National Transmission Planning Study

Chapter 2:

Long-Term U.S. Transmission Planning Scenarios

NREL

Pacific Northwest
NATIONAL LABORATORY

GDO
GRID DEPLOYMENT OFFICE

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Context

The National Transmission Planning Study (NTP Study) is presented as a collection of six chapters and an executive summary, each of which is listed next. The NTP Study was led by the U.S. Department of Energy's Grid Deployment Office, in partnership with the National Renewable Energy Laboratory and Pacific Northwest National Laboratory.

- The **Executive Summary** describes the high-level findings from across all six chapters and next steps for how to build on the analysis.
- **Chapter 1: Introduction** provides background and context about the technical design of the study and modeling framework, introduces the scenario framework, and acknowledges those who contributed to the study.
- **Chapter 2: Long-Term U.S. Transmission Planning Scenarios (this chapter)** discusses the methods for capacity expansion and resource adequacy, key findings from the scenario analysis and economic analysis, and High Opportunity Transmission interface analysis.
- **Chapter 3: Transmission Portfolios and Operations for 2035 Scenarios** summarizes the methods for translating zonal scenarios to nodal-network-level models, network transmission plans for a subset of the scenarios, and key findings from transmission planning and production cost modeling for the contiguous United States.
- **Chapter 4: AC Power Flow Analysis for 2035 Scenarios** identifies the methods for translating from zonal and nodal production cost models to alternating current (AC) power flow models and describes contingency analysis for a subset of scenarios.
- **Chapter 5: Stress Analysis for 2035 Scenarios** outlines how the future transmission expansions perform under stress tests.
- **Chapter 6: Conclusions** describes the high-level findings and study limitations across the six chapters.

As of publication, there are three additional reports under the NTP Study umbrella that explore related topics, each of which is listed next.[1] For more information on the NTP Study, visit https://www.energy.gov/gdo/national-transmission-planning-study:

- **Interregional Renewable Energy Zones** connects the NTP Study scenarios to ground-level regulatory and financial decision making—specifically focusing on the potential of interregional renewable energy zones.

[1] In addition to these three reports, the DOE and laboratories are exploring future analyses of the challenges within the existing interregional planning landscape and potential regulatory and industry solutions.

- **Barriers and Opportunities To Realize the System Value of Interregional Transmission** examines issues that prevent existing transmission facilities from delivering maximum potential value and offers a suite of options that power system stakeholders can pursue to overcome those challenges between nonmarket or a mix of market and nonmarket areas and between market areas.

- **Western Interconnection Baseline Study** uses production cost modeling to compare a 2030 industry planning case of the Western Interconnection to a high renewables case with additional planned future transmission projects based on best available data.

List of Acronyms

AC	alternating current
AEO	Annual Energy Outlook
APC	adjusted production cost
ATB	Annual Technology Baseline
B2B	back-to-back
BECCS	bioenergy with carbon capture and storage
CAISO	California Independent System Operator
CCS	carbon capture and storage
CO_2(e)	carbon dioxide equivalent
Coal-CCS	coal + carbon capture and storage
CSP	concentrating solar power
CT	combustion turbine
CTS	CO_2 transport and storage
DAC	direct air capture
DC	direct current
dGen	Distributed Generation Market Demand model
DOE	U.S. Department of Energy
EIA	Energy Information Administration
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
EUE	expected unserved energy
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
GADS	Generating Availability Data System

GCM	global climate model
GET	grid-enhancing technologies
GHG	greenhouse gas
GW	gigawatt
H_2-CT	hydrogen combustion turbine
HOT	high opportunity transmission
HVDC	high-voltage direct current
IRA	Inflation Reduction Act
ISO	independent system operator
ISONE	ISO New England
kg	kilogram
km	kilometer
kV	kilovolt
kW	kilowatt
LBNL	Lawrence Berkeley National Laboratory
LCC	line-commutated converter
LCOE	levelized cost of energy
Lim	Limited (transmission framework)
LOLE	loss of load expectations
LOLP	loss of load probability
m	meter
MISO	Midcontinent Independent System Operator
MMT	million metric ton (CO_2)
MT	multiterminal
MW	megawatt

MWh	megawatt-hour
MW-mile	megawatt-mile
NARIS	North American Renewable Integration Study
NEMS	National Energy Modeling System
NERC	National Electric Reliability Corporation
NEUE	normalized expected unserved energy
NG-CC	natural gas combined cycle
NG-CT	natural gas combustion turbine
NPV	net present value
NREL	National Renewable Energy Laboratory
NTP Study	National Transmission Planning Study
SMR	small modular reactor
NYISO	New York Independent System Operator
P2P	point-to-point
POI	point of interconnection
ppm	parts per million
PRAS	Probabilistic Resource Adequacy Suite
PV	photovoltaic
RA	resource adequacy
ReEDS	Regional Energy Deployment System
RTO	regional transmission organization
reV	Renewable Energy Potential
RPS	renewable portfolio standard
SCRTP	South Carolina Regional Transmission Planning
SERTP	Southeastern Regional Transmission Planning

SMR	small modular reactor
SPP	Southwest Power Pool
Sup3rCC	Super-Resolution for Renewable Energy Resource Data with Climate Change Impacts
TES	thermal energy storage
TW	terawatt
TWh	terawatt-hour
TW-mile	terawatt-mile
VRE	variable renewable energy
VSC	voltage source converter
W	watt
WECC	Western Electricity Coordinating Council

Chapter 2 Overview

Accelerating transmission expansion can offer benefits for the contiguous U.S. electricity system under a wide range of future uncertainties. The potential role and impacts of transmission expansion are evaluated in this chapter of the National Transmission Planning Study (NTP Study). The chapter presents the methods, assumptions, and findings from the zonal analysis of long-term U.S. transmission planning scenarios. The analysis compares a “Limited” transmission framework, which constrains transmission expansion, against three accelerated transmission frameworks: Alternating Current (AC), Point-to-Point (P2P), and Multiterminal (MT) (Figure I). Because future transmission expansion can vary depending on external conditions, the analysis compared scenarios across all four transmission frameworks under a range of policy, demand growth, and other conditions. The analysis includes an assessment of 96 total scenarios.

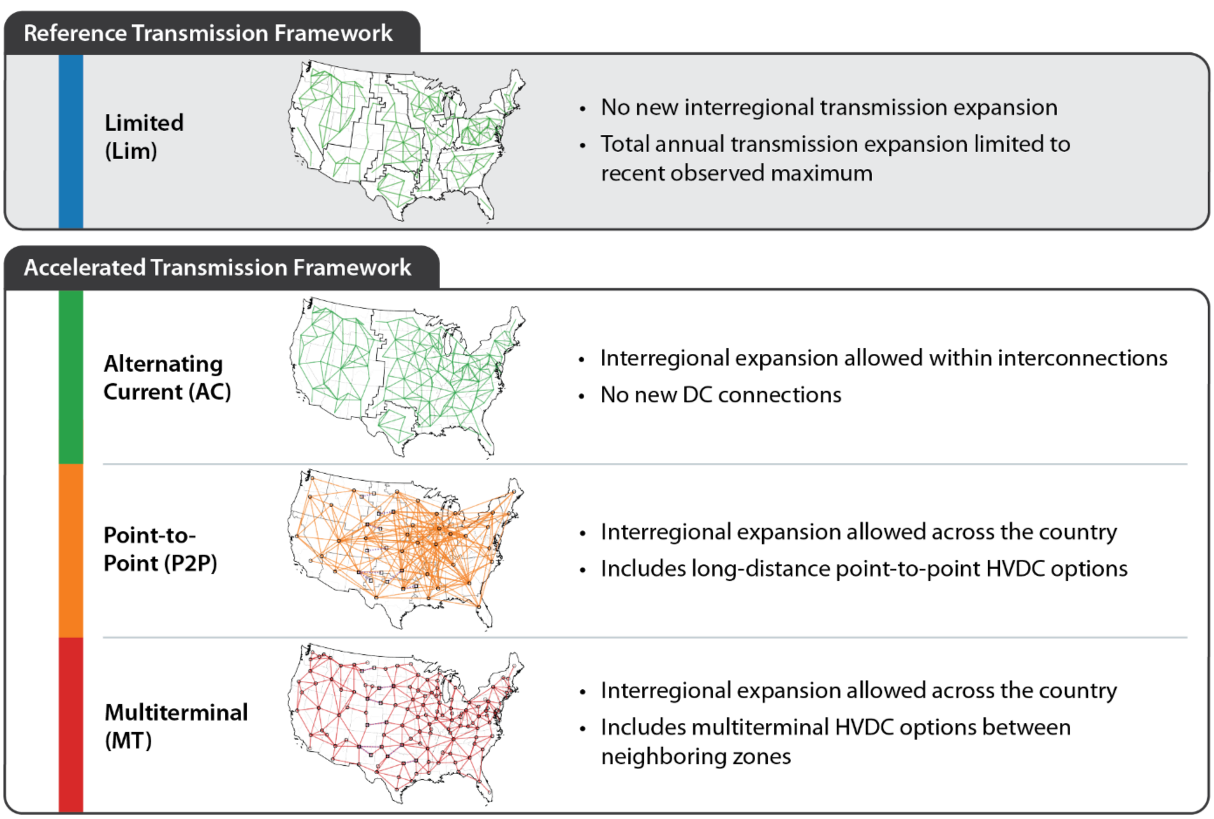

Figure I. NTP Study transmission frameworks

The scenario analysis first compares the different transmission frameworks without any new policies. Benefits from large-scale transmission expansion include billions of metric tons of avoided CO_2 emissions under current policies. Specifically, expanding transmission beyond historical rates—as occurs in the accelerated (AC, MT, P2P) frameworks—reduces power system CO_2 emissions by 10–11 billion metric tons (43%–48%) through 2050, relative to the Limited framework using “Mid” demand growth assumptions (2.0%/year). The emissions reductions from accelerated transmission expansion are driven by increased wind and solar deployment. Even with expanded transmission, current policies are insufficient to fully eliminate power sector emissions, especially in futures with high demand growth.

The transmission frameworks were then evaluated considering nine decarbonization and demand futures (Figure II). Under these decarbonization conditions, benefits of large-scale transmission expansion include hundreds of billions of dollars in system cost savings. Specifically, in the central decarbonization scenarios—which achieve 90% emissions reductions by 2035 (100% by 2045) and assume Mid demand growth—accelerated transmission expansion leads to national electricity system cost savings through 2050 of $270–$490 billion. Constraining transmission growth results in more nuclear generation, hydrogen, and carbon capture capacity to achieve emissions reduction targets, leading to higher costs. The cost savings from accelerated transmission reveal that the costs of new transmission are outweighed by reductions in capital, operating, and fuel expenditures for generation and storage. Approximately $1.60 to $1.80 is saved for every dollar spent on transmission in the AC, P2P, and MT transmission frameworks under our central decarbonization assumptions.

Demand growth

Emissions constraint			
	Low demand **Current policies**	**Mid demand** **Current policies**	**High demand** **Current policies**
	Low demand **90 by 2035,** **100 by 2045**	**Mid demand** **90 by 2035,** **100 by 2045**	**High demand** **90 by 2035,** **100 by 2045**
	Low demand **100 by 2035**	**Mid demand** **100 by 2035**	**High demand** **100 by 2035**

Figure II. Core demand and emissions assumptions.

The central demand and emissions assumption is highlighted in yellow.

The study finds rapid and significant growth in new transmission occurs in scenarios that achieve deep emissions reductions. Specifically, in the central decarbonization scenarios, the contiguous U.S. transmission system expands to 2.4–3.5 times the size of the 2020 system by 2050. This transmission occurs at all scales—including local, regional, and interregional—and for all regions of the country. Expansion of new long-distance transmission is concentrated in the central part of the country to enable increased access to wind and solar. Leveraging high-voltage direct current (HVDC) technologies, including advanced multiterminal converters, results in the greatest benefits. HVDC network solutions will require additional strengthening of AC networks. Similarly, the largest benefits of transmission are realized when interregional transmission is most substantial, including building across the interconnection seams. When U.S. electricity emissions are limited, future transfer capacities for many regions exceed 30% of the region's peak demand and total aggregate U.S. interregional transfer capacity increases to 2.6–4.6 times the 2020 capacity by 2050.

The analysis includes scenarios with faster rates of decarbonization (100% by 2035) and higher demand growth (2.7%/year) than assumed in the central scenario. These scenarios find that electrification drives greater deployment of transmission and generation capacity. The benefits of transmission expansion scale with the level of electricity demand and rate of decarbonization. Under "High" demand growth, estimated savings from accelerated transmission expansion range from $710 billion to $970 billion, and coupling High demand with more rapid decarbonization can yield more than $1 trillion in electricity system cost savings.

Accelerated transmission deployment consistently reduces system cost across a spectrum of sensitivities with the greatest reductions found when hydrogen, carbon capture, and/or advanced nuclear are unavailable. The economic net benefits of transmission outweigh the incremental transmission costs in all scenarios, leading to a benefit-to-cost ratio of at least 1.5 across all sensitivity cases and exceeding 2.0 in many cases.

All 96 modeled future grid scenarios in the study—including those with approximately 90% of annual generation from variable resources—meet or exceed current industry resource adequacy standards. A variety of technologies supports resource adequacy. Interregional transmission—over spatial scales larger than weather systems—enables the sharing of variable renewables during days with limited local resource availability. In scenarios that allow coordination, transmission flows bidirectionally across many regional interfaces to support resource adequacy. With coordination, system costs through 2050 are lowered by $170 billion to $380 billion. Significant amounts of interregional transmission are built primarily to serve resource adequacy needs.

Lastly, the many scenarios and sensitivity cases in this chapter are also used to inform High Opportunity Transmission (HOT) interfaces that offer a starting point for further study. Spatial patterns in transmission expansion are similar across many sensitivity cases, and the HOT interfaces are defined as transmission expansion through 2035 between subregions that occurs in 75% of the sensitivity cases. Transmission projects that align with these HOT interfaces could be starting points for the grid expansion envisioned in this study.

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1 Introduction

The transmission grid has always played a critical role in the highly interconnected U.S. power system by delivering electricity from generators to load centers and supporting overall system reliability. As the U.S. generation mix undergoes major changes driven by clean energy policies and ambitions for deep decarbonization, the role of transmission is changing. Looking forward, how transmission might evolve to meet transformative generation changes while maintaining reliability is an open question. This chapter presents an analysis designed to answer this question for the contiguous U.S. electricity system.

Recent national decarbonization studies have collectively demonstrated the significant changes required in the U.S. transmission system to dramatically lower national greenhouse gas emissions. These studies include Denholm et al. (2022), the Net Zero America study (Larson et al. 2021), the Solar Futures Study (DOE 2021), Brown and Botterud (2021), and the North American Renewable Integration Study (Brinkman et al. 2021). Chapter 1 of this report and the Transmission Needs Study (DOE 2023a) summarize this body of work.

In addition to national-scale studies, regional planners also regularly conduct studies to examine future transmission expansion needs. These studies can lead to transmission expansion in utility or system plans and, ultimately, transmission procurement. Examples include California's long-term transmission plan (CAISO 2023a) and the Midcontinent Independent System Operator (MISO) Long Range Transmission Planning initiative (MISO 2022). Interregional transmission planning is more limited, but recent examples such as the MISO-Southwest Power Pool (SPP) Joint Targeted Interconnection Queue (SPP and MISO 2022) and the U.S. Department of Energy (DOE) Atlantic Offshore Wind Transmission Study (Brinkman et al. 2024) demonstrate interest in broader multiregional planning efforts.

The analysis presented in this chapter is motivated by the growing awareness of transmission expansion needs and applies a scenario approach like many of the above-referenced national-scale studies. However, this chapter focuses on transmission using a scenario framework, described in Section 2, designed to isolate the impacts of transmission on the U.S. electricity system. The scenario analysis presented in this chapter uses long-term capacity expansion and resource adequacy (RA) modeling to provide insights into the following questions:

- What is the role of transmission in decarbonizing the U.S. energy system?
- What are the economic trade-offs between different transmission futures and corresponding resource mixes?
- What mechanisms help ensure future low-carbon grids are resource adequate, and how does transmission support these mechanisms?
- Which interregional transmission expansions are commonly developed across a range of scenarios?

The focus of the National Transmission Planning Study (NTP Study) on identifying transmission that will provide broad-scale benefits to electricity customers and inform interregional and national strategies to accelerate decarbonization while maintaining system reliability includes examining transformative changes to the entire portfolio and considering a full suite of generation, storage, and transmission options. The capacity expansion modeling used here enables such evaluations and the examination of a range of future conditions, of which there are several important uncertainties—especially for achieving a zero-emissions grid. Incorporating RA tools in the analysis helps develop plausible resource mixes that can be more thoroughly examined for reliability. The scenarios presented in this chapter serve as the starting points for the more detailed power system modeling presented in subsequent chapters to begin to examine other aspects of reliability.

Section 2 describes the grid models used and the scenario design and assumptions, and the appendices provide additional explanation and detail. Results are presented in Section 3, with each subsection presenting a different group of scenarios. Section 3.1 presents results from scenarios that include enacted policies only. Section 3.2 examines how results change under different emissions targets and demand assumptions but uses default assumptions for other model parameters. Section 3.3 focuses on scenarios under central decarbonization assumptions and includes results across the full set of sensitivity cases. Conclusions are discussed in Section 4.

2 Methodology

Two National Renewable Energy Laboratory (NREL) models, the Regional Energy Deployment System (ReEDS)[2] and Probabilistic Resource Adequacy Suite (PRAS),[3] are used for the capacity expansion and RA analysis presented in this chapter. Both open-source models operate with zonal resolution covering the contiguous United States as their geographic scope (Figure 1a). This section briefly describes these two models and additional approaches used for the scenario analysis presented in this chapter.[4]

2.1 Model Descriptions

Regional Energy Deployment System (ReEDS). The ReEDS model is used to create future power system scenarios. ReEDS chooses from a large set of new generation, storage, and transmission options to identify the systemwide least-cost portfolio that meets future demand, grid reliability, and policy requirements. For this study, the model finds the optimal resource mix in 5-year steps between 2020 and 2050. The model applies a centralized planning approach but subdivides the contiguous United States into 134 zones to represent the grid network and to reflect region-specific generation, demand, and policies. For investment and dispatch modeling, each solve year includes 33 representative days with 4-hour resolution from weather year 2012 (P. R. Brown, Cole, and Mai forthcoming). The ReEDS documentation (Ho et al. forthcoming) and 2023 Standard Scenarios report (Gagnon et al. 2024) describe the model in greater detail. Appendix A details newer features of ReEDS used for this study.

Probabilistic Resource Adequacy Suite (PRAS). The PRAS model assesses the resource adequacy[5] of the scenarios generated by ReEDS. PRAS measures adequacy by performing Monte Carlo analysis of thermal generator outages[6] and hourly dispatch over 7 weather years (2007–2013) of renewable energy availability. Reliability metrics estimated by PRAS include loss of load probability (LOLP), loss of load expectation (LOLE), and expected unserved energy (EUE). This study uses the normalized expected unserved energy (NEUE)—EUE divided by total annual load—for the contiguous United States as the principal resource adequacy metric. PRAS has the same geographic scope and 134-zone resolution as ReEDS; however, thermal generator capacity within each zone is further subdivided into individual representative units to appropriately simulate generator outages.

[2] https://www.nrel.gov/analysis/reeds/
[3] https://www.nrel.gov/analysis/pras.html
[4] This chapter presents the methods, assumptions, and findings associated with the “round 2” scenarios of the NTP Study. Chapter 1 describes the primary differences between this round 2 capacity expansion analysis and the earlier round 1 analysis.
[5] The North American Electric Reliability Corporation (NERC) defines resource adequacy as “[t]he ability of the electric system to supply the aggregate electric power and energy requirements of electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components” (NERC 2022).
[6] Transmission outages are not modeled; however, interregional transfer capacity assumed in PRAS and ReEDS partially accounts for transmission contingencies. See Appendix A for further detail.

Integrated ReEDS-PRAS modeling. The optimal resource mix identified by ReEDS accounts for RA by including up to 30 “stress periods” in addition to the 33 representative days. The stress periods are the days with the highest EUE, among 7 weather years, as estimated by PRAS. The stress periods can change over time or between scenarios; for example, with increasing electrification, stress periods can include winter days with high heating demand as well as hot summer days with air conditioning demand. ReEDS iteratively augments the portfolio to meet a user-specified reliability target. This study uses a national RA target of 10 parts per million (ppm) NEUE. Although NEUE-based system planning has yet to become widespread, systems that do use NEUE-based planning tend to use NEUE targets in the range of 10 to 30 ppm (Alberta Electricity system Operator 2017; Electric Power Research Institute 2024; NERC 2024). Appendix B provides further detail on the combined use of ReEDS and PRAS.

Other models. Multiple upstream models are used to develop key inputs for ReEDS. The Distributed Generation Market Demand (dGen) model (Sigrin et al. 2016) simulates the customer adoption of rooftop photovoltaic (PV) systems. Distributed PV projections from dGen are exogenously input to ReEDS. The Renewable Energy Potential (reV) model (Lopez et al. 2024) provides the wind and solar resource potential used in ReEDS as well as the hourly renewable generation profiles used by all the models. Additional key datasets are described in Appendix A.

Transmission value analysis. This chapter’s findings include results from an economic analysis of the scenarios, which assesses the relative costs between scenarios, the sources of those cost differences, and regional differences in costs and savings. This transmission value analysis primarily relies on a disaggregation of all the expenditures tracked in ReEDS—including generation, storage, and transmission capital and operating costs—through 2050 with additional adjustments to appropriately assess regional cost distributions.

2.2 Region and Transmission Terminology

The zonal ReEDS modeling represents the contiguous U.S. grid using 134 zones as shown in Figure 1a. These zones serve as the building blocks for larger regions for reporting purposes and to reflect policies and other factors. The zones conform to boundaries for the 48 states within the contiguous United States, which enables the representation of state clean energy policies.[7] This study focuses on 11 transmission “planning regions” that approximate Federal Energy Regulatory Commission (FERC) Order No. 1000 regions[8] and the Electric Reliability Council of Texas (ERCOT). The planning regions comprise aggregate model zones as shown in Figure 1c. These planning regions include the seven independent system operators (ISOs) and regional transmission organizations (RTOs) in the United States. The 11 planning regions are

[7] The District of Columbia (D.C.) is combined with the zone that represents Maryland.
[8] The South Carolina Regional Transmission Planning (SCRTP) region from FERC Order No. 1000 is included in the Southeastern Regional Transmission Planning (SERTP) in the analysis. Nonenrolled members of FERC planning regions and regions that are not part of FERC Order No. 1000 are *included* within the geographic boundaries shown in the figure.

fundamental to the scenario design (as discussed next). Because there is significant variation in geographic size between the 11 planning regions, the larger planning regions are further subdivided into "planning subregions" (Figure 1b).[9] Results are typically reported at the planning region and subregion levels and for the contiguous United States as a whole. Figure 1d also shows the three asynchronous interconnections in the contiguous United States.[10]

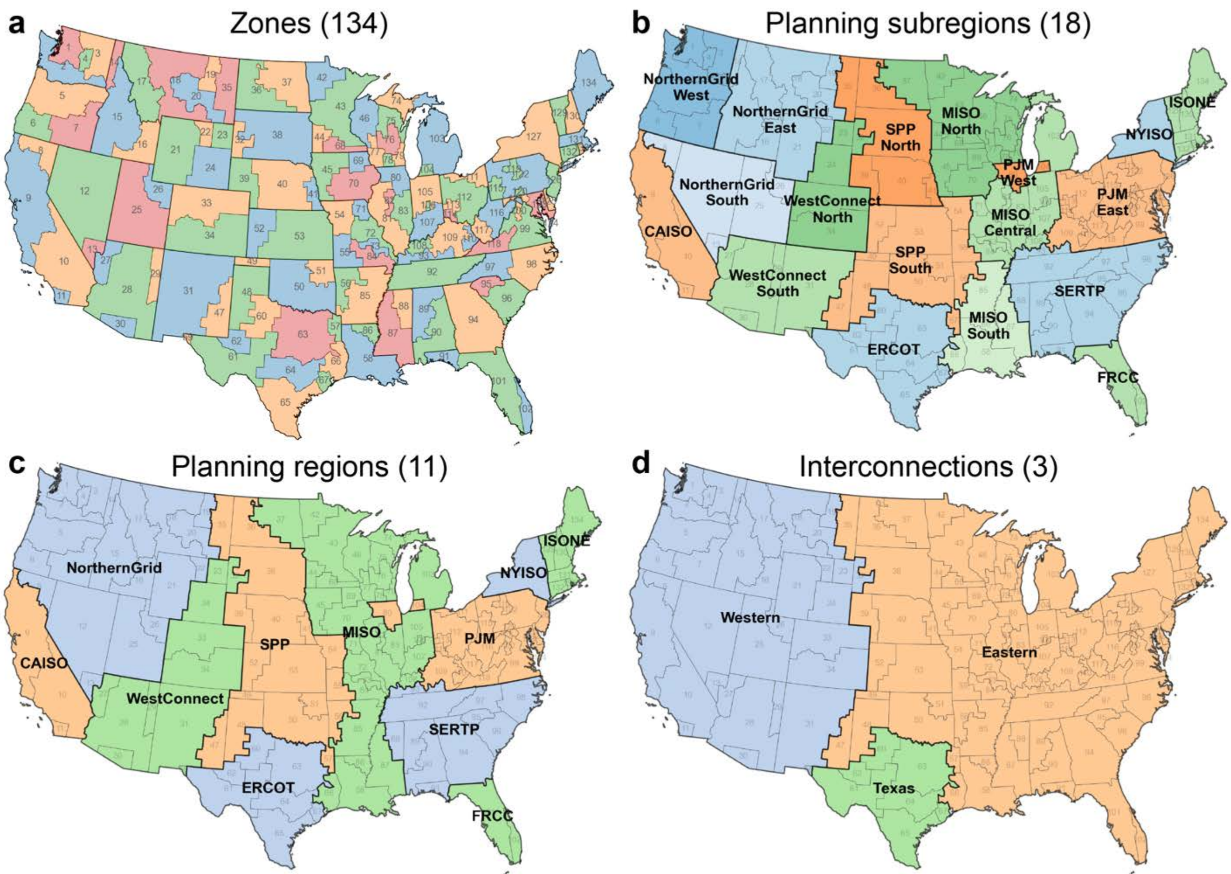

Figure 1. Hierarchy of regions used in the ReEDS model

Regional acronyms: California Independent System Operator (CAISO), Southwest Power Pool (SPP), Midcontinent Independent System Operator (MISO), New York Independent System Operator (NYISO), Independent System Operator of New England (ISONE), Southeastern Regional Transmission Planning (SERTP), Florida Reliability Coordinating Council (FRCC).

The geographic regions include Tribal lands within the boundaries shown in Figure 1. The modeling does not specifically exclude or encourage new transmission or generation projects on Tribal lands, but the study team recognizes that energy planning

[9] There are 18 total planning "subregions" in the contiguous United States. NorthernGrid and MISO are both subdivided into three subregions each. WestConnect, SPP, and PJM are subdivided into two subregions each.

[10] The Western and Eastern interconnections also include electrically connected regions in Canada and Mexico. Given the focus on the contiguous U.S. system, international imports and exports are exogenously specified in the modeling. The North American Renewable Integration Study (NARIS) (Brinkman et al. 2021) evaluated cross-border transmission expansion.

on such locations would require engagement, consultation, and participation from the relevant Tribes. Chapter 1 highlights Tribal engagement during the NTP Study.

Different categories and types of transmission, which are partly defined based on the regions, are modeled and reported:

- **Local** transmission refers to estimated transmission expansion *within* each of the 134 model zones. It includes transmission spur lines from wind and solar power plants to a point of interconnection (POI) and network upgrades or reinforcements needed beyond the POI to interconnect these plants to the grid. Local transmission capacity is modeled and tracked only for land-based wind, offshore wind, solar PV, and concentrating solar power (CSP). The costs to interconnect other resources are assumed to be $100/kilowatt (kW) (approximating recent interconnection costs for gas turbines (Seel et al. 2023)) whereas interconnection costs for wind and solar vary widely by location and can be several hundreds of dollars per kW (Lopez et al. 2024).[11]
- **Interzonal** transmission refers to the transfer capacity between any pair of zones from the 134 model zones. Unlike local transmission, interzonal transmission is not specific to any resource but instead serves systemwide needs. Existing transfer capacity between model zones is estimated based on a method summarized in Appendix A and presented by Brown et al. (2023). Expansion of interzonal transmission is a model decision because ReEDS co-optimizes generation, storage, and transmission simultaneously. Interzonal transmission can be based on high-voltage alternating current (AC) or direct current (DC) technology assumptions as specified in the scenarios. DC technology options modeled include back-to-back (B2B) ties across interconnections, line-commutated converters (LCC), and voltage source converters (VSC). In this report, interzonal transmission is presented by transmission technology (AC, B2B, LCC, VSC) or further subdivided as follows:
    - **Regional** transmission refers to interzonal transmission between zones within the same planning region.
    - **Interregional** transmission refers to the transfer capacity between two different planning regions.
    - **Seam-crossing** transmission refers to the subset of interregional transmission that crosses interconnection boundaries.

Unless otherwise noted, “transmission” capacity reported includes all types of transmission, including local and interzonal transmission, and is typically measured in terawatt-miles (TW-miles) to account for both the capacity and the distances of all transmission. *Interregional* transmission capacity is typically reported in gigawatts (GW) or terawatts (TW) to measure the transfer capacity across regional interfaces irrespective of the lengths of the transmission lines that cross these boundaries.

[11] Real 2022 dollars are used unless otherwise noted.

Transmission cost assumptions for local and interzonal transmission of various types are described in Appendix A.

2.3 Scenario Design

The scenario framework includes 96 scenarios modeled using the ReEDS and PRAS models.[12] These scenarios span a range of demand, policy, and technology conditions to assess the varied role and extent of transmission in the future U.S. energy system. The 36 “core” scenarios are all combinations of four transmission frameworks (Figure 2), three demand growth projections, and three levels of power sector emissions constraints (Figure 3). The remaining 60 scenarios studied include 15 different sensitivity cases, each modeled for the four transmission frameworks under the central demand growth and emissions constraint assumptions. No judgment is made about the relative likelihood of different scenarios or assumptions; instead, the scenarios are used to evaluate the role of transmission under a wide range of possible future conditions.

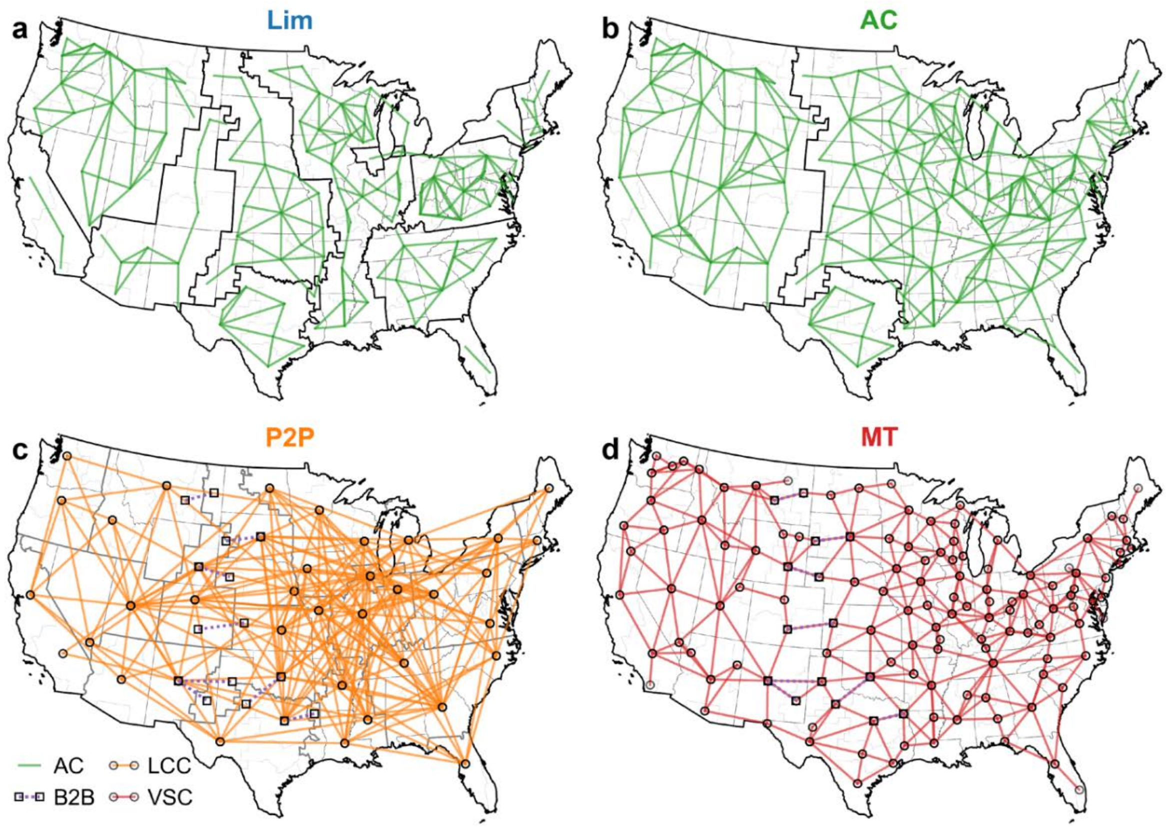

Figure 2. Expandable transmission interfaces in the four transmission frameworks considered in this study

Maps show interfaces where transmission capacity can be expanded under the corresponding transmission framework. AC interfaces in the AC framework are also allowed to be expanded in the point-to-point (P2P) and multiterminal (MT) frameworks but are not shown for clarity. Existing transmission interfaces are not shown. Allowable transmission types are AC (green), high-voltage direct current (HVDC) with line-commutated converters (LCC, orange), HVDC with voltage source converters (VSC, red), and back-to-back interties (B2B, purple dashed).

[12] Additional scenarios beyond these 96 are also modeled to address particular aspects as noted in the results.

Emissions constraint ↕ / Demand growth ↔			
	Low demand Current policies	Mid demand Current policies	High demand Current policies
	Low demand 90 by 2035, 100 by 2045	Mid demand 90 by 2035, 100 by 2045	High demand 90 by 2035, 100 by 2045
	Low demand 100 by 2035	Mid demand 100 by 2035	High demand 100 by 2035

Figure 3. Core demand and emissions assumptions

The central demand and emissions assumption is highlighted in yellow.

2.3.1 Transmission frameworks

The primary comparisons are between transmission frameworks (Figure 2), which enable the impacts of transmission on the overall evolution of the U.S. power system to be isolated. The four transmission frameworks differ by the types of constraints on and options for new transmission expansions. Differences in the constraints on transmission expansion represent factors other than cost that can affect transmission capacity growth (e.g. siting and permitting, interregional coordination). These transmission frameworks span a wide range of possibilities, from a “Limited” framework with severe constraints on new expansion to highly coordinated planning frameworks that incorporate the latest high-voltage direct current (HVDC) technology options.

- **Limited (Lim):** The Limited framework serves as the reference or counterfactual to the other transmission frameworks. In this framework, no new *interregional* transmission is allowed, reflecting a lack of coordination between planning regions or other barriers that prevent expansions of interregional transfer capacities.[13] Within each planning region, *regional* transmission expansion is allowed but is assumed to use AC technology. The exception is for existing HVDC connections, which are allowed to expand using new DC lines. In addition to excluding new interregional transmission, an annual limit on new transmission expansion is also applied in this framework, based on the maximum annual transmission builds since 2014 (Wiser et al. 2023). Using fixed carrying capacity assumptions for different voltages (see Appendix A), this limit is 1.83 TW-miles/year and is applied to total transmission—of all types—installed nationally across the contiguous United States. Because this limit applies to local as well as regional transmission expansion, it creates a de facto constraint on the growth rate for new wind and solar.
- **Alternating Current (AC):** The AC framework does not include an annual limit to the amount of transmission expansion. It also allows for interregional transmission expansion except for seam-crossing transmission. All interzonal transmission is assumed to use AC technology and associated costs and losses

[13] This framework may be more restrictive than current practices given interregional transmission planning processes already underway.

except for existing HVDC connections, where DC expansion is allowed. Transmission cost assumptions are presented in Appendix A.

- **Point-to-Point (P2P):** The P2P framework allows for the same expansions as in the AC framework but also allows new HVDC opportunities. These include B2B DC ties across interconnections and 195 candidate P2P connections, including those between nonadjacent regions. These P2P candidates, shown in Figure 2, are identified based on locations with the highest wind resource and/or demand in each planning subregion. Only connections within 1,000 miles are considered. For these P2P candidates, HVDC line costs, which are lower than AC line costs,[14] and converter costs are based on LCC technologies.[15] Converters and lines are required to be identically sized.
- **Multiterminal (MT):** The MT framework allows for the same expansions as the AC framework but also includes options for HVDC expansion between adjacent zones. HVDC line costs are assumed to be the same as those for the P2P framework, but converter costs are slightly higher and based on VSC technology. However, unlike the P2P framework, converters and lines are independently sized by ReEDS in the MT framework. This approach enables more flexibility for a meshed network design, but this framework does not allow the 195 long-distance candidates from the P2P framework.[16]

The analysis primarily compares results from the AC, P2P, and MT frameworks, which are referred to as *accelerated* transmission frameworks because the rate of transmission expansions can exceed recent maximum annual builds, to the Limited framework. Both the P2P and MT frameworks extend the transmission options allowed in the AC framework by emphasizing HVDC technologies but represent distinct HVDC network designs.

2.3.2 Policy assumptions and emissions targets

How the role of transmission might change depending on decarbonization levels is a key question of the analysis. The baseline level of grid decarbonization is affected by enacted policies, which are included in all 96 scenarios.[17] These electric sector policies include state laws and federal clean energy tax incentives. State policies modeled include 28 renewable portfolio standards (RPSs)[18] and 15 clean energy standards. The assumptions for these factors are based on data from Barbose et al. (2023) and from stakeholder feedback received during the study. Technology-specific requirements from state RPS policies are also modeled, including offshore wind targets. The assumed mandated offshore wind deployment targets are based on analysis from DOE's

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[14] HVDC line losses are also lower than AC losses, but additional losses are modeled for the AC-to-DC-to-AC conversions.
[15] Converter costs under the P2P and MT frameworks differ based on the assumed technologies used (LCC and VSC, respectively); however, the modeling is not prescriptive about which technology might be best suited.
[16] Connections between two nonadjacent zones would require multiple separate segments under the MT framework whereas P2P might have a direct connection with a shorter distance and lower costs.
[17] Existing policies as of June 2023 are modeled.
[18] Hawaii is not modeled. Washington, D.C. also has an RPS, and this policy is considered within the zone that includes both Maryland and D.C.

Offshore Wind Market Report: 2023 edition (Musial et al. 2023).[19] Electric sector greenhouse gas (GHG) emissions policies for the Regional Greenhouse Gas Initiative states and California are also included. State retirement policies for existing plants and bans for new nuclear or fossil capacity are also included (Gagnon et al. 2024). County and other local siting ordinances, tracked from Lopez et al. (2023), for new wind and solar development are also modeled as part of the wind and solar resource potential inputs to the model (Lopez et al. 2024).

Federal policies modeled include many of the clean energy tax incentive provisions from the Inflation Reduction Act (IRA) of 2022 and the Bipartisan Infrastructure Law of 2021.[20] The IRA tax incentives include production and investment tax credits for new wind, solar, other renewable energy, energy storage, and carbon capture and storage (CCS).[21] Steinberg et al. (2023) document the assumptions used to represent these policies in ReEDS. The tax credit level and period when the IRA incentives are available vary by technology. The wind, solar, and storage tax credits expire depending on the annual U.S. power sector emissions; the IRA specifies these credits expire when annual emissions are below 25% of 2022 levels or in 2032, whichever is later. For some scenarios, the IRA tax credits phase out as written, and for others the wind, solar, and storage tax credits are assumed to expire in 2032 to facilitate the comparison of scenarios without confounding changes in tax policy conditions.

In addition to the enacted policies, decarbonization scenarios are modeled using national emissions constraints (Figure 3). The following three power sector emissions trajectories are used in the scenarios:

- **Current policies:** Current policies include enacted state and federal policies as of June 2023 as described previously. No other policies, such as a national constraint on emissions, are included.
- **90% by 2035:** In addition to enacted policies, a national annual limit on power sector carbon dioxide equivalent (CO_2(e)) emissions is applied in the 90% by 2035 scenarios.[22] This limit is set to achieve 90% reductions from 2005 levels by

[19] These assumptions result in 47 GW of prescribed offshore wind capacity by the mid-2030s, all of which are off the Atlantic coast except for 4.7 GW of offshore wind by 2035 in the Pacific based on the Base case from the California Public Utilities Commission (2022).
[20] Only major legislation and mandates are included in the modeling. Nonbinding and voluntary targets from states, corporations, or utilities are not included. The modeling is not comprehensive of all policies, especially those applied at the local level. The assumptions also represent a snapshot in time of the policy environment, which can change rapidly.
[21] Tax credits for hydrogen technologies are not included in this analysis because guidance for these tax incentives was not released at the time this analysis was completed. Clean Air Act section 111 standards are not included because they were also not finalized when this analysis was completed.
[22] The limit applies to direct CO_2 emissions from fossil-fuel-fired power plants as well as from upstream CO_2(e) methane emissions. The modeling assumes a 100-year global warming potential of 34 to estimate the CO_2(e) of methane and assume a leakage rate of 2.3% in 2021 (Alvarez et al. 2018), declining by 30% to 1.6% in 2030 and thereafter (Denholm et al. 2022).

2035 and 100% reductions by 2045.[23] The limit declines linearly from 2025 to 2035, declines linearly between 2035 and 2045, and stays at 0 million metric tons (MMT) CO_2 after 2045. Figure 4 shows the emissions trajectory used in these scenarios along with historical emissions for context. This trajectory is used under the central decarbonization assumptions.

- **100% by 2035:** The emissions limit in the 100% by 2035 scenario is applied similarly to the 90% by 2035 scenario, except the trajectory achieves zero emissions by 2035 and stays at that level through 2050 (Figure 4). The 2035 zero emissions limit is consistent with the U.S. carbon-free electricity by 2035 target (Executive Office of the President 2021).

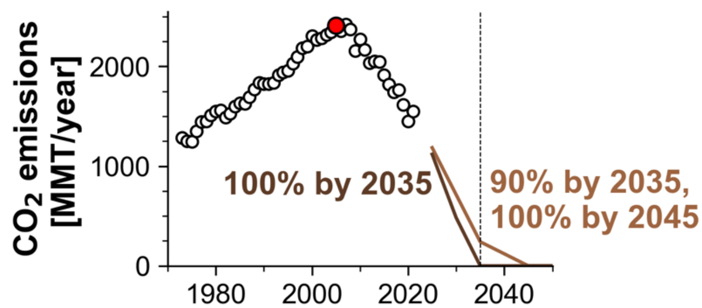

Figure 4. Emissions constraints under grid decarbonization scenarios

Historical emissions are from EIA (2024b). Power sector emissions in 2005 are 2,411 MMT CO_2.

2.3.3 Electricity demand growth assumptions

Historical and future load growth are impacted by macroeconomic factors, energy efficiency, and electrification or potential new sources of demand (e.g., growth in data centers). To account for significant uncertainties with these factors, three demand scenarios spanning a wide range of growth possibilities are modeled (Figure 5). The compound annual growth rate for demand in these scenarios varies from 0.9%/year to 2.7%/year (2021 to 2050) and is largely correlated with the rate of electrification and corresponding reductions in direct emissions from end-use sectors such as transportation, buildings, and industry.[24] For context, U.S. load grew by 1.1%/year during the prior 30 years (1992 to 2021) but experienced much flatter growth during the past 15 years (0.1%/year) and higher growth (2.8%/year) over the longer (1962–2021) period. The three demand trajectories are based on demand-side modeling from Evolved Energy Research and calibrated using 2021 state-level demand data from EIA (2021):

- **Low-Demand:** The Low-Demand trajectory is from the “Baseline” case from the 2022 Annual Decarbonization Pathway (Haley et al. 2022), which largely follows

[23] Noncaptured CO_2 from fossil with CCS plants count against these emissions limits; however, these emissions can be offset by bioenergy with CCS (BECCS) options or other negative emissions technologies when allowed. Direct air capture (DAC) is not included in the core scenarios but is included in a sensitivity. Emissions from fossil plants without CCS are not allowed to be offset in the definition used here.
[24] Appendix A shows the estimated end-use emissions by sector in the three demand cases.

EIA's Annual Energy Outlook (AEO) 2022 Reference case (EIA 2022). It does not include electric vehicle tax credits and other electrification or clean energy tax incentives from the IRA. Annual demand grows by 0.9%/year from 2021 to 2050 under Low-Demand.

- **Mid-Demand:** The Mid-Demand trajectory is more representative of enacted policies because it includes the electrification incentives for various end-use sectors from the IRA. This case features "moderate" electrification assumptions as used in Haley et al. (2023).[25] Load growth is 2.0%/year. This trajectory is used as the central decarbonization assumption.
- **High-Demand:** The High-Demand trajectory includes substantial electrification consistent with achieving net zero energy emissions by 2050. This assumption is from the "Central" case from the 2022 Annual Decarbonization Pathway (Haley et al. 2022). Because of high electrification, demand grows by 2.7%/year, resulting in 2050 annual demand that approximately doubles national demand from 2021.

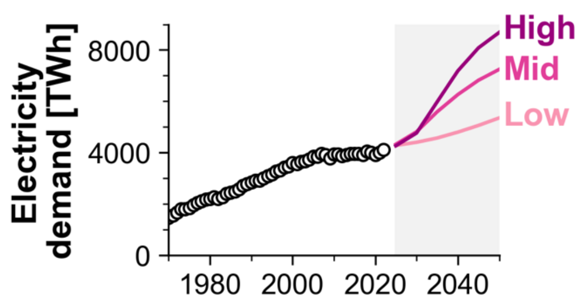

Figure 5. Annual demand assumptions for the contiguous United States

Historical demand shown is electricity sales to ultimate customers from EIA (2024b).

Hourly demand profiles also change over time and vary across the Low-, Mid-, and High-Demand trajectories. Electrification of buildings under Mid- and High-Demand results in winter demand peaks that grow faster than summer peaks in many regions. Figure 6 shows these changes in the demand profile over time for the contiguous United States, but the shifts toward winter peaks are even starker in colder regions. Demand data used in the models are at hourly resolution for each state; all zones within a state share the same normalized load profile, but state annual demand is partitioned based on historical distributions of load.

[25] Specifically, the "Current Policy" scenario from Haley et al. (2023) is used for the Mid-Demand case.

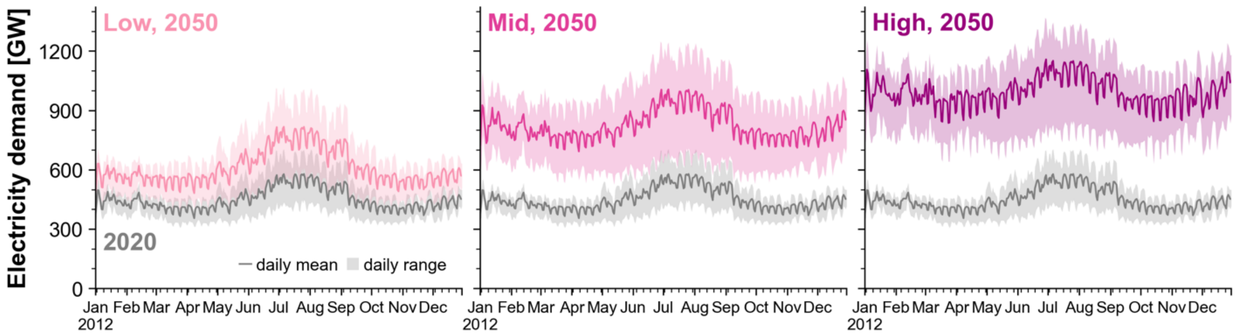

Figure 6. Daily demand profiles for the contiguous United States in 2020 and 2050

The demand profiles shown use 2012 weather.

2.3.4 Other default assumptions

Aside from the differences in transmission framework, power sector emissions target, and demand outlined previously, all other assumptions are the same across the 36 core scenarios. These default assumptions include technology cost and performance assumptions from the NREL Annual Technology Baseline (ATB) 2023 Moderate case (National Renewable Energy Laboratory 2023) (see Appendix C) and fuel costs from the EIA AEO 2023 Reference case (EIA 2023a). Distributed rooftop PV adoption is also held constant between scenarios and is assumed to reach 130 GW_{AC} by 2035 and 170 GW_{AC} by 2050 (Gagnon et al. 2024), compared with 48 GW_{AC} of small scale PV in 2023 (EIA 2024a).

For CO_2 transport and storage costs, a uniform $15/metric ton cost for all regions is applied, without limits on the amount of CO_2 that could be injected.[26] Hydrogen storage is modeled explicitly to ensure sufficient storage capacity for the daily balancing of H_2 production, storage, and use.[27] However, all hydrogen must be used in the same zone in which it is produced; transport of H_2 between zones is not allowed in any scenario. Further work is needed to compare trade-offs between electricity transmission and transport of other energy carriers. Appendix A details the hydrogen representation used for this study.

Unless otherwise noted, all other assumptions are from the NREL Standard Scenarios 2023 Mid-case (Gagnon et al. 2024).

2.3.5 Sensitivity cases

In addition to the core scenarios, 15 sensitivity cases are modeled under all four transmission frameworks. These 60 sensitivity cases all assume 90% by 2035 power sector emissions trajectory and Mid-Demand growth—which represent the central decarbonization conditions. Table 1 summarizes the sensitivity cases.

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[26] Brown et al. (forthcoming) presents the endogenous model representation for CO_2 transport and storage. A test scenario using this capability resulted in similar findings to those presented here. Scenarios with greater CCS deployment could have different implications.

[27] No hydrogen demand for industry, transportation, or other uses outside for electricity generation are considered; all reported hydrogen production and use in the scenarios are for grid applications.

