regional, high-voltage lines built in RTOs/ISOs that have led to system-wide cost reduction (Figure 14).[58] However, FERC risks enabling some regions to avoid considering many of the benefits evaluated by MISO if it declines to "require use of any specific benefits" in its final rule. It will be particularly important to consider the benefits of larger high-voltage lines during extreme conditions and extreme weather events: One study found that 50% of transmission congestion benefits come from just 5% of hours.[59]

Figure 14: **STANDARD PRODUCTION COST SAVINGS ALONE RARELY JUSTIFIED REGIONAL HIGH-VOLTAGE LINES IN ISO/RTOs**

The quantification of multiple types of benefits has been important for the approval of most regional high-voltage lines built in RTOs/ISOs.



Source: Pfeifenberger et al., (2021).

FERC risks enabling some regions to avoid considering many of the benefits evaluated by MISO if it declines to "require use of any specific benefits" in its final rule. It will be particularly important to consider the benefits of larger high-voltage lines during extreme conditions and extreme weather events: One study found that 50% of transmission congestion benefits come from just 5% of hours.

The region-wide business case for transmission should identify pure GHG reduction benefits and should be robust even if GHG benefits are zeroed out.

The MISO LRTP Tranche 1 portfolio of projects is well justified with or without relying upon the benefit of reduced GHG emissions:

- As shown in **Table 1**, in the case of a 20-year analysis with the minimum benefits (top left box), the benefit-cost ratio is 2.6x including climate (at $12.55/ton CO_2) and 2.4x excluding climate.[60]

- For a 40-year analysis with maximum benefits (lower right box), the benefit-cost ratio is 4.1x including climate (at $49/ton CO_2) and 3.1x excluding climate.

Table 1: **REGIONAL BENEFIT-COST ANALYSIS FOR MISO LRTP TRANCHE 1**

	Over 20 years	Over 40 years
Minimum benefits	$37.3B benefits ÷ $14.1B costs = **2.6x benefit-cost** *(2.4x excluding decarbonization benefit)*	$14.6B benefits ÷ $16.8B costs = **2.8x benefit-cost** *(2.5x excluding decarbonization benefit)*
Minimum benefits	52.4B benefits ÷ $14.1B costs = **3.8x benefit-cost** *(2.9x excluding decarbonization benefit)*	$69.1B benefits ÷ $16.1B costs = **4.1x benefit-cost** *(3.1x excluding decarbonization benefit)*

Source: Data from MISO Energy, ***LRTP Tranche 1 Portfolio Detailed Business Case***, (June 2022).

Retrospective analysis can enable a comparison of expected and actual benefits.

Since it is admittedly difficult to accurately estimate the economic benefits that a transmission investment may create a dozen years hence, taking a clear-eyed retrospective look at past investments is certainly among best practices for transmission operators.

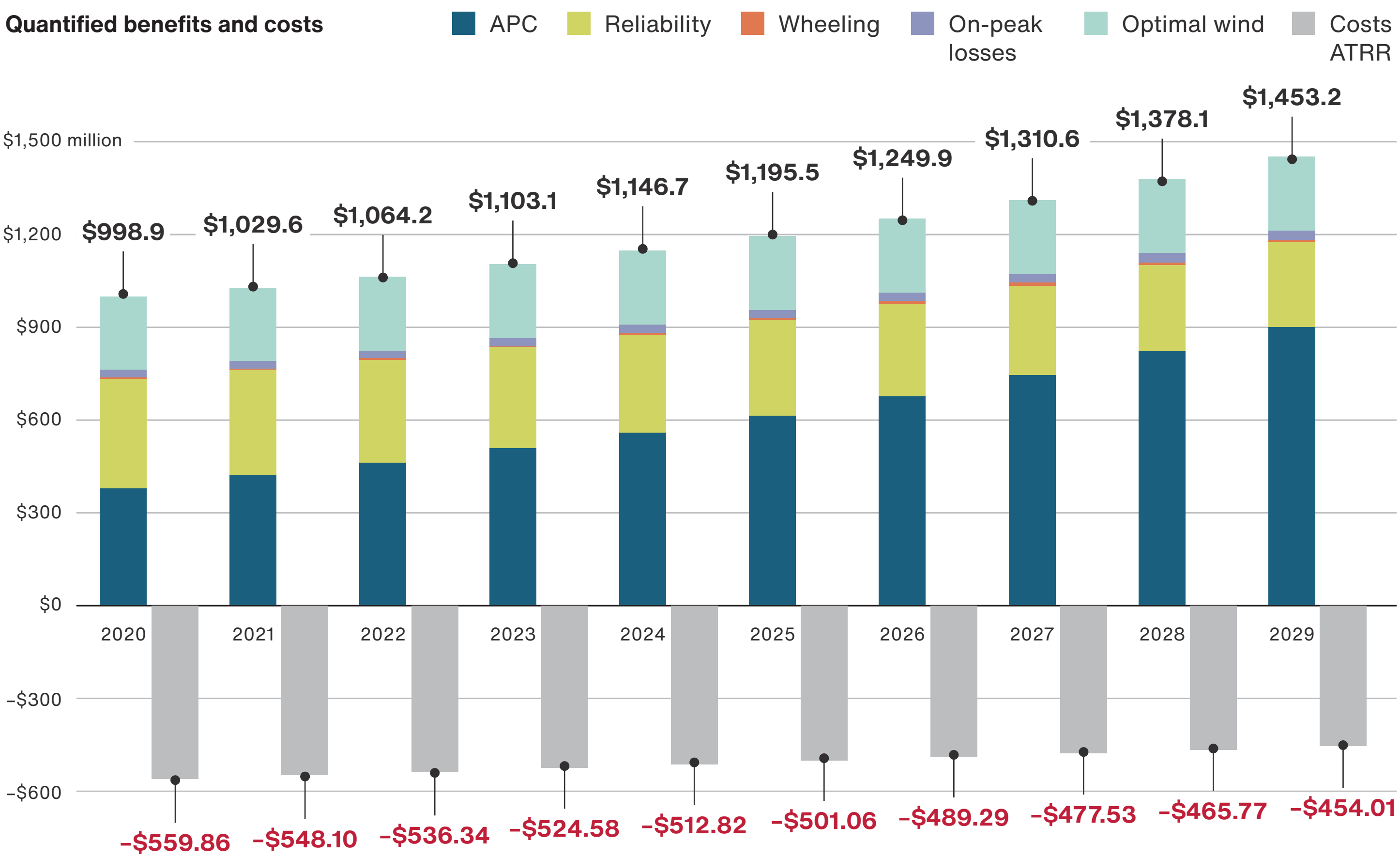
SPP forecasts future benefits over the remaining operational life of transmission investments after the investments have had a few years of operational history, giving an interim indicator of the projects' success based upon realized benefits and costs.

