U.S. DEPARTMENT OF ENERGY

National Transmission Needs Study: Supplemental Material

October 2023

United States Department of Energy
Washington, DC 20585

Executive Summary

This material supplements the United States Department of Energy's National Transmission Needs Study (Needs Study), published October 2023. Material here provides additional context, methodology, and data associated with information in the Needs Study. This document is organized to match the section numbers and headers of the Needs Study when appropriate; as a result, section numbering is not sequential.

National Transmission Planning Study: Supplemental Material

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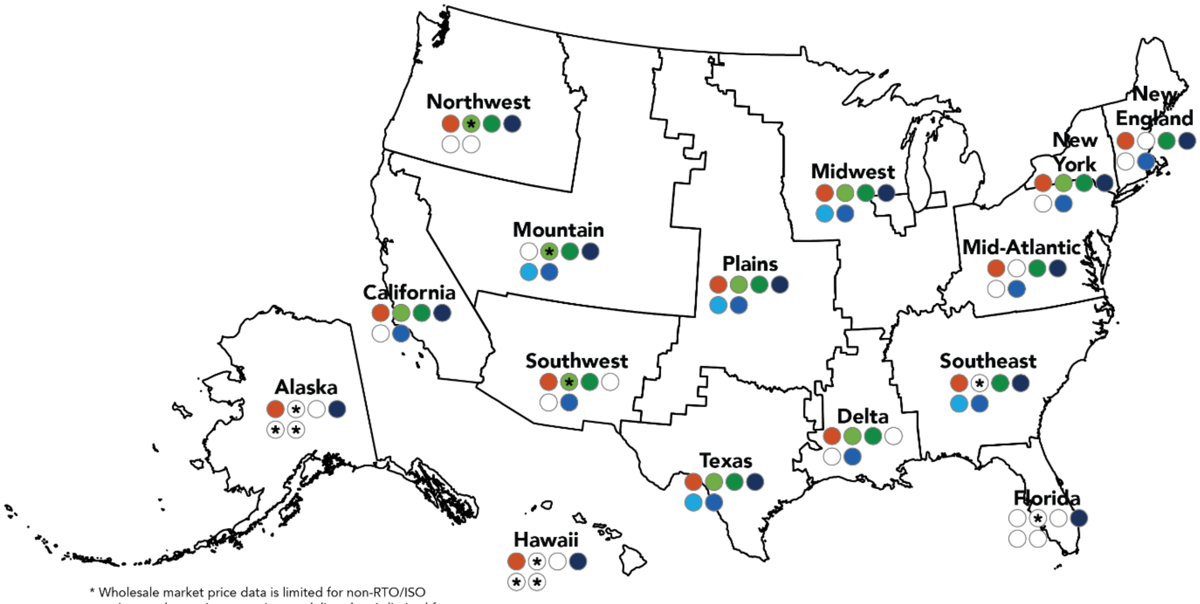
Findings Summary Graphic Methodology

The U.S. Department of Energy (the Department or DOE) summarizes regional findings of current and/or anticipated transmission need presented in the 2023 National Transmission Needs Study (Needs Study) in summary graphics located in the Executive Summary (Needs Study Figure ES-7, reproduced here as Figure S-1), as well as the conclusions of Section IV (Needs Study Figure IV-18), Section V (Needs Study Figure V-17), and Section VI (Needs Study Figure VI-12). Each graphic is composed of two pieces: a map (top) of the United States with different color circles within region boundaries and a table dashboard (bottom) that corresponds with categories of transmission needs. These categories are established in accordance with the definition of transmission need in Section I of the report (page 2):

> *"… this Needs Study includes an analysis of historical and anticipated electric transmission needs, defined as the existence of present or expected electric transmission capacity constraints or congestion in a geographic area. Geographic areas where a transmission need exists would benefit from an upgraded, uprated, or new transmission facility—including alternative transmission solutions—to improve the reliability and resilience of the power system; alleviate transmission congestion and unscheduled flows; alleviate power transfer capacity limits between neighboring regions; deliver cost-effective generation to meet demand; and/or meet projected future generation, electricity demand, or reliability requirements."*

The summary graphics contained in the conclusions of Needs Study Sections IV through VI (Needs Study Figures IV-18, V-17, and VI-12) summarize regional findings of current and/or anticipated transmission needs as determined by the data and studies referenced in the relevant section. Each finding of need presented in Needs Study Figure ES-7 (reproduced here as Figure S-1) is based on the aggregated findings of need included in Figures IV-18, V-17, and VI-12. In other words, if any one of Needs Study Figures IV-18, V-17, and VI-12 contains a finding of need for a particular region, that need will appear in both the map and dashboard portions of Needs Study Figure ES-7. The three summary graphics concluding each Needs Study section are not reproduced in this Supplemental Material for brevity.



* Wholesale market price data is limited for non-RTO/ISO regions and capacity expansion modeling data is limited for Alaska and Hawaii. Absence of data does not necessarily indicate that there is no need for new transmission.

Region

		California	Northwest	Mountain	Southwest	Texas	Plains	Midwest	Delta	Southeast	Florida	Mid-Atlantic	New York	New England	Alaska	Hawaii
Current or Anticipated Need	Improve reliability & resilience	●	●		●	●	●	●	●	●		●	●	●	●	●
	Alleviate congestion & unscheduled flows	●	●*	●*	●*	●	●	●	●	*	*		●		*	*
	Alleviate transfer capacity limits between neighbors	●	●	●	●	●	●	●	●	●		●	●	●		
	Deliver cost-effective generation to meet demand	●	●	●		●	●	●		●	●	●	●	●	●	●
Anticipated Need	Meet future generation & demand with within-region transmission			●		●	●	●		●					*	*
	Meet future generation & demand with interregional transfer capacity	●		●	●	●	●	●	●	●		●	●	●	*	*

Note: Reproduction of Figure ES-7 in the 2023 National Transmission Needs Study (page xi).

Figure S-1. Summary of current and future transmission needs identified in Needs Study by geographic region.

Each finding of need—indicated by a filled circle in both the map and dashboard of the graphics—corresponds with one or more references through which the Department has determined there is sufficient evidence to conclude the existence of a current and/or anticipated transmission need. In instances for which a summary graphic map includes a blank circle and the corresponding cell of the dashboard is empty, the Department concludes either there is not sufficient evidence to suggest a transmission need exists, or there is an absence of data that does not allow for a proper assessment of transmission need.[1] Known absences of data that inhibit properly assessing transmission need are indicated with an asterisk in the appropriate map circle and dashboard cell. It is important to note that while the Department draws upon findings included in references or interpreted from existing data included in the study, there may be published references and resources not captured in the Needs Study that determine a transmission need does, in fact, exist.

The Department uses the following methodology to determine whether findings from data or references included in the Needs Study demonstrate sufficient evidence to indicate a transmission need exists; the results are included in the relevant summary graphic. All regional transmission needs found given the methodology outlined below are summarized in Table S-1.

Section IV: Current Transmission Need Assessment through Historical Data

The Department determines a current transmission need exists in a region using the following methodology:

1. Improve reliability and resilience: Data and references included within the Section IV discussion of historical market conditions do not allow for findings of transmission need for this need category.
2. Alleviate congestion and unscheduled flows: The congestion value ($/megawatt-hour [MWh]) of hypothetical transmission links between select zonal nodes *within a region* from 2012 to 2020 as determined by Millstein et al. (2022) is greater than the national average value ($13/MWh) over the same time frame or if a qualified path passes through any region as determined by SPP (2022).
3. Alleviate transfer capacity limits between neighbors: The congestion value ($/MWh) of hypothetical transmission links between select zonal nodes *between regions* from 2012 to 2020 as determined by Millstein et al. (2022b) is greater than the national average value ($13/MWh) over the same time frame.
4. Deliver low-cost generation to meet demand: A region contains "high-priced" nodes as determined using the methodology referenced in Supplemental Material Section IV.b. below using data from Millstein et al. (2022b).

[1] For example, wholesale market price data are limited for non-RTO/ISO regions and capacity expansion modeling data are limited for Alaska and Hawaii. Absence of data does not necessarily indicate that there is no need for new transmission.

Section V: Current and Anticipated Needs Assessment and Identifcation of Transmission Benefits through Review of Existing Studies

The Department determines findings of need based on whether the authors of reports reviewed in the Section V literature review explicitly determine a transmission need exists for any region. *See* Table S-1 for a list of references.

Section VI: Anticipated Future Need Assessment through Capacity Expansion Modeling

The Department determines findings of need based on Section VI capacity expansion modeling results for the moderate load and high clean energy (Moderate/High) scenario group in the year 2035. Of the three scenario groups considered in the Needs Study, this group best represents the future power system should all current laws affecting the power system be realized.

The Department concludes a transmission need exists to meet future generation and demand with additional within-region transmission if capacity expansion modeling results indicate the percent growth of new within-region transmission in 2035 in the Moderate/High scenario group is greater than 50% relative to the 2020 transmission system. Similarly, the Department concludes a transmission need exists to meet future generation and demand with additional interregional transfer capacity if capacity expansion modeling results indicate the percent growth of new interregional transmission between a region and any neighboring region in 2035 in the Moderate/High scenario group is greater than 50% relative to the 2020 system.

Table S-1. All references supporting the findings of transmission need displayed in Figure S-1.

Need Category	California	Northwest	Mountain	Southwest	Texas	Plains	Midwest	Delta	Southeast	Florida	Mid-Atlantic	New York	New England	Alaska	Hawaii
Improve reliability and resilience	NERC (2021); CAISO (2022b)	NERC (2021)		NERC (2021)	FERC et al. (2021); NERC (2021); ERCOT (2022b); ERCOT (2022c); Clack et al. (2020b); Goggin (2021); Goggin and Zimmerman (2023)	FERC et al. (2021); Goggin (2021)	MISO (2022a); MISO (2022b); Novacheck et al. (2021); Prabhakar et al. (2021); FERC et al. (2021); FERC and NERC (2019); MISO (2021); NERC (2021); CapX2020 (2020); Goggin and Zimmerman (2023)	Prabhakar et al. (2021); FERC and NERC (2019); MISO (2021); NERC (2021); Goggin (2021); Potomac Economics (2020); Goggin and Zimmerman (2023)	Georgia Power (2022); Goggin (2021); Massie and Toth (2023); Duke Energy (2023); TVA (2023); RMI (2023); NERC (2022a)		Novacheck et al. (2021); PJM (2023b); Goggin (2021); PJM (2023d)	Novacheck et al. (2021); Goggin (2021); NYISO 2022b	ISO-NE (2022a); Novacheck et al. (2021); Goggin (2021)	Financial Engineering Company (2022); Ahtna and EPS (2020); AEA and EPS (2017)	KIUC (2023a); Hawaiian Electric (2023b); KIUC (2022)
Alleviate congestion and unscheduled flows	SPP (2020); Hildebrandt et al. (2021); Bailey and Mignella (2020); Lauby (2022)	SPP (2020); Millstein et al. (2022b)	SPP (2020); Millstein et al. (2022b); Simonson et al. (2021)	SPP (2020)	Millstein et al. (2022b); ERCOT (2022b); ERCOT (2022c); ERCOT (2022d); Clack et al. (2020b)	Warren et al. (2021)	Potomac Economics (2021a); MISO and SPP (2022); Prabhakar et al. (2021)	Potomac Economics (2021a); Prabhakar et al. (2021)				Millstein et al. (2022b); Patton et al. (2021); NYISO (2022a)			
Alleviate transfer capacity limits between neighbors	Millstein et al. (2022b)	Millstein et al. (2022b)	Millstein et al. (2022b)	Millstein et al. (2022b)	Millstein et al. (2022b); FERC et al. (2021)	Millstein et al. (2022b); FERC et al. (2021)	Millstein et al. (2022b); FERC et al. (2021); FERC and NERC (2019); MISO (2021)	Millstein et al. (2022b); FERC and NERC (2019); MISO (2021)	Goggin and Zimmerman (2023); Massie and Toth (2023)		Millstein et al. (2022b)	Millstein et al. (2022b)	Millstein et al. (2022b)		

Need Category	California	Northwest	Mountain	Southwest	Texas	Plains	Midwest	Delta	Southeast	Florida	Mid-Atlantic	New York	New England	Alaska	Hawaii
Deliver cost-effective generation to meet demand	Millstein et al. (2022b); CAISO's (2022b); Hildebrandt et al. (2021)	Evolved Energy Research (2021)	Simonson et al. (2021)		ERCOT (2022b); Xu et al. (2021)	Millstein et al. (2022b)	Millstein et al. (2022b); MISO (2022a); Xu et al. (2021); Prabhakar et al. (2021)		Xu et al. (2021); Duke Energy (2022)	Xu et al. (2021)	Millstein et al. (2022b)	Millstein et al. (2022b); Dimanchev et al. (2020); NYISO (2022a)	ISO-NE (2021a); ISO-NE (2021b); ISO-NE (2022a)	Ahtna and EPS (2020); Denholm et al. (2022b); Allen et al. (2016)	Hawaiian Electric (2021); Hawaiian Electric (2023a)
Meet future generation and demand with within-region transmission			Section VI mod/high study scenarios in 2035 with % growth relative to 2020 system levels >50%		Section VI mod/high study scenarios in 2035 with % growth relative to 2020 system levels >50%	Section VI mod/high study scenarios in 2035 with % growth relative to 2020 system levels >50%	Section VI mod/high study scenarios in 2035 with % growth relative to 2020 system levels >50%		Section VI mod/high study scenarios in 2035 with % growth relative to 2020 system levels >50%						
Meet future generation and demand with interregional transfer capacity	Section VI mod/high study scenarios in 2035 with % growth relative to 2020 system levels >50%		Section VI mod/high study scenarios in 2035 with % growth relative to 2020 system levels >50%	Section VI mod/high study scenarios in 2035 with % growth relative to 2020 system levels >50%	Section VI mod/high study scenarios in 2035 with % growth relative to 2020 system levels >50%	Section VI mod/high study scenarios in 2035 with % growth relative to 2020 system levels >50%	Section VI mod/high study scenarios in 2035 with % growth relative to 2020 system levels >50%	Section VI mod/high study scenarios in 2035 with % growth relative to 2020 system levels >50%	Section VI mod/high study scenarios in 2035 with % growth relative to 2020 system levels >50%		Section VI mod/high study scenarios in 2035 with % growth relative to 2020 system levels >50%	Section VI mod/high study scenarios in 2035 with % growth relative to 2020 system levels >50%	Section VI mod/high study scenarios in 2035 with % growth relative to 2020 system levels >50%		

Section IV. Current Transmission Need Assessment through Historical Data

Section IV.a. Historical Transmission Investments

Electricity demand data used in this section is from the Energy Information Administration (EIA) State Electricity Profiles (2022c).[2] Total annual retail sales, measured in MWh, were used as annual load, which is the net energy consumed by each state and does not include any energy generated behind-the-meter, such as distributed rooftp solar. These energy values more accurately reflect the energy that must be delivered across the transmission system to end-use customers. Load data were aggregated into the 15 different regions using the regional state boundaries shown in the bottom panel of Needs Study Figure III-4.

Data on historically built transmission lines was purchased through Endeavor Business Media's MAPSearch transmission GIS database, last updated in June 2023.[3] MAPSearch collects data on major new and rebuilt transmission lines from a variety of public data sources, such as the North American Electric Reliability Corporation (NERC) Electricity Supply & Demand database and Regional Transmission Operators/Independent System Operators' (RTO/ISO) annual transmission expansion plans. The MAPSearch database includes information about terminated, active, proposed, and conceptual transmission lines rated 69 kilovolt (kV) or higher. Only active projects rated above 100 kV were used in the data considered here. Additionally, the MAPSearch database includes information about each transmission project's sponsor, regional reliability entity, RTO/ISO, termination locations, electrical data, cost data, and project status.

Department staff reviewed the MAPSearch database and corrected obvious errors, such as redundant projects and the miscategorization of a project developer as incumbent or non-incumbent. Department staff also converted all project cost data to 2020 United States dollars (USD) using the annual average consumer price index retroactive series from the U.S. Bureau of Labor Statistics (Census 2022).

Transmission data were assigned to a region depending on the state(s) of its two termination points given the region groupings in Needs Study Figure III-4, in most cases. If a line terminated in two different regions, or nations, then it was classified as an "interregional" project. Recognizing that organizing transmission lines by termination states may miscategorize projects in states where multiple power system entities operate (*see* differences between the top and

[2] The *National Transmission Planning Study: Draft for Public Comment* issued in February 2023 used regional annual load data from NERC's 2020 Energy Supply and Demand (ES&D) database (NERC 2020), which required that the Midwest and Delta regions (corresponding to the Midwest ISO region in ES&D) and the Mountain and Northwest regions (corresponding to the Northwest Power Pool/Rocky Mountain Reserve Group region in ES&D) be combined in the previous version of these charts. State-level load data were used instead to separate the load-normalized data presented in this section into the 15 regions used in the *Needs Study*.

[3] The *National Transmission Planning Study: Draft for Public Comment* issued in February 2023 used a February 2022 version of this same database.

bottom panel in Needs Study Figure III-4), Department staff were careful to categorize transmission lines into their appropriate region using the metadata provided by MAPSearch. The predominant states within each region, as well notable exceptions for classifying different projects near the regional borders, are listed in Table S-2.

Table S-2. Transmission projects were organized into different geographic regions based on terminating states, with some notable exceptions along regional boundaries. Single state regions–Alaska, California, Florida, Hawaii, New York, Texas–are not listed. Refer to Needs Study Figures III-1 through III-4 to understand the geographic regions and different power sector entities within each.

Region	States Predominant to Each Region	Notable Exceptions Along Regional Boundaries
Delta	AR, LA, MS	Projects terminate in Texas and are categorized as MISO RTO/ISO
Mid-Atlantic	DE, DC, KY, MD NJ, OH, PA, VA, WV	Projects terminate in Illinois, Michigan, or Indiana and are categorized as PJM RTO/ISO
Midwest	IA, IL, IN, MI, MN, MO, WI	Projects terminate in North Dakota, South Dakota, or Kentucky and are categorized as MISO RTO/ISO
Mountain	CO, MT, NV, UT, WY	Projects terminate in South Dakota and are categorized as Western Electricity Coordinating Council regional reliability entity Projects terminate in California and RTO/ISO field is empty
New England	CT, MA, ME, NH, RI, VT	
Northwest	ID, OR, WA	
Plains	KS, ND, NE, OK, SD	Projects terminate in Texas, Arkansas, or Missouri and are categorized as SPP RTO/ISO
Southeast	AL, GA, NC, SC, TN	Projects terminate in Florida and are categorized as SERC regional reliability entity Projects terminate in Kentucky or Mississippi are categorized as SERC regional reliability entity, and the RTO/ISO field is empty
Southwest	AZ, NM	Projects terminate in Texas and are categorized as Western Electricity Coordinating Council regional reliability entity

MAPSearch classifies the primary objective, or driver, of all transmission lines as *reliability, economic*, *interconnect*, *renewable*, *generation*, or *multivalue*, and lists if more than one primary objective drove project development. *Reliability* projects are needed to improve reliability concerns of the local or regional electric grid. *Economic* projects are meant to alleviate economic congestion that exists on either side of its termination point. MAPSearch classifies a project as *multivalue* or with at least two drivers (e.g., *Reliability* and *Economic*) when a project meets one or more of the stated objectives. DOE classifies any project with two or more objectives as “multiple” in Needs Study Figures IV-6 and IV-7.

The *interconnect, renewable,* and *generation* drivers designate high-voltage generationtie-line projects that connect power plants directly to the transmission system. Projects designated as *interconnect* and *generation* are generally short lines (less than 20 miles) that connect a variety of fossil fuel, nuclear, solar and wind plants to the grid. Projects designated as *renewable* tend to be longer lines (20 to 250 miles) rated at least 230 kV. Several non-fosssil-based generation plants are given this designation, including wind, solar, geothermal, hydropower, and nuclear.

DOE removes the generation fuel source designation in these data by classifying any of the MAPSearch-designated *interconnect*, *renewable*, and *generation* projects as "interconnect" or "high-capacity" in Needs Study Figures IV-6 and IV-7. DOE subdivides lines with these drivers by voltage rating, classifying those that are rated at least 230 kV as *high-capacity interconnect* lines —shortened to simply "high-capacity" in the figures for brevity—providing further insight into the historic transmission data. Those rated less than 230 kV are simply "interconnect."[4]

Section IV.b. Market Price Differentials

Analysis in this section was performed by researchers at the Lawrence Berkeley National Laboratory. This work was the precursor to additional analysis published in Millstein et al. (2022). More detail on the methodology and motivation can be found in Millstein et al. (2022).

This analysis is built on recorded, real-time, hourly, nodal prices in wholesale markets. Nodal prices represent the marginal cost of the last unit of electricity (in units of $/MWh). The wholesale markets comprise seven major RTO/ISO regions. The seven major RTO/ISOs included in this analysis are the California ISO (CAISO), Southern Power Pool (SPP), Electric Reliability Council of Texas (ERCOT), Midcontinent ISO (MISO), PJM RTO (PJM), New York ISO, and ISO New England (ISO-NE). Additionally, the Western Energy Imbalance Market (WEIM), managed by CAISO, is included in the analysis and CAISO and WEIM are treated as a single region. Nodal prices are reported by each RTO/ISO, and records of these prices were purchased from a commercial vendor, Velocity Suite by Hitachi.

