U.S. DEPARTMENT OF ENERGY

National Transmission Needs Study

Draft for Public Comment

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United States Department of Energy

Washington, DC 20585

Executive Summary

A robust transmission system is critical to the Nation's economic, energy, and national security. The electric grid continues to face challenges from aging infrastructure and insufficient transmission capacity. The U.S. Department of Energy undertakes this National Transmission Needs Study (Needs Study) to identify needs that could be alleviated by transmission solutions. Findings of this Needs Study will inform the Department of Energy as it coordinates the use of its authorities and funding related to electric transmission, including implementing the many grid resilience and technology investment provisions of the Infrastructure Investment and Jobs Act and Inflation Reduction Act. The Needs Study reviews publicly available data and over 50 different industry reports published in the past five years that consider current and anticipated future needs given a range of electricity demand, public policy, and market conditions.

This study prescribes no particular solutions to issues faced by the Nation's power sector. Rather, it establishes findings of need in order for industry and the public to suggest best possible solutions for alleviating them in a timely manner. As used in this study, **an electric transmission need refers to the existence of present or expected electric transmission capacity constraints or congestion in a geographic area. Geographic areas where a transmission need exists could benefit from an upgraded or new transmission facility—including non-wire alternatives—to improve reliability and resilience of the power system; alleviate transmission congestion on an annual basis; alleviate transmission congestion during real-time operations; alleviate power transfer capacity limits between neighboring regions; deliver cost-effective generation to high-priced demand; or meet projected future generation, electricity demand, or reliability requirements.**

A review of historical transmission system data from 2011 to 2020 provides insight into key indicators that demonstrate the need for increased transmission capacity. These indicators include an overall decrease in historical transmission investment, regional and interregional wholesale electricity price differentials, and a record amount of new generation and storage capacity in interconnection queues across the county. Regional entities spent between $0.19 and $5.29 per MWh of annual load on new transmission in the past decade, on average. Most of these investments were made in the first half of the decade, with transmission investments steadily declining since 2015. Wholesale market price differentials across the Regional Transmission Organizations/Independent System Operators also provide insight into where transmission congestion currently exists. Several regions of the country have experienced consistent electricity price differentials over the past 3–5 years. Extreme conditions and high-value periods play an outsized role in the value of transmission, with 50% of transmission congestion value coming from only 5% of hours. Finally, a review of the new generation and energy storage resources currently awaiting interconnection agreements in different parts of the country suggests the generation mix will continue to shift toward more wind, solar, and battery storage technologies.

A review of recently published power systems studies highlights the historic and anticipated drivers, benefits, and challenges of expanding the Nation's electric transmission. Altogether, the studies reviewed signify a pressing need to expand electric transmission—driven by the need to improve grid reliability, resilience, and resource adequacy, enhance renewable resource integration and access to clean energy, decrease energy burden, support electrification efforts, and reduce congestion and curtailment. Interregional transmission investments will help improve system resilience by enabling access to diverse generation resources across different climatic zones, which is becoming increasingly important as climate change drives more frequent extreme weather events that damage the power system. Equitable investments made with a lens of energy justice in areas with higher cumulative burden may mitigate existing harms and increase benefits to frontline communities facing high energy burden, longer-duration outages, and higher levels of environmental hazards. In addition to changes in electricity supply, regional goals and heating and transportation legislation will also change the way electricity is used throughout the country over the next decade and beyond. Heating and transportation will become further electrified, which will significantly increase the total demand on the national grid and change daily electrical system demand patterns.

Analysis of anticipated future transmission and transfer capacity need was performed for several different power sector scenarios across three different future years. According to capacity expansion model results, the largest growth of transmission will be needed in the Texas, Mountain, Southeast, Midwest, and Plains regions. The largest growth in interregional transfer capacity occurs between the Plains and Midwest, the Midwest and the Mid-Atlantic, and between New York and New England. New connections between the three interconnections are also shown to grow significantly.

We organize the high-level findings by geographic region, as shown in Figure ES-1 and Table ES-1. Each summary includes a brief description and indicator of general need. The geographic regions align with the boundaries of established transmission planning and reliability regions. Next to the finding, we note the section of this study in which each finding is discussed in more detail.

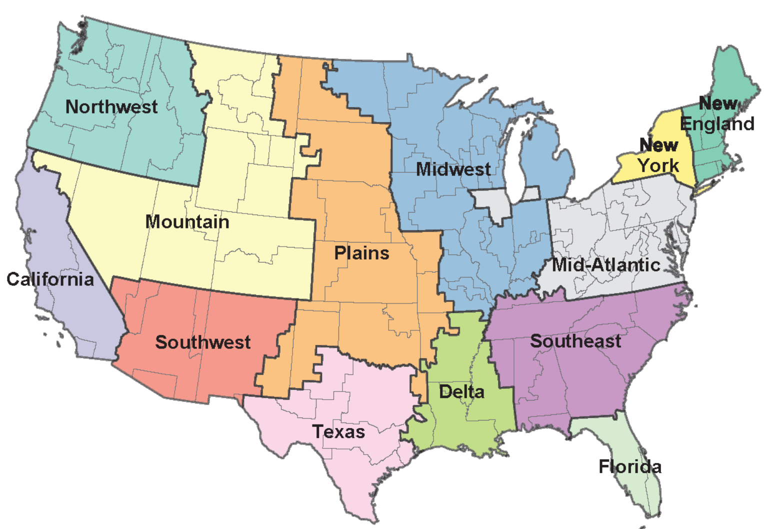


Figure ES-1. Geographic regions and names used in this report.

Table ES-1. Region names used throughout this report. The dominant regional transmission entities that serve operations, transmission planning, and reliability functions in each geographic region are also presented.

Geographic	RTO/ISO	Transmission Planning Entity	Reliability Assessment Area
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 the Federal Energy Regulatory Commission (FERC) at https://www.ferc.gov/media/regions-map-printable-version-order-no-1000 and reliability assessment area names from the North American Electric Reliability Corporation (NERC) 2021 Long-Term Reliability Assessment (LTRA) at (NERC 2021).

Note: CAISO is California Independent System Operator, ERCOT is Electric Reliability Council of Texas, SPP is Southwest Power Pool, MISO is Midcontinent Independent System Operator, NYISO is New York Independent System Operator, ISO-NE is ISO-New England, SERTP is Southeastern Regional Transmission Planning, SCRTP is South Carolina Regional Transmission Planning, FRCC is Florida Reliability Coordinating Council, NWPP is Northwest Power Pool, RMRG is Rocky Mountain Reserve Group, SRSG is Southwest Reserve Sharing Group, SERC is SERC Reliability Corporation, and NPCC is Northeast Power Coordinating Council, Inc. 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 through 2020.

Northwest

NEED: Improve system reliability and resilience.

- Extreme heat and wildfires in 2021 resulted in localized power outages for some communities. These reliability and resource adequacy concerns are increasing as extreme heat and wildfires become more prevalent due to climate change. (§V.a & §V.b)
- High dependence on variable energy resources to meet peak demand face high risk of load curtailment during extreme conditions. (§V.a)

NEED: Alleviate unscheduled flows between California and the Northwest.

- Transmission path 66 at the intersection of the Northwest, California, and Mountain regions is a Qualified Path.[1] (§IV.c)

NEED: Increase of transfer capacity between the Northwest and Mountain regions to meet projected load and generation growth.

- Anticipate between 2.7 and 4.4 gigawatts (GW) of new transfer capacity (median of 3.3 GW, a 26 percent increase relative to the 2020 system) needed in 2035 to meet moderate load and high clean energy futures. (§VI.c)

Mountain

NEED: Improve system reliability and resilience.

- Extreme heat and wildfires can result in power outages. These reliability concerns are increasing as extreme heat and wildfires become more prevalent due to climate change. (§V.a)
- Transmission upgrades may be necessary along the eastern edge of the Mountain region to protect system reliability in the Western Interconnection as transmission is expanded along the West Coast. (§IV.c)

NEED: Alleviate unscheduled flows on three Qualified Paths within the region.

- Transmission paths 30, 31, and 36, which align with Colorado's borders to the west, south, and north, respectively, are Qualified Paths. (§IV.c)

NEED: Increase in transmission deployment to meet projected generation and demand growth.

- Anticipate between 2,500 and 4,500 gigawatt-miles (GW-mi) of new transmission[2] (median of 3,100 GW-mi, a 90 percent increase relative to the 2020 system) needed in 2035 to meet moderate load and high clean energy futures. Current utility plans for transmission development in the combined Mountain and Northwest region do not meet anticipated need. (§VI.b)

NEED: Increase of transfer capacity between Mountain and its neighbors in the Western Interconnection to meet projected load and generation growth.

- Anticipate between 1.5 and 2.3 GW of new transfer capacity (median of 1.9 GW, an 88 percent increase relative to the 2020 system) needed in 2035 between Mountain and California to meet moderate load and high clean energy futures. (§VI.c)

[1] Qualified Paths in the West designate transmission with the highest levels of congestion. The parallel nature of the Qualified Paths creates simultaneous interactions between the eastern and western portions of the Western Interconnection that can create reliability risks.

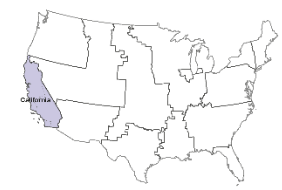
[2] Gigawatt-mile (GW-mi) is not a commonly used unit in the industry, but is the unit used by capacity expansion modeling results. For comparison, a 100-mile 345kV rated transmission line has an estimated carrying capacity of 860 MW, equivalent to 86 GW-mi (NRRI 1987). And a 200-mi 500kV line has a carrying capacity of 1,320 MW, equivalent to 264 GW-mi (NRRI 1987). See Table VI-2 for a comparison of carrying capacities and nominal voltage ratings for different length transmission lines.

- Anticipate between 0 and 0.5 GW of new transfer capacity (median of 1.7 GW, a 41 percent increase relative to the 2020 system) needed in 2035 between Mountain and Southwest to meet moderate load and high clean energy futures. (§VI.c)
- Anticipate between 2.7 and 4.4 GW of new transfer capacity (median of 3.3 GW, a 26 percent increase relative to the 2020 system) needed in 2035 between Mountain and Northwest to meet moderate load and high clean energy futures. (§VI.c)

NEED: Increase of transfer capacity between Mountain and Plains across the interconnection seam to alleviate transfer limits and meet projected future load and generation growth.

- The real-time, interregional value of transmission between the Mountain and Plains regions was high in 2021 and has been increasing over the past several years. (§IV.b)
- Anticipate between 1.6 and 3.4 GW of new transfer capacity (median of 2.6 GW, a 287 percent increase relative to the 2020 system) needed in 2035 between Mountain and Plains to meet moderate load and high clean energy futures. (§VI.c)

California



NEED: Improve system reliability and resilience.

- Extreme heat and wildfires can result in power outages. These reliability concerns are increasing as extreme heat and wildfires become more prevalent due to climate change. (§V.a & §V.b)
- High dependence on solar photovoltaics and imports to meet peak demand face high risk of load curtailment during extreme conditions. (§V.a)
- A constrained natural gas system poses a risk to winter reliability when demand for gas is high for both heating and electricity. (§V.a)
- Due to generation retirements, California will experience capacity shortfalls in 2026. (§V.b)

NEED: Alleviate unscheduled flows between California and the Northwest.

- Transmission path 66 at the intersection of the Northwest, California, and Mountain regions is a Qualified Path. (§IV.c)
- Congestion costs between these two regions increased threefold between 2019 and 2020, and these regions were the most frequently congested within the California ISO (CAISO). (§V.d)

NEED: Relieve high-priced areas by improving access to low-cost generation.

- The Los Angeles and San Diego areas in southern California have experienced consistently high prices for at least the past five years. Transmission to access low-cost generation (either locally or in neighboring regions) would alleviate high costs to consumers. (§IV.b)

- The Mendocino area in northern California has had consistently high prices for at least the past five years. Transmission to access low-cost generation would alleviate high costs to consumers. (§IV.b)

NEED: Increase of transfer capacity with neighboring regions to meet projected load and generation growth.