In the case of SPP the results are reassuring. SPP's post hoc benefit-cost re-analysis again demonstrates that (i) benefits far outweigh costs for regionalized grid-scale, high-voltage projects and (ii) policy/decarbonization benefits are unlikely to make or break a benefit-cost analysis.

The "optimal wind" benefit of $237 million per year in transmission capacity represents the benefit of locating wind in more productive sites, which is considered a policy/decarbonization benefit by SPP (the top portion of columns on **Figure 15**).[xix,61] However, this quasi-climate benefit is not dispositive to overall economics; it is only 10% of the present value of benefits over 40 years,[62] with a benefit-cost ratio of 5.2x. Removing the "optimal wind" benefit would only have reduced the benefit-cost ratio to 4.7x, still far above the FERC-required 1.25x threshold.

Figure 15: **SPP PROJECTED BENEFITS AND COSTS FOR 2020 TO 2029 FOR EXTRA-HIGH VOLTAGE TRANSMISSION PROJECTS COMPLETED IN 2015**

Benefits still far outweigh costs of SPP's extra-high-voltage (EHV) projects when re-analyzed with operational experience, even excluding the teal-colored "optimal wind" benefit. APC refers to adjusted production cost; ATRR refers to annual transmission revenue requirement.



Source: Adapted from **SPP Transmission Planning** (2021).

xix SPP recalculated the benefits-to-costs of transmission projects built in 2015 in a 2021 report.

3. Selection: Subregional re-analysis of benefits and costs can demonstrate that participant costs are commensurate with benefits, with and without GHG reductions.

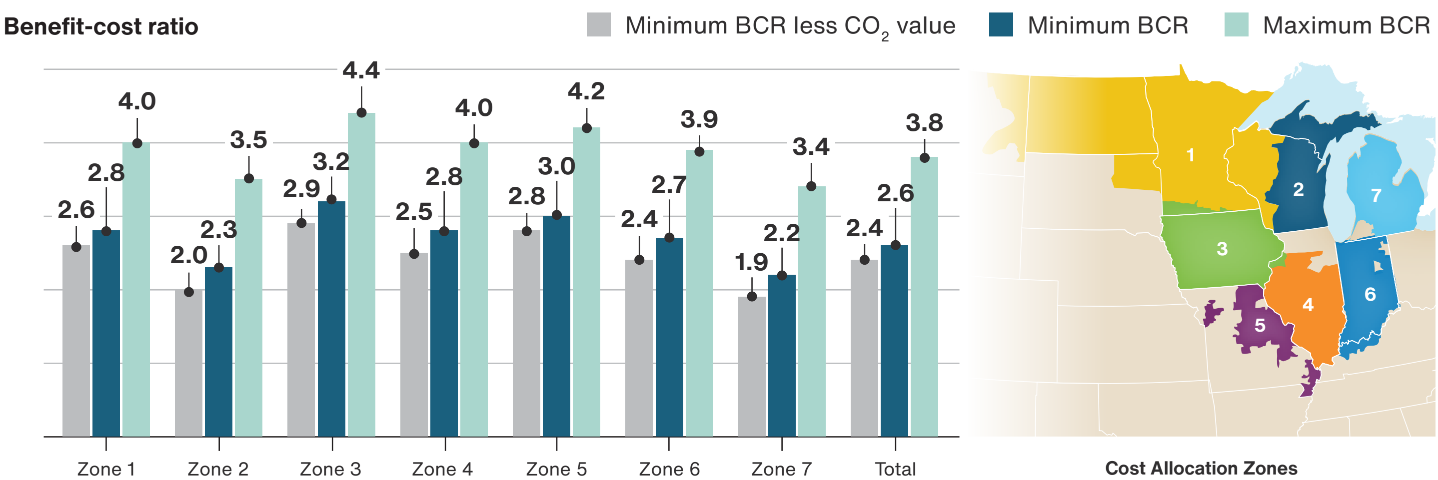
As discussed earlier, the critical test that an RP/CA effort in an ISO/RTO must meet is to show that costs are allocated to transmission users in a manner roughly commensurate with benefits. An ISO/RTO implements its RP/CA regime by way of a transmission tariff that must be approved by FERC and may be appealed to federal courts. Thus, the record of FERC's proceedings must show that FERC examined the method for allocating costs and was satisfied upon presentation of solid analytical evidence that costs are allocated roughly commensurate with benefits.

Benefits and costs need to be analyzed not just regionally but also subregionally to ensure that benefits and costs are equitably distributed. Such a subregional analysis is indispensable in proving that the benefit-cost ratios for *all* consumers are roughly commensurate, with benefits far outweighing costs even when *excluding* the more politically contentious "decarbonization" benefit. MISO includes this subregional benefit-cost calculation in its initial analysis.[63]

The analytical backup for the "selection" step of MISO's LRTP Tranche 1 (i.e., why the specific projects were chosen for inclusion in the portfolio) was a subregional benefit-cost analysis that demonstrated that costs and benefits of the portfolio are indeed roughly commensurate across all seven MISO subregional zones (**Figure 16**).[64,65] Additionally, MISO was transparent in the valuation of GHG reduction benefits on a subregional basis, so that each subregion could satisfy itself that it was receiving fair value in return for its cost share burden—even if a subregion were to place no value on GHG reduction.

Figure 16: **ESTIMATES OF SUBREGIONAL BENEFIT-COST RATIO BY COST ALLOCATION ZONE**

Even when decarbonization benefits are zeroed out, benefits are still at least 1.9x to 2.9x costs across all subregions.



Source: Adapted from **MISO's LRTP Tranche 1**, using both minimum and maximum benefit-cost ratios (BCRs).[xx] Gray bars are minimum benefit-cost ratios with CO_2 reduction benefits zeroed out. Map from **MISO Energy** (inset map).

xx The benefit-cost analysis uses a conservative assumption of benefits, with a 20-year present value and a 6.9% discount rate.

Summarizing the expert consensus and examples from transmission regions.

Before turning to what FERC proposed in the May NOPR, we conclude that experts have reached consensus on several elements of transmission planning and cost allocation that allow for proactive transmission buildout, ensuring that costs and benefits are roughly commensurate. These elements have in many cases been successfully demonstrated in practice. To summarize:

1. **Long-term planning is essential to developing an orderly, optimized, future grid topology that will be able to smoothly accommodate growing generation and deliver electricity to growing loads.** Long-term planning serves a different purpose than the ubiquitous short-term planning done by every transmission provider.

2. **Proposed plans should be composed of a portfolio of improvements that form a sensible, expanded, resilient network across the entire footprint of a transmission provider.** The portfolio should be evaluated by considering multiple benefits compared with costs in a clear and auditable benefit-cost analysis. The analysis should initially be done on a region-wide basis.