Average price differences from the median annual average price across all nodes

For the analysis shown in Needs Study Figure IV-8 (page 33), the average annual price at each node in each RTO/ISO region was calculated by averaging the hourly prices across a full year of data. We then found, for each RTO/ISO, the node with the median annual average price. In each region, this median price was then subtracted from the annual average price at each node, providing a difference from the median at each node. Positive values represent nodes with prices that are higher than the median node, and the opposite is true for negative values.

Market Price Differential metric

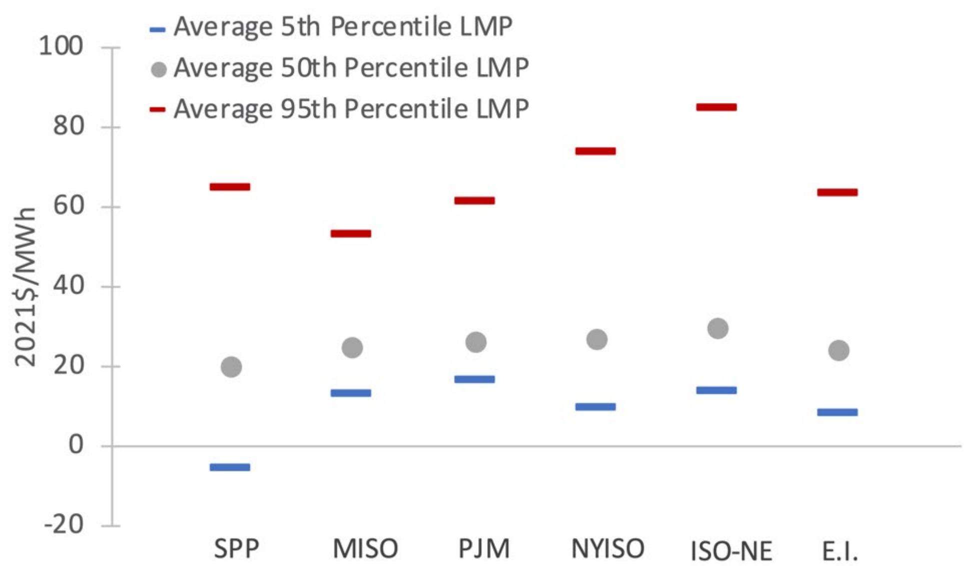
For the analysis shown in Needs Study Figure IV-9 (page 35), the 5th and 95th percentile price is calculated across all the hours in a particular year for each node. Across all nodes in an RTO/ISO, the nodal 5th and 95th percentil values are averaged to find an average 5th and 95th percentile value for the RTO/ISO. Nodes are then identifed as "high-priced" if their 95th percentile price is greater than 1 standard deviation above the RTO/ISO average 95th percentile price. A node is identified as "low-priced" if its 5th percentile value is less than 1 standard deviation below the RTO/ISO average 5th percentile value. Each node is evaluated for each year from 2017 to 2021, and the number of times it is identified as high- or low-priced is summed

[4] In the *Dra t National Transmission Needs Study* (published April 2023), DOE classified all renewable and generation projects as "high capacity." Upon conversations with stakeholders and closer scrutiny of the data, DOE believes "Interconnect" is the more appropriate driver for these projects, subdivided by voltage rating. "High-capacity" transmission lines are defined as being rated at or above 230 kV in 10 CFR Part 900 (2016).

over that time period. The results displayed in Needs Study Figure IV-9 (page 35) include nodes only if they have been identified as high or low for at least 2 years. Some nodes are identified as high- and low-priced nodes. This metric is based on a similar metric of the same name developed by FERC (2017).

For the purpose of determining the Market Price Differential metric, three interconnection-wide regions have been created, one incorporating all RTO/ISOs in the Eastern Interconnection (SPP, MISO, PJM, NYISO, ISO-NE), one incorporating CAISO and the rest of the WEIM, and ERCOT.

We provide additional context to the data presented in the Needs Study by examining how prices vary across each RTO/ISO within the region. Figure S-2 and Table S-3 show the 2017–2021 average 5th, 50th, and 95th percentile hourly prices across all nodes in each RTO/ISO and for the combined Eastern Interconnection. Average median prices are lowest in SPP at $20/MWh, highest in ISO-NE at $29/MWh, and the region-wide median is $24/MWh. Ninety-fifth percentile prices range from $52/MWh to $85/MWh, and 5th percentile prices range from −$6/MWh to $16/MWh. Notable differences between the RTO/ISOs are the negative prices found in SPP and the large standard deviation, relative to other RTO/ISOs, of the 5th percentile prices in SPP and the 95th percentile prices in SPP and NYISO. High standard deviations in extreme prices indicate the existence of within-RTO/ISO congestion because congestion is what drives the *geographic spread* in 95th or 5th percentile prices—which is captured by the standard deviation. In contrast, the difference in price between the 5th and 95th percentile price across an RTO/ISO reflects both congestion and other regional factors such as total load and natural gas prices. In other words, a region can have low price hours and high price hours even without congestion, but the spread of high (or low) prices across the region is determined primarily by congestion.



Note: Average 95th percentile is the uppermost line (ranging from $52/MWh to $85/MWh) and the Average 5th percentile is the lowest line (ranging from -$6/MWh to $16/MWh).

Figure S-2. Median, 5th, and 95th percentile hourly prices, averaged across nodes within each RTO/ISO in the Eastern Interconnect, and across the Eastern Interconnection as treated as a single region. Values shown represent the average of independently calculated values for each year from 2017 through 2021.

Table S-3. 5th, 50th, and 95th percentile hourly prices. Values are mean ± standard deviation, in 2021 $/MWh.

	SPP	MISO	PJM	NYISO	ISO-NE	E.I.
Average 5th Percentile LMP	−6 ± 10	13 ± 8	16 ± 3	9 ± 6	13 ± 5	8 ± 12
Average 50th Percentile LMP	20 ± 2	24 ± 2	26 ± 2	26 ± 4	29 ± 1	24 ± 4
Average 95th Percentile LMP	64 ± 14	52 ± 7	61 ± 1	74 ± 19	85 ± 3	63 ± 15

Interregional transmission value

The analysis shown in Needs Study Figure IV-10 (page 38) is limited to exploring differences in energy value and does not provide a comprehensive estimate of the value of transmission. For example, the value calculated here does not include value within the capacity markets, the value of facilitating emissions reductions, or the value of enhanced grid resiliency. Still this analysis provides a description of an important, although incomplete, source of transmission value. More detail on the importance of this transmission value is provided in Millstein et al. 2022.

Hub (or where hub nodes were unavailable, zonal nodes) were selected to represent each RTO/ISO region (often more than one hub node is chosen for each region to represent differences within the region). Neighboring selected nodes were then linked together. For each pair of nodes, the average annual hourly difference in price was found as shown in Eq. 1, where *N1* and *N2* represent the hourly price at each selected node in the node pairing and *h* represents each hour of the year. Note the absolute value of the difference is taken because the direction of the price difference is not important for this particular analysis. Eq. 1., as shown, is for a non-leap year. The number of hours is adjusted leap years, and case when a small number of hours were missing in the data.

$$\frac{\sum_{h=0}^{8760} |N1_h - N2_h|}{8760} \qquad \text{Eq. 1.}$$

National average electricity price is used to normalize interregional transmission value in some analysis presented here. The national average price is calculated in two steps. First, the average annual price is calculated for each RTO/ISO (CAISO and the West are treated as a single region) as the simple average of all hourly prices across all nodes within each RTO/ISO. Second, the national average is calculated by taking the simple average across the seven RTO/ISO-level annual average prices.

Section V: Current and Future Need Assessment and Identification of Transmission Benefits through Review of Existing Studies

All Studies Included in Section V

Section V of the 2023 National Transmission Needs Study surveys more than 120 recently published reports to highlight the historical and anticipated drivers of transmission needs, the multiple benefits that additional transmission infrastructure can provide to consumers, and the challenges of expanding the Nation's electric transmission infrastructure. The literature review includes reports from the U.S. Government, national laboratories, academia, consultants, and a cross section of industry participants that incorporate quantitative and qualitative measures of electric transmission needs. Reports were chosen on the basis of geographic diversity, diversity among sources, and author subject matter expertise, and to cover a range of critical reliability and congestion issues faced by the transmission system today. The title, author(s), publication date, publisher, and funding source(s) for all reviewed reports are included in Table S-4. The report title is hyperlinked to the study when an active link was available at the time of Needs Study publication.

Table S-4. List of all studies reviewed in this section. Funding source is listed as "N/A" when study was either author-funded or when funding source is not known.

Study Title	Author(s)	Publication Date	Publisher	Funding Source(s)
2022 Annual Report: Reducing the Cost of Energy in Alaska	Alaska Energy Authority	2022	Alaska Energy Authority	N/A
Alaska Energy Authority Railbelt Transmission Plan	Alaska Energy Authority & Electric Power Systems, Inc.	Mar. 2017	Alaska Energy Authority	N/A
Roadbelt Intertie Reconnaissance Engineering Report	Ahtna Environmental, Inc. & Electric Power Systems, Inc.	Nov. 2020	Denali Commission	Denali Commission
Sustainable Energy Solutions for Rural Alaska	Allen, Brutkoski, Farnsworth, Larsen	Apr. 2016	U.S. Department of Energy Office of Indian Energy Policy and Programs	DOE Office of Indian Energy Policy and Programs under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231
Solar Futures Study	Ardani, Denholm, Mai, Margolis, O'Shaughnessy, Silverman, Zuboy	Sept. 2021	U.S. Department of Energy	DOE Office of Energy Efficiency and Renewable Energy Strategic Priorities and Impact Analysis Office
2040 Clean Energy Sensitivities Study	Bailey	Jan. 2022	Western Electricity Coordinating Council	Western Electricity Coordinating Council

Study Title	Author(s)	Publication Date	Publisher	Funding Source(s)
WECC 2038 Scenarios Reliability Assessment	Bailey, Mignella	May 2020	Western Electricity Coordinating Council	Western Electricity Coordinating Council
Recommended Siting Practices for Electric Transmission Developers	Blaug, Nichols	Feb. 2023	Americans for a Clean Energy Grid	Americans for a Clean Energy Grid
The Value of Increased HVDC Capacity Between Eastern and Western U.S. Grids: The Interconnections Seam Study	Bloom, Novacheck, Brinkman, McCalley, Figueroa-Acevedo, Jahanbani-Ardakani, Nosair, Venkatraman, Caspary, Osborn, Lau	Oct. 2020	National Renewable Energy Laboratory	DOE Office of Energy Efficiency and Renewable Energy Wind Energy Technologies Office and the Office of Electricity
Strategic Asset Management Plan 2022	Bonneville Power Administration	2022	Bonneville Power Administration	N/A
Atlantic Offshore Wind Transmission Literature Review and Gaps Analysis	Bothwell, Marquis, Lau, Fu, Hartman	Oct. 2021	U.S. Department of Energy	DOE Office of Energy Efficiency and Renewable Energy Wind Energy Technologies Office
Climate Change and Energy Infrastructure Exposure to Storm Surge and Sea-Level Rise	Bradbury, Allen, Dell	July 2015	U.S. Department of Energy	U.S. Department of Energy
North American Renewable Energy Integration Study: A U.S. Perspective	Brinkman, Bain, Buster, Draxl, Das, Ho, Ibanez, Jones, Koebrich, Murphy, Narwade, Novacheck, Purkayastha, Rossol, Sigrin, Stephen, Zhang	Jun. 2021	National Renewable Energy Laboratory	Natural Resources Canada; DOE, Office of Energy Efficiency and Renewable Energy Wind Energy Technologies Office, Water Power Technologies Office, and Solar Energy Technologies Office; the Government of Mexico
Renewable Energy Resource Assessment Information for the United States	Brooks	Mar. 2022	U.S. Department of Energy Office of Energy Efficiency and Renewable Energy	U.S. Department of Energy
The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System	Brown, Botterud	Jan. 2021	Joule	MIT Energy Initiative Low-Carbon Energy Center for Solar Energy and the MITEI Future of Storage study
Offshore Wind Transmission White Paper	Burke, Goggin, Gramlich	Oct. 2020	The Business Network for Offshore Wind	The Business Network for Offshore Wind

Study Title	Author(s)	Publication Date	Publisher	Funding Source(s)
20-Year Transmission Outlook	California ISO	Jan. 2022	California Independent System Operator	N/A
Summer Market Performance Report	California ISO	Sept. 2022	California Independent System Operator	N/A
CapX2050 Transmission Vision Report	CapX2020	Mar. 2020	CapX2020	N/A
Advanced Conductors on Existing Transmission Corridors to Accelerate Low Cost Decarbonization	Caspary, Schneider	Mar. 2022	American Council on Renewable Energy	American Council on Renewable Energy CTC Global Corporation, Lamifil Inc North America, Natural Resources Defense Council, Taihan Electric USA Ltd., and TS Conductor Corporation
A Plan for Economy-Wide Decarbonization of the United States	Clack, Choukulkar, Coté, McKee	Oct. 2021	Vibrant Clean Energy	Coalition for Community Solar Access
Why Local Solar for All Costs Less: A New Roadmap for the Lowest Cost Grid	Clack, Choukulkar, Coté, McKee	Dec. 2020	Vibrant Clean Energy	Local Solar for All, Vote Solar, Coalition Community Solar Access
Consumer, Employment, and Environmental Benefits of Electricity Transmission Expansion in the Eastern U.S.	Clack, Goggin, Choukulkar, Coté, McKee	Oct. 2020	Americans for a Clean Energy Grid	Americans for a Clean Energy Grid
2021 Standard Scenarios Report: A U.S. Electricity Sector Outlook	Cole, Carag, Brown, Brown, Cohen, Eurek, Frazier, Gagnon, Grue, Ho, Lopez, Mai, Mowers, Murphy, Sergi, Steinberg, Williams	Nov. 2021	National Renewable Energy Laboratory	DOE Office of Energy Efficiency and Renewable Energy Strategic Priorities and Impact Analysis Office
Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035	Denholm, Brown, Cole, Mai, Sergi, Brown, Jadun, Ho, Mayernik, McMillan, Sreenath	2022	National Renewable Energy Laboratory	DOE Office of Energy Efficiency and Renewable Energy Strategic Priorities and Impact Analysis Office
Renewable Portfolio Standard Assessment for Alaska's Railbelt	Denholm, Schwarz, DeGeorge, Stout, Wiltse	Feb. 2022	National Renewable Energy Laboratory	Internal funding provided by the National Renewable Energy Laboratory
Two-Way Trade in Green Electrons: Deep Decarbonization of the Northeastern U.S. and the Role of Canadian Hydropower	Dimanchev, Emil; Hodge, Joshua; Parsons, John	Feb. 2020	Massachusetts Institute of Technology Center for Energy and Environmental Policy Research	Massachusetts Institute of Technology Center for Energy and Environmental Policy Research

Study Title	Author(s)	Publication Date	Publisher	Funding Source(s)
West Coast Offshore Wind Transmission Literature Review and Gaps Analysis	Douville, Severy, Eisdorfer, He, Pamintuan	Feb. 2023	U.S. Department of Energy	DOE Office of Energy Efficiency and Renewable Energy Wind Energy Technologies Office
2022 Carolinas Carbon Plan Appendix P – Transmission System Planning and Grid Transformation	Duke Energy	May 2022	Duke Energy	N/A
North Carolina Utilities Commission January 3, 2023 Briefing on Rolling Outages	Duke Energy	Jan. 2023	North Carolina Utilities Commission	N/A
Report on Existing and Potential Electric System Constraints and Needs	Electric Reliability Council of Texas	Dec. 2021	Electric Reliability Council of Texas	N/A
2020 Demand and Energy Report	Electric Reliability Council of Texas	Mar. 2021	Electric Reliability Council of Texas	N/A
Update to April 6, 2021, Preliminary Report on Causes of Generator Outages And Derates During the February 2021 Extreme Cold Event	Electric Reliability Council of Texas	Apr. 2021	Electric Reliability Council of Texas	N/A
Operating procedure Manual: DC Tie Desk. Version 1.0	Electric Reliability Council of Texas	2022	Electric Reliability Council of Texas	N/A
Report on Existing and Potential Electric System Constraints and Needs	Electric Reliability Council of Texas	Dec. 2022	Electric Reliability Council of Texas	N/A
Long-Term West Texas Export Study	Electric Reliability Council of Texas	Jan. 2022	Electric Reliability Council of Texas	N/A
Long-Term System Assessment for the ERCOT Region	Electric Reliability Council of Texas	Dec. 2022	Electric Reliability Council of Texas	N/A
Oregon Clean Energy Pathways Analysis	Evolved Energy Research	Jun. 2021	Evolved Energy Research	N/A
Transmission Metrics: Initial Results Staff Report	Federal Energy Regulatory Commission	Mar. 2016	Federal Energy Regulatory Commission	N/A
Transmission Metrics: Staff Report	Federal Energy Regulatory Commission	Oct. 2017	Federal Energy Regulatory Commission	N/A

Study Title	Author(s)	Publication Date	Publisher	Funding Source(s)
Report on Barriers and Opportunities for High Voltage Transmission	Federal Energy Regulatory Commission	Jun. 2020	Federal Energy Regulatory Commission	N/A
Notice of Proposed Rulemaking: Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection	Federal Energy Regulatory Commission	May 2022	Federal Energy Regulatory Commission	N/A
The February 2021 Cold Weather Outages in Texas and the South Central United States	Federal Energy Regulatory Commission, North American Electric Reliability Corporation, Regional Entity	Nov. 2021	Federal Energy Regulatory Commission, North American Electric Reliability Corporation, Regional Entity	N/A
The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018	Federal Energy Regulatory Commission, North American Electric Reliability Corporation	Jul. 2019	Federal Energy Regulatory Commission, North American Electric Reliability Corporation	N/A
Promising Practices for EJ Methodologies in NEPA Reviews	The Federal Interagency Working Group on Environmental Justice & NEPA Committee	Mar. 2016	The Federal Interagency Working Group on Environmental Justice & NEPA Committee	N/A
A Synoptic View of the Third Uniform California Earthquake Rupture Forecast	Field, E, Jordan T, Page M, Milner K, Shaw B, Dawson T, Biasi G, Parsons T, Hardebeck J, Michael A, Weldon R, Powers P, Johnson K, Zeng Y, Felzer K, van der Elst N, Madden C, Arrowsmith R, Werner M, Thatcher W	Jul. 2017	Seismological Research Letters	N/A
At the Crossroads in GVEA Generation	The Financial Engineering Company	Jun. 2022	Golden Valley Electric Association	Golden Valley Electric Association
2022 Integrated Resource Plan	Georgia Power	Jan. 2022	Georgia Power	N/A

Study Title	Author(s)	Publication Date	Publisher	Funding Source(s)
Preliminary PJM Load Forecast	Gledhill	Dec. 2021	PJM Interconnection, LLC	PJM Interconnection, LLC
Transmission Makes the Power System Resilient to Extreme Weather	Goggin	Jul. 2021	American Council on Renewable Energy	American Council on Renewable Energy
The Value of Transmission During Winter Storm Elliott	Goggin, Zimmerman	Feb. 2023	American Council on Renewable Energy	American Council on Renewable Energy
Integrated Grid Plan: A Pathway to a Clean Energy Future	Hawaiian Electric	May 2023	Hawaiian Electric	N/A
2021 System Stability Study O'ahu, Maui and Hawaii Island Study Report	Hawaiian Electric	Feb. 2023	Hawaiian Electric	N/A
Transmission Renewable Energy Zone (REZ) Study Report	Hawaiian Electric	Oct. 2021	Hawaiian Electric	N/A
2020 Annual Report on Market Issues & Performance	Hildebrandt, Blanke. Kurlinski, Avalos, Deshmukh, Koppolu, Maxson, McLaughlin, Mundt, O'Connor, Prendergast, Robinson, Rudder, Sanada, Shirk, Swadley, Westendorf	Aug. 2021	Department of Market Monitoring – California ISO	California ISO
2019 Economic Study: Significant Offshore Wind Integration	ISO New England, Inc.	Oct. 2020	ISO New England Inc.	N/A
First Cape Cod Resource Integration Study	ISO New England, Inc.	Jul. 2021	ISO New England Inc.	N/A
2021 Economic Study: Future Grid Reliability Study Phase 1	ISO New England, Inc.	Jul. 2022	ISO New England Inc.	N/A
2050 Transmission Study: Solution Development Update	ISO New England, Inc.	Dec. 2022	ISO New England, Inc.	N/A
Tribal Electricity Access and Reliability Congressional Report – Listening Session II	Johns W, Conrad D, Pierce L, Jones T	Jul. 2022	U.S. Department of Energy Office of Indian Energy	U.S. Department of Energy