- Anticipate between 1.5 and 2.3 GW of new transfer capacity (median of 1.9 GW, an 88 percent increase relative to the 2020 system) needed in 2030 between Mountain and California to meet moderate load and high clean energy futures. (§VI.c)
- Several interregional transmission system improvements are needed to integrate new generation resources aligned with California Senate Bill 100 (California Legislature 2018) (§V.c).
    - Median anticipated import capacity needed between California and the Mountain region is 4.3 GW (a 204 percent increase relative to the 2020 system) in 2040 to accommodate high load and high clean energy futures, a scenario group more in line with recent State of California policy mandates. (§VI.c)
    - Anticipate between 4.0 and 11.6 GW of new transfer capacity (median of 6.9 GW, a 132 percent increase relative to the 2020 system) needed between California and Southwest in 2040 to meet high load and high clean energy futures. Increased transfers between these two regions remain low for other scenario groups. (§VI.c)
    - Increased interregional transfer capacity is accompanied by very little projected within-region transmission deployment—only 230 GW-mi (median), a 5 percent increase relative to the 2020 system in 2040 for high load and clean energy futures—indicating additional transmission is needed primarily to support clean energy imports into California. (§VI.b)

Southwest

NEED: Improve system reliability and resilience.

- Extreme heat and wildfires can result in power outages. These reliability and resource adequacy concerns are increasing as extreme heat and wildfires become more prevalent due to climate change. (§V.a & §V.b)
- Transmission upgrades may be necessary along the eastern edge of the Southwest region to protect system reliability in the Western Interconnection as transmission is expanded along the West Coast. (§IV.c)
- Transmission needs related to lack of access to transmission also highlight the need for a more diverse generation portfolio, which can be achieved through additional interregional transmission interconnections. (§IV.d).

NEED: Increase in transmission deployment to meet projected generation and demand growth.

- Anticipate between 1,500 and 2,900 GW-mi of new transmission (median of 1,900 GW-mi, a 33 percent increase relative to the 2020 system) needed in 2035 to meet moderate load and high clean energy futures. Current utility plans for transmission development in Southwest do not meet anticipated need. (§VI.b)

NEED: Increase of transfer capacity between Southwest and Texas across the interconnection seam to alleviate transfer limits, particularly for reliability and resource adequacy needs.

- The real-time, interregional value of transmission between Southwest and Texas was the highest of all considered transfers and has been increasing over the past several years. The value of this transfer was particularly high in 2021 due to the outages caused by the February 2021 cold weather event. (§IV.b)

NEED: Increase of transfer capacity between Southwest and Plains across the interconnection seam to meet projected load and generation growth.

- Anticipate between 2.3 and 4.7 GW of new transfer capacity (median of 3.7 GW, a 914 percent increase relative to the 2020 system) needed in 2035 to meet moderate load and high clean energy futures. (§VI.c)

Texas

NEED: Improve system reliability and resilience.

- High dependence on variable energy resources to meet peak demand face high risk of load curtailment during extreme conditions. (§V.a)
- A constrained natural gas system poses a risk to winter reliability, particularly in the absence of winter hardening investments and when demand for gas is high for both heating and electricity. (§V.a)
- Texas experienced extremely high prices during the February 2021 cold weather event, which were isolated to the Electric Reliability Council of Texas (ERCOT) region. (§IV.b)
- Texas shed over 20,000 MW of firm load during the February 2021 cold weather event and was unable to import additional capacity above its 1,000 MW transfer limit, negatively impacting resource adequacy and system reliability. (§V.a & §V.b)
- The power system is susceptible to outages during intense hurricanes, demonstrated by the significant power outages caused by Hurricanes Laura in 2020 and Ida in 2021. (§V.f)

NEED: Significant increase in transmission deployment within Texas to meet projected generation and demand growth.

- Anticipate between 6,800 and 9,400 GW-mi of new transmission (median of 9,000 GW-mi, a 140 percent increase relative to the 2020 system) needed in 2035 to meet moderate load and high clean energy futures. (§VI.b)

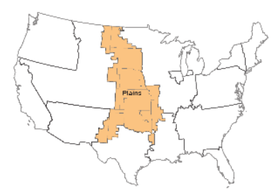
NEED: Increase of transfer capacity between Texas and the Eastern Interconnection to alleviate transfer limits, particularly for reliability and resource adequacy needs.

- The real-time, interregional value of transmission between the Texas, Plains, and Delta regions was high in 2021 and has been increasing over the past several years. The value of this transfer was particularly high in 2021 due to high prices in Texas during the February 2021 cold weather event. (§IV.b)
- Increased transfer capacity with neighbors will enable Texas to address capacity shortages when the system is stressed under emergency conditions. (§V.b)
- Anticipate between 4.3 and 12.6 GW of new transfer capacity (median of 9.8 GW, a 1200 percent increase relative to the 2020 system) needed between Texas and the Plains region in 2035 to meet moderate load and high clean energy futures. (§VI.c)

NEED: Increase of transfer capacity between Texas and the Western Interconnection to alleviate transfer limits, particularly for reliability and resource adequacy needs.

- The real-time, interregional value of transmission between Southwest and Texas was the highest of all considered transfers and has been increasing over the past several years. The value of this transfer was particularly high in 2021 due to high prices in Texas during the February 2021 cold weather event. (§IV.b)
- Increased transfer capacity with neighbors will enable Texas to address capacity shortages when the system is stressed under emergency conditions. (§V.b)

Plains



NEED: Improve system reliability and resilience.

- The Southwest Power Pool (SPP) region was unable to import additional capacity during the February 2021 cold weather event, negatively impacting resource adequacy. Increased bi-directional transfer capacities can improve system reliability during extreme weather events. (§IV.b & §V.b)

NEED: Deliver new, cost-effective generation to high-priced demand.

- Southeast Missouri and Southern Oklahoma have experienced consistently high prices for at least the past two to three years. Transmission to access low-cost generation (either locally or in neighboring regions) would alleviate high costs to consumers. (§IV.b)
- Large disparities in wholesale market prices occurred in the SPP region in 2021. Prices in southeast Oklahoma and western Arkansas were $20/megawatt-hour (MWh) more, on average, than the median price in the region. These two regions have had consistently high prices for at least the past five years, although less so in 2020. (§IV.b & §V.d)

NEED: Increase in transmission deployment to meet projected generation and demand growth.

- Anticipate between 7,300 and 9,900 GW-mi of new transmission (median of 8,300 GW-mi, a 119 percent increase relative to the 2020 system) needed in 2035 to meet moderate load and high clean energy futures. Current utility plans for transmission development in the Plains do not meet this anticipated need. (§VI.b)

NEED: Increase transfer capacity between Plains and its neighbors on all sides, including across both interconnection seams.

- Real-time, hourly price differences between Plains and its neighbors have been high and increasing for the past five years, indicating large value in increased transmission between the regions. These values are particularly large when sharing across the interconnection border with the Western Interconnection and ERCOT. (§IV.b)
- Anticipate between 15.4 and 25.8 GW of new transfer capacity (median of 21.1 GW, a 175 percent increase relative to the 2020 system) needed between the Plains and Midwest in 2035 to meet moderate load and high clean energy futures. (§VI.c)
- Anticipate between 1.6 and 3.4 GW of new transfer capacity (median of 2.6 GW, a 287 percent increase relative to the2020 system) needed between the Plains and Mountains in 2035 to meet moderate load and high clean energy futures. (§VI.c)
- Anticipate between 2.3 and 4.7 GW of new transfer capacity (median of 3.7 GW, a 915 percent increase relative to the 2020 system) needed between the Plains and Southwest in 2035 to meet moderate load and high clean energy futures. (§VI.c)
- Anticipate between 10.8 and 23.8 GW of new transfer capacity (median of 19.7 GW, a 414 percent increase relative to the 2020 system) needed between the Plains and the Delta in 2035 to meet moderate load and high clean energy futures. (§VI.c)
- In moderate load and high clean energy futures, transfer capacity with Texas becomes increasingly important, and median results show a 13-fold increase in 2020 capacity to 9.8 GW is needed. (§VI.c)

Midwest

NEED: Improve system reliability and resilience.

- Midcontinent Independent System Operator's (MISO) Renewable Integration Impact Assessment (RIIA) shows that the MISO transmission system maintains reliability up to 30 percent renewable energy generation without significant additional operational support. Accordingly, the effort required to plan for, support, and operate new resources reliably as they are integrated with the grid substantially increases at renewable penetration levels beyond 30 percent of annual load served. Transmission infrastructure must ensure reliable operations when more than 40 percent renewable energy is incorporated in the MISO territory. (§V.a)
- The MISO region was unable to import additional capacity during the February 2021 cold weather event, negatively impacting resource adequacy. Increased bi-directional transfer capacities can improve system reliability during extreme weather events. (§V.b)
- Generation retirements in MISO could result in capacity shortfalls as early as 2024. (§V.b)

NEED: Alleviate annual transmission congestion within the region.

- MISO North (North Dakota, South Dakota, Minnesota, Iowa) currently experiences higher congestion than other MISO regions. Congestion in this region doubled between 2019 and 2020 and is continuing to increase. (§V.d)
- Transmission loading relief (TLR) constraints with MISO's Northern (Ontario, Canada) and Southern (Southeast region) neighbors cause large congestion costs in MISO. (§V.d)

NEED: Relieve high-priced demand areas by improving access to low-cost generation.

- Northwest Wisconsin has experienced consistently high prices for at least the past two to three years. Transmission to access low-cost generation (either locally or in neighboring regions) would alleviate high costs to consumers. (§IV.b)
- Several areas across Michigan, including the Upper Peninsula, have experienced consistently high prices for at least the past three to four years. Transmission to access low-cost generation (either locally or in neighboring regions) would alleviate high costs to consumers. (§V.b)

NEED: Increase in transmission deployment to meet projected generation and demand growth.

- Anticipate between 10,000 and 14,900 GW-mi of new transmission (median of 13,300 GW-mi, a 112 percent increase relative to the 2020 system) needed in 2035 to meet moderate load and high clean energy futures. Current utility plans for transmission development in the combined Delta and Midwest regions (MISO) do not meet this anticipated need. (§VI.b)

NEED: Alleviate transfer capacity limits between the Midwest and Delta regions.

- Transfer limits between MISO Central (Kentucky, Missouri, Illinois, Indiana, Wisconsin, Michigan) and MISO South (Arkansas, Mississippi, Louisiana, Texas) regions are binding most of the year, contributing to operations challenges during extreme events in both regions. (§V.c)
- The historic wholesale price (§IV.b) and anticipated future capacity expansions model (§VI.c) analyses suggest congestion between the Midwest and the Delta regions is alleviated most cost effectively by increased transfer capacity between the Midwest and Plains and between the Plains and Delta, instead of between the Midwest and Delta directly.

NEED: Increase transfer limits between the Midwest and Plains regions to meet future load and generation growth.

- Connecting the Midwest with its western neighbor offers high real-time operational value. The real-time operational value of connecting these two regions has been growing over the past five years. (§IV.b)
- Anticipate between 15.4 and 25.8 GW of new transfer capacity (median of 21.1 GW, a 175 percent increase relative to the 2020 system) needed between the Plains and Midwest in 2035 to meet moderate load and high clean energy futures. (§VI.c)

NEED: Increase transfer limits between the Midwest and Southeast regions to meet future load and generation growth.

- Anticipate between 2.9 and 7.5 GW of new transfer capacity (median of 4.5 GW, a 54 percent increase relative to the 2020 system) needed in 2035 to meet moderate load and high clean energy futures. (§VI.c)

Delta

NEED: Improve system reliability and resilience.

- Midcontinent Independent System Operator's (MISO) Renewable Integration Impact Assessment (RIIA) shows that the MISO transmission system maintains reliability up to 30 percent renewable energy generation without significant additional operational support. Accordingly, the effort required to plan for, support, and operate new resources reliably as they are integrated with the grid substantially increases at renewable penetration levels beyond 30 percent of annual load served. Transmission infrastructure must ensure reliable operations when more than 40 percent renewable energy is incorporated in the MISO territory. (§V.a)
- The MISO region was unable to import additional capacity during the February 2021 cold weather event, negatively impacting resource adequacy. Increased bi-directional transfer capacities can improve system reliability during extreme weather events. (§V.b)
- Generation retirements in MISO could result in capacity shortfalls as early as 2024. (§V.b)
- The power system in the Delta region is susceptible to outages during intense hurricanes, demonstrated by the significant power outages caused by Hurricanes Laura in 2020 and Ida in 2021. (§V.f)

NEED: Increase in transmission deployment to meet projected generation and demand growth.