3. **When a portfolio of projects is being "selected" for regional "cost allocation," benefits and costs must be equitably allocated across each part of the transmission provider's region.** Costs must be roughly commensurate with benefits. The only reliable, robust demonstration of this fairness is to redo the BCA on a subregional basis. Critically, if future cost-share payments of a subregion are planned to be allocated by a particular algorithm—whether allocated by MWh of electricity used in a subregion (a.k.a. "postage stamp"), by the peak share in MWh of regional capacity used, or other, more complex methods—that exact algorithm must be embedded in the computation of subregional cost shares.

4. **GHG benefits are unlikely to be valued identically within subregions of large, politically complex ISO/RTOs.** Thus, to avoid intra-ISO/RTO gridlock, the BCA subregional analysis must allow stakeholders to easily re-analyze benefit-cost ratios by substituting in their own assumed values of GHG reduction. Further, to the extent that some benefits arise primarily from reducing the capital or operating costs of generation built to meet the renewable portfolio standard or other requirements of a particular state, then those benefits should be attributed solely to load-serving entities in the relevant states.

FERC's Principal Solutions in the May 2022 NOPR

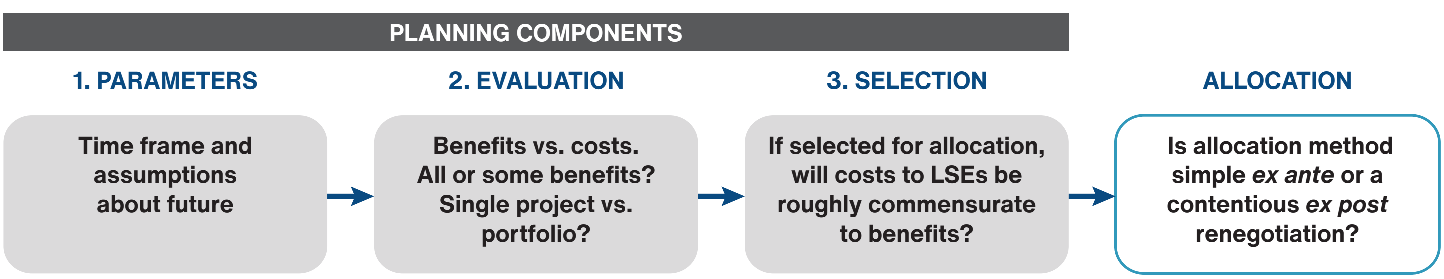
In the May 2022 NOPR, FERC presents its approaches for improving the RP/CA system and finds that a failure to do so now "may be resulting in unjust and unreasonable and unduly discriminatory and preferential Commission-jurisdictional rates to the extent that they lead to public utility transmission providers failing to identify transmission needs driven by changes in the resource mix and demand, failing to select more efficient or cost-effective transmission facilities to meet those transmission needs, and failing to allocate the costs of transmission facilities selected in the regional transmission plan."[66]

FERC stopped short of proposing the imposition of hard, prescriptive standards for all aspects of RP/CA in the proposed rule. However, FERC did express dissatisfaction with the status quo, hinted at relatively strong preferences for future best practices, and in some cases proposed to be fully prescriptive.[xxi] These best practices were based largely upon the regional experiences and expert consensus described in the preceding subsection.

Within the proposed rule, FERC methodically runs through its prescriptions and suggestions for future best practice across the sequence of RP/CA (Figure 17). Initially FERC reviews how an ISO/RTO should pursue three successive phases of regional transmission planning: (i) the planning parameters themselves, (ii) evaluation of projects or portfolios of projects, and (iii) selection of projects for regional cost allocation. FERC follows with its prescriptions and suggestions for the cost allocation mechanism.

Figure 17: **SCHEMATIC OF FERC'S CONCEPT OF THE RP/CA SEQUENCE**

Gray boxes represent the three planning phases within FERC's schematic. The outlined box represents the cost allocation phase.



xxi See "Recommendations" subsection later in this paper for details.

FERC's principal approaches aim to require public utility transmission providers to address three major areas of concern, listed below. The exact provisions by which FERC would implement these approaches follow in the next subsection.

1. Perform a sufficiently long-term assessment of transmission needs.

FERC wants ISO/RTOs and other jurisdictional transmission providers to project at least 20 years into the future in their planning and to act on that long-term assessment.[67] Thus, FERC makes the distinction between reactive transmission investments and 20-year scenario planning for a larger and more robust generation and transmission system. The 20-year plans are required to feature at least four different scenarios, with the scenarios encompassing different input data values for various factors (see #2 on next page).

Reactive transmission investments fix near-term NERC violations and obvious bottlenecks. These short-term-oriented investments in no way are sufficient to expand the grid at the magnitude and on the timescale needed to address the factors listed in the introduction, such as increasing load growth from new industry and electrification of existing industry and transportation. Nor are they in the right places to address the likely generation resources needed to provide cheap, clean, and reliable power to the future U.S. economy.

As FERC notes, even when RTOs/ISOs today carry out longer-term studies, these longer-term studies do not necessarily translate into final investment decisions and steel in the ground. For example, according to FERC's May 2022 NOPR, SPP does a 20-year study but is "prohibited from using that study as the basis for authorizing" new transmission;[68] while PJM "ostensibly considers a 15-year horizon" but does not account for changing generation mix beyond five years.[69]

A lack of long-term planning in today's RTOs/ISOs means they often are scrambling to build transmission reactively and uneconomically. Network upgrades for interconnectors in a given year's "cluster study" can take 7 to 10 years, while the generation projects can be built in 1 to 2 years.

Reactive investments in transmission result in higher costs for ratepayers.

Long-term planning also benefits from economies of scale through higher-capacity transmission investment. In the NOPR, FERC cites a report coauthored by The Brattle Group and Grid Strategies in 2021 showing that reactive investments in transmission via the interconnection process to serve offshore wind roughly doubled the costs relative to a more proactive approach ($6.4 billion to serve 15.5 GW versus $3.2 billion to serve 17 GW, respectively).[70] In other words, reactive investments in transmission result in higher costs for ratepayers.

2. Adequately account on a forward-looking basis for known determinants of transmission needs driven by changes in the resource mix and demand.

FERC demands that ISO/RTOs not ignore future trends that one can reasonably anticipate by the operation of law and based on economics—whether or not those trends are welcomed in all quarters.[71] In FERC's view, planning for factors that are "known in advance and have reasonably predictable effects … in the aggregate" is an important component of proactive planning. These factors include but are not limited to (i) the economics of new and existing generating facilities; (ii) state laws, utility integrated resource plans, and other regulatory actions; and (iii) electrification trends, energy efficiency improvements, and demand response.

In practical terms, FERC is saying that the four scenarios must include certain types of assumptions, i.e., "factors". Of course, some factors are more certain or "known" than others. FERC does not dictate the data input values for the factors: rather, FERC dictates that ISO/RTO planners must define and consider realistic data input values for these factors rather than ignoring them.[72] On the highly certain side of the ledger, "each Long-Term Scenario [must] incorporate and be consistent with federal, state, and local laws and regulations that affect the future resource mix and demand [and] . . . decarbonization and electrification"[73] as well as state-approved utility integrated resource plans. For less certain inputs, one would expect that the scenarios would model large uncertainty ranges for difficult-to-forecast data inputs like assumed natural gas prices or the rate of growth of AI and its associated data centers.