Study Title	Author(s)	Publication Date	Publisher	Funding Source(s)
Energy Pathways to Deep Decarbonization	Jones, Ryan; Haley, Ben; Williams, Jim (University of San Francisco); Farbes, Jamil; Kwok, Gabe; Hargreaves, Jeremy	Dec. 2020	Evolved Energy Research	Commonwealth of Massachusetts as part of the Decarbonization Roadmap Study
Storage Futures Study: Grid Operational Impacts of Widespread Storage Deployment	Jorgenson, Will Frazier, Denholm, Blair	Jan. 2022	National Renewable Energy Laboratory	DOE Office of Energy Efficiency and Renewable Energy Solar Energy Technologies Office, Wind Energy Technologies Office, Water Power Technologies Office, and Office of Strategic Analysis
Kauai Island Utility Cooperative Report and Analysis Kilohana 69kV Switchyard Project	Kaua'i Island Utility Cooperative	Nov. 2022	Kaua'i Island Utility Cooperative	N/A
Strategic Plan Update: 2023-2033	Kaua'i Island Utility Cooperative	Jan. 2023	Kaua'i Island Utility Cooperative	N/A
Interactions Between Hybrid Power Plant Development and Local Transmission in Congested Regions	Kemp, Millstein, Kim, Wiser	June 2023	Elsevier	U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy (EERE) Wind Energy Technologies Office and Solar Energy Technologies Office
Net-Zero America	Larson, Greig, Jenkins, Mayfield, Pascale, Zhang, Drossman, Williams, Pacala, Socolow, Baik, Birdsey, Duke, Jones, Haley, Leslie, Paustian, Swan	Oct. 2021	Princeton University	Andlinger Center for Energy and the Environment, BP and the Carbon Mitigation Initiative within Princeton's High Meadows Environmental Institute, ExxonMobil, and University of Queensland
Voices of Experience: Microgrids for Resiliency	Lightner, Leader, Berdahl, Cory, Morgenstein, Schwabe	Nov. 2020	National Renewable Energy Laboratory	DOE Office of Electricity, Advanced Grid Research Program
Alaska's Changing Arctic: Energy Issues and Trends	Lovecraft, Boylan, Burke, Glover, Parlato, Robb, Thoman, Walsh, Watson	Jan. 2023	University of Alaska Fairbanks	N/A
Wasted Wind and Tenable Transmission	Massie, Toth	Feb. 2023	Rocky Mountain Institute	Rocky Mountain Institute

Study Title	Author(s)	Publication Date	Publisher	Funding Source(s)
During Winter Storm Elliott				
Joint Targeted Interconnection Queue Study (JTIQ)	Midcontinent Independent System Operator, Southwest Power Pool, Inc	Jan. 2022	Midcontinent Independent System Operator, Southwest Power Pool, Inc	N/A
Report Addendum: Long Range Transmission Planning Tranche 1 Portfolio	Midcontinent Independent System Operator Energy Transmission Planning Team	Sept. 2022	Midcontinent Independent System Operator, Inc.	N/A
The February Arctic Event: February 14-18, 2021	Midcontinent Independent System Operator	2021	Midcontinent Independent System Operator, Inc.	N/A
Overview of Winter Storm Elliott December 23 Maximum Generation Event	Midcontinent Independent System Operator	Jan. 2023	Midcontinent Independent System Operator, Inc.	N/A
Techno-Economic Renewable Energy Potential on Tribal Lands	Milbrandt, Heimiller, Schwabe	Jul, 2018	National Renewable Energy Laboratory	DOE Office of Indian Energy Policy and Programs
Empirical Estimates of Transmission Value using Locational Marginal Prices	Millstein, Wiser, Gorman, Jeong, Kim, Ancell	Aug. 2022	Lawrence Berkeley National Laboratory	DOE Office of Energy Efficiency and Renewable Energy Strategic Analysis Team and Grid Deployment Office Transmission Division
State of the Market Report for PJM	Monitoring Analytics, LLC	Mar. 2022	Monitoring Analytics, LLC	PJM Interconnection, LLC
Offshore Wind Market Report: 2022 Edition	Musial, Spitsen, Duffy, Beiter, Marquis, Hammond, Shields	Aug. 2022	U.S. Department of Energy	DOE Office of Energy Efficiency and Renewable Energy Wind Energy Technologies Office
NextGen Highways Feasibility Study for the Minnesota Department of Transportation: Buried High-Voltage Direct Current Transmission	NGI Consulting, The Ray, Great Plains Institute, Satterfield Consulting, Tracy Warren, 5 Lakes Energy	2022	NGI Consulting	McKnight Foundation, Energy Foundation, and Breakthrough Energy
Polar Vortex Review	North American Electric Reliability Corporation	Sept. 2014	North American Electric Reliability Corporation	N/A
2021 Long-Term Reliability Assessment	North American Electric Reliability Corporation	Dec. 2021	North American Electric Reliability Corporation	N/A

Study Title	Author(s)	Publication Date	Publisher	Funding Source(s)
2022 State of Reliability Report	North American Electric Reliability Corporation	Jul. 2022	North American Electric Reliability Corporation	N/A
Glossary of Terms Used in NERC Reliability Standards	North American Electric Reliability Corporation	Mar. 2022	North American Electric Reliability Corporation	N/A
Electricity Supply & Demand	North American Electric Reliability Corporation	Dec. 2022	North American Electric Reliability Corporation	N/A
Order Adopting Initial Carbon Plan and Providing Direction for Future Planning	North Carolina Utilities Commission	Jul. 2022	North American Electric Reliability Corporation	N/A
Economic Study Request: Offshore Wind in Oregon	NorthernGrid	2023	NorthernGrid	N/A
The Evolving Role of Extreme Weather Events in the U.S. Power System with High Levels of Variable Renewable Energy	Novacheck, Sharp, Schwarz, Donohoo-Vallett, Tzavelis, Buster, Rossol	Dec. 2021	National Renewable Energy Laboratory	DOE Office of Energy Efficiency and Renewable Energy Strategic Analysis Team and Water Power Technologies Office
2021-2040 System and Resource Outlook	New York ISO	Sept. 2022	New York ISO	N/A
2022 Reliability Needs Assessment	New York ISO	Nov. 2022	New York ISO	N/A
Stability Considerations for a Synchronous Interconnection of the North American Eastern and Western Electric Grids	Overbye, Shetye, Wert, Li, Cathey, Scribner	Jan. 2022	Texas A&M University	Partially funded by the Southwest Power Pool through the PSERC project S-92G, by PSERC project S91, and by the U.S. National Science Foundation through Award ECCS-1916142
2020 State of the Market Report for the New York ISO Markets	Patton, LeeVanSchaick, Chen, Naga	May 2021	Potomac Economics	New York ISO
2020 Assessment of the ISO New England Electricity Markets	Patton, LeeVanSchaick, Chen, Naga, Coscia	Jun. 2021	Potomac Economics	ISO New England
2020 Annual Electric Reliability Report	Pacific Gas and Electricity Company	Jul. 2021	Pacific Gas and Electricity Company	N/A
PG&E Currents: PG&E Crews Respond to Humboldt County Earthquake	Pacific Gas and Electricity Company	Dec. 2022	Pacific Gas and Electricity Company	N/A
Transmission Planning and Benefit-Cost Analyses	Pfeifenberger	Apr. 2021	The Brattle Group	N/A

Study Title	Author(s)	Publication Date	Publisher	Funding Source(s)
The Benefit and Urgency of Planned Offshore Transmission: Reducing the Costs of and Barriers to Achieving U.S. Clean Energy Goals	Pfeifenberger, DeLosa III, Bai, Plet, Peacock, Nelson	Jan. 2023	The Brattle Group	Natural Resources Defense Council, GridLab, Clean Air Task Force, American Clean Power Association, American Council On Renewable Energy
Offshore Wind Transmission in New England: The Benefits of a Better-Planned Grid	Pfeifenberger, Newell, Graf	May 2020	The Brattle Group	ANBARIC
Offshore Wind Transmission: An Analysis of Options for New York	Pfeifenberger, Newell, Graf, Spokas	Aug. 2020	The Brattle Group	ANBARIC
The 2035 Report	Phadke, Paliwal, Abhyankar, McNair, Paulos, Wooley, O'Connell	Jun. 2020	Goldman School of Public Policy, University of California, Berkeley	MacArthur Foundation
Energy Transition in PJM: Emerging Characteristics of a Decarbonizing Grid	PJM Interconnection, LLC	May 2022	PJM Interconnection, LLC	N/A
Energy Transition in PJM: Resource Retirements, Replacements & Risks	PJM Interconnection, LLC	Feb. 2023	PJM Interconnection, LLC	N/A
Winter Storm Elliott: Event Analysis and Recommendation Report	PJM Interconnection, LLC	Jan. 2023	PJM Interconnection, LLC	N/A
MISO Independent Market Monitor Quarterly Report: Fall 2020	Potomac Economics	Dec. 2020	Potomac Economics	Midcontinent Independent System Operator
2020 State of the Market Report for MISO Electricity Markets	Potomac Economics	May 2021	Potomac Economics	Midcontinent Independent System Operator
2020 Assessment of the ISO New England Electricity Markets	Potomac Economics	Jun. 2021	Potomac Economics	ISO New England
MISO's Renewable Integration Impact Assessment (RII)	Prabhakar, Figueroa-Acevedo, Heath, Tsai, Manjure, Massey, Ruccolo, Brown, Okullo, Phillips, Lawhorn, Bakke, Smith, Munukutla, Hannah, Zhao, Keillor, Boese,	Feb. 2021	Midcontinent Independent System Operator	Midcontinent Independent System Operator

Study Title	Author(s)	Publication Date	Publisher	Funding Source(s)
	Thompson, Mohan, Jung, Peng, Hess, Li			
Underground Electric Transmission Lines	Public Service Commission of Wisconsin	May 2011	Public Service Commission of Wisconsin	N/A
The Demand for a Domestic Offshore Wind Energy Supply Chain	Shields, Marsh, Stefek, Oteri, Gould, Rouxel, Diaz, Molinero, Moser, Malvik, Tirone	June 2022	National Renewable Energy Laboratory	National Offshore Wind Research and Development Consortium and the Maryland Energy Administration
Utah Transmission Study: A Study of the Options and Benefits to Unlocking Utah's Resource Potential	Simonson, Ramirez, Muhs, Emery, Moyer	Jan. 2021	Energy Strategies	Utah Office of Energy Development
Grid of the Future	Southwest Power Pool	April 2023	Southwest Power Pool	N/A
Report on Barriers and Opportunities for High Voltage Transmission	Staff of the Federal Energy Regulatory Commission	Jun. 2020	Federal Energy Regulatory Commission	N/A
Winter Storm Elliott Update	Tennessee Valley Authority	Feb. 2023	Kentucky General Assembly	N/A
Building a Better Grid: How Grid-Enhancing Technologies Complement Transmission Buildout	Tsuchida, Bai, Grove,	Apr. 2023	The Brattle Group	The WATT Coalition
A Clean Energy Transmission Policy Platform for Thriving Communities and Wildlife	Ung-Kono	2023	National Wildlife Federation	National Wildlife Federation
Advanced Transmission Technologies	U.S. Department of Energy	Dec. 2020	U.S. Department of Energy	N/A
Strategy White Papers on Microgrids: Program Vision, Objectives, and R&D Targets in 5 and 10 Years	U.S. Department of Energy	May 2021	U.S. Department of Energy	N/A
Grid-Enhancing Technologies: A Case Study on Ratepayer Impact	U.S. Department of Energy	Feb. 2022	U.S. Department of Energy	N/A

Study Title	Author(s)	Publication Date	Publisher	Funding Source(s)
Advancing Offshore Wind Energy in the United States: Strategic Contributions Toward 30 Gigawatts and Beyond	U.S. Department of Energy	Mar. 2023	U.S. Department of Energy	N/A
An Action Plan for Offshore Wind Transmission Development in the U.S. Atlantic Region. Interim Draft Report.	U.S. Department of Energy	2023	U.S. Department of Energy	N/A
Magnitude 6.4 Earthquake Near Ferndale, California	U.S. Geological Survey	Dec. 2022	U.S. Geological Survey	N/A
Remote Areas of Alaska: Affordable and Reliable Options for Meeting Energy Needs and Reducing Emissions	U.S. Environmental Protection Agency	Sept. 2020	U.S. Environmental Protection Agency	N/A
Regulatory Evolution for a Decentralized Electric Grid: State of Performance-based Ratemaking in the U.S.	Wang, Crawford	Jun. 2019	Wood Mackenzie	Wood Mackenzie
State of the Market 2020	Warren, Collins, Woods, Sorenson, Luallen, Arnold, Bates, Bulloch, Daniels, Greenwalt, Guney, Hurtado, Lemley, Rouse, Vestal, Wren, Xu	Aug. 2021	Southwest Power Pool, Inc. Market Monitoring Unit	Southwest Power Pool, Inc.
Long-term Transmission Planning in the West – Draft	Western Electricity Coordinating Council	2023	Western Electricity Coordinating Council	N/A
A 2030 United States Macro Grid	Xu, Olsen, Xia, Livengood, Hunt, Li, Smith	Jan. 2021	Breakthrough Energy Sciences	Breakthrough Energy Sciences

Co-location of Transmission Corridors Is Possible in Some Cases

Section V.e. of the 2023 National Transmission Needs Study considers siting and land-use constraints that major transmission projects often experience. The subsection "Co-location of transmission corridors is possible in some cases" summarizes the National Renewable Energy Laboratory's development of a process to conduct a geospatial assessment that characterized select highway ROWs by relevant siting considerations (Figure S-3) in pursuit of identifying possible transmission routes along U.S. interstates. The assessment provides a detailed quantification of every mile and ROW acre with siting criteria germane to the development of underground transmission lines. Siting considerations included land use/land cover, terrain, sensitive wildlife habitat, soils, road intersections, and more (*see* Table S-5 for a full list of data used).

Figure S-3. Select highway ROW routes assessed. Each route is categorized by dominant direction. Blue routes are north–south and black routes are east–west.

Table S-5. Data included in the ROW characterization. Datasets used are the most up to date as of December 2021.

Category	Data Source	Attribute
Environmental/ Land Use	National Hydrography Dataset from U.S. Geological Survey	Feature Type
	Protected Area Database (PAD-US 2.1) from U.S. Geological Survey	Gap Analysis Project Status
	U.S. Fish & Wildlife Service Threatened & Endangered Species Active Critical Habitat Report	Endangered Species Assessment Listing Status
	The Nature Conservancy Lands	Area Name
	The Nature Conservancy Resilient Land	Resilient Level
	National Land Cover Database 2019	Land Cover Classification
	The National Wetlands Inventory from U.S. Fish & Wildlife Service	Wetland type
	Soil Survey Geographic Database Depth to Bedrock	Bedrock Depth – Minimum
	Soil Survey Geographic Database Depth to Water Table	Water Table Depth – Annual Minimum
	Oak Ridge National Laboratory Average Soil Sediment Thickness	Soil and Sedimentary Deposit Thickness
Terrain	ASTER Global Digital Elevation Model V003	Elevation
	Slope calculated from ASTER Global Digital Elevation Model V003	Slope
	Terrain Roughness Index calculated from ASTER Global Digital Elevation Model V003	Topographic Ruggedness Index
Administrative	Lightbox Parcel data	Parcel Ownership
	Surface Management Agency from U.S. Geological Survey	Code for Land Ownership
	State boundary from U.S. Census	State Name
	County boundary from U.S. Census	County Name
	Urban Area from U.S. Census	Urban Area Name
	Combined Statistical Areas from U.S. Census	Legal/Statistical Area Description Code
	Core-Based Statistical Area from U.S. Census	Legal/Statistical Area Description Code
Infrastructure	HERE Technologies Roads	Street Name
	Microsoft Building Footprints	Building Geometry
	Homeland Infrastructure Foundation-Level Data (HIFLD) – Railroad	Geographic Information
	HIFLD – Transmission	Geographic Information
	HIFLD – Natural Gas Line	Geographic Information
	HIFLD – Substation	Maximum Voltage
	Prospect- and Mine-Related Features from U.S. Geological Survey 7.5- and 15-Minute Topographic Quadrangle Maps of the United States	Feature Type
Natural Hazard	National Flood Hazard Layer from Federal Emergency Management Agency	Flood Zone Subtype
Cultural	National Register for Historic Places	Name
Social	Centers for Disease Control and Prevention Social Vulnerability Index	RPL Theme

Highway ROWs were defined as the right side of the highway and assuming a 65-meter swathe. The 65-meter swathe assumes mulltiple lines would be installed and is representative of a maximum construction zone. The process of creating the ROW area is shown in Figure S-4. Figure S-5 shows an example of the buffering and characterization results.

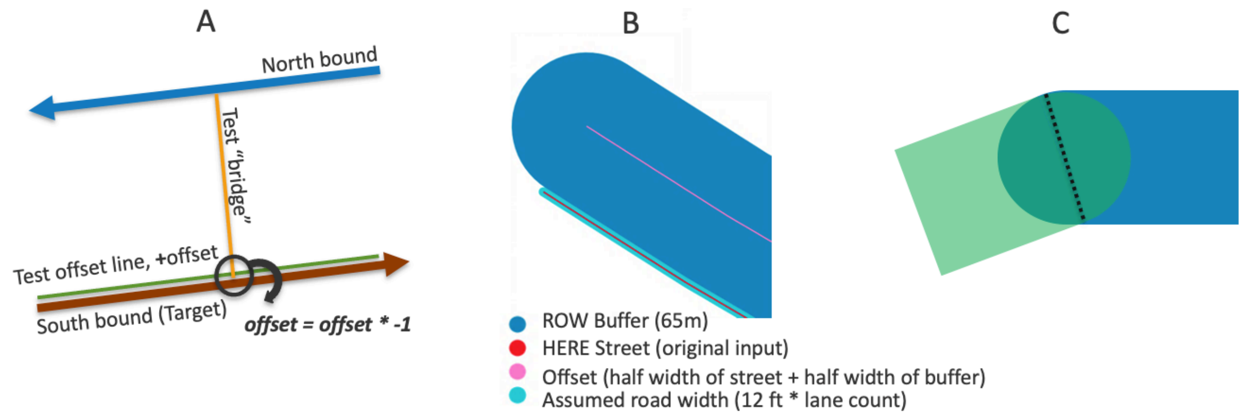


Figure S-4. Process to create highway ROW areas. A) test bridges are created at the midpoint of the highway centerline vector segment to find the right side of the road. B) An offset line is created by shifting half the width of the road plus half the width of the target zone. A buffer is then created. C) End caps are mitered to avoid double counting characteristics.

Figure S-5. Example showing a fully characterized highway ROW with aerial imagery (National Agriculture Imagery Program).

Figure S-6 shows the total mileage and acres associated with each highway route. The magnitude difference of each route's area and length should be considered alongside the characterizations as the number of siting considerations can increase with length. ROWs located within major urban areas (identified as those being within a metropolitan statistical area) were excluded from the analysis, which is reflected in the resulting miles and acreage associated with each route. Minor urban areas, on the other hand, were maintained and characterized in the analysis, which is seen in Figure S-7 in which I-80 has approximately 70 miles of ROWs traversing minor urban areas.

