U.S. DEPARTMENT OF ENERGY

National Transmission Needs Study: Supplemental Material

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United States Department of Energy
Washington, DC 20585

Executive Summary

This material supplements the United States Department of Energy's 2022 National Transmission Needs Study (Needs Study) Consultation Draft. 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.

National Transmission Planning Study: Supplemental Material

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Section IV. Historical Data: Current Need

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 Independent System Operator (ISO) regions, in some cases called Regional Transmission Organizations (RTOs). Hereafter, we will refer to these regions as ISOs as the differences between ISOs and RTOs are not critical for this analysis. The seven major 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 ISO, and we purchased records of these prices from a commercial vendor, the product is called Velocity Suite, by Hitachi.

Section IV.b.1 Regional Price Differentials

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

For the analysis shown in *Needs Study* Figure IV-4 (page 24), the average annual price at each node in each ISO region was calculated based on averaging the hourly prices across a full year of data. We then found, for each 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 VI-5 (page 26), the 5th and 95th percentile price is calculated across all the hours in a particular year for each node. Across all nodes in an ISO, the nodal 5th and 95th percentile values are averaged to find an average 5th and 95th percentile value for the ISO. Nodes are then identified as 'high-priced' if their 95th percentile price is greater than 1 standard deviation above the 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 ISO average 5th percentile value. Each node is evaluated for each year from 2017 – 2021, and the number of times it is identified as high or low priced is summed over that time period. The results displayed in *Needs Study* Figure VI-5 (page 26) only displays nodes if they have been identified as higher or low for at least two 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, we have created three regions, one incorporating all ISOs/RTOs in the Eastern Interconnect (SPP, MISO, PJM, NYISO, ISO-NE), one incorporating CAISO and the rest of the Western Energy Imbalance Market, and ERCOT.

We provide additional context to the data presented in the *Needs Study* by examining how prices vary across each ISO/RTO within the region. ***Figure S-1*** and ***Table S-1*** show the 2017 – 2021 average 5th, 50th, and 95th percentile hourly prices across all nodes in each ISO/RTO and for the combined Eastern Interconnect. 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. 95th percentile prices range from $52/MWh to $85/MWh, and 5th percentile prices range from -$6/MWh to $16/MWh. Notable differences between the ISOs are the negative prices found in SPP, and the large standard deviation, relative to other 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-ISO congestion because congestion is what drives the *geographic spread* in 95th or 5th percentile prices—which is captured by the standard deviation. Congestion is not the sole driver of high to low range in prices (i.e., the difference between 5th percentile and 95th percentile prices), however, because these differences are also greatly impacted by trends over time that impact the entire region (not just geography) such as daily load changes, which may be driven by fuel price variations, large swings in load, and other factors.

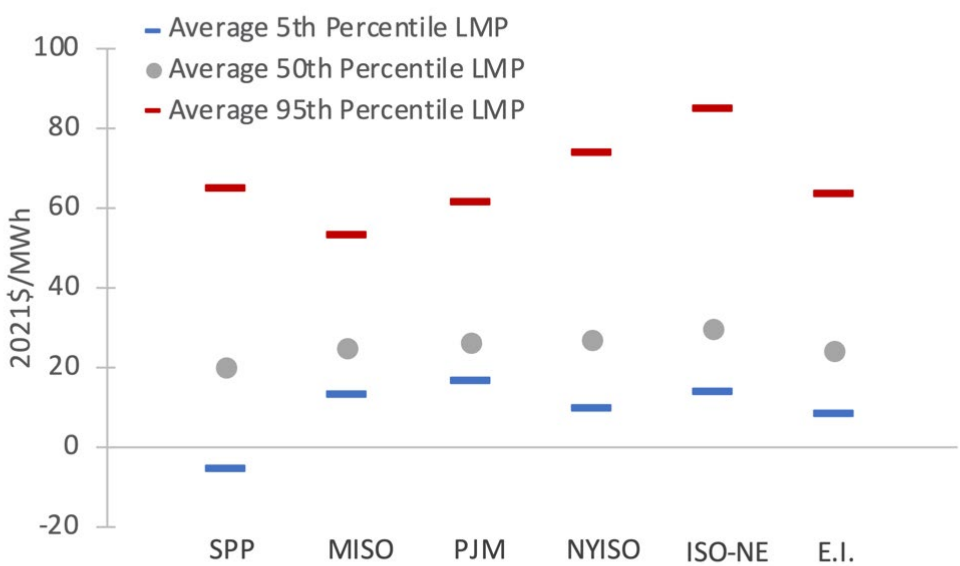


Figure S-1. Median, 5th, and 9th percentile hourly prices, averaged across nodes within each ISO/RTO in the Eastern Interconnect, and across the Eastern Interconnect as treated as a single region. Values shown represent the average of independently calculated values for each year from 2017 through 2021.

Table S-1. 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

Section IV.b.2. Interregional Price Differences

Interregional transmission value

The analysis shown in *Needs Study* Figure VI-6 (page 28) is limited to exploring differences in energy value and does not provide a comprehensive estimate of the value of transmission. For example, the value we calculate here does not include value within the capacity markets, the value of facilitating emission reductions, or the value of enhanced grid resiliency. Still this analysis provides a description of an important, if not complete, 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 ISO region (often more than one hub node is chosen for each region to represent differences within the region). Neighboring selected nodes (each in a different region) 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 for a leap year, or in the 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 with two steps. First, the average annual price is calculated for each ISO (CAISO and the West are treated as a single region) as the simple average of all hourly prices across all nodes within each ISO. Second, the national average is calculated by taking the flat average across the seven ISO-level annual average prices.

Section VI. Capacity Expansion Modeling: Anticipated Future Need

Section VI.a. Included Studies and Scenarios

North American Renewable Integration Study (NREL)

The *North American Renewable Integration Study* (NARIS) is an NREL study which 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 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 involved varying one assumption at a time. The four core scenarios include a business-as-usual case, a scenario which assumes low-cost variable generation, a scenario which intentionally reduces CO_2 emissions in the United States to 80% of 2005 levels by 2050, and a scenario which electrifies end-use loads such that total electricity demand in 2050 is double 2020 demand. The results shows 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 (NREL)

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 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 which assumes no carbon policies beyond those in place as of June 2021, one which assumes national power sector CO_2 emissions decreases linearly to 95% below 2005 emissions by 2050, and finally one which 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 (NREL)

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 non-renewable 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 non-renewable (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 which follows expected trend of solar and renewable energy deployment, one which focuses on fully decarbonizing the transmission grid by 2050, and one which 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, *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* scenarios included high levels of distributed, rooftop solar adoption, reaching levels of over 227 TWh by 2040, an eight-fold increase compared to 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 to other scenarios used in this analysis.

Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035 (NREL)

The *Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035* (referred to hereafter as simply the "100% by 2035 study") is the most recent study considered here (Denholm, et al. 2022). 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[1]. 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 three-fold increase in electricity demand. The *100% by 2035* study is the only NREL study which 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 which assumes all clean electricity technologies see improved performance and cost reductions in line with current projections, a scenario which assumes improved transmission technologies and siting processes lead to increased transmission deployment, a scenario which assumes local and regional opposition to generation and transmission solutions limit deployment, and a scenario which 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 while 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 one hundred additional sensitives were analyzed to capture future uncertainties related to technology cost, performance, and availability.

Net Zero America (Princeton University)

Princeton University's *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 & 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 used both capacity expansion and economic impact modeling for the study. The study utilized 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 utilized the Regional Investment and Operations (RIO) supply-side cost minimization model to identify lowest-cost (30-year societal NPV) mix of

[1] *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.

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 contiguous U.S.) 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 considered 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 limited 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 carried out 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.

The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System (Massachusetts Institute of Technology)

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 inter-state transmission expansion, while four scenarios allow for new inter-state transmission expansion between states within regional planning areas and/or between synchronous or asynchronous planning areas. The research concludes that inter-state coordination and transmission expansion reduce electricity costs by 46% relative to a state-by-state approach.