FERC groups many of these factors under the rubric of "changes in resource mix and demand," a phrase used dozens of times in the NOPR. According to FERC, failing to look into the future and plan for knowable emerging trends that appear "likely" or "very likely" is a recipe for haphazard development of the system and unnecessarily high costs to ratepayers:

"[S]ome transmission planning regions do a better job than others in accounting for changes in the resource mix and demand when performing transmission planning studies. We are concerned that the reality is that none do so in a manner that ensures the consideration of more efficient or cost-effective transmission facilities to meet transmission needs driven by changes in the resource mix and demand."

— May 2022 NOPR at paragraph #50

3. Consider the broader set of benefits and beneficiaries of transmission facilities planned to meet those transmission needs.

FERC seeks to be much clearer in specifying the broad categories of benefits that are likely to come from building according to long-term planning and taking account of "known and predictable" future facts on the ground.[74] In contrast, when FERC issued Order No. 1000, the commission neither prescribed a particular set of "benefits" or "beneficiaries," nor required consideration of any specific benefits.

Today, regional planning entities in their short-term-oriented plans often will design transmission projects to achieve a single type of benefit, such as addressing just reliability issues or just accomplishing economic savings through congestion relief. That siloing of benefits ignores the fact that high-capacity investments typically provide many types of benefits and misses the opportunity to more efficiently design transmission projects to provide a broad range of benefits.

A project could create a half dozen types of benefits that *collectively* create benefits that are 3x costs, while at the same time none of the six benefits considered *one at a time* would be large enough to justify the project. In other words, FERC recommends that economies of scope be incorporated and captured for the benefit of consumers.

The discussion of benefit types can seem theoretical and arcane, and yet doing the analysis correctly is extremely important as a pocketbook matter to electricity ratepayers. For instance, there may be serious economic waste if renewable projects have been built, and yet transmission system congestion blocks consumer access to that zero marginal cost energy. If the ratepayer benefit of getting access to that cheap electricity exceeds the cost of transporting the energy, i.e., the cost of increasing transmission capacity at the congestion point, then the transmission is a worthwhile investment. The value of the investment is the amount of savings on the cost of electricity to customers minus the extra transportation cost to reach consumers. The complication FERC seeks to address is that such benefits should not be considered in isolation: there may be several other similar economic benefits to consumers, all of which should be considered together in a sensible investment of public utility infrastructure investment.

The NOPR includes a list of 12 benefits that "may be useful," and notably does not include decarbonization/climate benefits (**Table 2**, next page).[75]

In Sen. Joe Manchin's Building American Energy Security Act of 2023, he recommended that regional tariffs fairly reflect and allocate the costs of the benefits of "improved reliability, reduced congestion, reduce power losses, greater carrying capacity, reduced operating reserve requirements, and improved access to generation."[76] There is significant overlap between the minimum set of benefits that Sen. Manchin sets forth and the benefits FERC recommends for consideration.

Table 2: **BENEFITS FERC RECOMMENDS FOR CONSIDERATION IN MAY 2022 NOPR**

1. Avoided or deferred reliability transmission projects and aging infrastructure replacement
2. Reduced congestion due to transmission outages*
3. Deferred generation capacity investments
4. Either reduced loss of load probability or reduced planning reserve margin*
5. Mitigation of extreme events and system contingencies*
6. Access to lower-cost generation*
7. Production cost savings*
8. Mitigation of weather and load uncertainty
9. Increased competition
10. Reduced transmission losses
11. Capacity cost benefits from reduced peak energy losses*
12. Increased market liquidity

Note: Benefits that Sen. Manchin recommends in his Building American Energy Security Act of 2023 are denoted with an asterisk (*). Source: Analyzed from May 2022 NOPR at paragraph #176 & Senate bill 1399

FERC's May 2022 NOPR includes specific proposed requirements for jurisdictional regional planning entities and public utility transmission providers.

FERC starts with three very broad general principles: (i) longer-term planning, (ii) accounting for "known changes in resource mix and demand," and (iii) considering a broad set of benefits. Specific implementation requirements are needed to operationalize these three principles. Those implementation requirements were organized in the applicable sequential steps in FERC's conceptual planning and cost allocation sequence and summarized in Figure 18.

Figure 18: **FERC'S PROPOSED REQUIREMENTS IN THE MAY 2022 NOPR**

PLANNING COMPONENTS			
1. PARAMETERS	**2. EVALUATION**	**3. SELECTION**	**ALLOCATION**
FERC requirements in May 2022 NOPR			
Require: 1. 20-year plan with ... 2. At least 4 plausible and diverse scenarios using ... 3. Commission identified factors re: changes in resource mix and demand and using ... 4. "Best available data," i.e., diverse and expert perspectives **#91**	Require public utility transmission providers to "identify on compliance the set of benefits they will use in LRTP," how they will reflect benefits, and how the chosen set of benefits will reasonably reflect benefits of facilities to meet needs created by changes in resource mix and demand. **#183**	Transparent selection criteria that: (i) "maximize benefits ... over time without overbuilding" and (ii) identify and evaluate facilities needed for changes in resource mix and demand. Require state input. **#241**	Must set up *ex ante* long-range transmission plan cost allocation method in open access transmission tariffs and seek to get state buy-in on it. If states want a one-off State Agreement allocation, *require* them to act in 90 days. **#302**

Notes: # Numbers refer to paragraph numbers in the NOPR. Source: Based off of Notice of Proposed Rulemaking, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 179 FERC 61,028 (May 2022).

Mitigating Political Divisions Over Who Pays for New Transmission Through Better Regional Transmission Planning

When a transmission project that is included in a regional plan is also selected for regional cost allocation (the third planning step in **Figure 18**), then a cost allocation methodology must be specified. The purpose of this methodology is to spread the annualized costs of the selected projects among ISO/RTO participants. Revenues collected in accordance with the cost allocation methodology provide the cash flow required to pay operating and maintenance expense, capital repairs, regulatory depreciation allowances, interest expense, and regulated return on equity for owners of the transmission facilities.

In FERC regulations, such as Order No. 1000 and the May 2022 NOPR, the Selection step of planning and Cost Allocation step are treated as separate, sequential processes. Selection goes first, followed by Cost Allocation. However, in practice Cost Allocation may be pre-ordained by the manner in which subregional benefit-cost analysis is conducted in Selection. Following this logical process flow may help streamline processes, reduce conflict, and bring analytical consistency to RP/CA.