Table 1. Sensitivity Cases

Name	Description
PV+Battery Low Cost	PV and battery technologies follow the ATB 2023 Advanced cost and performance projections (National Renewable Energy Laboratory 2023).
Wind Low Cost	Land-based and offshore wind technologies follow the ATB 2023 Advanced cost and performance projections (National Renewable Energy Laboratory 2023).
Electrolyzer Low Cost	Electrolyzer costs are based on DOE (2023b). Electrolyzer costs in the core scenarios decline linearly from $1,750/kW in 2022 to $550/kW in 2030 and stay constant thereafter; costs in this sensitivity case undergo further linear declines from $550/kW in 2030 to $157/kW in 2050.
+Nuclear SMR +DAC	Assumes nuclear small modular reactor (SMR) and direct air capture (DAC) technologies are commercially available. Nuclear SMR costs are from the ATB 2023 Moderate case (National Renewable Energy Laboratory 2023) and DAC costs are from Brown et al. (forthcoming). DAC can be used to offset emissions from fossil CCS plants.
No Interface Expansion Limit	In all other scenarios, a 30-GW limit is imposed for total interzonal capacity (combined existing and new, AC and DC). This sensitivity case eliminates this maximum level.[28]
Transmission 2x Cost	Interzonal $/megawatt-mile (MW-mile) transmission costs are doubled for all interfaces for both AC and DC capacity. Default transmission costs are presented in Appendix A.
No RA Sharing	Requires each of the 18 subregions to meet adequacy needs locally; no trades are allowed across subregion boundaries during the modeled stress periods. This represents a lack of interregional coordination for resource adequacy. (See Appendix A for details.)
Siting Limited	Uses more-constrained siting supply curves for land-based wind and utility PV, based on “Limited Access” from Lopez et al. (2024), as opposed to the default “Reference Access.” This reduces the technical potential from 11.1 TW to 5.9 TW for wind and from 112 TW to 58 TW for PV. Reductions are not uniform by region.
CTS High Cost	CO_2 transport and storage (CTS) costs are assumed to be $36/metric ton instead of $15/metric ton under default assumptions. These assumptions are based on Grant et al. (2019) as discussed in Brown et al. (forthcoming).
Many Challenges	Uses higher technology costs for PV, wind, battery, CCS, and nuclear technologies based on projections from the ATB 2023 Conservative case (National Renewable Energy Laboratory 2023). Uses the more-constrained supply curves for wind and utility PV as in the “Siting Limited” sensitivity.
No H_2	Hydrogen electrolyzers and combustion turbines (CTs) are not available.

[28] The 30-GW limit is based on iterations with the preliminary nodal modeling in the study that indicated expanding beyond this level would be technically challenging.

Name	Description
No CCS	CCS technologies are not available.
No H_2 or CCS	Hydrogen and CCS technologies are not available.
No H_2 or New Nuclear	Hydrogen technologies and new nuclear deployment are not available.
Climate	Modifies demand, solar, and wind profiles to be based on future weather conditions developed from a global climate model and downscaled (Buster et al. 2023). Hydropower capacity during stress periods is assumed to be reduced by 20% in 2050. Summer capacities for thermal generators and transmission for 2050 are derated by 15% and 5%, respectively. Capacity derates ramp linearly from 0% in 2025 to these values. (See Appendix A for details.)

2.4 Modeling and Analysis Limitations

The analysis examines the future role of transmission using sophisticated power sector tools; however, there are limitations of the analysis especially given the transformative and wide-ranging scenarios examined and the very large and complex nature of the U.S. electricity system. Here, several important limitations of the modeling in this chapter are discussed.

Behavioral, institutional, and regulatory aspects are not fully reflected in the models. The models apply a centralized economic optimization approach rather than the more-complex decision-making reality in today's energy system. Diverse decision makers can have different objectives and considerations that would lead to different planning and operational outcomes than those found by the models. Select sensitivity cases partially address interregional coordination and uncertainties with siting and permitting renewable energy projects. Additional analysis is needed to study these issues in greater depth and to quantify their impacts.

Energy planning for transmission and other electricity resources is complicated by the limited foresight of future policy, market, and technology conditions and the long-lived nature of these assets. These uncertainties are partially captured through the wide range of scenarios modeled; however, the capacity expansion modeling used here does not reflect the limited foresight conditions of reality. Specifically, ReEDS finds the optimal resource mix sequentially for each 5-year increment from 2020 to 2050 with no foresight on how policies, technologies, or fuel prices might change. This would give a suboptimal solution relative to an intertemporally optimized model that sees the full 30-year period altogether. On the other hand, ReEDS assumes the construction, permitting, and other planning and approval efforts are successfully executed prior to the modeled installation dates. This perfect "construction" foresight approach does not account for manufacturing, supply chain, and workforce needs that may impact the rate of technology deployment. The modeling does not directly reflect all these complexities—either inside or outside of the electricity sector—that may be required to realize these scenarios. Similarly, perfect foresight is assumed in the dispatch decisions from ReEDS and PRAS.

Comprehensively evaluating full economywide and broader societal cost and benefits of the scenarios is outside the scope of this analysis. The analysis compares differences in direct power system expenditures, nationally and by region, to evaluate the economic viability of transmission under a range of future conditions. This includes all expenditures for the bulk power system but does not include distribution system expenditures or an economic evaluation of the demand-side sectors under the various electrification futures modeled. Moreover, the cost, benefits, and impacts of GHG emissions levels or other air pollution are out of scope. Finally, distributional impacts to different demographic groups and stakeholders are also not evaluated in this analysis.

Although the analysis includes many scenarios, not all possibilities are analyzed. Importantly, the modeling does not explicitly include all technology options. For example, the cost assumptions for new transmission are based on estimates for greenfield projects; transmission upgrades or grid-enhancing technologies (GETs) that could yield expanded transfer capacity at potentially lower costs are not directly modeled in ReEDS. Some of the expanded transmission capacities reported can be realized through these other options. ReEDS modeling also includes diurnal and seasonal (hydrogen) energy storage (see Appendix A) but does not explicitly include other long-duration storage options. The scenarios also include increases in rooftop PV capacity, but other distributed energy resources, demand response, and demand-side flexibility options are not modeled.[29] The omission of demand flexibility—including managed electric vehicle charging—could be particularly important with respect to the RA results presented.

This chapter's analysis includes RA modeling but does not fully consider other elements of reliability, such as operational reliability and resilience. Resource adequacy is considered through the integrated ReEDS-PRAS modeling, which includes generator outages and variability, weather-driven variability, a wide range of long-term demand projections, and approximations for transmission contingencies through interregional capacity derates. However, generator fuel supply limits, correlated outages, and transmission outages are not modeled. Appendix B discusses these and other limitations of the RA analysis. Subsequent chapters supplement the analysis with other elements of reliability not considered by the capacity expansion models used in this chapter.

Further study is needed to examine these important aspects.

[29] Sensitivity cases with higher distributed PV levels were modeled in earlier stages of the study but had less impact on the scenario outcomes than many other sensitivity cases presented here.

3 Results

3.1 Current Policies

This section reports findings from scenarios assuming current policies (as of June 2023) only. Scenarios with additional constraints on national carbon emissions are presented in subsequent sections.

3.1.1 Benefits from large-scale transmission expansion include billions of metric tons of avoided CO_2 emissions

Accelerating transmission expansion beyond the historical rate specified in the Limited framework has a strong effect on electricity sector CO_2 emissions under current policies (Figure 7). Under mid demand, modeled electricity sector emissions in 2035 are roughly 810 MMT CO_2 per year in the Limited framework and 440–460 MMT/year in the three accelerated transmission frameworks (AC, P2P, MT), a 44%–45% reduction. Annual emissions reductions from accelerated transmission are even larger in 2050, roughly 56%–61%. On a cumulative (2025–2050) basis, the accelerated frameworks avoid 10.2–11.2 billion metric tons of CO_2 (43%–48%) relative to the Limited framework.

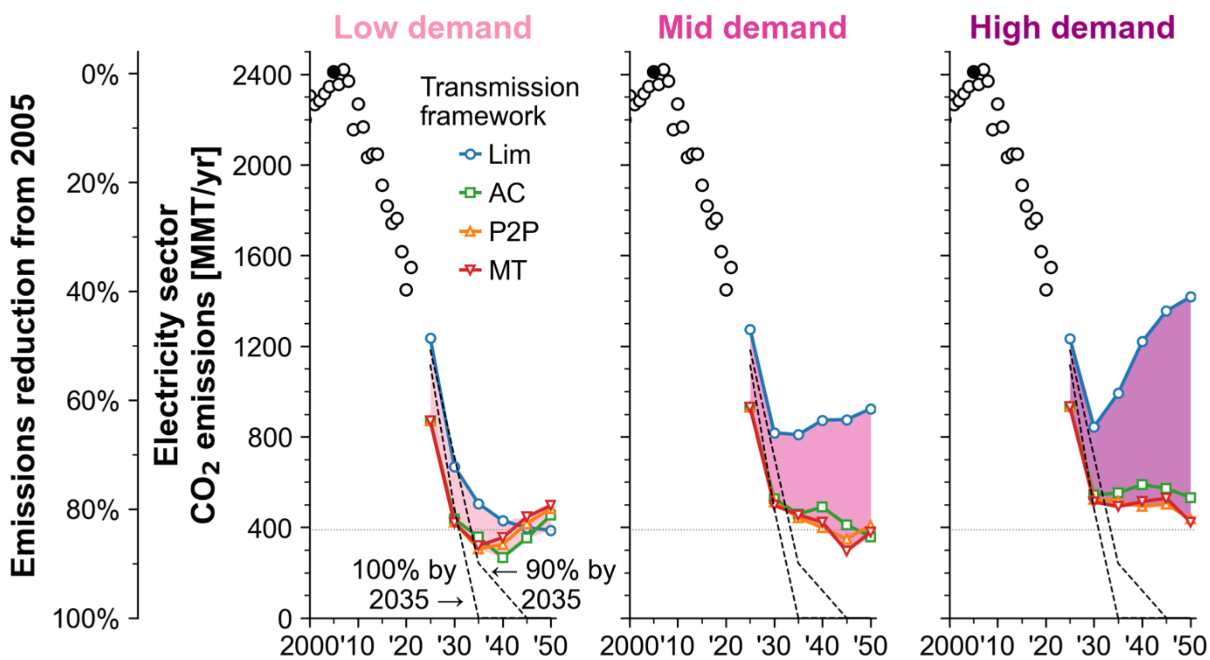


Figure 7. Electricity sector CO_2 emissions under current policies across demand assumptions

The 90% by 2035/100% by 2045 and 100% by 2035 emissions trajectories are indicated by black dashed lines. The IRA tax credit phaseout threshold (75% CO_2 emissions reduction compared to 2022) is indicated by gray dotted lines. Historical emissions (black circles) are from EIA (EIA 2024b). The shaded area represents the change in emissions from the Limited transmission framework.

Notably, even without new policies, each of the three accelerated transmission frameworks is on track for CO_2 emissions reductions on par with both the 90% by 2035 and 100% by 2035 emissions trajectories through 2030 (Figure 7). The Limited transmission framework, by contrast, reaches at most a 66% emissions reduction relative to 2005. As discussed below, under current policies, emissions reductions stall or even reverse after 2030 as a result of the phaseout of the IRA tax credits (with low demand) or accelerated demand growth in the decades after 2030 (with mid or high demand).

Modeled emissions also depend strongly on the assumed demand growth. In the Limited transmission framework, 2050 CO_2 emissions with High-Demand are 3.7 times the emissions under Low-Demand (Figure 7a,c). The annual emissions reductions from accelerated transmission under high demand are 44%–50% in 2035 (440–500 MMT CO_2/year) and 62%–70% in 2050 (890–990 MMT CO_2/year), resulting in cumulative CO_2 savings of 14.3–15.7 billion metric tons (48%–52%). Conversely, cumulative CO_2 savings are more modest with Low-Demand (3.1–3.8 billion metric tons, or 21%–26%). This comparison applies only to electricity sector emissions; different demand trajectories have very different direct end-use emissions (Appendix A).

The emissions trends are complicated by the phaseout conditions for the IRA tax credits; as written, the credits start phasing out in 2032 or the year in which electricity sector emissions drop 75% below their 2022 level, whichever is later. The three accelerated transmission frameworks trigger the tax credit phaseout under Low-Demand growth, leading to increasing emissions between 2040 and 2050, whereas the Limited transmission framework never reaches 75% emissions reductions and thus never triggers the phaseout.

Emissions reductions from accelerated transmission expansion are driven by increased wind and solar deployment

Wind and solar deployment are significantly accelerated in the AC, P2P, and MT transmission frameworks compared to the Limited framework (Figure 8) because the annual deployment limits on local interconnection capacity (required for new wind and solar) and long-distance transmission are removed. Under Mid-Demand Current Policies assumptions, wind capacity expands to 5.8 times its 2020 capacity by 2050 in the Limited framework and 8.6–8.8 times in the accelerated transmission frameworks; solar capacity expands 10 times in the Limited framework and 14–17 times in the accelerated transmission frameworks. In 2035, wind capacity is 34%–42% higher in the accelerated transmission frameworks than in the Limited framework; solar capacity is 32%–59% higher. The share of total 2050 generation from variable renewable energy (VRE)—wind and solar combined—expands to 55% in the Limited framework and 77%–79% in the three accelerated transmission frameworks.

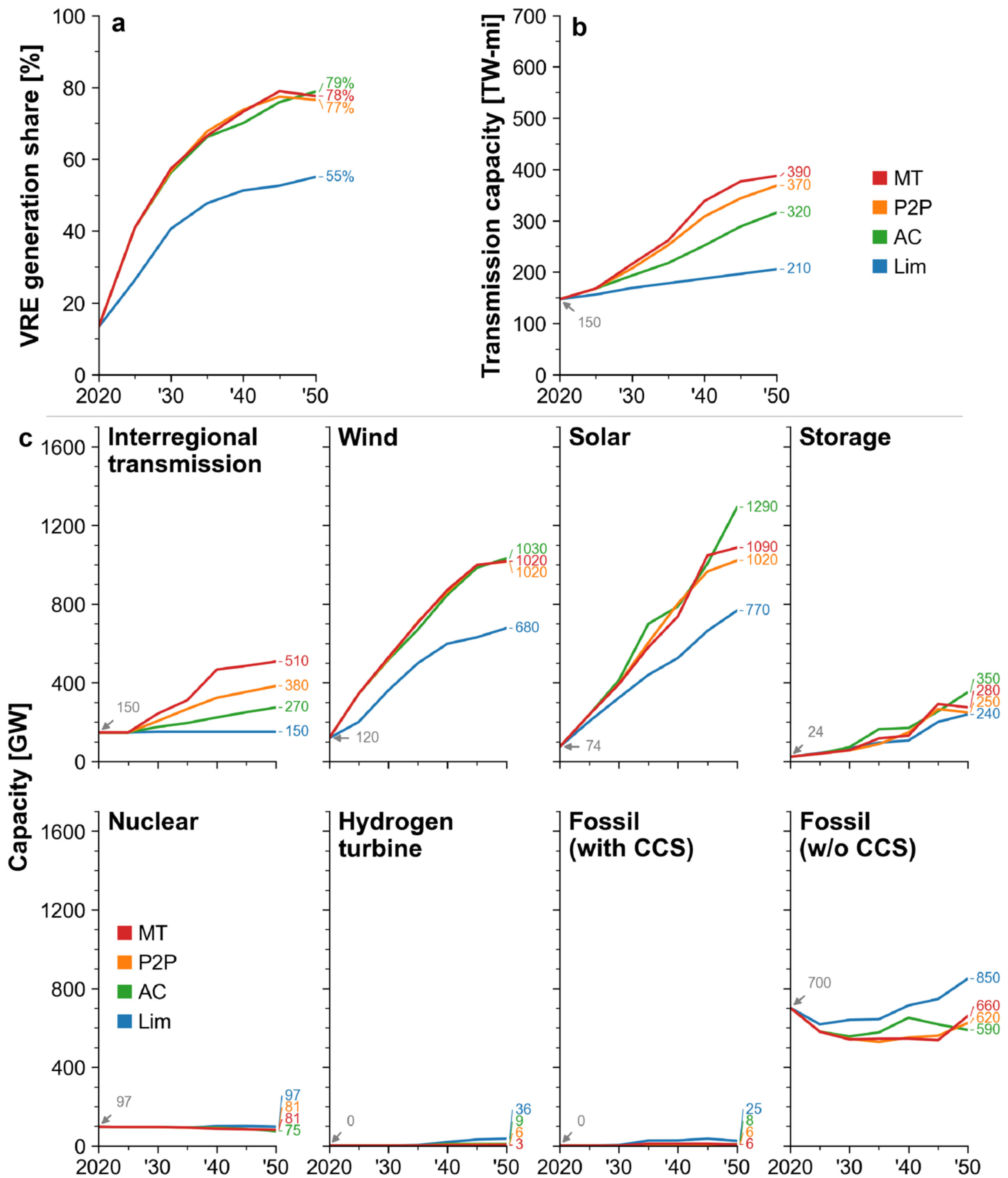


Figure 8. Trajectories of VRE share (a), transmission capacity (b), and nameplate capacity (c) under mid demand and current policies

"Total" transmission capacity (Figure 8b), including both local interconnection capacity (spur lines and network reinforcement associated with new wind and solar additions) within the 134 ReEDS model zones and long-distance interzonal transmission capacity between the model zones, is reported in units of TW-miles. Compared to the estimated

2020 capacity of ~150 TW-miles, total transmission capacity in 2050 grows to 1.4 times in the Limited framework, 2.1 times in the AC framework, 2.5 times in the P2P framework, and 2.6 times in the MT framework. “Interregional” transmission (Figure 8c) is shown in GW and represents the total bidirectional transfer capability between the 11 planning regions (Figure 1c). Compared to the estimated 2020 transfer capacity of ~150 GW, interregional transmission capacity does not expand in the Limited framework (as required by the scenario design, discussed in Section 2.3.1) and grows to 1.9 times in AC, 2.6 times in P2P, and 3.5 times in MT.

Even with expanded transmission, current policies are insufficient to fully eliminate power sector emissions, especially in futures with high demand growth

Though modeled power sector emissions are in line with the 90% by 2035 and 100% by 2035 trajectories through 2030, they diverge over the subsequent two decades (Figure 7). Fossil capacity is higher in 2050 than in 2020 in the Limited framework because the total transmission deployment limit of ~1.83 TW-miles/year substantially constrains the deployment of competing wind and solar technologies. Even in the accelerated transmission frameworks, fossil capacity in the Mid-Demand scenarios never drops more than 25% below its 2020 capacity under current policies (Figure 8), and electricity sector CO_2 emissions never drop more than 81% below their 2022 level (Figure 7).

3.2 Demand Growth and Emissions Constraints

This section presents findings from the core scenarios (Figure 3), including those that span multiple demand growth trajectories and different constraints on national power sector emissions. Unless otherwise noted, in the following results the IRA tax credits are assumed to expire in 2032 to facilitate more direct comparisons using the same policy conditions.

3.2.1 Rapid and significant growth in new transmission capacity occurs in scenarios that achieve deep emissions reductions

Applying an emissions requirement significantly expands the deployment of transmission in frameworks that allow transmission expansion (Figure 9). Under Mid-Demand assumptions, 2050 transmission capacity is 37%–68% higher with a 90% by 2035 emissions requirement than with Current Policies for each of the three accelerated transmission expansion frameworks. The Limited transmission framework is bound by the 1.83 TW-miles/year deployment constraint in nearly all scenarios.[30] Because the 90% by 2035 and 100% by 2035 scenarios achieve 100% emissions reductions by 2045 at the latest, the 2050 transmission capacity does not change significantly between these scenarios when demand scenario and transmission framework are held constant. However, near-term transmission deployment is accelerated in the 100% by 2035 scenarios: 2035 transmission capacity is 15%–34% higher in the 100% by 2035 scenarios than in the 90% by 2035 scenarios for the three accelerated transmission frameworks.

[30] With low demand and current policies, the annual transmission growth constraint of the Limited framework is not reached.

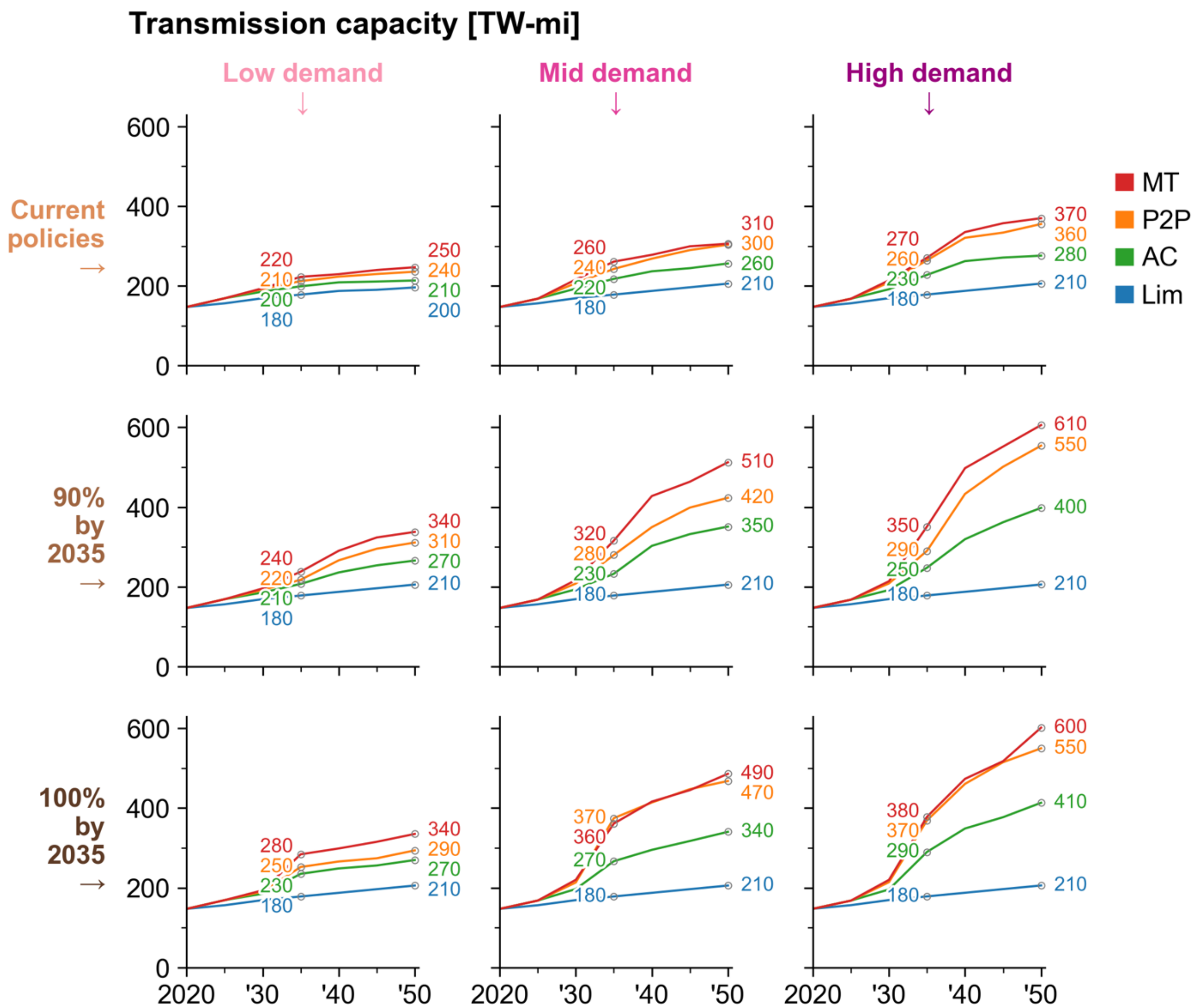


Figure 9. Total transmission capacity as a function of demand (columns) and emissions constraint (rows)

Total transmission capacity includes local interconnection capacity (spur lines and network reinforcement) within the 134 ReEDS zones and long-distance interzonal transmission capacity between ReEDS zones. For this plot, the IRA tax credit is assumed to begin phasing out in 2032 for all scenarios (including for current policies), irrespective of emissions, to facilitate comparison across scenarios while keeping policy assumptions constant.

For context, Figure 10 shows the average transmission growth rate between 2025 and 2050 compared to different benchmarks for historical transmission deployment. In the central Mid-Demand 90% by 2035 scenario, annual transmission additions in the three accelerated transmission frameworks range from 2.0 to 3.8 times the maximum annual rate of transmission deployment observed in the United States since 2009. Alternatively, comparing the modeled rate of annual transmission deployment to individual HVDC links that have been built in the past in a collection of countries shows this rate of growth equates to the addition of 2.7–5.1 “Pacific-DC Intertie” links (built in the United States in 1970 and upgraded since) per year (Pierre et al. 2019), 0.8–1.5 “Rio Madeira” links (completed in Brazil in 2014) per year (Hitachi 2022), or one “Changji-Guquan” link (completed in China in 2019) every 1.8–3.3 years (Hitachi 2020).

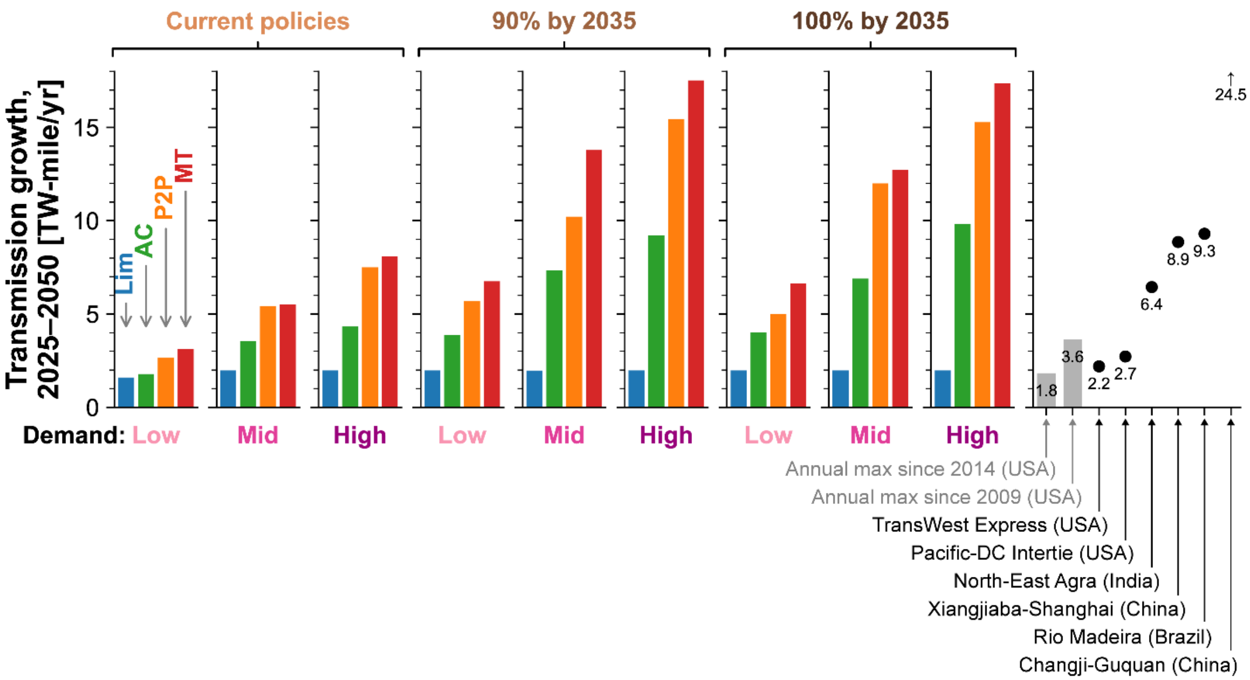


Figure 10. Total transmission growth rate in TW-miles/year as a function of demand, emissions constraint, and transmission framework

The gray bars for "Annual max since 2009" and "Annual max since 2014" refer to U.S. transmission additions as discussed in Wiser et al. (2023). The filled markers indicate individual historically constructed HVDC projects for scale (Pierre et al. 2019; TransWest Express 2024; Power Technology 2020; Hitachi 2020; 2022; 2024).

Electrification drives greater deployment of transmission and generation capacity

The assumed level of demand growth has a significant impact on total transmission deployment. Relative to 2020 transmission capacity, the 2050 transmission capacity in the three accelerated transmission scenarios grows from 1.5 to 1.7 times for low demand to 1.9–2.5 times for high demand under current policies (Figure 9). Combined with a decarbonization policy, the impact of demand growth is even stronger: With 90% by 2035 and 100% by 2035 emissions reductions, 2050 transmission capacity grows from 1.8 to 2.3 times its 2020 level for low demand to 2.7–4.1 times for high demand. Scenarios with high demand through electrification and that achieve 100% grid emissions reductions approximate net zero emissions for the U.S. energy system as a whole (Section 2.3.3).

As with total transmission capacity, demand growth and decarbonization policy are strong drivers of interregional transmission deployment (Figure 11). Interregional transmission capacity, which is defined as the capacity between the 11 planning regions in Figure 1c, grows to 1.5–2.7 times its 2020 capacity by 2035 in the three accelerated transmission frameworks in the Mid-Demand 90% by 2035 scenario and 1.6–3.3 times in the High-Demand 100% by 2035 scenario. By 2050, these ranges grow to 2.6–4.6 times in the Mid-Demand 90% by 2035 scenario and 2.6–5.3 times in the High-Demand 100% by 2035 scenario.

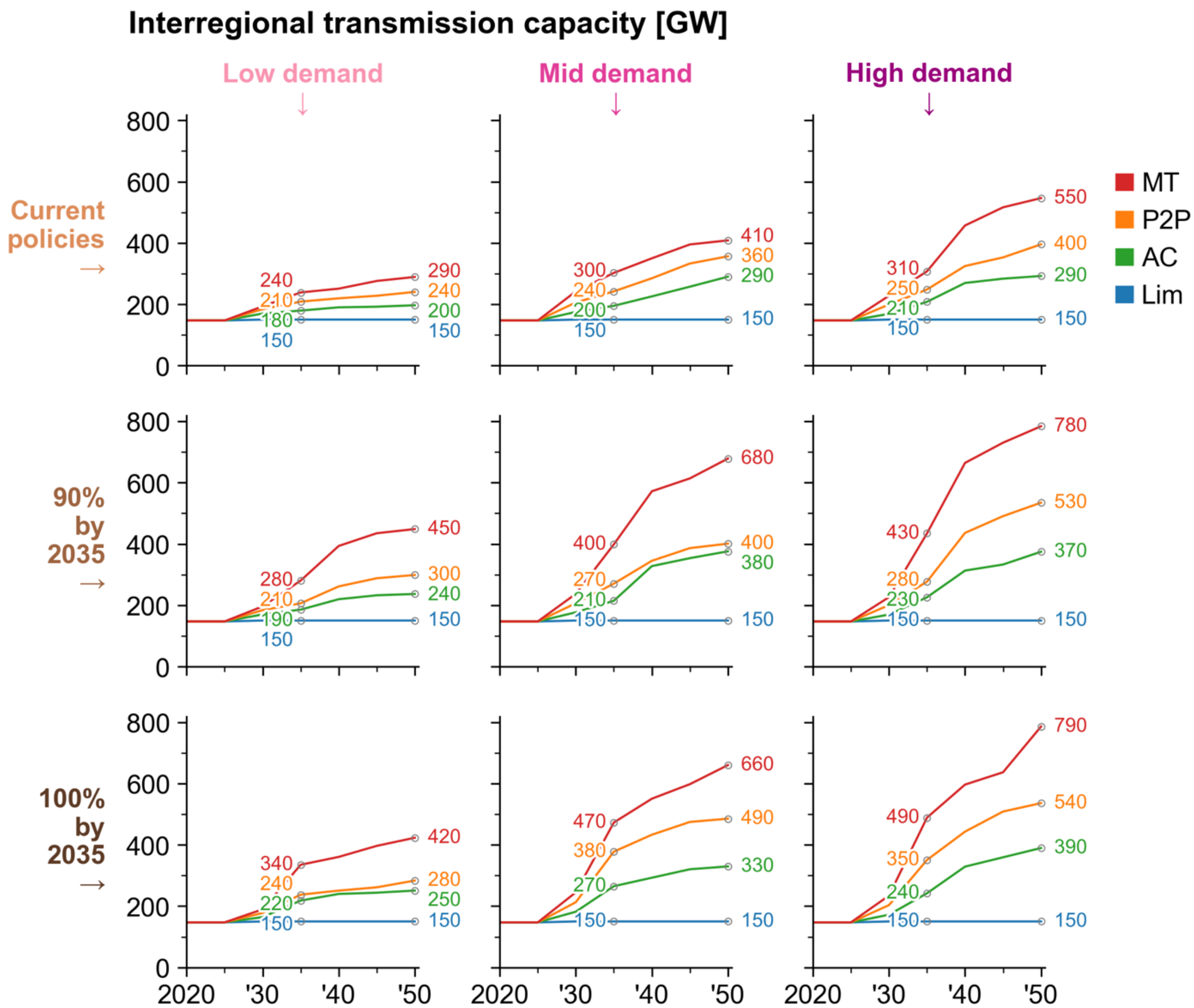


Figure 11. Interregional transmission capacity as a function of demand (columns) and emissions constraint (rows)

"Interregional" transmission capacity is measured between the 11 planning regions shown in Figure 1. For this plot, the IRA tax credit phaseout is assumed to begin in 2032 for all scenarios (including for current policies) to facilitate comparison across scenarios while keeping policy assumptions constant.

Installed wind and solar capacity also scales with demand growth in the accelerated transmission frameworks (Figure 12). In the 90% by 2035 scenarios, 2050 wind capacity grows to 6–7 times its 2020 capacity with low demand, 9–10 times with mid demand, and 12–13 times with high demand; PV capacity grows to 13–14 times, 15 times, and 18–19 times, respectively. Nuclear capacity grows appreciably only in the Limited transmission framework with mid/high demand and either 90% by 2035 or 100% by 2035 emissions constraints, where it grows to ~2 times 2020 capacity under mid demand and ~4 times under high demand (compared to ≤3% growth in all other transmission frameworks and demand/emissions assumptions).

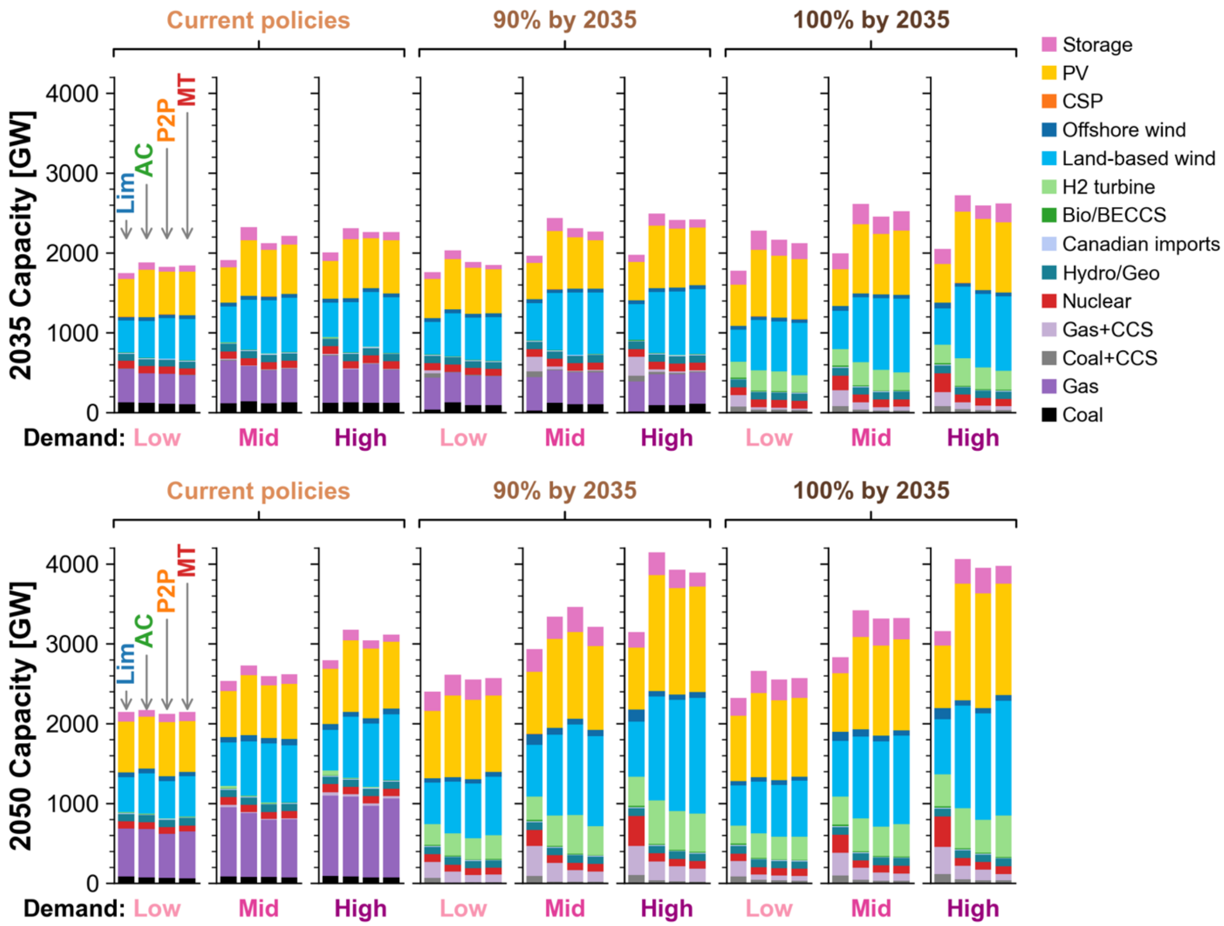


Figure 12. Generation capacity in 2035 and 2050 as a function of demand, emissions constraint, and transmission framework

3.2.2 Benefits from large-scale transmission expansion include hundreds of billions of dollars in system cost savings under decarbonization futures

Though accelerating transmission expansion leads to reductions in CO_2 emissions under current policies, with national emissions limits that fully eliminate grid emissions, the primary impact of accelerated transmission expansion is a reduction in electricity system costs. The main cost metric is the net present value (NPV) of total electricity system costs through 2050, including fixed and operating costs and tax incentives for electricity producers.[31] Figure 13 shows this metric across the 90% by 2035 and 100% by 2035 emissions assumptions (rows), three demand trajectories (columns), and four transmission frameworks (bars). Accelerating transmission expansion reduces costs by $270–490 billion under Mid-Demand/90% by 2035 assumptions, with the AC framework at the bottom of the range of savings and MT at the top (a 4%–8% reduction compared to the $6,370 billion NPV of system costs in the Limited framework).

[31] Unless otherwise noted, the NPV costs are for all expenditures from 2022 to 2050 using a 1.7% societal real discount rate (OMB 2023).

Savings from accelerated transmission increase when decarbonization is achieved more quickly (to $570–810 billion under Mid-Demand/100% by 2035 assumptions) and when demand growth increases (to $710–970 billion in High demand/90% by 2035 and to $860–1,220 billion in High demand/100% by 2035).

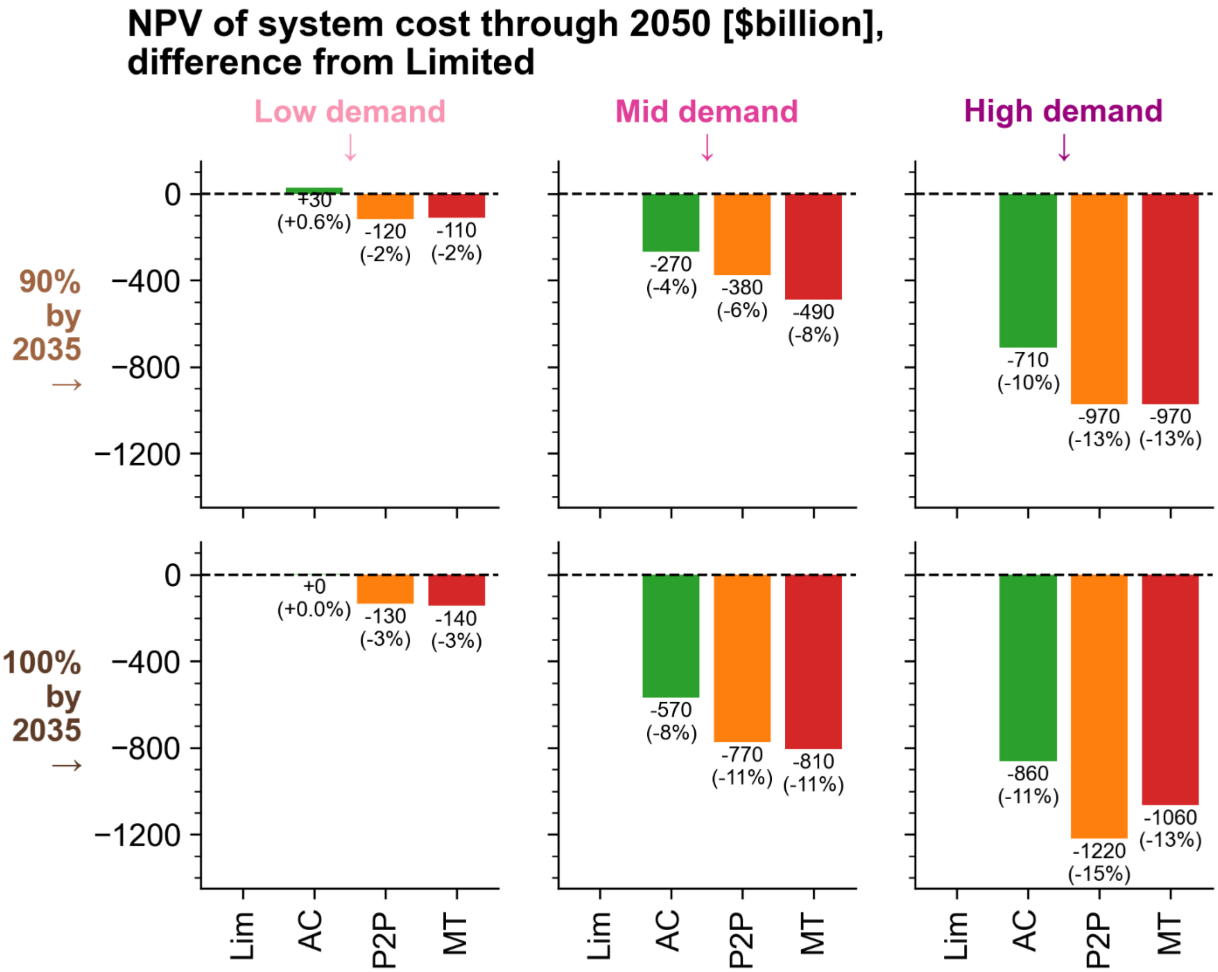


Figure 13. Net present value of total system cost through 2050 expressed as savings relative to the Limited framework

The cost change in each of the three accelerated transmission frameworks relative to the Limited framework is given in $billion and as a percent change below each bar. Differences below ~1% (~$50 billion) are considered within the model uncertainty bounds resulting from imperfect foresight and scenario-specific stress periods.

3.3 Central Demand and Emissions Assumptions

Sections 3.1 and 3.2 show results across all core scenarios, which cover a range of emissions reductions and demand growth assumptions. This section presents findings from the central demand and emissions constraint scenarios, which assume Mid-Demand growth trajectories and 90% emissions reductions by 2035 (100% by 2045). These central scenarios include both the core and the 15 sensitivity cases (Table 1).

3.3.1 Accelerating transmission deployment consistently reduces system cost across a spectrum of sensitivity cases

Across all modeled sensitivity cases, the system cost of a given case is uniformly lower in the three accelerated transmission frameworks than in the Limited transmission framework (Figure 14, Figure 15, and Figure 16), and transmission expansion consistently delivers hundreds of billions of dollars of savings. The core scenario savings of $270–490 billion are on the low end of the modeled sensitivity cases (Figure 16): The range of savings across all sensitivity cases is $270–760 billion for the AC framework; $380–1,170 billion for P2P; and $350–1,170 billion for MT.

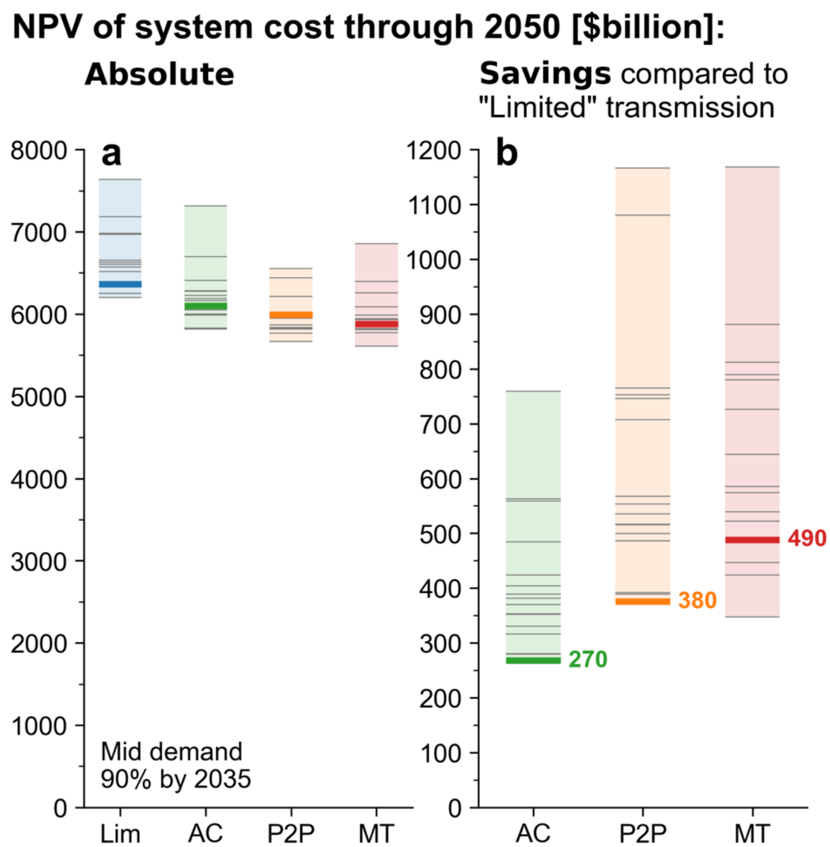


Figure 14. Net present value of total system cost through 2050 under central (Mid-Demand 90% by 2035) assumptions expressed in absolute terms (a) and as savings relative to the Limited framework (b)

Note the change in y-axis scale between panels (a) and (b). Bold line indicates the core scenario result.

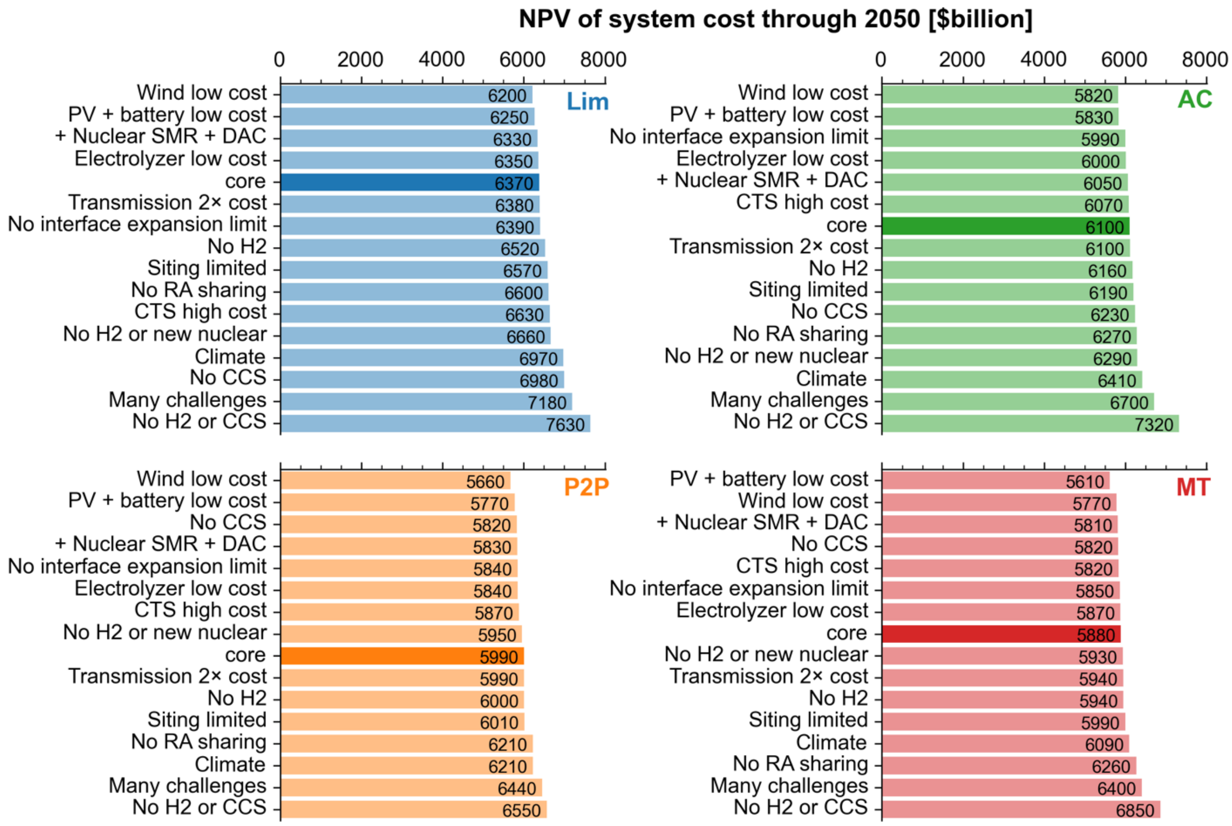


Figure 15. Net present value of total system cost through 2050 for each transmission framework and sensitivity case under Mid-Demand 90% by 2035 assumptions

The savings in each of the three accelerated transmission frameworks relative to the Limited framework are given as numbers in billions of dollars at the right of each bar. Scenarios within each transmission framework are sorted by absolute system cost.