The authors utilized 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 conducted a sensitivity analysis across 48 different cases to account for uncertain future technology costs and demand levels. They found that a reduction in photovoltaic solar, wind, and lithium-ion battery costs led to the lowest system cost of electricity under the transmission expansion scenario, while nuclear power or long-duration energy storage cost reductions led to greater electricity cost reductions for isolated systems.

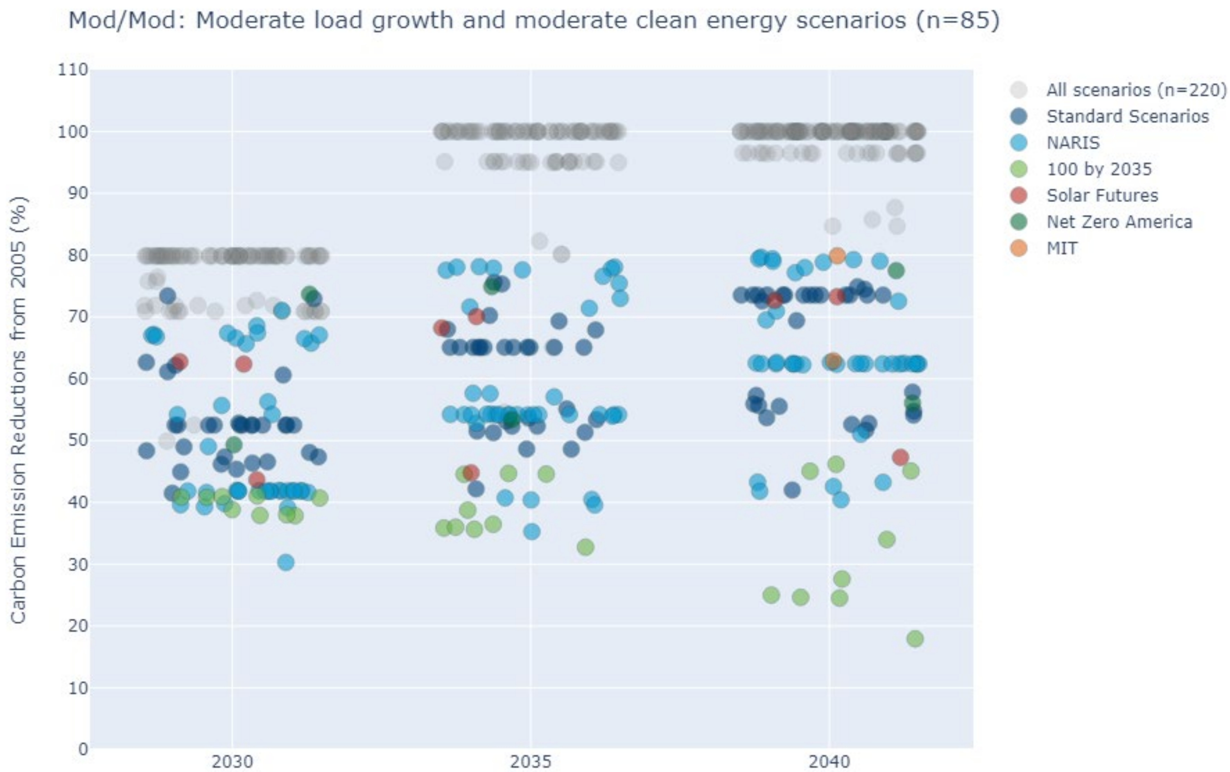
Scenario characteristics: Carbon emission reductions

The anticipated power sector carbon dioxide emission reductions from 2005 levels **Invalid source specified.** given various electrification levels achieved by scenarios considered in this analysis are shown in ***Figure S-2*** for years 2030, 2035 and 2040. Power sector emission 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—where most scenarios from the *100% by 2035* study reach full decarbonization—and by 2040 more than half of the scenarios have reached at least 90% reduction in carbon emissions compared to 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 emission reductions for scenarios in each scenario group are shown in ***Figure S-3*** through ***Figure S-5*** 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 emission reductions by 2035, with many more reaching that level by 2040. The final scenario group—High/High—have the most power sector carbon emission reductions.

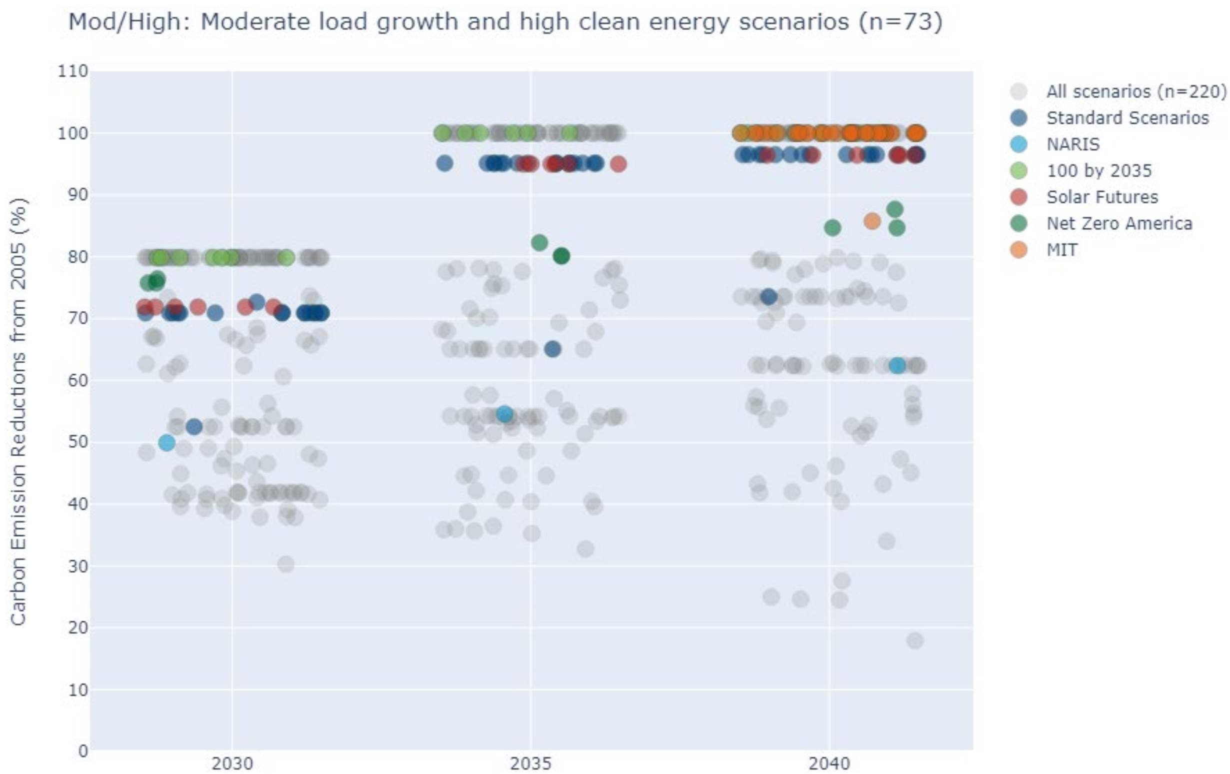
Note: A single point represents the emission reductions from 2005 levels for a single scenario in that year. The color of the datapoint indicates the associated study.

Figure S-2. Carbon dioxide emission reductions for the 220 scenarios considered in this analysis in 2030, 2035, and 2040.