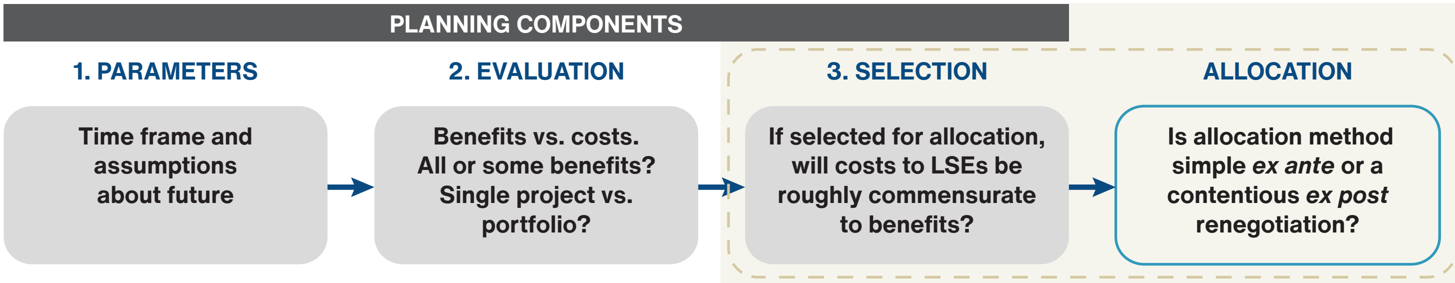
Selection component of planning overlaps and shapes allocation negotiations.

The overlap between planning and allocation (see shaded box in **Figure 19**, next page) arises because the serious negotiations of which projects should be paid for across an entire region can take place at either stage:

Selection heavy/allocation light: A comprehensive, analytically intense selection process may result in consensus on a geographically dispersed portfolio with widely similar benefit-cost ratios across subregions. It is mathematically impossible to compute the subregional benefit-cost ratio without having specified the methodology for allocation of the costs. If that consensus portfolio is selected, then allocation could be a mechanical step (like a “postage stamp” transmission adder, in which the costs for electric transmission are distributed across customers based on the identical cost allocation method previously utilized in the benefit-cost analysis.

Selection light/allocation heavy: If selection merely produces a list of good projects without a rigorous subregional analysis of the costs and benefits, then allocation is an entirely new step of arguing about who benefits and thus who should pay.

Figure 19: **FIGHTS OVER BENEFICIARIES OF TRANSMISSION PROJECTS CAN ARISE AT EITHER THE SELECTION OR ALLOCATION STAGE**



Allocation conflicts may be avoided if the preceding selection stage performs subregional benefit-cost analysis based upon an agreed *ex ante* cost allocation method.

MISO's LRTP Tranche 1 used a selection heavy/allocation light methodology, calculating the estimated benefits and the real-world costs and benefits to consumers in subregions within MISO Midwest. A pre-agreed (i.e., *ex ante*) cost allocation method was implicitly agreed upon at the selection stage. Then, costs allocated in the *ex ante* method were used in computations showing that costs and benefits were roughly commensurate across subregions. Thus, potential conflicts among states and LSEs were not deferred to a subsequent, separate allocation stage.

Benefits (the numerator) were regionally calculated and attributed to the subregion, with different methodologies for each benefit. Some benefits were calculated specifically at the subregion: (i) "Avoided fuel cost and congestion" was directly model derived at the subregional level; (ii) "avoided local transmission investment" was based upon attributes at each location; and (iii) "resource adequacy" was calculated by "zonal capacity savings." The rest of the benefits were spread across the region based on demand: "Avoided local generation cost," "avoided loss of load," and "decarbonization" benefits were allocated by load-share ratio.[xxii]

Costs (the denominator) were first calculated for all of MISO Midwest including operations and maintenance and capital recovery, then arithmetically allocated to each subregion based on each subregion's load-share-ratio. Since the MISO Midwest participants had already agreed *ex ante* that the selected portfolio would use a load-share-ratio methodology to calculate each subregion's payments (i.e., to allocate costs), the denominator of allocated costs in the theoretical benefit-cost analysis calculation matched the real-world revenue collection methodology.

xxii Load-share-ratio was calculated as the percentage of total annual electric energy (MWh) used in each of the seven subregions as a percentage of total energy usage across all seven MISO subregions.

Although most regions that have used the selection heavy/allocation light process to build transmission allocated costs through the postage-stamp methodology, the cost allocation methodology itself is less important than overall consensus of the RP/CA process.

Maintaining a proper stakeholder role for the states.

Among those who are skeptical of FERC's proposed role, some influential decision-makers have voiced concerns that a strong planning and cost allocation rule will disenfranchise states and state energy regulators. EF³'s analysis suggests the opposite is likely true: A stakeholder-driven and analytically rigorous selection process enhances states' ability to weigh in on transmission plans.

A crucial component of effective planning is securing consensus on the methodologies that will be employed during the analysis, including (i) the algorithm for allocating costs, (ii) the inputs for producing 20-year projections, and (iii) the benefits under consideration and how they will be quantified. Building stakeholder buy-in for such components increases opportunities for states to voice their priorities early in the process, thereby increasing trust in the analysis results.

The point of rigorous planning analyses is to streamline and rationalize the procedures involved, not to disenfranchise state regulators. Instead of the planning and the cost allocation being determined sequentially, in a disjointed manner, the project selection phase of planning and determination of the appropriate cost allocation algorithms should be determined simultaneously in a coordinated manner.

Indeed, the procedural benefits of such a simultaneous, coordinated approach were demonstrated in MISO's tariff filing for its LRTP Tranche 1, which used a per-MWh "postage stamp" regional cost allocation. FERC Commissioner Mark C. Christie stated his support for "this filing despite concerns over postage stamp cost allocation ... because of the strong involvement and support of the states in MISO."[77] It is not clear that the convincing support would have emerged if projects were planned first, with cost allocation fights being deferred to a later date.

Further, in many ISOs, state regulators either directly control governance (e.g., SPP's Regional State Committee) or constitute a significant portion of a formal stakeholder governance process (e.g., MISO's Advisory Committee and the Organization of MISO States). Finally, as FERC noted in the May 2022 NOPR, a single state or groups of states are free to voluntarily sponsor transmission improvements via the so-called State Agreement Process, a process that FERC has not proposed to alter.

High-Level Conclusions on the State of Play and Importance of FERC's Final Rule

EF³'s project drew three primary conclusions regarding the current barriers and the implications of FERC's reforms:

1. **Long-term regional planning of transmission is crucial for ensuring access to reliable, affordable, and clean power.** Planning for future needs over a 20-year time horizon is a crucial component of conventional annual capital budgeting for reliability and congestion. It is not about adding new bureaucracy or top-down industrial policy.

2. **Transmission benefits ratepayers in a variety of ways, which should be accounted for when evaluating portfolios of projects.** Methodologies for quantifying those benefits should be analytically rigorous and analysis results must be transparent. This is particularly important if climate benefits are considered so that stakeholders who do not prioritize climate goals can trust that the non-climate benefits still exceed costs.