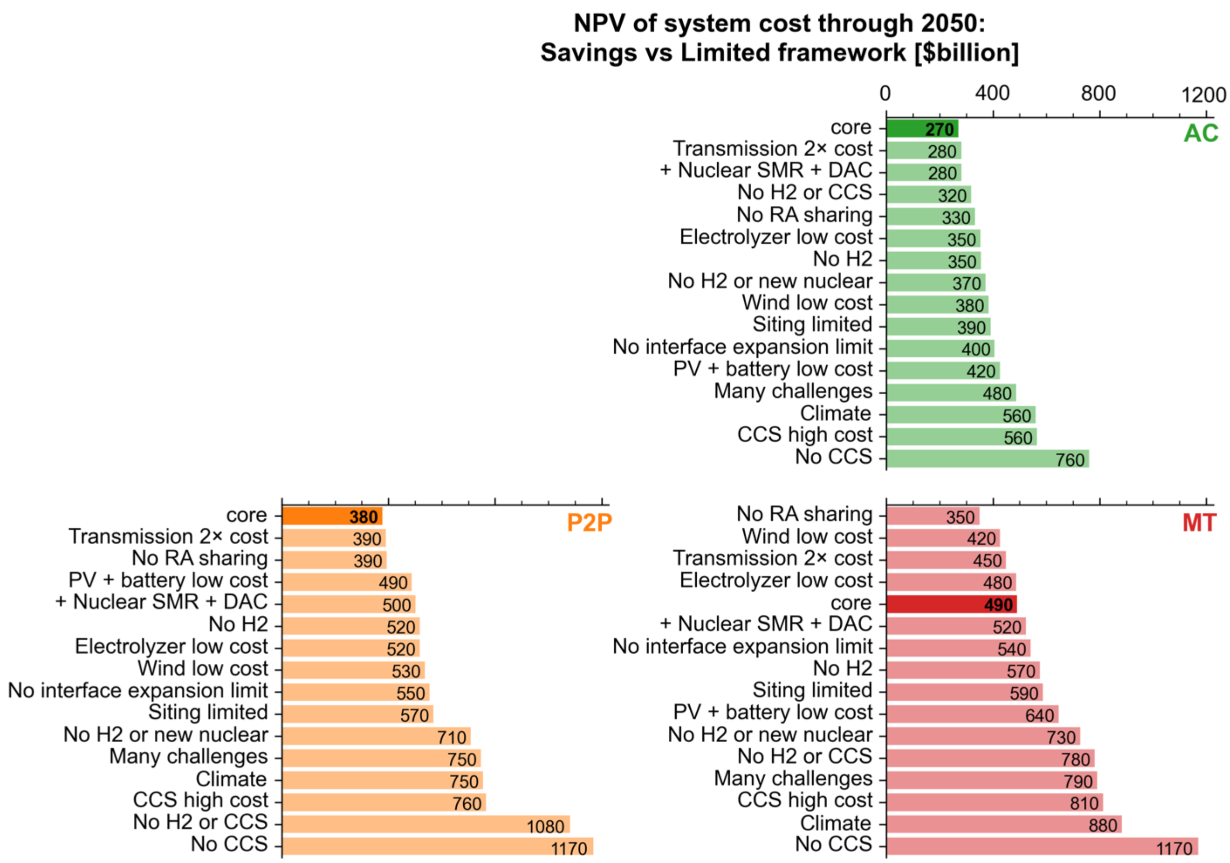


Figure 16. Net present value of total system cost savings relative to the Limited framework under Mid-Demand 90% by 2035 assumptions

Scenarios within each transmission framework are sorted by system cost savings relative to the Limited framework.

Savings from accelerated transmission are largest in futures where alternative technologies are constrained or more expensive. The highest savings from accelerated transmission are in the “No CCS” sensitivity case: Without CCS, costs rise by ~$600 billion in the Limited framework but are relatively unaffected in the other frameworks, leading to savings of ~$800–1,200 billion from accelerated transmission when CCS is unavailable. Transmission-induced savings also increase in the “No H_2” and “No H_2 or new nuclear” sensitivity cases. Transmission expansion could help hedge against the possibility that new low-carbon technologies face difficulties in scaling up from their currently low annual deployment rates. Conversely, if these low-carbon generation technologies become commercially available—as assumed under the core scenarios—the benefits of accelerated transmission expansion are lower but still substantial as discussed previously. Savings from accelerated transmission expansion are also $100–190 billion higher in the “Siting limited” case than in the core scenario, $220–370 billion higher in the “Many challenges” case, and $290–390 billion higher in the “Climate” case. Notably, cost savings from accelerated transmission expansion under the “Transmission 2× cost” case ($280–450 billion) are similar to savings under the core scenario.

Lower system costs in the accelerated transmission frameworks significantly outweigh the costs of new transmission

Across all accelerated transmission frameworks and sensitivity cases, the system cost savings exceed the additional cost of building the transmission compared to the Limited scenario. Figure 17 shows the range of benefit-to-cost ratios for the portfolio of transmission investments in the AC, P2P, and MT scenarios for the 90% by 2035 emissions constraint scenarios.[32] The highest benefit-to-cost ratios are achieved in the P2P and MT scenarios that allow for HVDC transmission development. The core P2P and MT scenarios achieve a benefit-to-cost ratio of 1.7 and 1.8, respectively, compared to the core AC scenario benefit-to-cost ratio of 1.6. As with system cost savings, the benefit-to-cost ratios for the core scenarios are toward the lower end of the ranges. Many sensitivity cases have benefit-to-cost ratios close to 2. Sensitivity cases where new low-carbon technologies are not available typically have higher benefit-to-cost ratios (1.9 to 2.3). The benefit-to-cost ratio exceeds 1.5 across all sensitivity cases; for context, the maximum threshold allowed in FERC Order No. 1000 to determine whether transmission facilities have significant enough benefits to be selected in a regional transmission plan for the purpose of cost allocation is 1.25 (Federal Energy Regulatory Commission 2011).[33]

[32] Benefits are defined as the difference in total nontransmission system costs including generation and storage capital and operating costs and policy incentives between the accelerated transmission framework (AC, P2P, or MT) and the Limited framework. Costs are defined as the NPV of transmission capital and operating costs for all transmission types including spurline, intra- and interzonal lines, and converter stations. More information on the cost analysis is provided in Appendix E.

[33] FERC Order No. 1000 specifies that a benefit-to-cost ratio of 1.25 is the maximum threshold for determining if transmission facilities have sufficient net benefits to be included in regional transmission plans.

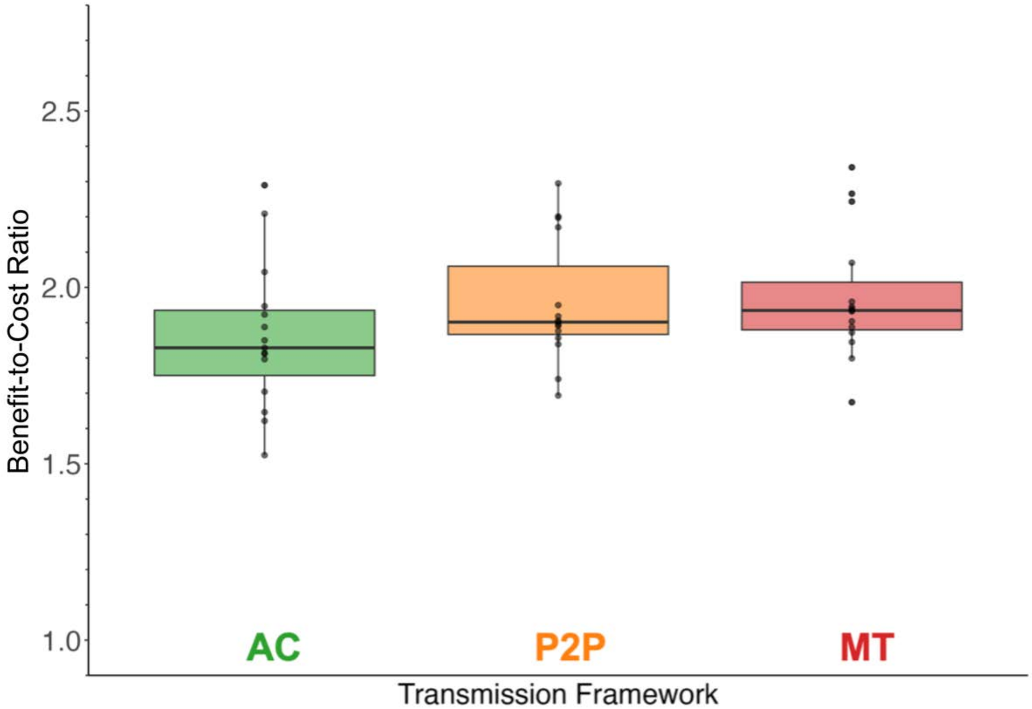


Figure 17. Benefit-to-cost ratio of systemwide savings compared to additional transmission costs relative to the Limited framework under Mid-Demand 90% by 2035 assumptions

The center line indicates the median value, and upper and lower box lines indicate the 25th and 75th percentiles, respectively. The benefit-to-cost ratios exclude the added cost of transmission when calculating benefits.

Transmission expansion helps reduce capital, operating, and fuel expenditures for generation and storage

Historically, savings in production costs have been the primary metric for valuing transmission investments (Chang, Pfeifenberger, and Hagerty 2013; Federal Energy Regulatory Commission 2022). However, transmission development can—positively and negatively—impact a broader range of system costs, including capital investments, fixed operation and maintenance (O&M) costs, and the ability to capture policy incentives. The impact on system costs may change over time as the underlying generation mix changes. Figure 18 shows the change in different types of system costs for the AC, P2P, and MT scenarios compared to the Limited framework from 2025 through 2050.

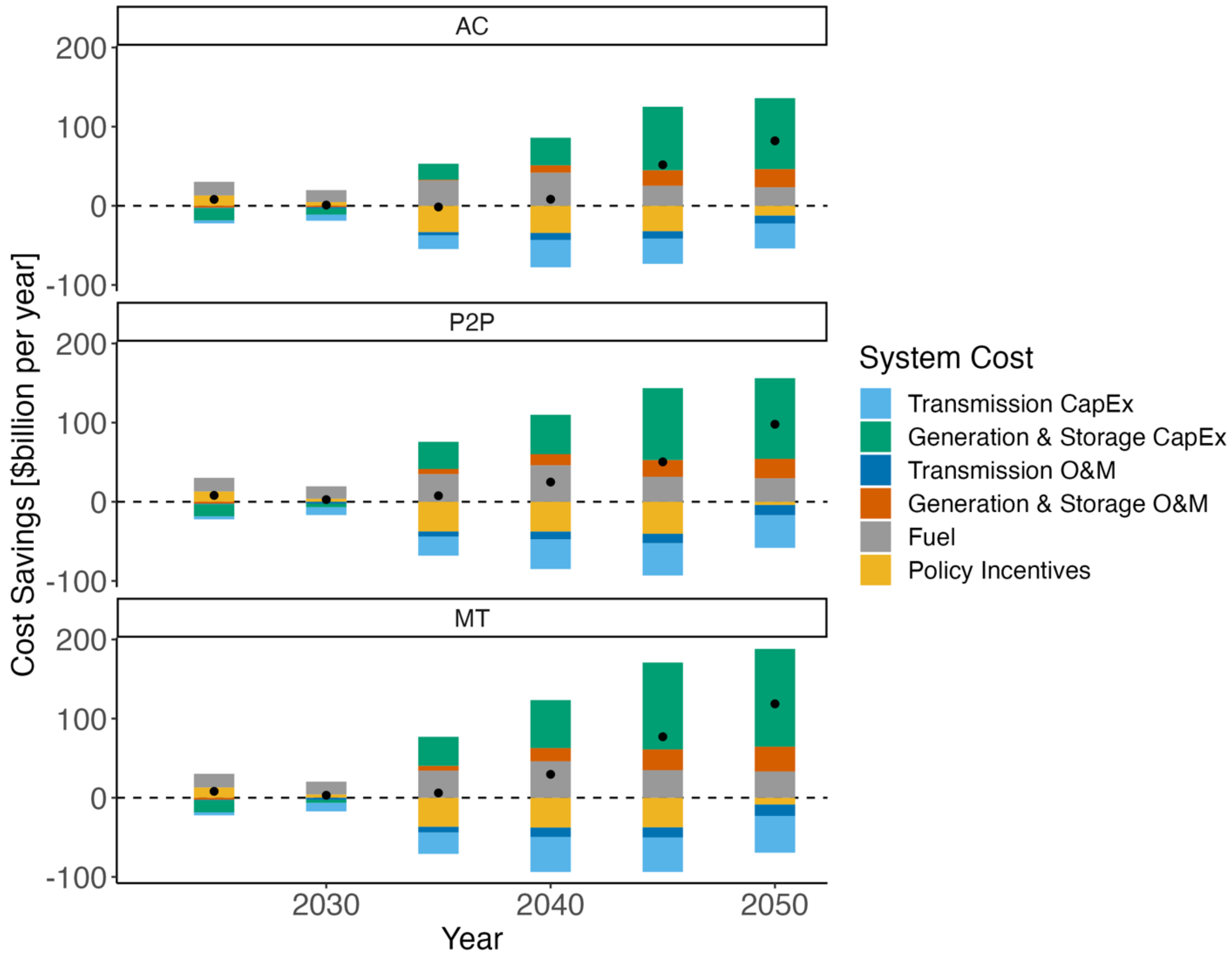


Figure 18. Source of cost savings (real $billion per year) compared to the Limited framework under Mid-Demand 90% by 2035 assumptions

Negative values indicate greater costs compared to the Limited framework; positive values represent savings. Black dots indicate net savings across all system cost categories.

Savings in generation and storage capital costs are the largest source of system savings, totaling $420 billion in the AC framework and more than $700 billion in the MT framework (present value), equivalent to an 11%–20% reduction in total generation and storage capital costs. These savings do not begin until after 2030 and increase in magnitude over the planning period. Reductions in fuel costs make up the second largest source of savings because increased investments in transmission enable greater use of VRE resources, resulting in a 44%–49% decrease in fuel expenditures. Annual savings from avoided fuel costs peak around 2040 and start to decline as the share of VRE increases and opportunities to displace fuel generation are reduced.

Though total system costs decrease in the accelerated transmission development scenarios, capital and operating costs for transmission increase compared to the Limited framework as investments in all types of transmission increase. Total expenditures for transmission (present value) are $760 billion; $1,220 billion; $1,320 billion; and $1,390 billion for the Limited, AC, P2P, and MT frameworks, respectively

(Figure 19). Investments and operating costs for local transmission infrastructure make up the largest share of transmission costs, accounting for more than 40% of total transmission expenditures for all transmission frameworks. Investments in interregional transmission are smaller in all scenarios but grow noticeably after 2030 in the accelerated transmission frameworks (AC, P2P, MT) and reach $12 billion per year by 2050. For context, recent historical transmission investments are estimated to be $20–25 billion per year (Edison Electric Institute 2024).[34] Annual fixed O&M costs for transmission infrastructure—assumed to be 1.5% of the upfront capital cost—make up a significant share of total expenditures, accounting for 50% of total transmission expenditures in 2025, falling to 30% by 2050. Increased transmission development also impacts the tax credit outlay, particularly including the production and investment tax credits for wind, solar, and storage as well as the CO_2 capture tax credit.[35]

[34] The scope of Edison Electric Institute's estimates may not align with the transmission cost categories. In particular, spur lines and other interconnection investments modeling may not be included in the historical data.

[35] The system cost metric and associated benefit-cost-ratio method includes the value of tax credits (tax credits are treated as negative costs to the electricity system) because this metric is intended to measure the impact from the perspective of the electricity system, including producers. This electric sector perspective differs from an economywide perspective where tax credits are typically viewed as transfers between taxpayers and those receiving the credits. When tax credits are excluded in the cost metrics to be more aligned with this perspective, the system cost savings from accelerated transmission change to $570–830 billion (compared with $270–490 billion) under the core scenarios and the benefit-cost ratios change to 2.2–2.3 (compared with 1.6–1.8).

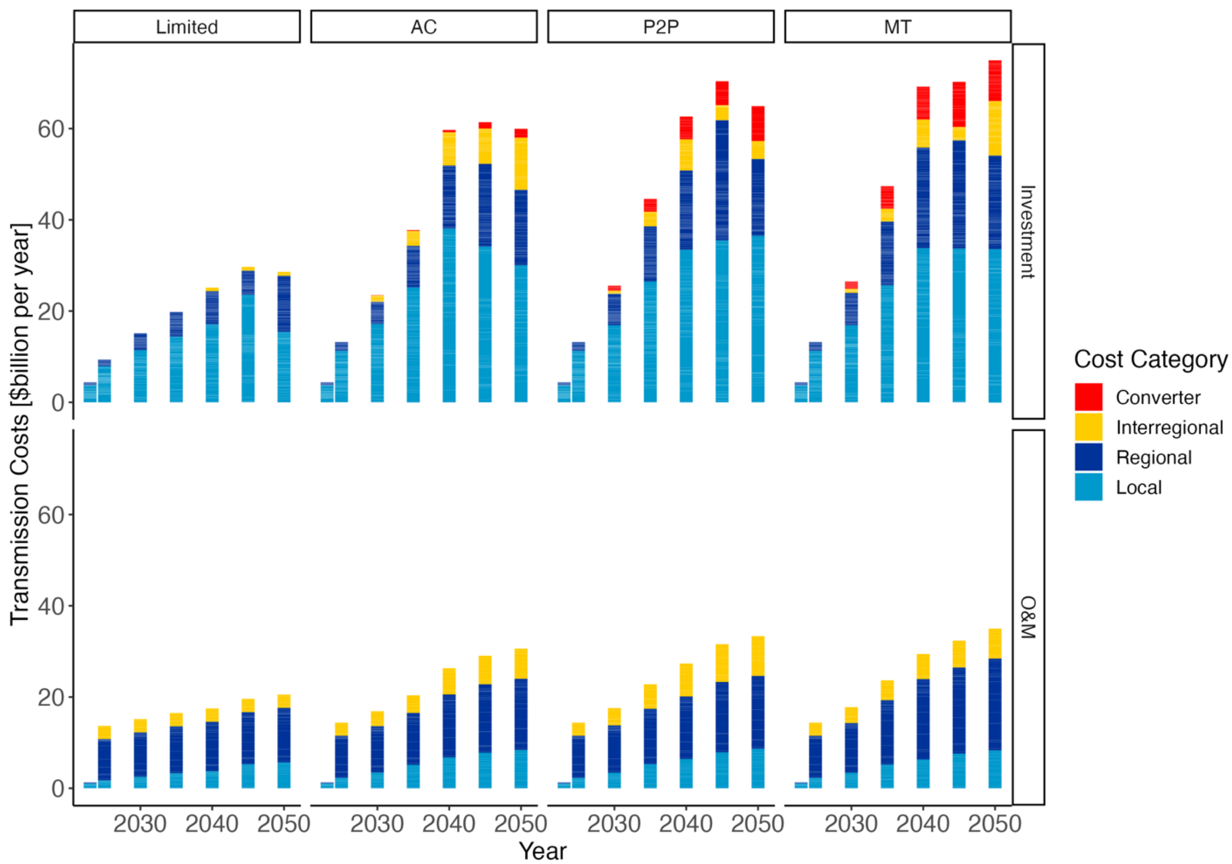


Figure 19. Transmission costs under Mid-Demand 90% by 2035 assumptions

Investments in converters serve both regional and interregional transmission needs.

Interregional transmission enables cost savings for most regions

Though the systemwide value and benefit-cost ratio of each accelerated transmission framework are high, they are not uniform across all individual transmission planning regions. When evaluating the benefit distribution among regions, further consideration of where power is exported and imported—and the value of the power traded—is needed to capture the transmission benefits of interregional trade to each region. To disaggregate benefits regionally, operational costs are adjusted to approximate how these costs might be allocated between importing and exporting regions. To do so, the analysis uses the adjusted production cost (APC) metric.[36] This metric is the difference in total production costs adjusted for import costs and export revenues with and without a proposed transmission investment. For this study, the APC is based on zonal marginal prices from the capacity expansion model. Further study with full 8,760 hourly resolution at a nodal resolution can be used to refine the estimated adjusted production costs for each region. The following figures show the total savings to each region

[36] See Appendix E for more details on the APC method used in current planning processes and the adjustment values calculated for the core transmission scenarios.

compared to the Limited scenario by system cost category (Figure 20a) and as a share of each region's costs (Figure 20b).

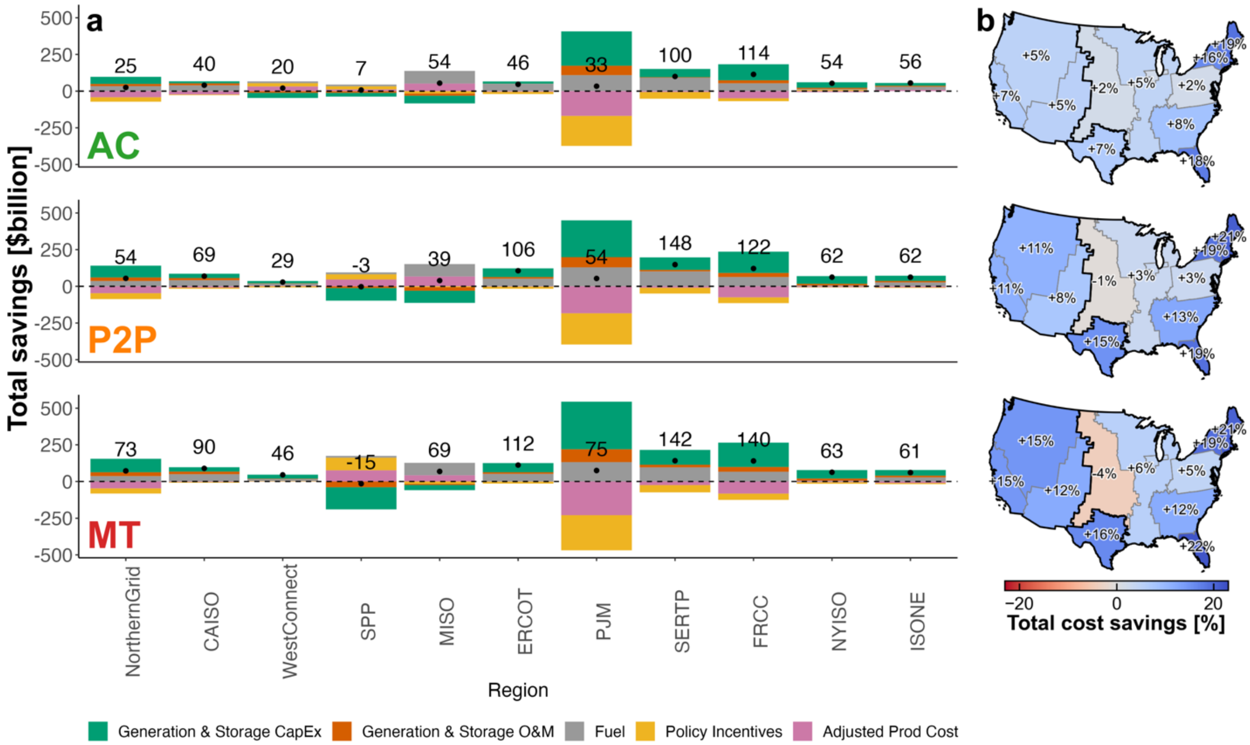


Figure 20. Net present value of system savings by region in absolute $billion (a) and percentage (b) of avoided costs relative to the Limited framework under Mid-Demand 90% by 2035 assumptions

Black dots in (a) indicate net savings across all system cost categories. These results show the disaggregation of system benefits evaluated as part of this study and are not intended to prescribe any specific cost allocation among planning regions.

Among planning regions, savings from increased transmission interconnection in 90% by 2035 Mid-Demand scenarios are highest in the Southeast (SERTP, FRCC) and Texas (ERCOT). These regions see large decreases in fuel costs and generation and storage capital costs because the transmission network allows them to make greater use of lower-cost resources located in other regions. As a share of total costs, ISONE, FRCC, and NYISO see the highest savings, with costs declining by more than 20% in the MT framework. In other regions, such as SPP, total costs increase in some scenarios compared to the Limited framework because these regions are building more generation capacity to export to neighboring regions. In these regions, the additional benefits from collecting more investment and production tax credits and increased generation revenues from selling power to neighbors do not outweigh the additional cost of building and operating more generation capacity.

Similar to systemwide cost savings, the regional transmission value—measured by the savings in investment and operating costs transmission can provide—is sensitive to technology availability and costs, climate impacts, siting constraints, and other varying system characteristics. Figure 21 shows the range of transmission values by region across all sensitivity cases using the Mid-Demand 90% by 2035 assumptions.

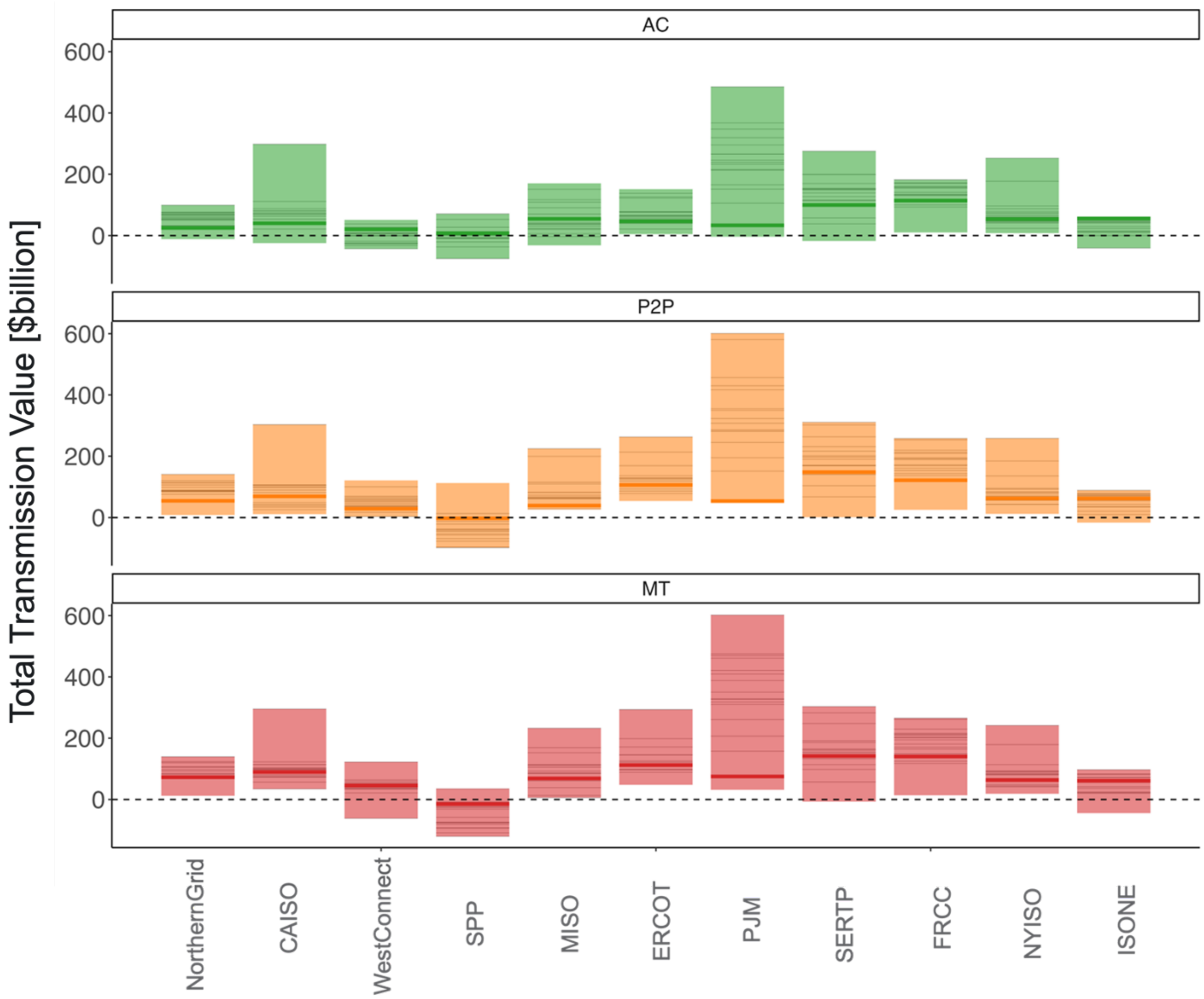


Figure 21. Net present value of total system cost savings to each transmission planning region relative to the Limited framework under Mid-Demand 90% by 2035 assumptions

Bold line indicates the core scenario result.

The impact of each sensitivity varies by region. For example, in regions that rely on CCS and H_2 technologies to achieve emissions reductions targets, the value of transmission increases when these technologies are not available. Detailed results for each modeled sensitivity are presented in Appendix D.4.

3.3.2 Transmission expansion enables increased access to wind and solar

As in the Current Policies scenarios (Section 3.1), accelerating transmission expansion increases the share of VRE in the resource mix across all sensitivity cases (Figure 22). The VRE share (annual solar and wind generation divided by total annual generation from all sources) is ~20% higher in the AC, P2P, and MT core scenarios (77%–82% VRE share) than in the Limited core scenario (58% VRE share).

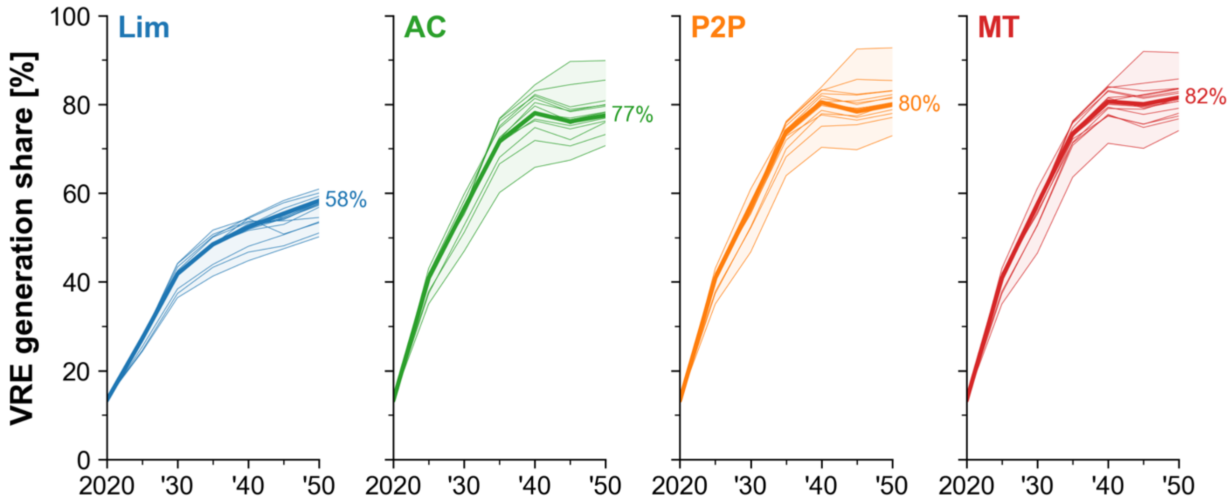


Figure 22. VRE share of total generation for the Mid-Demand 90% by 2035 scenarios for each transmission framework

Core scenarios are shown by a thick line, with the 2050 value labeled; sensitivity cases are shown by thin lines, with the shaded area showing the range between sensitivity cases.

There is considerable spread in 2050 VRE share across sensitivity cases for a given transmission framework, but the sizable increase in VRE through accelerated transmission is consistently observed across all sensitivity cases. The 2050 VRE share in the Limited framework ranges from 50% to 61% across sensitivity cases, versus 71%–90% in the AC framework, 73%–93% in P2P, and 74%–92% in MT. Excluding the “No CCS,” “No H_2 or CCS,” “No H_2,” and “No H_2 or new nuclear” sensitivity cases, the nuclear generation share ranges from 16% to 27% in the Limited framework and 6% to 9% in the accelerated transmission frameworks. The generation share from fossil generation with CCS ranges from 12% to 18% in the Limited framework and 2% to 11% in the accelerated transmission frameworks. Figure 23 shows the 2050 generation mix for all sensitivity cases. The capacity mix for all sensitivity cases is shown in a similar format in Figure D-10.

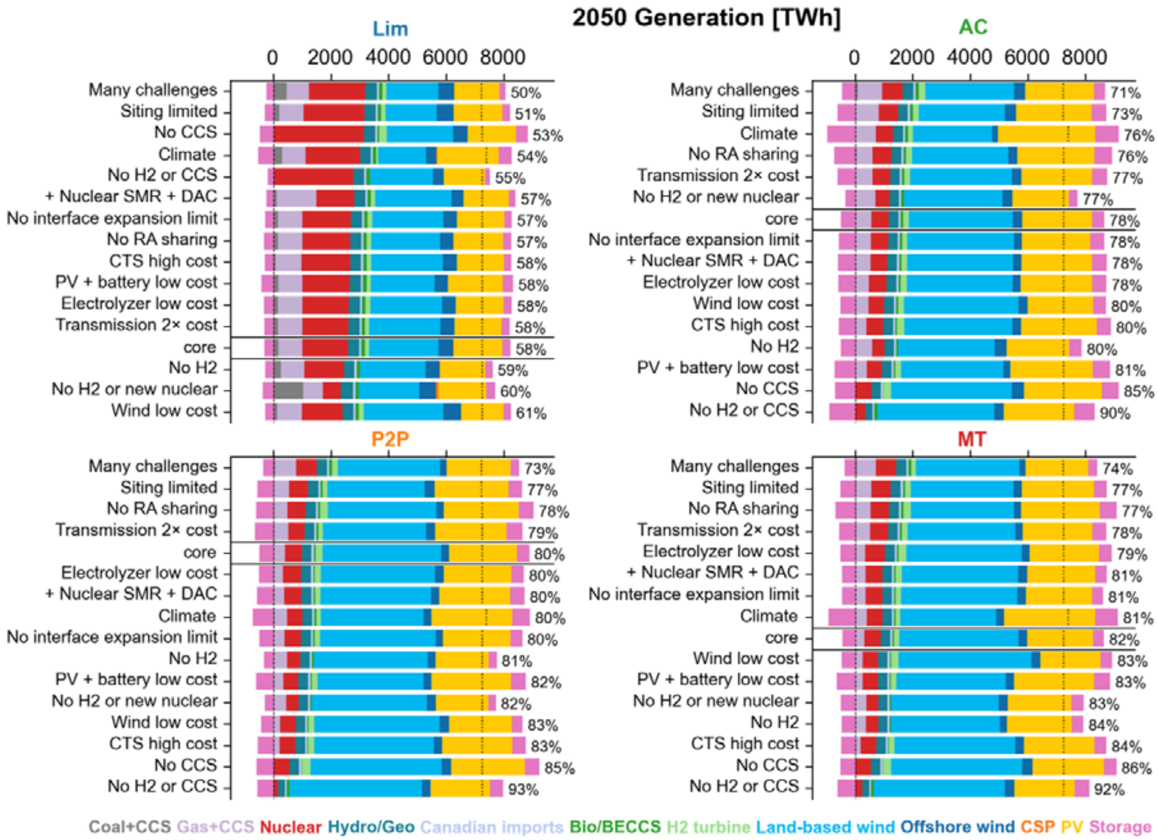


Figure 23. National generation mix in 2050 for the Mid-Demand 90% by 2035 scenarios for each transmission framework and sensitivity case

Within each transmission framework, the sensitivity cases are sorted by 2050 VRE share (indicated by the percentage value to the right of each generation bar). Total generation is greater than end-use demand (vertical dotted line) because of transmission and distribution losses, storage losses, and generation for hydrogen production via electrolyzers. Total storage charging is shown as negative values and discharging as positive values.

3.3.3 Significant amounts of transmission are added at all scales (local, regional, and interregional) in decarbonized systems

When transmission additions are limited, local generator interconnection takes precedence over longer-distance transmission

Both long-distance and local transmission expansion play large roles in the lowest-cost decarbonized power systems (Figure 24). But in the Limited transmission framework, where annual total transmission additions are limited to 1.83 TW-mile/year, the large majority of the limited “budget” for transmission additions is used for local interconnection of new wind and solar resources in both the core scenarios (Figure 24) and sensitivity cases (Figure 25). Roughly 92% of total transmission additions between 2020 and 2050 in the Limited framework is associated with local interconnection. As the availability of new long-distance transmission increases, this fraction drops—to 56% in the AC framework, 42% in the P2P framework, and 31% in the MT framework—although the absolute amount of new interconnection capacity is greater in the accelerated transmission frameworks (110–120 TW-miles) than in the Limited framework (~50 TW-miles), reflecting the larger renewable energy share in these scenarios.

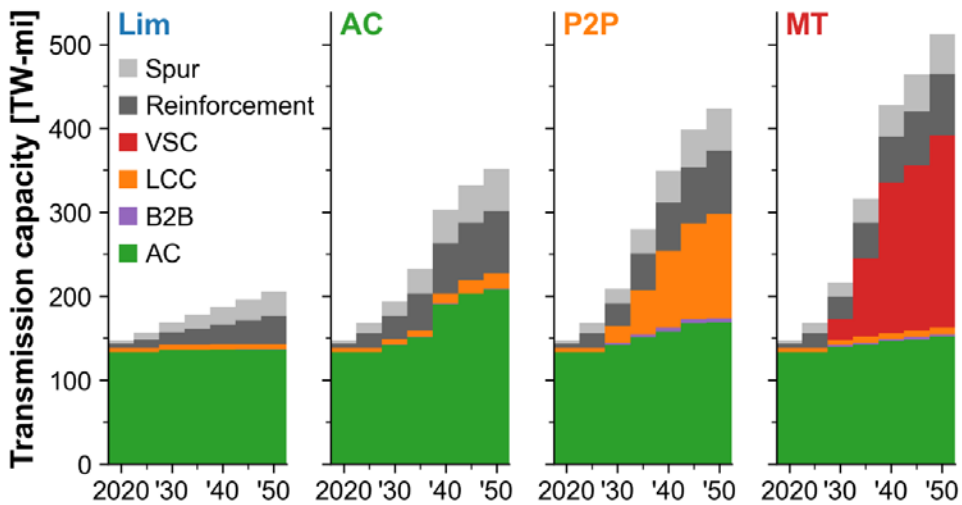


Figure 24. Transmission capacity under Mid-Demand 90% by 2035 assumptions for each transmission framework

Local transmission for wind and solar interconnections includes both spur and reinforcement capacity. Other categories are for interzonal transmission.

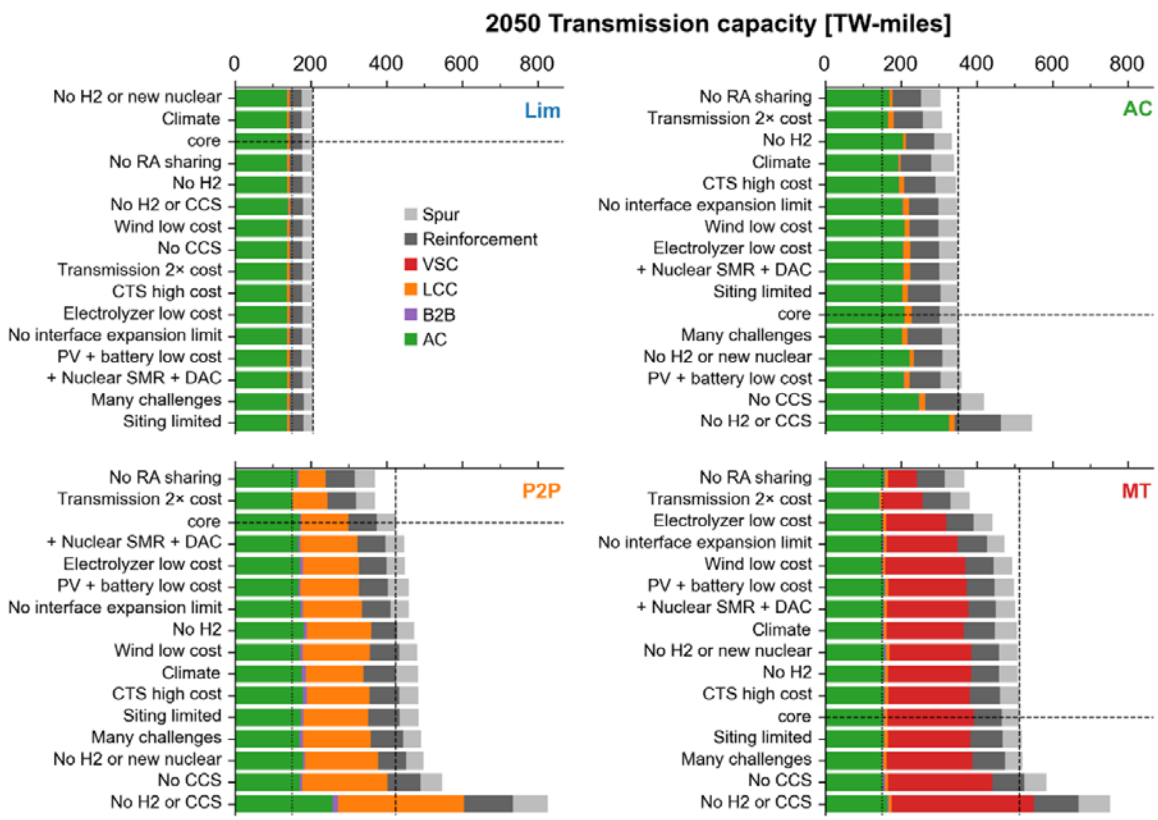


Figure 25. Transmission capacity in 2050 in the Mid-Demand 90% by 2035 scenario for each transmission framework and sensitivity case

Values for the core scenarios for each transmission framework are marked by dashed black lines. Within each transmission framework, sensitivity cases are sorted by total transmission capacity in 2050. The lighter vertical dashed line shows the 2020 capacity (~150 TW-miles). The 1.83-TW-mile/year limit on annual transmission additions is binding in all sensitivity cases for the Limited transmission framework, making 2050 transmission capacity the same in all sensitivity cases for this framework.

If available, HVDC transmission additions outpace AC additions for long-distance transmission

Both AC and HVDC transmission additions are allowed in the P2P and MT frameworks, but HVDC additions significantly outweigh interzonal AC additions in all sensitivity cases in these frameworks (Figure 25). The amount of new HVDC capacity added through 2050 is 2.3–6.0 times the amount of new interzonal AC capacity in the P2P framework and 3.9–16 times in the MT framework. ReEDS does not explicitly model AC power flow or the implications of DC protection on system design; the choice between AC and DC for interzonal transmission investments is thus driven solely by $/MW cost (including the cost of AC/DC converter stations and associated reactive power support) and losses, both of which are lower for DC than AC when distances exceed ~200–500 miles (Alassi et al. 2019).

3.3.4 Expansion of interregional transmission is significant in decarbonized systems

Expansion of long-distance transmission is concentrated in the central part of the country

Previous studies have noted the synergy between transmission and wind deployment (P. R. Brown and Botterud 2021; Denholm et al. 2022); because wind capacity factors exhibit greater spatial variability than solar capacity factors (Figure 26) and because daily solar variability is well-matched with short-duration storage, transmission deployment tends to be correlated with wind deployment and storage deployment tends to be correlated with solar deployment (Blair et al. 2022; Frazier et al. 2021). A similar relationship—that the greatest density of new long-distance (interzonal) transmission additions occurs around the midwestern “wind belt” (Figure 26, Figure 27)—is observed in the scenarios. The trend is most pronounced in the AC transmission framework, where three multilink connections are observed between the wind belt and demand centers in the Southwest, Midwest, and Southeast. A greater amount of long-distance transmission overall is added in the P2P and MT frameworks, but most of the largest links have an endpoint in the wind belt. Though some north-south additions are observed, most new long-distance transmission capacity is oriented predominantly east-west.

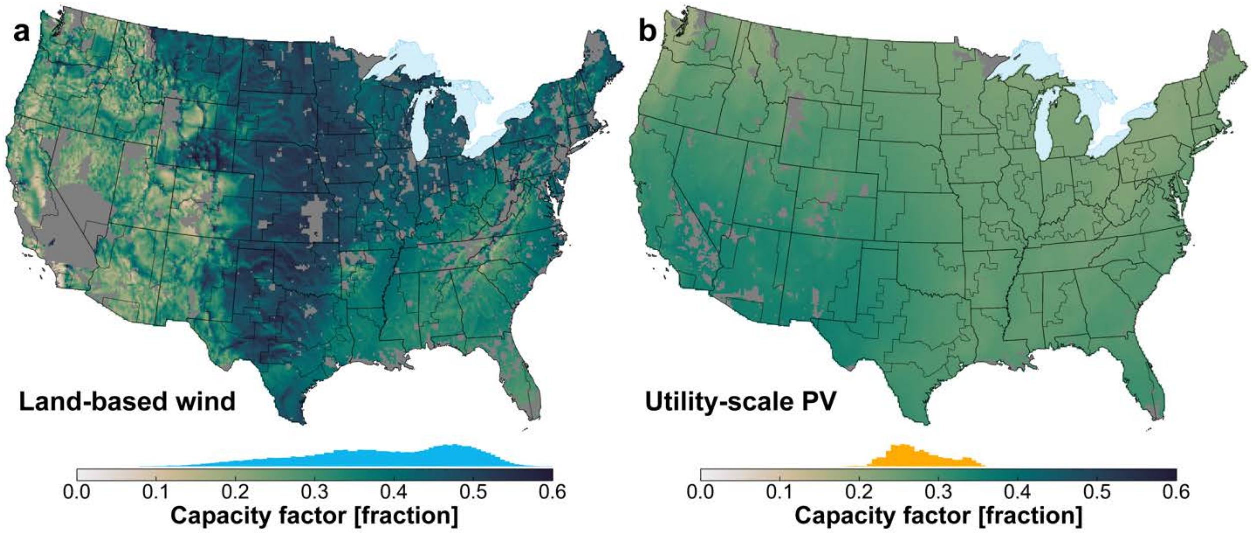


Figure 26. Average capacity factor of land-based wind (a) and utility-scale PV (b) over 2007–2013

Both maps assume Reference Access siting (Appendix A); sites without developable capacity are shown in gray. Both maps show AC capacity factor using the same color scale range. The “wind belt” refers to the darkest-colored (highest-capacity-factor) region in the wind map extending from north to south through the center of the country. Histograms above color bars indicate the frequency of occurrence of the indicated capacity factor values across the ~50,000 reV model sites shown in the corresponding map.

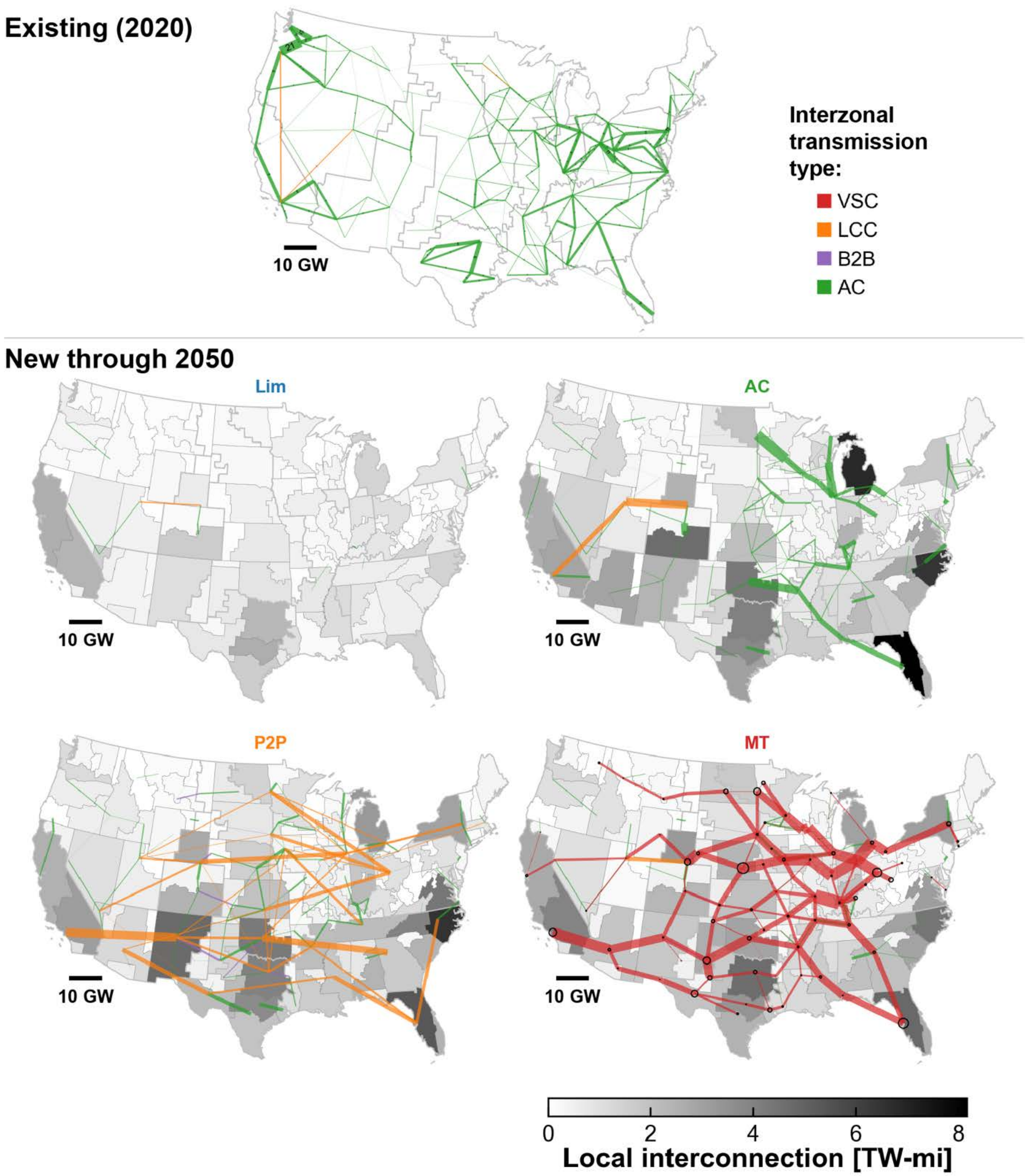


Figure 27. New local and long-distance transmission through 2050 in the Mid-Demand 90% by 2035 scenarios for each transmission framework, with existing 2020 long-distance transmission capacity for context (top)

Interface transfer capability is indicated by the thickness of the lines connecting ReEDS zones. Converter capacity in the MT framework is indicated by the diameter of empty black circles, using the same length scale as the interface lines. The depiction of interzonal transmission capacity as straight lines between zone centers is a visual simplification; in practice, the interzonal transfer capacity would be spread across many transmission corridors for each interface.