- Anticipate between 1,400 and 3,900 GW-mi of new transmission (median of 1,700 GW-mi, a 49 percent increase relative to the 2020 system) needed in 2035 to meet moderate load and high clean energy futures. (§VI.b)

NEED: Alleviate transfer capacity limits between the Midwest and Delta regions.

- Transfer limits between MISO Central (KY, MO, IL, IN, WI, MI) and MISO South (AR, MS, LA, TX) are binding most of the year, contributing to insecure operations during extreme events in both regions. (§V.d)
- The historic wholesale price (§IV.b) and anticipated future capacity expansions model (§VI.c) analyses suggest congestion between the Midwest and the Delta regions is alleviated most cost effectively by increased transfer capacity between the Midwest and Plains and between the Plains and Delta, instead of between the Midwest and Delta directly.

NEED: Increase in transfer capacity between the Delta and two of its neighbors in the Eastern Interconnection to meet future load and generation growth.

- Anticipate between 10.8 and 23.8 GW of new transfer capacity (median of 19.7 GW, a 414 percent increase relative to the 2020 system) needed between the Delta and Plains regions in 2035 to meet moderate load and high clean energy futures. (§VI.c)

- Anticipate between 2.8 and 8.5 GW of new transfer capacity (median of 5.1 GW, a 86 percent increase relative to the 2020 system) needed between the Delta and Southeast regions in 2035 to meet moderate load and high clean energy futures. (§VI.c)

Southeast

NEED: Increase in transmission deployment to meet projected generation and demand growth.

- Anticipate between 5,400 and 8,000 GW-mi of new transmission (median of 6,800 GW-mi, a 77 percent increase relative to the 2020 system) needed in 2035 to meet moderate load and high clean energy futures. Current utility plans for transmission development in the Southeast do not meet this anticipated need. (§VI.b)

NEED: Increase in transfer capacity between the Southeast and all its neighbors to meet future load and generation growth.

- Anticipate between 0.3 and 4.4 GW of new transfer capacity (median of 1.4 GW, a 32 percent increase relative to the 2020 system) needed with Florida in 2035 to meet moderate load and high clean energy futures. (§VI.c)
- Anticipate between 2.9 and 7.5 GW of new transfer capacity (median of 4.5 GW, a 54 percent increase relative to the 2020 system) needed with the Midwest region in 2035 to meet moderate load and high clean energy futures. (§VI.c)
- Anticipate between 2.8 and 8.5 GW of new transfer capacity (median of 5.1 GW, an 86 percent increase relative to the 2020 system) needed with the Delta region in 2035 to meet moderate load and high clean energy futures. (§VI.c)
- Anticipate between 5.8 and 9.9 GW of new transfer capacity (median of 6.9 GW, a 97 percent increase relative to the 2020 system) needed with the Mid-Atlantic region in 2035 to meet moderate load and high clean energy futures. (§VI.c)

Florida

NEED: Increase system reliability and resilience.

- The power system is susceptible to outages during intense hurricanes and subsequent flooding. (§V.f)

NEED: Increase in transmission deployment to meet projected generation and demand growth.

- Anticipate between 510 and 2,000 GW-mi of new transmission (median of 810 GW-mi, a 27 percent increase relative to the 2020 system) needed in 2035 to meet moderate load and high clean energy futures. (§VI.c)

NEED: Increase in transfer capacity between Florida and Southeast to meet future load and generation growth.

- Anticipate between 0.3 and 4.4 GW of new transmission (median of 1.4 GW, a 32 percent increase relative to the 2020 system) needed in 2035 to meet moderate load and high clean energy futures. (§VI.c)

Mid-Atlantic

NEED: Alleviate congestion within the Mid-Atlantic region.

- Congestion costs increased considerably from 2020 to 2021 in the Mid-Atlantic region, surpassing energy costs and adding to overall costs to consumers. (§V.d)
- Top congestion constraints are in the eastern portion of the Mid-Atlantic region near the borders of Maryland, Delaware, Pennsylvania, and New Jersey. Large price differentials occur in this part of the region. (§0 & §V.d)

NEED: Relieve high-priced areas by providing access to low-cost generation.

- The southern tip of the Delmarva Peninsula in Maryland has experienced consistently high prices for at least the past five years. Transmission to access low-cost generation (either locally or in neighboring regions) would alleviate high costs to consumers. (§IV.b)
- Southern Pennsylvania, Eastern Virginia, and the District of Columbia have experienced consistently high prices for at least the past five years. Transmission to access low-cost generation (either locally or in neighboring regions) would alleviate high costs to consumers. (§IV.b)

NEED: Increase in transmission capacity to meet projected generation and demand growth.

- Anticipate between 2,700 and 4,600 GW-mi of new transmission (median of 3,300 GW-mi, a 23 percent increase relative to the 2020 system) in 2035 to meet moderate load and high clean energy futures. Current utility plans for transmission development in the Mid-Atlantic do not meet anticipated need. (§VI.b)

NEED: Increase in transfer capacity between the Mid-Atlantic and all its neighbors to meet future load and generation growth.

- Anticipate between 1.6 and 3.4 GW of new transfer capacity (median of 2.4 GW, a 122 percent increase relative to the 2020 system) needed with New York in 2035 to meet moderate load and high clean energy futures. (§VI.c)
- Anticipate between 27.9 and 51.7 GW of new transfer capacity (median of 33.8 GW, a 156 percent increase relative to the 2020 system) needed with the Midwest region in 2035 to meet moderate load and high clean energy futures. (§VI.c)
- Anticipate between 5.8 and 9.9 GW of new transfer capacity (median of 6.9 GW, a 97 percent increase relative to the 2020 system) needed with the Southeast region in 2035 to meet moderate load and high clean energy futures. (§VI.c)

New York

NEED: Alleviate congestion within New York.

- Large price disparities exist between upstate New York and Long Island, although congestion causing those price disparities was less in 2020 due to the COVID-19 impact on electricity use in Long Island. (§IV.b & §V.d)

NEED: Relieve high-priced areas by providing access to low-cost generation.

- Long Island has experienced consistently high prices for at least the past five years. Transmission to access low-cost generation (either locally, from upstate New York or from neighboring regions) would alleviate high costs to consumers. (§IV.b)

NEED: Increase transfer capacity between New York and both of its neighbors to meet future load and generation growth.

- Anticipate between 1.6 and 3.4 GW of new transfer capacity (median of 2.4 GW, a 122 percent increase relative to the 2020 system) needed with the Mid-Atlantic region in 2035 to meet moderate load and high clean energy futures. (§VI.c)
- Anticipate between 3.4 and 6.3 GW of new transfer capacity (median of 5.2 GW, a 255 percent increase relative to the 2020 system) needed with New England in 2035 to meet moderate load and high clean energy futures. (§VI.c)

New England

NEED: Improve system reliability and resilience.

- A constrained natural gas system poses a risk to winter reliability when demand for gas is high for both heating and electricity. (§V.a)
- A well-designed offshore transmission system can integrate offshore wind generation without compromising reliability of the onshore transmission system; designing and building the offshore grid with the capability of a networked system will improve reliability and reduce curtailments when transmission outages occur. (§V.c)

NEED: Increase transfer capacity with New York to meet future load and generation growth.

- The real-time, interregional value of transmission between New York and New England has been increasing over the past several years. (§IV.b)
- Anticipate between 3.4 and 6.3 GW of new transfer capacity (median of 5.2 GW, a 255 percent increase relative to the 2020 system) needed with New York in 2035 to meet moderate load and high clean energy futures. (§VI.c)

NEED: Increase transfer capacity with Canada to meet future load and generation growth.

- Increased transfer capacity between New England and Canada will enable bidirectional flow of hydropower, wind, and solar generation between the regions, helping to meet State clean energy targets. (§V.c)

NATIONAL TRANSMISSION NEEDS STUDY

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Acronyms and Abbreviations

Term	Abbreviation
AC	alternating current
ATC	available transfer capability
BA	balancing authority
CA/MX	California/Mexico
CAISO	California Independent System Operator
CEM	capacity expansion model
ckt-mi	circuit-mile
COI	California Oregon Interface
COVID	coronavirus disease of 2019
DA	day-ahead
DC	direct current
DER	distributed energy resource
dGen	Distributed Generation Market Demand model
DLR	dynamic line rating
DOE	U.S. Department of Energy
ERCOT	Electric Reliability Council of Texas
ESD	Energy Supply & Demand
FERC	Federal Energy Regulatory Commission
FGRS	Future Grid Reliability Scenarios
FPA	Federal Power Act
FRCC	Florida Reliability Coordinating Council
GET	grid-enhancing technology
GW	gigawatt
GW-mi	gigawatt-mile
HVAC	high-voltage alternating current
HVDC	high-voltage direct current
Hz	hertz
IIJA	Infrastructure Investment and Jobs Act
IRA	Inflation Reduction Act
IQR	interquartile range
ISO	independent system operator
ISO-NE	Independent System Operator New England
JTIQ	Joint Targeted Interconnection Queue
kV	kilovolt
LTRA	Long-Term Reliability Assessment
LRTP	Long Range Transmission Planning
M2M	market-to-market
MISO	Midcontinent Independent System Operator

Term	Abbreviation
MMU	Market Monitoring Unit
MW	megawatt
MWh	megawatt-hour
NARIS	North American Renewable Integration Study
NERC	North American Electric Reliability Corporation
NIETC	National Interest Electric Transmission Corridor
NPCC	Northeast Power Coordinating Council, Inc.
NREL	National Renewable Energy Laboratory
NWPP	Northwest Power Pool
NYISO	New York Independent System Operator
OSW	offshore wind
PCM	production cost model
PFC	power flow controller
PG&E	Pacific Gas & Electric Company
PJM	PJM Interconnection LLC
PRAS	Probabilistic Resource Adequacy Suite
R&D	research and development
RA	resource adequacy
RD&D	research, design, and development
RTOs/ISOs	regional transmission organizations/independent system operators
ReEDS	Regional Energy Deployment System
RIIA	Renewable Integration Impact Assessment
RMRG	Rocky Mountain Reserve Group
RT	real-time
RTO	regional transmission organization
SCE	Southern California Edison
SCRTP	South Carolina Regional Transmission Planning
SDG&E	San Diego Gas & Electric
SEEM	Southeast Energy Exchange Market
SEMA	Southeastern Massachusetts
SERC	SERC Reliability Corporation
SERC-FP	SERC Florida Peninsula
SERTP	Southeastern Regional Transmission Planning
SPP	Southwest Power Pool
SRSG	Southwest Reserve Sharing Group
TLR	transmission loading relief
TVA	Tennessee Valley Authority
TW	terawatt
TW-mi	terawatt-mile
U.S.C.	United States Code

Term	Abbreviation
UP MI	Upper Peninsula of Michigan
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council
WPP	Western Power Pool
WEIM	Western Energy Imbalance Market
WEIS	Western Energy Imbalance Service
WIUFMP	Western Interconnection Unscheduled Flow Mitigation Plan

Figures

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I. Introduction

A robust transmission system is critical to the Nation's economic, energy, and national security, and the U.S. Department of Energy (the Department or DOE) is utilizing a variety of tools to address challenges to expanding and upgrading the nation's transmission infrastructure to meet current and future needs.[3] As one part of that effort, DOE undertakes this Needs Study to identify high-priority national electric transmission needs—specifically, to identify geographic areas where the power grid could benefit from new or upgraded transmission facilities. This Needs Study will inform DOE as it coordinates the use of its authorities and funding related to electric transmission.[4] For example, the results of this needs assessment can inform DOE's work implementing various provisions of the Infrastructure Investment and Jobs Act[5] (IIJA) and Inflation Reduction Act relating to DOE's work on transmission expansion, grid resilience, and grid technology. This Needs Study will also support the implementation of existing Department programs, including the Department's Loan Programs and Transmission Infrastructure Program, the regional transmission planning processes, and the potential designation of National Interest Electric Transmission Corridors (NIETC, pronounced \nit-SEE\).