3. **Decisions about who pays for transmission can be simplified by integrating the planning process (i.e., identifying, evaluating, and selecting projects) and the cost allocation process (i.e., deciding how costs should be spread).** The cornerstone of planning is a comprehensive evaluation of the costs and benefits to participants and how those are distributed. Logically, a benefit-cost analysis cannot be performed conclusively if the method of assigning costs is indeterminate. The ideal scenario is one in which stakeholders reach a consensus *before evaluating and selecting potential projects* on the algorithm for how costs will be calculated and allocated sub-regionally once a portfolio of projects is selected.

   Consensus also should be sought on the methodologies for quantifying benefits and how those benefits will be attributed. This approach is termed an *ex ante* cost allocation and enables the cost allocation process to be tightly integrated with the planning process. In an *ex post* approach, cost allocation is up for discussion *after* "planning" (including after project selection and benefit-cost analysis is completed). Such a disjointed decision-making process is bound to fuel contentious debates among stakeholders, especially state regulators. *To advocate for a coordinated ex ante process is to advocate for the early involvement of state regulators—not for the disenfranchisement of state regulators.*

Recommendations

If the United States is to dramatically accelerate and expand efforts to modernize the grid, it will require (i) close coordination among transmission planners, electricity suppliers and consumers, and government agencies; and (ii) a significant deployment of capital.

Several of the recommendations relate to the RP/CA regime suggested in FERC's May 2022 NOPR. Others relate to the federal aid that may ultimately be required to incentivize transmission organizations and state regulators to take prompt action.

The following recommendations are oriented to four stakeholder groups: FERC, regional transmission stakeholders, the Department of Energy, and Congress.

1. FERC: Recommendations to strengthen the final transmission planning and cost allocation rule

FERC's NOPR appears to align with expert consensus on best planning and cost allocation practices. However, the rule's ultimate effectiveness will hinge on the degree to which FERC "requires," "encourages," or "gives flexibility" to regions in implementing certain best practices (Figure 20, next page). As noted in the sections above, an analytically defensible planning stage reduces stakeholder protests when it comes to allocating costs. How firmly FERC comes down on each of these components will have implications for the pace of grid modernization within the United States, particularly within regions that face more significant political disagreements.

Figure 20: **MAY 2022 NOPR SUMMARY OF COMPONENTS OF PLANNING AND ALLOCATION FOR WHICH FERC PROPOSES TO "REQUIRE" ACTION VERSUS PROPOSING TO "ENCOURAGE" OR TO "GIVE FLEXIBILITY"**

FERC's May 2022 NOPR included a combination of requirements and recommendations The top row of boxes summarize many of the proposed requirements included in the NOPR. The bottom row of boxes summarize many of the practices that FERC proposed to recommend. The quotes are derived from the text of the NOPR.

PLANNING COMPONENTS			
1. PARAMETERS	**2. EVALUATION**	**3. SELECTION**	**ALLOCATION**
Propose to "require" an approach			
Require: 1. 20-year plan with ... 2. At least 4 plausible and diverse scenarios using ... 3. Commission identified factors re: changes in resource mix and demand and using ... 4. "Best available data," i.e., diverse and expert perspectives **#91**	Require public utility transmission providers to "identify on compliance the set of benefits they will use in LRTP," how they will reflect benefits, and how the chosen set of benefits will reasonably reflect benefits of facilities to meet needs created by changes in resource mix and demand. **#183**	Transparent selection criteria that: (i) "maximize benefits ... over time without overbuilding" and (ii) identify and evaluate facilities needed for changes in resource mix and demand. Require state input. **#241**	Must set up *ex ante* long-range transmission plan cost allocation method in open access transmission tariffs and seek to get state buy-in on it. If states want a one-off State Agreement allocation, *require* them to act in 90 days. **#302**
Encouraging and giving flexibility while declining to "require"			
We "do not propose to require" specific scenarios or that "explicit weightings" of scenarios be identified. **#121**	We "decline to ... prescribe any particular definition of 'benefits' or 'beneficiaries,' nor require use of any specific benefits" and recommends 12 benefits that "may be useful." **#183**	Propose providing public utility transmission providers "flexibility" to: "propose selection criteria" **#242**; "determine criteria," i.e., using BCA or aggregate net benefits, **#243**; and use least regrets or Expected Value scenario evaluation, **#251**.	"We continue to believe that the availability of an *ex ante* cost allocation method helps to ensure the development of more efficient or cost-effective regional transmissions facilities.... " **#315**

Notes: # Numbers refer to paragraph numbers in the NOPR.

Source: Based off of Notice of Proposed Rulemaking, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 179 FERC 61,028 (May 2022).

The following endorsements and recommendations are intended to help FERC maximize the effectiveness of the final rule and minimize delays due to disputes between stakeholders:

1.1 Continue to require 20-year planning horizons that include multiple scenarios and incorporate known factors, such as approved integrated resource plans and enacted laws.

In implementing this requirement, transmission planners may also benefit from expressing some explicit probability of each scenario occurring, where possible. The Australia Energy Market Operator provides a potential example: Planners develop multiple scenarios and then assign a probability of occurring to each one. Those scenarios and associated probabilities serve as the foundation for quantifying benefits based on expected values (e.g., Scenario 1 may produce $100 of benefits and have an 80% chance of occurring. The weighted benefit is therefore $80.)[78] Scenarios should represent market uncertainties, but weights can indicate to stakeholders which transmission projects are likely to be the best investments within this range. FERC appropriately points out that the values for some factors are more certain than others, with the impacts of state, federal, and local statutes regarding decarbonization/electrification and PUC-approved utility integrated resource plans being quite certain. Other factors that are less certain, like fuel costs and plans for bringing large sources of new load onto the grid, must be modeled.

1.2 Require a minimum set of benefits to be considered and require that costs and benefits be considered on a portfolio basis.

Despite fears from certain stakeholders that transmission projects may require certain states to pay for other states' policy mandates, FERC made clear in its May 2022 NOPR that it was encouraging ISOs/RTOs to consider only economic and reliability benefits for the purposes of cost allocation (**Table 2**).

However, with regard to "requiring" versus "recommending" consideration of certain benefits, FERC "decline[d] to … prescribe any particular definition of 'benefits' or 'beneficiaries,' nor require the use of any specific benefits (**Figure 20**)."[79] Failing to require consideration of some reasonable set of well-documented and widely used metrics of benefits of transmission projects appears to be a recipe for fragmented transmission planning approaches, thereby leading to litigation as individual RTO/ISOs pursue vastly different approaches. The minimum benefit set should at least include the six benefits recommended by both FERC and Sen. Manchin in his Building America's Energy Security Act of 2023.