The MT scenario tends to make the most efficient use of AC/DC converter capacity. Some zones have minimal converter capacity (indicated by the small black circles in Figure 27), instead acting primarily as pass-throughs in the HVDC network, while exporting zones (in the wind belt) and importing zones (in southwestern and eastern demand centers) install converters sized to their usage needs. The P2P scenario, on the other hand, may make more efficient use of transmission rights-of-way by using higher-voltage (thus higher-power-capacity) LCC architectures (Alassi et al. 2019), although transmission land use is not directly considered here.

Regional transmission trends can be summarized at the planning region level using the ratio of "transfer capability to other planning regions" (GW) to "peak demand within the planning region" (GW) (Figure 28). A range of interregional transfer capabilities is observed in the current (2020) system: ERCOT has a transfer capability ratio of 0.01; ISONE, SERTP, and FRCC range from 0.1 to 0.3, and other regions range from 0.3 to 0.7. In the Limited transmission framework, new additions of interregional transfer capacity are not allowed; thus, as peak demand increases over time, the transfer capability ratio falls. In the AC framework, many regions maintain transfer capability ratios similar to their 2020 values, although there are notable increases in SPP and MISO. The transfer capability ratio increases dramatically for the wind-rich regions of SPP, MISO, and WestConnect in the MT transmission framework, reaching ~2.6 for SPP and ~1.8 for MISO and WestConnect. When interconnection-seam-crossing capacity additions are allowed in the two HVDC scenarios, the transfer capability ratio in ERCOT increases to roughly 0.3, on par with other regions with stronger existing connections to neighboring regions.

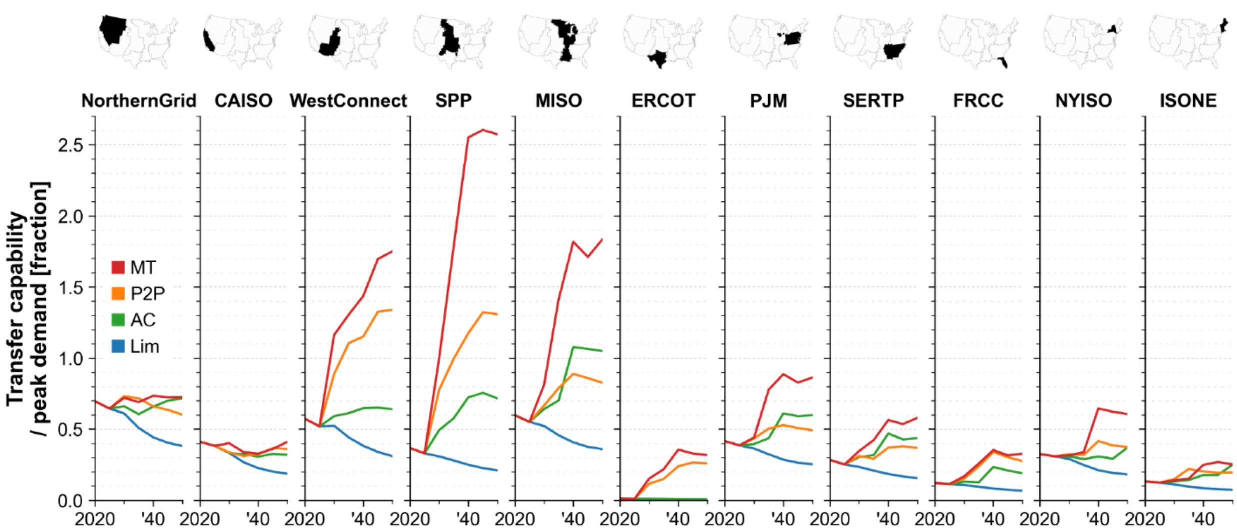


Figure 28. Ratio of interregional transfer capability to peak demand for the 11 planning regions with Mid-Demand 90% by 2035 assumptions across the four transmission frameworks

Interregional transfer capability for a given planning region is defined as the sum of import/export capacity between that planning region and other planning regions.

When allowed, transmission capacity expands significantly across the three interconnection seams

Though many interregional interfaces host large transmission capacity additions in the decarbonization scenarios, the interconnection "seams" demonstrate particularly large capacity additions relative to their currently small transfer capability (Figure 29). New seam-crossing capacity is not allowed in the Limited or AC frameworks but expands to ~80 GW by 2050 in the P2P framework (~37 times the currently installed seam-crossing capacity of 2.1 GW) and ~110 GW (~50 times) in the MT framework. By 2035, the seam-crossing capacity reaches roughly half of its 2050 value: 44 GW in P2P and 52 GW in MT. Transmission capacity is added across each of the three seams in both HVDC frameworks.

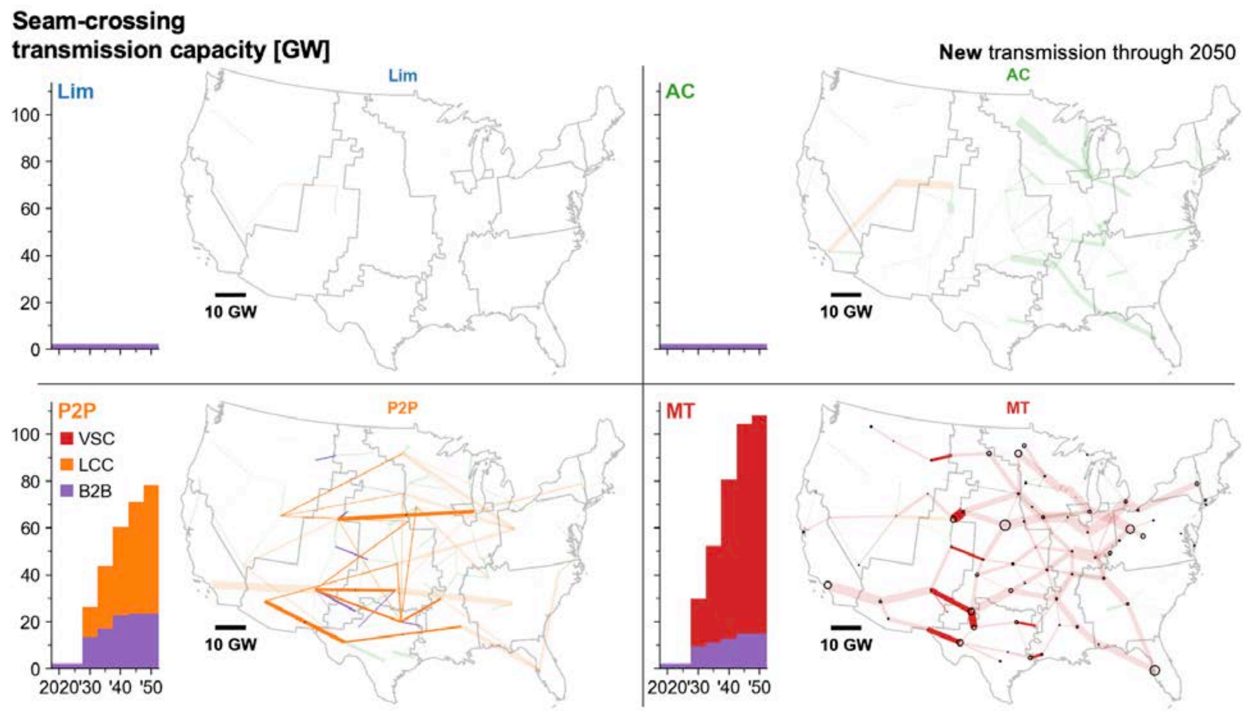


Figure 29. New interconnection-seam-crossing transmission capacity in each of the transmission frameworks with Mid-Demand 90% by 2035 assumptions.

Spatial patterns in transmission expansion are similar across many sensitivity cases

The transmission deployment maps shown thus far have used core scenario assumptions, but there is significant uncertainty in the projected cost and availability of different technologies between now and 2050. It is therefore important to understand whether the spatial trends discussed thus far vary under different assumptions regarding technology evolution, here parameterized through the 15 sensitivity cases described previously. Though the absolute amount of transmission capacity deployed varies substantially across sensitivity cases for a given transmission framework (Figure 25), the spatial distribution of new long-distance transmission is largely consistent (Figure 30, Figure 31, and Figure 32). The greatest density of long-distance transmission additions is observed around the wind belt, and the orientation of new long-distance transmission additions (particularly in the P2P and MT frameworks) is predominantly east-west.

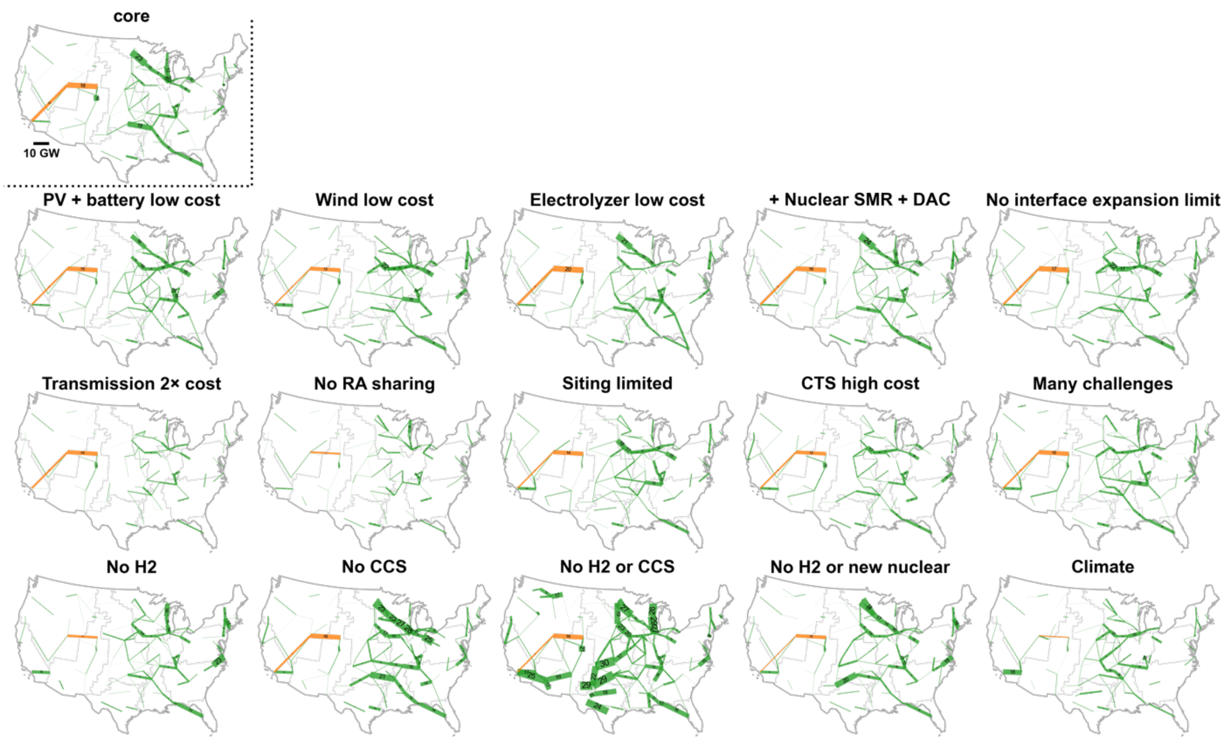


Figure 30. New long-distance transmission additions through 2050 with Mid-Demand 90% by 2035 assumptions for each sensitivity case under the AC transmission framework

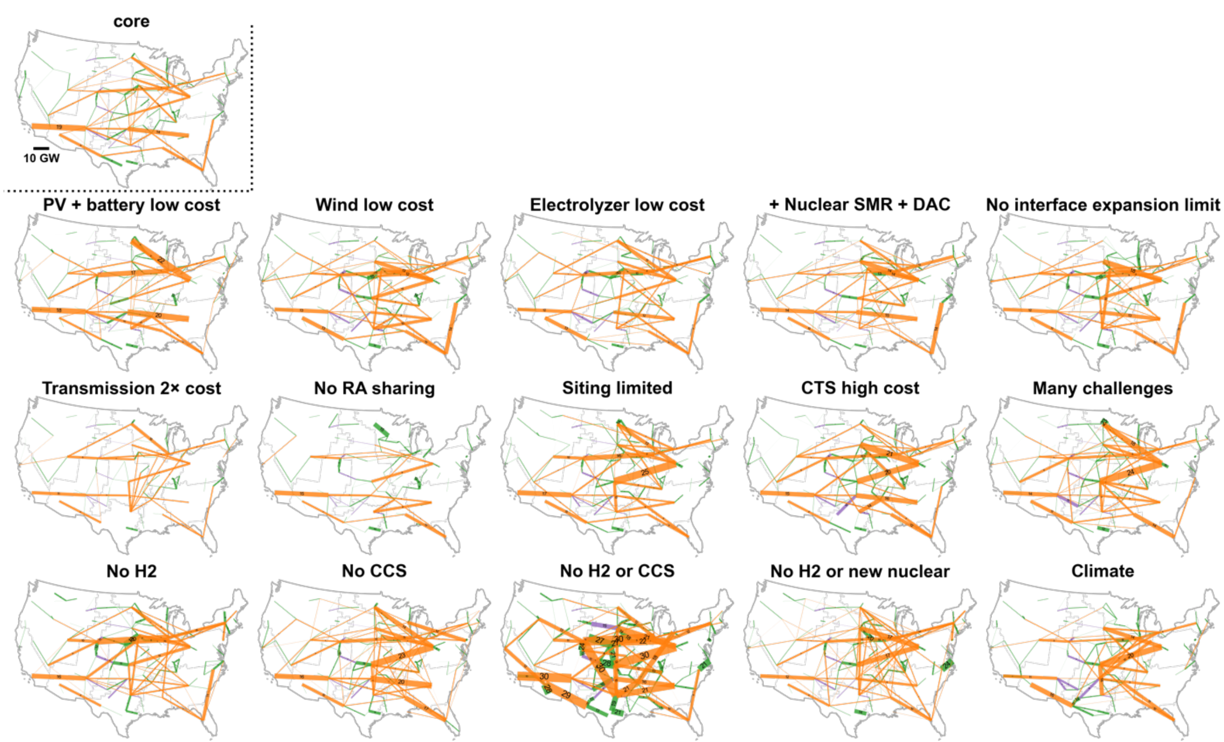


Figure 31. New long-distance transmission additions through 2050 with Mid-Demand 90% by 2035 assumptions for each sensitivity case under the P2P transmission framework

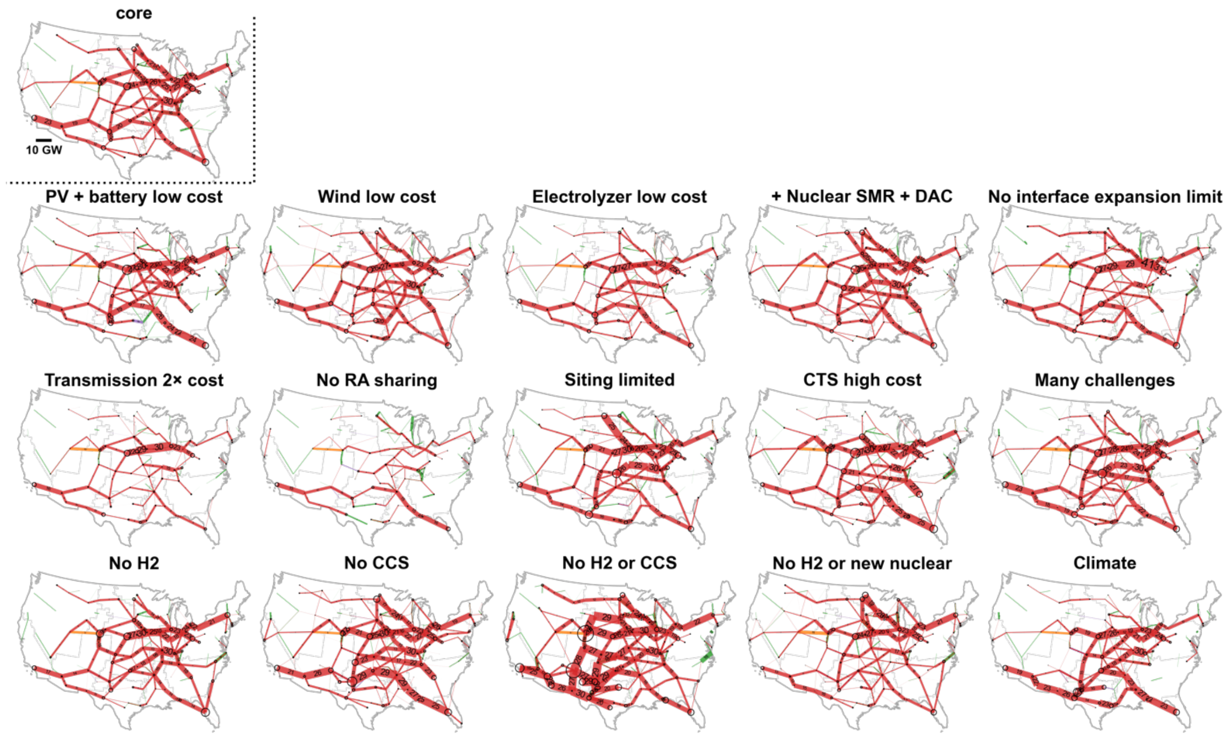


Figure 32. New long-distance transmission additions through 2050 with Mid-Demand 90% by 2035 assumptions for each sensitivity case under the MT transmission framework

Figure 30, Figure 31, and Figure 32 visually demonstrate the similarity in the spatial trends in transmission development across the sensitivity cases modeled. The following text box presents an analysis that more systematically evaluates interregional transmission expansion in these scenarios to identify subregional High Opportunity Transmission (HOT) interfaces from the scenarios. The HOT interfaces serve as an initial screening to determine how much and where additional high-capacity transmission may be needed between the subregional pairs given the full set of sensitivity cases considered here.

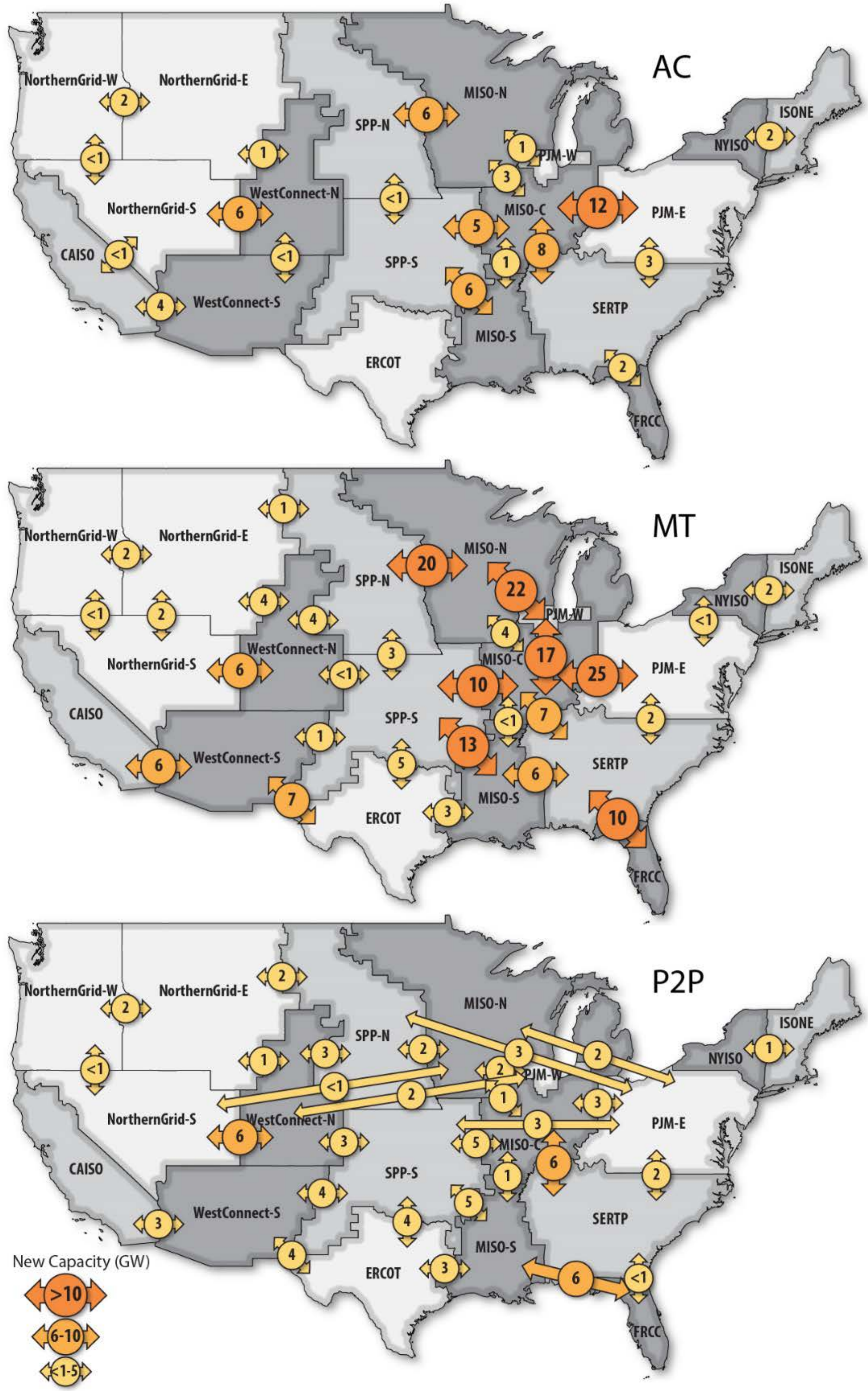
High Opportunity Transmission

An objective of the NTP Study is to identify potential transmission solutions that will provide broad-scale benefits to electricity customers under a wide range of potential futures. To support this objective, this text box presents a screening analysis to identify High Opportunity Transmission (HOT) interfaces between planning subregions developed using the scenarios presented in this chapter.

Subregional HOT interfaces are specified by the amount of transfer capacity expanded between a pair of planning subregions (Figure 1b) from 2020 to 2035. These interfaces are found by systematically evaluating this transfer capacity increase from the 16 scenarios (one core scenario plus 15 sensitivity cases) under the central demand/emissions assumptions (Mid-Demand, 90% by 2035) for each of the three accelerated transmission frameworks (AC, P2P, and MT). Specifically, a HOT interface capacity is defined as the expansion between subregions that occurs in 75% of the scenarios, i.e., the 25th percentile of transmission expansion. This 25th percentile is chosen to reflect robustness in development across a wide range of future conditions about technology costs and availability, renewable energy siting, and level of interregional coordination.

The following maps show HOT interfaces identified for the three accelerated transmission frameworks. In all frameworks, HOT interfaces are found for all regions although a concentration is found in MISO and neighboring regions. The HVDC frameworks (P2P and MT) generally have more HOT interfaces, and their capacities tend to be greater than those in the AC framework. The P2P framework includes long-distance connections, including between nonadjacent planning regions. The MT framework has the highest-capacity HOT interfaces with several having an increased transfer capacity of 10–25 GW. Although some HOT interfaces have very high capacities, a significant fraction of the benefits of interregional transmission can be realized with a smaller amount of expansion as revealed from a side analysis that tests the same scenarios with maximum limits on transmission development across major subregions.

Appendix F provides additional information for the HOT interfaces for each planning region. It also includes the 50th and 75th percentile results to inform more ambitious transmission development opportunities. The HOT interfaces are found by systematically examining the capacity expansion scenarios but are limited by the number and type of sensitivity cases modeled. Additional sensitivity cases would increase the robustness of the interfaces identified, and further assessments are required to determine the viability of any individual project that may align with the HOT interfaces shown. Nonetheless, these subregional HOT interfaces provide a general scale of how much new interregional transmission capacity is needed over the next decade to realize many of the decarbonization scenarios envisioned.



High Opportunity Transmission interfaces with Mid-Demand 90% by 2035 assumptions under the (top) AC, (middle) MT, and (bottom) P2P transmission frameworks

3.3.5 Zero-carbon power systems dominated by variable renewable energy can meet resource adequacy targets

The NTP Study uses a coupled ReEDS-PRAS modeling approach, described above, which results in power system reliability levels (for systems with net zero carbon emissions and generation mixes dominated by VRE) that fall comfortably within the range of resource adequacy targets used in industry (Figure 33). The median NEUE for the Mid-Demand 90% by 2035 scenarios across all model years, transmission frameworks, and sensitivity cases (384 total observations) is 0.9 ppm, well below the industry target range of 10–30 ppm (Alberta Electricity system Operator 2017; Electric Power Research Institute 2024; NERC 2024). In 2045 and 2050—the years in which these scenarios are constrained to net zero electricity system emissions—the median NEUE stays similarly low.

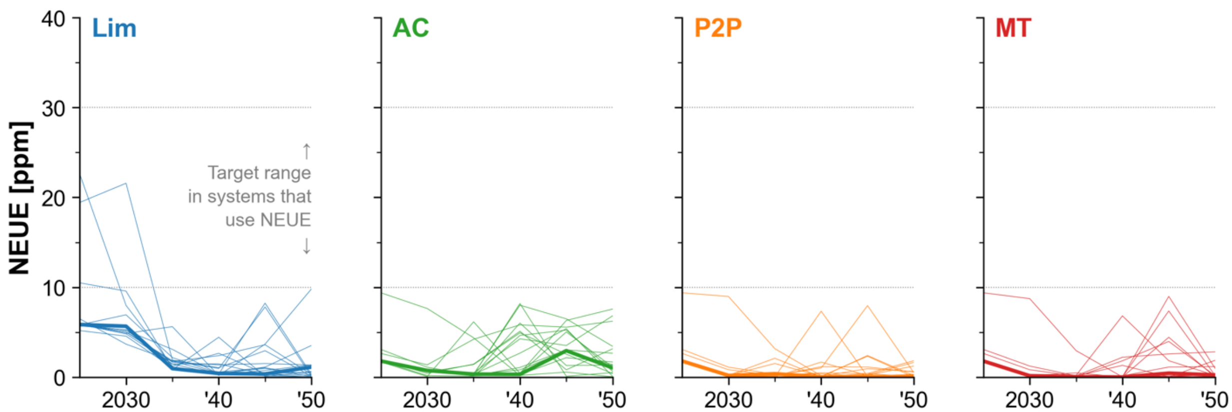


Figure 33. Normalized expected unserved energy (NEUE) in each transmission framework and sensitivity case with Mid-Demand 90% by 2035 assumptions.

Results for the core scenarios are indicated by thick lines; results for sensitivity cases are indicated by thin lines.

Because systems are planned to ensure a minimum RA target is met, there is no trend in RA outcomes between transmission frameworks. Instead, the value of transmission for RA is realized as the change in cost of meeting RA needs, discussed in Section 3.3.1.

A variety of technologies supports resource adequacy

As discussed in Section 2.1 and Appendix B, the coupled ReEDS-PRAS model addresses RA requirements by identifying "stress periods" with a high risk of unserved energy and including them in the co-optimization of generation, storage, and transmission capacity/operation in ReEDS. Though the nameplate capacity and average generation mix of the decarbonized systems explored here are dominated by wind and solar (Figure 23), wind and solar make up a smaller share of the generation mix during stress periods than during representative periods[37] (Figure 34). Hydropower and thermal technologies, conversely, make up a larger share of the generation mix

[37] Low availability of wind and/or solar on a given day can be the reason that day qualifies as a stress period.

during stress periods than during representative periods. These results show that all technologies—including wind and solar—contribute to the energy and RA needs although the relative contributions between technologies can vary significantly.

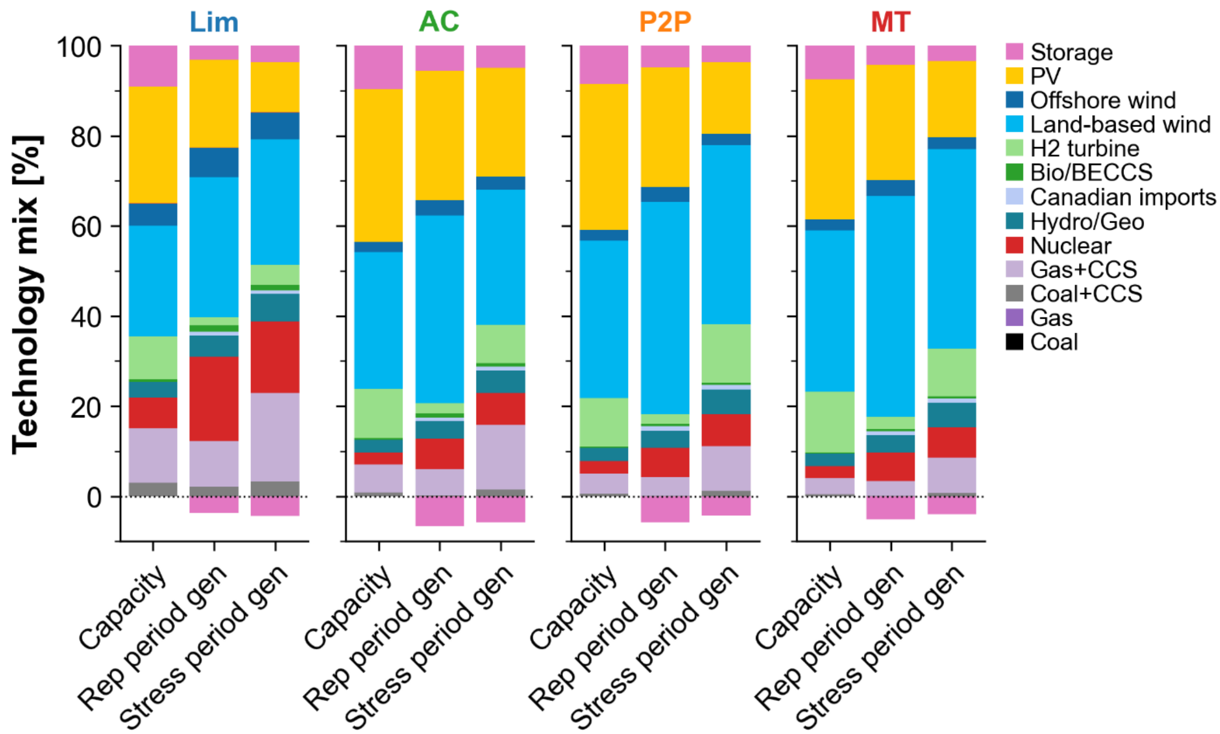


Figure 34. Nameplate capacity mix, representative period generation mix, and stress period generation mix for the core transmission frameworks in 2050 under Mid-Demand 90% by 2035 assumptions.

Stress periods in this study are modeled as coincident 24-hour days over the contiguous United States.

Though wind and solar contribute more to the bulk energy mix (the "Rep period gen" bars in Figure 34) than to the stress period resource mix, accelerating transmission deployment increases the contribution of wind and solar to the resource mix during stress periods. In the Mid-Demand 90% by 2035 scenario in 2050, wind and solar constitute 44% of the stress-period generation mix in the Limited transmission framework and 57%–64% in the accelerated transmission frameworks. The generation fractions provided here are for all hours of the modeled stress periods and for the contiguous United States as a whole; in particular hours and regions, the contribution of wind and solar can be much smaller (e.g., during low-wind or nighttime hours), and hydro/thermal technologies make up a larger share (Figure 35).

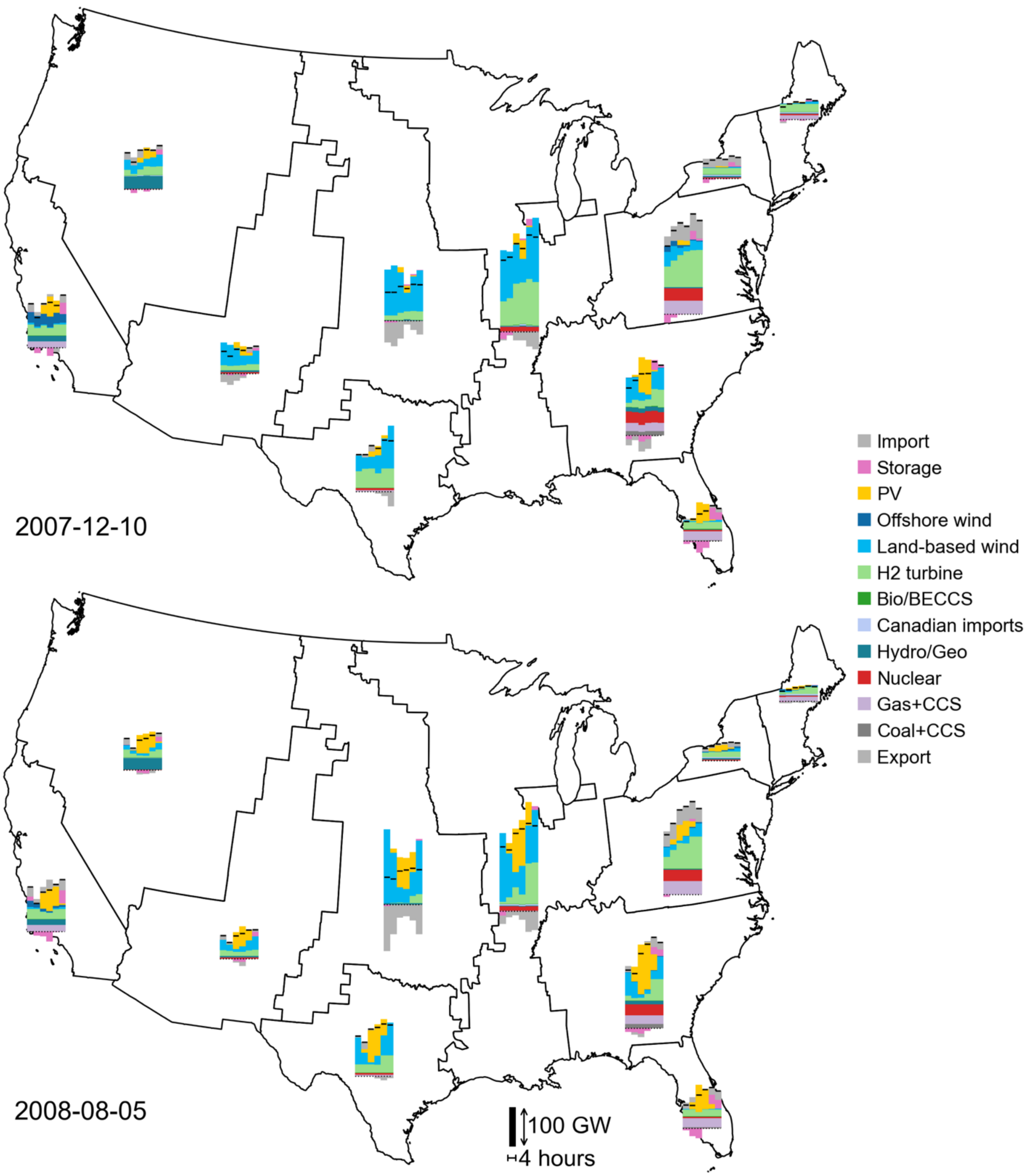


Figure 35. Regional dispatch in the MT framework under Mid-Demand 90% by 2035 assumptions in 2050 modeled in ReEDS during two example stress periods

Dates in this figure are given as year-month-day. The dates shown here refer to weather days from the 2007–2013 weather sample; the capacity and demand mix are for the 2050 model year. 2007-12-10 is the stress period with least VRE generation; 2011-08-05 is the stress period with peak load. Regional load is indicated by thin black lines. Storage charging and exports to other regions are shown as negative values. Daily profiles are at the 4-hour resolution used within the ReEDS model for this study.

Interregional transmission—over spatial scales larger than weather systems—enables the sharing of variable renewables during days with limited local resource availability

Figure 34 shows wind and solar make up a larger share of the stress period generation mix in the accelerated transmission frameworks than in the Limited framework. Though improved access to high-quality resource regions with uniformly higher capacity factors explains part of this trend, interregional transmission also smooths out the geographic variability of these weather-dependent resources, particularly for wind (Kempton et al. 2010; Grams et al. 2017; Goggin 2021).

On the least-windy day in the weather dataset for a given planning region, neighboring regions are often significantly windier (Figure 36). For example, on ERCOT's least-windy day (2012-09-15), when the daily average capacity factor of ERCOT wind is only 6%, the wind capacity factor is 31% in neighboring SPP and 34% in MISO (a ~5 times difference). For CAISO, where daily wind capacity factor drops to 2% on 2013-11-17, the capacity factor in neighboring WestConnect and NorthernGrid is 40%–45%, ~20 times higher. These opportunities are sometimes bidirectional: On WestConnect's least-windy day (7% on 2010-12-05), neighboring CAISO has a wind capacity factor of 42%, ~6 times higher.[38]

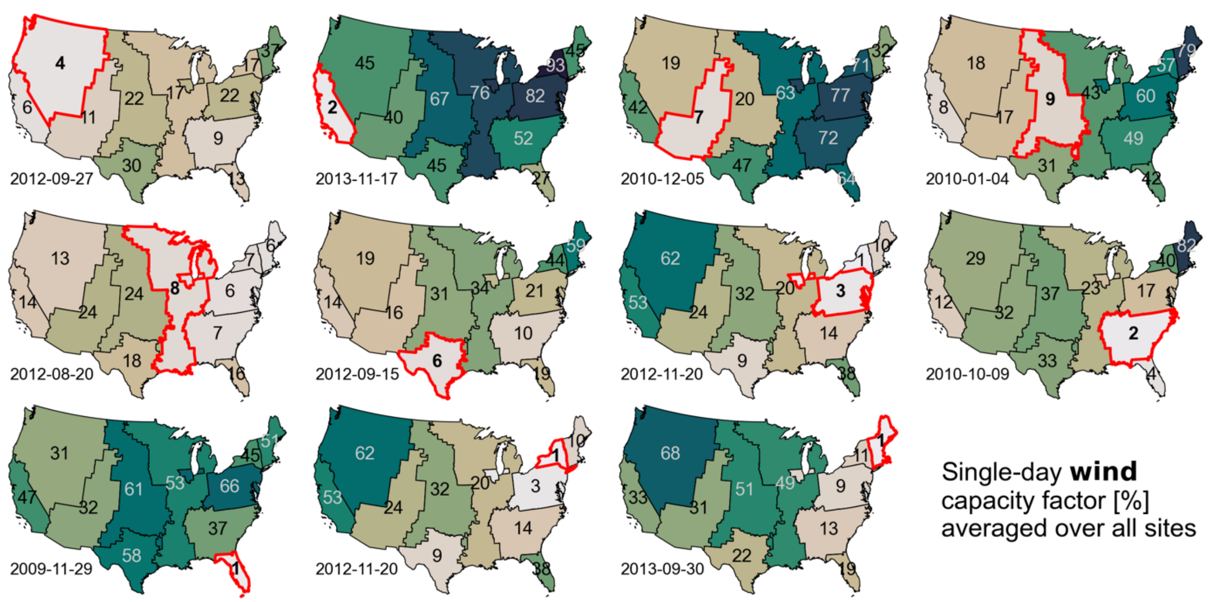


Figure 36. Single-day wind capacity factor on the least-windy day from 2007 to 2013 weather years in each planning region

For each map, the focused planning region is outlined in red, the date of the least-windy day in that region is given in the lower left, and the values and colors in each region represent the daily wind capacity factor on that date. Planning region values are taken as the available-capacity-weighted average modeled capacity factor over all resource sites in the planning region. Capacity factors are modeled using the reV model as discussed in Appendix A.2. Most of these sites are never developed; if only developed or higher-quality resource sites in each planning region were included, the capacity factors would be higher than shown here.

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[38] Complementarity between different resource types—illustrated in Figure D-14—provides further flexibility: On 2012-08-20, MISO and all its eastern neighbors aside from FRCC have wind capacity factors ≤8%, but solar capacity factor in these regions is above average on this summer day.

Similar examples can be observed for solar (Figure 37), though to a smaller degree than for wind given the uniformly greater seasonal variability of solar (all of the lowest-regional-capacity-factor days for solar occur during winter, with fewer hours of sunlight available regardless of weather). Though there are some strong resource-sharing opportunities—on MISO's least-sunny day (1% on 2009-12-24), the capacity factor in neighboring PJM is ~10 times higher—there are also days when large fractions of the country have uniformly low resource: On 2007-12-28, no planning region east of SPP has higher than a 6% capacity factor. On ISONE's least-sunny day (1% on 2012-12-10), resource sharing would have to extend to MISO or SERTP to reach ≥5% capacity factor.

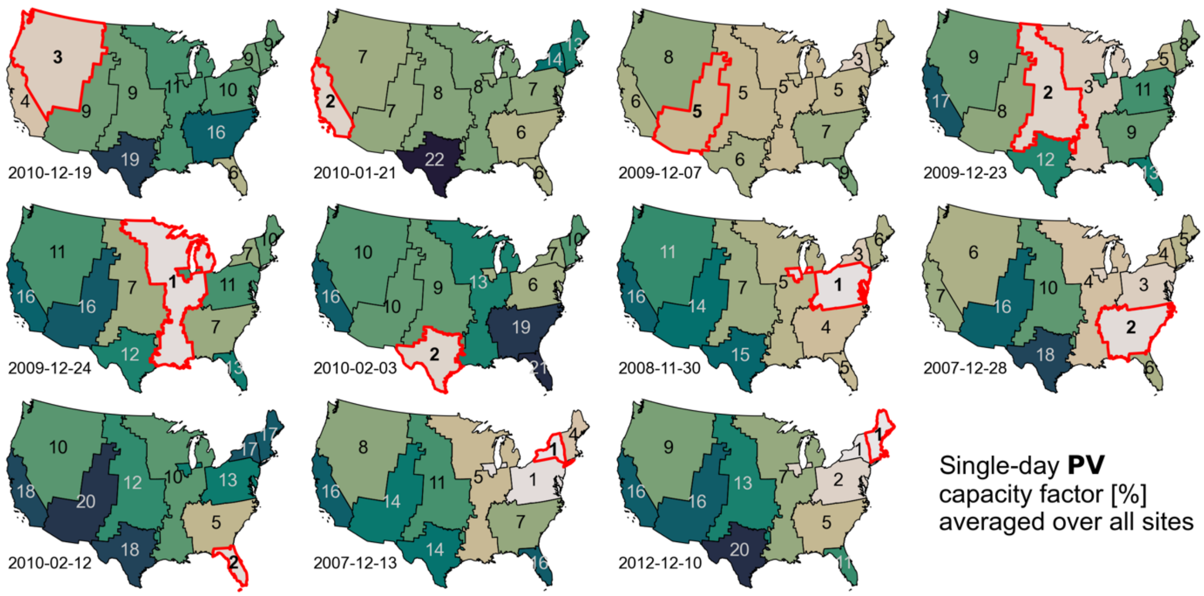

Figure 37. Single-day PV capacity factor on the least-sunny day from 2007 to 2013 weather years in each planning region

For each map, the focused planning region is outlined in red, the date of the least-sunny day in that region is given in the lower left, and the values and colors in each region represent the daily PV capacity factor on that date. Planning region values are taken as the available-capacity-weighted average modeled capacity factor over all resource sites in the planning region. Capacity factors are modeled using the reV model as discussed in Appendix A.2. Most of these sites are never developed; if only developed or higher-quality resource sites in each planning region were included, the capacity factors would be higher than shown here.

Electricity demand also demonstrates interregional variability, which can be smoothed by interregional transmission (Figure 38) although the opportunities are less pronounced than for wind and solar. Here, if adjacent planning regions reach peak demand on different days, they could have spare capacity to assist neighboring regions in meeting their peaks. The greatest opportunity observed in the Mid-Demand scenario for 2050 is on MISO's peak day of 2009-01-15, when demand in neighboring ERCOT reaches only 69% of its peak. For most regions on their peak-containing day, demand in neighboring regions is ~85%–90% of its regional peak.

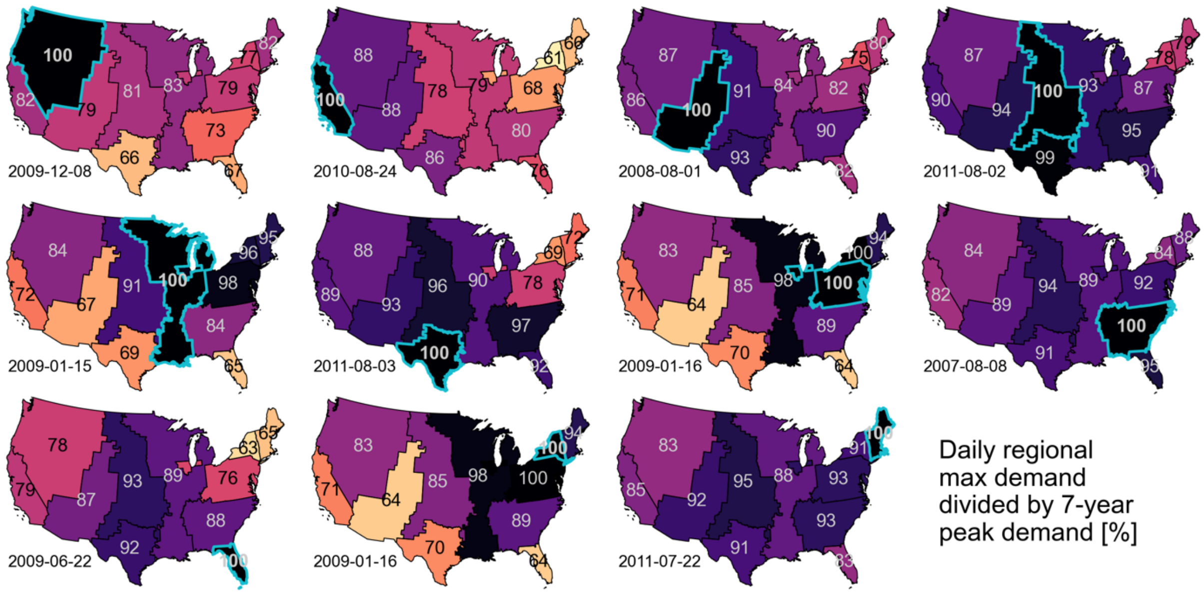

Figure 38. Daily regional maximum demand divided by 7-year peak demand for that region, shown for the regional peak demand day from 2007 to 2013 weather years for each planning region

For each map, the focused planning region is outlined in blue, the date of the peak demand day in that region is given in the lower left, and the values and colors in each region represent the relative regional peak demand (normalized to the total regional peak demand across all 7 weather years) on that date. For example, 2009-12-08 is the peak demand day for NorthernGrid over 2007–2013; on that day, CAISO demand reaches 82% of peak CAISO demand over 2007–2013. Demand data are from the Mid-Demand assumption for 2050.

Bidirectional power flows between regions support resource adequacy

Within the PRAS model, transmission is used only to avoid dropping load; PRAS does not consider variations in marginal cost between generation technologies. Transmission flows in PRAS thus illuminate the use of transmission specifically related to grid reliability when local generation alone does not meet RA needs.

A diversity of usage patterns is observed in the PRAS model results for interregional transmission in the accelerated transmission frameworks (Figure 39). Hourly flow patterns are presented in Appendix D.3. Some interfaces in the P2P framework are used almost entirely unidirectionally: for the SPP→SERTP, MISO→FRCC, and MISO→PJM interfaces, 99.9+% of RA flows are in the indicated direction on a megawatt-hour (MWh) basis. Others are bidirectional: For the MISO→ERCOT, NYISO→ISONE, ERCOT→WestConnect, MISO→SPP, and CAISO→NorthernGrid interfaces, the distribution of RA flows between the two directions is between 50/50 and 60/40, with the arrow denoting the predominate flow direction. For the SPP→PJM interface, the large majority (98%) of RA flows are from wind-rich SPP to demand centers in PJM, but ~900 hours in the 7-year weather sample have energy flows from PJM to SPP to help SPP meet its RA needs. This observation mirrors the examples shown in Figure 35 and Figure 36, where high-renewable-resource regions can still be aided by neighbors on locally poor resource days.