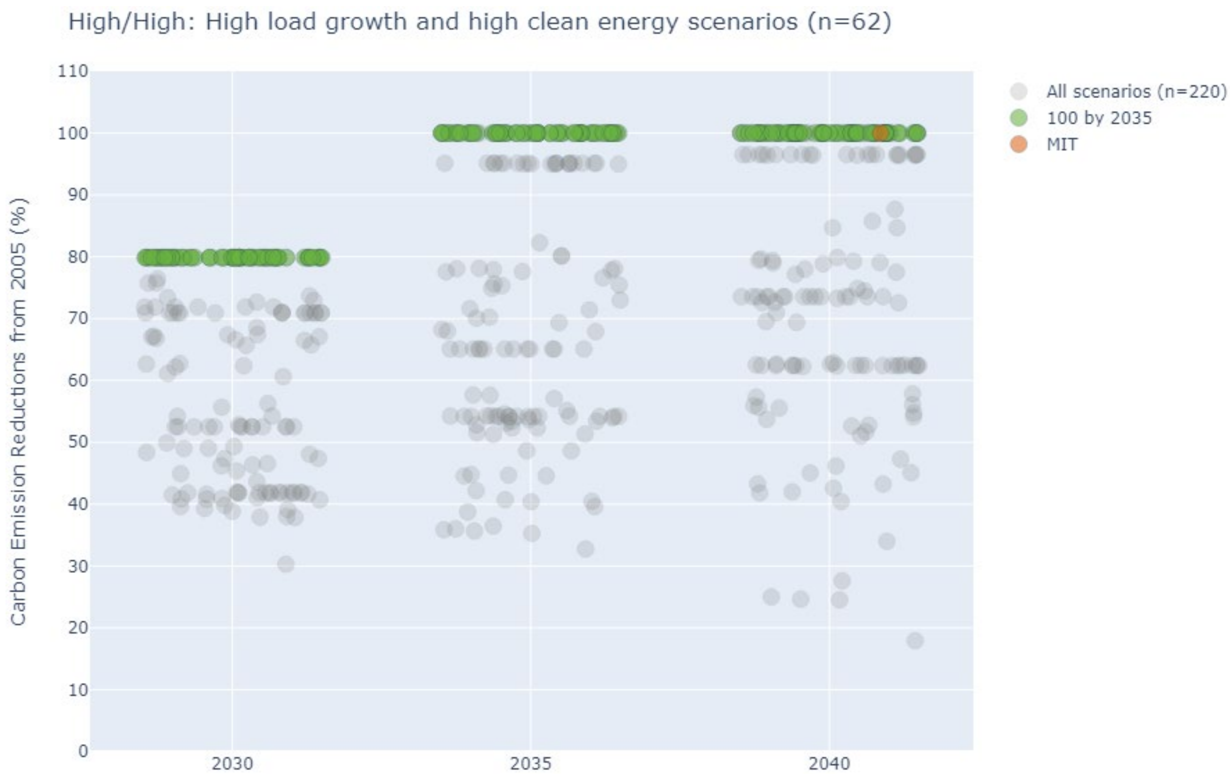
Note: A single point represents the emission reductions from 2005 levels for a single scenario in that year. The color of the datapoint indicates the associated study.

Figure S-3. Carbon emissions reductions for Moderate/Moderate scenarios in 2030, 2035, and 2040. Grey datapoints are scenarios associated with other groups.



Note: A single point represents the emission reductions from 2005 levels for a single scenario in that year. The color of the datapoint indicates the associated study.

Figure S-4. Carbon emissions reductions for Moderate/High scenarios in 2030, 2035, and 2040. Grey datapoints are scenarios associated with other groups.



Note: A single point represents the emission reductions from 2005 levels for a single scenario in that year. The color of the datapoint indicates the associated study.

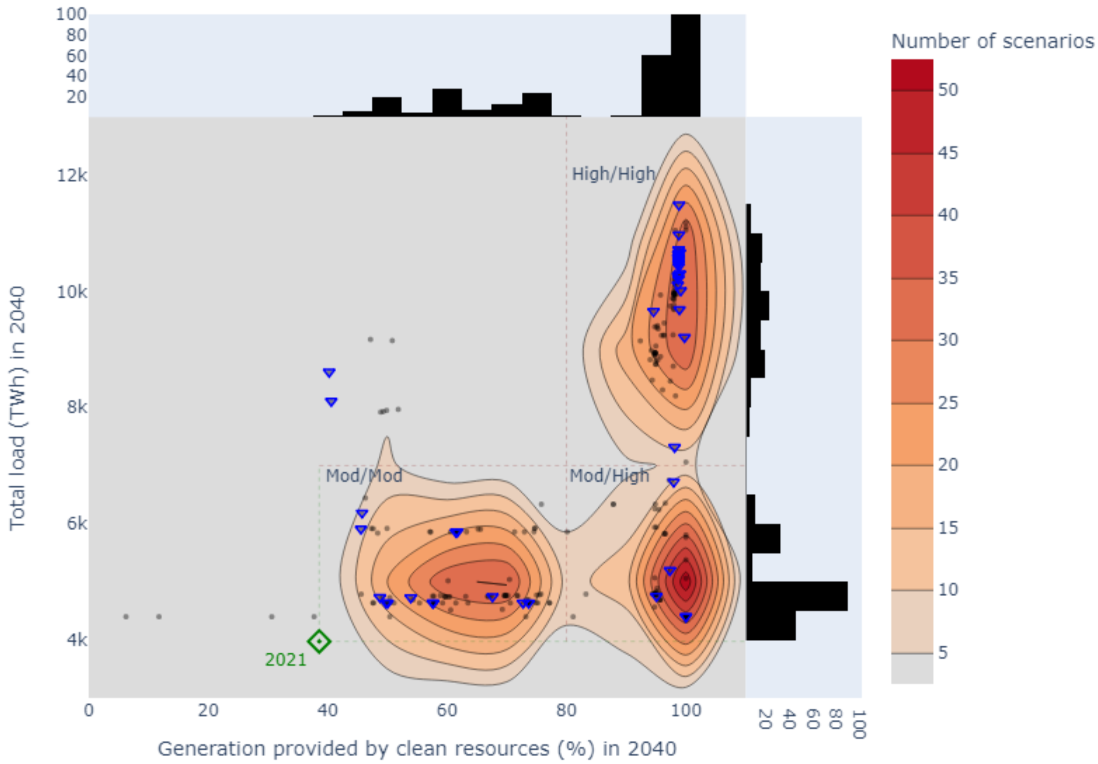
Figure S-5. Carbon emissions reductions for High/High scenarios in 2030, 2035, and 2040. Grey datapoints are scenarios associated with other groups.

Scenario characteristics: Excluded scenarios

Scenarios which artificially disallowed new transmission builds are excluded from this analysis. These are the "no cross-border expansion" sensitivities from *NARIS*, "low transmission availability" scenarios from *Standard Scenarios*, "constrained siting" core scenarios from *100% by 2035*, and the "no existing transmission" and "no new ac or dc" scenarios from the MIT studies. Scenarios which increase hurdle rates or transmission costs but do allow the model to build new transmission if found to be cost effective (e.g., "uncoordinated" sensitivity from *NARIS*) are included in this analysis. Scenarios which artificially constrained are found in ***Figure S-7***.

Percentage of clean energy resources of total annual generation shown in ***Figure S-6*** and ***Figure S-7*** (and *Needs Study* Figure VI-1, page 74) are determined from the sum of distributed solar photovoltaic systems, utility-scale solar photovoltaic systems, concentrating solar power, land-based wind, offshore wind, hydropower, geothermal, biomass, hydrogen production, nuclear power, landfill gas, and any fossil fuel resources paired with carbon capture and storage technologies. This aligns with the calculation of 2021 clean energy penetration from EIA's *2022*

Annual Energy Outlook (EIA 2022), which does not include carbon capture technologies. Fossil fuel generation paired with carbon capture technologies does contribute to overall system carbon emissions reductions of the scenarios, shown elsewhere in the study.



Note: Histogram (black bars along x- and y-axes) and contour (red topographical lines in center plot) axes are shown counts of scenarios. Diamond indicates 2021 levels (EIA 2022)*. Down triangles indicate scenarios which artificially constrain transmission builds. Thresholds separating the three scenario groups are shown as dashed lines, and each scenario group is labeled.*

Figure S-6. Histograms and contour plot for all study scenarios describing the amount of clean energy generation (in percent of total annual generation) and the total annual load in 2040.