One of the underlying authorities for this Needs Study is Section 216 of the Federal Power Act (FPA), which as amended directs DOE and the Federal Energy Regulatory Commission (FERC) to take specific actions aimed at accelerating electricity transmission development. Section 216(a)(1) of the FPA directs the Department to conduct assessments of national electric transmission capacity constraints and congestion not less frequently than once every 3 years.[6] Pursuant to Section 216(a)(1) and (3) of the FPA, DOE has initiated and will continue to consult with affected states, Indian Tribes, and appropriate regional entities. Section 216(a)(2) of the FPA directs DOE to issue a report based on the study conducted under Section 216(a)(1) or other information related to electric transmission capacity constraints and congestion, which may designate one or more NIETCs. Prior to issuing the next report, DOE intends to engage in further process and collect additional information for purposes of potential NIETC designations.

Although this Needs Study builds on findings from previous congestion studies, its scope has expanded because amendments to FPA Section 216 enacted in the IIJA require examination of both current and expected transmission capacity constraints and congestion. **Consequently, 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 could benefit from an upgraded or new transmission facility—including non-wire alternatives—to**

[3] U.S. Department of Energy, Building a Better Grid Initiative to Upgrade and Expand the Nation's Electric Transmission Grid to Support Resilience, Reliability, and Decarbonization, 87 Fed. Reg. 2769 (Jan.19, 2022), https://www.govinfo.gov/content/pkg/FR-2022-01-19/pdf/2022-00883.pdf.

[4] As noted in the Notice of Intent for the Building a Better Grid Initiative, DOE intends to launch a coordinated transmission deployment program to implement both IIJA and previously enacted authorities through studies and funding. The notice provided further background on the Department's tools and authorities to accelerate transmission deployment. See 87 Fed. Reg. at 2770–73.

[5] Infrastructure Investment and Jobs Act, Pub. L. No. 117-58, 135 Stat. 429 (2021).

[6] See 16 U.S.C. 824p.

improve reliability and resilience of the power system; alleviate transmission congestion on an annual basis; alleviate transmission congestion during real-time operations; alleviate power transfer capacity limits between neighboring regions; deliver cost-effective generation to high-priced demand; or meet projected future generation, electricity demand, or reliability requirements.

In conducting this Need Study, the Department is cognizant of the factors that drive industry transmission planning today and the entities and institutions that perform such planning. Transmission planning is conducted today by local utilities, who plan for local transmission needs on their own transmission systems, and Regional Planning Authorities, which were formed pursuant to FERC Order No. 1000 to plan for regional needs and identify regional transmission projects that would meet regional and local needs more cost-effectively or efficiently.[7] In aggregate, these assessments evaluate the reliability, economic and public policy requirements of the future power system. Many of these plans are primarily focused on compliance with NERC and local reliability standards with very limited scopes and planning horizons. These assessments typically are performed to ensure that future system will address expected reliability needs for a select set of futures that reflect a more limited set of potential resources changes, such as announced resource retirements or modification commitments, as well as executed generation interconnection agreements and approved transmission service requests.

This Needs Study is not meant to displace these planning processes, the reliability standards they address, or the planning efforts of utilities and Regional Planning Authorities. Rather, this Study is intended to help inform and drive effective regional and interregional planning to properly assess the multiple values of transmission and the ability of robust transmission plans to improve reliability and resilience and lower overall delivered energy prices to consumers under a broader and more diverse set of factors impacting the current and expected future electricity system, as well help guide the Department in the execution of its transmission-related authorities (as discussed above). The National Transmission Needs Study is focused on identifying current and expected future congestion and constraints through a holistic assessment of the multiple drivers of transmission needs and multiple values of transmission infrastructure. In this way, the Department believes it will be an important addition to overall industry planning efforts and will evolve with time to incorporate the findings of industry and other government initiatives to determine a consensus long-range national plan for the bulk electric power system.

This Needs Study also addresses the fact that transmission planning is becoming more difficult and complex as clean energy resources proliferate in response to policy drivers and consumer demands and as the adoption and integration of new distributed and variable resources affect the performance and capabilities required at the bulk power system. Advanced transmission technologies are being incorporated on the grid to enhance asset utilization, mitigate

[7] Federal Energy Regulatory Commission, Report on barriers and opportunities for high voltage transmission: A report to the Committees on Appropriations of both Houses of Congress pursuant to the 2020 Further Consolidated Appropriations Act, (June 2020), https://www.congress.gov/116/meeting/house/111020/documents/HHRG-116-II06-20200922-SD003.pdf.

curtailments of renewable resources, and better manage congestion patterns. These technologies may not be adequately considered in existing planning processes. Although it may be a paradigm shift compared to traditional operations, leveraging technology to increase an operator's visibility, and understanding of power system flows and capabilities on critical components should actually improve grid security, not jeopardize reliability.

Further, this Needs Study recognizes and considers the fact that in many cases, flexibility and optionality provided by a robust transmission plan may not be captured in individual or more narrowly focused planning processes. Recent experience with extreme weather events demonstrates that planning for the bulk power system needs to extend beyond the footprint of individual utilities or regions to provide assurance that energy can be delivered from where it is available to where it is needed to mitigate risks associated with common mode failures.

Holistic, scenario-based, multi-value transmission expansion planning can also provide energy price benefits to consumers, and this Needs Study seeks to assess opportunities to lower consumer energy costs through such coordinated transmission planning and development efforts to meet expected future conditions. More holistic and comprehensive planning assessments that consider a range of scenarios of the future of the bulk power system help ensure a more robust and cost-effective bulk power system that will address future needs and ensure that expected transmission constraints and congestion are identified and mitigated before they harm consumers.

This study is organized as follows:

Section II provides the legislative language that compels this study.

Section III introduces the role of transmission in the power system, benefits provided by transmission, and challenges to transmission expansion. The section includes an overview of the physical factors and grid-reliability considerations that lead to constraints within the transmission system and clarifies the relationship between transmission constraints and congestion. It then reviews regional variations in the approaches used to manage congestion and resolve capacity constraints.

Section IV discusses trends in transmission investments and what they indicate about transmission infrastructure needs. The section reviews several metrics assessing historical transmission investment, including load-weighted dollar investment in new transmission and load-weighted circuit miles of transmission. It then examines historical market price differentials and wholesale market prices within and across regions to understand trends in congestion and quantify the value of interregional transmission. Finally, the section presents data from generation interconnection queues to further demonstrate the need for new transmission infrastructure.

Section V synthesizes DOE's key findings from a literature review on the historical and anticipated drivers, benefits, and challenges of expanding U.S. transmission infrastructure.

Section VI outlines anticipated transmission needs from capacity expansion modeling scenarios for several studies. The section details electricity demand and generation assumptions across scenarios and the resulting regional deployment of transmission and interregional transfer capacity expansion.

Section VII reviews the Department's process in preparing this study. The section describes the Department's consultation with states, Indian Tribes and regional entities on a consultation draft of the study, as require by Section 216.

Appendix A-1 contains a list of entities that submitted written or verbal comments on the consultation draft of the study, and an overview summary of the comments received. Appendix A-2 contains a detailed "comment matrix" that documents each individual comment received during consultation and the manner in which the Department resolved each comment.

Supplemental Material which contains supporting information about regional and interregional congestion, and further detail on the capacity expansion modeling studies used to discuss anticipated transmission need can be found online to accompany this Needs Study.[8]

[8] Supplemental Material and more information related to this Needs Study can be found at https://www.energy.gov/gdo/national-transmission-needs-study.

II. Legislative Language

Congress has granted the Secretary of Energy (Secretary) various authorities to examine and implement programs supporting electric grid reliability and resilience. The IIJA directs the Secretary to establish several programs for grid infrastructure resilience and reliability, including in the following provisions: Section 40101 (Preventing Outages and Enhancing Resilience of the Electric Grid); Section 40103(b) (Program Upgrading Our Electric Grid and Ensuring Reliability and Resiliency); Section 40106 (Transmission Facilitation Program); and Section 40107 (Deployment of Technologies to Enhance Grid Flexibility). The Inflation Reduction Act also includes relevant authorities, including Section 50151 (Transmission Facility Financing); Section 50152 (Grants to Facilitate the Siting of Interstate Electricity Transmission Lines); and Section 50153 (Interregional and Offshore Wind Electricity Transmission Planning, Modeling, and Analysis).

Further, Section 40105 of the IIJA amends Section 216 of the FPA. This Needs Study implements Section 216(a)(1) of the FPA, as amended, which directs the Secretary to "conduct a study of electric transmission capacity constraints and congestion" at least once every three years.[9] The Needs Study can also assist the Secretary in evaluating the criteria necessary for designation of a NIETC, as provided by Section 216(a).[10] Section 216(a)(2) of the FPA directs DOE to issue a report, which may designate a NIETC(s) based on the information provided in the Needs Study as well as other information. Prior to issuing the next report, DOE intends to engage in further process and collect additional information for purposes of potential NIETC designations.

As the purpose and underlying authority of this Needs Study is broad, the scope of this study is not constrained solely to the authority set forth in Section 216(a) of the FPA. In addition to the authorities provided in the IIJA, DOE maintains existing authorities to perform grid-related research and development (R&D) programs, including under the Energy Policy Act of 2005, Section 925 (Electric Transmission and Distribution Programs) and Section 936 (R&D into

[9] 16 U.S.C. 824p(a)(1).

[10] Section 216(a)(2) gives the Secretary authority to designate a NIETC in any geographic area that: "(i) is experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers; or (ii) is expected to experience such energy transmission capacity constraints or congestion." 16 U.S.C. 824p(a)(2).
In determining whether to designate a NIETC, the Secretary may consider whether:
"(A) the economic vitality and development of the corridor, or the end markets served by the corridor, may be constrained by lack of adequate or reasonably priced electricity;
(B)(i) economic growth in the corridor, or the end markets served by the corridor, may be jeopardized by reliance on limited sources of energy; and (ii) a diversification of supply is warranted;
(C) the energy independence or energy security of the United States would be served by the designation;
(D) the designation would be in the interest of national energy policy;
(E) the designation would enhance national defense and homeland security;
(F) the designation would enhance the ability of facilities that generate or transmit firm or intermittent energy to connect to the electric grid;
(G) the designation—(i) maximizes existing rights-of-way; and (ii) avoids and minimizes, to the maximum extent practicable, and offsets to the extent appropriate and practicable, sensitive environmental areas and cultural heritage sites; and
(H) the designation would result in a reduction in the cost to purchase electric energy for consumers."
16 U.S.C. 824p(a)(4).

Integrating Renewable Energy onto the Electric Grid); Energy Independence and Security Act of 2005, Title XIII (Smart Grid Programs); and Energy Act of 2020, Sections 8001–8004 (Grid Modernization RD&D Programs). DOE also maintains other financing authorities that support grid infrastructure development, such as those implemented through the Loan Programs Office[11] and Transmission Infrastructure Program.[12]

Lastly, to ensure the Federal government, states, and the public have access to and can obtain reliable energy information, Congress granted the Secretary broad authorities to collect and study information as the Secretary determines necessary to help formulate energy policy.[13] This broad grant of authority is not limited by any other authority of the Secretary.[14]

[11] For example, under the Title 17 Innovative Energy Loan Guarantee Program and the Tribal Energy Loan Guarantee Program, the Department is authorized to provide loan guarantees to projects that will expand and improve the transmission grid.
[12] The Transmission Infrastructure Program implements Section 402 of the America Recovery and Reinvestment Act of 2009, which amended Section 301 of the Hoover Power Plant Act of 1984.
[13] *See* 15 U.S.C. 772(a) and 796; 42 U.S.C. 7135(b).
[14] *See* 15 U.S.C. 796(g), 42 U.S.C. 7151(a).