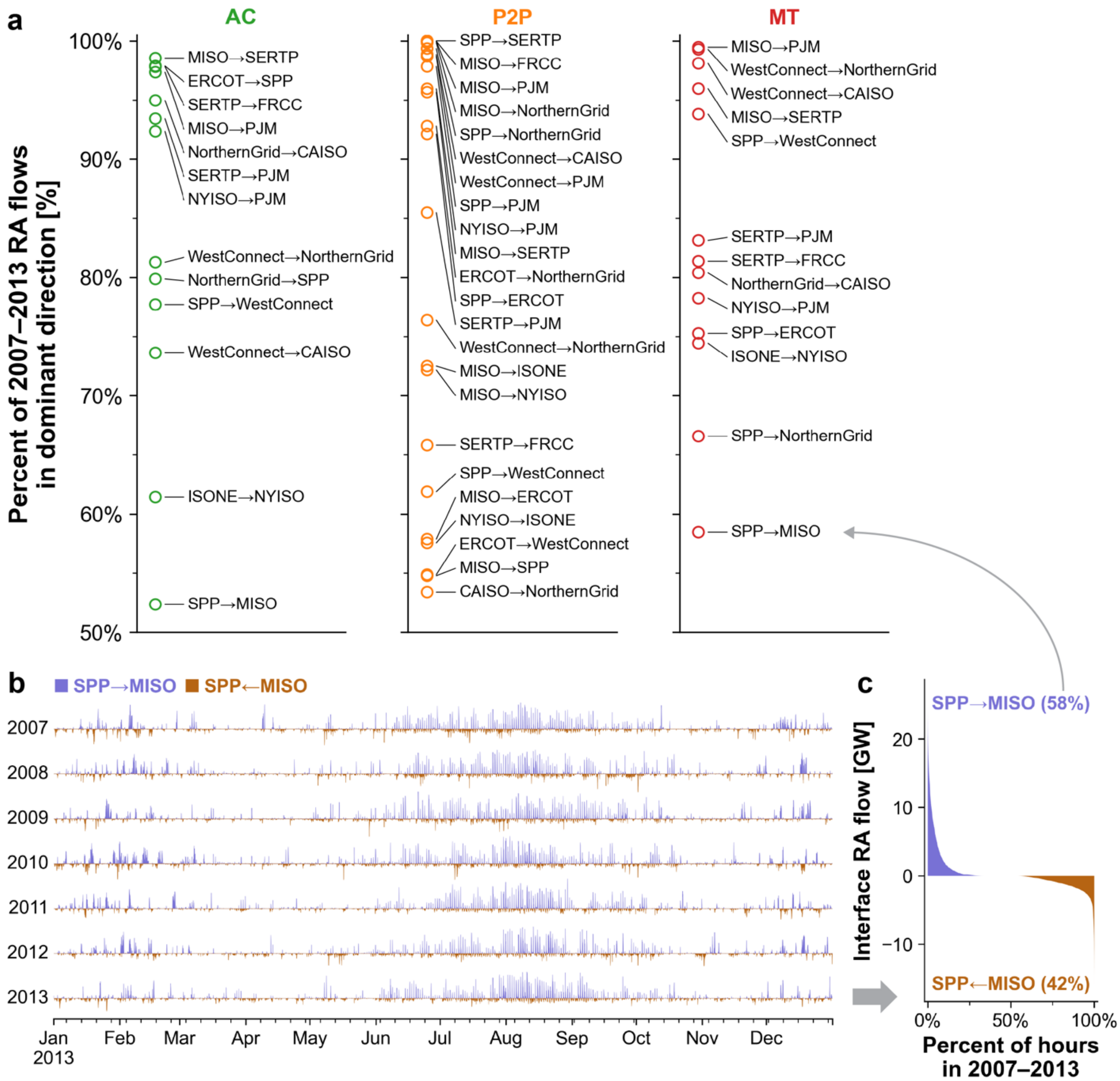

Figure 39. Bidirectional transmission flows between regions for resource adequacy in 2050 under Mid-Demand 90% by 2035 conditions as modeled by PRAS

For each interface between planning regions (Figure 1c), the dominant direction is determined by the fraction of total hourly flow modeled in PRAS on a MWh basis over the 7 weather years spanning 2007–2013, and the percent of total flow in the dominant direction for each interface is shown in panel (a). Illustrative hourly flows and the sorted distribution of flows for the SPP→MISO interface in the MT framework are shown in (b) and (c), respectively.

Interregional resource adequacy coordination reduces the cost of meeting resource adequacy requirements

Because ReEDS co-optimizes the deployment and operation of generation and transmission to meet demand in both representative and outlying periods at least cost, it is difficult to disentangle the “energy value” and “RA value” (or “capacity value”) of interzonal transmission investments within a single ReEDS scenario.

To isolate the effects of interregional coordination of RA planning (or "RA sharing") on system cost and transmission deployment, two scenarios are compared: the "core" scenario using default assumptions and the "No RA sharing" sensitivity case where transmission flows are not allowed between planning subregions (Figure 1b) to meet RA needs. In effect, this sensitivity case requires each planning subregion to meet its RA needs solely from resources within its own borders rather than rely on interregional transmission and excess resource availability from neighbors.

Total costs through 2050 are notably higher in the "No RA sharing" case than in the "core" scenario that allows regions to coordinate to meet RA needs—roughly $200 billion higher in the Limited, AC, and P2P transmission frameworks and ~$380 billion higher in the MT framework (Figure 40a). Substantial savings could accrue from using existing interregional transmission for RA sharing, as evidenced by the large savings in the Limited transmission framework where new interregional transmission additions are not allowed.

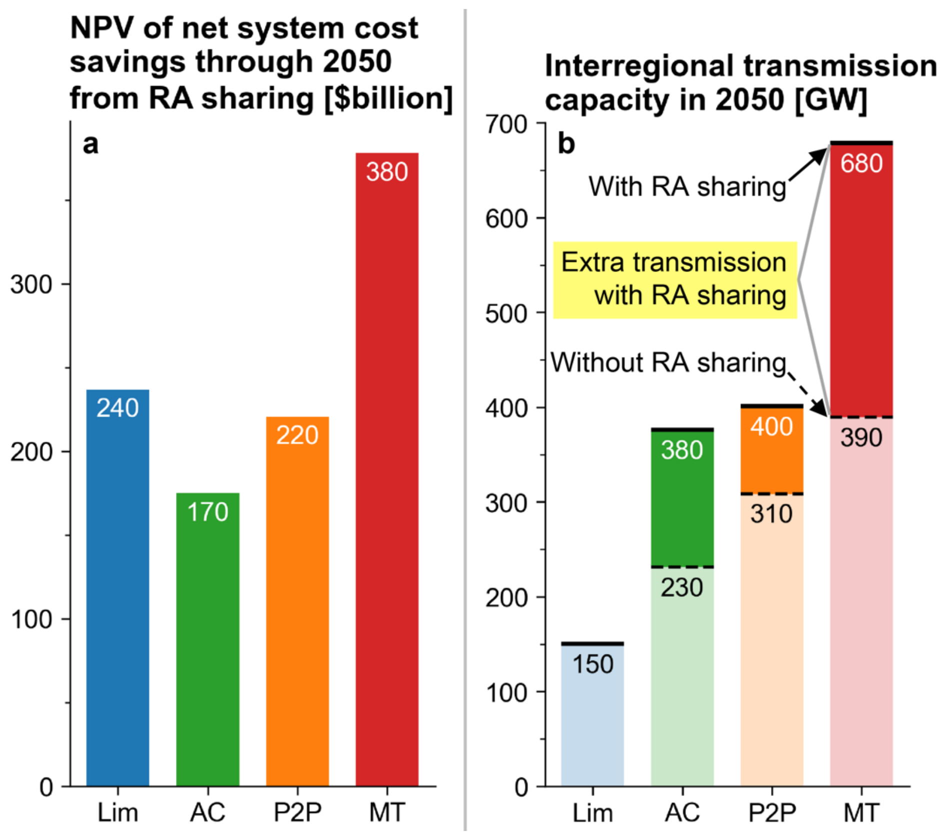

Figure 40. Impact of the allowance of interregional RA sharing on system cost (a) and optimized interregional transmission capacity (b)

System cost savings (as shown in panel (a)) for each of the demand and emissions assumptions shown in Figure 3 are provided in Figure D-17.

Significant amounts of interregional transmission are built primarily to serve resource adequacy needs

The ability to use interregional transmission to meet RA needs also leads to substantial additions of new interregional transmission in scenarios that allow it (Figure 40b and Figure 41). Cost-minimizing interregional transmission capacity additions drop by ~40%–60% across the three accelerated transmission frameworks if RA sharing is not allowed, contributing to the ~$200–350 billion higher system cost compared to when RA sharing is allowed. Large interregional transmission additions in the upper Midwest drop out of the optimal solution if RA sharing is not allowed, highlighting the significant value of transmission during scarce but high-consequence periods of system stress and aligning with recent studies exploring the contribution of short-duration electricity price spikes to long-distance transmission value (Millstein et al. 2022).

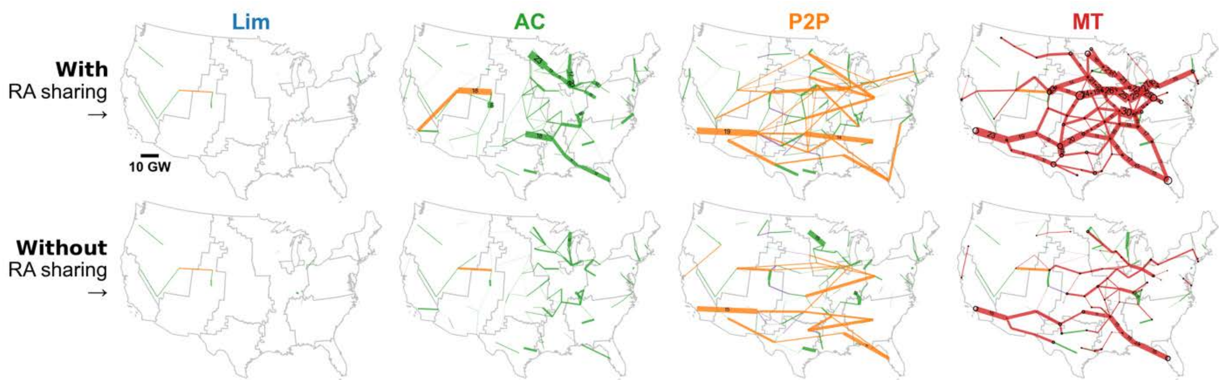

Figure 41. New transmission through 2050 with Mid-Demand 90% by 2035 assumptions for the four transmission frameworks with (top) and without (bottom) RA sharing between planning subregions.

Conclusions

This chapter documents the methods, assumptions, scenario design, and results from the zonal capacity expansion, resource adequacy, and transmission value analyses of the NTP Study. The analysis is designed to assess the role of transmission in the future U.S. electricity system. It compares how different transmission frameworks—ranging from those where transmission expansion is limited to futures with highly coordinated transmission planning and development with advanced technologies—might impact this role. The analysis includes 96 scenarios that capture a broad range of possible market, policy, and technology uncertainties.

Overall, the analysis finds that accelerating transmission expansion enables decarbonization of the U.S. power system at lowest cost by enabling the interconnection and delivery of large amounts of inexpensive wind and solar energy—and other low-emissions resources—to all electricity consumers and to support resource adequacy.

Under Current Policies scenarios—which do not apply a limit on national emissions—accelerating transmission expansion can lead to cumulative CO_2 emissions reductions of 10.2–11.2 billion metric tons (43%–48%). With a limit on national CO_2 emissions, the benefits of transmission expansion are expressed through lower total system costs. These benefits increase with more rapid grid decarbonization and greater electrification. With the core central decarbonization assumptions, which include 90% emissions reductions by 2035 and Mid-Demand growth (2.0%/year), accelerated transmission expansion saves $270–490 billion in electricity system expenditures through 2050. The system cost savings outweigh expenditures for transmission, resulting in high transmission benefit-cost ratios (above 1.5) for all scenarios and sensitivity cases.

Significant amounts of transmission are added in the decarbonized systems modeled. In the central decarbonization scenarios, total U.S. transmission grows to 2.4–3.5 times the size of the 2020 grid by 2050 across the accelerated transmission frameworks; the amount of growth scales with decarbonization rate and demand growth. Transmission expansion occurs at all scales, including local interconnections for new wind and solar, longer-distance interregional transmission, and, when allowed, seam-crossing transmission that increases the transfer capacities between the Western, Eastern, and Texas interconnections. Scenarios that consider HVDC additions result in greater total regional and interregional transmission expansions and yield the largest economic benefits.

Transmission is added in all regions of the country, but the highest concentration is developed in the central wind belt. This geographic distribution of transmission development is robust across the sensitivity cases modeled. The amount and location of interregional transmission expansion between subregional pairs by 2035 is identified based on the full suite of sensitivity cases and referred to as High Opportunity Transmission (HOT) interfaces. Further study is needed to identify potential transmission projects that align with the subregional HOT interfaces.

Resource adequacy is considered in the development of all the scenarios modeled to ensure RA needs are met in decarbonized systems, including those with significant transmission expansion and much greater reliance on remote and variable resources. A variety of technologies contributes to meeting adequacy needs. Transmission can support RA by enabling the sharing of resources and increasing geospatial diversity of load and VRE, especially with interregional transmission over spatial scales larger than weather systems. Without interregional RA coordination to take advantage of transmission's capabilities to support RA, total system costs to decarbonize are estimated to increase significantly and less transmission development occurs. In other words, RA is an important source of value for transmission in the future.

These findings demonstrate how accelerating transmission expansion can support a lower-cost transition toward energy system decarbonization while maintaining reliability. However, the complexities of transmission planning require higher-fidelity analysis to increase confidence in these results. For example, this chapter examines resource adequacy for the scenarios, but operational reliability and resiliency are not analyzed. The scenario analysis presented in this chapter provides the starting point for further study. Subsequent chapters present the production cost, power flow, and other detailed analysis for a subset of—and variations to—the scenarios described in this chapter.

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Appendix A. Regional Energy Deployment System (ReEDS) Model

The National Renewable Energy Laboratory (NREL) ReEDS model is a capacity expansion model for the contiguous United States electricity system. ReEDS co-optimizes generation, storage, and transmission to find the systemwide least-cost portfolio that meets demand, grid reliability, and policy requirements. For this study, ReEDS starts in 2020 and optimizes each 5-year solve period sequentially through 2050. The ReEDS documentation (Ho et al. forthcoming) and latest NREL Standard Scenarios report (Gagnon et al. 2024) provide further details about the model. The model is open source and can be accessed at https://www.nrel.gov/analysis/reeds/. Earlier versions of ReEDS have been used in several transmission, grid integration, and policy and scenario studies, such as the North American Renewable Integration Study (Brinkman et al. 2021), Denholm et al. (2022), and the Electrification Futures Study (C. Murphy et al. 2021).

This appendix highlights newer capabilities in ReEDS that are relevant to the NTP Study.

A.1 Transmission Modeling

This section describes multiple aspects of transmission modeling in ReEDS: 1) existing interface transfer limits for the zonal structure of the model, 2) prescribed transmission projects in the scenarios, 3) transmission cost assumptions, 4) high-voltage direct current (HVDC) specific assumptions and modeling, and 5) assumptions for the annual build limits applied in the Limited framework.

For generation and storage, the model is initialized using unit-level data from the EIA Annual Energy Outlook. The capacity for each of these units is associated with a generator or storage type and one of the 134 model zones.[39] Retirements and new capacity builds are primarily endogenously determined as part of the model's decision-making process.[40]

Initializing the current transmission capacity for the zonal model is more challenging because of the alternating current (AC) nature of power flow dictated by Kirchhoff's laws. In particular, the aggregate interface transfer limit between two zones cannot be simply approximated by the sum of thermal capacities of the lines crossing the zonal boundary. A better approximation for the interface limits uses a method documented in Brown et al. (2023), which applies a DC power flow approximation approach. The approach starts with a nodal transmission dataset and results in estimates for the maximum transfer capacities across all interfaces for the 134 model zones.

[39] Multiple vintages are also tracked particularly to reflect the range of heat rates for thermal generators.

[40] Recently installed (2021–2023) capacity and projects that are under final stages of deployment, as identified by EIA, are also prescribed for development in the model across all scenarios. Similarly, announced plant retirements from EIA are also modeled.

For most interfaces, the method assumes all lines are available when estimating the interface transfer limits. However, for interregional interfaces—interfaces between zones in different transmission planning subregions, e.g., between SPP-North and MISO-North—a more conservative approach where the single largest line crossing the interface is assumed to be unavailable, reducing the maximum transfer limits between such zones, is applied. This approach serves as a proxy for the transfer capacity between planning subregions accounting for N-1 contingencies. One MW of new transmission between two zones adds one MW of transfer capability between the zones (no derate), but the sum of new transmission crossing between transmission planning subregions is derated by 15% for the determination of maximum interregional flows (so if 100 MW of new transmission capacity is added across interfaces between SPP-North and MISO-North, the transfer capability between SPP-North and MISO-North is increased by 85 MW) as a linear approximation of security constraints.

The ~65,000-bus North American Renewable Integration Study (NARIS) database (Brinkman et al. 2021) represents expected transmission capacity for 2024 and is used to estimate currently installed transmission in ReEDS. ReEDS begins installing new, currently unplanned transmission in the 2030 solve year to minimize total system cost. Select transmission projects that are under construction but not yet completed are prescribed to be built in the model during the 2030 solve period.[41]

In addition to the existing transfer capacity and prescribed transmission projects, ReEDS can decide to build new transmission capacity as part of its co-optimization framework. The cost for new transmission is based on cost estimates from Western Electricity Coordinating Council (WECC) (Western Electricity Coordinating Council 2019), MISO (MISO 2021), Southern California Edison (Southern California Edison 2021), and a representative southeast utility. Transmission cost estimates also account for terrain, land type, and other siting factors included in the Renewable Energy Potential (reV) model (Lopez et al. 2024).[42] For interzonal transmission, distances between model zones are estimated based on a least-cost path method between the largest load centers in the zones. These distances are longer than the straight-line paths between the load centers. For interzonal AC transmission, assumed costs are based on new greenfield 500-kilovolt (kV) (1500-MW) single-circuit lines (Western Electricity Coordinating Council 2019). Figure A-1 shows the resulting interzonal AC transmission capital costs that result from this process. Annual transmission fixed O&M costs are assumed to be 1.5% of the upfront capital costs per year (European Commission. Joint Research Centre. Institute for Energy and Transport. and SERTIS. 2014).

[41] Prescribed transmission projects in the scenarios include Colorado Power Pathway (3,274 MW), TransWest Express (3,000 MW), Greenlink Nevada (2,000 MW), and Boardman to Hemingway (1,732 MW). Several other transmission projects, some announced after the analysis was completed, are at various stages of development. Their exclusion does not imply any judgment about their viability.
[42] https://github.com/NREL/reV

The same approach for estimating transmission costs is used to estimate interconnection costs for new wind and solar capacity (see Section A.2) but with lower voltages and associated higher costs on a per MW-mile basis.

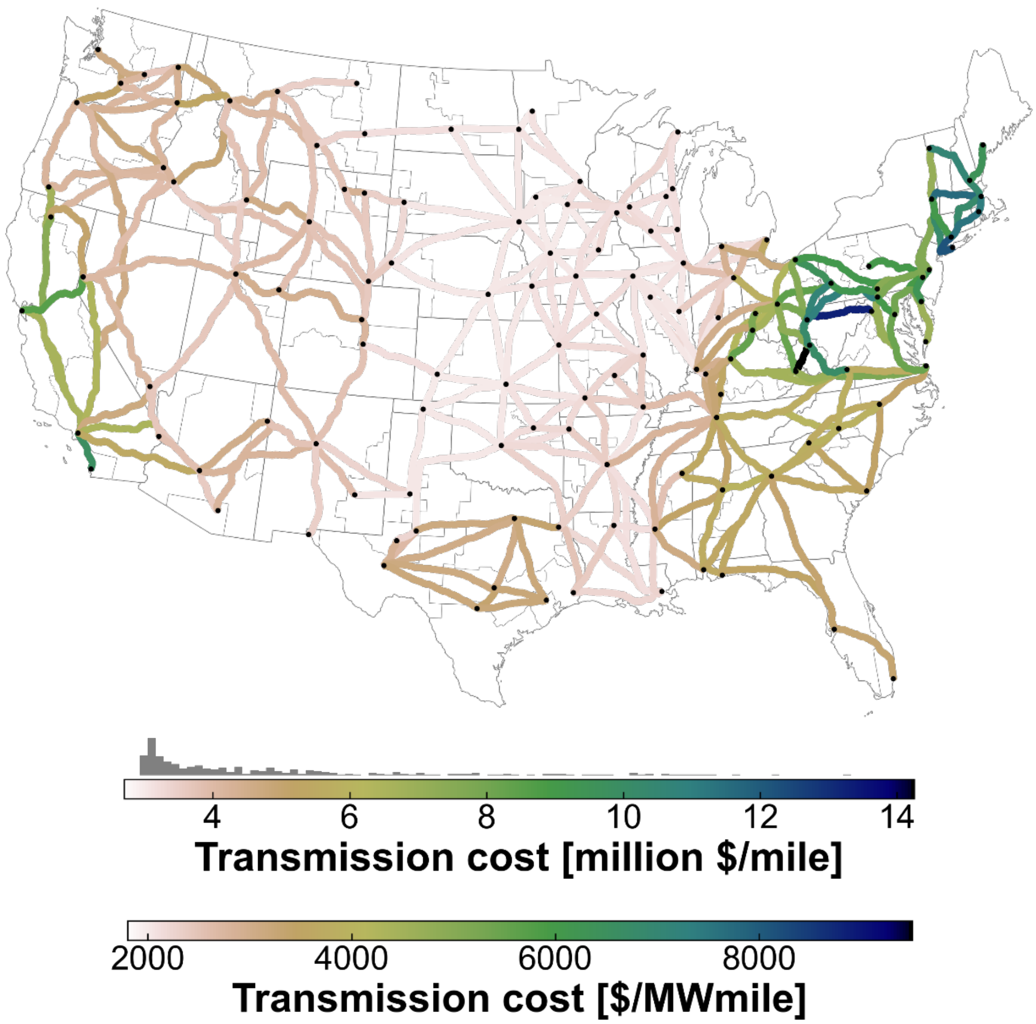


Figure A-1. Interzonal AC transmission cost assumptions

Direct current (DC) transmission line costs are assumed to be approximately 60% less than the $/MW-mile costs shown in Figure A-1 for AC transmission based on the MISO cost estimation guide (MISO 2021). However, DC transmission has the added cost of the converter stations. These are assumed to be $140/kW for line-commutated converters (LCCs) and back-to-back (B2B) interties and $180/kW for voltage source converters (VSC), also based on MISO (MISO 2021).

For the multiterminal (MT) framework, HVDC connection options are the same as those shown in Figure A-1 for AC transmission. For point-to-point (P2P), a new set of long-distance 195 candidate connections is included (Figure 2c). These are identified based on the highest wind resource and load centers in each region. Distances between these points are also based on the least-cost path estimation method.

Transmission losses are approximated based on distances between the zone "centers" (taken as the largest urban center when available, or a large transmission substation for zones without urban areas). Line losses are assumed to be 1% per 100 miles for AC transmission and 0.5% per 100 miles for DC. Losses are also modeled for the AC to DC conversion with 0.7% losses assumed for LCC technologies (used in the P2P framework) and 1.0% for VSC (used in the MT framework) (Alassi et al. 2019).

As a linear model, ReEDS considers continuous amounts of transmission capacity—with transmission costs in units of dollars per MW-mile—rather than discrete transmission circuits or projects. This simplification can lead to unrealistically sized transmission lines, particularly for HVDC transmission under the P2P and MT frameworks. To partially mitigate this, the analysis applies an iterative approach with two model runs for each of the scenarios under the HVDC (P2P and MT) frameworks. The first run uses all possible candidates. During the second, HVDC connections for which ReEDS builds less than 1.5 GW of capacity by 2050 are excluded.[43] This approach does not preclude small capacities but greatly reduces their number. ReEDS does not comprehensively account for additional upgrades or reinforcements for expansion of high-voltage DC or AC lines—e.g., that may be necessary to address voltage or stability issues—but estimated network reinforcement costs are included for new wind and solar development (see next section).

Under the Limited framework, a constraint is applied to the annual rate of transmission deployment. This rate is based on the maximum amount of transmission build in the United States over the past 10 years (2014–2023). Data from Federal Energy Regulatory Commission (FERC) collected by Lawrence Berkeley National Laboratory (LBNL) (Wiser et al. 2023) are used to estimate this maximum. The historical transmission data are reported by voltage and miles. To use this in ReEDS requires converting the voltage into capacity, and the following simple conversion factors are assumed: 400 MW for ≤230 kV, 750 MW for 345 kV, and 1500 MW for 500 kV. This approach results in 1.83 TW-mile/year of maximum annual transmission builds.

A.2 Wind and Solar Supply Curves

Assumptions for wind and solar developable potential, resource quality, and transmission access used in ReEDS are developed from the reV model (Maclaurin et al. 2021). reV is a high-resolution geospatial tool that considers renewable resources, land availability, hourly generation profiles, and transmission interconnection costs for approximately 60,000 potential sites across the contiguous United States. The most recent results and assumptions of the reV analysis for land-based wind and utility-scale solar photovoltaics (PV)[44] are documented by Lopez et al. (2024) and summarized below.

The technical resource potential for wind and solar is affected by the available land that could be developed. Land availability is estimated by considering siting suitability and

[43] For the scenarios translated for nodal modeling (Chapter 3), this iteration is also applied in 2035 instead of 2050 because the nodal modeling is conducted for 2035 systems.
[44] reV is also used similarly for offshore wind and concentrating solar power.

spatial exclusions from other uses. These siting considerations include terrain (e.g., slope, elevation), airspace and defense (e.g., airports, radar), environmental factors (e.g., endangered species habitat, wetlands, national parks and conservation areas), and siting regulations (e.g., setbacks from existing structures, roads, railroads, transmission lines, and pipelines). Default exclusion assumptions used for nearly all scenarios are based on the "Reference Access" case (Lopez et al. 2024). Under these assumptions, the total developable areas for wind and PV across the contiguous United States are 1.9 million square kilometers (km^2) and 2.6 million km^2, respectively. These land areas correspond to a technical potential of 11 TW of capacity potential for wind and 112 TW for PV; the higher PV potential is because of the relatively lower total land use requirements.[45] The developable potential for these resources is not spatially uniform with generally lower resource potential in locations with higher populations and associated built environment. Figure A-2a,c shows maps of the assumed resource potential for wind and solar, respectively, under the default assumptions. This available potential represents *options* that ReEDS could choose to deploy based on its optimization framework, which is much larger than the resulting buildout in the scenarios. ReEDS aggregates these available sites into its 134-zone structure but includes additional resource classes and transmission cost bins (Ho et al. forthcoming).

To capture the uncertainty associated with renewable energy siting over the next 3 decades, a Siting Limited sensitivity (Section 2.3.5) is included. For the Siting Limited sensitivity, the "Limited Access" siting regimes from Lopez et al. (2024) replace the Reference Access assumptions. Limited Access has more stringent exclusions, such as greater environmental exclusions and much larger setbacks that represent social challenges with siting. In this case, the developable area (and capacity) for wind is reduced to 800,000 km^2 (5.9 TW) and to 1.4 million km^2 (58 TW) for PV. As shown by Figure A-2b,d, the available resources are even more concentrated in the central regions of the country with lower population densities.

[45] The disturbed land area for these technologies differs, with <5% of the area of wind plants from roads, pads, and other infrastructure whereas approximately 90% of the area is covered by solar panels and other infrastructure.

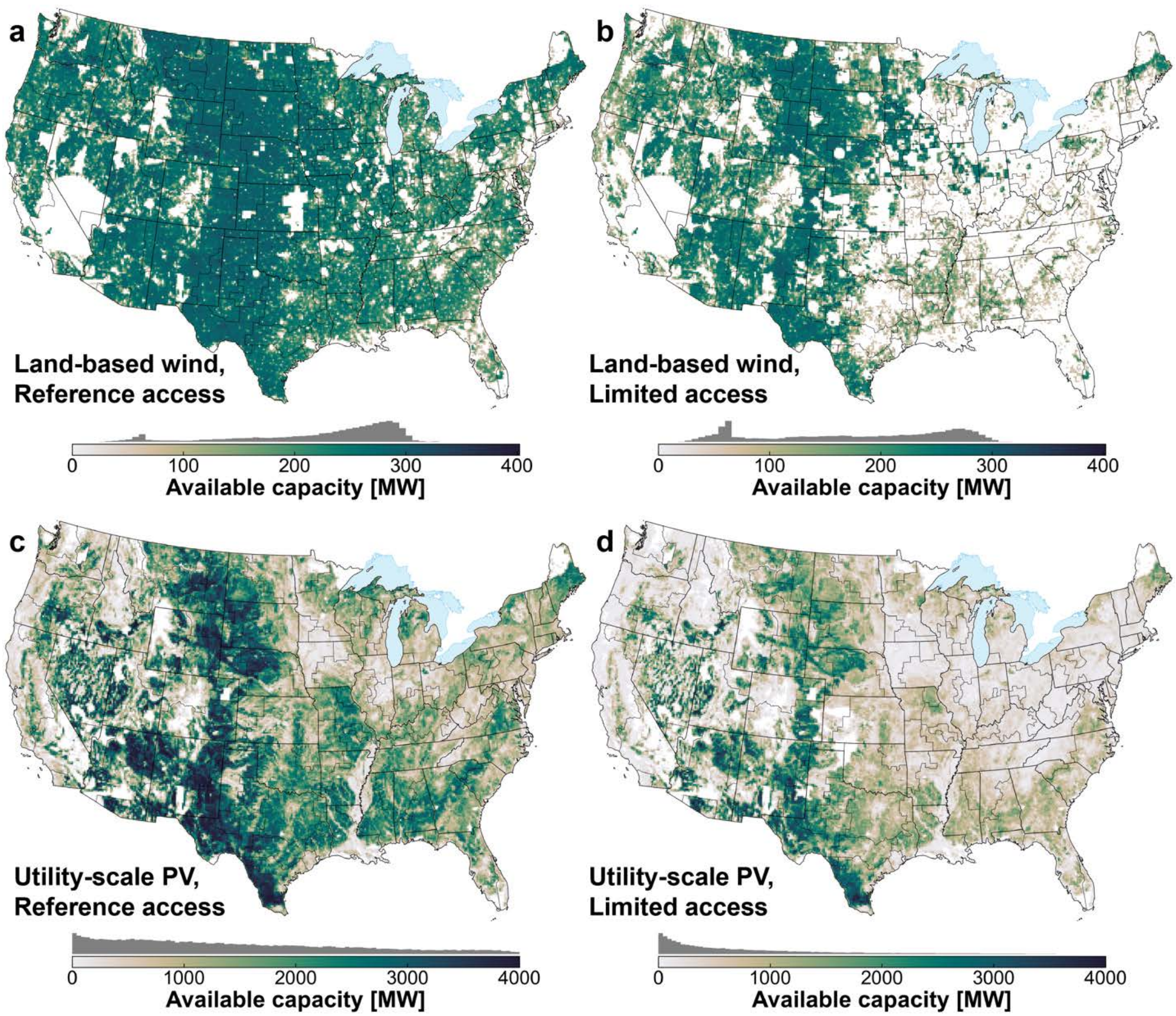


Figure A-2. Available land-based wind (a, b) and utility-scale PV (c, d) capacity under Reference Access (a, c) and Limited Access (b, d) assumptions

Histograms of available capacity by site are included above color bars. Note the difference in color scale limits between wind (a, b) and PV (c, d).

In addition to the developable potential, reV also estimates the performance (capacity factor) and generation profiles for each of the ~60,000 sites. Generation is modeled using the System Advisor Model[46] and based on meteorological data (e.g., wind speed, irradiance, temperature) from the 2-km resolution WIND Toolkit (Draxl et al. 2015) and 4-km resolution National Solar Radiation Database (Sengupta et al. 2018), including losses. Hourly generation is modeled for 7 weather years (2007–2013) for which coincident wind, solar, and demand data are available. The wind and solar technology assumptions are based on the Annual Technology Baseline (ATB) 2023 Moderate case for 2030.

[46] https://sam.nrel.gov/

Figure A-3 shows supply curves—the resource potential (in GW) ordered by lowest levelized cost of energy (LCOE)[47] in 2030—based on the land availability and performance assumptions from reV. The dashed lines show the supply curves without considering interconnection costs (Site LCOE). Interconnection costs as modeled in reV include spur lines to connect the renewable energy site to an existing substation that is the point of interconnection (POI), POI substation upgrade costs, and network reinforcements that represent other upgrades needed for the grid network. The underlying equipment costs and routing methods associated with these are based on the same sources used for interzonal transmission (Section A.1) but based on a wider range of voltages (Lopez et al. 2024). For network reinforcement costs, assumed per mile costs for upgrades are 50% of the cost of greenfield transmission and effective distance of upgrades based on the POI location and the largest load center in each of the 134 model zones (traced along the existing transmission system). This is a simplified approach to estimating interconnection costs but provides regionally varying costs that are approximately aligned with empirically observed costs (Seel et al. 2023). Figure A-3 shows how including interconnection costs (All-in LCOE, solid lines) is estimated to increase LCOEs by at least \$5–\$10/MWh for many locations. The modeling does not choose sites and technologies based on LCOE; LCOEs from Figure A-3 are shown to indicatively display the resource potential and quality assumed.

[47] ReEDS does not select resources based on LCOE. For example, options with higher LCOE can be chosen if their profiles are better aligned with system needs or the locations are preferred because of transmission congestion or for other reasons.

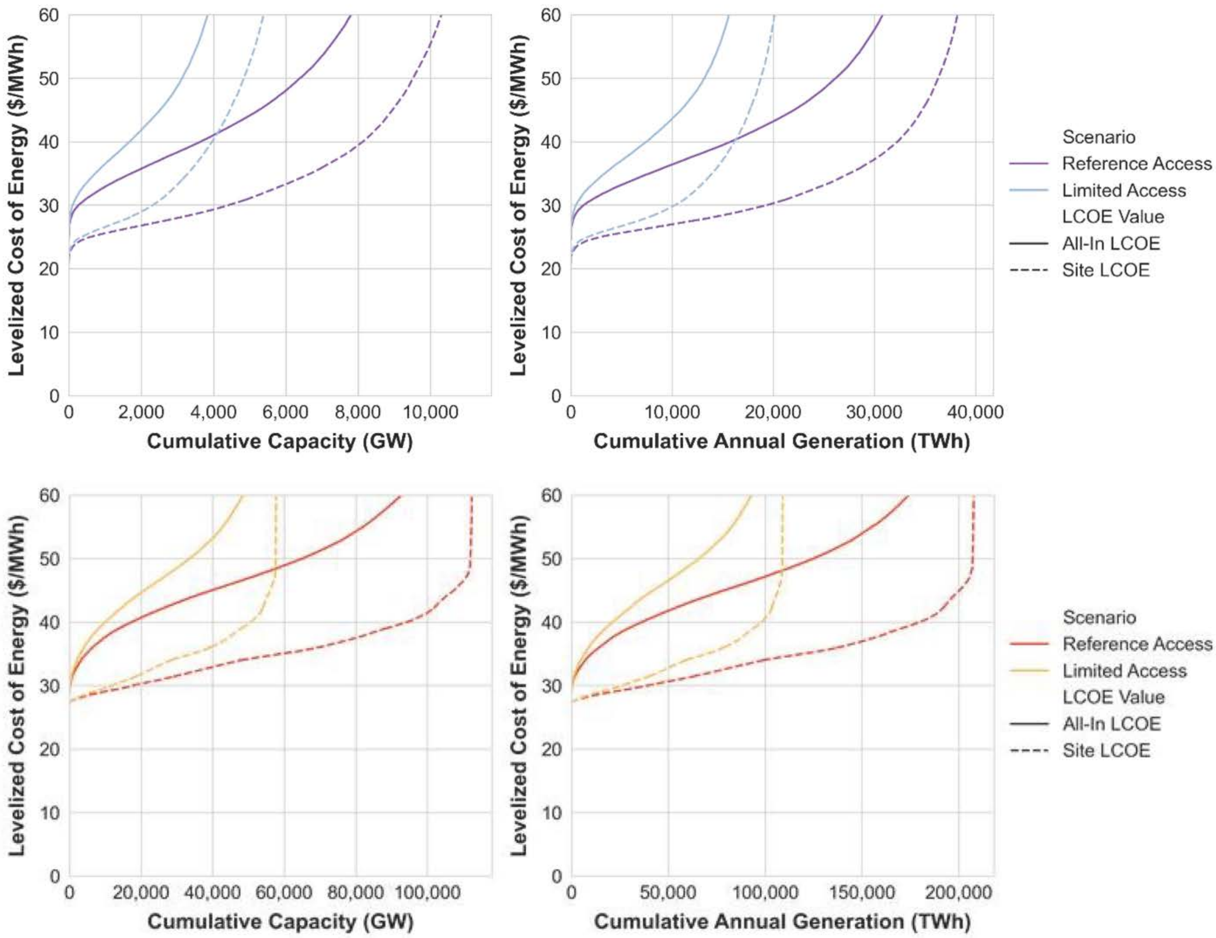


Figure A-3. LCOE supply curves for land-based wind (top) and solar PV (bottom)

Source: Adapted from Lopez et al. (2024). LCOEs are based on 2030 technology assumptions. Values above $60/MWh are not shown. "Site" LCOE excludes interconnection costs. "All-in" LCOE includes interconnection costs.

The interconnection costs modeled here are reflected in ReEDS, and these expenditures are tracked as local transmission investments. Local transmission distances and capacities—usually reported in MW-miles—also use the spur line distances and traced network upgrades.

A.3 Hydrogen Modeling

Hydrogen production and use for grid applications is endogenously modeled in ReEDS for the NTP Study. In other words, capacity for electrolyzers, hydrogen storage, and hydrogen-fueled generation are all decisions made by the model considering their assumed costs and constraints. For the NTP Study scenarios, hydrogen production is modeled via electrolysis only; steam methane reforming with or without carbon capture and storage (CCS) is not considered. In the default scenarios, electrolyzer costs are assumed to decline from $1,750/kW in 2022 to $550/kW in 2030 and remain constant after 2030 (DOE 2023b). In the Electrolyzer Low Cost sensitivity, electrolyzer costs decline to $157/kW by 2050 (DOE 2023b).

The model includes the electricity demand needed for electrolysis, which increases overall demand beyond the level shown in Figure 5 and Figure 6. Two forms of geological hydrogen storage—salt caverns and hard rock formations—are included as well as the ability to construct storage in underground pipe systems. Data on the availability of geological storage are taken from Lord et al. (2014) (Lord, Kobos, and Borns 2014). Costs for all three storage options are based on Papadias and Ahluwalia (2021) (Papadias and Ahluwalia 2021) and are approximately $40/kilogram of hydrogen (kg-H_2) for salt caverns, $65/kg-$H_2$ for hard rock, and $590/kg-$H_2$ for underground pipes. Electricity generation based on hydrogen is modeled to be from combustion turbines (CTs). These can be new greenfield H_2-CTs or can be retrofitted from existing natural gas (NG) power plants. The cost of greenfield H_2-CTs is assumed to be the same as that of new NG-CTs except with a 3% cost increase to account for adding a clutch to enable the CT to operate as a synchronous condenser (Denholm et al. 2022). Upgrades from NG-CT to H_2-CT are assumed to be 33% of the cost of a new plant, and upgrades from natural gas combined cycle (NG-CC) to H_2-CT are assumed to be 55% of the cost of a new plant because of the need to upgrade the steam turbine as well. Heat rates are assumed to be the same between H_2-CTs and NG-CTs.

Hydrogen storage levels are tracked chronologically over the modeled weather year at daily resolution within each model zone. In this way, the modeled hydrogen option is representative of seasonal storage and serves the primary purpose of supporting resource adequacy in the scenarios. Transport of hydrogen between zones is not allowed. Future work is needed to assess the relative trade-offs between hydrogen and electricity transmission. In addition, the scenarios do not include the use of hydrogen outside of the electricity sector, e.g., for use in industry and transportation. And, as noted in Section 2.3.2, hydrogen tax credits are not included in this study because the final policy was not released when the analysis was completed.

A.4 End-Use Emissions

The three electricity demand cases (Low, Mid, High) are based on different levels of electrification and associated reductions in end-use emissions as described in Section 2.3.3. Figure A-4 shows how direct emissions from the end-use sectors (e.g., vehicle tailpipe emissions for transportation, emissions from natural gas combustion in furnaces and water heaters in buildings, and emissions from heating and other processes in industry) vary across these cases. The power sector emissions results from ReEDS can be combined with these to estimate total energy emissions in the United States; however, care is needed to account for emissions from indirect electrification because consumption of hydrogen outside the power sector is not included.

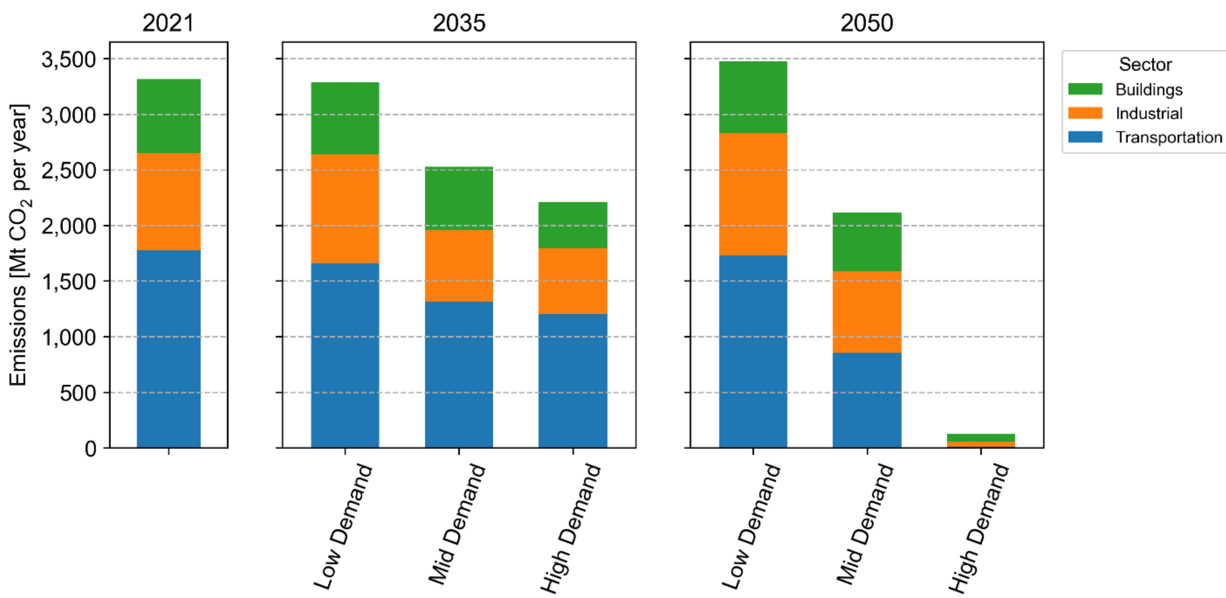


Figure A-4. End-use emissions for the three electricity demand cases

A.5 Climate Change Sensitivity

By default, ReEDS uses historical weather data for load and VRE generation profiles. Because future weather—and associated electricity demand patterns and generation performance—will likely differ from historical weather, a "Climate Change" case with a different set of assumptions is included as a sensitivity.

For this sensitivity, climate-change-impacted load and generation profiles were created from Super-Resolution for Renewable Energy Resource Data with Climate Change Impacts (Sup3rCC) (Buster et al. 2023). The Sup3rCC data are based on global climate model (GCM) data and use generative machine learning models to represent realistic spatiotemporal variability in wind, solar, and load profiles at a nominal 4-km hourly resolution. The Sup3rCC data used in this project are based on the climate model MRI-ESM-2.0 for the SSP5 Climate Change scenario with a climate forcing of 8.5 W/m^2 (Yukimoto et al. 2019). The projected weather data for 7 years (2050–2056) from this scenario are applied to all model years.[48]

Wind and solar PV generation profiles are created using the reV model with the Sup3rCC weather inputs and the same technology assumptions as used in ReEDS (Lopez et al. 2024). The climate-impacted load profiles are created using regression models that establish a relationship between state-level subsector loads (e.g., residential cooling loads for Colorado) and population-weighted hourly meteorological variables (e.g., air temperature, humidity, and irradiance). The regression models were trained on meteorological years 2007–2012 and validated in 2013. The validation results show low bias error, including during peak load hours, and demonstrate the

[48] In other words, the weather forecasted for 2050–2056 is applied to load, wind, and solar PV generation in all model years from 2020 to 2050. This is justified given the long-lived nature of most power system assets and the uncertainties with long-term load forecasts.

models' ability to extrapolate peak loads with nonhistorical temperature inputs (necessary to explore the impacts of climate change on high-stress events).

The climate-impacted load data show an increase in spring and fall demand during high-load periods, especially in the Southeast and the Pacific Northwest because of more frequent and intense heat events (Figure A-5). Summer peak loads generally increase within a state by 2%–8% in magnitude although there is significant spatial variability with some states exhibiting small decreases in load whereas others exhibit increases of up to 14%. Winter peak loads are highly dependent on weather year and region with most states in the East exhibiting a decrease in peak load and other states in the West exhibiting a slight increase in peak load. Because of the local nature of weather events that drive peak load events, the change in coincident peak load tends to decrease with larger spatial aggregations. For example, the coincident peak load across the contiguous United States increases only by 2%. The changes in peak load discussed here are based on isolated effects of weather. Load from both historical and future weather in these comparisons is based on end-use sector (i.e., electrification) assumptions from the 2050 model year in the High-Demand scenario. The impact of climate change on demand profiles is typically smaller in earlier years and for the lower electrification scenarios.

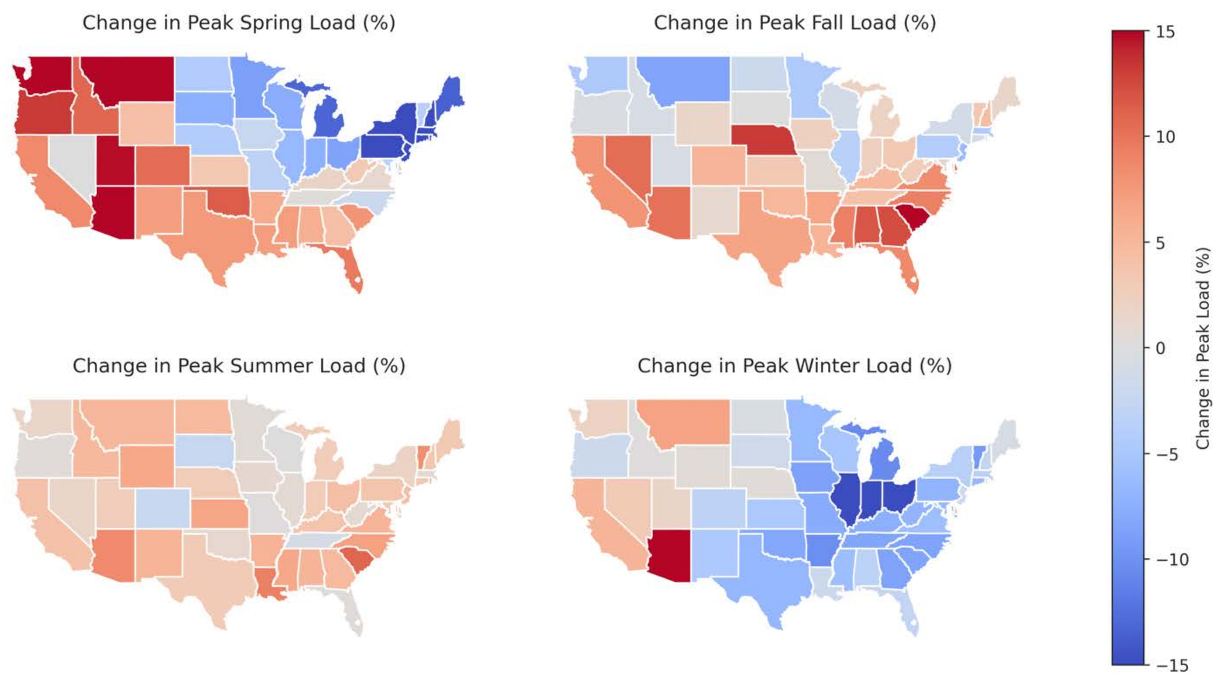


Figure A-5. Changes in seasonal all-sector peak load from historical weather (2007–2013) to future weather impacted by climate change (2050–2056)

The differences are based on the maximum hourly demand for each season across all 7 future weather years relative to the maximum during the 7 historical-weather-year period. This comparison is for the High-Demand case for the 2050 model year, which includes significant electrification.

The climate model and scenario used here do not project significant changes in renewable energy generation. Other GCMs have found larger changes to wind resources that could impact net load profiles and outcomes modeled (Martinez and Iglesias 2022). The Sup3rCC data used here are based on only 7 years (2050–2056) from a single climate model. Additional weather years would better represent the uncertainty from interannual variability. Alternative GCMs and scenarios would also yield different outcomes. Finally, because Sup3rCC is based on GCM data, it does not represent many important meteorological phenomena such as wildfires and hurricanes. Future work will study uncertainty from additional weather years, GCMs, and climate scenarios.

In addition to changes to demand, wind, and solar generation, the Climate Change sensitivity also includes adjustments to the potential contribution of hydropower, thermal resources, and transmission. Specifically, simple derate factors are applied to the summer capacity of these resources during both “representative” and “stress” periods modeled in ReEDS to represent various phenomena that could reduce the performance of these technologies or to reduce planners’ confidence in these resources for meeting system adequacy requirements.

To represent potential climate change impacts on hydropower resources, reservoir hydropower capacity is reduced by 20% during the modeled stress periods. This 20% reduction is applied for the 2050 model year with a simple linear ramp to this ultimate value starting in 2025. Derates are applied uniformly in all regions. The 20% value approximates impacts estimated by Turner et al. (2022) for hydropower facilities in WECC.

To represent climate change impacts on thermal cooling units, all available thermal generation capacity is derated during summer periods by 15% in 2050 with the same linear ramp starting from 2025. For thermal power plants, ReEDS uses summer capacity ratings, as reported for the EIA National Energy Modeling Systems data and supplemented with EIA form-860 data, for all nonwinter seasons. Summer capacity ratings are typically lower than winter or nameplate capacities, and the derate applied here is on top of this reduction as a proxy for higher temperatures and lower cooling water availability compared to historical summer periods.[49] This value is based on a 15% reduction in WECC thermal capacity driven by cooling water availability (Voisin et al. 2017). In addition, data from Electric Reliability Council of Texas (ERCOT) imply an 11% reduction in thermal capacity during summer (Electric Reliability Council of Texas 2022).

To represent climate change impacts on transmission, summer transmission capacity is derated by 5% by 2050 using a linear ramp starting from 2025. In ReEDS the transmission capacities are already based on summer ratings, so this reduction would be incremental to those driven by higher-than-historical temperatures during summer.

[49] Winter capacities are used for winter periods in ReEDS. All reported capacities in this study reflect summer ratings.

The 5% value is within the range estimated by Bartos et al. (2016). Another study for California suggests a 7% reduction (Sathaye et al. 2011).

Climate change impacts on demand, generation resources, and transmission are complex with significant uncertainties. Given the simple representation and proxy assumptions applied here, the results from the climate change sensitivity cases should be interpreted as indicative rather than definitive.