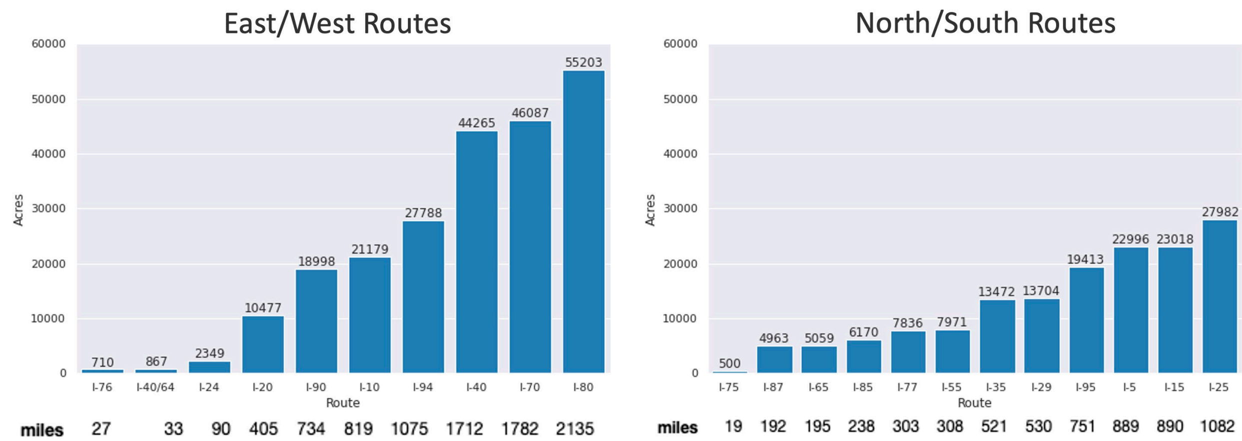
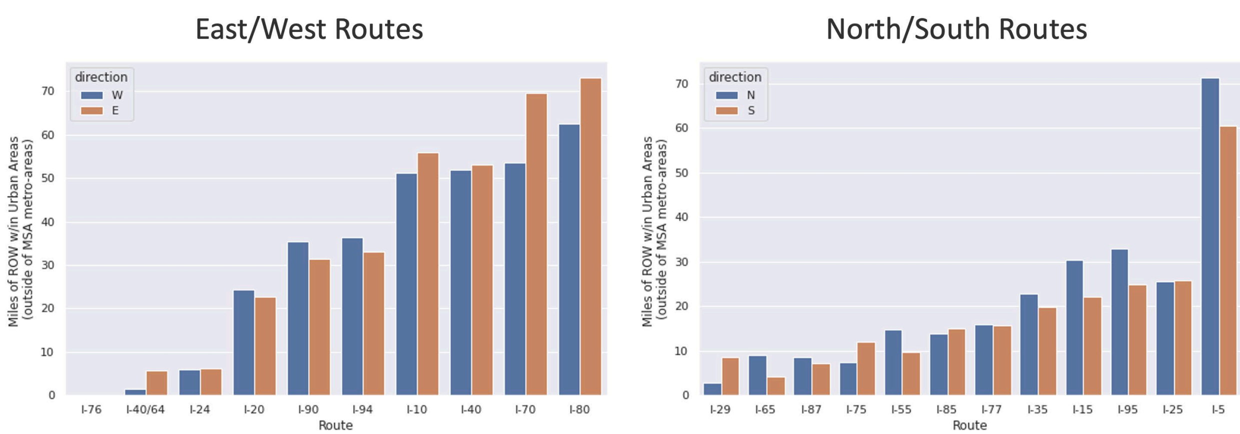


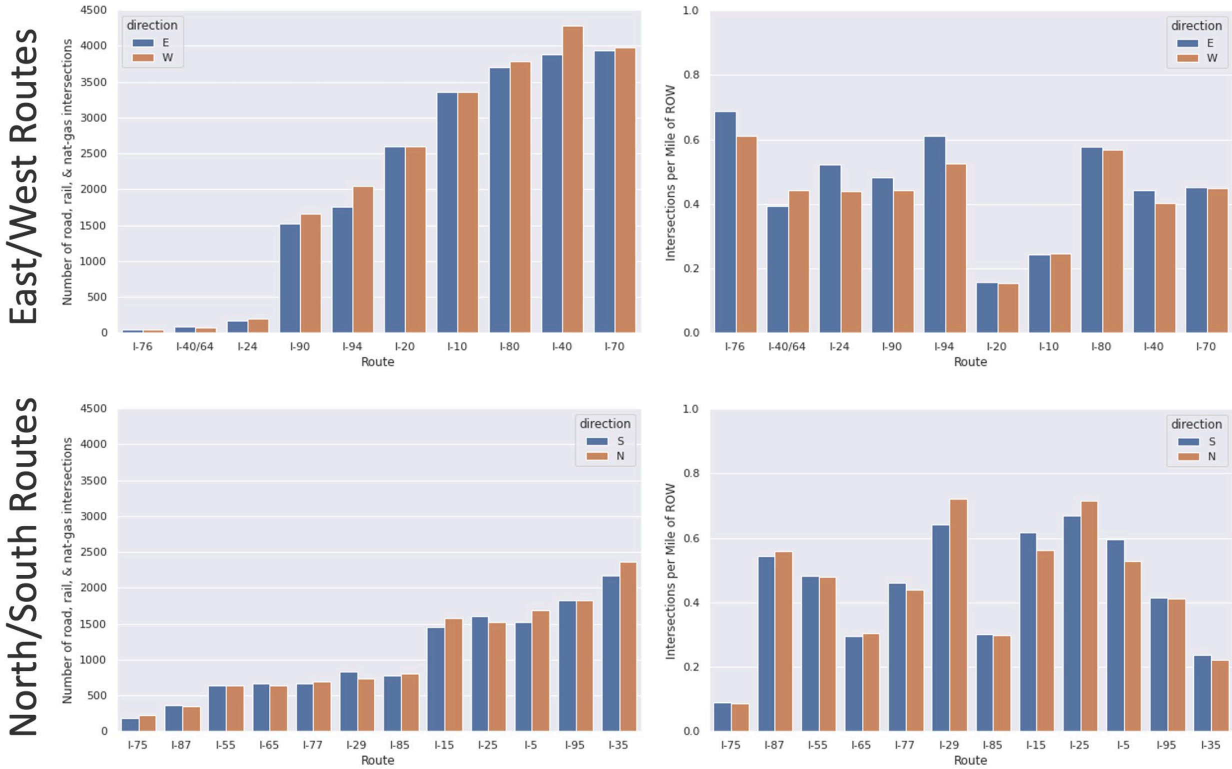
Figure S-6. Total acreage for each highway right-of-way. The analysis is partitioned and characterized by sides of each highway; however, the acreage is not significantly different and was left out in this graph for clarity.



Note: West-direction routes are shown on the left of each set of clustered bars for East/West routes and North-direction routes are shown on the left of each set of clustered bars for North/South routes.

Figure S-7. Miles of ROW within minor urban area boundaries. Note the travel route (direction) can lead to differences in urbanization mileage (e.g., I-70 has ~28 miles more of urbanization between the west-bound and east-bound ROW).

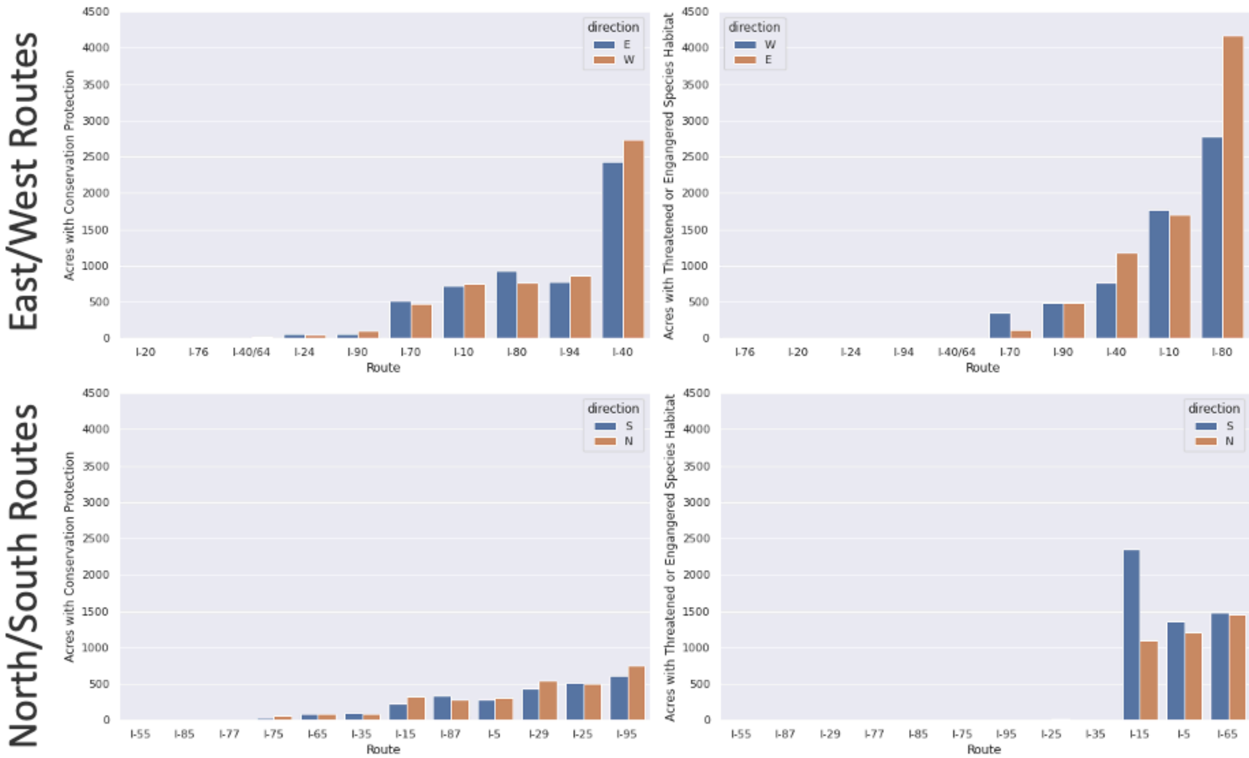
For each highway route, Figure S-8 shows the number of intersections with other roads, rail, and natural gas pipelines. These graphs are sorted by the total intersections for each route. These are naturally higher for longer routes. The graphs on the right normalize by each route's mileage, showing intersections per mile of ROW. For example, I-35 has the most intersections among north/south routes and has an intersection roughly every 0.2 miles.



Note: East-direction routes are shown on the left of each set of clustered bars for East/West routes and South-direction routes are shown on the left of each set of clustered bars for North/South routes.

Figure S-8. Infrastructure intersections for each ROW route.

While highway ROWs offer opportunities to reduce siting restrictions, challenges remain. The number of acres in ecologically sensitive lands is shown in Figure S-9. These lands are defined as those with existing conservation protections (left graphs) and those with Threatened, Proposed Threatened, and Endangered species habitat (right graphs). The acreage between the two sets is not additive as some lands exist in both categories (e.g., some threatened species habitat is under a conservation easement). I-40 and I-80 have significantly more ecologically sensitive lands within the ROW compared with other east/west routes. Among the north/south routes, there is little variation in conservation easements, however, I-15, I-5, and I-65 have significant ROW overlap with Threatened, Proposed Threatened, and Endangered species habitat.



Note: East-direction routes are shown on the left of each set of clustered bars for left East/West routes chart and on the right for the right East/West routes chart. South-direction routes are shown on the left of each set of clustered bars for North/South routes.

Figure S-9. Highway ROW located in ecologically sensitive areas.

In addition to the ROW buffer characterizations, a parcel distance assessment was conducted from the highway centerline vertices (Figure S-10). This proxy analysis was performed to understand a) the typical ROW distance from the centerline of the highway to the nearest parcel boundary and b) to understand the parcel ownership type, e.g., residential, industrial, agricultural.

The parcel distance assessment results are presented as graphs showing the cumulative probability distribution for each route's distance to the nearest parcel and its tax use code (Figure S-11). The vertical dotted line shows 65-meter distance. For example, at 65 meters or less, 75% of I-70's route is closest to lands with tax use codes of vacant, agriculture, government administered, or unknown. In the case of I-70, the large "unknown" category is representative of the ROW through the Rocky Mountains. In some states, "unknown" is the ROW or Bureau of Land Management–administered land. The parcel database is imperfect in this sense but provides an understanding of the magnitude of specific land tenure.

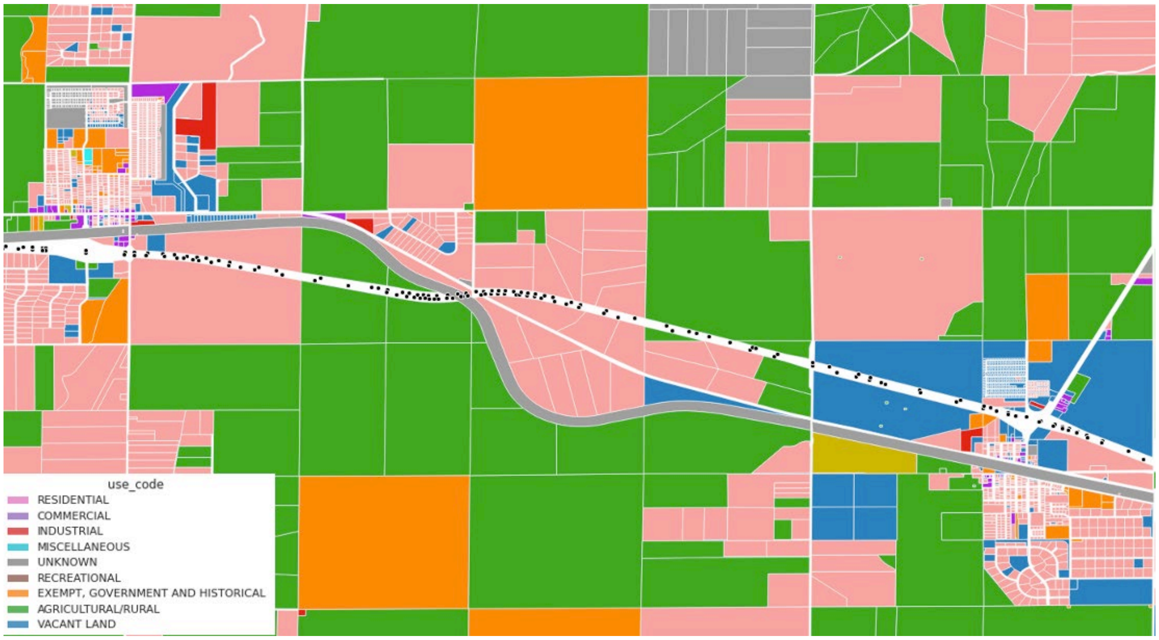
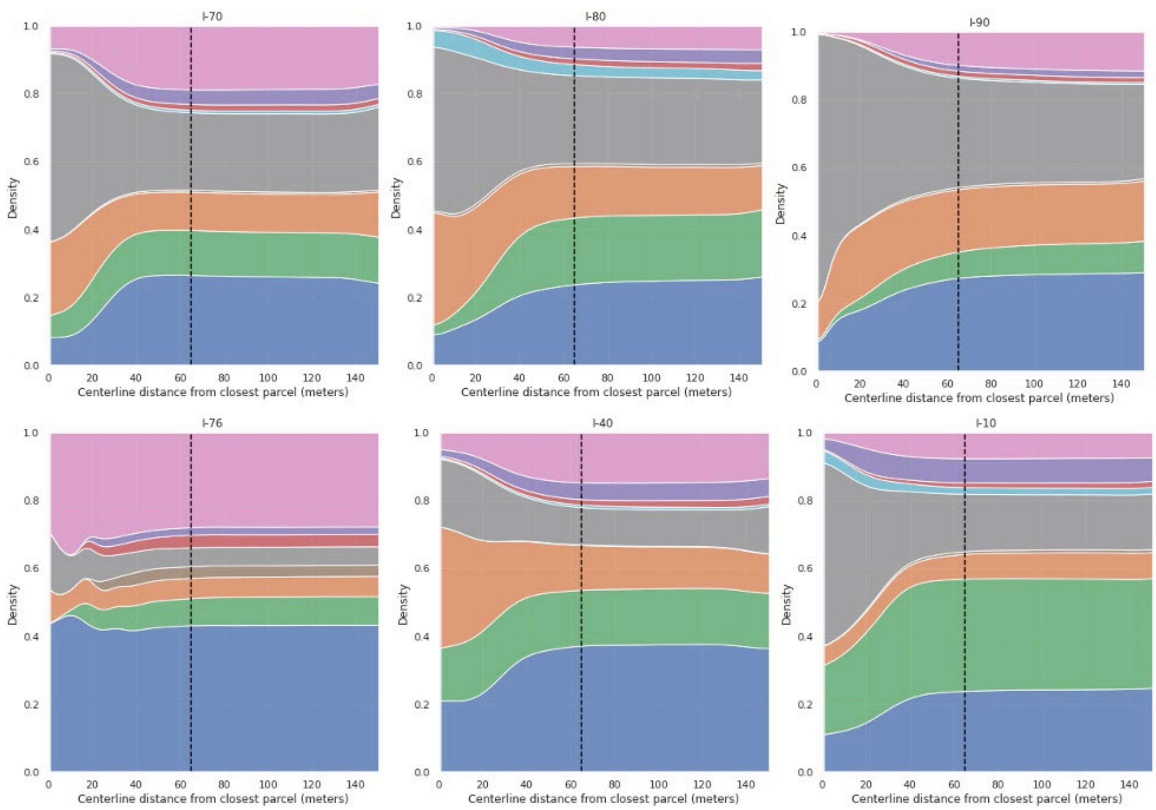


Figure S-10. Black dots are highway centerline vertices. The polygons are parcel boundaries from LightBox (see Table S-5).



Note: Use codes from top to bottom are: Residential in pink; commercial in purple; industrial in red; miscellaneous in aqua; unknown in gray; recreational in brown; exempt, government, and historical in orange; agricultural/rural in green; and vacant land in blue.

Figure S-11. Cumulative probability distribution graphs for select routes. Graphs show the distance to the nearest parcel and its tax use code (as defined in Figure S-10).

This analysis did not compare the relative siting difficulties relative to overhead transmission but provides a means of comparison in future work. A comparison of greenfield transmission portfolio designs vis-à-vis underground highway transmission would illuminate relative siting challenges and enable policymakers to better understand the tradeoffs.

The analysis reveals that land-tenure issues could be reduced if construction area requirements are reduced from 65 meters. The construction swathe is dictated by the number of transmission lines. To determine the number of lines needed, additional engineering analysis is needed (e.g., power flow and production cost modeling).

Direct burial of transmission lines would require a transformation of the existing land cover and use. However, most disturbances in the area would be temporary with a fraction being permanent (National Grid 2017; PSCW 2011). The permanent disturbance for a single line is spatially smaller than the resolution available for many datasets (e.g., land cover is 30-meter horizontal spatial resolution), which poses a challenge in evaluating the permanent land-use impacts and requirements of underground transmission on a national scale.

Section VI. Anticipated Future Need Assessment through Capacity Expansion Modeling

Section VI of the 2023 National Transmission Needs Study considers six different capacity expansion studies from the national laboratories and academia that co-optimize generation and transmission solutions to meet different power sector futures. This section includes a discussion of details of those studies and nuances of the results published in the Needs Study.

Section VI.a. Included Studies and Scenarios

High-level Description of Six Capacity Expansion Modeling Studies

The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System (Brown and Botterud 2020a)

The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System study authored by P. Brown and A. Botterud uses a co-optimized capacity-planning and dispatch model to estimate the system cost of electricity in a 100%-renewable U.S. power system under six different cases of regional coordination and transmission expansion (Brown and Botterud 2020). Two scenarios prohibit new interstate transmission expansion, while four scenarios allow for new interstate transmission expansion between states within regional planning areas and/or between synchronous or asynchronous planning areas. The research concludes that interstate coordination and transmission expansion reduce electricity costs by 46% relative to a state-by-state approach.

The authors use a linear optimization model with hourly resolution of historical weather conditions (2007–2013), as well as “scaled up” historical demand profiles to project system costs by 2040. In addition to the six core scenarios, the authors also conduct a sensitivity analysis across 48 different cases to account for uncertain future technology costs and demand levels. They find that a reduction in photovoltaic solar, wind, and lithium-ion battery costs lead to the lowest system cost of electricity under the transmission expansion scenario, while nuclear power or long-duration energy storage cost reductions lead to greater electricity cost reductions for isolated systems.

North American Renewable Integration Study (Brinkman et al. 2021)

The *North American Renewable Integration Study* (NARIS) is a National Renewable Energy Laboratory (NREL) study that analyzes grid evolution through 2050 for the entire North American continent (Brinkman 2021). The NARIS study is the most comprehensive long-term analysis of power system evolution on the entire North American grid to date. NARIS aims to inform grid planners, operators, policymakers, and other stakeholders about the potential opportunities for system integration of large amounts of wind, solar, and hydropower to create a low-carbon grid in the future.

NARIS considers four core scenarios and 38 additional sensitivity scenarios, which typically involve varying one assumption at a time. The four core scenarios include a business-as-usual case, a scenario that assumes low-cost variable generation, a scenario that intentionally reduces CO_2 emissions in the United States to 80% of 2005 levels by 2050, and a scenario that electrifies end-use loads such that total electricity demand in 2050 is double 2020 demand. The results show that multiple pathways can lead to 80% power sector carbon reduction by 2050; a future low-carbon system can balance supply and demand in a wide range of conditions; regional and international cooperation yield significant benefits; and operational flexibility comes from transmission, electricity storage, and flexible operation of all generator types.

Standard Scenarios (Cole et al. 2021)

NREL's seventh annual installment of the *Standard Scenarios* summarizes the results of 50 forward-looking scenarios of the U.S. power sector, designed to capture a wide range of possible power system futures (Cole et al. 2021). The objective of the scenarios is to identify a range of possible futures that illuminate specific energy system issues. Scenarios are designed to cover a range of technology, market, and macroeconomic assumptions and were assessed by market models to understand resulting outcomes related to energy technology deployment and production, energy costs, and emissions. The study primarily relies on two NREL models: the Regional Energy Deployment System (ReEDS) model—which projects utility-scale power sector evolution using a system-wide, least-cost approach—and the Distributed Generation Market Demand Model (dGen)—a distributed generation diffusion model. For select scenarios, systems built by ReEDS and dGen are run using the PLEXOS production cost model to provide hourly outputs of system operation (Gagnon et al. 2021).

Standard Scenarios include three core scenarios with different levels of power sector decarbonization: one that assumes no carbon policies beyond those in place as of June 2021, one that assumes national power sector CO_2 emissions decreases linearly to 95% below 2005 emissions by 2050, and finally one that assumes national power sector CO_2 emissions decline to 95% below 2005 levels by 2035 and are eliminated on a net basis by 2050. The study includes 47 total sensitivities. The scenario outcomes highlight how varying levels of CO_2 emission abatement impact the energy sector at both a national and regional level.

Solar Futures Study (Ardani et al. 2021)

NREL's *Solar Futures Study* supports DOE's Solar Energy Technologies Office efforts to explore the role of solar technologies to decarbonize the power and energy systems. The study examines the interactions between solar and other technologies as well as the integration of renewable and nonrenewable technologies in future decarbonized U.S. electric grids and electrification strategies that could extend decarbonization to the broader energy system through 2050 (DOE 2021). This analysis examines the necessary changes to the power system through interactions between renewable (biopower, concentrating solar plants, geothermal, hydropower, onshore and offshore wind, photovoltaic solar, renewable energy combustion turbines) and nonrenewable (nuclear, coal, and natural gas) generation technologies, bulk energy storage, demand flexibility, and transmission system expansion. The study additionally explores the role of solar in deep decarbonization through the lens of equity frameworks, focusing on four themes of energy justice: equitable distribution of benefits, equitable distribution of costs, procedural justice, and a just transition.