III. Transmission Concepts

This section introduces key transmission concepts. First, it describes the role of transmission in the operation of the bulk power system and provides a brief overview of the benefits of transmission to consumers and challenges to transmission expansion. Second, it discusses the physical factors and grid-reliability considerations that create constraints within the transmission system, which in turn can cause congestion during system operations. Finally, the section reviews regional variations in the approaches historically used to manage congestion in the Eastern and Western U.S. Interconnection transmission systems. The congestion management practices include:

- Centralized unit commitment and economic dispatch procedures used in areas operated by Regional Transmission Organizations/Independent System Operators (RTOs/ISOs)
- Transmission services requests based on posted available transfer capability (ATC) information used in non-RTO/ISO areas
- Transmission loading relief (TLR) used in real-time operation in both RTO/ISO and non-RTO/ISO areas
- The Western Interconnection Unscheduled Flow Mitigation Plan (WIUFMP) used in the non-RTO/ISO areas in the Western Interconnection

Unlike prior studies, this Needs Study does not review historic ATC and TLR data in identifying persistent congestion, except where ATC or TLR analysis was provided in the industry reports reviewed for this Study. Instead, the Department uses a market price differential metric developed by FERC (2017) to identify persistent congestion.[15] ATC and TLR procedures are discussed in this section along with other congestion management schemes to provide a comprehensive view of the congestion management methods used in the U.S. power sector.

The Western Interconnection Unscheduled Flow Mitigation Plan (WIUFMP) was used for the first time in this Needs Study to identify congested areas in the Western Interconnection. Accepted by FERC in March 2016, the WIUFMP monitors real-time flows on selected transmission paths where congestion is significant and could affect grid reliability, and it uses control devices and curtailment to manage congestion and unscheduled flows on the grid.

III.a. Role of Transmission in the Power Sector

The Nation's transmission system facilitates the transfer of electricity from power supply sources, such as generating stations, to load centers where the power will be used. Transmission networks are designed to transport energy over long distances with minimal power losses, achieved by boosting voltages at specific points along the electricity supply chain. In the United States, transmission lines are typically rated between 69 kilovolts (kV) and 765 kV,

[15] Starting with ABB Velocity Suite data through 2014, FERC staff found 1,986 generator or load points in FERC-jurisdictional RTOs/ISOs where relatively high or low real-time Locational Marginal Prices occurred persistently. A discussion of congestion metrics based on transmission loading relief and on wholesale electricity price differentials compared can be found in (FERC 2016).

although exceptions can occur based on the function of the line.[16] Lines rated 230 kV and above are generally used to deliver power across long distances, such as between states or regions.

Transmission can refer to any facility that helps in the delivery of power from where it is generated to where it is used. Transmission lines are currently the primary means to connect remote generation sources to the locations of electricity demand. An underlying network of transmission lines facilitates the delivery of large amounts of power from utility-scale power generation installations to consumers. In addition to the transmission network, other transmission solutions such as non-wire alternatives can be employed to improve the efficiency of the grid, improve power quality, or enable power delivery at lower costs.

Because generation resources are usually located far from load centers, transmission infrastructure is required to connect those resources to the larger system. As more generation is developed and the transmission grid reaches its limit, the capacity of the grid must be expanded through the addition of new infrastructure, such as transmission lines and transformers, or through rebuilds using components that provide higher ratings.

Transmission infrastructure improvements provide several benefits to consumers. Transmission improves grid reliability, resource adequacy, and resilience of the power system. Transmission also helps reduce congestion and losses, which can lead to economic benefits in the form of reduced electricity prices and reduced system costs. Relatedly, diversity in load, generation, and weather patterns within and between regions helps support resource adequacy and reliability; this diversity can typically be improved with increased transmission infrastructure, so long as regional planners guard against shifting resource adequacy responsibilities to neighboring regions that face inter-dependent risks. New transmission advances clean energy goals by enabling greater access to clean energy resources, which can be in remote areas, far from load and the existing transmission system. Many new energy resources that would help reduce power prices and meet reliability and clean energy goals are currently within backlogged interconnection queues and a more efficient transmission study process that ensures the Essential Reliability Services are included can help hasten connection of those resources to the grid.[17] In areas with high resource penetration, transmission buildout can reduce resource generation curtailment and improve the output of renewable resources. A more robust transmission system—along with associated upgrades to the distribution system—supports the electrification of end-use devices which presently rely on fossil fuel combustion, resulting in environmental benefits in the form of improved air quality and avoided adverse health effects. Lastly, investing in new lines results in increased employment, tax revenues, increased resilience, and other economic development benefits. These benefits are gained directly via new and upgraded transmission infrastructure and with upgrades to distribution and generation associated with a more robust transmission network.

Expanding transmission capacity, however, can be challenging. Navigating complex state processes and meeting federal and local requirements in efforts to permit and site new lines can be difficult and can result in long development periods. The problems are compounded for

[16] The North American Electric Reliability Corporation (NERC) considers transmission lines to be facilities that carry electric energy at relatively high voltages varying from 69 kV to 765 kV. (NERC 2022b)
[17] NERC published sufficiency guidelines for Essential Reliability Services. (NERC 2016)

regional projects that cross multiple states and jurisdictions. Deciding who pays the cost of transmission capacity expansion is another challenge, which can delay or even derail a project. Further, quantifying the benefits of transmission is not straightforward. For cases in which project approval or allocation of project costs depend on the benefits, disputes about the size of benefits or the beneficiaries can be a significant hurdle. Transmission projects also frequently face public opposition or "not-in-my-backyard" concerns for various reasons. These challenges can lead to increased costs, schedule delays, or even project cancellations.

III.b. Transmission Needs

This study evaluates national transmission needs. For purposes of this document, we consider a *transmission need* to be the existence of present or expected electric transmission capacity constraints or congestion in a geographic area.

Transmission congestion. *Transmission congestion*[18] refers to the economic impacts on the users of electricity that result from operation of the system within the physical limits on the amount of electricity flow the system is allowed to carry to ensure safe and reliable operation (otherwise known as a *transmission constraint*[19]). For example, power flow could be constrained by the maximum thermal limit of a transformer or power line conductor. As a result, power is rerouted through less optimal paths to deliver more expensive generation while curtailing delivery of less expensive generation to safely meet customer demand. This process occurs either manually through operator intervention or automatically via Security Constrained Economic Dispatch.

A constraint on the transmission system that may drive transmission congestion could refer to:

- An element of the transmission system, for example, an individual piece of equipment, such as a transformer, or a group of closely related pieces of equipment, such as the conductors that link one substation to another, that limits power flows to avoid an overload that could cause one or more elements to fail and thereby jeopardize reliability; or
- An operational limit imposed on an element or group of elements to ensure that the system, as a whole, will continue to operate reliably following the failure of one or more elements; or
- A transfer limitation established to manage flows in accordance with coordination agreements.

Transmission constraints. *Transmission constraints* are the result of many factors, including load level, generation dispatch, and the possibility of equipment failure. Jointly, these conditions establish a specific level or limit—as defined above (in the second case)—to the permissible flow of electricity over the affected element(s) under specific operating conditions,

[18] EIA defines *congestion* as "a condition that occurs when insufficient transfer capacity is available to implement all of the preferred schedules for electricity transmission simultaneously." (EIA 2022b)

[19] NERC and EIA define a transmission constraint as "a limitation on one or more transmission elements that may be reached during normal or contingency operations." (NERC 2022b) (EIA 2022b).

to ensure safe and secure operations in compliance with reliability rules.[20] Transmission operating limits, which specify the maximum throughput allowable on affected transmission elements, are created to comply with these nationally established and enforced reliability rules.

As described below, the three main transmission operating limits are voltage limits, stability limits, and thermal limits:

- Voltage limits: To ensure reliability of the bulk power system, substation voltages must be close to their nominal voltages. Operating limits, which are set by equipment operators, specify the tolerances around the nominal levels. Voltages that are too high (overvoltages) or too low (undervoltages) can damage equipment and affect the ability to transfer power across the network. To avoid voltage violations, operators might place limits on the amount of power that can be transferred across some transmission facilities on the basis of system conditions.
- Stability limits: System stability refers to the ability of the power system to return to a stable operating point after a momentary disturbance, such as a fault, sudden change in load, or loss of a generator. To maintain system stability, planning standards specify acceptable frequency deviation tolerances during normal operations. In the United States, the bulk power system is operated at a nominal frequency level of 60 Hertz (Hz). Frequency deviations can occur when the operating frequency deviates outside the tolerance around 60 Hz (over or under frequency) or when voltage and current waveforms are not synchronized (phase deviations). Stability limits might be required to ensure that the power flow does not exceed levels that could pose a risk to system operations.
- Thermal limits: Transmission equipment is designed to operate within limits that depend on the physical properties of the equipment. As electricity flows through a line, it heats the line. The thermal limit is based on the operating temperature of the conductor. Exceeding the limit can cause the line to overheat and sag excessively, posing safety problems if the line contacts vegetation or other items within or close to the right-of-way. Extreme overheating can lead to annealing, which will change the metallic properties of the line and compromise its integrity. The thermal limit ensures the line does not exceed its safe operating temperature.

A fundamental responsibility of transmission system operators is to ensure reliable operation of the transmission system within these limits. This responsibility is executed by referring to transmission operating limits when approving or denying transmission service requests by parties seeking to use the transmission system. Operators practice congestion management to ensure both reliable operation and economic efficiencies.

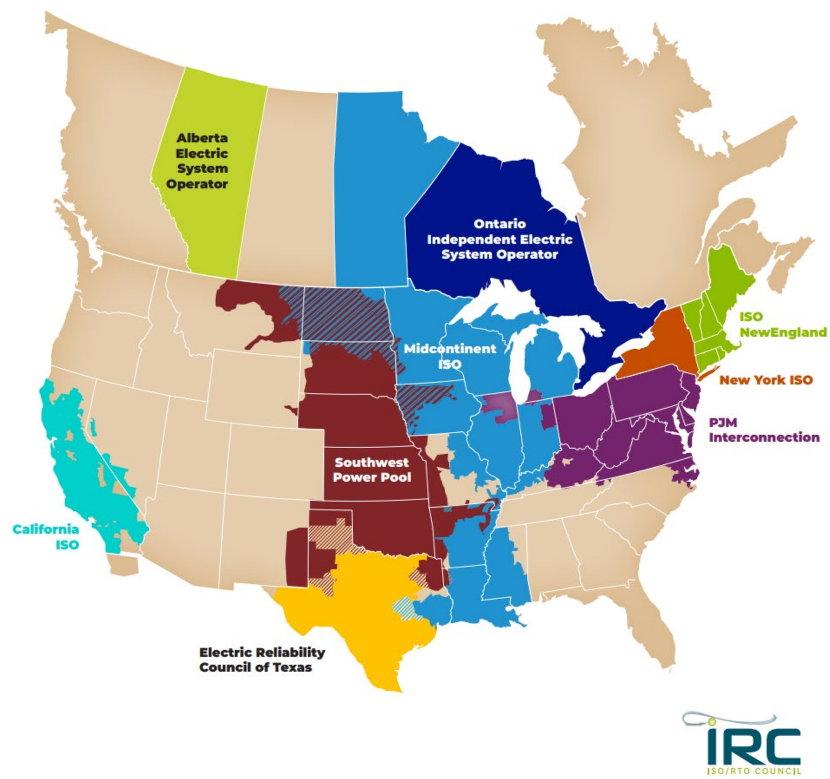
Transmission capacity constraint. While *transmission congestion* (and the related but not identical *transmission constraint)* have industry standard definitions, *transmission capacity constraints* do not. We define it here to be a suboptimal limit of transfer of electric power on the grid, including those that reduce operational reliability of the power system; power transfer

[20] Reliability standards developed by NERC and approved by FERC specify how equipment or facility ratings are to be established to avoid exceeding thermal, voltage, and stability limits. (NERC 2022b)

capability[21] or capacity[22] limits between neighboring regions that reduce resilience or increase production costs; and limits on the ability of cost-effective generation to be delivered to high-priced demand.

III.c. Transmission Regions

Several different power system regional entities are responsible for regional transmission planning and operations. The RTOs/ISOs operate and facilitate open access to the transmission system in their area, fostering competition among market participants. Seven RTOs/ISOs in the United States and two RTOs/ISOs in Canada operate on the North American power grid. Figure III-1 shows the illustrative boundaries of each organization.