Modeling Transmission

All capacity expansion models used in these studies have a different means of modeling the transmission system. All three models calculate the distance and transfer capacity needed for transmission spur lines to connect new generators to the existing network. Both the Brown & Botterud and the *Net Zero America* models 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 (Ho, et al. 2021). Both the MIT and NREL models build new interregional transmission lines that are necessary to move power from one region to another (Brown and Botterud 2020) (Pascale and Jenkins 2021).

NREL's ReEDS model considers the length of representative transmission routes between the centers of modeling zones and applies this mileage to any new transfer capacity calculated by the model. For example, if ReEDS calculates that 10 GW of new transfer capacity between modeling zones A and B will be needed in year 2040 and the representative transmission route connecting the centers of the two regions is 60 miles long, then the resulting new transmission need in 2040 will be 600 GW-mi. The *NARIS* study used straight-line routes between modeling zones centroids, while the other ReEDS studies used 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 here on recommendation of the authors (Brinkman 2021). See (Ho, et al. 2021) for more details.

The MIT model builds within region network upgrades as the shortest distance line between existing substations (at least 230kV) 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 2020) for more details.

The *Net Zero America* model 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 161kV and (2) from that substation along an existing right of way 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 *Net Zero America* 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 rights of way 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 rights of way. 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 modelling methods used in the *Net Zero America* study have been iteratively improved in The Nature Conservancy's Power of Place West project (Wu 2021), the Princeton Zero Lab's REPEAT project (J. D. Jenkins 2021) (Jenkins, et al. 2022), and the ongoing Net-Zero Australia project (The University of Queensland School of Chemical Engineering 2021).

Interregional results presented in the *Needs Study* were calculated as the sum of all transfer 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.

Modeling Regions

The regions used in this analysis are named in ***Table S-2*** and shown in ***Figure S-8***. Regions were chosen based on the geographic resolution of data available for each of the six studies used in this analysis. The regions roughly match the transmission planning and reliability assessment regions (National American Electric Reliability Corporation 2021). Regional data from the four NREL studies were aggregated from the ReEDS modeling zones, shown as light gray outlines in ***Figure S-8*** (left). Regional data from the Brown & Botterud and *Net Zero America* studies were aggregated from state boundaries, shown as light gray outlines in ***Figure S-8*** (right). The results from these two studies thus have a coarser resolution than what is used by NREL.

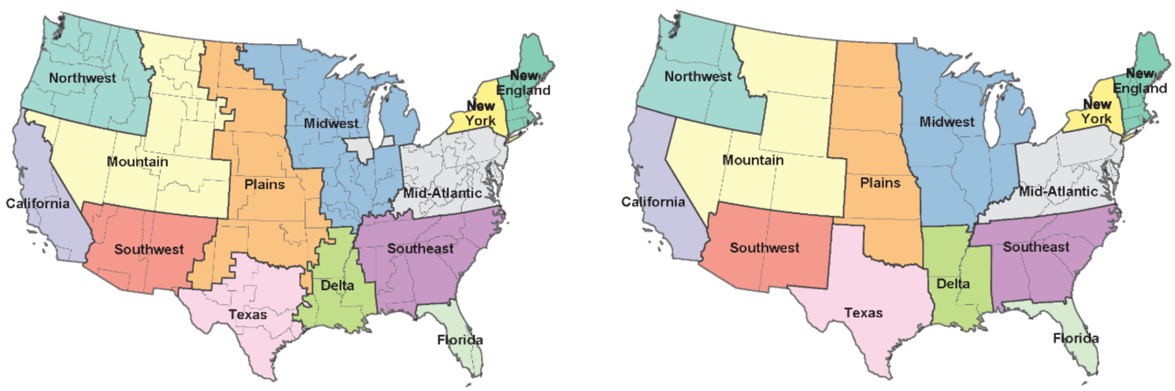


Figure S-7. Geographic regions used to present study results in this analysis. (left) NREL ReEDS modeling zone boundaries shown underlying larger analysis regions. All four NREL studies had this level of granularity. (right) State boundaries underlying larger analysis regions. The Brown & Botterud and Princeton studies had state-level granularity.

Table S-2. Region names used throughout this report. The dominant regional transmission entities that serve operations, planning, and reliability functions in each geographic region are also presented.

Geographic Region	RTO/ISO	Transmission Planning	Reliability Assessment
California	CAISO	CAISO	WECC: CA / MX
Northwest		Northern Grid	WECC: NWPP & RMRG
Mountain		Northern Grid & WestConnect	WECC: NWPP & RMRG
Southwest		WestConnect	WECC: SRSG
Texas	ERCOT	ERCOT	Texas RE: ERCOT
Plains	SPP	SPP	SPP
Midwest	MISO	MISO	MISO
Delta	MISO	MISO	MISO
Southeast		SERTP & SCRTP	SERC: Central, East & Southeast
Florida		FRCC	SERC: Florida Peninsula
Mid-Atlantic	PJM	PJM	PJM
New York	NYISO	NYISO	NPCC: New York
New England	ISO-NE	ISO-NE	NPCC: New England

Source: Transmission planning regions from FERC at https://www.ferc.gov/media/regions-map-printable-version-order-no-1000 and reliability assessment region names from NERC at https://www.nerc.com/pa/RAPA/ra/Reliability Assessments DL/NERC_LTRA_2021.pdf.

Note: RMRG participants joined the NWPP in 2019 and later renamed to the Western Power Pool (WPP). The abbreviations in this table reflect those used by NERC data through 2020.

Section VI.b. Within Region Transmission Deployment

Median results for aggregated regional transmission deployment were presented in Table VI-2 (page 75) in the *Needs Study* by scenario group for years 2030, 2035, and 2040. Figure VI-2 through Figure VI-5 (pages 78-81) of the *Needs Study* additionally showed the interquartile range of regional transmission deployment for each scenario group and year. A more complete look at the statistical results is provided in the tables below, where the minimum, 25th percentile, median, mean, 75th percentile, and maximum values are listed. ***Table S-3*** provides the statistical results for 2030, ***Table S-4*** for 2035, and ***Table S-5*** for 2040.

Table S-3. Regional transmission deployment (GW-mi) results from all capacity expansion studies in 2030. Minimum, 25th percentile (Q1), median, mean, 75th percentile (Q3), maximum, and sample size (n) shown for each region and scenario group.

Region	Scenario Group	Min	Q1	Median	Mean	Q3	Max	n
California	Mod/Mod	3.8	34.5	62.4	102.8	100.6	1,548.0	44
	Mod/High	0.3	37.5	88.7	238.4	117.4	2,338.9	33
	High/High	0.2	37.8	47.4	64.6	82.5	280.9	61
Mountain	Mod/Mod	37.3	919.6	1,462.5	1,494.6	1,662.1	11,552.3	44
	Mod/High	339.3	1,413.0	2,278.3	3,453.7	2,577.5	25,236.5	33
	High/High	2,583.6	2,948.1	3,117.7	3,232.1	3,503.7	4,337.8	61
Northwest	Mod/Mod	0.4	1.3	33.0	230.1	37.5	8,016.5	44
	Mod/High	0.7	39.0	66.1	788.0	107.7	10,368.3	33
	High/High	132.7	367.0	618.9	598.4	800.3	1,106.0	61
Southwest	Mod/Mod	14.8	324.7	414.5	721.3	485.2	9,886.4	44
	Mod/High	529.4	727.5	934.7	2,208.7	2,049.3	15,539.2	33
	High/High	2,035.4	2,569.8	2,755.0	2,882.1	3,202.0	4,533.4	61
Texas	Mod/Mod	218.9	1,720.8	2,779.3	3,231.1	3,501.3	11,191.4	44
	Mod/High	1,616.3	4,021.7	6,038.4	6,505.6	6,596.2	22,533.3	33
	High/High	1,590.3	2,670.1	3,332.4	3,633.2	4,751.0	6,037.9	61
Delta	Mod/Mod	0.0	0.0	8.2	249.9	95.1	5,090.5	44
	Mod/High	5.8	70.8	387.0	959.0	1,574.7	4,320.2	33
	High/High	2,030.0	2,525.8	2,978.9	3,206.2	3,935.3	4,583.3	61
Florida	Mod/Mod	0.0	0.0	0.0	65.0	0.0	978.1	44
	Mod/High	0.0	0.0	63.0	464.5	339.6	4,004.9	33
	High/High	0.0	1.6	8.7	24.9	25.0	317.9	61
Mid-Atlantic	Mod/Mod	126.9	394.9	564.4	626.4	743.2	1,860.8	44
	Mod/High	208.5	627.4	1,094.8	2,059.1	1,361.0	16,254.7	33
	High/High	1,314.5	1,857.8	2,489.2	2,460.0	3,021.9	3,697.7	61
Midwest	Mod/Mod	459.5	893.6	1,133.4	1,881.3	1,495.6	13,206.3	44
	Mod/High	2,209.7	3,297.2	3,714.8	6,268.5	4,221.1	36,404.6	33
	High/High	6,455.7	7,369.3	7,727.2	8,149.1	8,847.7	13,661.3	61
New England	Mod/Mod	13.6	15.2	16.9	76.2	79.6	766.4	44
	Mod/High	16.2	20.9	48.9	215.6	291.2	1,607.1	33
	High/High	237.3	331.2	367.0	485.6	677.6	1,154.3	61