Solar Futures considers three core scenarios: a reference scenario that follows expected trend of solar and renewable energy deployment, one that focuses on fully decarbonizing the transmission grid by 2050, and one that includes both decarbonization and electrification. There were additional sensitivities modeled with increased roles for advanced load flexibility, distributed energy resources (DERs), and other clean energy technologies (e.g., concentrating solar power, hydropower, geothermal, and nuclear). Like all NREL studies considered here, the *Solar Futures Study* uses the ReEDS capacity expansion and dispatch model to project future bulk power systems, including new generation, transmission, and storage. PLEXOS and Probabilistic Resource Adequacy Suite (PRAS) models were used to supplement ReEDS and better assess the operability and adequacy of the scenarios.

Six of the nine *Solar Future* scenarios included high levels of distributed, rooftop solar adoption, reaching levels of over 227 terawatt hours (TWh) by 2040, an eightfold increase compared with today's residential rooftop levels (EIA 2022). These scenarios incorporate more distributed solar than the high DER scenarios in Vibrant Clean Energy's *Why Local Solar for All Costs Less* study (Clack et al. 2020). The next section describes how these high DER scenarios compare with other scenarios used in this analysis.

Net Zero America (Larson et al. 2021)

The *Net Zero America: Potential Pathways, Infrastructure, and Impacts* project maps five different pathways—with varying degrees of electrification and wind and solar capacity—to obtain net-zero greenhouse gas emissions economy-wide in the United States by 2050 (Larson et al. 2021). The study identifies six pillars of net-zero emissions transition: energy efficiency and electrification; clean electricity (wind and solar generation, transmission, firm power, nuclear); industrial biofuels and hydrogen; CO_2 capture and sequestration; reduced non-CO_2 emissions; enhanced land sinks.

Princeton University uses both capacity expansion and economic impact modeling for the study. The study utilizes the EnergyPATHWAYS demand-side model to construct two scenarios —aggressive electrification and less-aggressive electrification—to determine final energy demand for electricity and other fuels. It utilizes the Regional Investment and Operations (RIO) supply-side cost minimization model to identify lowest-cost (30-year societal net present value) mix of supply-side energy technologies and network infrastructure under various constraints to meet required demand and achieve economy-wide net-zero emissions by 2050. RIO outputs at course geographic resolution (14 regions for the contiguous United States) were then downscaled using various methodologies to state and sub-state resolution, on the basis of which impacts on land use, capital mobilization, incumbent fossil fuel industries, jobs, and air pollution were assessed.

Net Zero America considers six scenarios: a reference scenario, an aggressive electrification with relatively unconstrained energy supply scenario, a less-aggressive electrification with relatively unconstrained energy supply scenario, a less-aggressive electrification with high biomass availability scenario, an aggressive electrification with constrained variable renewable energy scenario, and an aggressive electrification with 100% renewable energy by 2050 scenario. Each of these scenarios except the high biomass availability scenario limits biomass availability to avoid large-scale conversion of land devoted to forestry, agriculture, or conservation into bioenergy feedstock production. Downscaling of siting of variable renewable generators was conducted for three variants of the aggressive electrification scenario (unconstrained supply, constrained variable renewable energy, and 100% renewable energy) using a baseline set of land-use constraints and a more restrictive set of land-use constraints. Transmission system results were not published for the less-aggressive electrification scenarios, so they are omitted in this analysis.

Examining Supply-side Options to Achieve 100% Clean Electricity by 2035 (Denholm et al. 2022)

The *Examining Supply-side Options to Achieve 100% Clean Electricity by 2035* study (referred to hereafter as simply the "100% by 2035 study") is the most recent study (Denholm et al. 2022) considered here. This study considers multiple pathways to achieve complete power sector decarbonization by 2035 and continued decarbonization of other sectors to reach net-zero emissions economy-wide by 2050, in accordance with the Biden Administration goals.[5] Economy-wide decarbonization will result from electrifying the residential, commercial, industrial, and transportation sectors and powering those sectors with 100% clean electricity. Studies have shown that electrifying these sectors will result in a threefold increase in electricity demand. The 100% by 2035 study is the only NREL study that considers either a macrogrid transmission topology or high-power sector decarbonization and load growth, making it unique from the previously mentioned studies.

Four core scenarios are considered in the 100% by 2035 study: a scenario that assumes all clean electricity technologies see improved performance and cost reductions in line with current projections, a scenario that assumes improved transmission technologies and siting processes lead to increased transmission deployment, a scenario that assumes local and regional opposition to generation and transmission solutions limit deployment, and a scenario that assumes carbon capture and storage (CCS) technologies do not achieve cost and performance targets necessary to be deployed at scale. No fossil fuel generation is allowed to deploy in this latter scenario, but the other three scenarios do allow fossil and biomass generation paired with CCS. The first scenario includes direct air capture of carbon dioxide, whereas the latter three scenarios assume direct air capture technologies are not deployed at scale. These core scenarios were compared against a reference scenario with low demand and a reference scenario with high demand. Beyond the four core 100% clean electricity scenarios and associated reference cases, over 100 additional sensitives were analyzed to capture future uncertaintis related to technology cost, performance, and availability.

[5] *See* Exec. Order 14057, Catalyzing Clean Energy Industries and Jobs Through Federal Sustainability, 86 Fed. Reg. 70935 (Dec. 13, 2021), https://www.govinfo.gov/content/pkg/FR-2021-12-13/pdf/2021-27114.pdf.

Modeling Features of Different Studies

Transmission

More details on the specifics of the transmission system used in all capacity expansion models can be found in Ho et al. (2021) for the four NREL studies, in Brown and Botterud (2020b) for Brown and Botterud (2020a), and in Pascale and Jenkins (2021) for Larson et al. (2021). The transmission modeling features described below are a summary of information found in greater detail in these three sources.

All capacity expansion models used in these studies have a different means of modeling the transmission system, with significant overlap. All three models build new interzonal transmission that is necessary to move power from one area to another.[6] All three models consider intrazonal transmission spur lines to connect new generators to the existing network. The models used in Brown and Botterud (2020a) and Larson et al. (2021) consider network reinforcement upgrades that must be made to existing transmission lines to transfer more power within a region. The NREL ReEDS model reflects the within-region network upgrades as new spur lines.

The model used in Brown and Botterud (2020a) estimates interzonal transmission lines from the NREL ReEDS transmission system (discussed below). Their model builds intrazonal network upgrades as the shortest distance line between existing substations rated at least 230 kV and the edge of the nearest urban area. Spur line distances are measured as the shortest distance between each renewable energy centroid (Voronoi polygons mapped to contiguous United States) and whichever existing substation minimizes the combined annual cost of the spur line and associated network upgrade line. *See* Brown and Botterud (2020b) for more details.

The model used in Larson et al. (2021) estimates least-cost interconnection routes between every new generator site and a large load center, defined as a metropolitical statistical area of at least 750,000 people. The route calculated for each generator site follows the “least-cost” path (1) from the generator site to a substation of at least 161 kV and (2) from that substation along an existing ROW to a substation within a load center (if the first substation is not already located within a load center). After all interconnection routes to load centers are calculated, the model estimates additional “least-cost” transfer capacity between large load centers. This additional capacity transfer is meant to account for any shortfalls in generation to load that new spur lines entering those service areas do not provide. The study considers the capacities, lengths, costs, voltage classes, and geospatially located paths of all additional high-voltage transmission needed. Note that all high-voltage transmission lines are incentivized to follow existing ROWS because existing routes are indicative of realistic geographic paths to load centers (e.g., they account for topology and conflicting land uses), but this process is not meant to be predictive of actual routes, as not all transmission expansion may be accommodated on existing ROWs. *See* Pascale and Jenkins (2021) and the *Net Zero America* transmission datasets hosted at the Princeton University Library (E. Larson 2021) for more details. The transmission modeling methods used in the *Net Zero America* study have been iteratively improved in the

[6] Here, “zones” and “areas” which transmission is deployed within and between are unique to each study. These differ from the “regions” used in the *Needs Study*.

Nature Conservancy's Power of Place West project (Wu et al. 2023), the Princeton Zero Lab's REPEAT project (Jenkins 2021; Jenkins et al. 2022), and the Net-Zero Australia project (University of Queensland School of Chemical Engineering 2021).

NREL's ReEDS model is based on the 2010 transmission system and all planned transmission builds through 2022 from ABB's GridView model (ABB 2013). Major high-voltage direct current lines and interconnection ties are also included in the base transmission system. The ReEDS model converts the base transmission system to roughly 300 corridors, representitive in length and nominal carrying capacity—based on NERC-reported line limits—of the actual system. The length of each representative transmission corridor is set equal to the distance between the largest population center of each modeling zone, following the existing path of the highest voltage transmission line. New transmission lines built by the ReEDS model are defined by the product of this distance between zonal population centers (in miles) and the modeled carrying capacity (in MW) needed to transfer power between zones. For example, if ReEDS calculates that 10 gigawatts (GW) of new carrying capacity between modeling zones A and B will be needed in year 2040 and the representative transmission corridor connecting the two corridors is 60 miles long, then the resulting new transmission need in 2040 will be 600 GW-mi.

The calculated transmission deployment (in GW or GW-mi) could feasibly be provided by a range of transmission lines of different designs and voltage ratings. In order to apply appropriate cost assumptions to the model, ReEDS assumes that the new transmission will be equivalent to the highest voltage of the existing transmission between the two zones in question, with a few exceptions. Transmission cost assumptions are based on industry costs from EIPC (2012).

The NARIS study (Brinkman et al. 2021) uses straight-line routes between modeling zone centroids, while the other ReEDS studies uses realistically meandering paths between the largest population centers in connected modeling zones when calculating new transmission distances. Given that the straight-line approach in NARIS underestimates the line-miles needed to deliver power between modeling zones, the NARIS results are excluded from calculation of transmission deployment in the Needs Study on recommendation of the NARIS authors Brinkman et al. 2021. *See* Ho et al. 2021 for more details.

Interregional results presented in the Needs Study were calculated as the sum of all carrying capacities (in MW) between regions (next section) for any given year and study. Regional results were calculated as the sum of total transmission deployment (in MW-mi) within a single region for any given year and study.

Regions

The regions used in this analysis are shown in Figure S-12. Regions were chosen based on the geographic resolution of data available for each of the six studies used in this analysis. All six studies considered only the bulk power system of the contiguous United States and did not consider capacity expansion in Alaska or Hawaii, which have isolated power grids. Regional data from the four NREL studies were aggregated from the ReEDS modeling zones, shown as light gray outlines in Figure S-12 (left). Regional data from the Brown and Botterud (2020) and Larsen et al. (2021) studies were aggregated from state boundaries, shown as light gray outlines in in Figure S-12 (right). The results from these two studies thus have a coarser resolution than the NREL results.

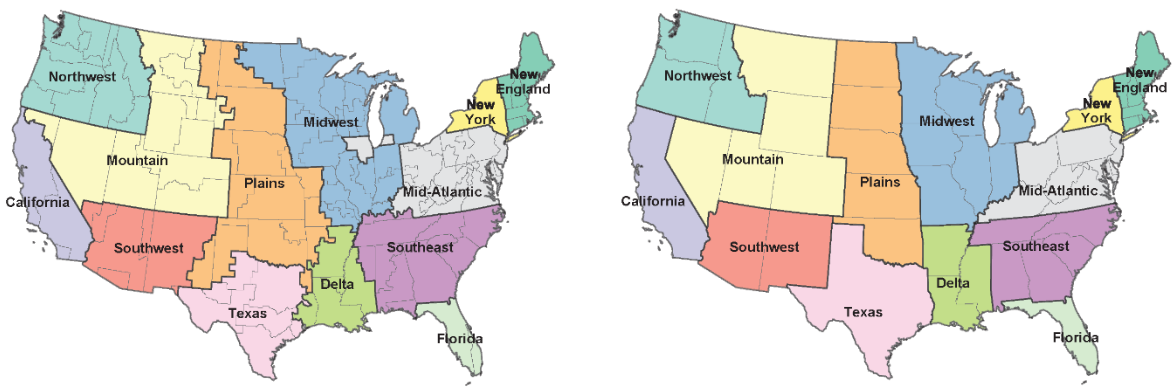


Figure S-12. Geographic regions used to present study results in this analysis. Left: NREL ReEDS modeling zone boundaries shown underlying larger analysis regions. All four NREL studies had this level of granularity. Right: State boundaries underlying larger analysis regions. The Brown and Botterud and Princeton studies had state-level granularity.

Study scenarios in each scenario group. The six studies considered a total of 300 scenarios describing a wide range of different power sector futures. To better understand transmission system needs based on future power system assumptions, the 300 scenarios were split up into three different scenario groups based on the underlying annual load and clean energy growth assumptions in the year 2040, as shown in Needs Study Figure VI-1. Those three groups are:

- **Moderate/Moderate:** moderate load growth between 2021 baseline (3,974 TWh) and 7,000 TWh and moderate clean energy penetration between 2021 baseline (38.6%) and 80% in 2040; 2021 load and penetration values from EIA (2022a).
- **Moderate/High:** moderate load growth between 2021 baseline (3,974 TWh) and 7,000 TWh and high clean energy penetration above 80% in 2040.
- **High/High:** high load growth above 7,000 TWh and high clean energy penetration above 80% in 2040.

Scenarios that artificially constrained new transmission builds—e.g., disallowed interregional transmission—were omitted from this analysis. Several outlying scenarios did not fall into any of the above groups but did not constitute a large enough group on their own to create a new scenario group. After excluding these two categories of scenarios, 220 scenarios remained for analysis. Table S-6 lists all scenarios included in the six studies and indicates which scenario group they were categorized into based on the load and generation mix assumptions.

Table S-6. All scenarios of the six considered capacity expansion modeling studies and their respective scenario group used in the Needs Study analysis. The number of scenarios (n) included in each group is shown. Scenario names correspond with the nomenclature used in the source capacity expansion modeling study.

Scenario Group	Study	Scenarios	
Moderate/ Moderate (n = 85)	Brown and Botterud (2020a)	2030 mid VRES, 2030 high gas	2018 VRES, 2030 high gas
	Brinkman et al. (2021)	BAU Tech_Break C_Constrained C_Constrained_Elec BAU_High_Gas BAU_Low_Cost_Storage BAU_Low_Gas BAU_Macro BAU_Uncoordinated Tech_Break_Base_Ret Tech_Break_CanExport100 Tech_Break_CanExport30 Tech_Break_High_Gas Tech_Break_Low_Cost_Storage Tech_Break_Low_Gas Tech_Break_Macro Tech_Break_Uncoordinated C_Constrained_Base_Ret C_Constrained_CanExport100 C_Constrained_CanExport30	C_Constrained_High_Gas C_Constrained_Low_Cost_Storage C_Constrained_Low_Gas C_Constrained_Macro C_Constrained_Uncoordinated C_Constrained_Elec_Base_Ret C_Constrained_Elec_CanExport100 C_Constrained_Elec_CanExport30 C_Constrained_Elec_High_Gas C_Constrained_Elec_Low_Cost_Storage C_Constrained_Elec_Low_Gas C_Constrained_Elec_Macro C_Constrained_Elec_Uncoordinated C_Constrained_High_DG C_Constrained_Tech_Break C_Constrained_Tech_Break_High_Gas C_Constrained_Tech_Break_Low_Cost_Storage C_Constrained_Elec_Tech_Break C_Constrained_Elec_Tech_Break_Low_Cost_Storage
	Cole et al. (2021)	Electrification Electrification_95_by_2050 Electrification_EnhancedFlex Electrification_EnhancedFlex_95_by_2050 High_Demand_Growth High_Demand_Growth_95_by_2050 High_NG_Price High_RE_Cost High_RE_Cost_95_by_2050 High_Trans High_Trans_95_by_2050 Low_Demand_Growth Low_Demand_Growth_95_by_2050 Low_Everything Low_Everything_95_by_2050	Low_NG_Price Low_NG_Price_95_by_2050 Low_Nuclear_CCS_Cost Low_Nuclear_CCS_Cost_95_by_2050 Low_RE_Cost Low_RE_Cost_95_by_2050 Mid_Case Mid_Case_95_by_2050 Mid_case_Base_Flex Mid_case_Base_Flex_95_by_2050 NoCDR_95_by_2050 PTC_ITC_Ext PTC_ITC_Ext_95_by_2050 Reduced_RE_resource Reduced_RE_resource_95_by_2050
	Ardani et al. (2021)	Reference.Adv Reference.Adv+DR	Reference.Mod
	Larson et al. (2021)	REF	E+RE-
	Denholm et al. (2022)	AllOptions_noPolicyDemandLTS AllOptions_noPolicyDemandAEO AllOptions_noPolicyHighEFS Infrastructure_noPolicyDemandLTS Infrastructure_noPolicyDemandAEO	Infrastructure_noPolicyHighEFS NoCDR_noPolicyDemandLTS NoCDR_noPolicyDemandAEO NoCDR_noPolicyHighEFS

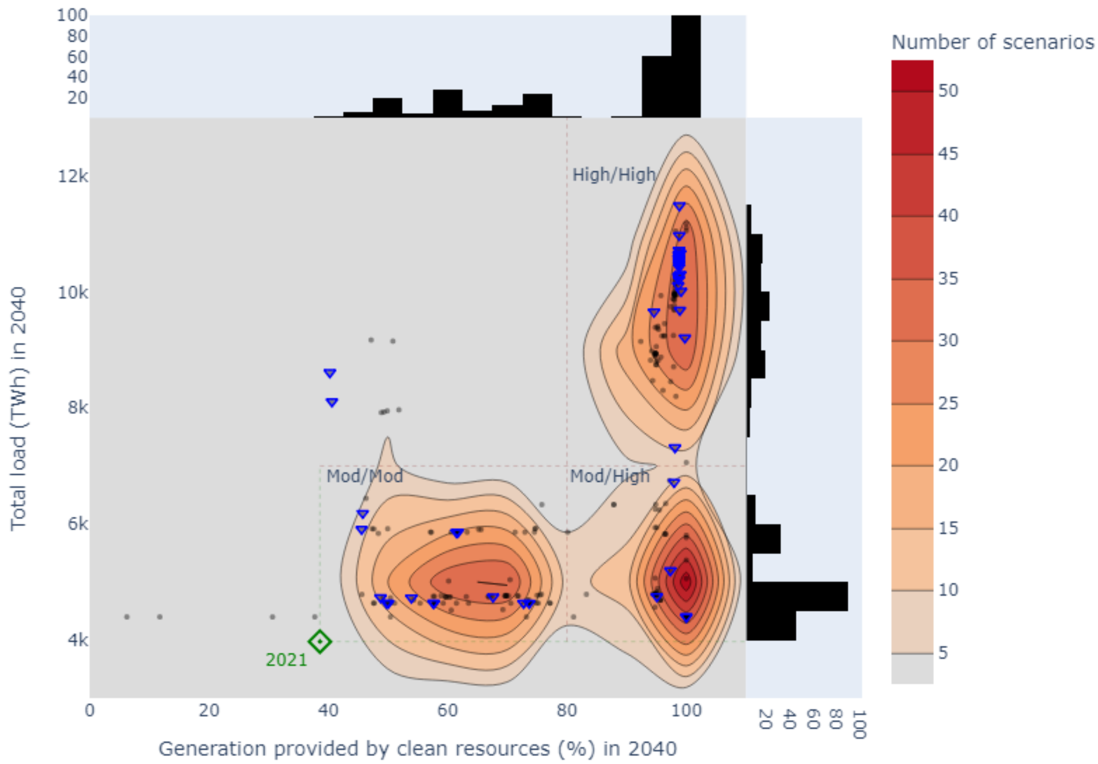
Scenario Group	Study	Scenarios	
Moderate/ High (n = 73)	Brown and Botterud (2020a)	default 2x transmission cost 2x interconnection cost no new dc 5x transmission cost 5x interconnection cost existing PHS noflex nuclear_existing noflex nuclear_$12000/kW noflex nuclear_$6180/kW midflex nuclear_$6180/kW fullflex nuclear_$6180/kW fullflex nuclear_$5000/kW fullflex nuclear_$4000/kW 0.5x VRE available 0.2x VRE available 0.1x VRE available 2030 low VRE&S prices LDES ($5/kWh) 3% wacc	LDES ($50/kWh) EIA regional cost scalers 6% wacc 5x Li-ion cost 2018 VRE&S prices Leitwind:LTW90/1000 Suzlon:S120/2100 WTKclass3 Vestas:V110/2000 WTKclass2 demand Reference_Rapid demand Medium_Moderate demand High_Rapid demand High_Slow $9000/MWh load shedding 20% reserves 50% reserves 100% reserves 2030 low VRES, 2030 high gas
	Brinkman et al. (2021)	C_Constrained_Elec_Tech_Break_High_Gas	
	Cole et al. (2021)	Electrification_95_by_2035 Electrification_EnhancedFlex_95_by_2035 High_Demand_Growth_95_by_2035 High_NG_Price_95_by_2035 High_NG_Price_95_by_2050 High_RE_Cost_95_by_2035 High_Trans_95_by_2035 Low_Demand_Growth_95_by_2035 Low_Everything_95_by_2035	Low_NG_Price_95_by_2035 Low_Nuclear_CCS_Cost_95_by_2035 Low_RE_Cost_95_by_2035 Mid_Case_95_by_2035 Mid_case_Base_Flex_95_by_2035 NoCDR_95_by_2035 PTC_ITC_Ext_95_by_2035 Reduced_RE_resource_95_by_2035
	Ardani et al. (2021)	95-by-35.Adv 95-by-35.Adv+DR 95-by-35.Mod	95-by-35+Elec.Adv 95-by-35+Elec.Adv+DR 95-by-35+Elec.Mod
	Larson et al. (2021)	E+ E+_constrRE	E+RE+
	Denholm et al. (2022)	AllOptions_demandLTS AllOptions_demandAEO AllOptions_highEFS Infrastructure_demandLTS	Infrastructure_demandAEO Infrastructure_highEFS NoCDR_demandAEO
High/High (n = 62)	Brown and Botterud (2020a)	demand 2050_High_Slow	
	Denholm et al. (2022)	AllOptions Infrastructure AllOptions_noClipping AllOptions_highCostHydro AllOptions_highCostPV AllOptions_highCostWind AllOptions_highCostBatt	Infrastructure_highCostHydro Infrastructure_highCostPV Infrastructure_highCostWind Infrastructure_highCostBatt Infrastructure_highCostREBatt Infrastructure_highCostGas Infrastructure_lowCostCCS