Proper benefit measurement is a serious pocketbook matter to ratepayers. When ratepayers open their monthly bills, the total bill reflects the sum of prices paid for the raw electricity and the transportation cost of that electricity, i.e., transmission and distribution. It may be worth it to ratepayers to have the transmission portion of their bills rise if the electricity portion of the bill falls by a larger amount, resulting in a lower total bill. The technocratic methodology for weighing these factors is "benefit-cost analysis" (see 1.4 and 1.5); but if entire categories of benefits are not considered, transmission underinvestment may occur, which could amount to a "hidden tax" on ratepayers.

1.3 Require clear disclosure of the methodology behind each benefit valuation in a transparent and replicable fashion.

The NOPR properly states that transmission providers must "identify how they will calculate benefits." For packages of capital investments that may amount to many billions of dollars, the methodology and analyses need to be crystal clear and capable of being audited by outside experts for technoeconomic logic and computational accuracy. Merely identifying the nature of the methodology falls below the bar for transparency.

Clearly identifying how benefits are quantified builds trust among stakeholders that benefits were rigorously analyzed and reflect the best information available. Building that trust is crucial because it reduces potential pushback once costs are allocated.

Additionally, though FERC did not list climate benefits as one of the benefits that should be considered, if an RTO/ISO does calculate climate benefits, it should be clear about the method and magnitude of these GHG-reduction benefits. Without that, the chances of misunderstanding, suspicion, and procedural delays stemming from disagreements between stakeholders on both sides of climate issues will increase.

Based on analyses by RTO/ISOs such as SPP and MISO, the non-controversial economic, reliability, and resilience benefits of enhancing the grid appear ironclad. The climate benefits simply strengthen the investment case.

1.4 Recommend that benefit-cost analyses for project portfolios be conducted at both a regional and subregional level.

Transmission planners should report analysis results in terms of both benefit-cost ratios and absolute dollars to (i) demonstrate the balancing of net benefits against the risk of overbuilding and (ii) show that subregional cost burdens are roughly commensurate to subregional benefits.

Costs included in the benefit-cost analysis should match the methodology of the proposed *ex ante* cost allocation regime. Doing so enables the selection decisions to match the cost allocation mechanism.

1.5 Require *ex ante* cost allocation methodologies to be published in transmission tariffs in advance.

ISOs/RTOs should publish the *ex ante* method in their Open Access Transmission Tariffs (OATT). So doing would define a default methodology that transmission planners will be required to adopt if regional stakeholders cannot achieve consensus on a cost allocation methodology after developing regional transmission plans. The *ex ante* method could allow "state agreement" but clearly state the default cost allocation methodology in case of delay or deadlock. A backstop default methodology promulgated by FERC incentivizes stakeholders to engage in good-faith negotiations on methodologies.

2. Regional transmission stakeholders: Recommendations to strengthen implementation of the final rule

For regional stakeholders to agree on how costs are allocated for portfolios of transmission projects, they must agree that future projections of transmission needs are reasonable. The following recommendations address how to develop 20-year plans based on known factors. The recommendations are based on leading practices already adopted in certain regions. They are intended to enable greater coordination and collaboration among planning entities while also providing the transparency necessary to build consensus for planning and paying for project portfolios.

2.1 ISOs/RTOs should adopt strategies for coordinating the development of 20-year load projections, resource planning, and transmission planning, where feasible.

Such strategies will likely be most easily adopted in single-state ISOs/RTOs given the comparative alignment of policy priorities (relative to multi-state markets). These strategies could be modeled on recent efforts in California to improve coordination among three agencies: the California Energy Commission (responsible for load projections), California Public Utilities Commission (responsible for resource planning), and CAISO (responsible for transmission planning). Each entity has agreed to coordinate inputs and outputs for its respective projections, with a goal of "[enhancing] coordination of resource planning and transmission planning to achieve state reliability and policy needs, and coordinate the timely development of resources, resource interconnections, and the needed transmission infrastructure."[80]

2.2 Where high degrees of coordination of load projections, resource planning, and transmission planning are not practicable, ISOs/RTOs should at least publish assumptions, data, and methodologies used in developing future projections.

Multi-state markets will face substantial coordination challenges, e.g., states with different integrated resource plan timelines and regulatory requirements. Given the challenges in coordinating inputs and outputs, multi-state ISOs/RTOs should, at a minimum, publish the inputs regarding load forecasts and expected changes in the resource mix. The data, assumptions, and methodologies to inform those long-term projections should be made public and, given the highly technical nature of transmission data, presented in user-friendly formats. The Western Electricity Coordinating Council provides a positive example with regard to publishing data about load projections and resource planning.[81]

2.3 Large customers should take a more active role in the development of regional transmission tariffs.

One major driver of new transmission is new manufacturing and data center load. Data centers, the largest of which require gigawatt-scale capacity, represent a new class of large customers that have not historically engaged in ISO/RTO transmission planning and tariff-setting processes. However, data center developers are increasingly feeling the strain of a lack of transmission capacity, which is resulting in multi-year delays in connecting to the grid.[82]

Those large buyers procure their own energy either directly or in close coordination with their host utilities. They often know what type of power and the locations from which they will be procuring. Surveys of load-serving entities and large energy buyers would be an excellent source of information for transmission planners about new generation, load, and the likely transmission pathways that will be needed to connect them.

In addition to directly providing data inputs, large customers also can share their development plans with state economic development offices, which can in turn weigh in on long-term projections to ensure that their states will have sufficient power to satisfy new investments.

3. Department of Energy: Recommendations for improving long-term projections and enabling greater participation in planning processes

FERC's proposed rule would require planners to develop 20-year projections of load, generation, and transmission that are highly complex, both methodologically and computationally. DOE has technical expertise within its own offices and in the National Laboratories (e.g., through the Grid Modernization Laboratory Consortium) that could help.[xxiii] Those experts could help ISOs/RTOs craft portfolios of transmission projects that are optimized and demonstrably equitable on a sub-regional basis. Additionally, as states, tribes, and nongovernmental groups potentially play a greater role in transmission planning, DOE can allocate funds to ensure that they have the resources to do so effectively.

3.1 DOE should devise recommended methodologies and computational techniques for developing and assessing long-term planning scenarios.

As various ISOs/RTOs have sought to select optimal portfolios of projects, maximizing benefits versus costs, they have run into serious technical challenges. The ISOs/RTOs face a triple problem of figuring out what future generation is likely to be built, how that generation will be dispatched (i.e., which sources of power are turned on or off), and how the generation will be helped or harmed by a proposed transmission layout. Those three calculations are known as capacity expansion models, dispatch models, and transmission system flow models. Without being able to clearly explain why the chosen transmission portfolio is indeed optimal and how benefits are calculated and assigned to subregions, it will be difficult to reach agreement within regions on whether the investment is beneficial. Technical help for the ISOs/RTOs could be invaluable in this regard.

Such methodologies could include how to develop 20-year projections of supply, demand, and power flows as well as how to quantify the benefits included in FERC's final rule. Planning for the impacts of extreme weather events, cyberattacks, and other unexpected occurrences that may result in outages will be important, yet this data collection and extrapolation will be an administrative burden for regional planners alone. The methodologies could also include guidelines for how to consider the adoption of grid-enhancing technologies (e.g., dynamic line ratings and advanced power flow controls) as well as reconductoring existing lines.