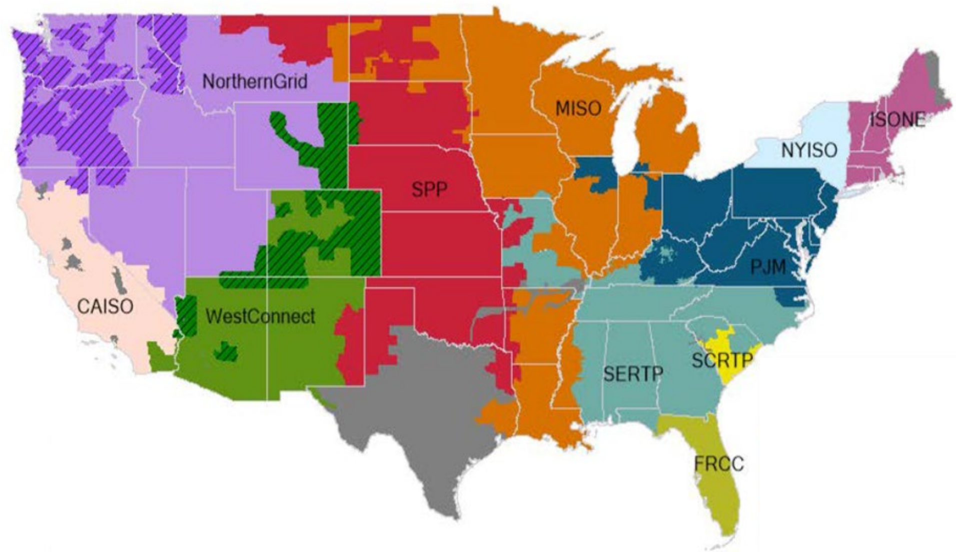


Source: ISO/RTO Council, at https://isorto.org/.

Figure III-1. RTO/ISO footprints.

Regional transmission planning occurs within the FERC Order 1000 Transmission Planning Regions (Order 1000 regions) and the Electric Reliability Council of Texas (ERCOT). The seven U.S. RTOs/ISOs serve as Order 1000 regions in their territories. The Order 1000 regions for 2021 are shown in Figure III-2.

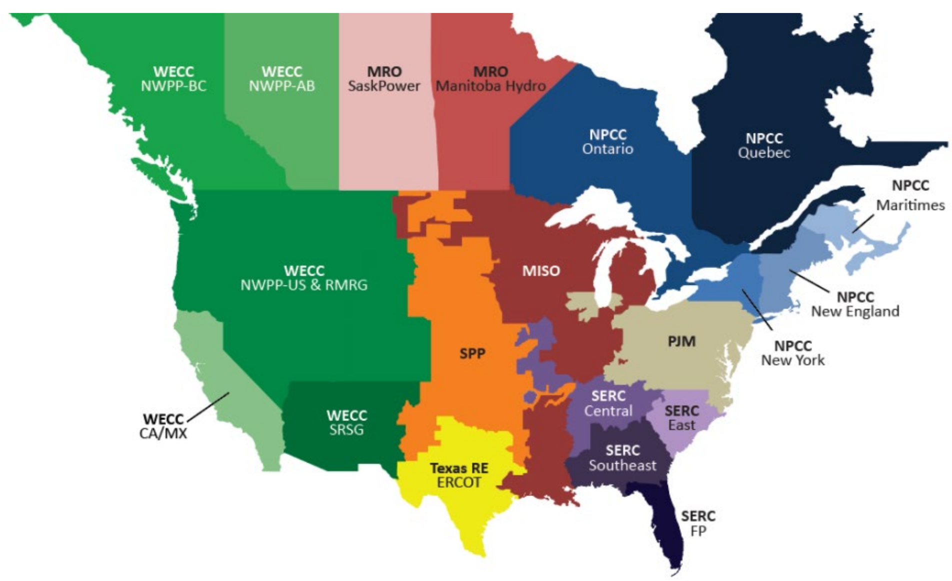
[21] Transfer capability is defined in NERC (2022b) as "The measure of the ability of interconnected electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines (or paths) between those areas under specified system conditions."
[22] Transfer capacity does not have an industry standard definition but does commonly refer to the sum of thermal limits of all transmission tie lines between two regions.



Source: Federal Energy Regulatory Commission (FERC), at https://www.ferc.gov/media/regions-map-printable-version-order-no-1000.

Figure III-2. FERC Order 1000 regions.

Reliable operations of the power system are coordinated within the North American Electric Reliability Corporation (NERC) assessment areas The 2021 NERC assessment areas are shown in Figure III-3. Similarly, the RTOs/ISOs often serve this reliability coordination function in conjunction with their associated reliability organization.



Source: North American Electric Reliability Corporation (NERC), at (NERC 2021).

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

Figure III-3. NERC assessment areas.

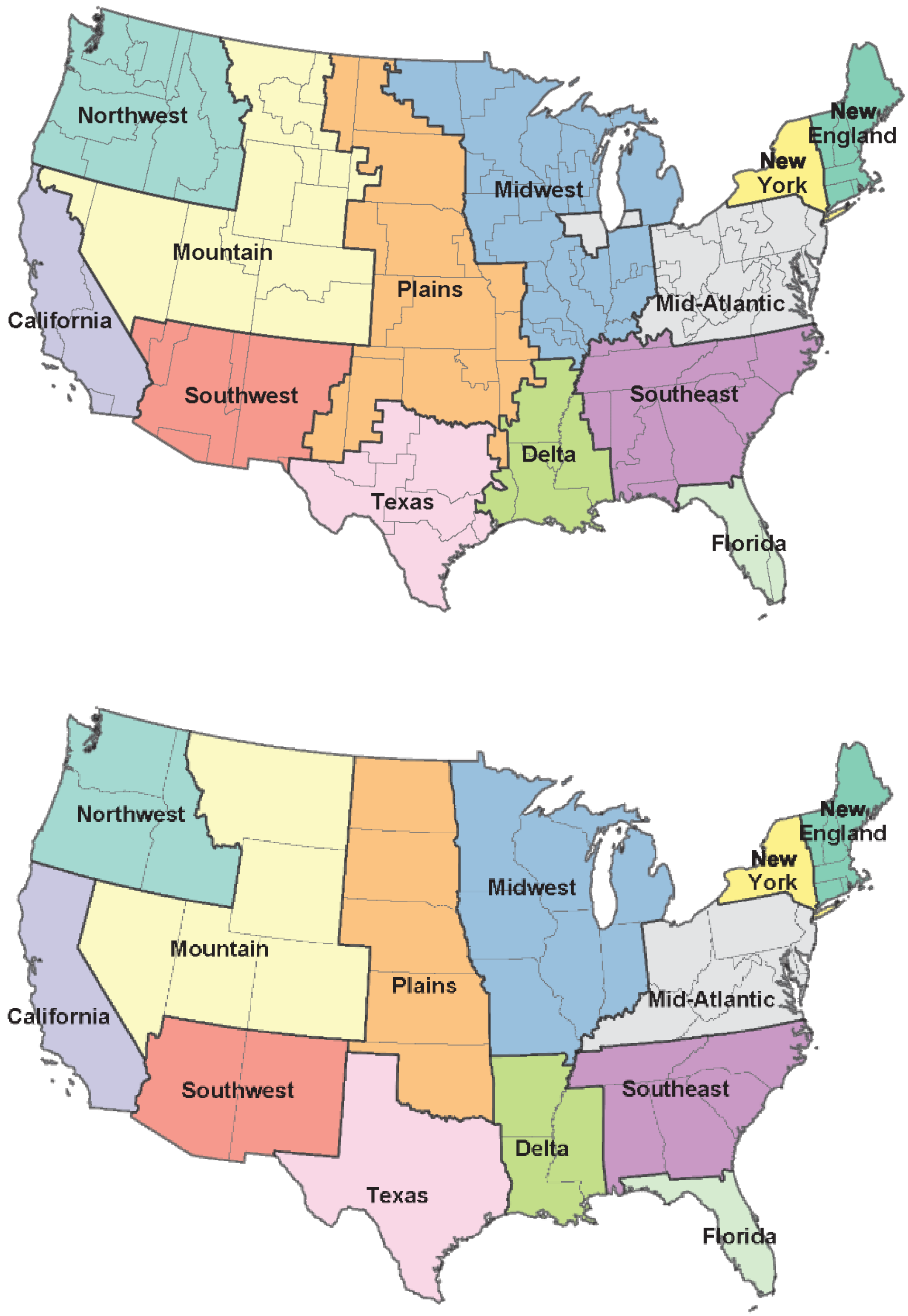
This study organizes transmission need results by geographic region, to the extent possible. If data sources are specific to an RTO/ISO, Order 1000, or NERC assessment area, the appropriate regional entity name also is used. For example, the wholesale market prices that underlie the analysis presented in Section IV.b rely on historical prices from the RTOs/ISOs, so those names are used in that section. Otherwise, a geographic naming convention is adopted here. Figure III-4 shows the geographic regions used in this analysis, the boundaries of which were chosen to represent the unique boundaries of the regional transmission entities. Table III-1 identifies the geographic region nomenclature used in this study and the associated power system entity that dominates that geographic area for completeness.

Table III-1. Region names used throughout this report. The dominant regional transmission entities that serve operations, transmission planning, and reliability assessment 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 area names from NERC LTRA at (NERC 2021).

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.



Note: Geographic boundaries that align with the reliability assessment and the transmission planning regions (top) are used whenever possible. If underlying data was only available at the state-level, then geographic boundaries align with state boundaries (bottom).

Figure III-4. Geographic regions used to present study results in this analysis, where appropriate.

III.d. Regional Practices for Managing Congestion

FERC Order Nos. 888 and 889 promulgated rules and procedures for the use of the U.S. portions of the transmission systems in the Eastern and Western Interconnections. The orders sought to ensure nondiscriminatory practices by transmission system operators and provide open access to the transmission system for all qualified parties. Pursuant to these orders, transmission system operators established two broad classes of business practices for providing transmission service to parties in advance of real-time operations.

The first class of practices, upon which RTOs/ISOs rely, involves the use of market-based approaches for allocating ATC on the basis of users' expressed willingness to pay for transmission services. See Figure III-1. The second class of practices, upon which transmission operators whose systems lie outside the footprints of the RTOs/ISOs rely, involves the use of administrative approaches wherein the availability of transmission service is announced, and requests for such service are then accepted. Both RTO/ISO and non-RTO/ISO transmission system operators also rely on specialized procedures for managing the operations of the systems in real time.

III.d.1. RTO/ISO Congestion Management Practices

RTOs/ISOs use centralized unit commitment and economic dispatch procedures driven by competitive offers from generators to sell electricity to purchasers. These procedures account for all transmission constraints to form a marginal price at each point within the transmission system, that is, the point at which wholesale electricity is either injected into the system by a seller or withdrawn by a purchaser.

Ignoring the effect of transmission losses, when no transmission or generation constraints are restricting economic dispatch and all desirable transactions are occurring, all the marginal prices at all points will be identical. If a constraint is present, the marginal prices on the two sides of the constraint will differ. The difference in price is an economic measure of the congestion cost.

If transmission investment removes a transmission constraint to relieve congestion, the investment will reduce congestion costs. Reducing load or increasing generation on the load side of a constraint will have a similar effect in reducing congestion costs. The congestion costs avoided are a direct measure of the economic benefit from, or value of, this investment. In actual cases, these benefits, intrinsically, might or might not be sufficiently large and recurrent to warrant the investment. Reducing congestion costs is not the only economic benefit that might justify a transmission investment, as discussed later in this Study.

III.d.2. Non-RTO/ISO Congestion Management Practices

Transmission system operators that are not part of an RTO/ISO publicly post the availability of transmission service, called ATC, on their systems long in advance of real-time operations. These operators then receive, review, and either accept or deny users' requests for transmission service on a firm or non-firm basis at established rates.