Scenario Group	Study	Scenarios	
		AllOptions_highCostREBatt AllOptions_highCostGas AllOptions_lowCostCCS AllOptions_lowCostCSP AllOptions_lowCostGeo AllOptions_lowCostHydro AllOptions_lowCostPV AllOptions_lowCostNuclear AllOptions_lowCostWind AllOptions_lowCostElectrolyzer AllOptions_lowCostBatt AllOptions_lowCostREBatt AllOptions_lowCostDAC AllOptions_lowCostAll AllOptions_lowCostGas AllOptions_gasCCSupgrades AllOptions_noNewGas AllOptions_bioExpand AllOptions_CCS95 AllOptions_CCS99 AllOptions_noMethaneLeak AllOptions_methaneLeak20 AllOptions_noH2CT Infrastructure_noClipping	Infrastructure_lowCostCSP Infrastructure_lowCostGeo Infrastructure_lowCostHydro Infrastructure_lowCostPV Infrastructure_lowCostNuclear Infrastructure_lowCostWind Infrastructure_lowCostElectrolyzer Infrastructure_lowCostBatt Infrastructure_lowCostREBatt Infrastructure_lowCostAll Infrastructure_lowCostGas Infrastructure_gasCCSupgrades Infrastructure_noNewGas Infrastructure_bioExpand Infrastructure_CCS95 Infrastructure_CCS99 Infrastructure_noMethaneLeak Infrastructure_methaneLeak20 Infrastructure_noH2CT NoCDR_highCostHydro NoCDR_highCostGas NoCDR_lowCostElectrolyzer NoCDR_lowCostGas
Artificially constrained (n = 48)	Brown and Botterud (2020a)	no existing transmission	no new ac or dc
	Brinkman et al. (2021)	BAU_No_CB BAU_No_CB_Uncoord Tech_Break_No_CB Tech_Break_No_CB_Uncoord	C_Constrained_No_CB C_Constrained_No_CB_Uncoord C_Constrained_Elec_No_CB C_Constrained_Elec_No_CB_Uncoord
	Cole et al. (2021)	Low_Trans Low_Trans_95_by_2035	Low_Trans_95_by_2050
	Denholm et al. (2022)	Constrained Constrained_noPolicy Constrained_demandLTS Constrained_noPolicyDemandLTS Constrained_demandAEO Constrained_noPolicyDemandAEO Constrained_highEFS Constrained_noPolicyHighEFS Constrained_noClipping Constrained_noPolicyNoClipping Constrained_highCostHydro Constrained_highCostPV Constrained_highCostWind Constrained_highCostBatt Constrained_highCostREBatt Constrained_highCostGas Constrained_lowCostCCS Constrained_lowCostCSP	Constrained_lowCostGeo Constrained_lowCostHydro Constrained_lowCostPV Constrained_lowCostNuclear Constrained_lowCostWind Constrained_lowCostElectrolyzer Constrained_lowCostBatt Constrained_lowCostREBatt Constrained_lowCostAll Constrained_gasCCSupgrades Constrained_noNewGas Constrained_CCS95 Constrained_CCS99 Constrained_noMethaneLeak Constrained_methaneLeak20 Constrained_allowDAC Constrained_noH2CT

Scenario Group	Study	Scenarios	
Outlying (n = 32)	Brown and Botterud (2020a)	2030 mid VRES, 2030 low gas 2030 mid VRES, 2030 mid gas	2030 low VRES, 2030 low gas 2018 VRES, 2030 low gas
	Denholm et al. (2022)	NoCDR AllOptions_noPolicy AllOptions_noPolicyNoClipping Infrastructure_noPolicy Infrastructure_noPolicyNoClipping NoCDR_noPolicy NoCDR_demandLTS NoCDR_highEFS NoCDR_noClipping NoCDR_noPolicyNoClipping NoCDR_highCostPV NoCDR_highCostWind NoCDR_highCostBatt NoCDR_highCostREBatt	NoCDR_lowCostCSP NoCDR_lowCostGeo NoCDR_lowCostHydro NoCDR_lowCostPV NoCDR_lowCostNuclear NoCDR_lowCostWind NoCDR_lowCostBatt NoCDR_lowCostREBatt NoCDR_lowCostAll NoCDR_noNewGas NoCDR_bioExpand NoCDR_noMethaneLeak NoCDR_methaneLeak20 NoCDR_noH2CT

Scenario Characteristics: Excluded Scenarios

Scenarios that artificially disallowed new transmission builds are excluded from this analysis. These are the “no cross-border expansion” sensitivities from Brinkman et al. (2021), “low transmission availability” scenarios from Cole et al. (2022), “constrained siting” core scenarios from Denholm et al. (2022), and the “no existing transmission” and “no new ac or dc” scenarios from Brown and Botterud (2020a). Scenarios that increase hurdle rates or transmission costs but do allow the model to build new transmission if found to be cost-effective (e.g., the “uncoordinated” sensitivity from Brinkman et al. [2021]) are included in this analysis. The 48 scenarios that artificially constrained transmission are found both in Table S-6 above and in Figure S-13 below.



Note: Histogram (black bars along x- and y-axes) and contour (red topographical lines in center plot) plots show counts of scenarios by clean energy generation (in percent of total annual generation) and total annual load in 2040. The green diamond indicates 2021 levels (EIA 2022). Blue triangles indicate scenarios that artificially constrain transmission builds. Thresholds separating the three scenario groups are shown as dashed lines and each scenario group is labeled.

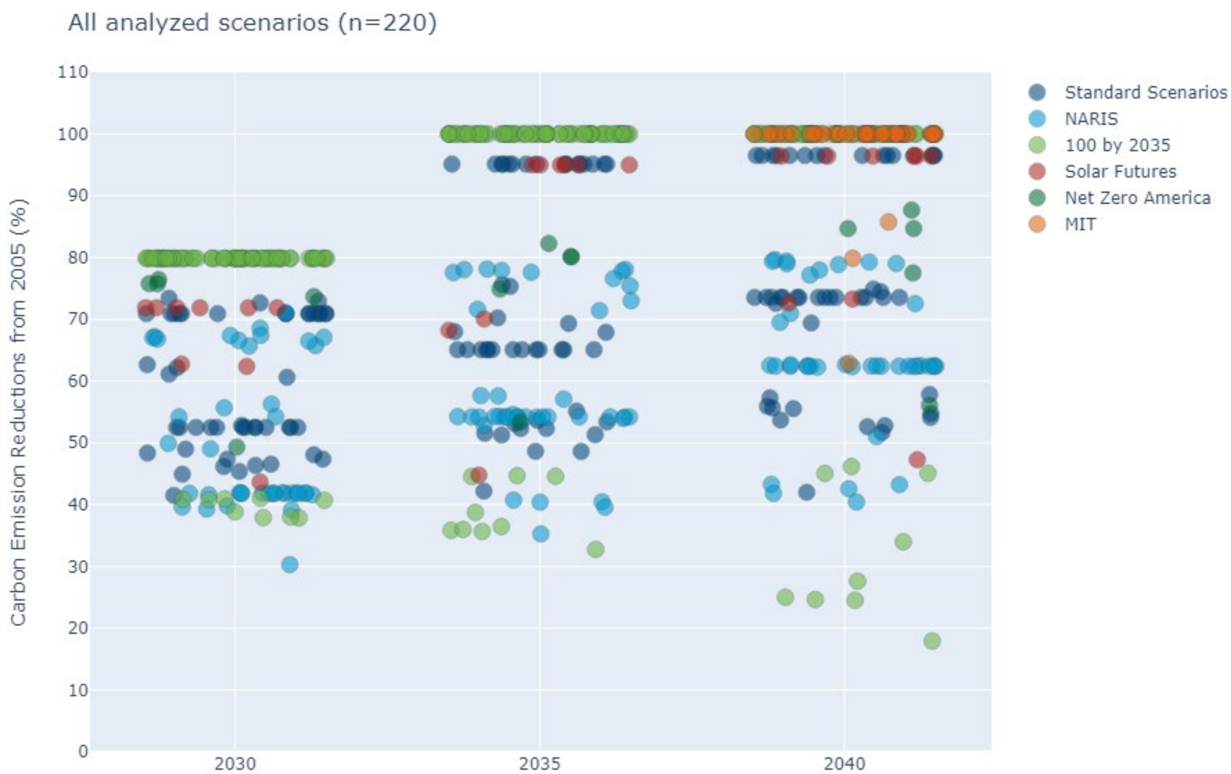
Figure S-13. All 300 capacity expansion scenarios considered in this analysis, with the 48 scenarios that artificially disallow transmission builds highlighted.

Scenario Characteristics: Carbon Emissions Reductions

The anticipated power sector carbon dioxide emissions reductions from 2005 levels (EPA 2020) given various electrification levels achieved by scenarios considered in this analysis are shown in Figure S-14 for years 2030, 2035, and 2040. Only those scenarios that were used in transmission system analysis are considered here. Power sector emissions reductions of most study scenarios reach between 40% (today's carbon emission levels) and 80% in the year 2030. These reduction levels continue to increase in 2035—when most scenarios from Denholm et al. (2022) reach full decarbonization—and by 2040 more than half of the scenarios have reached at least 90% reduction in carbon emissions compared with 2005 levels.

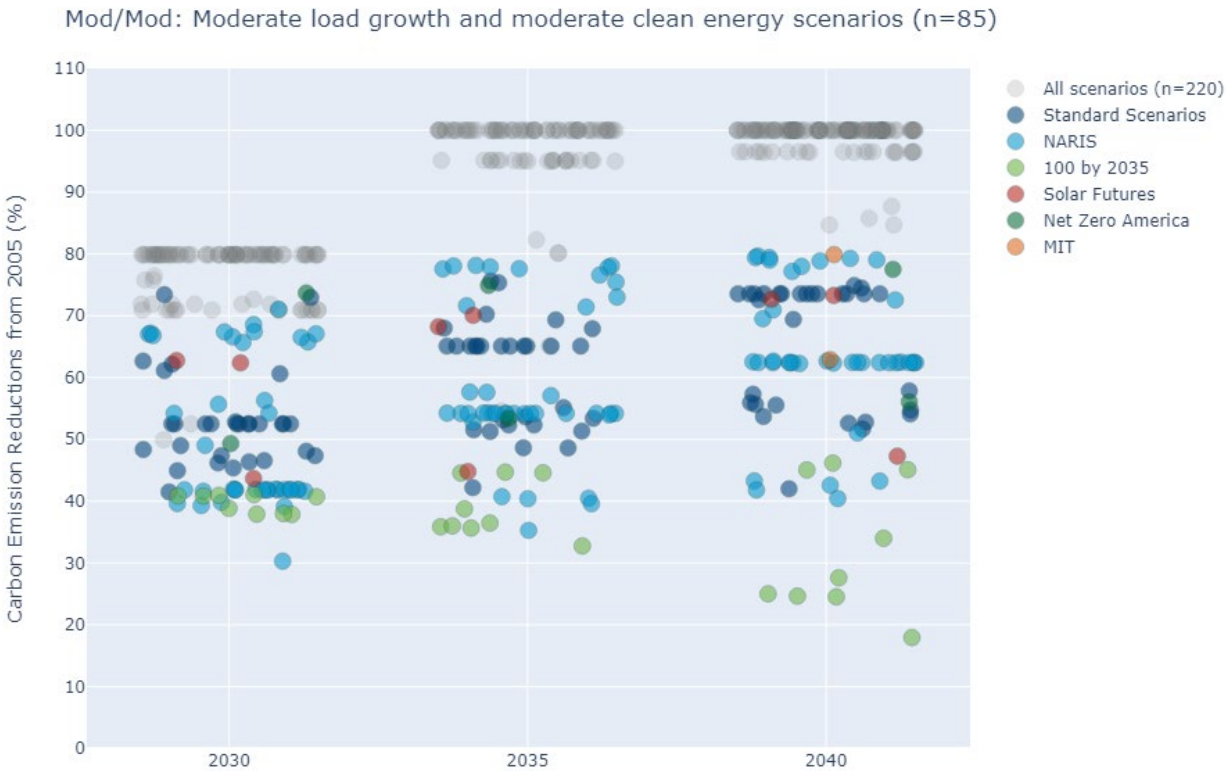
The carbon emissions reductions for all years are also shown by scenario group to understand how the combination of clean energy generation and total load contributes to power sector emissions. The carbon emissions reductions for scenarios in each scenario group are shown in Figure S-15 through Figure S-17. No scenario in the Moderate/Moderate group reaches more than 80% carbon reductions in any year. Several scenarios in the Moderate/High group reach

100% carbon emissions reductions by 2035, with many more reaching that level by 2040. The High/High scenario group has the most power sector carbon emissions reductions.



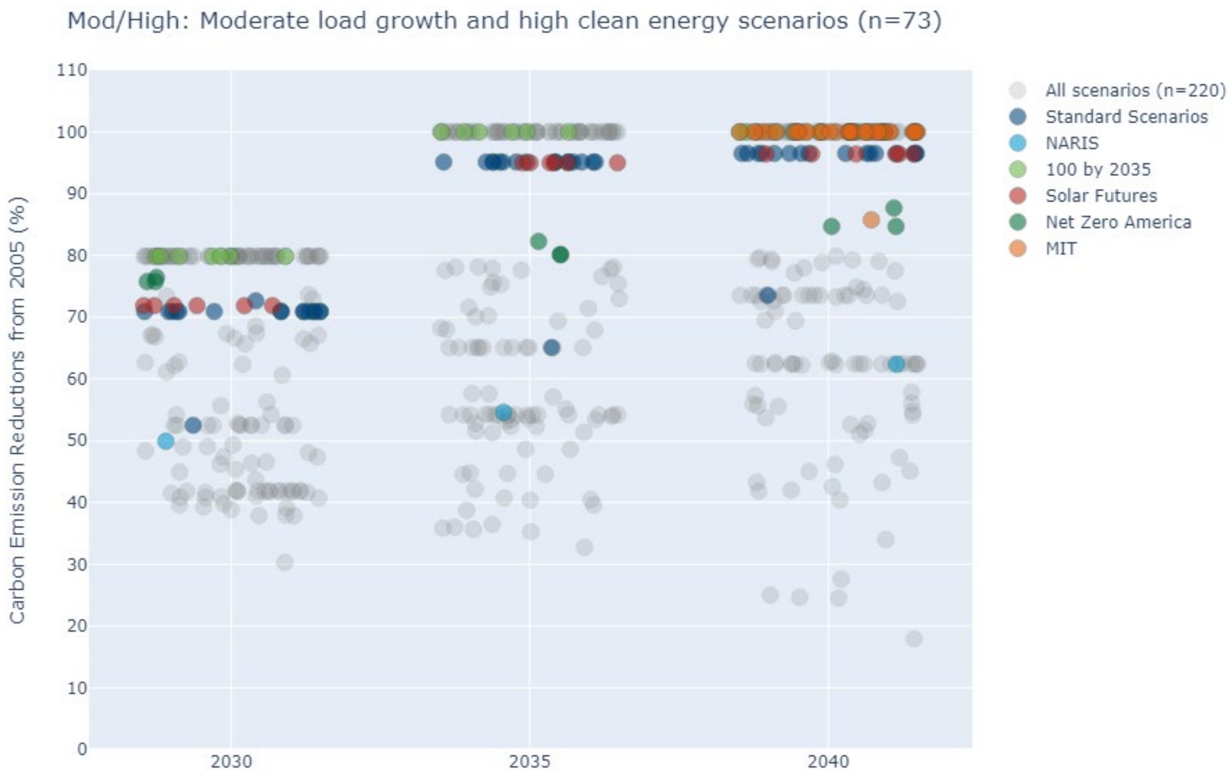
Note: A single point represents the emissions reductions from 2005 levels (EPA 2020) for a single scenario in that year. The color of the datapoint indicates the associated study: "Standard Scenarios" is Cole et al. (2021), "NARIS" is Brinkman et al. (2021), "100 by 2035" is Denholm et al. (2022), "Solar Futures" is Ardani et al. (2021), "Net Zero America" is Larson et al. (2021), and "MIT" is Brown and Botterud (2020).

Figure S-14. Carbon dioxide emissions reductions for the 220 scenarios considered in this analysis in 2030, 2035, and 2040.



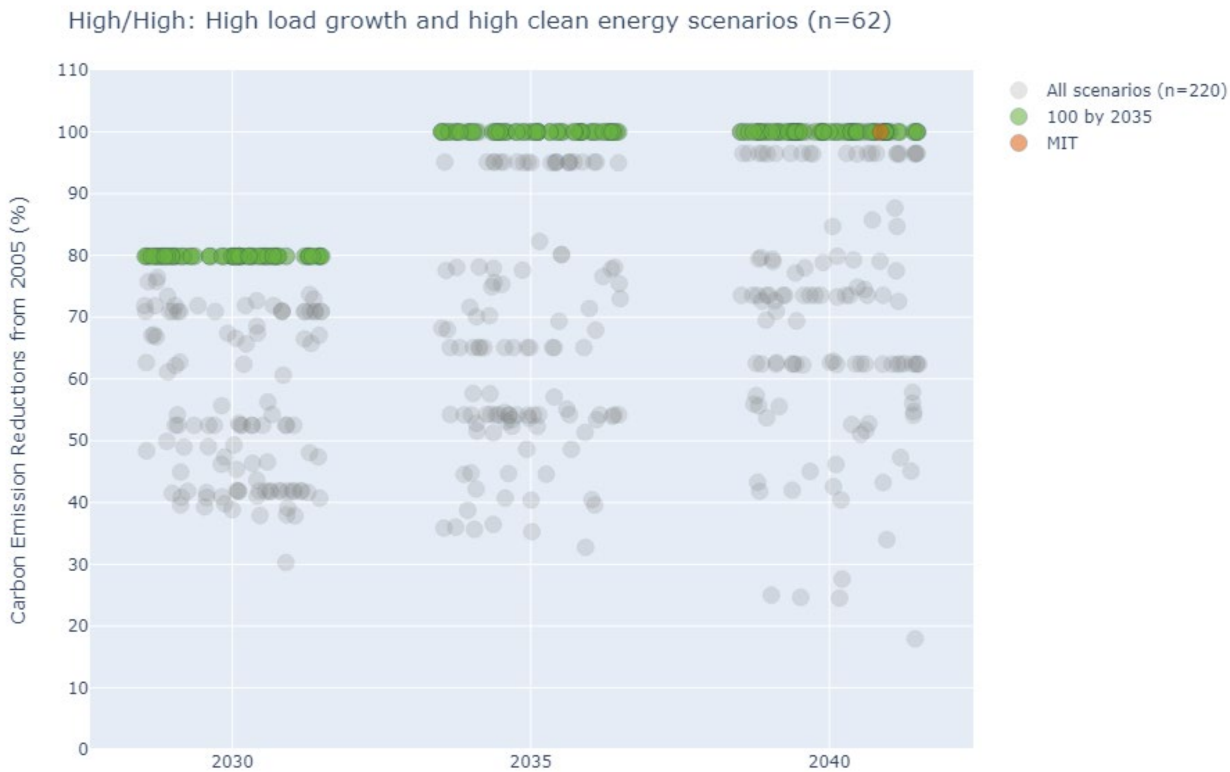
Note: A single point represents the emissions reductions from 2005 levels (EPA 2020) for a single scenario in that year. The color of the datapoint indicates the associated study: “Standard Scenarios” is Cole et al. (2021), “NARIS” is Brinkman et al. (2021), “100 by 2035” is Denholm et al. (2022), “Solar Futures” is Ardani et al. (2021), “Net Zero America” is Larson et al. (2021), and "MIT” is Brown and Botterud (2020).

Figure S-15. Carbon emissions reductions for Moderate/Moderate scenarios in 2030, 2035, and 2040. Gray datapoints are scenarios associated with other groups.



Note: A single point represents the emissions reductions from 2005 levels (EPA 2020) for a single scenario in that year. The color of the datapoint indicates the associated study: "Standard Scenarios" is Cole et al. (2021), "NARIS" is Brinkman et al. (2021), "100 by 2035" is Denholm et al. (2022), "Solar Futures" is Ardani et al. (2021), "Net Zero America" is Larson et al. (2021), and "MIT" is Brown and Botterud (2020).

Figure S-16. Carbon emissions reductions for Moderate/High scenarios in 2030, 2035, and 2040. Gray datapoints are scenarios associated with other groups.