Appendix B. Integrated Capacity Expansion and Resource Adequacy Modeling

The Regional Energy Deployment System (ReEDS) and Probabilistic Resource Adequacy Suite (PRAS) models are operated in concert to analyze the scenarios presented in this chapter. Both models are summarized in Section 2.1. Appendix A provides more details about ReEDS; this appendix provides additional detail about PRAS and discusses how the models are integrated to help ensure the future portfolios analyzed are resource adequate. Mai et al. (forthcoming) provide further explanation about the combined modeling. Documentation for an earlier version of the PRAS model can be found in Stephen (2021), and the model is available open source.[50]

B.1 What Is PRAS?

PRAS is a probabilistic tool that simulates thermal generator outages and economic dispatch over a multiyear period to generate adequacy metrics for power system portfolios. It covers the same geographic extent (contiguous United States) with the same zonal spatial resolution (134 zones) as ReEDS. As described next, most of the data used in PRAS are passed directly from ReEDS. For example, hourly wind, solar, and load profiles are the same as those used in ReEDS. For this analysis, PRAS executes hourly simulations over 7 weather years (2007–2013).

PRAS models transmission in the same zonal manner as ReEDS and does not represent transmission outages. For thermal generators, the total capacity in each zone is disaggregated into individual units to facilitate the Monte Carlo assessment performed by PRAS. This disaggregation process uses data for existing units from the EIA National Energy Modeling System (NEMS) model (EIA 2023b) and, for new capacity, typical unit sizes from the 2023 Annual Technology Baseline (National Renewable Energy Laboratory 2023). Outage rates for thermal generators and storage are based on 2014–2018 data from the North American Electric Reliability Corporation (NERC) Generating Availability Data System (GADS) (NERC 2023b).

By using multiple years of hourly renewable energy and load possibilities along with thermal generator and storage outages, PRAS can provide statistical measures about the likelihood of unserved load. Reliability metrics estimated by PRAS include loss of load probability (LOLP), loss of load expectation (LOLE), and expected unserved energy (EUE). This can be used to assess system adequacy as well as when and where the system is likely to be stressed.

B.2 Integrated ReEDS-PRAS process

Figure B-1 shows how ReEDS and PRAS are used together. For a given solve period (e.g., 2035), ReEDS develops an initial system design that is passed on to PRAS. PRAS is then executed to estimate the total normalized expected unserved energy (NEUE)—where the normalization divides EUE by total contiguous U.S. load—and to

[50] https://www.nrel.gov/analysis/pras.html

identify the days of highest system stress (highest EUE). If a specified NEUE target is met, ReEDS proceeds to the next solve period (e.g., 2040). If the target is not met, ReEDS re-solves for the same solve period but with additional stress periods considered and the iterative process repeats. To limit computational runtimes, an iteration limit is also imposed, where ReEDS proceeds to the next solve period despite not meeting NEUE target; however, this seldom occurs in the scenarios.

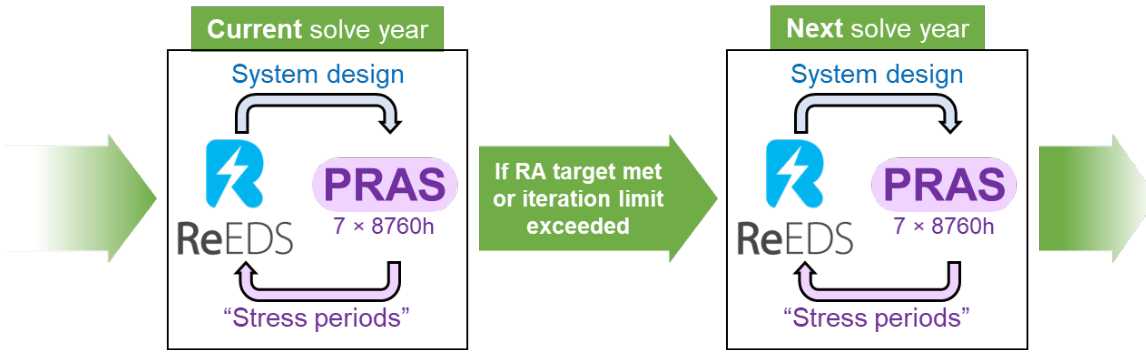


Figure B-1. Integrated capacity expansion and resource adequacy modeling

ReEDS models up to 30 stress periods, which are the periods with highest EUE as estimated by PRAS.[51] During the stress periods, ReEDS models dispatch in largely the same manner as the "representative periods." Important differences are that demand during these periods is elevated by the planning reserve margin (12%–18%), which is based on reference reserve margins from the 2021 NERC Long-Term Reliability Assessment (NERC 2021). Differences between this approach and a traditional planning reserve margin approach—including how it better addresses systems with higher VRE and transmission exchanges—are discussed by Mai et al. (forthcoming).

B.3 Planning Threshold

There are many metrics used to quantify resource adequacy (RA), with associated target reliability levels used in system planning. Most power systems in the United States quantify RA using LOLE, with a target of LOLE ≤1 day in 10 years (NERC 2023a). LOLE does not capture the severity of loss of load events; a power system that experiences a 1-day interconnection-wide blackout every 10 years and a power system that curtails 1 GW of industrial load on 1 day in 10 years would both satisfy the 1-in-10 LOLE target (Stenclik et al. 2021; Stephen et al. 2022). The EUE, measured in MWh, and load-normalized EUE (NEUE), measured as a percent or parts per million (ppm), metrics are volumetric rather than event-based, so the 1-blackout-in-10-years system would have much higher EUE and NEUE (and thus lower reliability) than the 1-industrial-load-shed-event-in-10-years system. Though NEUE-based system planning based has yet to become widespread, systems that do use NEUE-based planning tend to use NEUE targets in the range of 10 to 30 ppm (Alberta Electricity system Operator 2017; Electric Power Research Institute 2024; NERC 2024). In this study, the NEUE metric is used with a conservatively set threshold of 10 ppm. For context, if load were equally distributed across a year, 10 ppm would be equivalent to 5 minutes of complete

[51] The model is seeded with the highest demand period as a stress period to start.

load shedding (blackout) per year, 9% load shedding spread over a one-hour period, or 0.4% load shedding spread over a 24-hour day.

B.4 Caveats

The integrated ReEDS-PRAS formulation used here attempts to incorporate many of the practices recommended for evaluating systems with significant deployment of renewable energy, storage, and transmission (Stenclik 2023). However, as with any modeling analysis, there are limitations—and this section describes important caveats.

- **Reliability target.** The NEUE reliability metric is used in the scenario modeling for the reasons described previously, but this metric is not yet commonly adopted in practice. Another reliability metric could result in different outcomes. Moreover, because there are trade-offs between cost and reliability, different portfolio outcomes could result if the NEUE threshold assumption of 10 ppm were changed. The 10-ppm threshold is an upper bound in the model implementation; thus, the level of reliability can vary between 0 and 10 ppm across scenarios. Regional NEUE thresholds would also yield outcomes different from the national threshold used here.
- **Weather years.** Most scenarios consider 7 years of historical (2007–2013) weather in the PRAS modeling. Additional weather years would enable a more robust assessment of RA. Future weather conditions could also change and affect demand profiles and the contributions from weather-dependent resources.[52] The Climate Change sensitivity provides one sample of impacts from future weather (see Appendix A).
- **Outages.** PRAS simulates thermal generator and storage outages, but in the modeling these outage rates do not vary with time or weather conditions. In reality, thermal outages are correlated with extreme temperatures (S. Murphy, Sowell, and Apt 2019). PRAS also does not represent transmission outages, which could be a higher source of system risk in the scenarios with significantly expanded transmission.
- **Demand response.** The versions of ReEDS and PRAS used for this study do not include demand response. Demand response is used in some systems to provide RA capacity—e.g., 1.9 GW in CAISO in 2022, roughly 3%–4% of total RA capacity (CAISO 2023b). All unserved energy is included in the NEUE values discussed here, but in practice some of this unserved energy would be served by appropriately compensated demand response and would not be considered to contribute to “dropped load” events. If demand response for RA were included in the simulations, the resulting NEUE would be reduced.

[52] The impact of future electrification on demand profiles are reflected in the scenarios, but demand from the use of these new electrified end uses is based on historical weather in most scenarios.

Appendix C. Technology Cost Assumptions

The Regional Energy Deployment System (ReEDS) models a large suite of technologies, including electricity generation technologies, energy storage technologies, CO_2 capture and storage, and hydrogen-producing technologies.

C.1 Supply-Side Technologies

Table C-1 lists the electricity generation and storage technologies available in ReEDS and outlines which technologies are deployable under default assumptions in this study and which are included and excluded in various sensitivity cases.

Table C-1. Technologies Modeled in ReEDS

Technology	Expansion Allowed in Core Scenario	Included Sensitivity Cases	Excluded Sensitivity Cases
4-Hr Battery[a]	Yes		
8-Hr Battery[a]	Yes		
Bioenergy with CCS (BECCS)	Yes		
Biopower	Yes		
Concentrating Solar Power (CSP)	Yes		
Geothermal[b]	Yes		
Hydropower[b]	Yes		
Natural Gas Combined Cycle (NG-CC)	Yes		
Natural Gas Combustion Turbine (NG-CT)	Yes		
Land-Based Wind[b]	Yes		
Offshore Wind[b]	Yes		
Pumped Hydropower[b]	Yes		
Utility-Scale Solar PV[b]	Yes		
Coal + Carbon Capture and Storage (Coal-CCS)[d]	Yes		No CCS; No H_2 or CCS
Hydrogen Combustion Turbine (H_2-CT)[d]	Yes		No H_2; No H_2 or CCS; No H_2 or new nuclear

Technology	Expansion Allowed in Core Scenario	Included Sensitivity Cases	Excluded Sensitivity Cases
Technology	**Expansion Allowed in Core Scenario**	**Included Sensitivity Cases**	**Excluded Sensitivity Cases**
Natural Gas Combined Cycle with CCS (NG-CC-CCS)[d]	Yes		No CCS; No H_2 or CCS
Nuclear	Yes		No H_2 or new nuclear
Nuclear Small Modular Reactor (SMR)	No	+Nuclear SMR + DAC	
Coal[c]	No, existing capacity only		
Landfill Gas[c]	No, existing capacity only		
Oil-Gas-Steam[c]	No, existing capacity only		
Distributed PV[e]	Expansion is exogenously specified		

[a] ReEDS can model 2-, 4-, 6-, 8-, and 10-hour batteries, but only the 4-hour and 8-hour battery durations are modeled in this study to reduce computation time while allowing for both shorter-duration and longer-duration storage options.

[b] Plants of these types are modeled with a supply curve because these technologies have site-specific characteristics and multiple technology configurations. For land-based wind, offshore wind, and utility-scale solar PV, these supply curves and generation profiles are from the reV model.

[c] Existing plants of these types are included, but expanded capacity is not allowed in this analysis.

[d] Plants of these types can be greenfield builds or retrofits. More detail on retrofits can be found in Appendix C.2.

[e] Distributed PV deployment is exogenously specified based on simulations from NREL's Distributed Generation Market Demand (dGen) model (Sigrin et al. 2016). The same distributed PV projection featuring 130 GW of distributed PV capacity by 2035 is used for all scenarios and based on the Standard Scenarios 2023 Mid-case (Gagnon et al. 2024). Distributed PV cannot be curtailed in ReEDS.

Most scenarios use technology cost and performance assumptions from the 2023 ATB Moderate case. Capital, fixed operation and maintenance, and variable operation and maintenance cost data for the core scenarios are shown in Table C-2, Table C-3, and Table C-4, respectively. Costs for hydropower and geothermal options vary significantly by technology type and location and are therefore not shown in the tables. These costs are based on DOE's Hydropower Vision Report (DOE 2016) and the 2023 ATB (National Renewable Energy Laboratory 2023) for the two technologies, respectively. Other technology assumptions (e.g., heat rate, capacity factor improvements), as well as more conservative or advanced cost assumptions used in the cost sensitivity cases, can be found in the ATB.

Table C-2. Overnight Capital Costs ($/kW) in the Core Scenarios

Technology	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
4-Hr Battery	1,551	1,300	1,199	1,099	999	899
8-Hr Battery	2,790	2,282	2,093	1904	1,715	1,528
BECCS[a]	7,373	7,259	7,155	7,051	6,947	6,843
Coal-CCS	4,943	4,641	4,339	4,102	3,866	3,629
CSP[b]	4,529	3,658	3,528	3,397	3,266	3,136
NG-CC	1,174	1,122	1,070	1026	982	938
NG-CC-CCS	2,424	2,179	1934	1,823	1,713	1,602
NG-CT	1,057	1,014	971	928	885	843
H_2-CT[c]	1,088	1,044	1,000	956	912	868
Land-Based Wind	1,194	1,083	1,029	976	923	869
Nuclear	6,925	6,603	6,384	6,159	5,947	5,696
Nuclear SMR	7,563	7,213	6,974	6,729	6,500	6,227
Offshore Wind, Fixed-Bottom[d]	2,228	2048	1937	1,856	1,793	1,740
Offshore Wind, Floating Platform[d]	3,329	3,071	2,912	2,796	2,705	2,630
Utility-Scale Solar PV	1,300	1,082	864	795	727	659

[a] *Costs shown assume a 90% emissions capture rate. BECCS cost and performance values are from Young (2020).*

[b] *Costs shown for CSP assume 8 hours of thermal energy storage (TES). ReEDS models four classes of CSP technologies, including various durations of TES.*

[c] *Hydrogen combustion turbine capital costs are not included in the ATB. Assumed costs for new H_2-CTs are 3% greater than for new NG-CTs (Denholm et al. 2022).*

[d] *Offshore wind costs shown for fixed-bottom technologies are for Wind Resource Class 3, and those shown for floating platform technologies are for Wind Resource Class 10. There are seven classes for each offshore wind technology in the ATB, and each class has different capital costs. See the 2023 ATB for more details (National Renewable Energy Laboratory 2023).*

Table C-3. Fixed Operation and Maintenance Costs in $/(kW-year) in the Core Scenarios

Technology	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
4-Hr Battery	38.8	32.5	30.0	27.5	25.0	22.5
8-Hr Battery	69.8	57.1	52.3	47.6	42.9	38.2
BECCS	217	217	217	217	217	217
Coal-CCS	129	122	115	110	104	98.7
CSP	47.1	39.7	39.7	39.7	39.7	39.7
NG-CC	32.6	31.0	29.3	28.2	27.1	26.0
NG-CC-CCS	64.9	58.3	51.7	49.0	46.3	43.6
NG-CT	25.5	24.7	24.1	23.3	22.6	21.9
H_2-CT	23.7	23.7	23.7	23.7	23.7	23.7
Land-Based Wind	28.8	27.0	26.1	25.2	24.2	23.3
Nuclear	164	164	164	164	164	164
Nuclear SMR	128	128	128	128	128	128
Offshore Wind, Fixed-Bottom	107	97.6	91.3	86.5	82.7	79.5
Offshore Wind, Floating Platform	80.3	73.8	69.4	66.1	63.4	61.2
Utility-Scale Solar PV	22.1	19.4	16.8	16.0	15.3	14.6

Table C-4. Variable Operations and Maintenance Costs in $/MWh in the Core Scenarios

Technology	2025	2030	2035	2040	2045	2050
4-Hr Battery	0	0	0	0	0	0
8-Hr Battery	0	0	0	0	0	0
BECCS	22.3	22.3	22.3	22.3	22.3	22.3
Coal-CCS	15.4	14.7	14.0	13.7	13.5	13.2
CSP	2.6	2.3	2.3	2.3	2.3	2.3
NG-CC	2.1	2.0	1.9	1.9	1.8	1.7
NG-CC-CCS	4.8	4.4	4.0	3.9	3.7	3.6
NG-CT	7.0	7.0	7.0	7.0	7.0	7.0
H_2-CT	5.6	5.6	5.6	5.6	5.6	5.6
Land-Based Wind	0	0	0	0	0	0
Nuclear	2.7	2.7	2.7	2.7	2.7	2.7
Nuclear SMR	3.4	3.4	3.4	3.4	3.4	3.4
Offshore Wind, Fixed-Bottom	0	0	0	0	0	0
Offshore Wind, Floating Platform	0	0	0	0	0	0
Utility-Scale Solar PV	0	0	0	0	0	0

C.2 Retrofits With CCS

Existing fossil-fuel-fired capacity is allowed to retrofit with carbon capture and storage. Retrofits are allowed starting in 2030. Capital costs for retrofits and capacity derates are based on data from EIA NEMS assumptions (EIA 2023b) as described in Table C-5.

Table C-5. Retrofit Assumptions for Technologies in ReEDS

Original Technology	Retrofit Technology	Capital Costs	Capacity Derate
Coal	Coal-CCS	Uses NEMS retrofit capital cost data when available for existing plants. Otherwise, retrofit costs are from ATB where retrofit costs start at \$3,100/kW in 2023 and decrease to \$1,600/kW by 2050 (National Renewable Energy Laboratory 2023).	Uses NEMS heat rate data when available for existing plants to approximate capacity derate. Otherwise assumes a 29% derate after retrofitting.
NG-CC	NG-CC-CCS	Uses NEMS retrofit capital cost data when available for existing plants. Otherwise, retrofit costs are from ATB where retrofit costs start at \$1,690/kW in 2023 and decrease to \$1,010/kW by 2050 (National Renewable Energy Laboratory 2023).	Uses NEMS heat rate data when available for existing plants to approximate capacity derate. Otherwise assumes a 14% capacity derate after retrofitting.

C.3 Negative Emissions Technologies

ReEDS models two negative emissions technologies: bioenergy with CCS (BECCS) and direct air capture (DAC). BECCS is enabled by default in these scenarios and allowed to expand. The cost assumptions for BECCS are shown in Appendix C.1 because BECCS is also a supply-side technology. BECCS is assumed to have a 90% capture rare and an emissions rate of -0.060 metric tons CO_2 per MMBtu. DAC is turned off by default but enabled in the +Nuclear SMR + DAC scenario. The assumed levelized cost of DAC is between \$300 and \$400 per metric ton of CO_2 captured and sequestered based on Brown et al. (forthcoming).

The national CO_2(e) emissions constraint in ReEDS is modeled on a net basis, meaning negative emissions technologies can offset (positive) emissions to reach the desired target level. However, offsets of emissions are allowed only from fossil with CCS. Based on this definition, generation from fossil plants without CCS is not allowed when the requirement is net zero (e.g., after 2035 under the 100% by 2035 scenarios or after 2045 under the 90% by 2035 scenarios).

C.4 Financing and Retirement Assumptions

The economic lifetime assumptions for various technologies are shown in Table C-6. Most generators are assumed to have a 20-year economic lifetime whereas 15 years is assumed for batteries and electrolyzers and 40 years for transmission.

There are multiple ways plants can retire:

- **Announced retirements.** Plants that have announced their retirement date (EIA 2023b) are retired during that year.
- **Age-based retirements.** Plants must retire on or before their maximum age as shown in Table C-6. Utility-scale solar PV, distributed scale solar PV, land-based wind, and offshore wind can be repowered—with the associated new plant capital cost but without the need for new interconnection costs—once they reach their maximum age.
- **Endogenous retirements.** The model decides to retire capacity to avoid ongoing operation and maintenance and fuel costs if the plant does not receive sufficient value or revenue in the model. This is allowed only for fossil fuel plants.
- **Policy-based retirements.** Certain technologies in ReEDS regions and model years are forced to retire because of policy requirements.

Table C-6. Financing and Maximum Age Assumptions for Technologies in ReEDS

Technology	Economic Lifetime (years)	Maximum Age (years)
Hydropower	20	*
(Non-hydro) Renewable energy (wind, solar PV, geothermal, CSP)	20	30
Coal (with and without CCS)	20	70
NG-CC (with and without CCS)	20	55
NG-CTs and H_2-CTs	20	55
Nuclear	20	80
Nuclear SMR	20	80
Storage (pumped hydropower)	20	*
Storage (batteries)	15	15
Electrolyzer	15	*
Transmission	40	*

** No maximum age is modeled for these technologies.*

Appendix D. Additional Results

D.1 ReEDS Results for 2035

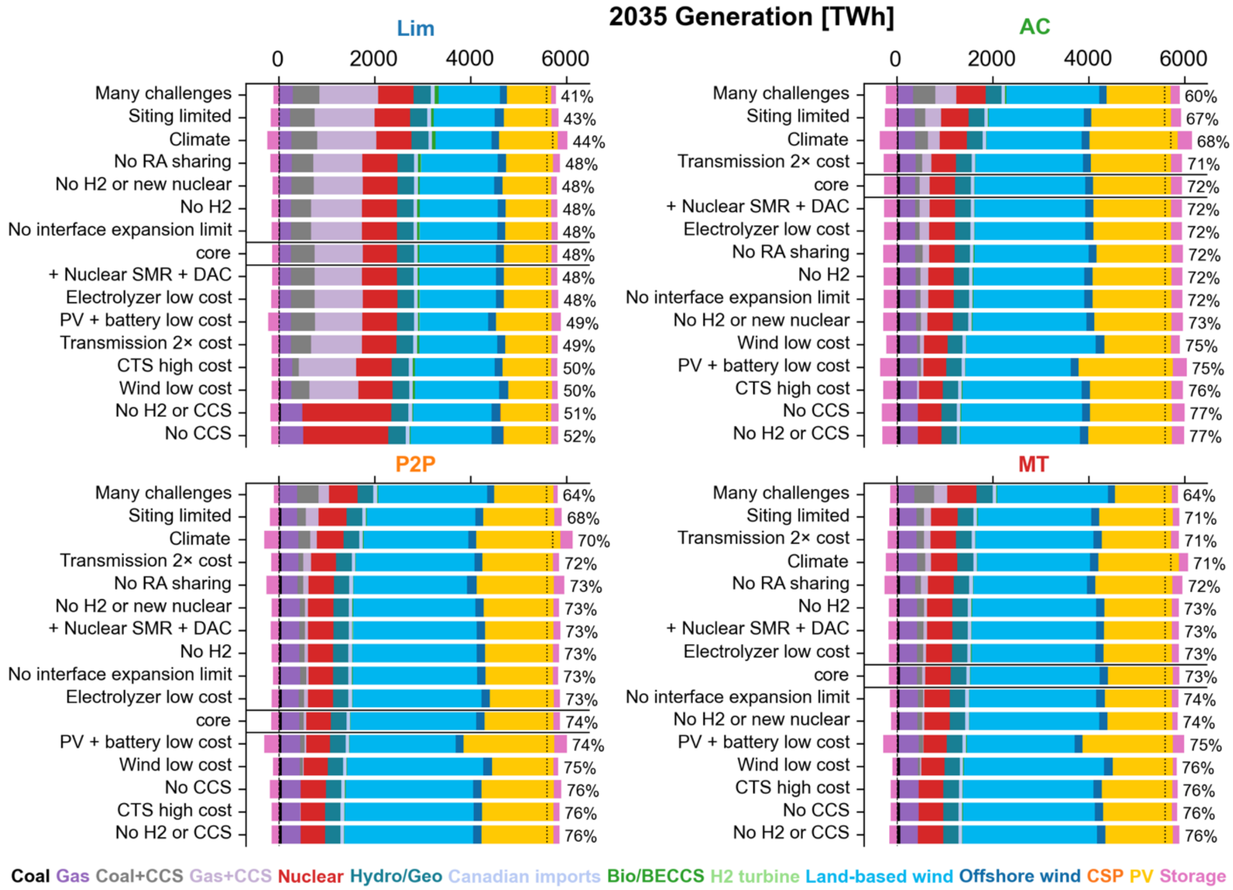


Figure D-1. National generation mix in 2035 with Mid-Demand 90% by 2035 assumptions for each transmission framework and sensitivity case

Within each transmission framework, the sensitivity cases are sorted by 2035 VRE share (indicated by the percentage value to the right of each generation bar). Total generation is greater than end-use demand (vertical dotted line) because of transmission and distribution losses, storage losses, and generation for hydrogen production via electrolyzers. Total storage charging is shown as negative values and discharging as positive values.

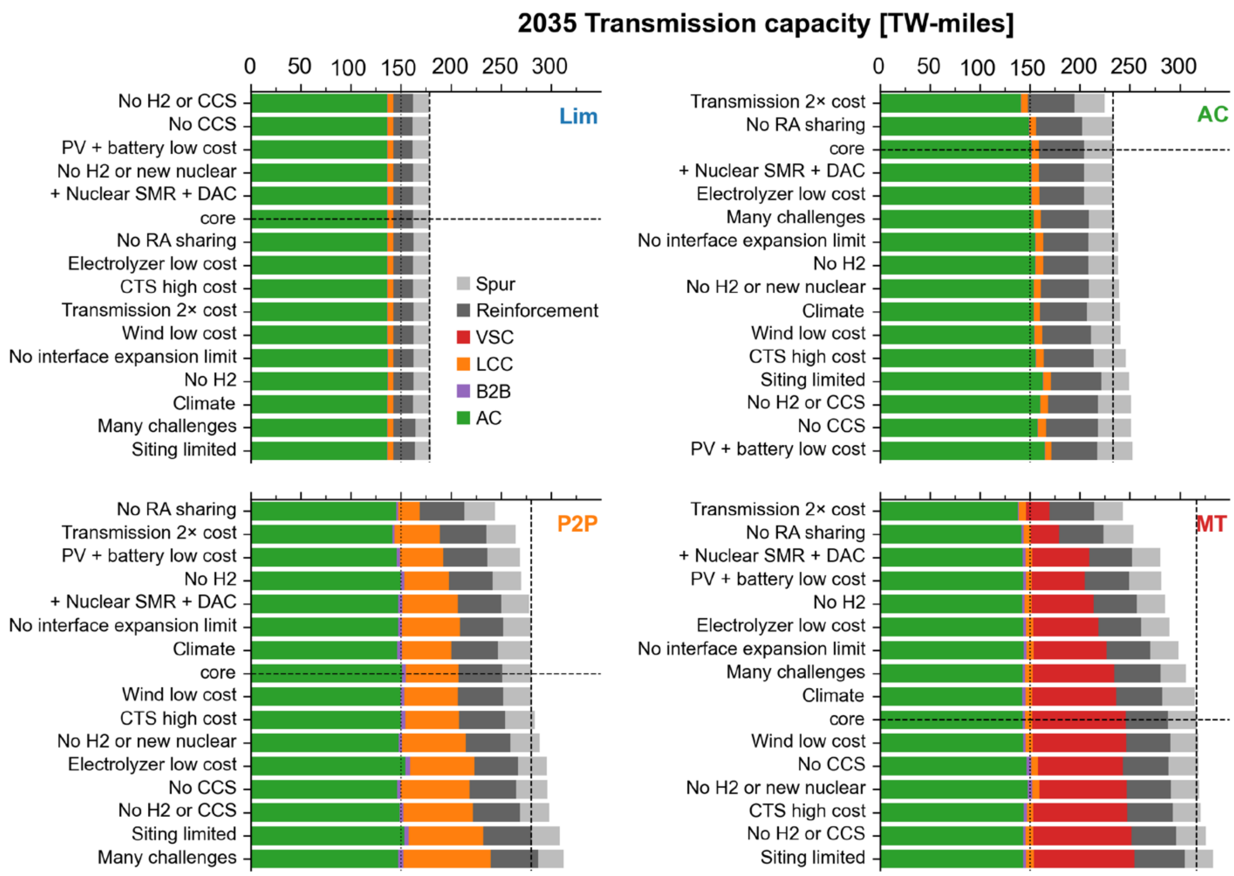


Figure D-2. Transmission capacity in 2035 with Mid-Demand 90% by 2035 assumptions for each transmission framework and sensitivity case

Values for the core scenario for each transmission framework are marked by dashed black lines. Within each transmission framework, sensitivity cases are sorted by total transmission capacity in 2035. The 1.83 TW-mile/year limit on annual transmission additions is binding in all sensitivity cases for the Limited transmission framework, making 2035 transmission capacity the same in all sensitivity cases for this framework.

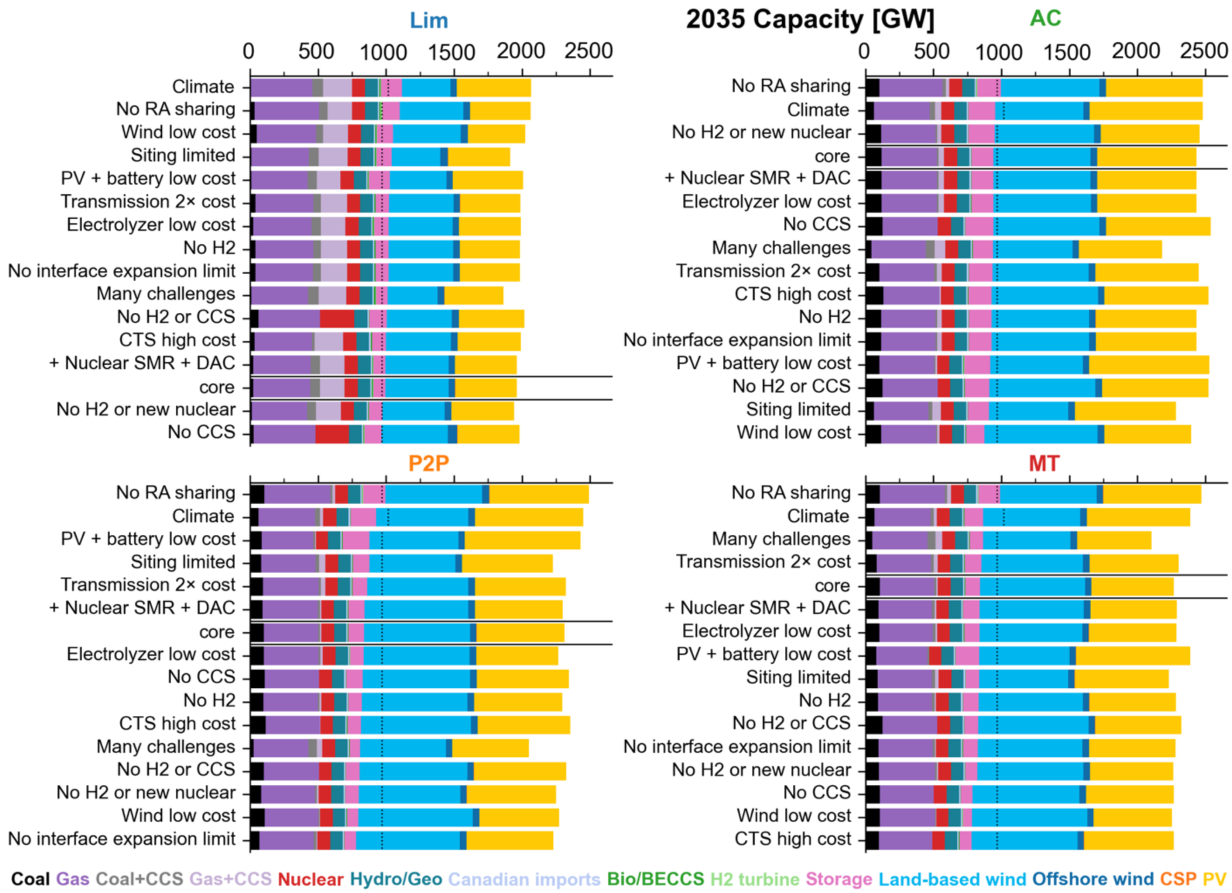


Figure D-3. National capacity mix in 2035 with Mid-Demand 90% by 2035 assumptions for each transmission framework and sensitivity case

Within each transmission framework, the sensitivity cases are sorted by 2035 VRE capacity share. Peak coincident end-use demand is shown as vertical dotted lines.

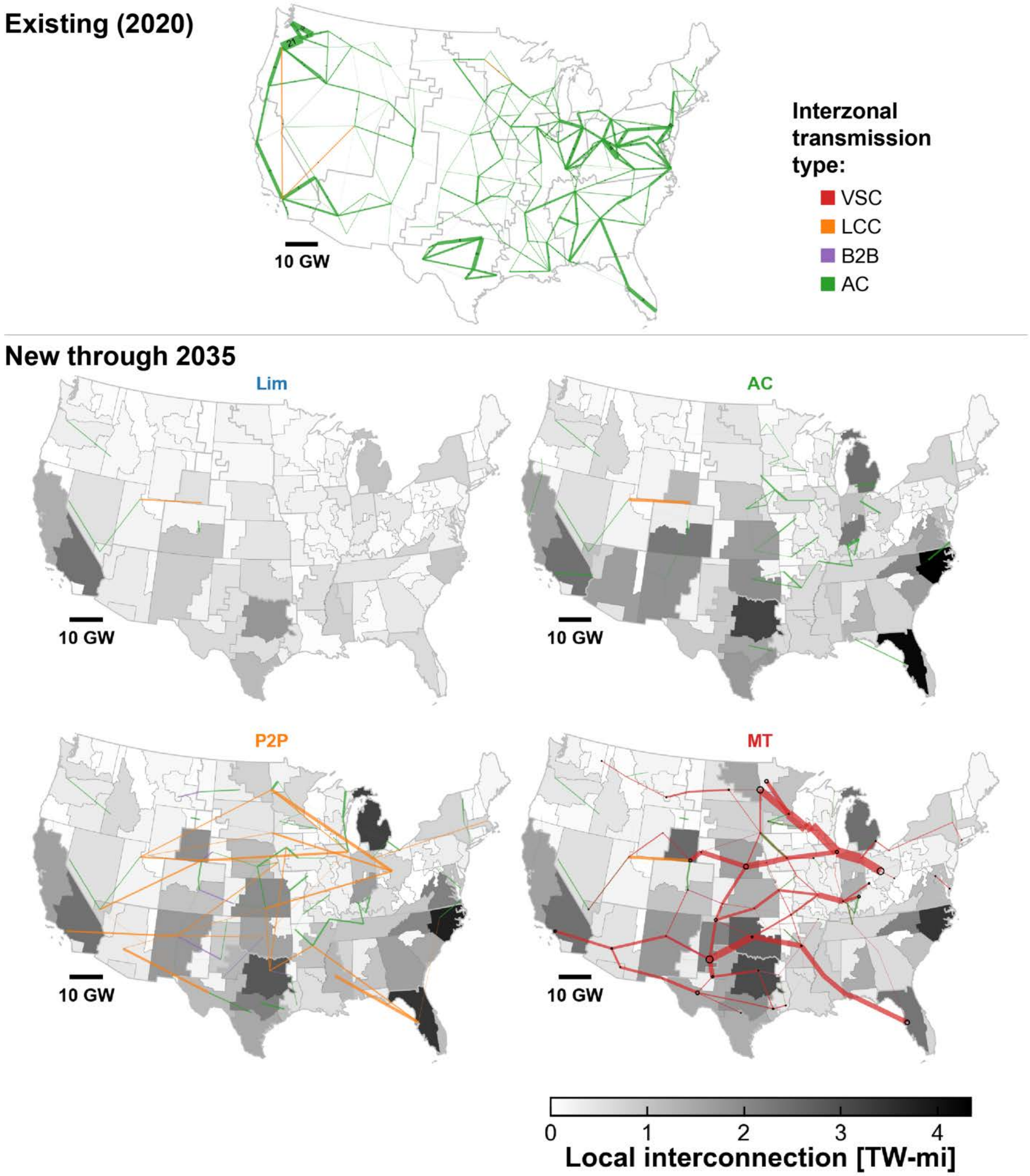


Figure D-4. New local and long-distance transmission through 2035 under Mid-Demand 90% by 2035 assumptions for each of the four transmission frameworks, with existing 2020 long-distance transmission capacity for context (top)

Interface transfer capability is indicated by the thickness of the lines connecting ReEDS zones. Converter capacity in the MT framework is indicated by the diameter of empty black circles, using the same length scale as the interface lines. The depiction of interzonal transmission capacity as straight lines between zone centers is a visual simplification; in practice, the interzonal transfer capacity would be spread across many transmission corridors for each interface.

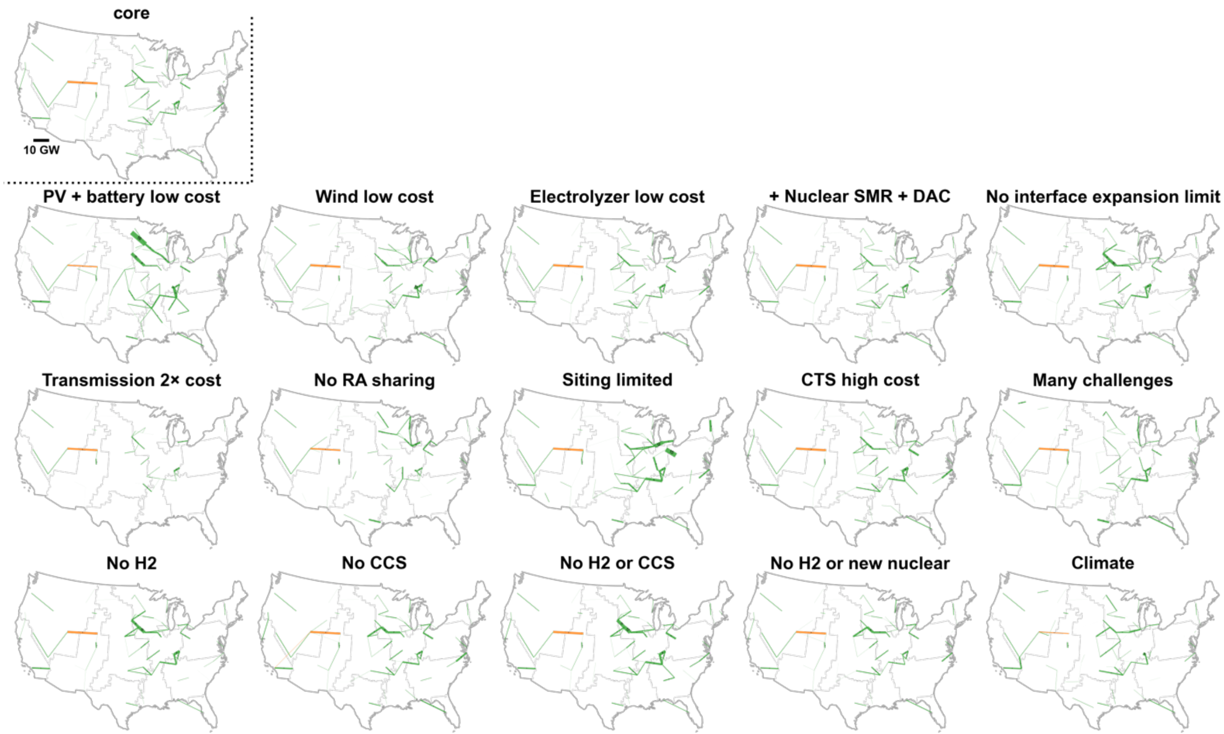


Figure D-5. New long-distance transmission additions through 2050 with Mid-Demand 90% by 2035 assumptions for each sensitivity case under the AC transmission framework

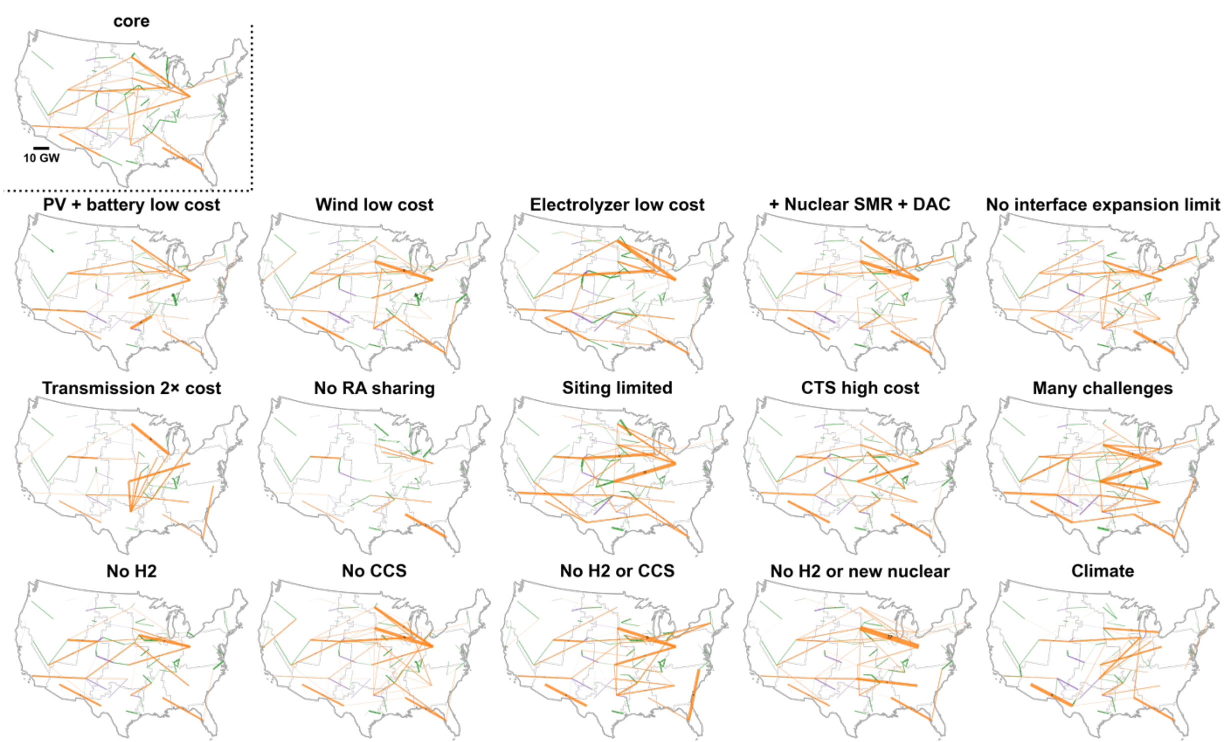


Figure D-6. New long-distance transmission additions through 2050 with Mid-Demand 90% by 2035 assumptions for each sensitivity case under the P2P transmission framework

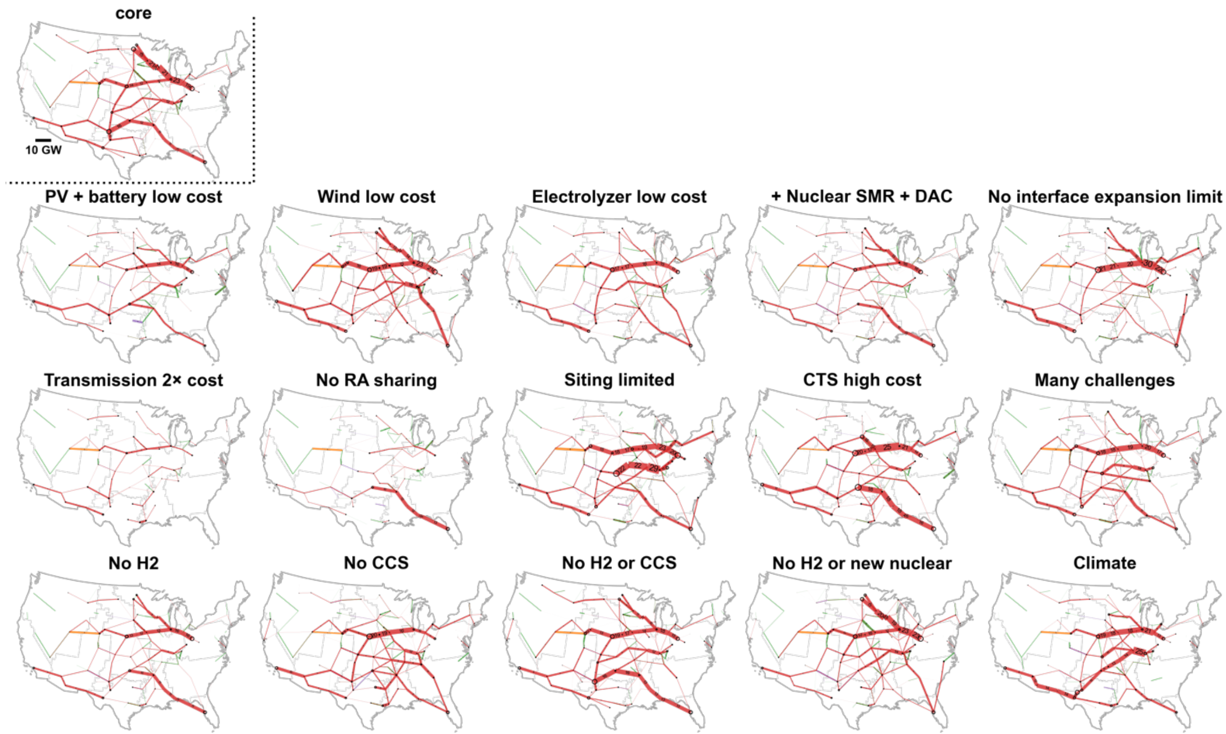


Figure D-7. New long-distance transmission additions through 2050 with Mid-Demand 90% by 2035 assumptions for each sensitivity case under the MT transmission framework

D.2 Additional Capacity Expansion Modeling Results Through 2050

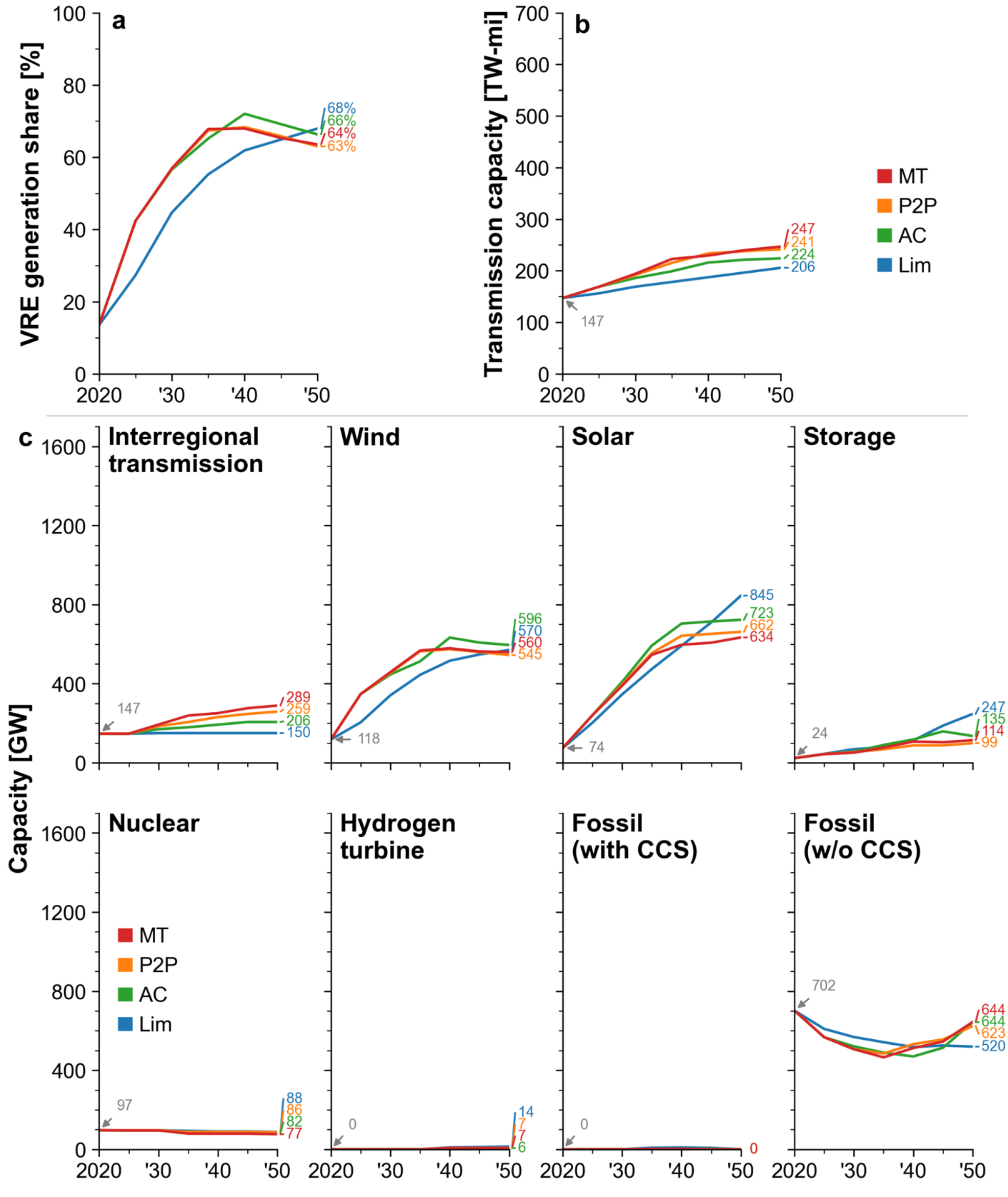


Figure D-8. Trajectories of VRE share (a), transmission capacity (b), and nameplate capacity (c) under Low-Demand Current Policies conditions