Region	Scenario Group	Min	Q1	Median	Mean	Q3	Max	n
New York	Mod/Mod	0.0	0.0	0.0	47.7	0.8	962.0	44
	Mod/High	0.0	0.0	0.0	201.3	53.7	2,548.3	33
	High/High	0.0	68.6	101.8	98.7	119.9	251.4	61
Plains	Mod/Mod	630.3	1,141.6	1,561.9	1,979.9	2,321.1	8,656.3	44
	Mod/High	2,231.1	3,060.8	3,520.3	5,391.6	4,615.5	22,665.8	33
	High/High	3,678.3	5,456.1	6,881.4	10,569.7	16,143.3	22,512.3	61
Southeast	Mod/Mod	0.8	328.7	552.9	808.0	1,092.1	4,379.3	44
	Mod/High	8.8	2,262.0	2,827.9	3,105.3	3,558.6	8,991.1	33
	High/High	1,099.9	2,284.0	2,678.5	2,769.7	3,373.3	4,284.0	61

Table S-4. 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
California	Mod/Mod	4.2	38.1	69.1	132.5	106.2	2,502.1	44
	Mod/High	6.9	91.4	120.0	471.7	208.0	4,597.4	33
	High/High	10.6	115.0	159.9	175.9	232.2	636.4	61
Mountain	Mod/Mod	90.6	1,109.9	1,664.8	2,041.9	1,898.1	21,663.1	44
	Mod/High	937.5	2,522.0	3,143.1	6,073.5	4,457.8	50,671.4	33
	High/High	3,318.2	4,973.3	6,000.2	6,872.2	8,967.7	12,321.9	61
Northwest	Mod/Mod	0.4	16.2	38.9	429.9	72.2	12,670.3	44
	Mod/High	65.0	333.5	535.1	1,837.6	930.1	14,749.7	33
	High/High	961.0	3,554.8	4,708.2	4,514.2	5,251.5	8,982.6	61
Southwest	Mod/Mod	94.8	517.4	633.5	1,057.9	760.5	13,417.8	44
	Mod/High	754.0	1,453.7	1,865.8	3,517.4	2,879.4	20,542.8	33
	High/High	2,635.4	5,920.9	6,691.3	6,797.2	8,166.5	9,923.7	61
Texas	Mod/Mod	585.5	2,762.4	4,350.9	4,879.9	6,534.7	15,181.1	44
	Mod/High	2,881.6	6,767.4	8,998.7	9,973.7	9,441.0	35,173.4	33
	High/High	3,890.4	6,187.5	7,274.1	7,653.6	9,558.0	10,729.2	61

Region	Scenario Group	Min	Q1	Median	Mean	Q3	Max	n
Delta	Mod/Mod	0.0	41.6	152.9	505.0	427.2	7,950.4	44
	Mod/High	580.2	1,356.1	1,652.0	2,806.5	3,910.3	10,692.4	33
	High/High	5,525.8	6,661.2	7,759.7	8,295.7	10,313.4	12,699.9	61
Florida	Mod/Mod	0.0	13.2	80.4	172.2	168.3	1,246.1	44
	Mod/High	94.1	507.5	812.8	1,430.7	2,045.0	7,341.9	33
	High/High	88.1	455.9	725.9	799.5	1,185.1	1,621.0	61
Mid-Atlantic	Mod/Mod	251.4	762.2	955.3	1,074.2	1,251.4	3,026.8	44
	Mod/High	1,275.1	2,652.0	3,280.8	5,158.8	4,618.5	26,334.4	33
	High/High	6,121.2	7,362.4	8,837.5	8,739.9	9,726.1	13,081.5	61
Midwest	Mod/Mod	604.7	1,637.0	2,260.7	3,267.1	3,133.3	20,086.2	44
	Mod/High	4,038.1	10,031.1	13,338.4	15,514.7	14,902.6	60,730.0	33
	High/High	16,590.3	18,967.1	20,695.0	21,867.4	25,368.8	30,729.0	61
New England	Mod/Mod	15.3	17.7	31.3	86.5	99.6	928.5	44
	Mod/High	40.1	66.6	100.4	466.0	646.0	2,994.7	33
	High/High	1,535.8	2,096.5	2,438.5	2,425.2	2,733.2	3,236.5	61
New York	Mod/Mod	0.0	0.0	0.0	97.4	35.6	1,316.1	44
	Mod/High	0.0	0.0	0.0	404.4	347.8	4,625.4	33
	High/High	77.8	337.6	375.6	374.4	411.7	748.8	61
Plains	Mod/Mod	1,298.4	2,285.6	2,933.4	3,356.9	3,765.7	14,308.0	44
	Mod/High	4,671.3	7,339.5	8,316.3	12,127.3	9,905.0	36,885.6	33
	High/High	12,265.1	21,545.2	28,469.6	35,439.8	52,342.3	57,614.5	61
Southeast	Mod/Mod	56.3	656.0	1,088.0	1,730.4	2,642.8	7,040.6	44
	Mod/High	3,915.8	5,386.5	6,822.1	7,214.6	7,985.7	18,460.6	33
	High/High	5,306.7	8,167.4	9,114.5	9,562.6	11,458.3	12,382.1	61