Furthermore, enhanced standardization of data collection and analysis methodologies can create greater interoperability among regions, which would facilitate greater stakeholder participation and transparency. The recommended

xxiii The Grid Modernization Laboratory Consortium was formed in 2015 and is an effort by DOE and 13 National Laboratories to create a more adaptive and resilient electric grid.

leading practices could be used as default methodologies that ISOs/RTOs could use when planning stakeholders cannot achieve consensus on how to develop forward-looking projections.

3.2 National Laboratories should undertake rigorous systems modeling of the benefits of intra- and interregional high-voltage transmission.

While MISO's benefit-cost analyses provide a strong foundation for modeling the benefits of project portfolios, regions across the country would benefit from a rigorous, third-party analysis of the potential benefits. In particular, the DOE labs could emphasize modeling of benefits related to resilience, energy cost, and avoided generation capital expenditures, as these were areas that MISO acknowledged it needed to revisit for its LRTP Tranche 2 planning efforts.

Results and methods from DOE labs should be designed to serve as an input to benefit-cost analyses performed for regional plans. If the modeling appropriately distinguishes between decarbonization and non-decarbonization benefits, the analyses would provide analytical support for planning and cost allocation methodologies that achieve decarbonization goals while mitigating state-level fights over decarbonization benefits.

3.3 DOE should allocate capacity funding from IIJA, IRA, and other legislation to enable state agencies to engage in regional transmission planning and tariff-setting processes.

FERC's proposed rule articulates a recognition of the value of a robust role for states to participate in transmission planning processes. As noted above, a defensible selection process provides significant opportunities for states to ensure that their priorities are reflected in long-term projections and the associated suite of projects to meet future needs. Such state agencies include but are not limited to public utilities commissions, state energy offices, and economic development offices.

To enable such state entities to engage effectively, DOE could allocate remaining funds from programs like the Grid Resilience State and Tribal Formula Grant and the Transmission Siting and Economic Development Grants Program. DOE's allocation of $3 million to the National Association of State Energy Officials (NASEO) through the Wholesale Electricity Market Studies and Engagement Program provides a good example of how funds can be used for capacity building; the funding is for NASEO to inform State Energy Offices on the implications of policy decisions in regional wholesale market design.[83] In addition to financing the costs for state agencies to meaningfully participate, DOE could support efforts to translate technical analyses, and the underlying assumptions, into easily digestible formats for non-expert stakeholders.

4. Congress: Recommendations for additional federal financial assistance

Without some form of federal assistance, today's ratepayers are likely to bear significant costs as the United States seeks to build tomorrow's transmission system. The United States will be building transmission to accommodate future load growth and harden the system against increasingly catastrophic weather events—all in an environment of inflation and higher interest rates. Additional federal support could ameliorate the strain on ratepayers, whether through targeted grant programs or through more broadly applicable investment tax credits (ITC) for high-voltage regional transmission.

Regardless of how costs are ultimately allocated, a phrase regularly heard during this investigation is apt: "The ratepayer always ultimately pays." Even for transmission project portfolios that can claim high benefit-cost ratios, costs tend to start immediately, whereas benefits tend to grow over the 40- to 50-year life of a transmission line. So there is bound to be resistance to the rate shock created by the intergenerational mismatch between the timing of benefits and costs. Thus, federal financial assistance may be necessary to ease that rate shock, especially given the multi-hundred-billion-dollar magnitude of capital investment required.[xxiv]

Such support would fit in with a longstanding practice of the federal government supporting the buildout of infrastructure (especially interstate infrastructure) that provides widespread public benefits (e.g., economic development, reliability and resilience, environmental, clean energy transition, social equity).

4.1 Congress should appropriate additional funds for the Transmission Facilitation Program and Transmission Facilities Financing Program.

The expanded use of the DOE Transmission Facilitation Program and Transmission Facility Financing Program can also play an important role in facilitating long-term regional transmission planning and cost allocation. The Transmission Facilitation Program, funded through the IIJA, authorizes DOE to borrow up to $2.5 billion through three financing tools: (i) capacity contracts in which DOE buys up to 50% of a line's rated capacity; (ii) loans from DOE; and (iii) participation in public-private partnerships for regional lines.[84] Similarly, the Transmission Facilities Financing Program provides $2 billion of direct loans for transmission projects deemed to be in the national interest.

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xxiv Example: MISO represents only ~12% of overall electric consumption in the U.S. Though MISO has only completed planning for its first tranche of projects, it expects the total cost of all four tranches to cost up to $100 billion. If MISO is broadly representative of the United States, we would expect ~$800 billion to expand transmission comparably across the country. The 12% is calculated based on MISO load figures used in LRTP Tranche 1 planning spreadsheets versus NERC loads for the United States. The $100 billion cost figure is from S&P (Kate Winston, "INTERVIEW: US Midcontinent ISO to Measure More Benefits in Next Grid Portfolio," SP Global, March 14, 2023, https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/electric-power/031423-interview-us-midcontinent-iso-to-measure-more-benefits-in-next-grid-portfolio).

The ability of DOE to contract for currently unallocated transmission capacity will help ensure that adequate reserve capacity is planned for the longer term. It also will avoid cost allocation issues that might otherwise arise over uncertainties in the projections of future requirements.

While both programs are already providing funds to enable needed capacity expansion, it is impossible to escape the fact that high-voltage transmission is expensive. As **Figure 8** demonstrates, the most cost-effective alternating current transmission line is a 765 kV line, which costs about $1,320/MW-mile or $1,320,000/GW-mile. If the total $4.5 billion described above had funded 765 kV lines,[xxv] it would build only 3,400 GW-miles of lines. When that figure is compared against the 123,000 GW-miles of lines by 2040 that DOE identified in high load, high clean energy transmission needs scenario, the need for additional funds becomes clear.[85]

4.2 Congress should adopt an investment tax credit of up to 30% of the cost of high-voltage regional transmission projects (345 kV and above).

A transmission ITC would make transmission spending less daunting and risky for stakeholders, especially if it includes the "direct pay" provisions of the IRA. An ITC, which cuts capital cost by 30%, instantly boosts computed project benefit-cost ratios. The 30% ITC would apply to high-voltage regional lines that are included in regional plans (i.e., selected for cost allocation) and whose costs are allocated in a manner approved by FERC.

If FERC's final rule does not fully require many of the leading practices described in this report, eligibility for the ITC could also include a requirement that planning processes for transmission adopt any recommended practices included in the final rule.

xxv DOE announced in October 2023 that $1.3 billion of funding through the Transmission Facilitation Program had been awarded to three projects: a 500 kV line, a 345 kV double-circuit line, and a high-voltage direct current line. The last project withdrew from contract negotiations.

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