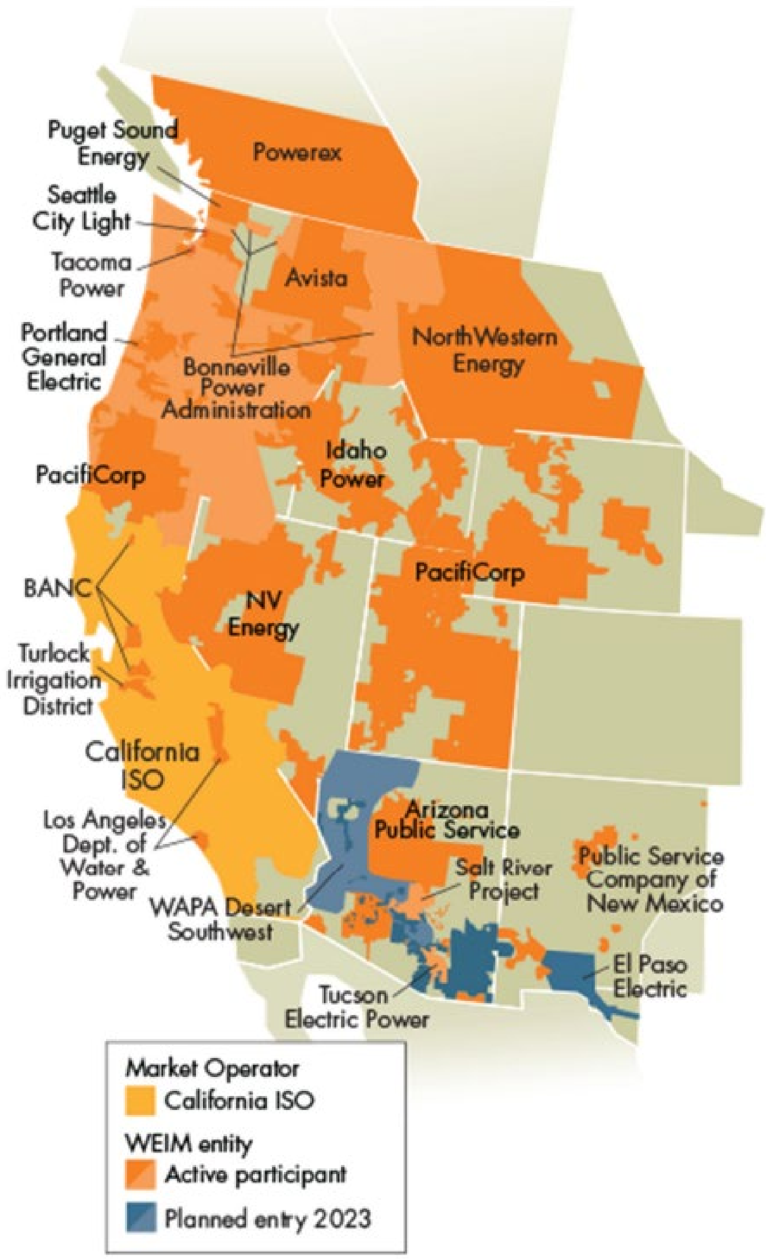
ATC directly reflects how close operation is to a transmission constraint. An ATC value of zero means no further requests for transmission services can be accepted, because no additional flows of electricity can be accommodated without violating a reliability limit.

Denials of requests for transmission service provide a direct, but incomplete, measure of congestion. Denials are a direct measure because they reflect a desire to use the transmission system that was foregone because of one or more transmission constraints. But denials do not provide information on the economic significance of the congestion they represent and no information on the value of transmission or other efforts to relieve the constraints that underlie this congestion. Information on denials of requests for transmission service is also an incomplete measure because it does not capture requests that were not made because of users' perceptions of the availability of services. That is, the availability of transmission services is routinely updated. Potential users seeking those services might forego requesting them at times of limited availability, in part because of past experience of requests being denied under these conditions. An additional reason a desired service might not be requested is because the ATC had already been set to zero.

The RTO economic dispatch procedures which serve, in part, to manage congestion in real-time are becoming available to the non-RTO regions through energy imbalance markets or services (Chen 2020). There are three active energy imbalance markets in the United States. In 2014, the California ISO (CAISO) launched the Western Energy Imbalance Market (WEIM), a real-time energy market that extended the market-based approach for congestion management in the real-time market beyond CAISO's footprint. By 2022, WEIM had expanded to include market participants in all states in the Western Interconnection except Colorado (*see* Figure III-5). SPP began administering the Western Energy Imbalance Service (WEIS) Market for utilities in the Western Interconnect not currently part of an RTO in 2020 (SPP 2022). Utilities in the Southeast are in the process of developing the Southeastern Energy Exchange Market (SEEM) to trade energy in real-time (SEEM 2022), an extension of the bilateral contracts currently used in that region. Notably, however, SEEM does not price or reflect congestion.

III.d.3. Specialized Congestion Management Practices Used in Real-Time Operations

System operators of both types of transmission classes (i.e., ISO/RTO and non-RTO/ISO) also rely on specialized procedures for managing congestion during real-time operations. These procedures are necessary to ensure reliable operation of the power system when unforeseen events occur that alter the capabilities of the transmission system from those that were assumed when the requests for transmission service were made (e.g., unexpected outage of a transmission facility), or when conflicts arise among the services agreed upon by different transmission system operators.



Source: California Independent System Operator Corporation at *https://www.westerneim.com/Pages/About/default.aspx/*

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Figure III-5. Western Energy Imbalance Market footprint.

In the Eastern Interconnection, principally but not exclusively in the Southeastern regions served by non-RTOs/ISOs, transmission operators use the Transmission Loading Relief (TLR)[23] administrative procedure to address congestion that arises in real-time.[24] Five levels of TLR procedures can be invoked. TLR level 3 is the lowest level that involves curtailments of transmission service to ensure that constrained transmission facilities are not loaded beyond safe reliability operating limits. TLR level 5 is the most severe level; it involves reducing the levels of firm transmission services. Information on TLRs is posted publicly by NERC.[25]

TLRs of level 3 and above involve curtailments of, or reductions to, previously agreed-upon transmission services. TLRs are a direct measure of transmission congestion because the measurement represents transmission services that must be foregone because of a transmission constraint. They are not economic measures of congestion because, like denials of requested transmission service, they provide no information on the value of the transmission services that have been foregone. They also do not provide insight into expected future congestion.

III.d.4. The Western Interconnection Unscheduled Flow Mitigation Plan (WIUFMP)

The WIUFMP was developed to manage congestion and loop flows in the Western Interconnection. Because of the topology of the transmission in the West, transactions from the Northwest to California result in unscheduled energy (loop) flows into Wyoming, Colorado, New Mexico, and Arizona. Under WIUFMP, stakeholders have identified Qualified Paths where congestion is significant enough to pose a reliability risk. To be included as a Qualified Path in the WIUFMP, a transmission path must have operated at or near its rated capacity for a minimum of 100 hours over the past 36 months, along with curtailments to manage the flow on the path. The path should also be susceptible to unscheduled flows. The WIUFMP manages congestion on the Qualified Paths using designated Qualified Controllable Devices and using curtailment when necessary. Qualified Controllable Devices are selected on the basis of their effectiveness in reducing unscheduled flows on the Qualified Paths.

[23] RTOs/ISOs in the Eastern Interconnection principally use price to manage congestion, and rarely invoke TLR, when compared to the non-RTO/ISO regions.

[24] In the Western Interconnection, the real-time administrative counterpart to the TLRs used in the Eastern Interconnection is called “unscheduled flow mitigation.” Unlike in the Eastern Interconnection, information on unscheduled flow mitigation in the Western Interconnection is not posted publicly.

[25] See https://nercstg.nerc.com/pa/rrm/TLR/Pages/default.aspx.

IV. Historical Data: Current Need

Several indicators point to an immediate need for more transmission infrastructure. For example, wholesale market price differences across geographic locations directly assess the impact of congestion on the transmission system. Additional transmission could remove or reduce the variation in prices caused by congestion, allowing lower-cost energy to reach high demand areas. Examining price differences between RTOs/ISOs can also help identify valuable transmission opportunities. Interregional transmission might be a better option than within-region transmission because load and generation patterns across regional markets are less temporally correlated than within different subregions of a single market.

Furthermore, over the past several years, installation of new generators has been delayed because of longer wait times for interconnection agreements (Rand et al. 2022) and increased costs to connect to the electricity grid (Caspary et al. 2021). As described in the recent Notice of Proposed Rulemaking, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection* (FERC 2022), these wait time and cost challenges are related to an increasing portion of overall transmission investment occurring through these interconnection agreement processes, which could result in less cost-effective transmission deployment. FERC suggests that the "piecemeal" approach to transmission deployment that occurs with the interconnection agreement process will not benefit from the economies of scale that would accompany a full regional transmission planning process (FERC 2022).

This section explores recent trends in transmission investments and what they reveal about current transmission need. Section IV.a reviews the past decade of transmission investments in each U.S. region using metrics as outlined in the *2017 Transmission Metrics Report* (FERC 2017). Section IV.b considers transmission congestion that currently exists within each region by analyzing historical Market Price Differentials across the contiguous United States and the Qualified Paths in the Western Interconnection. Section IV.c analyzes differences in simultaneous wholesale market prices between neighboring regions to quantify the value of interregional transmission. Section IV.d presents data from the interconnection queues, demonstrating the amount of generation waiting to be connected to the grid.

IV.a. Historical Transmission Investments

In 2016, FERC developed several metrics to assess historical transmission investment (FERC 2017). Two of these metrics show historical transmission investments—in terms of cost and circuit-miles—of projects installed annually in each NERC assessment area. To account for different sizes of the regions, both metrics are weighted by annual regional load.

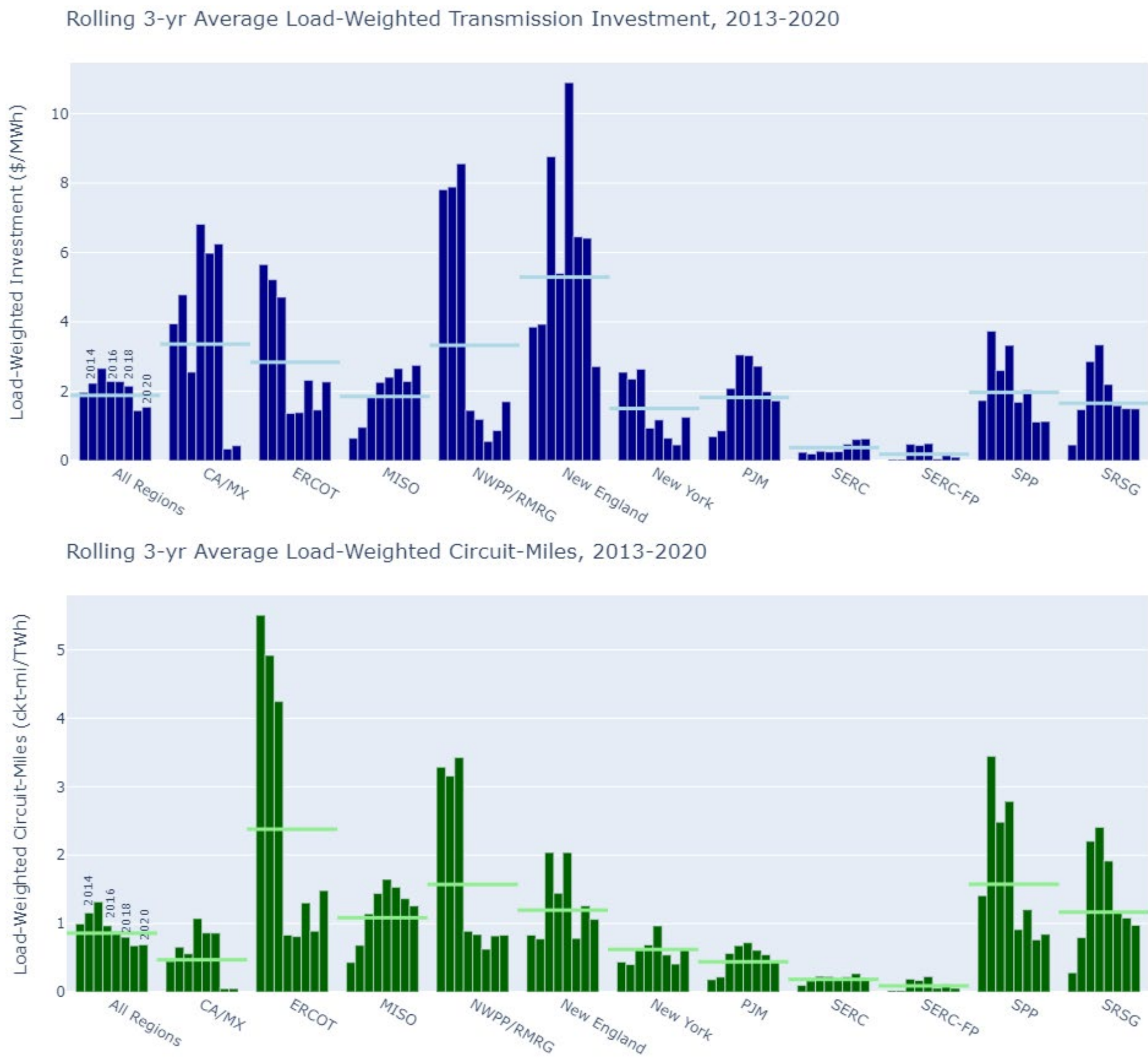
Transmission investments are inherently "lumpy," or unevenly distributed. Many projects that have been in development for several years might all be energized in the same year, giving the appearance of large investments during that single year without acknowledgement of when projects first entered the development pipeline. To account for this lumpiness, we present temporal trends using rolling averages, which differ from the metrics FERC has developed. FERC presented data from 2008 to 2015 in its metrics report (FERC 2017); we consider the decade of investments from 2011 to 2020.