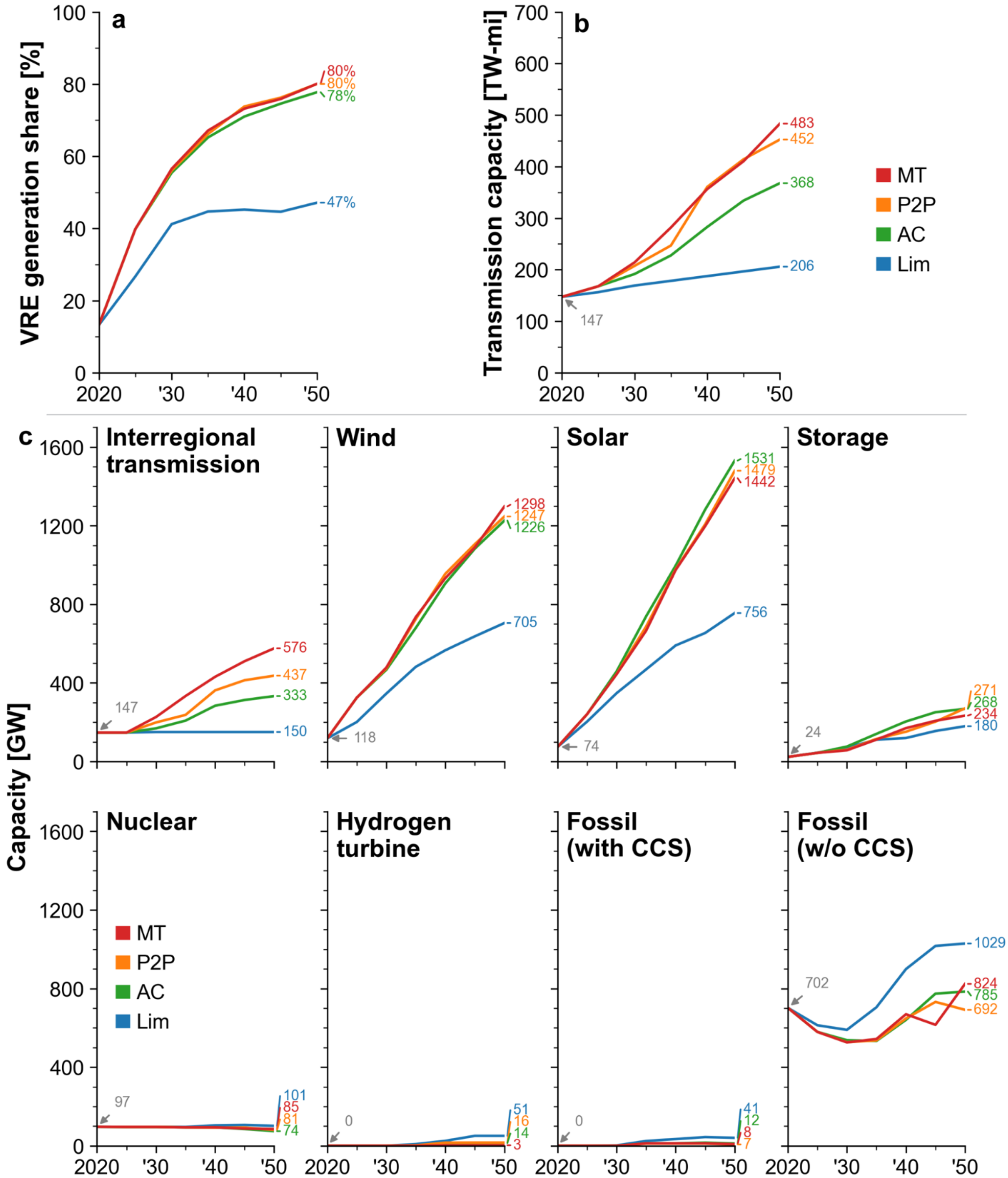


Figure D-9. Trajectories of VRE share (a), transmission capacity (b), and nameplate capacity (c) under High-Demand Current Policies conditions

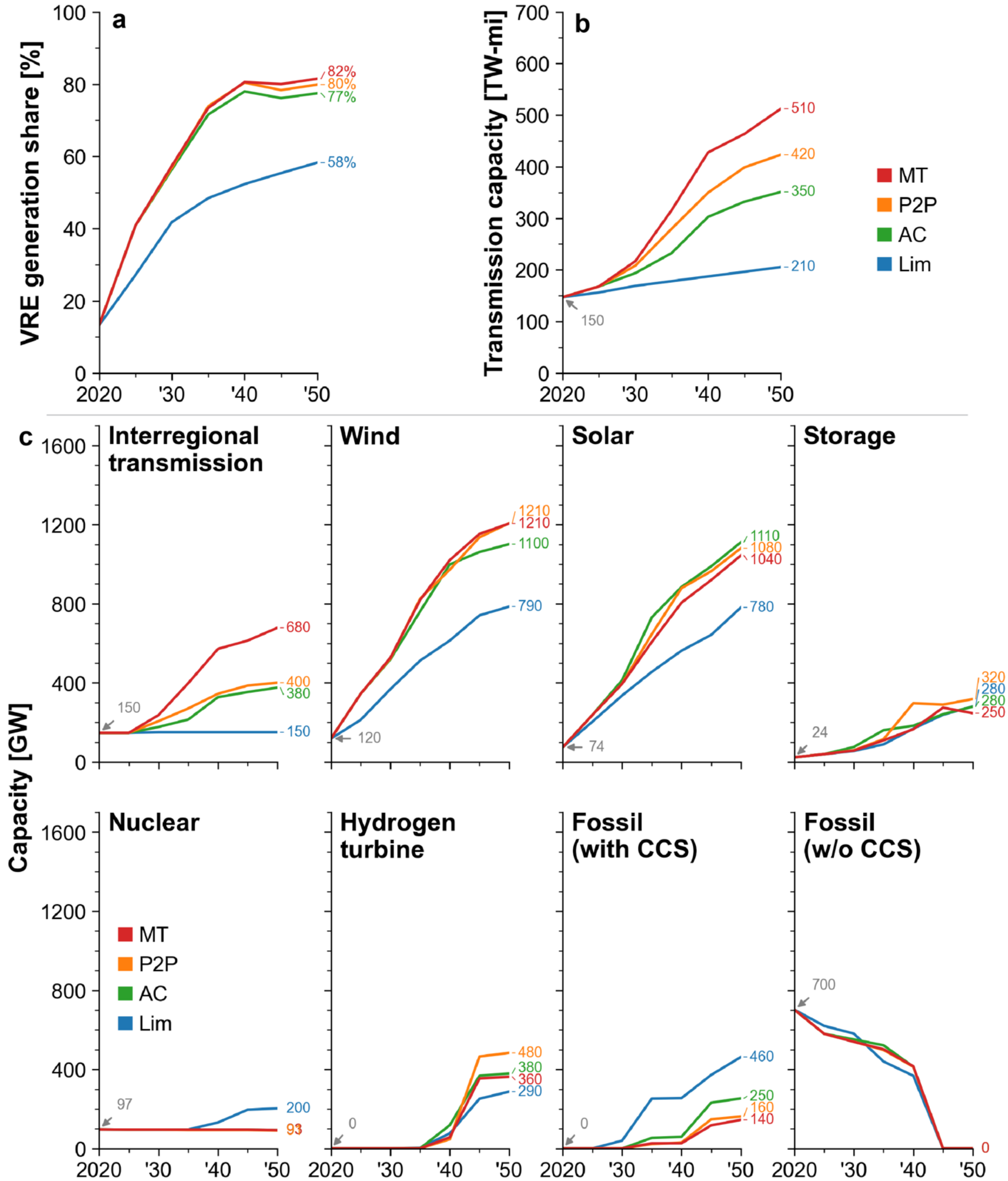


Figure D-10. Trajectories of VRE share (a), transmission capacity (b), and nameplate capacity (c) under Mid-Demand 90% by 2035 conditions

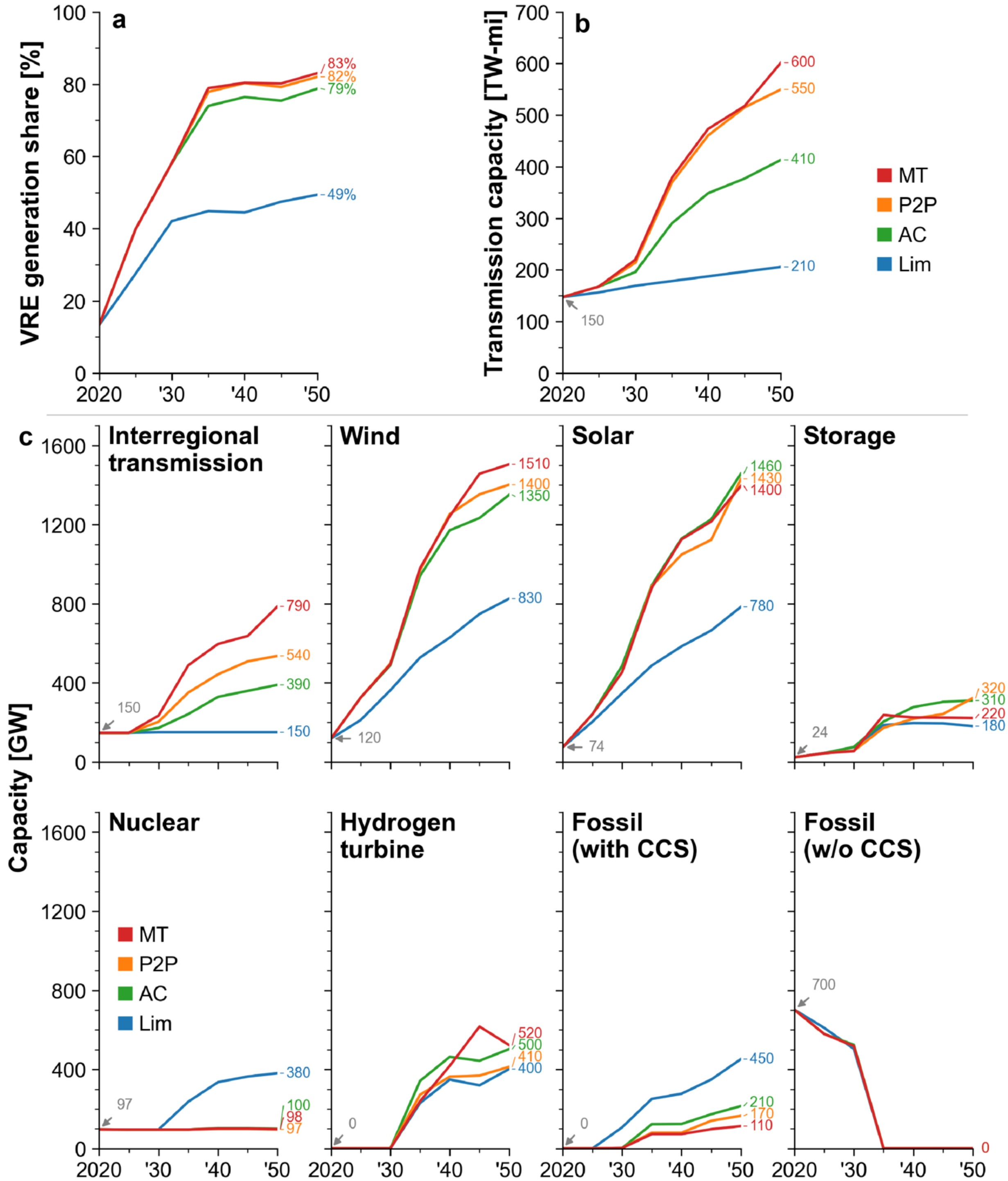


Figure D-11. Trajectories of VRE share (a), transmission capacity (b), and nameplate capacity (c) under High-Demand 100% by 2035 conditions

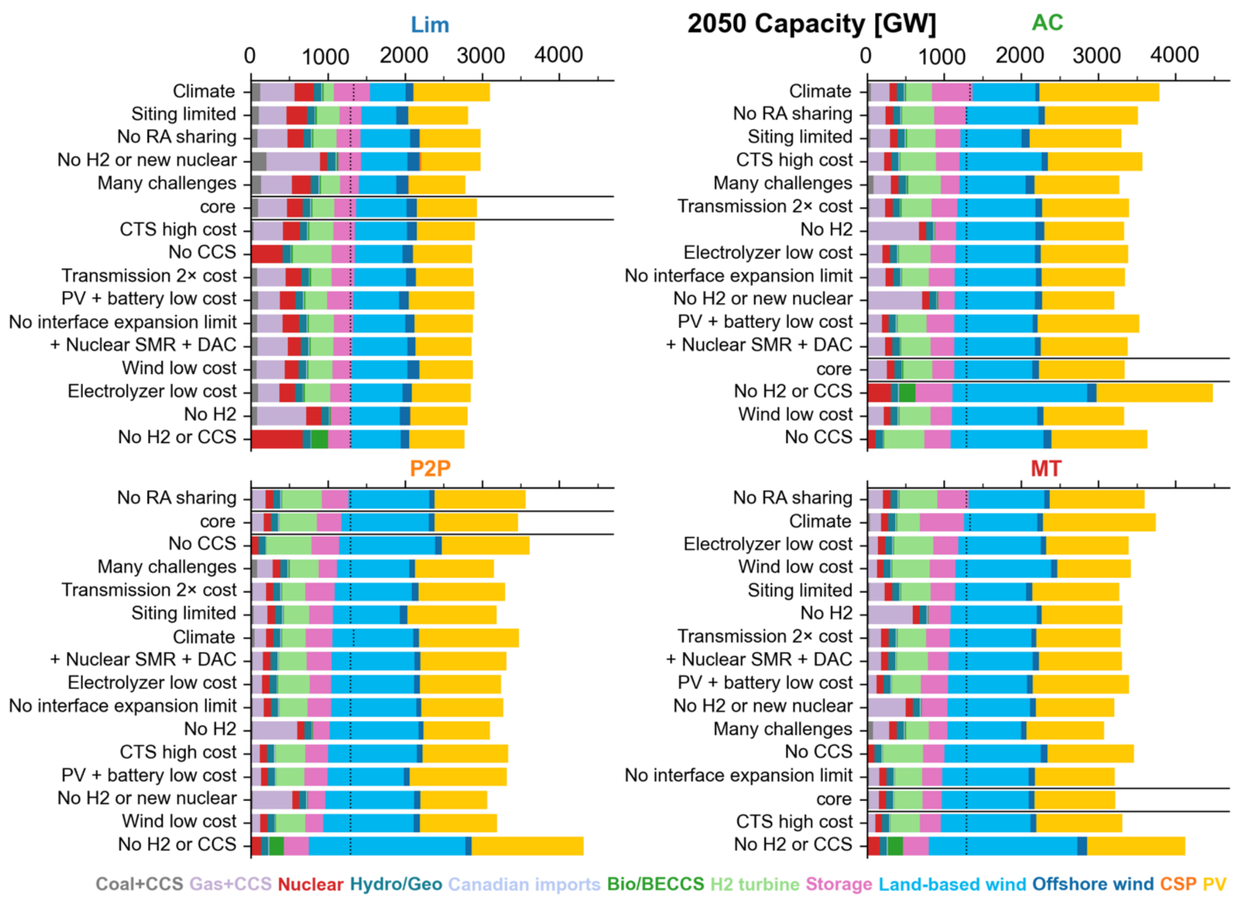


Figure D-12. National capacity mix in 2050 with Mid-Demand 90% by 2035 assumptions for each transmission framework and sensitivity case

Within each transmission framework, the sensitivity cases are sorted by 2050 VRE capacity share. Peak coincident end-use demand is shown as vertical dotted lines.

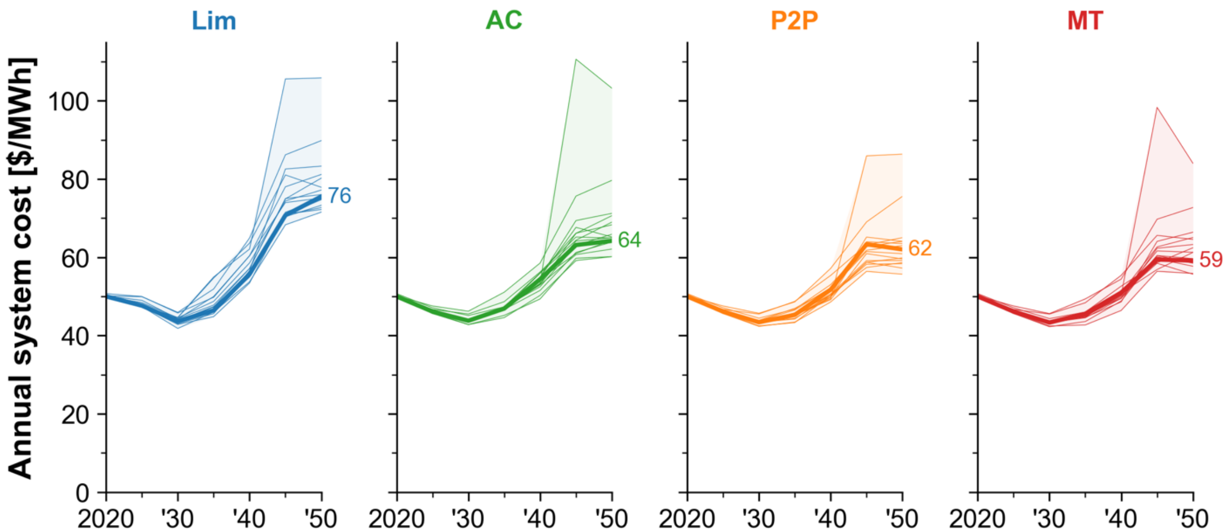


Figure D-13. Annual system cost ($/MWh) for the four transmission frameworks and all sensitivity cases under Mid-Demand 90% by 2035 conditions

Annual system cost is given by the sum of undiscounted annualized electricity system expenditures (fixed and operating) and tax credits, divided by annual end-use electricity demand (excluding induced demand from storage charging, H_2 production for use in H_2-CTs, and transmission losses).

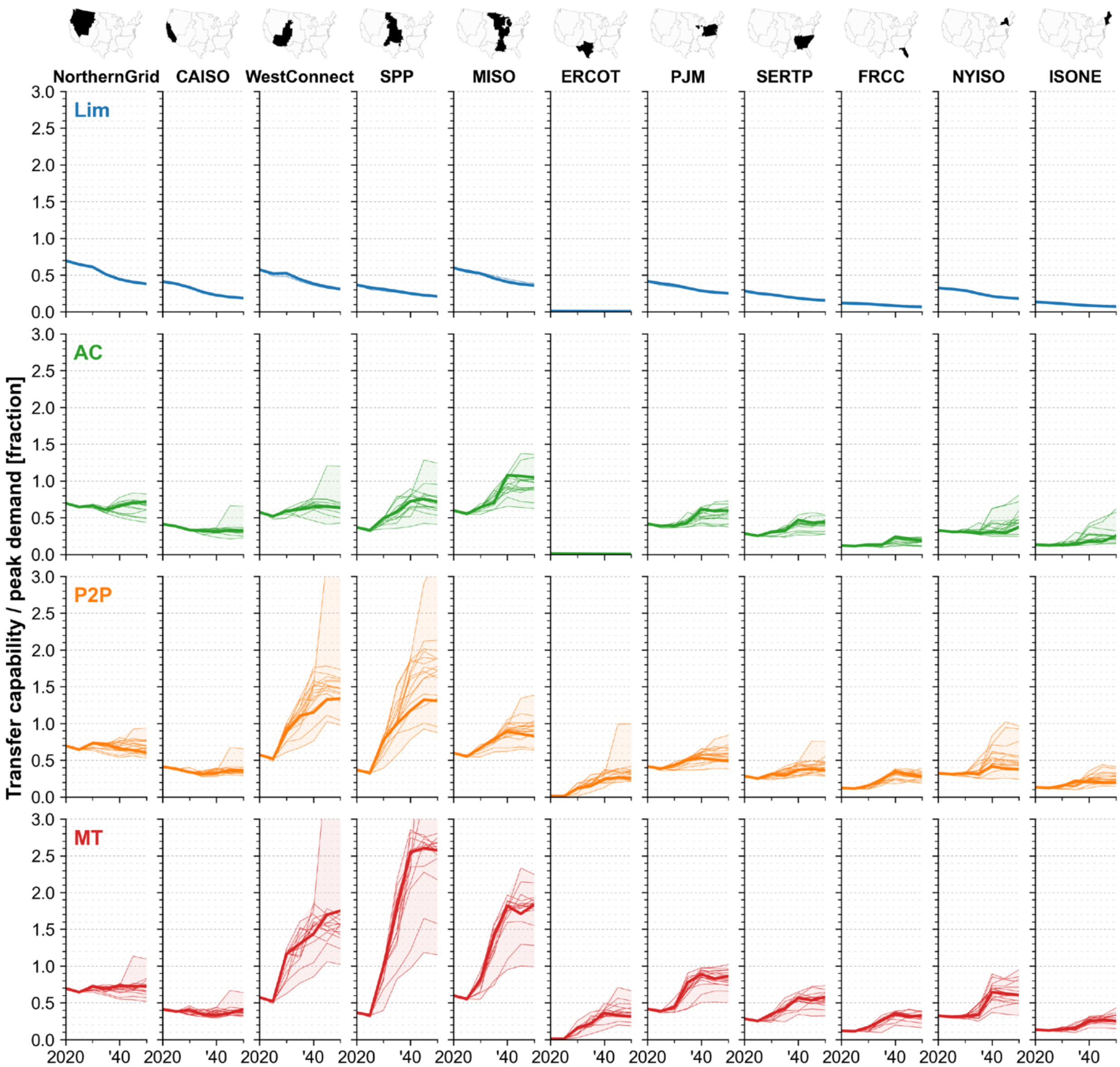


Figure D-14. Ratio of interregional transfer capability to peak demand for the 11 planning regions with Mid-Demand 90% by 2035 assumptions across the four transmission frameworks and all sensitivity cases

Interregional transfer capability for a given planning region is defined as the sum of import/export capacity between that planning region and other planning regions.

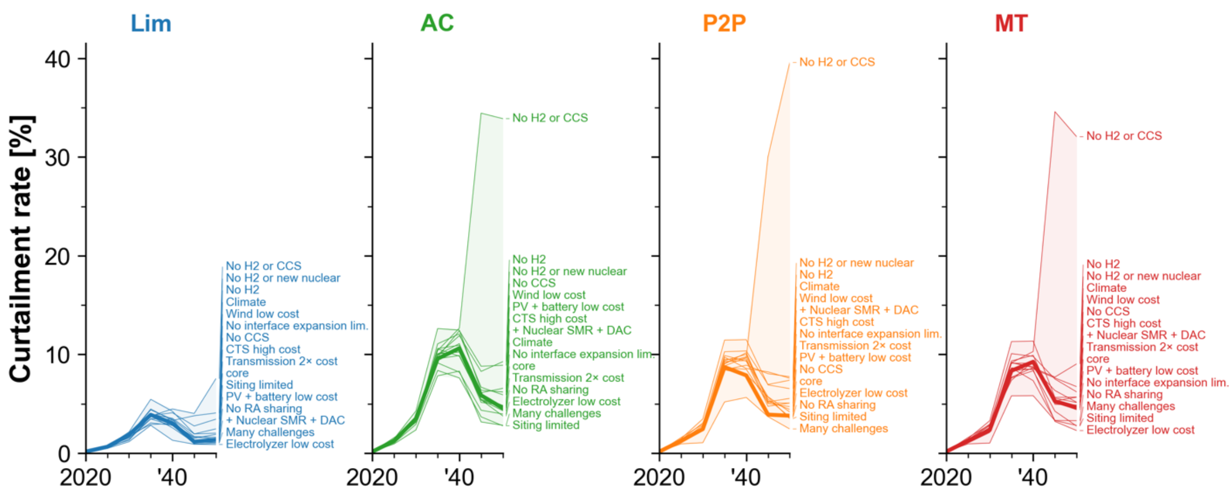


Figure D-15. National average VRE curtailment rate [$MWh_{curtailed}$ / $MWh_{available}$] with Mid-Demand 90% by 2035 assumptions for all sensitivity cases

D.3 Additional Resource Adequacy Results

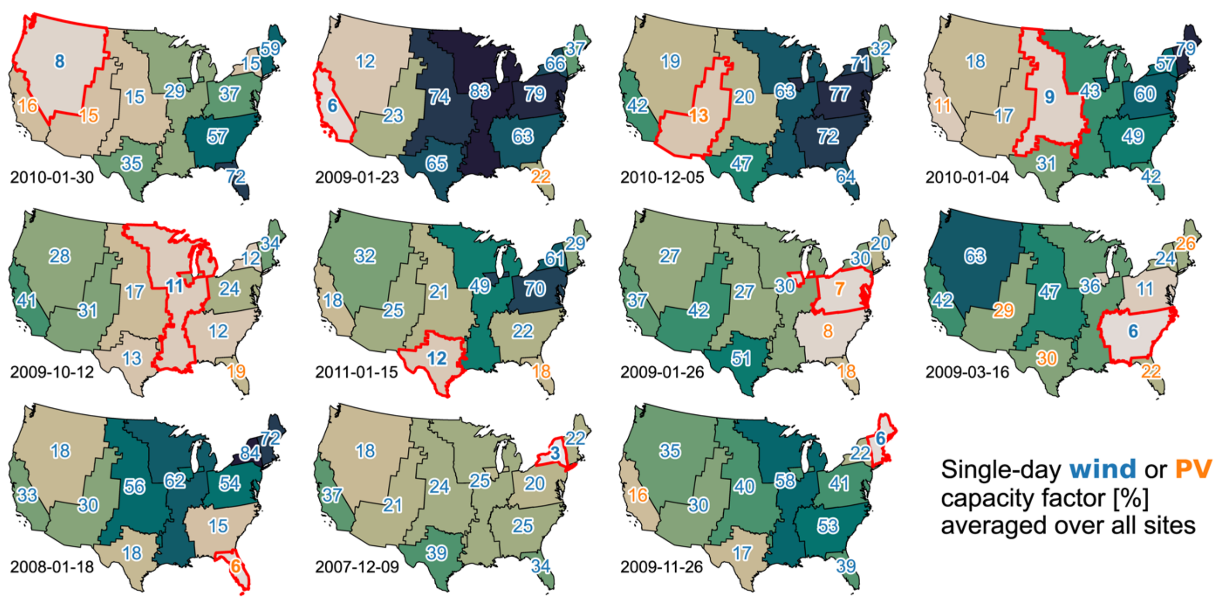


Figure D-16. Single-day wind (blue) or PV (orange) capacity factor on the least-windy/sunny day from 2007 to 2013 weather years in each planning region

For each map, the focused planning region is outlined in red, the date of the least-windy/sunny day in that region is given in the lower left, and the values and shading in each region represent the daily wind or PV capacity factor on that date, whichever is larger. (For example, on 2010-01-30, the wind capacity factor in NorthernGrid is 8% and the solar capacity factor is ≤8%; on the same day, the solar capacity factor in CAISO is 16%.) Planning region values are taken as the available-capacity-weighted average modeled capacity factor over all resource sites in the planning region. Capacity factors are modeled using the reV model as discussed in Appendix A.2. Most of these sites are never developed; if only developed or higher-quality resource sites in each planning region were included, the capacity factors would be higher than shown here.

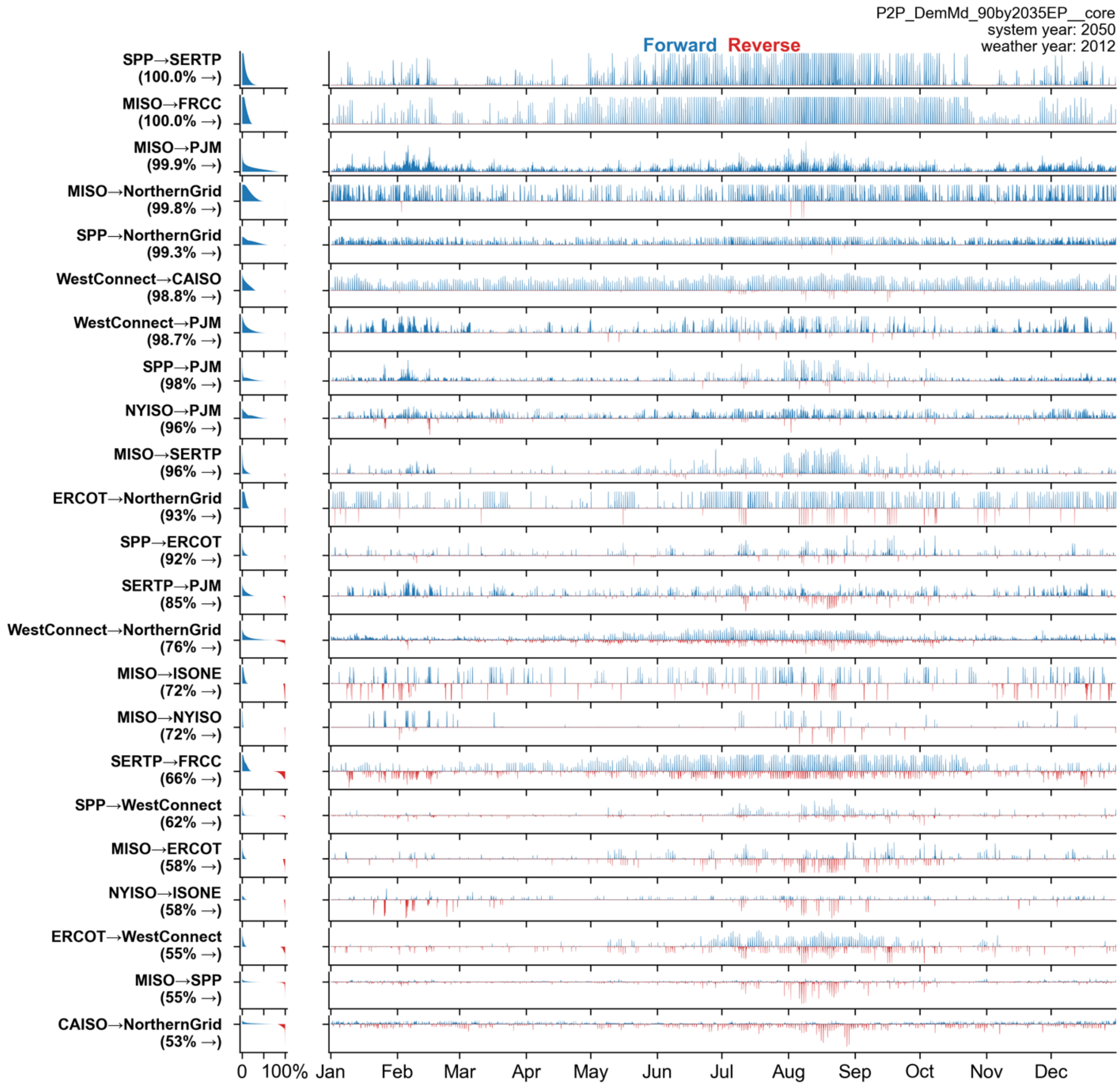


Figure D-17. Hourly interregional transmission flows for the P2P transmission framework in 2050 under Mid-Demand 90% by 2035 conditions as modeled by PRAS

Interfaces are labeled according to the predominant direction of flow. Flow in the predominant ("forward") direction is shown as positive blue values; flow in the "reverse" direction is shown as negative red values. Interfaces are sorted and labeled by the fraction of total flow in the "forward" direction on a MWh basis over the 7 weather years spanning 2007–2013. Distributions on the left include all weather years; hourly profiles on the right include only 2012 for clarity.

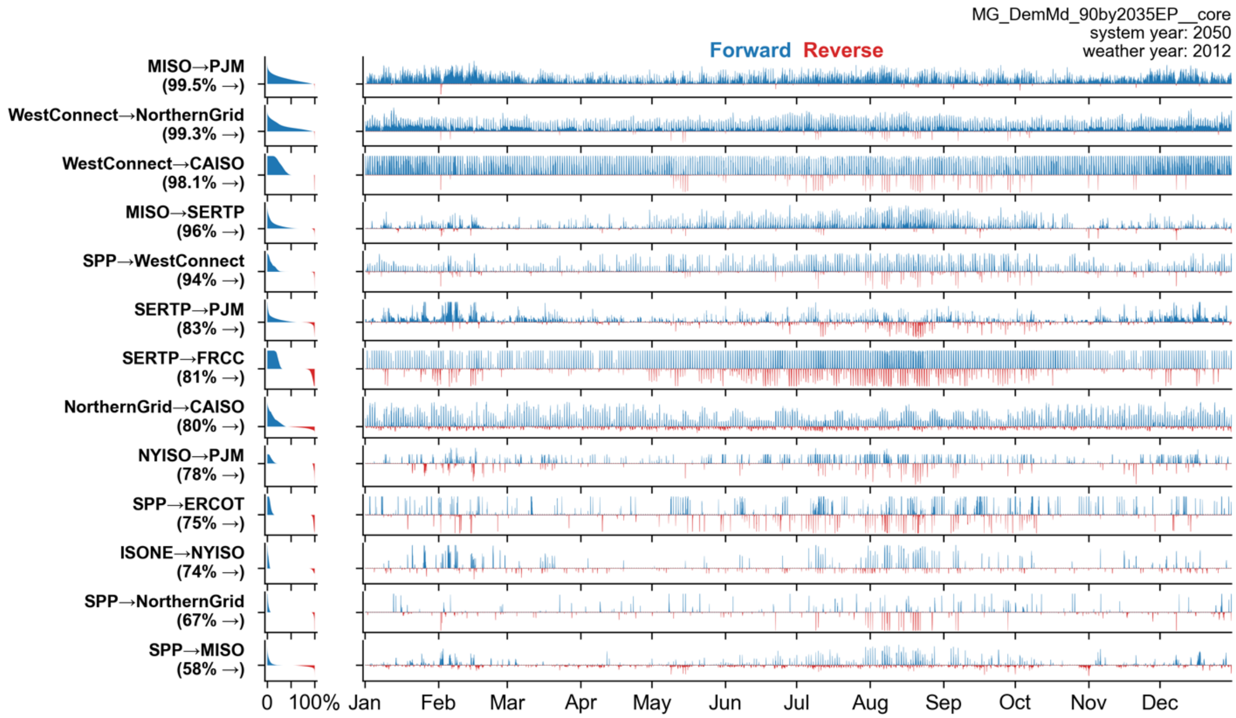


Figure D-18. Hourly interregional transmission flows for the MT transmission framework in 2050 under Mid-Demand 90% by 2035 conditions as modeled by PRAS

Data are presented in the same manner as Figure D-9.

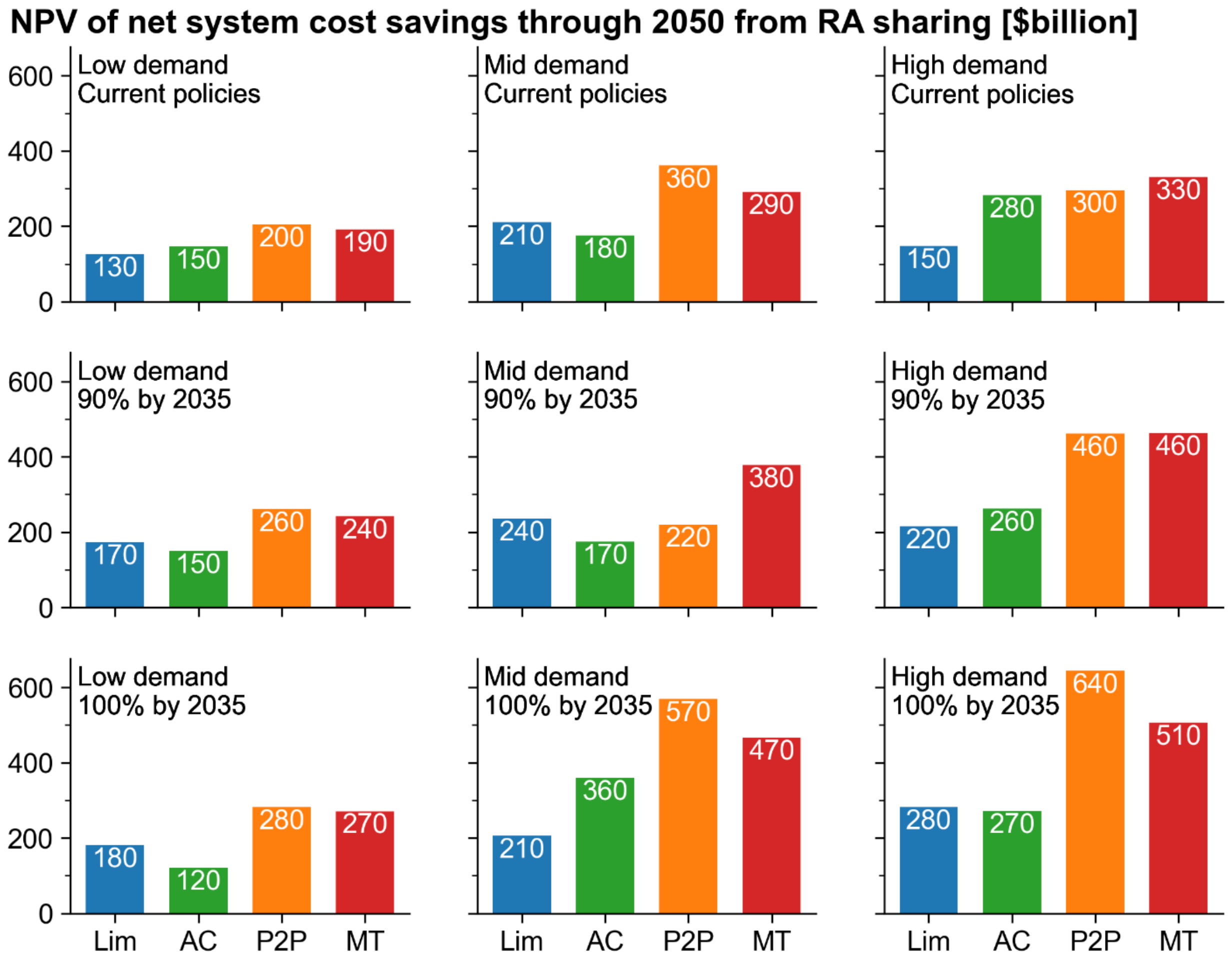


Figure D-19. Impact of the allowance of interregional RA sharing on system cost for each of the demand and emissions assumptions

Data are presented in the same manner as Figure 40a. The "No RA Sharing" sensitivity case was run for each set of demand and emissions assumptions to generate this figure.

D.4 Regional Economic Benefits

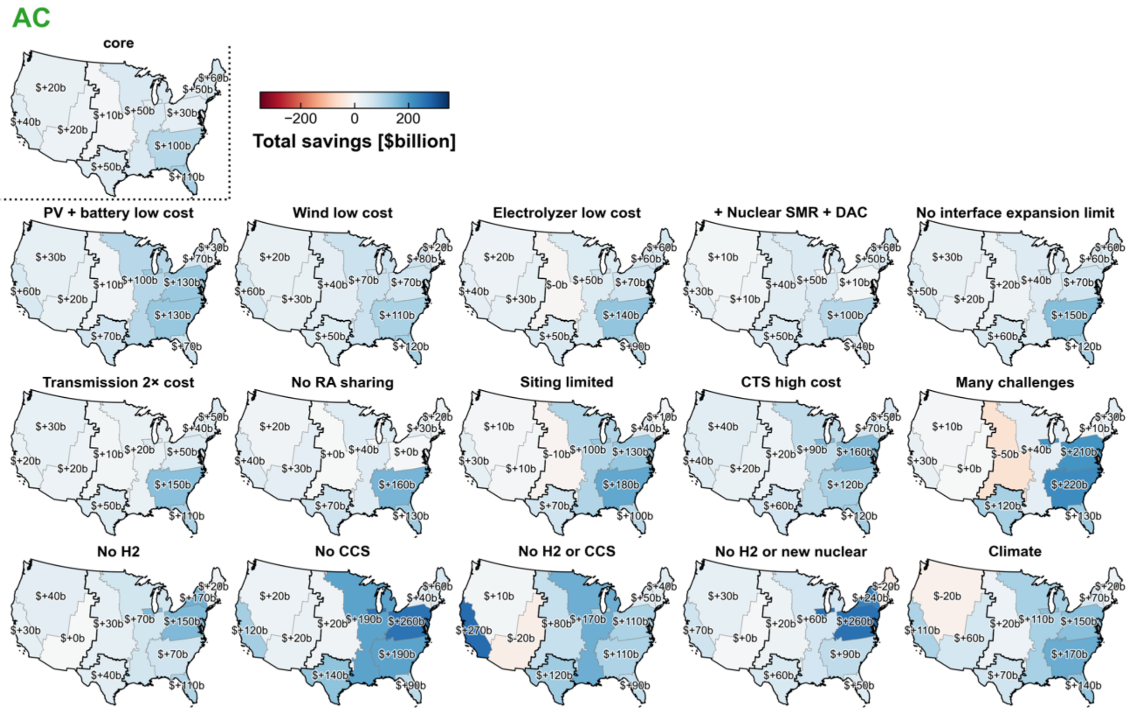


Figure D-20. Net present value of system savings in the AC transmission framework by region in $billion of avoided costs relative to the Limited framework under Mid-Demand 90% by 2035 scenario assumptions

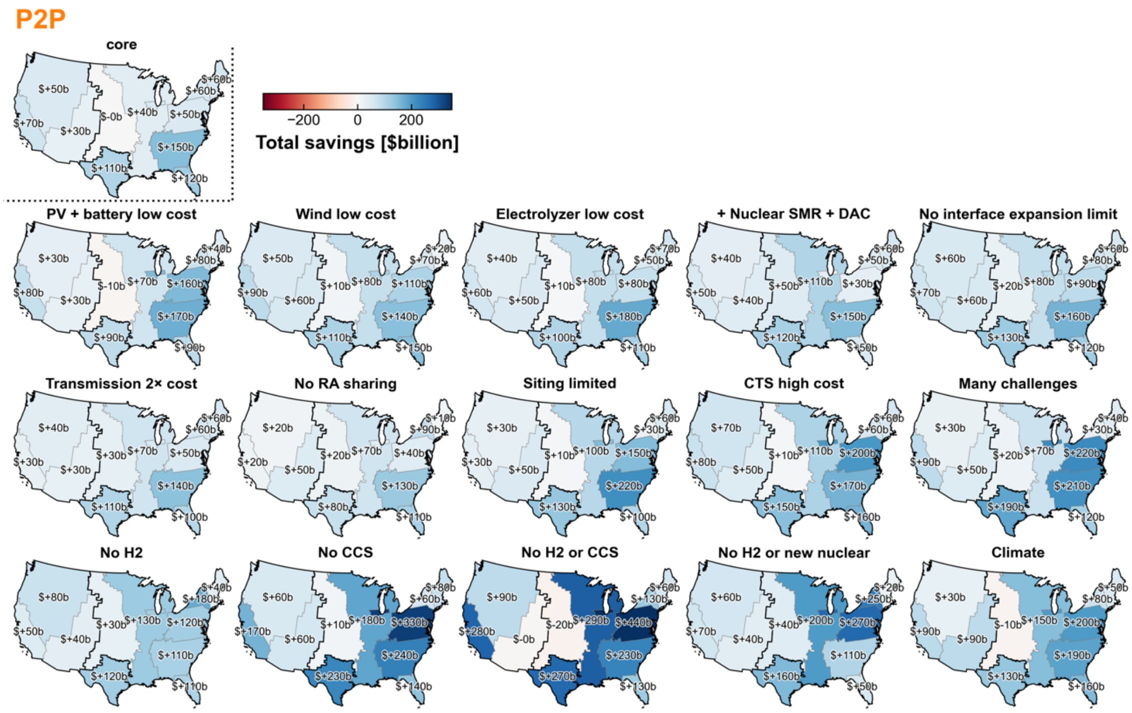


Figure D-21. Net present value of system savings in the P2P transmission framework by region in $billion of avoided costs relative to the Limited framework under Mid-Demand 90% by 2035 scenario assumptions

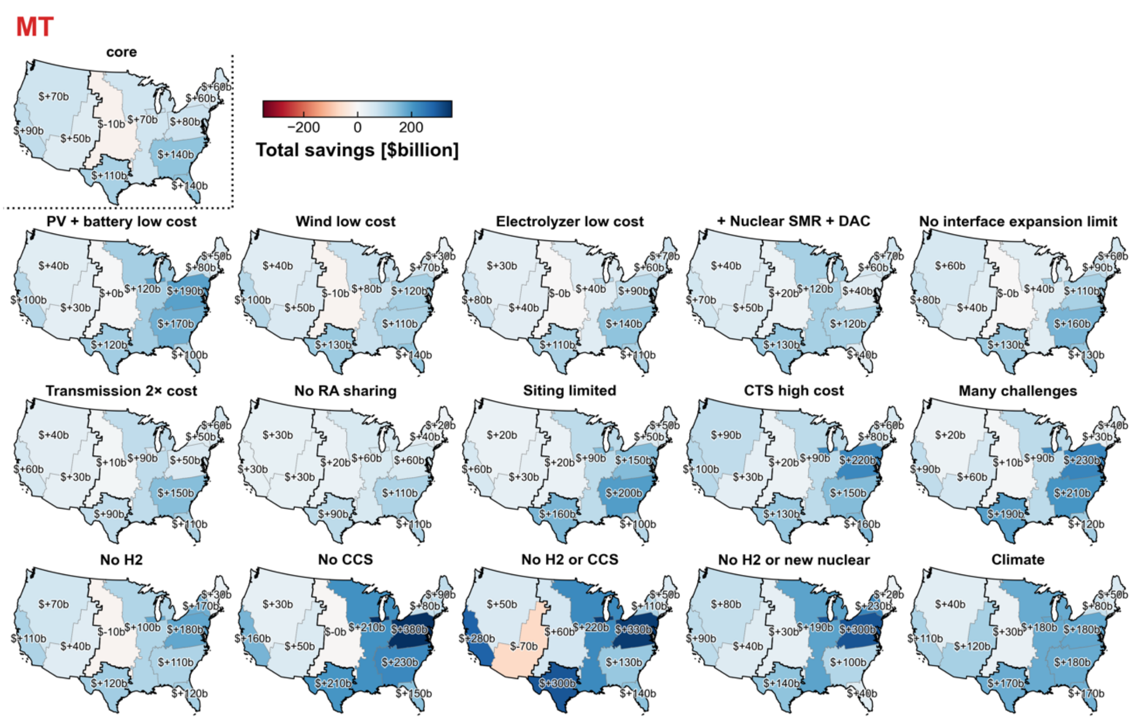


Figure D-22. Net present value of system savings in the MT transmission framework by region in $billion of avoided costs relative to the Limited framework under Mid-Demand 90% by 2035 scenario assumptions

Table D-1. Wind and Solar Capacity (GW) by State in the Core Mid-Demand 90% by 2035 Scenarios

	Land-based wind								Utility-scale solar							
	2035				2050				2035				2050			
	Lim	AC	P2P	MT	Lim	AC	P2P	MT	Lim	AC	P2P	MT	Lim	AC	P2P	MT
AL	3.7	8.6	7.3	12.4	8.1	12.6	24.3	16.8	3.2	23.2	17.1	16.5	18.3	50.5	31.1	43.6
AR	10.4	12.2	20.7	14.4	15.3	12.8	26.4	21.8	1.8	1.8	1.8	3.1	1.6	4.6	18	4.8
AZ	3.3	6.2	2.8	4.1	3.5	10.4	20.3	3.8	19.1	42.7	19	22.4	27.8	62.5	19.2	41
CA	7.5	8.1	7.8	8.9	8.9	12	12.2	10.3	28	32.5	33.5	33.6	25.7	40.5	46.1	47.9
CO	12.3	15.9	9.3	7.8	13.1	26.9	15	13.6	3.5	7.7	8.5	9.2	12	12.5	11.1	12.4
CT	0.6	0.7	0.7	0.7	0.6	1.3	1.1	1	0.5	0.5	0.5	0.5	0.3	0.3	0.3	0.3
DE	1.3	1.9	2.7	1.9	2.1	1.9	2.7	1.9	2.2	0.3	0.3	0.3	4.3	4.3	2.7	2.2
FL	3.2	17.7	12.2	6.7	3.6	27.4	15.6	17.7	18.2	56.8	54.1	44.5	35.8	103.7	82.8	74.8
GA	0	4.2	13.7	3.1	2.3	4.2	14.3	16.6	4.7	4.7	4.7	4.7	2.7	13.8	2.7	2.7
IA	15.9	13.4	16.1	13.4	19.2	7.7	15.3	40.6	2.3	6.9	0.3	0.3	2.3	6.9	1.9	7.6
ID	7.2	8.2	7.7	9.8	10.7	15.4	12.5	15.4	0.4	8.6	10.2	3.8	1.1	15.9	11.4	12.5
IL	18.5	22.2	17.7	16.8	24.9	19.5	31.9	39.7	9.3	11	5.8	5.3	11.9	10.9	7.8	10.2
IN	17.1	34.7	24.8	24.4	27.9	33.5	36.9	33	5.5	33.2	33	26.9	7.2	41.2	43.1	34.4
KS	10.6	14.9	18	13.1	11.5	14.9	19.4	19.7	2.8	22.1	26.4	19.4	5.3	26.4	30.6	31
KY	10.9	23.7	12.9	14.7	17.6	24.2	20.7	20.2	13.6	22.4	27	25.5	44.1	44.6	58.4	52
LA	9.3	17.9	18.3	17.9	14	23.9	29.1	25.6	7.5	7.7	4.9	4.4	13.1	18.1	8.4	10.2
MA	0.1	0.1	0.2	0.2	1.7	1	1.5	0.6	1.4	1.4	1.4	1.4	0.7	0.7	0.7	0.7
MD	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	3.9	3.1	3.1	3.1	5.8	5.4	5.5	5.4
ME	2.9	3.1	3.1	3.1	2.7	4.5	4.7	5.4	0.8	0.8	0.8	0.8	0.7	1.7	0.7	0.7
MI	22.3	38.8	52.3	38.8	26.1	73.9	53	46	5.6	10.2	2	4.7	9.7	34.3	8.9	9.8
MN	13.9	18.1	34.1	46.1	20.9	22.7	47.1	48.2	5.1	5.2	1.2	1.2	4.9	5.7	0.2	10.4
MO	15.9	19.8	23.6	16.2	29.8	30.6	27.3	61.2	15.4	10.6	6.2	8.5	21.8	11.2	17	9.7
MS	19.7	22.7	30.3	22.6	23.7	33.8	38.5	41.9	23.9	20.1	23.1	14	41.9	27	25.4	18.8
MT	7.9	7.2	5.5	9.4	10.2	10.9	6.4	9.5	0.9	1.2	1.9	0.8	1.3	1.2	3.3	2.8
NC	3.3	34.4	29.1	28.9	13.4	46.9	43.6	31.9	7.3	41.7	41.2	35.9	7.3	61.9	79.2	51.5
ND	11.9	13.5	24.7	36.3	13.6	37	28.3	46.2	0	6.4	0	0	0.7	11.4	12.6	13.3
NE	13.1	24.9	36.2	40.2	15.7	23.6	44.2	63.9	3	8.5	0.1	0.1	4.7	8.5	5	7.7
NH	0.2	0.5	0.5	0.5	2.2	4.3	2.3	4.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
NJ	0	0.7	1.8	0.7	0	0.7	1.8	0.7	1	1	1	1	0.6	0.6	0.6	0.6
NM	12.9	17.9	12.4	15.8	16.4	24.1	52.4	15	5.4	5.3	10.1	8.7	8.6	9.1	15.9	10.7
NV	0.2	0.4	0.4	0.4	0.3	4.2	2.7	2.5	8	21.5	17.2	17.6	27.9	25	20.9	20.6
NY	8.7	8.4	8.4	8.3	8.5	18.6	21.8	19.2	4.4	4.2	4.2	4.2	4.8	7.4	28.4	34.4
OH	9.7	20.4	19.3	10.9	30.2	20.3	30.2	10.5	4.4	4.6	4.4	4.4	8.4	4.5	4.4	4.4
OK	18.9	32.5	30.2	49.8	22.7	59.4	62.3	56.1	9.2	6.2	6.9	10.3	16.3	6.1	14.7	12.1
OR	9.1	9.7	10.8	5.4	8.5	12.2	11.9	16.3	1.6	1.6	1.6	1.6	2.8	8.4	5	1
PA	4.2	6.4	8.9	7.2	6.9	8.7	18.9	9	1.1	0.8	0.8	0.7	3.5	3.1	4.2	2.3
RI	0.9	0.8	0.8	0.8	1.2	1.2	1.2	1.2	0.3	0.3	0.3	0.3	3.3	3.4	1.4	2.4
SC	2.7	17.3	14.7	8.3	6.8	19.9	19.9	19.9	4.3	10.1	8.9	8.2	15.3	17.9	18	29.3
SD	3.3	9	9.7	14.4	5.2	8.3	13.7	16.8	0.3	0.1	0.1	0.1	1.3	0.1	0.9	0.8
TN	7.1	9.3	6.8	9.3	9.7	11.1	13.3	9.3	1.2	2.6	8.2	1.9	1.1	2.5	20.1	1.8
TX	88.9	109.6	128	136.6	110.2	147.9	164.3	175	66.8	116.1	96.1	109	120.7	159.4	163.5	190.2
UT	0.7	1	0.9	0.9	0.9	2.4	2	0.8	2.9	2.8	2.8	2.8	6.8	9.5	6.5	1.8
VA	5.7	18.9	24	16.4	14.6	21.6	29.6	30.8	16.5	21.7	20.8	10.8	35.6	36.3	45	17.8
VT	0.5	1	1.2	0.7	3.4	4.9	2.5	2.7	0.2	0.2	0.2	0.2	0.1	4.3	0.1	0.1
WA	10.4	15.4	12.3	15.1	13.6	26.7	29.7	19.4	0.4	0.4	0.4	0.4	13.1	0.6	7.2	6.2
WI	17.5	13.6	18.6	13.8	23.5	39.2	19.1	17	4.5	9.4	2.3	2.3	18.1	14.3	15	11
WV	0.9	0.9	0.9	0.9	3.4	0.7	0.7	0.4	0	0	0	0	0	0	0	0
WY	19	26.3	35	41.9	20.6	43	42.9	48.8	2.3	0.1	1.1	0.6	6.7	0	2.2	5.6

Appendix E. Transmission Value Analysis

The economic analysis presented here identifies and evaluates quantifiable benefits associated with transmission development across NTP Study zonal planning and operational analysis. The following sections outline the overall approach to quantify and regionally disaggregate the benefits of transmission applied to the NTP zonal scenarios.