Table S-5. 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
California	Mod/Mod	4.8	46.1	75.2	160.0	113.8	3,316.5	44
	Mod/High	11.2	94.0	122.8	806.1	219.9	9,020.7	33
	High/High	14.4	186.2	231.3	249.7	312.6	729.0	61
Mountain	Mod/Mod	0.0	1,219.6	1,861.2	2,449.8	2,323.3	29,667.2	46
	Mod/High	0.0	520.8	2,879.9	4,857.6	4,103.9	74,844.7	72
	High/High	3,977.9	6,016.6	7,689.9	9,132.8	12,116.4	21,754.0	62
Northwest	Mod/Mod	0.0	49.7	80.2	568.1	142.9	15,625.2	46
	Mod/High	0.0	0.0	0.0	1,422.2	909.0	23,119.7	72
	High/High	201.9	6,589.9	8,543.1	8,501.9	10,646.2	18,182.8	62
Southwest	Mod/Mod	0.0	606.3	777.6	1,229.7	959.3	15,815.0	46
	Mod/High	0.0	34.0	809.3	2,074.9	1,840.2	26,668.1	72
	High/High	776.4	6,545.2	7,635.5	8,159.8	10,296.9	13,162.1	62
Texas	Mod/Mod	636.7	3,273.7	5,680.7	5,871.0	7,511.8	19,229.9	44
	Mod/High	3,173.5	7,775.9	9,596.7	12,061.2	10,220.9	59,672.0	33
	High/High	4,591.8	7,694.7	8,716.2	9,509.9	12,035.1	15,684.0	61
Delta	Mod/Mod	0.0	118.1	404.2	721.6	733.9	10,409.6	46
	Mod/High	0.0	0.0	1,370.4	1,929.2	2,121.0	14,216.9	72
	High/High	135.4	7,125.5	8,793.5	9,305.7	11,627.8	15,670.8	62
Florida	Mod/Mod	0.0	36.7	148.6	374.4	696.5	1,431.2	44
	Mod/High	94.1	636.8	1,043.1	1,766.4	2,208.8	8,444.3	33
	High/High	96.5	591.0	1,036.4	1,218.0	1,822.0	4,237.0	61
Mid-Atlantic	Mod/Mod	266.9	885.2	1,105.1	1,243.6	1,475.0	3,493.0	46
	Mod/High	567.7	2,723.1	3,612.6	4,966.8	4,606.4	45,379.7	72
	High/High	7,149.7	11,210.3	11,691.9	11,685.5	12,220.3	15,143.0	62
Midwest	Mod/Mod	635.4	1,868.7	3,400.1	4,337.9	4,665.9	30,080.8	46
	Mod/High	766.5	13,091.5	16,219.6	17,332.9	17,501.0	105,066.8	72
	High/High	15,471.4	21,553.0	23,395.1	26,630.3	33,704.8	38,772.0	62
New England	Mod/Mod	15.5	31.4	47.0	120.2	146.4	1,068.4	46
	Mod/High	74.2	200.9	2,719.3	2,412.8	4,194.6	7,180.7	72
	High/High	1,889.0	2,696.8	2,977.8	2,955.6	3,100.2	6,143.5	62

Region	Scenario Group	Min	Q1	Median	Mean	Q3	Max	n
New York	Mod/Mod	0.0	0.0	0.0	105.4	0.0	1,525.2	46
	Mod/High	0.0	0.0	61.8	307.4	91.6	7,219.3	72
	High/High	79.9	361.4	411.3	445.4	476.3	1,072.5	62
Plains	Mod/Mod	1,840.2	2,887.2	3,927.5	4,501.4	5,141.6	20,958.2	46
	Mod/High	1.2	3,703.9	6,305.6	9,802.3	11,038.1	63,082.8	72
	High/High	5,473.9	25,932.0	31,264.8	43,826.0	67,020.8	75,629.6	62
Southeast	Mod/Mod	41.6	1,014.3	1,578.7	2,310.1	3,512.7	9,658.7	46
	Mod/High	152.8	5,284.2	6,043.1	7,122.6	8,065.9	32,238.3	72
	High/High	5,481.4	9,895.7	11,457.4	12,492.5	15,463.9	19,580.7	62

Section VI.c. Interregional Transfer Capacity

Median results for aggregated interregional transfer capacities were presented in Table VI-3 (pages 82-84) in the *Needs Study* by scenario group for years 2030, 2035, and 2040. Figure VI-6 through Figure VI-8 (pages 86-88) of the *Needs Study* additionally showed the interquartile range of interregional transfer capacities for each scenario group and year. A more complete look at the statistical results is provided in the tables below, where the minimum, 25th percentile, median, mean, 75th percentile, and maximum values are listed. ***Table S-6*** provides the statistical results for 2030, ***Table S-7*** for 2035, and ***Table S-8*** for 2040.

Table S-6. 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.

Region	Scenario Group	Min	Q1	Median	Mean	Q3	Max	n
California – Mountain	Mod/Mod	0.00	0.06	0.31	0.32	0.50	1.01	81
	Mod/High	0.03	0.37	0.58	0.71	0.98	1.99	31
	High/High	0.39	0.97	1.21	1.22	1.45	2.23	61
California – Northwest	Mod/Mod	0.00	0.00	0.00	0.13	0.00	2.70	81
	Mod/High	0.00	0.00	0.00	0.02	0.01	0.22	31
	High/High	0.00	0.04	0.25	0.24	0.40	0.61	61
California – Southwest	Mod/Mod	0.00	0.00	0.00	0.36	0.14	5.40	81
	Mod/High	0.00	0.00	0.05	0.39	0.60	2.74	31
	High/High	1.01	1.39	1.90	2.34	3.17	5.81	61
Mountain – Northwest	Mod/Mod	0.00	0.00	0.00	0.28	0.46	1.67	81
	Mod/High	0.15	0.31	1.08	1.23	1.81	3.89	31
	High/High	3.24	5.19	6.25	6.22	7.41	9.49	61
Mountain – Southwest	Mod/Mod	0.00	0.00	0.04	0.32	0.45	2.87	81
	Mod/High	0.00	0.19	0.37	0.52	0.74	1.68	31
	High/High	0.95	1.41	2.08	2.42	3.47	5.67	61
Delta – Texas	Mod/Mod	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
	Mod/High	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
	High/High	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
Mountain – Plains	Mod/Mod	0.00	0.25	0.36	0.90	0.86	5.79	81
	Mod/High	0.00	0.25	0.79	1.23	1.11	5.17	31
	High/High	3.32	4.86	6.10	6.88	9.30	12.72	61
Plains – Southwest	Mod/Mod	0.00	0.00	0.69	1.57	3.00	6.32	81
	Mod/High	0.00	1.87	2.53	2.42	3.18	5.82	31
	High/High	2.13	4.05	5.54	5.62	6.89	12.59	61
Plains – Texas	Mod/Mod	0.00	0.00	0.02	0.38	0.51	3.47	81
	Mod/High	0.00	0.78	1.15	3.26	4.27	14.85	31
	High/High	10.45	13.19	14.32	15.33	17.54	22.69	61

Region	Scenario Group	Min	Q1	Median	Mean	Q3	Max	n
Delta – Midwest	Mod/Mod	0.00	0.00	0.00	0.22	0.00	2.70	81
	Mod/High	0.00	0.00	0.00	0.10	0.01	2.88	31
	High/High	0.00	0.03	0.10	0.11	0.17	0.36	61
Delta – Plains	Mod/Mod	0.00	0.00	0.00	0.84	0.88	9.26	81
	Mod/High	0.71	4.43	4.89	7.49	9.57	23.65	31
	High/High	10.75	18.79	20.67	23.18	28.73	33.49	61
Delta – Southeast	Mod/Mod	0.00	0.00	0.00	0.20	0.00	2.70	81
	Mod/High	0.00	0.06	0.92	1.60	1.96	7.98	31
	High/High	3.28	7.52	10.10	10.09	12.13	16.95	61
Florida – Southeast	Mod/Mod	0.00	0.00	0.00	0.42	0.00	2.70	81
	Mod/High	0.00	0.00	0.00	0.26	0.00	2.55	31
	High/High	0.11	0.37	0.87	1.81	3.24	5.48	61
Mid-Atlantic – Midwest	Mod/Mod	0.00	0.28	1.10	1.68	2.32	9.75	81
	Mod/High	1.97	4.72	9.87	13.11	15.89	40.63	31
	High/High	22.67	38.74	42.40	41.94	45.83	57.37	61
Mid-Atlantic – New York	Mod/Mod	0.00	0.00	0.00	1.57	3.15	9.51	81
	Mod/High	0.00	0.00	0.00	0.08	0.00	1.56	31
	High/High	0.41	1.04	2.03	2.49	3.75	5.71	61
Mid-Atlantic – Southeast	Mod/Mod	0.00	0.00	0.19	0.87	1.49	7.56	81
	Mod/High	0.22	1.38	2.78	3.03	4.00	9.79	31
	High/High	2.62	3.88	4.36	4.42	4.84	7.44	61
Midwest – Plains	Mod/Mod	0.00	0.56	1.35	1.66	2.21	7.62	81
	Mod/High	2.18	5.44	7.99	10.05	10.30	34.56	31
	High/High	15.82	19.19	24.63	29.78	40.25	56.82	61
Midwest – Southeast	Mod/Mod	0.00	0.00	0.00	0.35	0.00	3.86	81
	Mod/High	0.00	0.05	1.28	2.50	2.84	14.98	31
	High/High	5.34	8.61	10.34	11.32	14.62	19.52	61
New England – New York	Mod/Mod	0.00	0.94	1.46	1.69	2.34	6.58	81
	Mod/High	0.18	1.23	1.53	1.47	1.95	2.56	31
	High/High	2.51	3.37	3.96	4.33	5.47	7.49	61

Table S-7. 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.