Note: A single point represents the emissions reductions from 2005 levels (EPA 2020) for a single scenario in that year. The color of the datapoint indicates the associated study: "100 by 2035" is Denholm et al. (2022) and "MIT" is Brown and Botterud (2020).

Figure S-17. Carbon emissions reductions for High/High scenarios in 2030, 2035, and 2040. Gray datapoints are scenarios associated with other groups.

Section VI.c. Within-Region Transmission Deployment

Median results for aggregated regional transmission deployment are presented in the Needs Study Table VI-3 (page 123–124) by scenario group for years 2030, 2035, and 2040. Needs Study Figures VI-3 through VI-6 (pages 126–129) additionally show the interquartile range of within-region transmission deployment for the contiguous United States (CONUS) and each individual region for each scenario group and year. A more complete look at the statistical results is provided in Table S-7 through Table S-9 below, in which the minimum, 25th percentile, median, mean, 75th percentile, and maximum values are listed for 2030, 2035, and 2040, respectively.

Table S-7. Regional transmission deployment (GW-mi) results from all capacity expansion studies in 2030. Minimum (Min), 25th percentile (Q1), median, mean, 75th percentile (Q3), maximum (Max), and sample size (n) shown for each region and scenario group.

Region	Scenario Group	Min	Q1	Median	Mean	Q3	Max	n
CONUS	Mod/Mod	4,060	7,580	11,600	13,600	14,000	77,600	44
CONUS	Mod/High	15,900	19,600	23,400	33,700	27,200	146,000	33

Region	Scenario Group	Min	Q1	Median	Mean	Q3	Max	n
CONUS	High/High	25,700	30,400	33,200	39,100	48,900	62,600	61
California	Mod/Mod	4	35	62	103	101	1,550	44
California	Mod/High	0	38	89	238	117	2,340	33
California	High/High	0	38	47	65	83	281	61
Mountain	Mod/Mod	37	920	1,460	1,490	1,660	11,600	44
Mountain	Mod/High	339	1,410	2,280	3,450	2,580	25,200	33
Mountain	High/High	2,580	2,950	3,120	3,230	3,500	4,340	61
Northwest	Mod/Mod	0	1	33	230	38	8,020	44
Northwest	Mod/High	1	39	66	788	108	10,400	33
Northwest	High/High	133	367	619	598	800	1,110	61
Southwest	Mod/Mod	15	325	415	721	485	9,890	44
Southwest	Mod/High	529	728	935	2,210	2,050	15,500	33
Southwest	High/High	2,040	2,570	2,760	2,880	3,200	4,530	61
Texas	Mod/Mod	219	1,720	2,780	3,230	3,500	11,200	44
Texas	Mod/High	1,620	4,020	6,040	6,510	6,600	22,500	33
Texas	High/High	1,590	2,670	3,330	3,630	4,750	6,040	61
Delta	Mod/Mod	0	0	8	250	95	5,090	44
Delta	Mod/High	6	71	387	959	1,570	4,320	33
Delta	High/High	2,030	2,530	2,980	3,210	3,940	4,580	61
Florida	Mod/Mod	0	0	0	65	0	978	44
Florida	Mod/High	0	0	63	465	340	4,000	33
Florida	High/High	0	2	9	25	25	318	61
Mid-Atlantic	Mod/Mod	127	395	564	626	743	1,860	44
Mid-Atlantic	Mod/High	209	627	1,090	2,060	1,360	16,300	33
Mid-Atlantic	High/High	1,310	1,860	2,490	2,460	3,020	3,700	61
Midwest	Mod/Mod	460	894	1,130	1,880	1,500	13,200	44
Midwest	Mod/High	2,210	3,300	3,710	6,270	4,220	36,400	33
Midwest	High/High	6,460	7,370	7,730	8,150	8,850	13,700	61
New England	Mod/Mod	14	15	17	76	80	766	44
New England	Mod/High	16	21	49	216	291	1,610	33
New England	High/High	237	331	367	486	678	1,150	61
New York	Mod/Mod	0	0	0	48	1	962	44
New York	Mod/High	0	0	0	201	54	2,550	33
New York	High/High	0	69	102	99	120	251	61
Plains	Mod/Mod	630	1,140	1,560	1,980	2,320	8,660	44
Plains	Mod/High	2,230	3,060	3,520	5,390	4,620	22,700	33
Plains	High/High	3,680	5,460	6,880	10,600	16,100	22,500	61
Southeast	Mod/Mod	1	329	553	808	1,090	4,380	44
Southeast	Mod/High	9	2,260	2,830	3,110	3,560	8,990	33
Southeast	High/High	1,100	2,280	2,680	2,770	3,370	4,280	61

Note: Values rounded to nearest whole number and shown to three significant figures.

Table S-8. Regional transmission deployment (GW-mi) results from all capacity expansion studies in 2035. Minimum (Min), 25th percentile (Q1), median, mean, 75th percentile (Q3), maximum (Max), and sample size (n) values shown for each region and scenario group.

Region	Scenario Group	Min	Q1	Median	Mean	Q3	Max	n
CONUS	Mod/Mod	6,450	10,100	17,000	20,900	23,500	120,000	44
CONUS	Mod/High	29,800	43,100	54,500	69,500	59,100	282,000	33
CONUS	High/High	65,800	93,500	110,000	117,000	149,000	163,000	61
California	Mod/Mod	4	38	69	133	106	2,500	44
California	Mod/High	7	91	120	472	208	4,600	33
California	High/High	11	115	160	176	232	636	61
Mountain	Mod/Mod	91	1,110	1,660	2,040	1,900	21,700	44
Mountain	Mod/High	938	2,520	3,140	6,070	4,460	50,700	33
Mountain	High/High	3,320	4,970	6,000	6,870	8,970	12,300	61
Northwest	Mod/Mod	0	16	39	430	72	12,700	44
Northwest	Mod/High	65	334	535	1,840	930	14,700	33
Northwest	High/High	961	3,550	4,710	4,510	5,250	8,980	61
Southwest	Mod/Mod	95	517	634	1,060	761	13,400	44
Southwest	Mod/High	754	1,450	1,870	3,520	2,880	20,500	33
Southwest	High/High	2,640	5,920	6,690	6,800	8,170	9,920	61
Texas	Mod/Mod	586	2,760	4,350	4,880	6,530	15,200	44
Texas	Mod/High	2,880	6,770	9,000	9,970	9,440	35,200	33
Texas	High/High	3,890	6,190	7,270	7,650	9,560	10,700	61
Delta	Mod/Mod	0	42	153	505	427	7,950	44
Delta	Mod/High	580	1,360	1,650	2,810	3,910	10,700	33
Delta	High/High	5,530	6,660	7,760	8,300	10,300	12,700	61
Florida	Mod/Mod	0	13	80	172	168	1,250	44
Florida	Mod/High	94	508	813	1,430	2,050	7,340	33
Florida	High/High	88	456	726	800	1,190	1,620	61
Mid-Atlantic	Mod/Mod	251	762	955	1,070	1,250	3,030	44
Mid-Atlantic	Mod/High	1,280	2,650	3,280	5,160	4,620	26,300	33
Mid-Atlantic	High/High	6,120	7,360	8,840	8,740	9,730	13,100	61
Midwest	Mod/Mod	605	1,640	2,260	3,270	3,130	20,100	44
Midwest	Mod/High	4,040	10,000	13,300	15,500	14,900	60,700	33
Midwest	High/High	16,600	19,000	20,700	21,900	25,400	30,700	61
New England	Mod/Mod	15	18	31	87	100	929	44
New England	Mod/High	40	67	100	466	646	2,990	33

Region	Scenario Group	Min	Q1	Median	Mean	Q3	Max	n
New England	High/High	1,540	2,100	2,440	2,430	2,730	3,240	61
New York	Mod/Mod	0	0	0	97	36	1,320	44
New York	Mod/High	0	0	0	404	348	4,630	33
New York	High/High	78	338	376	374	412	749	61
Plains	Mod/Mod	1,300	2,290	2,930	3,360	3,770	14,300	44
Plains	Mod/High	4,670	7,340	8,320	12,100	9,910	36,900	33
Plains	High/High	12,300	21,500	28,500	35,400	52,300	57,600	61
Southeast	Mod/Mod	56	656	1,090	1,730	2,640	7,040	44
Southeast	Mod/High	3,920	5,390	6,820	7,210	7,990	18,500	33
Southeast	High/High	5,310	8,170	9,110	9,560	11,500	12,400	61

Note: Values rounded to nearest whole number and shown to three significant figures.

Table S-9. Regional transmission deployment (GW-mi) results from all capacity expansion studies in 2040. Minimum (Min), 25th percentile (Q1), median, mean, 75th percentile (Q3), maximum (Max), and sample size (n) values shown for each region and scenario group.

Region	Scenario Group	Min	Q1	Median	Mean	Q3	Max	n
CONUS	Mod/Mod	7,390	13,000	20,900	25,800	30,700	162,000	46
CONUS	Mod/High	3,600	33,700	42,200	60,100	61,400	472,000	72
CONUS	High/High	1,390	25,200	33,400	28,900	37,000	49,600	40
California	Mod/Mod	5	46	75	160	114	3,320	44
California	Mod/High	11	94	123	806	220	9,020	33
California	High/High	14	186	231	250	313	729	61
Mountain	Mod/Mod	0	1,220	1,860	2,450	2,320	29,700	46
Mountain	Mod/High	0	521	2,880	4,860	4,100	74,800	72
Mountain	High/High	3,980	6,020	7,690	9,130	12,100	21,800	62
Northwest	Mod/Mod	0	50	80	568	143	15,600	46
Northwest	Mod/High	0	0	0	1,420	909	23,100	72
Northwest	High/High	202	6,590	8,540	8,500	10,600	18,200	62
Southwest	Mod/Mod	0	606	778	1,230	959	15,800	46
Southwest	Mod/High	0	34	809	2,070	1,840	26,700	72
Southwest	High/High	776	6,550	7,640	8,160	10,300	13,200	62
Texas	Mod/Mod	637	3,270	5,680	5,870	7,510	19,200	44
Texas	Mod/High	3,170	7,780	9,600	12,100	10,200	59,700	33
Texas	High/High	4,590	7,690	8,720	9,510	12,000	15,700	61
Delta	Mod/Mod	0	118	404	722	734	10,400	46

Region	Scenario Group	Min	Q1	Median	Mean	Q3	Max	n
Delta	Mod/High	0	0	1,370	1,930	2,120	14,200	72
Delta	High/High	135	7,130	8,790	9,310	11,600	15,700	62
Florida	Mod/Mod	0	37	149	374	697	1,430	44
Florida	Mod/High	94	637	1,040	1,770	2,210	8,440	33
Florida	High/High	97	591	1,040	1,220	1,820	4,240	61
Mid-Atlantic	Mod/Mod	267	885	1,110	1,240	1,480	3,490	46
Mid-Atlantic	Mod/High	568	2,720	3,610	4,970	4,610	45,400	72
Mid-Atlantic	High/High	7,150	11,200	11,700	11,700	12,200	15,100	62
Midwest	Mod/Mod	635	1,870	3,400	4,340	4,670	30,100	46
Midwest	Mod/High	767	13,100	16,200	17,300	17,500	105,000	72
Midwest	High/High	15,500	21,600	23,400	26,600	33,700	38,800	62
New England	Mod/Mod	16	31	47	120	146	1,070	46
New England	Mod/High	74	201	2,720	2,410	4,190	7,180	72
New England	High/High	1,890	2,700	2,980	2,960	3,100	6,140	62
New York	Mod/Mod	0	0	0	105	0	1,530	46
New York	Mod/High	0	0	62	307	92	7,220	72
New York	High/High	80	361	411	445	476	1,070	62
Plains	Mod/Mod	1,840	2,890	3,930	4,500	5,140	21,000	46
Plains	Mod/High	1	3,700	6,310	9,800	11,000	63,100	72
Plains	High/High	5,470	25,900	31,300	43,800	67,000	75,600	62
Southeast	Mod/Mod	42	1,010	1,580	2,310	3,510	9,660	46
Southeast	Mod/High	153	5,280	6,040	7,120	8,070	32,200	72
Southeast	High/High	5,480	9,900	11,500	12,500	15,500	19,600	62

Note: Values rounded to nearest whole number and shown to three significant figures.

Section VI.d. Interregional Transfer Capacity

Median results for aggregated interregional transfer capacities are presented in Needs Study Table VI-4 (pages 131–133) by scenario group for years 2030, 2035, and 2040. Needs Study Figures VI-7 through VI-10 (pages 134–138) additionally show the interquartile range of interregional transfer capacities for the CONUS and each pair of individual regions for each scenario group and year. A more complete look at the statistical results is provided in Table S10 through Table S-12 below, in which the minimum, 25th percentile, median, mean, 75th percentile, and maximum values are listed for 2030, 2035, and 2040, respectively.

Table S-10. Interregional transfer capacity (GW) results from all capacity expansion studies in 2030. Minimum (Min), 25th percentile (Q1), median, mean, 75th percentile (Q3), maximum (Max), and sample size (n) values shown for each interregional boundary and scenario group.

Regional Pair	Scenario Group	Min	Q1	Median	Mean	Q3	Max	n
California – Mountain	Mod/Mod	0.0	0.1	0.3	0.3	0.5	1.0	81
California – Mountain	Mod/High	0.0	0.4	0.6	0.7	1.0	2.0	31
California – Mountain	High/High	0.4	1.0	1.2	1.2	1.5	2.2	61
California – Northwest	Mod/Mod	0.0	0.0	0.0	0.1	0.0	2.7	81
California – Northwest	Mod/High	0.0	0.0	0.0	0.0	0.0	0.2	31
California – Northwest	High/High	0.0	0.0	0.3	0.2	0.4	0.6	61
California – Southwest	Mod/Mod	0.0	0.0	0.0	0.4	0.1	5.4	81
California – Southwest	Mod/High	0.0	0.0	0.1	0.4	0.6	2.7	31
California – Southwest	High/High	1.0	1.4	1.9	2.3	3.2	5.8	61
Mountain – Northwest	Mod/Mod	0.0	0.0	0.0	0.3	0.5	1.7	81
Mountain – Northwest	Mod/High	0.2	0.3	1.1	1.2	1.8	3.9	31
Mountain – Northwest	High/High	3.2	5.2	6.3	6.2	7.4	9.5	61
Mountain – Southwest	Mod/Mod	0.0	0.0	0.0	0.3	0.5	2.9	81
Mountain – Southwest	Mod/High	0.0	0.2	0.4	0.5	0.7	1.7	31
Mountain – Southwest	High/High	1.0	1.4	2.1	2.4	3.5	5.7	61
Mountain – Plains	Mod/Mod	0.0	0.3	0.4	0.9	0.9	5.8	81
Mountain – Plains	Mod/High	0.0	0.3	0.8	1.2	1.1	5.2	31
Mountain – Plains	High/High	3.3	4.9	6.1	6.9	9.3	12.7	61
Plains – Southwest	Mod/Mod	0.0	0.0	0.7	1.6	3.0	6.3	81
Plains – Southwest	Mod/High	0.0	1.9	2.5	2.4	3.2	5.8	31
Plains – Southwest	High/High	2.1	4.1	5.5	5.6	6.9	12.6	61
Plains – Texas	Mod/Mod	0.0	0.0	0.0	0.4	0.5	3.5	81
Plains – Texas	Mod/High	0.0	0.8	1.2	3.3	4.3	14.9	31
Plains – Texas	High/High	10.5	13.2	14.3	15.3	17.5	22.7	61
Delta – Midwest	Mod/Mod	0.0	0.0	0.0	0.2	0.0	2.7	81
Delta – Midwest	Mod/High	0.0	0.0	0.0	0.1	0.0	2.9	31
Delta – Midwest	High/High	0.0	0.0	0.1	0.1	0.2	0.4	61
Delta – Plains	Mod/Mod	0.0	0.0	0.0	0.8	0.9	9.3	81
Delta – Plains	Mod/High	0.7	4.4	4.9	7.5	9.6	23.7	31
Delta – Plains	High/High	10.8	18.8	20.7	23.2	28.7	33.5	61
Delta – Southeast	Mod/Mod	0.0	0.0	0.0	0.2	0.0	2.7	81
Delta – Southeast	Mod/High	0.0	0.1	0.9	1.6	2.0	8.0	31

Regional Pair	Scenario Group	Min	Q1	Median	Mean	Q3	Max	n
Delta – Southeast	High/High	3.3	7.5	10.1	10.1	12.1	17.0	61
Florida – Southeast	Mod/Mod	0.0	0.0	0.0	0.4	0.0	2.7	81
Florida – Southeast	Mod/High	0.0	0.0	0.0	0.3	0.0	2.6	31
Florida – Southeast	High/High	0.1	0.4	0.9	1.8	3.2	5.5	61
Mid-Atlantic – Midwest	Mod/Mod	0.0	0.3	1.1	1.7	2.3	9.8	81
Mid-Atlantic – Midwest	Mod/High	2.0	4.7	9.9	13.1	15.9	40.6	31
Mid-Atlantic – Midwest	High/High	22.7	38.7	42.4	41.9	45.8	57.4	61
Mid-Atlantic – New York	Mod/Mod	0.0	0.0	0.0	1.6	3.2	9.5	81
Mid-Atlantic – New York	Mod/High	0.0	0.0	0.0	0.1	0.0	1.6	31
Mid-Atlantic – New York	High/High	0.4	1.0	2.0	2.5	3.8	5.7	61
Mid-Atlantic – Southeast	Mod/Mod	0.0	0.0	0.2	0.9	1.5	7.6	81
Mid-Atlantic – Southeast	Mod/High	0.2	1.4	2.8	3.0	4.0	9.8	31
Mid-Atlantic – Southeast	High/High	2.6	3.9	4.4	4.4	4.8	7.4	61
Midwest – Plains	Mod/Mod	0.0	0.6	1.4	1.7	2.2	7.6	81
Midwest – Plains	Mod/High	2.2	5.4	8.0	10.1	10.3	34.6	31
Midwest – Plains	High/High	15.8	19.2	24.6	29.8	40.3	56.8	61
Midwest – Southeast	Mod/Mod	0.0	0.0	0.0	0.4	0.0	3.9	81
Midwest – Southeast	Mod/High	0.0	0.1	1.3	2.5	2.8	15.0	31
Midwest – Southeast	High/High	5.3	8.6	10.3	11.3	14.6	19.5	61
New England – New York	Mod/Mod	0.0	0.9	1.5	1.7	2.3	6.6	81
New England – New York	Mod/High	0.2	1.2	1.5	1.5	2.0	2.6	31
New England – New York	High/High	2.5	3.4	4.0	4.3	5.5	7.5	61

Note: Values shown to nearest tenth.

Table S-11. Interregional transfer capacity (GW) results from all capacity expansion studies in 2035. Minimum (Min), 25th percentile (Q1), median, mean, 75th percentile (Q3), maximum (Max), and sample size (n) values shown for each interregional boundary and scenario group.