E.1 Multivalue

This analysis considers a broad range of transmission benefits including reduced capital and operating costs, reduced cost of meeting reliability requirements, and increased capture of federal and state incentives. Using outputs from the zonal production cost model, the economic analysis includes six categories of transmission benefits (Figure 42). Annualized savings for capital investments are based on the equivalent annual cost assuming a 1.7% discount rate. Transmission assets are assumed to have a 40-year asset life; all other technologies are assumed to have a 20-year asset life.

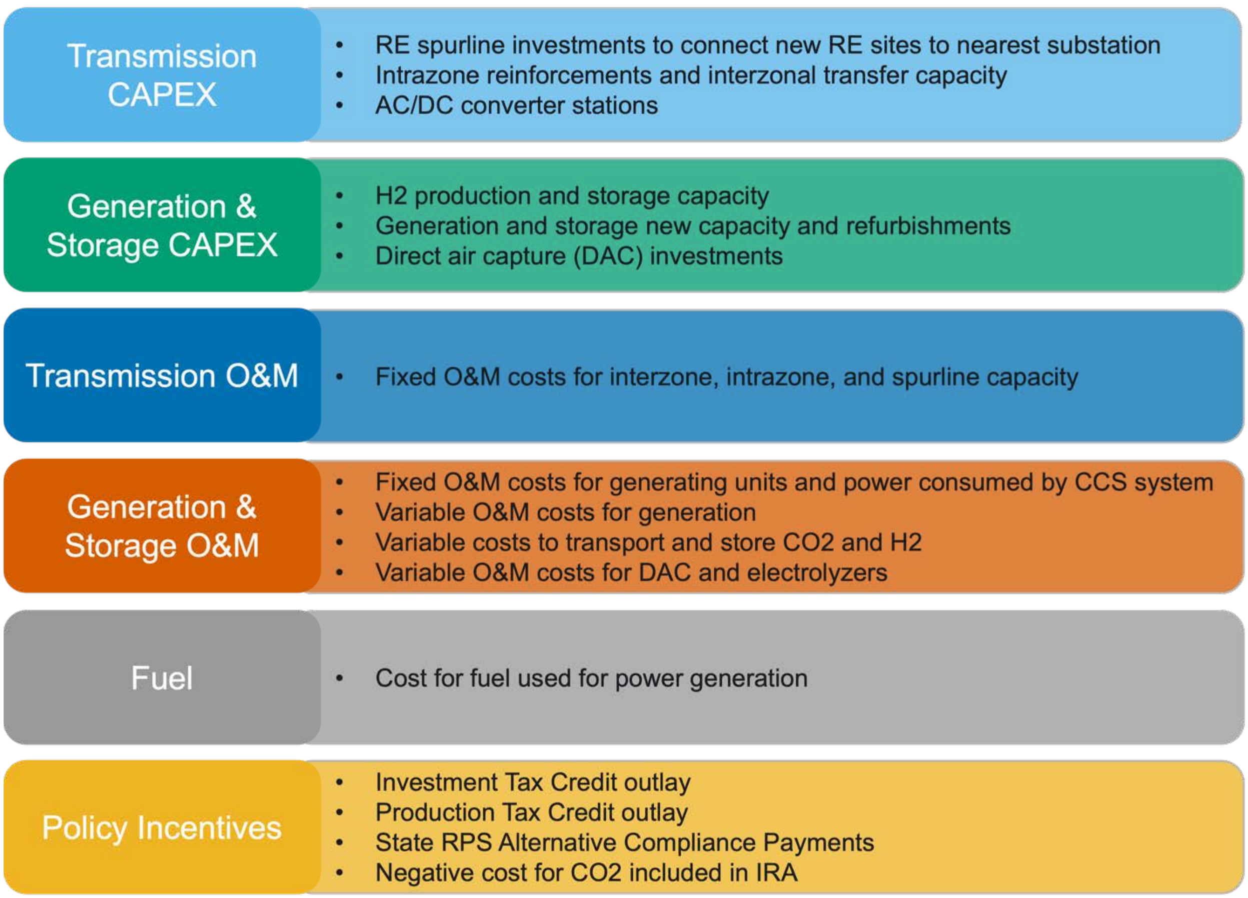


Figure E-1. System costs included in transmission valuation. Many benefits are correlated and not mutually exclusive.

E.2 System Perspective

The NTP Study evaluates transmission investments and operations across the entire contiguous United States. The economic analysis evaluates the value of transmission across this entire system as well as to a given region (e.g., ISONE, NYISO, CAISO). The analysis does not disaggregate the benefits experienced by different types of network users within each region (e.g., generators, consumers). In addition, no assumptions about how transmission cost recovery is allocated within a region or among customer classes are made.

E.3 Project Scope

This analysis evaluates the net benefits for the portfolio of transmission investments identified in NTP Study accelerated transmission frameworks rather than evaluating individual projects or transmission corridors. This approach reflects planning processes in place, such as MISO's multivalue project process that evaluates bundles of projects. It also aligns with the NTP Study approach, in which transmission investments and system operations are optimized on a multiregion scale. To isolate the impact of specific types of transmission development, the reference scenario (Limited) is compared with alternative "change" cases (AC, P2P, MT) that represent different types of transmission development.

E.4 Planning Horizon

The analysis considers an almost 30-year planning horizon, covering the period 2022–2050.[53] This extended planning horizon will inform how the benefits of transmission change over time as the underlying power system changes. It is also aligned with guidance under consideration by FERC to consider system needs and changes 20+ years in the future for transmission planning.

E.5 Uncertainty

The transmission valuation captures a range of possible future outcomes, drawing from the broad set of NTP Study sensitivity cases including macroeconomic drivers such as technology prices and availability as well as a range of system states such as different weather conditions. This analysis uses scenario-based comparisons to capture uncertainty system costs across a range of system futures.

E.6 Regional Disaggregation: Adjusted Production Cost

As interregional transmission enables more coordinated operation of low-cost generation resources, the distribution of operating costs within each region changes. For systemwide analysis, operating costs comprise variable operation and maintenance, fuel, and startup and shutdown. These metrics are sufficient to evaluate the change in operating costs for the entire system but, when evaluating the benefit distribution among regions, a further consideration is needed to capture the

[53] 2030 is the first year in which new interregional transmission can be commissioned in the NTP Study modeling.

transmission benefits of interregional trade to each region. The adjusted production cost (APC) metric is used to evaluate these benefits. The APC is the difference in total production costs adjusted for import costs and export revenues with and without a proposed transmission upgrade. This metric is used among independent system operators/regional transmission operators in the United States for transmission valuation and cost allocation including SPP, MISO, and PJM and is defined as follows:

$$\text{APC} = \text{Production Cost} + \text{Purchase Costs} - \text{Generator Revenue}$$

where

$$\text{Purchase Costs} = (\text{Hourly Consumer Load} + \text{Storage Charging} + \text{Imports}) \times \text{Locational Marginal Price}$$

$$\text{Generator Revenue} = \text{Hourly Generation} \times \text{Locational Marginal Price}$$

A key benefit of the APC when trying to disaggregate transmission benefits is that it does not strictly rely on the physical location where costs are incurred to estimate costs and benefits. As a simple example, a new transmission upgrade may enable the development of low-cost generation capacity in one region (Region A) that can serve additional load in a neighboring region (Region B). Strictly looking at where costs are occurring, the new transmission line will increase capital and operating costs in Region A because it is building more capacity and generating more. By contrast, capital and operating costs will decrease in Region B because it is building less capacity and relying on imports to meet its load. However, Region A is also benefiting through increased sales of power to its neighbors. In addition, Region B is not getting these imports for free; it incurs some cost to purchase imported energy. By including an adjustment for import costs and export revenues, the APC can capture these benefits. Figure E-1 shows the production cost adjustment (change in purchase cost – generator revenue) added to the transmission value for each region and topology for the core Mid-Demand 90% by 2035 scenarios.[54]

[54] For this study, the adjusted production cost is based on zonal marginal prices from the capacity expansion model based on the marginal price of meeting capacity, energy, and policy requirements in each balancing area. The capacity expansion model represents each modeled year with 33 representative days at 4-hr resolution, for a total of 198 modeled hours. Further study with full 8,760 hourly resolution at a nodal resolution can be used to refine the estimated adjusted production cost for each region.

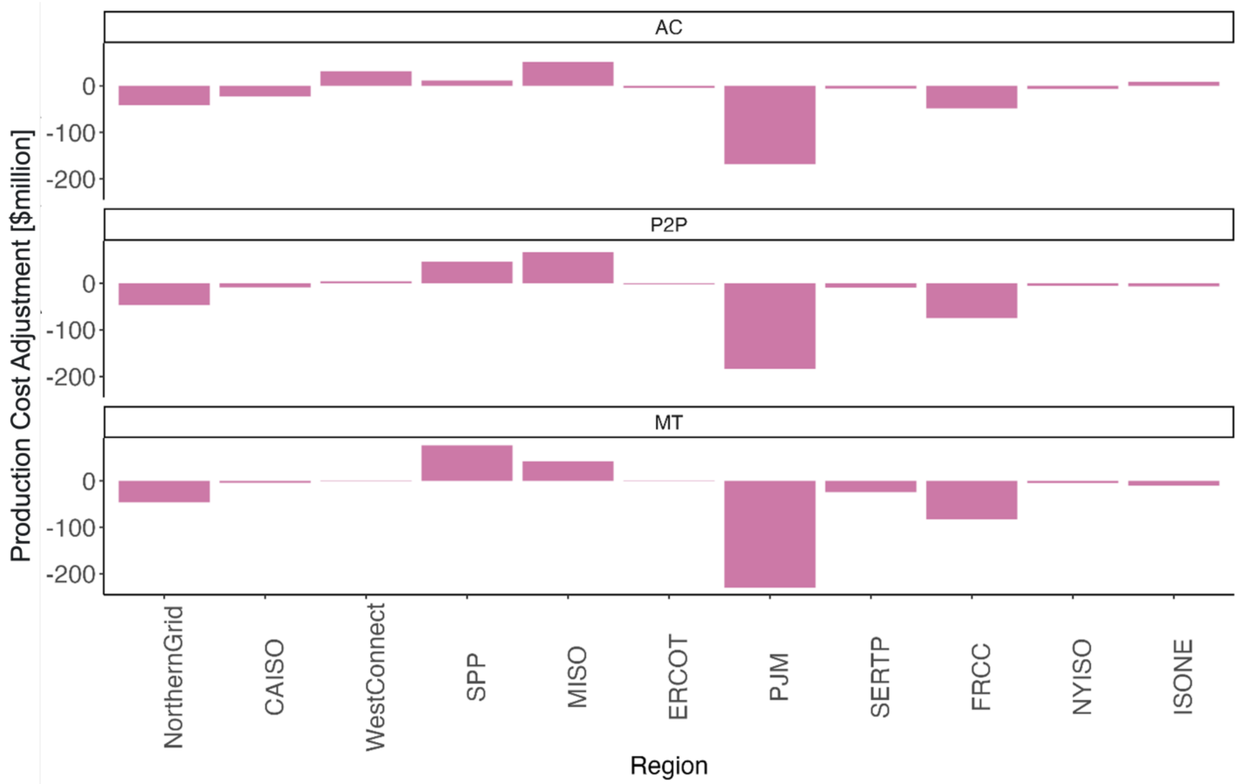


Figure E-2. Production cost adjustment for each transmission planning region and network topology for the core Mid-Demand 90% by 2035 scenarios ($million)

Appendix F. High Opportunity Transmission Interfaces: Regional Detail

The High Opportunity Transmission (HOT) analysis highlights robustly chosen transmission expansion opportunities for each of the 11 planning regions and each of the AC, P2P, MT transmission frameworks. The following maps show the interfaces with nearby planning regions and the 25th percentile of new transmission capacity built across those interfaces in the 16 sensitivity cases. These are the same data as shown in the national maps in the Text Box in Section 3.3 but provide a more granular view of transmission expansion in that planning region. The tables accompanying the maps show the 25th percentile as well as the 50th and 75th percentile results to inform more ambitious transmission development opportunities. Also included in the tables is the amount of existing transmission capacity across that interface. The interfaces are color coordinated to identify them in the table and map and across the other transmission framework maps. Three maps and associated tables are shown for each region showing the AC, P2P, and MT frameworks in that order. Some regions are grouped together when they have common borders (e.g., SERTP and FRCC; NYISO and ISONE).

CAISO

AC Framework

Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25^{TH}	50^{TH}	75^{TH}
Northern Grid S.	11	0.1	0.7	1.4
West Connect S.	5.3	3.6	4.0	4.7

P2P Framework

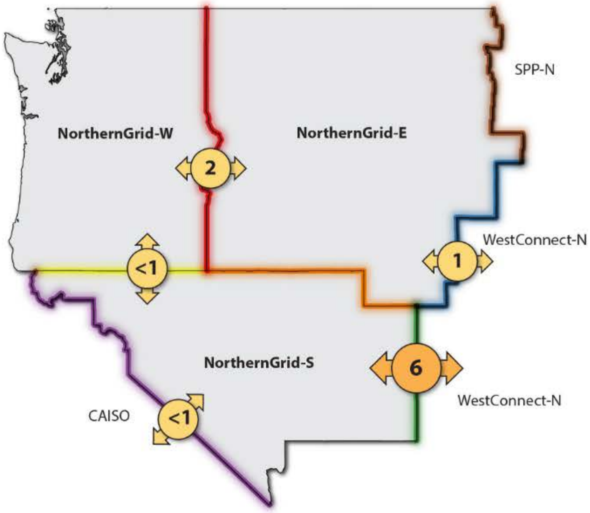
Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25^{TH}	50^{TH}	75^{TH}
Northern Grid S.	11	0	0.1	0.4
West Connect S.	5.3	3.0	4.1	4.9

MT Framework

Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25^{TH}	50^{TH}	75^{TH}
Northern Grid S.	11	0	0.4	0.6
West Connect S.	5.3	6.2	6.8	9.1

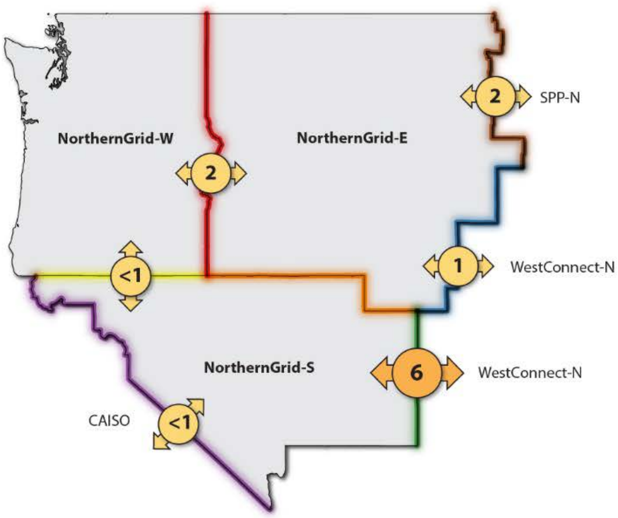


NorthernGrid

AC Framework

Interface Capacity (GW)

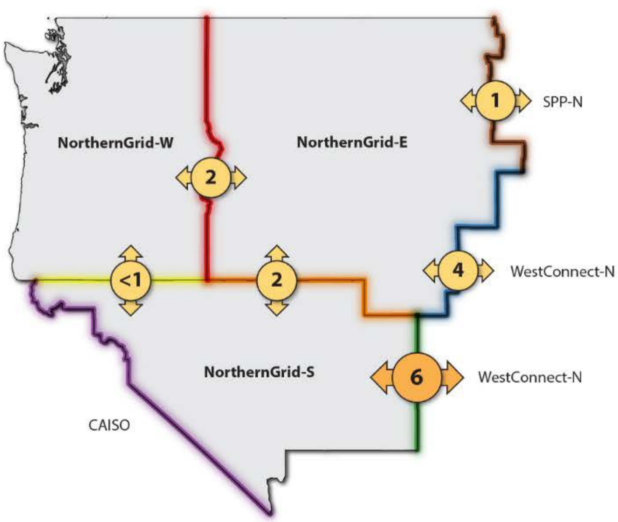
REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
NG-W, NG-E	13.2	1.7	1.7	1.7
NG-E, SPP-N	0.2	0	0	0
NG-E, WC-N	4.0	1.1	1.2	1.8
NG-E, NG-S	3.1	0	0	0.6
NG-W, NG-S	0.5	0.1	0.4	1.2
NG-S, WC-N	2.4	6.3	7.1	7.2
NG-S, CAISO	11	0.1	0.7	1.4



P2P Framework

Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
NG-W, NG-E	13.2	1.7	1.7	1.7
NG-E, SPP-N	0.2	1.8	2.2	2.5
NG-E, WC-N	4.0	1.4	2.1	2.5
NG-E, NG-S	3.1	0	0	0
NG-W, NG-S	0.5	0.1	0.3	0.5
NG-S, WC-N	2.4	5.8	7.0	7.9
NG-S, CAISO	11	0.1	0.4	0.3



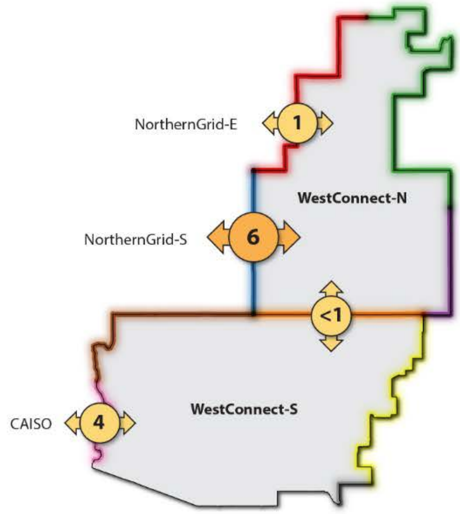
MT Framework

Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
NG-W, NG-E	13.2	1.7	1.7	1.7
NG-E, SPP-N	0.2	1.2	1.8	2.1
NG-E, WC-N	4.0	3.9	5.0	5.7
NG-E, NG-S	3.1	2.0	2.6	3.9
NG-W, NG-S	0.5	0.2	0.5	1.2
NG-S, WC-N	2.4	6.0	6.4	6.7
NG-S, CAISO	11	0	0.4	0.6

WestConnect

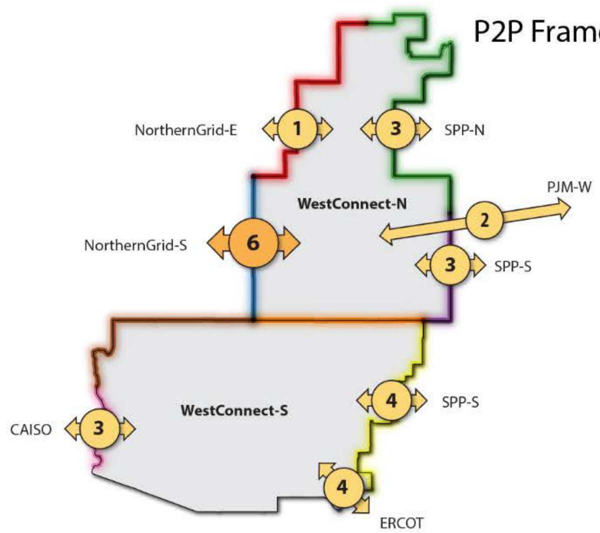
AC Framework



Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
WC-N, NG-E	4.0	1.1	1.2	1.8
WC-N, NG-S	2.4	6.3	7.1	7.2
WC-N, SPP-N	0.5	0	0	0
WC-N, SPP-S	0.2	0	0	0
WC-N, WC-S	1.4	0.1	0.7	0.8
WC-S, NG-S	7.3	0	0	0
WC-S, SPP-S	0.4	0	0	0
WC-S, ERCOT	0	0	0	0
WC-S, CAISO	5.3	3.6	4.0	4.7

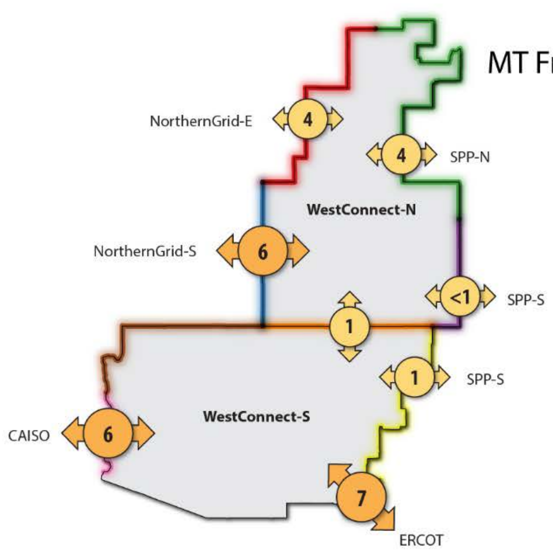
P2P Framework



Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
WC-N, NG-E	4.0	1.4	2.1	2.5
WC-N, NG-S	2.4	5.8	7.0	7.9
WC-N, SPP-N	0.5	2.6	3.1	3.9
WC-N, SPP-S	0.2	2.7	3.1	3.9
WC-N, WC-S	1.4	0	0.1	0.3
WC-S, NG-S	7.3	0	0	0
WC-S, SPP-S	0.4	4.2	5.7	6.5
WC-S, ERCOT	0	4.1	5.7	7.3
WC-S, CAISO	5.3	3.0	4.1	4.9

MT Framework

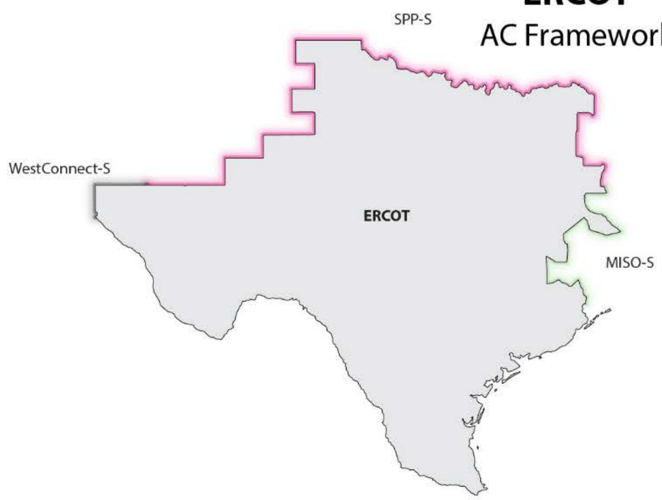


Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
WC-N, NG-E	4.0	3.9	5.0	5.7
WC-N, NG-S	2.4	6.0	6.4	6.7
WC-N, SPP-N	0.5	3.9	5.4	6.6
WC-N, SPP-S	0.2	0.5	0.9	1.5
WC-N, WC-S	1.4	1.0	1.6	2.4
WC-S, NG-S	7.3	0	0	0
WC-S, SPP-S	0.4	1.4	1.9	3.7
WC-S, ERCOT	0	6.5	7.1	9.5
WC-S, CAISO	5.3	6.2	6.8	9.1

ERCOT

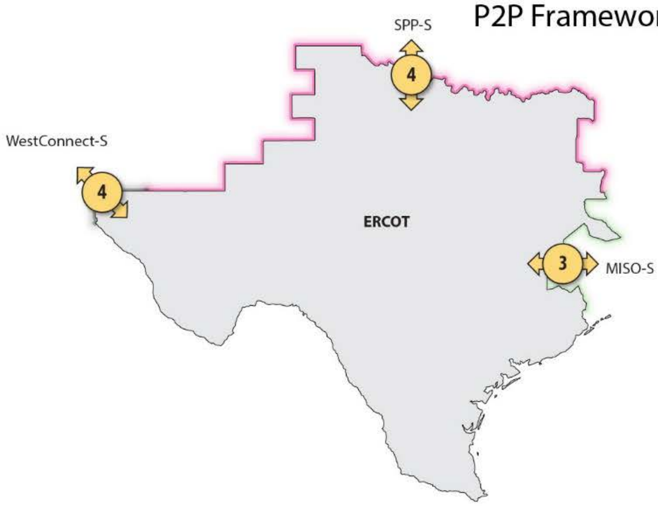
AC Framework



Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
ERCOT, SPP-S	0.8	**0**	0	0
ERCOT, WC-S	0	**0**	0	0
ERCOT, MISO-S	0	**0**	0	0

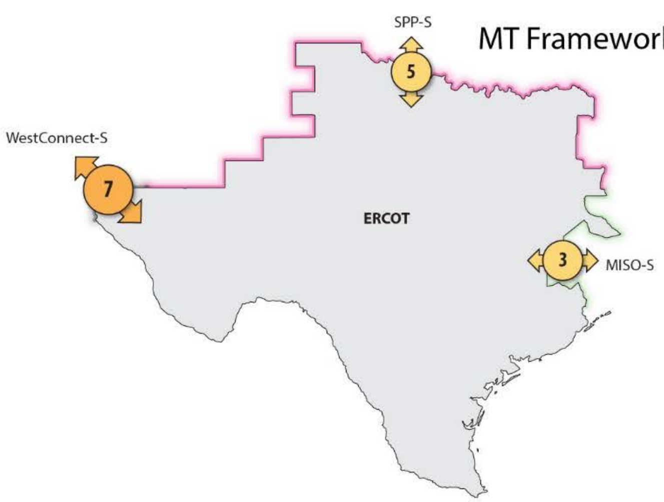
P2P Framework



Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
ERCOT, SPP-S	0.8	**4.1**	5.1	5.7
ERCOT, WC-S	0	**4.1**	5.7	7.3
ERCOT, MISO-S	0	**3.3**	4.4	4.9
Nonadjacent Region Interfaces				
ERCOT, MISO-N	0	**0**	0.2	1.3
ERCOT, NG-S	0	**0**	0	0.4
ERCOT, SPP-N	0	**0**	0	0.2
ERCOT, WC-N	0	**0**	0	0.3

MT Framework

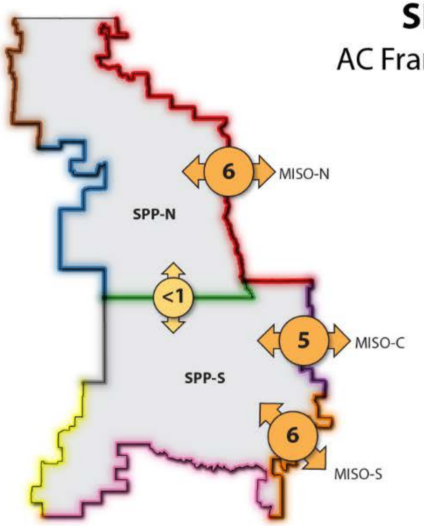


Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
ERCOT, SPP-S	0.8	**4.9**	6.3	12
ERCOT, WC-S	0	**6.5**	7.1	9.5
ERCOT, MISO-S	0	**2.6**	3.7	4.6

SPP

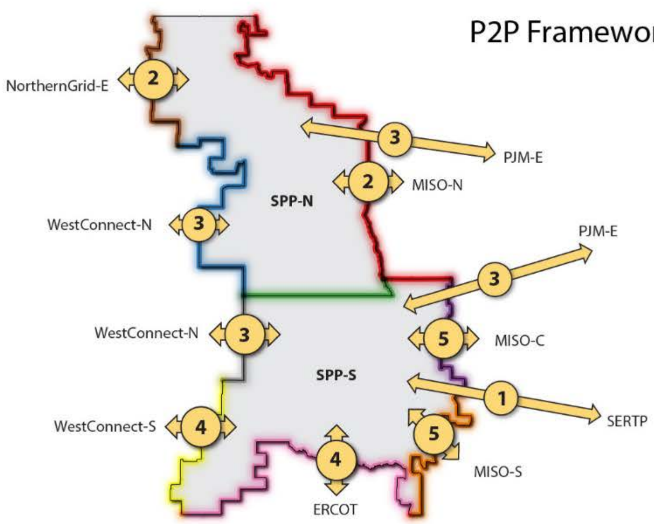
AC Framework



Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
SPP-N, NG-E	0.2	0	0	0
SPP-N, MISO-N	10.0	6.0	7.6	9.4
SPP-N, WC-N	0.5	0	0	0
SPP-N, SPP-S	5.4	0.2	0.3	0.4
SPP-S, MISO-C	2.0	4.7	6.0	6.0
SPP-S, MISO-S	3.3	5.8	6.4	7.0
SPP-S, WC-N	0.2	0	0	0
SPP-S, WC-S	0.4	0	0	0
SPP-S, ERCOT	0.8	0	0	0

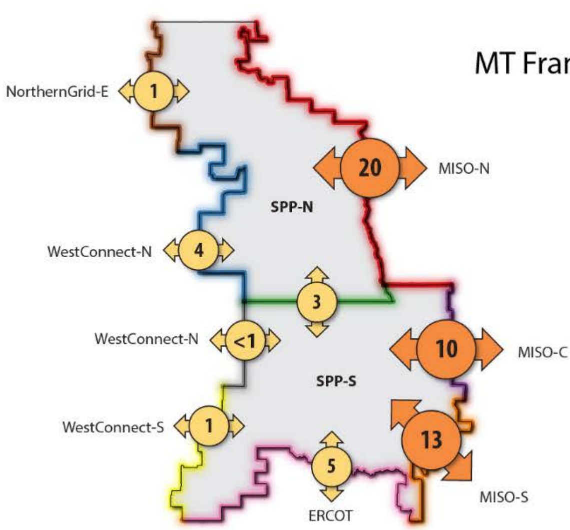
P2P Framework



Interface Capacity (GW)

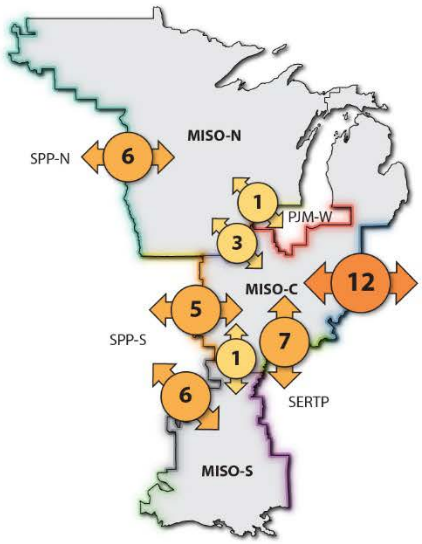
REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
SPP-N, NG-E	0.2	1.8	2.2	2.5
SPP-N, MISO-N	10.0	1.7	2.6	3.8
SPP-N, WC-N	0.5	2.6	3.1	3.9
SPP-N, SPP-S	5.4	0	0.2	0.7
SPP-S, MISO-C	2.0	4.8	5.6	5.8
SPP-S, MISO-S	3.3	4.5	5.5	6.3
SPP-S, WC-N	0.2	2.7	3.1	3.9
SPP-S, WC-S	0.4	4.2	5.7	6.5
SPP-S, ERCOT	0.8	4.1	5.1	5.7
Nonadjacent Region Interfaces				
SPP-N, PJM-E	0	3.4	5.2	10
SPP-S, PJM-E	0	3.3	4.7	7.1
SPP-S, SRTP	0	1.0	2.5	4.6

MT Framework



Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
SPP-N, NG-E	0.2	1.2	1.8	2.1
SPP-N, MISO-N	10.0	20.3	24.8	27.8
SPP-N, WC-N	0.5	3.9	5.4	6.6
SPP-N, SPP-S	5.4	3.4	5.8	7.5
SPP-S, MISO-C	2.0	9.9	13.8	16.8
SPP-S, MISO-S	3.3	12.6	16.5	18.1
SPP-S, WC-N	0.2	0.5	0.9	1.5
SPP-S, WC-S	0.4	1.4	1.9	3.7
SPP-S, ERCOT	0.8	4.9	6.3	12.0

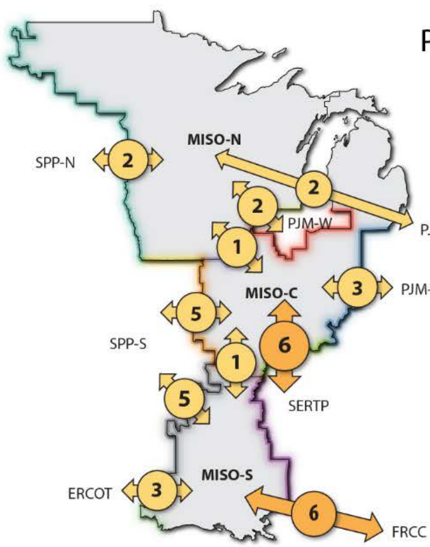


MISO

AC Framework

Interface Capacity (GW)

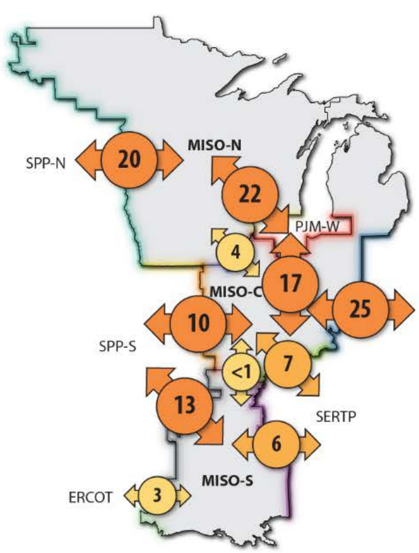
REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
MISO-N, SPP-N	10.0	6.0	7.6	9.4
MISO-N, PJM-W	5.0	1.4	2.9	4.9
MISO-N, MISO-C	5.5	2.6	4.3	5.1
MISO-C, PJM-W	15.1	0	0.7	1.0
MISO-N, SPP-S	1.1	0	0	0
MISO-C, PJM-E	28.3	11.7	14.4	16.1
MISO-C, SPP-S	2.0	4.7	6.0	6.0
MISO-C, SERTP	4.1	7.5	10.1	12.2
MISO-C, MISO-S	2.1	1.4	1.8	2.3
MISO-S, SPP-S	3.3	5.8	6.4	7.0
MISO-S, SERTP	11.0	0	0	0.1
MISO-S, ERCOT	0	0	0	0



P2P Framework

Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
MISO-N, SPP-N	10.0	1.7	2.6	3.8
MISO-N, PJM-W	5.0	1.5	2.0	3.4
MISO-N, MISO-C	5.5	1.0	1.8	4.3
MISO-C, PJM-W	15.1	0	0	0
MISO-N, SPP-S	1.1	0	0	0
MISO-C, PJM-E	28.3	2.6	4.7	7.9
MISO-C, SPP-S	2.0	4.8	5.6	5.8
MISO-C, SERTP	4.1	5.6	6.8	7.7
MISO-C, MISO-S	2.1	1.2	1.8	2.7
MISO-S, SPP-S	3.3	4.5	5.5	6.3
MISO-S, SERTP	11.0	0	0	0
MISO-S, ERCOT	0	3.3	4.4	4.9
Nonadjacent Region Interfaces: MISO-N, PJM-E	0	2.0	4.4	7.1
MISO-S, FRCC	0	6.2	7.3	8.6



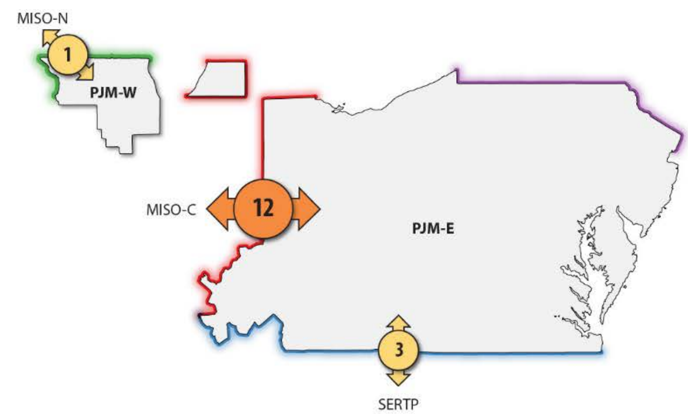
MT Framework

Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
MISO-N, SPP-N	10.0	20.3	24.8	27.8
MISO-N, PJM-W	5.0	21.8	23.4	27.5
MISO-N, MISO-C	5.5	3.8	5.0	5.5
MISO-C, PJM-W	15.1	16.5	19.7	22.8
MISO-N, SPP-S	1.1	0	0	0.1
MISO-C, PJM-E	28.3	24.7	28.0	32.6
MISO-C, SPP-S	2.0	9.9	13.8	16.8
MISO-C, SERTP	4.1	7.2	9.3	12.5
MISO-C, MISO-S	2.1	0.7	1.3	2.3
MISO-S, SPP-S	3.3	12.6	16.5	18.1
MISO-S, SERTP	11.0	5.8	9.7	11.1
MISO-S, ERCOT	0	2.6	3.7	4.6

PJM

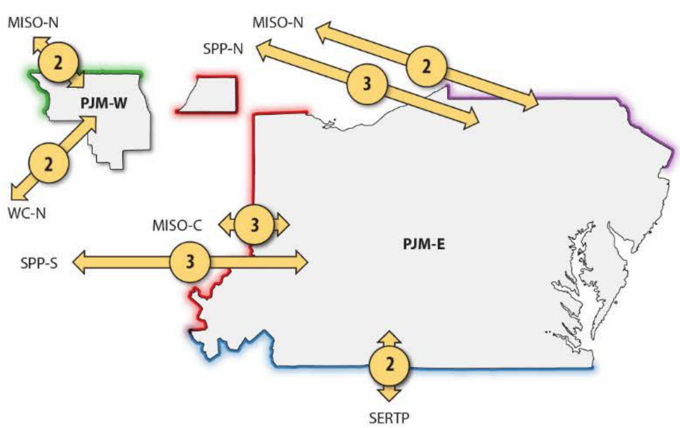
AC Framework



Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
PJM-W, MISO-N	5.0	1.4	2.9	4.9
PJM-E, MISO-C	28.3	11.7	14.4	16.1
PJM-E, SERTP	10.9	3.2	6.8	7.4
PJM-E, NYISO	6.6	0	0	0

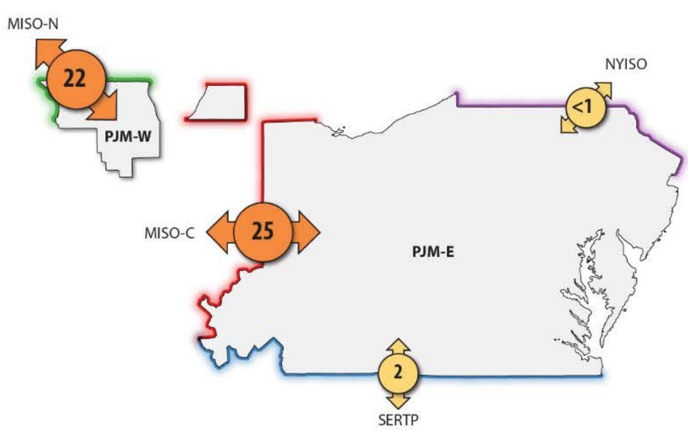
P2P Framework



Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
PJM-W, MISO-N	5.0	1.5	2.0	3.4
PJM-E, MISO-C	28.3	2.6	4.7	7.9
PJM-E, SERTP	10.9	2.2	5.0	6.3
PJM-E, NYISO	6.6	0	0	0
Nonadjacent Region Interfaces				
PJM-E, MISO-N	0	2.0	4.4	7.1
PJM-E, SPP-N	0	3.4	5.2	10.0
PJM-E, SPP-S	0	3.3	4.7	7.1
PJM-W, WC-N	0	2.2	3.1	4.9

MT Framework

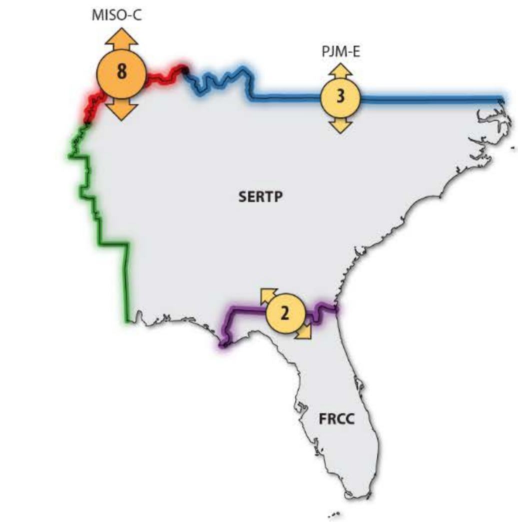


Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
PJM-W, MISO-N	5.0	21.8	23.4	27.5
PJM-E, MISO-C	28.3	24.7	28.0	32.6
PJM-E, SERTP	10.9	1.6	3.8	5.7
PJM-E, NYISO	6.6	0.9	2.4	3.7

SERTP & FRCC

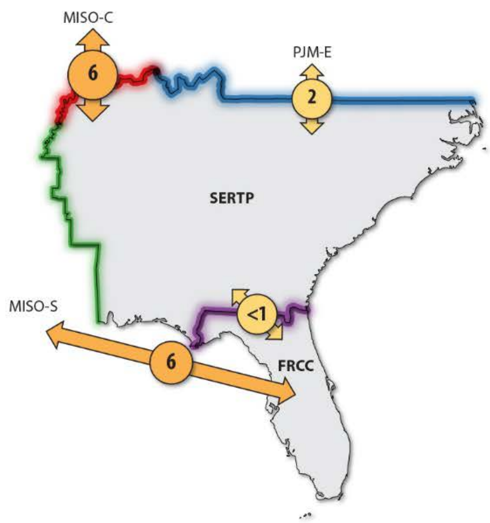
AC Framework



Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
SERTP, MISO-C	4.1	7.5	10.1	12.2
SERTP, PJM-E	10.9	3.2	6.8	7.4
SERTP, MISO-S	11.0	0	0	0.1
SERTP, FRCC	6.6	1.9	2.3	2.6

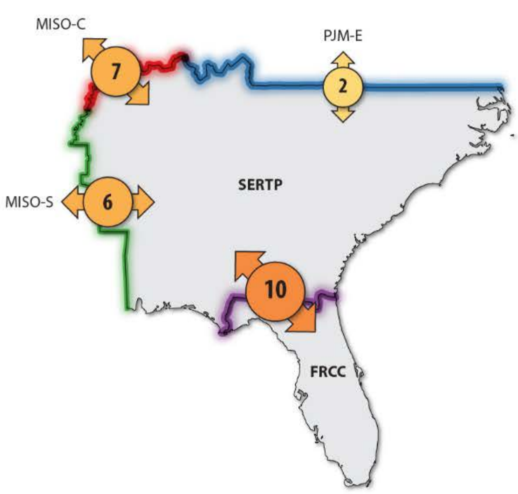
P2P Framework



Interface Capacity (GW)

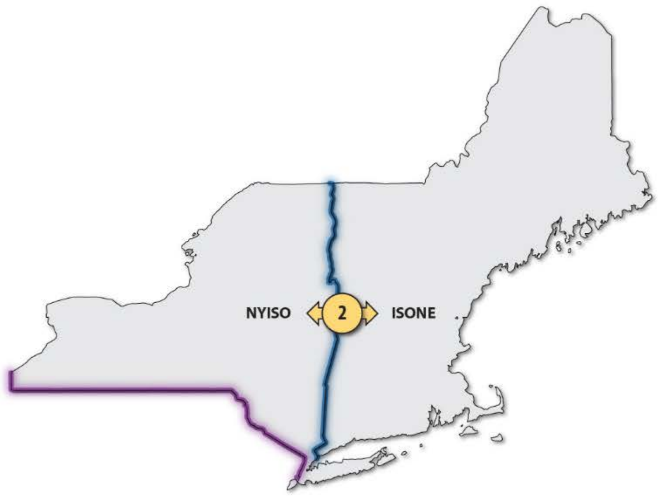
REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
SERTP, MISO-C	4.1	5.6	6.8	7.7
SERTP, PJM-E	10.9	2.2	5.0	6.3
SERTP, MISO-S	11.0	0	0	0
SERTP, FRCC	6.6	0.1	0.8	1.7
Nonadjacent Region Interfaces				
FRCC, MISO-S	6.9	6.2	7.3	8.6

MT Framework



Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
SERTP, MISO-C	4.1	7.2	9.3	12.5
SERTP, PJM-E	10.9	1.6	3.8	5.7
SERTP, MISO-S	11.0	5.8	9.7	11.1
SERTP, FRCC	6.6	10.1	11.7	12.4

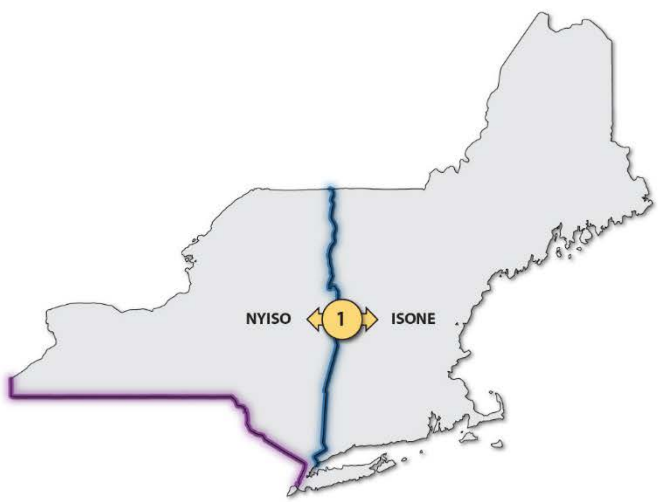


NYISO & ISONE

AC Framework

Interface Capacity (GW)

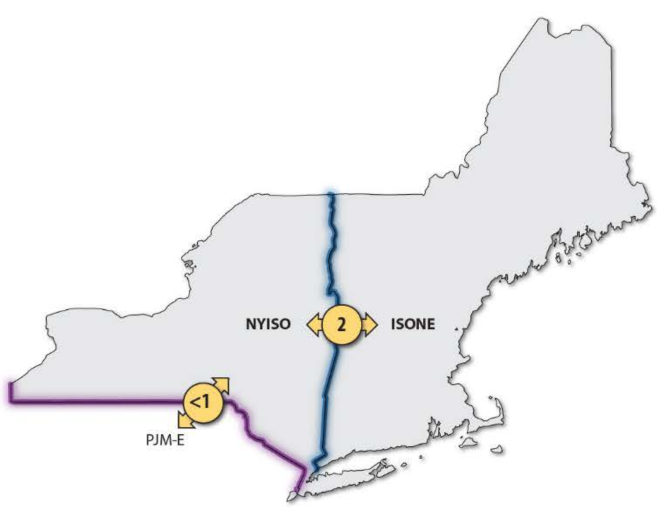
		Percentile of New Capacity		
REGION	EXISTING	25TH	50TH	75TH
NYISO, ISONE	3.5	**1.7**	1.8	2.5
NYISO, PJM-E	6.6	**0**	0	0



P2P Framework

Interface Capacity (GW)

		Percentile of New Capacity		
REGION	EXISTING	25TH	50TH	75TH
NYISO, ISONE	3.5	**1.4**	1.9	2.4
NYISO, PJM-E	6.6	**0**	0	0



MT Framework

Interface Capacity (GW)

		Percentile of New Capacity		
REGION	EXISTING	25TH	50TH	75TH
NYISO, ISONE	3.5	**1.6**	2.2	2.9
NYISO, PJM-E	6.6	**0.9**	2.4	3.7

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