Region	Scenario Group	Min	Q1	Median	Mean	Q3	Max	n
California – Mountain	Mod/Mod	0.00	0.26	0.96	1.01	1.56	3.26	81
	Mod/High	0.23	1.51	1.87	1.98	2.27	4.53	31
	High/High	0.91	2.36	2.75	2.75	3.05	5.62	61
California – Northwest	Mod/Mod	0.00	0.00	0.00	0.15	0.01	2.70	81
	Mod/High	0.00	0.08	0.13	0.23	0.32	1.16	31
	High/High	0.07	1.02	1.28	1.48	1.85	3.77	61
California – Southwest	Mod/Mod	0.00	0.00	0.14	0.90	0.32	6.77	81
	Mod/High	0.00	0.02	0.31	0.83	0.88	5.47	31
	High/High	1.18	3.43	5.31	5.81	7.59	12.72	61
Mountain – Northwest	Mod/Mod	0.00	0.00	0.09	0.46	0.66	3.80	81
	Mod/High	1.42	2.71	3.30	4.30	4.40	14.18	31
	High/High	5.23	22.84	25.66	24.60	28.49	37.02	61
Mountain – Southwest	Mod/Mod	0.00	0.03	0.09	0.43	0.64	2.94	81
	Mod/High	0.54	1.14	1.65	1.82	2.05	5.39	31
	High/High	1.15	3.86	5.24	6.31	9.02	13.68	61
Delta – Texas	Mod/Mod	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
	Mod/High	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
	High/High	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
Mountain – Plains	Mod/Mod	0.00	0.32	0.94	1.71	2.00	10.62	81
	Mod/High	0.00	1.61	2.64	3.66	3.41	17.91	31
	High/High	6.80	12.06	19.34	18.86	24.35	31.49	61
Plains – Southwest	Mod/Mod	0.00	0.00	1.16	1.82	3.17	7.23	81
	Mod/High	0.00	2.28	3.66	3.66	4.74	10.82	31
	High/High	4.18	11.26	12.95	13.78	17.23	23.68	61
Plains – Texas	Mod/Mod	0.00	0.04	0.49	1.00	1.50	4.83	81
	Mod/High	0.00	4.28	9.84	10.35	12.62	33.17	31
	High/High	17.93	26.09	28.86	32.66	41.76	48.83	61

Region	Scenario Group	Min	Q1	Median	Mean	Q3	Max	n
Delta – Midwest	Mod/Mod	0.00	0.00	0.00	0.25	0.00	2.88	81
	Mod/High	0.00	0.00	0.00	0.27	0.29	3.22	31
	High/High	0.25	0.61	0.91	0.97	1.15	2.29	61
Delta – Plains	Mod/Mod	0.00	0.00	0.35	1.81	3.43	10.69	81
	Mod/High	2.10	10.80	19.70	20.24	23.83	52.87	31
	High/High	27.07	39.22	48.52	50.55	64.71	73.11	61
Delta – Southeast	Mod/Mod	0.00	0.00	0.00	0.24	0.01	2.70	81
	Mod/High	0.61	2.82	5.10	7.00	8.52	25.62	31
	High/High	19.83	26.99	33.86	33.16	39.87	49.29	61
Florida – Southeast	Mod/Mod	0.00	0.00	0.00	0.67	1.15	4.43	81
	Mod/High	0.00	0.30	1.14	2.65	4.43	12.65	31
	High/High	3.86	8.11	10.63	12.09	16.74	19.37	61
Mid-Atlantic – Midwest	Mod/Mod	0.00	0.64	2.39	3.21	4.32	13.75	81
	Mod/High	5.13	27.95	33.84	42.19	51.66	109.00	31
	High/High	79.56	95.74	102.84	109.29	125.50	140.88	61
Mid-Atlantic – New York	Mod/Mod	0.00	0.00	0.29	1.98	3.68	9.51	81
	Mod/High	0.18	1.61	2.43	2.58	3.42	5.90	31
	High/High	3.57	7.18	8.24	8.38	9.78	11.88	61
Mid-Atlantic – Southeast	Mod/Mod	0.00	0.12	0.51	1.17	1.94	8.15	81
	Mod/High	2.11	5.80	6.86	7.42	9.94	13.64	31
	High/High	6.83	9.27	9.88	9.92	10.39	12.53	61
Midwest – Plains	Mod/Mod	0.00	0.88	3.14	3.61	5.04	10.74	81
	Mod/High	3.52	15.41	21.05	28.18	25.82	95.01	31
	High/High	58.50	71.81	88.03	99.47	129.08	150.68	61
Midwest – Southeast	Mod/Mod	0.00	0.00	0.00	0.46	0.17	3.91	81
	Mod/High	0.85	2.95	4.46	9.06	7.52	38.31	31
	High/High	19.02	29.04	34.37	37.25	45.85	52.62	61
New England – New York	Mod/Mod	0.00	1.61	2.84	2.71	3.69	6.58	81
	Mod/High	0.94	3.40	5.19	4.87	6.28	8.59	31
	High/High	10.13	14.68	16.99	16.47	17.80	22.56	61

Table S-8. 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.

Region	Scenario Group	Min	Q1	Median	Mean	Q3	Max	n
California – Mountain	Mod/Mod	0.00	0.80	1.80	1.84	2.51	8.50	83
	Mod/High	0.23	2.71	4.97	11.09	21.01	44.26	70
	High/High	1.15	3.09	4.31	5.63	7.02	48.49	62
California – Northwest	Mod/Mod	0.00	0.00	0.00	0.21	0.14	2.70	83
	Mod/High	0.00	0.00	0.00	0.52	0.51	7.13	70
	High/High	0.19	1.56	1.94	2.11	2.53	8.11	62
California – Southwest	Mod/Mod	0.00	0.10	0.22	1.67	1.80	9.27	83
	Mod/High	0.00	0.45	5.09	12.01	24.59	53.24	70
	High/High	1.24	3.98	6.89	8.74	11.58	58.46	62
Mountain – Northwest	Mod/Mod	0.00	0.01	0.51	0.90	1.35	5.28	83
	Mod/High	0.00	0.00	0.00	3.55	5.26	25.34	70
	High/High	0.00	33.00	39.15	37.02	43.52	67.51	62
Mountain – Southwest	Mod/Mod	0.00	0.09	0.38	0.53	0.70	2.94	83
	Mod/High	0.00	0.41	1.70	1.82	2.38	7.82	70
	High/High	1.32	4.58	6.06	9.47	14.17	31.27	62
Delta – Texas	Mod/Mod	14.14	18.15	22.16	22.16	26.17	30.18	2
	Mod/High	0.00	30.00	48.34	46.33	55.91	117.11	39
	High/High	106.66	106.66	106.66	106.66	106.66	106.66	1
Mountain – Plains	Mod/Mod	0.00	0.36	1.40	2.38	2.70	14.79	83
	Mod/High	0.00	3.52	11.88	10.82	14.74	38.50	70
	High/High	8.03	18.83	29.17	27.03	35.84	47.73	62
Plains – Southwest	Mod/Mod	0.00	0.00	1.48	2.37	3.35	18.00	83
	Mod/High	-0.10	4.12	13.10	12.25	17.34	47.22	70
	High/High	5.17	12.52	14.41	16.88	22.83	41.62	62
Plains – Texas	Mod/Mod	0.00	0.07	0.91	1.55	2.42	7.14	83
	Mod/High	0.00	10.54	14.56	16.61	24.05	41.48	70
	High/High	18.99	29.85	34.94	38.49	49.76	60.48	62