Regional Pair	Scenario Group	Min	Q1	Median	Mean	Q3	Max	n
California – Mountain	Mod/Mod	0.0	0.3	1.0	1.0	1.6	3.3	81
California – Mountain	Mod/High	0.2	1.5	1.9	2.0	2.3	4.5	31
California – Mountain	High/High	0.9	2.4	2.8	2.8	3.1	5.6	61
California – Northwest	Mod/Mod	0.0	0.0	0.0	0.2	0.0	2.7	81
California – Northwest	Mod/High	0.0	0.1	0.1	0.2	0.3	1.2	31
California – Northwest	High/High	0.1	1.0	1.3	1.5	1.9	3.8	61
California – Southwest	Mod/Mod	0.0	0.0	0.1	0.9	0.3	6.8	81
California – Southwest	Mod/High	0.0	0.0	0.3	0.8	0.9	5.5	31
California – Southwest	High/High	1.2	3.4	5.3	5.8	7.6	12.7	61
Mountain – Northwest	Mod/Mod	0.0	0.0	0.1	0.5	0.7	3.8	81
Mountain – Northwest	Mod/High	1.4	2.7	3.3	4.3	4.4	14.2	31
Mountain – Northwest	High/High	5.2	22.8	25.7	24.6	28.5	37.0	61
Mountain – Southwest	Mod/Mod	0.0	0.0	0.1	0.4	0.6	2.9	81
Mountain – Southwest	Mod/High	0.5	1.1	1.7	1.8	2.1	5.4	31
Mountain – Southwest	High/High	1.2	3.9	5.2	6.3	9.0	13.7	61
Mountain – Plains	Mod/Mod	0.0	0.3	0.9	1.7	2.0	10.6	81
Mountain – Plains	Mod/High	0.0	1.6	2.6	3.7	3.4	17.9	31
Mountain – Plains	High/High	6.8	12.1	19.3	18.9	24.4	31.5	61
Plains – Southwest	Mod/Mod	0.0	0.0	1.2	1.8	3.2	7.2	81
Plains – Southwest	Mod/High	0.0	2.3	3.7	3.7	4.7	10.8	31
Plains – Southwest	High/High	4.2	11.3	13.0	13.8	17.2	23.7	61
Plains – Texas	Mod/Mod	0.0	0.0	0.5	1.0	1.5	4.8	81
Plains – Texas	Mod/High	0.0	4.3	9.8	10.4	12.6	33.2	31
Plains – Texas	High/High	17.9	26.1	28.9	32.7	41.8	48.8	61
Delta – Midwest	Mod/Mod	0.0	0.0	0.0	0.3	0.0	2.9	81
Delta – Midwest	Mod/High	0.0	0.0	0.0	0.3	0.3	3.2	31
Delta – Midwest	High/High	0.3	0.6	0.9	1.0	1.2	2.3	61
Delta – Plains	Mod/Mod	0.0	0.0	0.4	1.8	3.4	10.7	81
Delta – Plains	Mod/High	2.1	10.8	19.7	20.2	23.8	52.9	31
Delta – Plains	High/High	27.1	39.2	48.5	50.6	64.7	73.1	61
Delta – Southeast	Mod/Mod	0.0	0.0	0.0	0.2	0.0	2.7	81
Delta – Southeast	Mod/High	0.6	2.8	5.1	7.0	8.5	25.6	31

Regional Pair	Scenario Group	Min	Q1	Median	Mean	Q3	Max	n
Delta – Southeast	High/High	19.8	27.0	33.9	33.2	39.9	49.3	61
Florida – Southeast	Mod/Mod	0.0	0.0	0.0	0.7	1.2	4.4	81
Florida – Southeast	Mod/High	0.0	0.3	1.1	2.7	4.4	12.7	31
Florida – Southeast	High/High	3.9	8.1	10.6	12.1	16.7	19.4	61
Mid-Atlantic – Midwest	Mod/Mod	0.0	0.6	2.4	3.2	4.3	13.8	81
Mid-Atlantic – Midwest	Mod/High	5.1	28.0	33.8	42.2	51.7	109.0	31
Mid-Atlantic – Midwest	High/High	79.6	95.7	102.8	109.3	125.5	140.9	61
Mid-Atlantic – New York	Mod/Mod	0.0	0.0	0.3	2.0	3.7	9.5	81
Mid-Atlantic – New York	Mod/High	0.2	1.6	2.4	2.6	3.4	5.9	31
Mid-Atlantic – New York	High/High	3.6	7.2	8.2	8.4	9.8	11.9	61
Mid-Atlantic – Southeast	Mod/Mod	0.0	0.1	0.5	1.2	1.9	8.2	81
Mid-Atlantic – Southeast	Mod/High	2.1	5.8	6.9	7.4	9.9	13.6	31
Mid-Atlantic – Southeast	High/High	6.8	9.3	9.9	9.9	10.4	12.5	61
Midwest – Plains	Mod/Mod	0.0	0.9	3.1	3.6	5.0	10.7	81
Midwest – Plains	Mod/High	3.5	15.4	21.1	28.2	25.8	95.0	31
Midwest – Plains	High/High	58.5	71.8	88.0	99.5	129.1	150.7	61
Midwest – Southeast	Mod/Mod	0.0	0.0	0.0	0.5	0.2	3.9	81
Midwest – Southeast	Mod/High	0.9	3.0	4.5	9.1	7.5	38.3	31
Midwest – Southeast	High/High	19.0	29.0	34.4	37.3	45.9	52.6	61
New England – New York	Mod/Mod	0.0	1.6	2.8	2.7	3.7	6.6	81
New England – New York	Mod/High	0.9	3.4	5.2	4.9	6.3	8.6	31
New England – New York	High/High	10.1	14.7	17.0	16.5	17.8	22.6	61

Note: Values shown to nearest tenth.

Table S-12. Interregional transfer capacity (GW) results from all capacity expansion studies in 2040. Minimum (Min), 25th percentile (Q1), median, mean, 75th percentile (Q3), maximum (Max), and sample size (n) values shown for each interregional boundary and scenario group.

Regional Pair	Scenario Group	Min	Q1	Median	Mean	Q3	Max	n
California – Mountain	Mod/Mod	0.0	0.8	1.8	1.8	2.5	8.5	83
California – Mountain	Mod/High	0.2	2.7	5.0	11.1	21.0	44.3	70
California – Mountain	High/High	1.2	3.1	4.3	5.6	7.0	48.5	62
California – Northwest	Mod/Mod	0.0	0.0	0.0	0.2	0.1	2.7	83
California – Northwest	Mod/High	0.0	0.0	0.0	0.5	0.5	7.1	70
California – Northwest	High/High	0.2	1.6	1.9	2.1	2.5	8.1	62
California – Southwest	Mod/Mod	0.0	0.1	0.2	1.7	1.8	9.3	83
California – Southwest	Mod/High	0.0	0.5	5.1	12.0	24.6	53.2	70
California – Southwest	High/High	1.2	4.0	6.9	8.7	11.6	58.5	62
Mountain – Northwest	Mod/Mod	0.0	0.0	0.5	0.9	1.4	5.3	83
Mountain – Northwest	Mod/High	0.0	0.0	0.0	3.6	5.3	25.3	70
Mountain – Northwest	High/High	0.0	33.0	39.2	37.0	43.5	67.5	62
Mountain – Southwest	Mod/Mod	0.0	0.1	0.4	0.5	0.7	2.9	83
Mountain – Southwest	Mod/High	0.0	0.4	1.7	1.8	2.4	7.8	70
Mountain – Southwest	High/High	1.3	4.6	6.1	9.5	14.2	31.3	62
Delta – Texas	Mod/Mod	14.1	18.2	22.2	22.2	26.2	30.2	2
Delta – Texas	Mod/High	0.0	30.0	48.3	46.3	55.9	117.1	39
Delta – Texas	High/High	106.7	106.7	106.7	106.7	106.7	106.7	1
Mountain – Plains	Mod/Mod	0.0	0.4	1.4	2.4	2.7	14.8	83
Mountain – Plains	Mod/High	0.0	3.5	11.9	10.8	14.7	38.5	70
Mountain – Plains	High/High	8.0	18.8	29.2	27.0	35.8	47.7	62
Plains – Southwest	Mod/Mod	0.0	0.0	1.5	2.4	3.4	18.0	83
Plains – Southwest	Mod/High	-0.1	4.1	13.1	12.3	17.3	47.2	70
Plains – Southwest	High/High	5.2	12.5	14.4	16.9	22.8	41.6	62
Plains – Texas	Mod/Mod	0.0	0.1	0.9	1.6	2.4	7.1	83
Plains – Texas	Mod/High	0.0	10.5	14.6	16.6	24.1	41.5	70
Plains – Texas	High/High	19.0	29.9	34.9	38.5	49.8	60.5	62
Delta – Midwest	Mod/Mod	0.0	0.0	0.0	0.3	0.0	3.1	83
Delta – Midwest	Mod/High	0.0	0.0	0.0	0.6	0.6	7.4	70
Delta – Midwest	High/High	0.0	0.9	1.3	1.3	1.7	2.7	62
Delta – Plains	Mod/Mod	0.0	0.0	0.7	2.4	4.5	10.9	83
Delta – Plains	Mod/High	0.0	0.0	0.0	10.4	18.9	60.3	70

Regional Pair	Scenario Group	Min	Q1	Median	Mean	Q3	Max	n
Delta – Plains	High/High	0.0	45.7	55.3	57.6	75.8	87.6	62
Delta – Southeast	Mod/Mod	0.0	0.0	0.0	0.5	0.2	8.3	83
Delta – Southeast	Mod/High	0.7	5.6	10.7	14.7	18.5	101.5	70
Delta – Southeast	High/High	21.4	30.0	37.7	39.3	49.0	62.1	62
Florida – Southeast	Mod/Mod	0.0	0.0	0.0	0.9	1.9	5.5	83
Florida – Southeast	Mod/High	0.0	2.5	7.2	8.3	13.2	29.8	70
Florida – Southeast	High/High	3.9	9.3	12.9	15.2	21.6	26.1	62
Mid-Atlantic – Midwest	Mod/Mod	0.0	1.2	2.7	4.1	5.8	20.7	83
Mid-Atlantic – Midwest	Mod/High	0.0	12.8	21.9	30.5	38.2	134.0	70
Mid-Atlantic – Midwest	High/High	25.4	108.9	119.3	132.9	166.2	188.1	62
Mid-Atlantic – New York	Mod/Mod	0.0	0.0	0.8	2.2	3.9	9.5	83
Mid-Atlantic – New York	Mod/High	0.5	3.7	14.8	24.6	44.1	86.1	70
Mid-Atlantic – New York	High/High	4.3	10.2	12.7	13.4	15.7	69.4	62
Mid-Atlantic – Southeast	Mod/Mod	0.0	0.3	1.5	2.0	3.2	8.8	83
Mid-Atlantic – Southeast	Mod/High	0.0	7.5	12.5	17.6	25.8	85.1	70
Mid-Atlantic – Southeast	High/High	7.3	11.2	12.2	13.6	13.1	100.0	62
Midwest – Plains	Mod/Mod	0.0	1.5	3.6	5.4	8.0	16.2	83
Midwest – Plains	Mod/High	0.6	17.5	23.0	29.5	33.7	118.9	70
Midwest – Plains	High/High	67.4	83.2	98.7	120.9	166.4	191.1	62
Midwest – Southeast	Mod/Mod	0.0	0.0	0.0	0.8	1.6	5.4	83
Midwest – Southeast	Mod/High	0.0	4.0	6.2	8.6	8.7	47.2	70
Midwest – Southeast	High/High	0.0	33.3	39.9	45.0	58.1	75.6	62
New England – New York	Mod/Mod	0.2	1.8	2.9	2.9	4.1	6.6	83
New England – New York	Mod/High	1.9	6.4	11.4	11.2	15.8	27.2	70
New England – New York	High/High	12.6	18.3	21.4	21.0	23.2	28.6	62

Note: Values shown to nearest tenth.

International Transfer Capacity

The *North American Renewable Integration Study* (Brinkman et al. 2021) calculated international transfers between the United States and Canada or Mexico. Scenarios with international transfers fell exclusively into the Moderate/Moderate scenario group. Given that only a single study considered international transfers and only with scenarios that fell into a single scenario group, results were not included in the Needs Study, but are shown here for completeness.

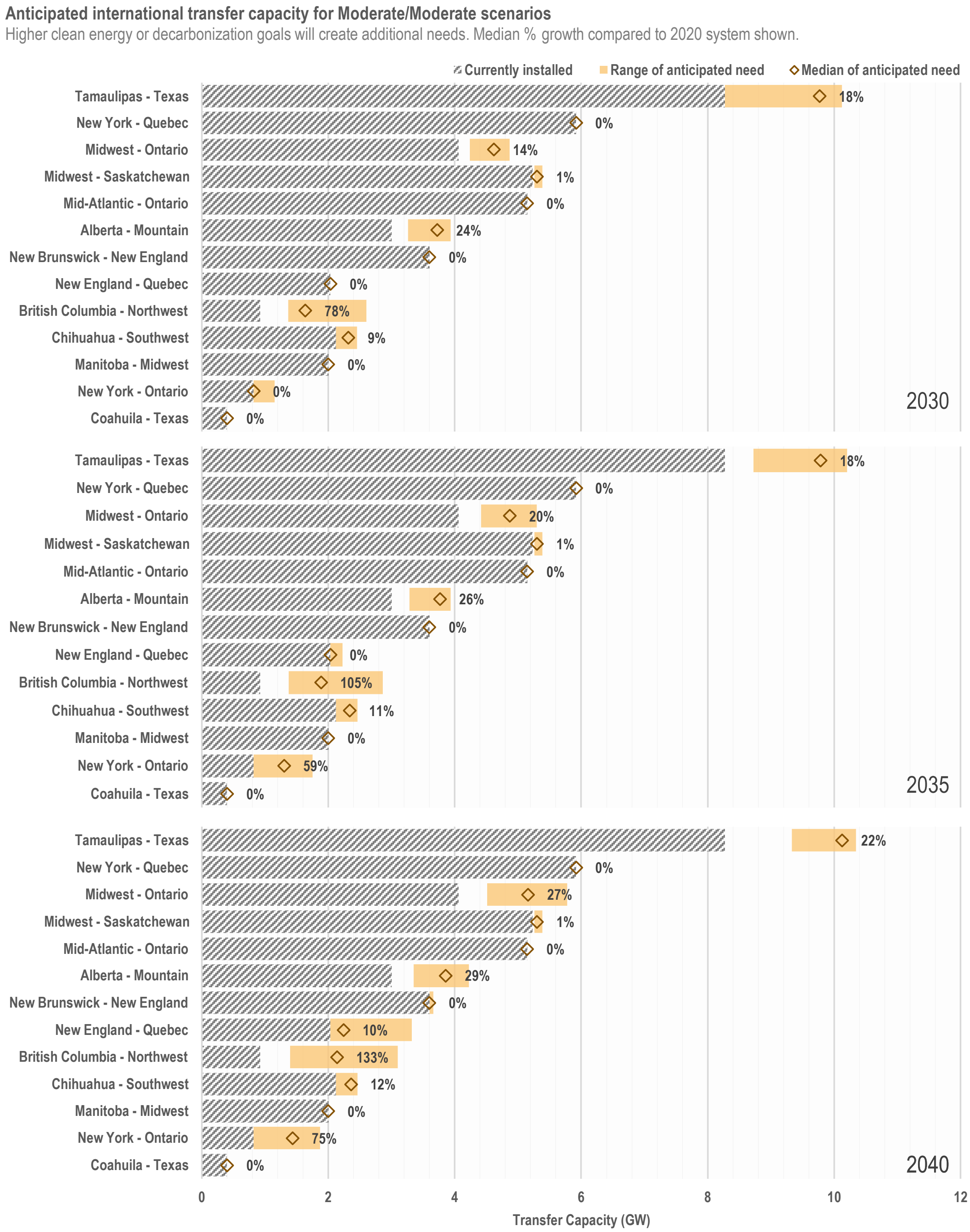
A summary of the modeled transfer capacities across international borders in future years is shown in Figure S-18. The statistical results are provided in Table S-13 through Table S-15 below, in which the minimum, 25th percentile, median, mean, 75th percentile, and maximum values are listed for 2030, 2035, and 2040, respectively.

Scenarios that modeled international transfer results shown in this section assumed only moderate load and moderate clean energy growth by 2040, comparable with the interregional transfers of the Moderate/Moderate scenario group in the Needs Study. Consistent with these results, international transfers are expected to increase above that shown here, given clean energy and load growth enabled by currently enacted policies, including both the Infrastructure Investment and Jobs Act of 2021 and the Inflation Reduction Act of 2022.

In general, the range of international transfer capacities is about half the range of anticipated domestic interregional transfers resulting from moderate clean energy and moderate load growth (Needs Study Figure VI-8 and Table S-11). The greatest increase in international transfers is between Texas and Tamaulipas, Mexico (a median value of 1.9 GW) in 2040 (median), more than the median transfer between Texas and the Plains in 2040 (1.4 GW). Other significant international transfers are between those regions that share a border with Canada. The Northwest, Mountain, and Midwest regions show transfer capacities of approximately 1 GW (2035 median) with their Canadian provisional neighbors.

Appreciable international transfer capacities between Canada and New York and New England do not arise until 2040 in Brinkman et al. (2021). For comparison, an anticipated 1.8 to 4.1 GW of new transfer capacity is modeled between New England and New York in 2040 in the analogous Moderate/Moderate scenario group. The domestic interregional transfer results include scenarios from the studies that did not consider growth in international transfers, putting increased reliance on domestic transfers between regions that cannot otherwise share with their international neighbors given model assumptions. That domestic interregional transfers might decrease commensurate with increased international transfers for a particular region is a reasonable expectation, all other resource operating characteristics on balance.

Several external studies considered the need for increased imports from Canada into the New England region given higher decarbonization scenarios than those considered in Brinkman et al. (2021). Dimanchev et al. (2020) found increased imports of hydropower into New England from neighboring Québec would complement, rather than substitute, deploying low-carbon technologies in the United States. Jones et al. (2020) similarly identify Canadian hydropower as an essential element of regional energy balancing in New England. The study estimates that an additional 4.1 to 7.1 GW of capacity between Québec and New England would be required to meet existing state clean energy targets.



Note: New transfer capacity relative to the 2020 system is shown for 2030 (top), 2035 (middle), and 2040 (bottom). Currently installed and the anticipated future median and interquartile range transfer capacity results for all scenarios from Brinkman et al. (2021).

Figure S-18. International transfer capacity for all Brinkman et al. (2021) scenarios, which fell exclusively into the Moderate/Moderate scenario group.

Table S-13. International transfer capacity (GW) results from all capacity expansion studies in 2030. Minimum (Min), 25th percentile (Q1), median, mean, 75th percentile (Q3), maximum (Max), and sample size (n) values shown.

Regional Pair	Scenario Group	Min	Q1	Median	Mean	Q3	Max	n
Alberta – Mountain	Mod/Mod	0.0	0.3	0.7	0.7	0.9	1.7	48
British Columbia – Northwest	Mod/Mod	0.0	0.4	0.7	1.0	1.7	3.3	48
Chihuahua – Southwest	Mod/Mod	0.0	0.0	0.2	0.2	0.3	1.0	48
Coahuila – Texas	Mod/Mod	0.0	0.0	0.0	0.0	0.0	0.0	48
Manitoba – Midwest	Mod/Mod	0.0	0.0	0.0	0.0	0.0	0.1	48
Mid-Atlantic – Ontario	Mod/Mod	0.0	0.0	0.0	0.1	0.0	1.5	48
Midwest – Ontario	Mod/Mod	0.0	0.2	0.6	0.6	0.8	2.5	48
Midwest – Saskatchewan	Mod/Mod	0.0	0.0	0.1	0.1	0.2	0.7	48
New Brunswick – New England	Mod/Mod	0.0	0.0	0.0	0.0	0.0	0.4	48
New England – Québec	Mod/Mod	0.0	0.0	0.0	0.1	0.0	2.2	48
New York – Ontario	Mod/Mod	0.0	0.0	0.0	0.2	0.3	1.2	48
New York – Québec	Mod/Mod	0.0	0.0	0.0	0.1	0.0	1.0	48
Tamaulipas – Texas	Mod/Mod	0.0	0.0	1.5	1.2	1.9	2.1	48

Note: Values rounded to nearest tenth.

Table S-14. International transfer capacity (GW) results from all capacity expansion studies in 2035. Minimum (Min), 25th percentile (Q1), median, mean, 75th percentile (Q3), maximum (Max), and sample size (n) values shown.

Regional Pair	Scenario Group	Min	Q1	Median	Mean	Q3	Max	n
Alberta – Mountain	Mod/Mod	0.0	0.3	0.8	0.8	0.9	2.9	48
British Columbia – Northwest	Mod/Mod	0.0	0.5	1.0	1.2	1.9	4.0	48
Chihuahua – Southwest	Mod/Mod	0.0	0.0	0.2	0.3	0.3	1.0	48
Coahuila – Texas	Mod/Mod	0.0	0.0	0.0	0.0	0.0	0.0	48
Manitoba – Midwest	Mod/Mod	0.0	0.0	0.0	0.0	0.0	0.1	48
Mid-Atlantic – Ontario	Mod/Mod	0.0	0.0	0.0	0.1	0.0	1.5	48
Midwest – Ontario	Mod/Mod	0.0	0.4	0.8	0.9	1.2	2.5	48
Midwest – Saskatchewan	Mod/Mod	0.0	0.0	0.1	0.2	0.2	1.0	48
New Brunswick – New England	Mod/Mod	0.0	0.0	0.0	0.0	0.0	0.5	48
New England – Québec	Mod/Mod	0.0	0.0	0.0	0.3	0.2	2.2	48
New York – Ontario	Mod/Mod	0.0	0.0	0.5	0.5	0.9	1.7	48
New York – Québec	Mod/Mod	0.0	0.0	0.0	0.1	0.0	1.0	48
Tamaulipas – Texas	Mod/Mod	0.0	0.5	1.5	1.3	1.9	3.3	48

Note: Values rounded to nearest tenth.

Table S-15. International transfer capacity (GW) results from all capacity expansion studies in 2040. Minimum (Min), 25th percentile (Q1), median, mean, 75th percentile (Q3), maximum (Max), and sample size (n) values shown.

Regional Pair	Scenario Group	Min	Q1	Median	Mean	Q3	Max	n
Alberta – Mountain	Mod/Mod	0.0	0.4	0.9	0.9	1.2	3.2	48
British Columbia – Northwest	Mod/Mod	0.0	0.5	1.2	1.4	2.2	4.0	48
Chihuahua – Southwest	Mod/Mod	0.0	0.0	0.2	0.3	0.3	1.0	48
Coahuila – Texas	Mod/Mod	0.0	0.0	0.0	0.0	0.0	0.1	48
Manitoba – Midwest	Mod/Mod	0.0	0.0	0.0	0.0	0.0	0.1	48
Mid-Atlantic – Ontario	Mod/Mod	0.0	0.0	0.0	0.1	0.0	1.5	48
Midwest – Ontario	Mod/Mod	0.0	0.5	1.1	1.1	1.7	2.6	48
Midwest – Saskatchewan	Mod/Mod	0.0	0.0	0.1	0.2	0.2	1.3	48
New Brunswick – New England	Mod/Mod	0.0	0.0	0.0	0.1	0.1	0.7	48
New England – Québec	Mod/Mod	0.0	0.0	0.2	0.7	1.3	2.2	48
New York – Ontario	Mod/Mod	0.0	0.0	0.6	0.6	1.1	2.5	48
New York – Québec	Mod/Mod	0.0	0.0	0.0	0.2	0.0	1.0	48
Tamaulipas – Texas	Mod/Mod	0.0	1.1	1.9	1.6	2.1	4.1	48

Note: Values rounded to nearest tenth.

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