Region	Scenario Group	Min	Q1	Median	Mean	Q3	Max	n
Delta – Midwest	Mod/Mod	0.00	0.00	0.00	0.25	0.00	3.07	83
	Mod/High	0.00	0.00	0.00	0.58	0.64	7.35	70
	High/High	0.00	0.94	1.32	1.31	1.70	2.66	62
Delta – Plains	Mod/Mod	0.00	0.00	0.73	2.38	4.51	10.88	83
	Mod/High	0.00	0.00	0.00	10.40	18.92	60.27	70
	High/High	0.00	45.71	55.32	57.64	75.81	87.56	62
Delta – Southeast	Mod/Mod	0.00	0.00	0.00	0.50	0.23	8.27	83
	Mod/High	0.66	5.60	10.69	14.74	18.45	101.54	70
	High/High	21.37	30.02	37.72	39.31	48.96	62.10	62
Florida – Southeast	Mod/Mod	0.00	0.00	0.00	0.93	1.90	5.47	83
	Mod/High	0.00	2.46	7.20	8.32	13.20	29.77	70
	High/High	3.87	9.33	12.94	15.23	21.55	26.14	62
Mid-Atlantic – Midwest	Mod/Mod	0.00	1.20	2.65	4.11	5.80	20.68	83
	Mod/High	0.00	12.77	21.86	30.52	38.21	134.03	70
	High/High	25.35	108.88	119.27	132.90	166.20	188.11	62
Mid-Atlantic – New York	Mod/Mod	0.00	0.02	0.81	2.15	3.88	9.51	83
	Mod/High	0.48	3.73	14.83	24.58	44.06	86.06	70
	High/High	4.27	10.17	12.69	13.40	15.69	69.35	62
Mid-Atlantic – Southeast	Mod/Mod	0.00	0.27	1.50	2.00	3.23	8.80	83
	Mod/High	0.00	7.50	12.49	17.61	25.76	85.05	70
	High/High	7.30	11.22	12.24	13.61	13.06	100.04	62
Midwest – Plains	Mod/Mod	0.00	1.46	3.62	5.35	8.04	16.18	83
	Mod/High	0.55	17.45	23.02	29.48	33.69	118.93	70
	High/High	67.37	83.21	98.71	120.90	166.39	191.11	62
Midwest – Southeast	Mod/Mod	0.00	0.00	0.00	0.81	1.56	5.40	83
	Mod/High	0.00	3.98	6.23	8.64	8.68	47.20	70
	High/High	0.03	33.30	39.93	44.97	58.12	75.56	62
New England – New York	Mod/Mod	0.21	1.76	2.90	2.91	4.13	6.58	83
	Mod/High	1.89	6.43	11.37	11.16	15.77	27.23	70
	High/High	12.62	18.30	21.42	21.04	23.22	28.62	62

Section VI.d. International Transfers

Median results for aggregated international transfer capacities were presented in Table VI-4 (page 90) in the *Needs Study* for years 2030, 2035, and 2040. Results for international transfers fell into only the Moderate/Moderate scenario group. Figure VI-9 (page 91) of the *Needs Study* additionally showed the interquartile range of interregional transfer capacities. A more complete look at the statistical results is provided in the tables below, where the minimum, 25th percentile, median, mean, 75th percentile, and maximum values are listed. ***Table S-9*** provides the statistical results for 2030, ***Table S-10*** for 2035, and ***Table S-11*** for 2040.

Table S-9. 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.

Region	Scenario Group	Min	Q1	Median	Mean	Q3	Max	n
Alberta – Mountain	Mod/Mod	0.00	0.26	0.72	0.67	0.93	1.69	48
British Columbia – Northwest	Mod/Mod	0.00	0.44	0.72	0.99	1.68	3.27	48
Chihuahua – Southwest	Mod/Mod	0.00	0.00	0.20	0.22	0.33	0.95	48
Coahuila – Texas	Mod/Mod	0.00	0.00	0.00	0.00	0.00	0.00	48
Manitoba – Midwest	Mod/Mod	0.00	0.00	0.00	0.00	0.00	0.05	48
Mid-Atlantic – Ontario	Mod/Mod	0.00	0.00	0.00	0.13	0.00	1.50	48
Midwest – Ontario	Mod/Mod	0.00	0.18	0.55	0.63	0.81	2.52	48
Midwest – Saskatchewan	Mod/Mod	0.00	0.02	0.07	0.14	0.15	0.65	48
New Brunswick – New England	Mod/Mod	0.00	0.00	0.00	0.01	0.00	0.38	48
New England – Quebec	Mod/Mod	0.00	0.00	0.00	0.11	0.00	2.20	48
New York – Ontario	Mod/Mod	0.00	0.00	0.00	0.23	0.33	1.23	48
New York – Quebec	Mod/Mod	0.00	0.00	0.00	0.06	0.00	1.00	48
Tamaulipas – Texas	Mod/Mod	0.00	0.00	1.50	1.18	1.85	2.08	48

Table S-10. 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.

Region	Scenario Group	Min	Q1	Median	Mean	Q3	Max	n
Alberta – Mountain	Mod/Mod	0.00	0.29	0.77	0.79	0.93	2.88	48
British Columbia – Northwest	Mod/Mod	0.00	0.46	0.97	1.19	1.94	3.95	48
Chihuahua – Southwest	Mod/Mod	0.00	0.00	0.22	0.25	0.34	0.95	48
Coahuila – Texas	Mod/Mod	0.00	0.00	0.00	0.00	0.00	0.00	48
Manitoba – Midwest	Mod/Mod	0.00	0.00	0.00	0.00	0.00	0.05	48
Mid-Atlantic – Ontario	Mod/Mod	0.00	0.00	0.00	0.13	0.00	1.50	48
Midwest – Ontario	Mod/Mod	0.00	0.35	0.81	0.88	1.23	2.52	48
Midwest – Saskatchewan	Mod/Mod	0.00	0.02	0.07	0.16	0.15	1.01	48
New Brunswick – New England	Mod/Mod	0.00	0.00	0.00	0.03	0.00	0.51	48
New England – Quebec	Mod/Mod	0.00	0.00	0.00	0.33	0.19	2.20	48
New York – Ontario	Mod/Mod	0.00	0.00	0.48	0.51	0.93	1.66	48
New York – Quebec	Mod/Mod	0.00	0.00	0.00	0.11	0.00	1.00	48
Tamaulipas – Texas	Mod/Mod	0.00	0.45	1.52	1.33	1.93	3.30	48

Table S-11. 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.

Region	Scenario Group	Min	Q1	Median	Mean	Q3	Max	n
Alberta – Mountain	Mod/Mod	0.00	0.35	0.86	0.90	1.23	3.15	48
British Columbia – Northwest	Mod/Mod	0.00	0.47	1.22	1.41	2.17	3.95	48
Chihuahua – Southwest	Mod/Mod	0.00	0.00	0.24	0.26	0.34	0.95	48
Coahuila – Texas	Mod/Mod	0.00	0.00	0.00	0.00	0.00	0.05	48
Manitoba – Midwest	Mod/Mod	0.00	0.00	0.00	0.00	0.00	0.05	48
Mid-Atlantic – Ontario	Mod/Mod	0.00	0.00	0.00	0.14	0.00	1.50	48
Midwest – Ontario	Mod/Mod	0.00	0.45	1.09	1.09	1.72	2.56	48
Midwest – Saskatchewan	Mod/Mod	0.00	0.02	0.07	0.17	0.15	1.28	48
New Brunswick – New England	Mod/Mod	0.00	0.00	0.00	0.10	0.06	0.74	48
New England – Quebec	Mod/Mod	0.00	0.00	0.21	0.68	1.29	2.20	48
New York – Ontario	Mod/Mod	0.00	0.00	0.62	0.62	1.05	2.52	48
New York – Quebec	Mod/Mod	0.00	0.00	0.00	0.17	0.00	1.00	48
Tamaulipas – Texas	Mod/Mod	0.00	1.06	1.85	1.56	2.07	4.05	48

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