Figure IV-1 (top) shows the load-weighted dollar investment of new transmission (>100 kV) energized annually in each region between 2013 and 2020, calculated as the simple moving average over the preceding three years. Figure IV-1 (bottom) shows the load-weighted circuit-miles in each region over the same time period. Data are presented by the year the transmission project was put into service (energized). The 10-year averages for each region are shown as horizontal lines in Figure IV-1 and listed in Table IV-1. Table IV-1 describes the general investment trends for each region. Because load data used in this analysis originate from NERC, the regional boundaries and naming convention matches those of the NERC reliability regions (see Figure III-3 and Table III-1) (NERC 2021).

The general historical trends for dollar investments match those of circuit-mile investments in each region. Transmission costs per mile vary markedly across regions—driven by differences in terrain, population densities, etc. (Table IV-1). Many regions—notably California (CA/MX), Texas (ERCOT), New York, and the Northwest and Mountain regions (NWPP/RMRG)—had relatively large transmission financial investments in the first half of the decade, followed by several years of decreased energization. Some regions—notably the Midwest (MISO) and New England—steadily increased transmission financial investments through most of the decade. Texas (ERCOT) built more transmission circuit-miles than any other region in the first half of the decade. The Southeast (SERC) and Florida (SERC-FP) regions (made consistent and relatively low investments throughout the decade.

These investments resulted in a national total of over 34,000 circuit-miles of either newly constructed or rebuilt transmission lines rated above 100 kV. Of these, more than 22,000 circuit-miles were higher capacity lines rated at least 345 kV (MAPSearch 2022).

In addition to reviewing trends in total transmission investments, examining trends in the primary driver and developer type for new transmission installations is also instructive. Figure IV-2 shows the proportion of transmission circuit-miles (rated above 100 kV) installed between 2011 and 2020 by different developer type. Incumbent transmission developers, or entities that develop transmission within their own retail distribution footprint, have always dominated project development space nationwide. The proportion of project circuit-miles installed by non-incumbent transmission developers, or entities that do not have a retail distribution footprint or that are public utilities developing transmission outside of their footprint, has steadily decreased from 40 percent in 2013 to less than 2 percent in 2020.



Source: Transmission data from MAPSearch Transmission Database (2022) and load data from 2020 NERC Energy Supply & Demand (ES&D) Database (2020).

Note: CA/MX is California and Baja California, Mexico reliability region, ERCOT is Electric Reliability Council of Texas, SPP is Southwest Power Pool, MISO is Midcontinent Independent System Operator, SERC is the SERC Reliability Coordinator for the Southeast (not including Florida), SERC-FP is the Florida Peninsula region of SERC, , NWPP/RMRG is a legacy name for what is now the Western Power Pool representing both the Northwest and Mountain regions, SRSG is Southwest Reserve Sharing Group.

Figure IV-1. Load-weighted transmission investment (top, $/MWh) and circuit-miles (bottom, ckt-mi/TWh) for new transmission above 100 kV energized between 2011 and 2020 for each region (shown as 3-year rolling averages between 2013 and 2020).

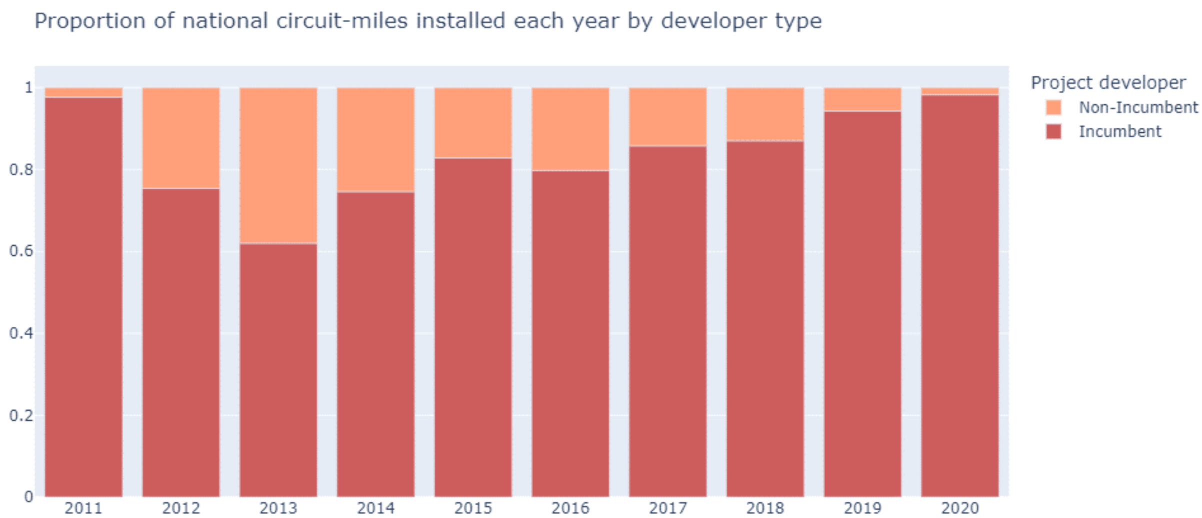
Table IV-1. Qualitative trends in new transmission investments between 2011 and 2020 for each region and for the United States as a whole. Decadal mean of both load-weighted transmission investments and circuit-miles for new transmission rated over 100 kV and energized in each year of the decade are shown.

Region	Load-Weighted Investment (US$/MWh)		Load-Weighted Circuit-Miles (ckt-mi/TWh)	
	Decade Average	General Trend	Decade Average	General Trend
New England	5.29	Sharp increase 2015 Sharp decrease 2018	1.20	Notable increase 2015-2017
CA/MX	3.36	Sharp decrease in 2019	0.47	Sharp decrease 2019-2020
NWPP/RMRG	3.33	Sharp decrease in 2016	1.57	Sharp decrease in 2016
ERCOT	2.84	Sharp decrease in 2016	2.38	Sharp decrease 2016-2020
SPP	1.99	Steady decrease since 2014	1.58	Steady decrease since 2014
All Regions	1.88	Relatively flat	0.86	Steady decrease
MISO	1.85	Steady increase	1.09	Steady increase 2013-2017 Steady decrease 2017-2020
PJM	1.82	Steady increase through 2016 Steady decrease after 2017	0.44	Slight increase through 2017 Slight decrease after 2017
SRSG	1.66	Steady increase through 2016 Steady decrease after 2016	1.17	Steady increase through 2016 Steady decrease after 2016
New York	1.50	Steady decrease	0.62	Slight increase through 2017 Slight decrease after 2017
SERC	0.38	Relatively flat	0.18	Relatively flat
SERC – FP	0.19	Relatively flat	0.09	Relatively flat

Source: Transmission data from MAPSearch (2022) and load data from NERC ES&D (2020).

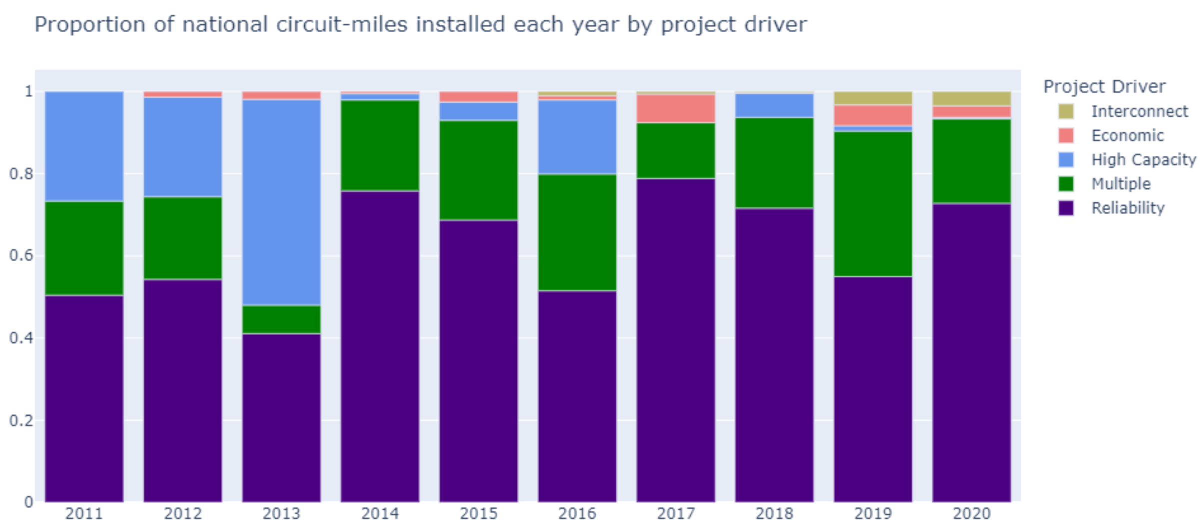
Figure IV-3 shows the primary driver for all transmission projects (rated above 100 kV) energized between 2011 and 2020 across the United States. New transmission projects can be a response to a single, or combination of drivers, including a specific reliability need, the opportunity to realize far-reaching economic benefits, and the ability to interconnect new generators to the power system, especially in moving renewable or fossil-based generation long distances over high-capacity power lines (predominantly rated above 230 kV). The primary driver for a project is identified in transmission planning studies for cost allocation purposes.

The proportion of projects installed nationwide to provide at least two drivers (“Multiple”) was relatively constant over the past decade. The proportion of circuit-miles installed to provide high transmission capacity for moving generation long distances dropped precipitously after 2013, and few circuit-miles have been installed in response to this primary driver since. The proportion of circuit-miles installed to increase system reliability, however, has grown with time.



Source: Data from MAPSearch Transmission Database (2022).

Figure IV-2. Project developer type for all projects installed nationally between 2011 and 2020. Proportion of circuit-miles of new projects energized in each year are also shown.



Source: Data from MAPSearch Transmission Database (2022).

Figure IV-3. Primary driver of all projects installed nationally between 2011 and 2020. Proportion of circuit-miles of new projects energized in each year are also shown.

IV.b. Market Price Differentials

Wholesale electricity prices from the seven RTO/ISO electricity markets can be used to identify regions that would benefit from additional transmission resources. Prices within these wholesale electricity markets are determined at locational marginal price nodes allowing prices to vary depending on local conditions. Nodal prices are divided into three constituent parts: energy, losses, and congestion. The energy component is constant at all nodes within a single market, but the losses and congestion components vary by location. The cost of losses is small, which means that price variation by location within each market is driven primarily by transmission system congestion.

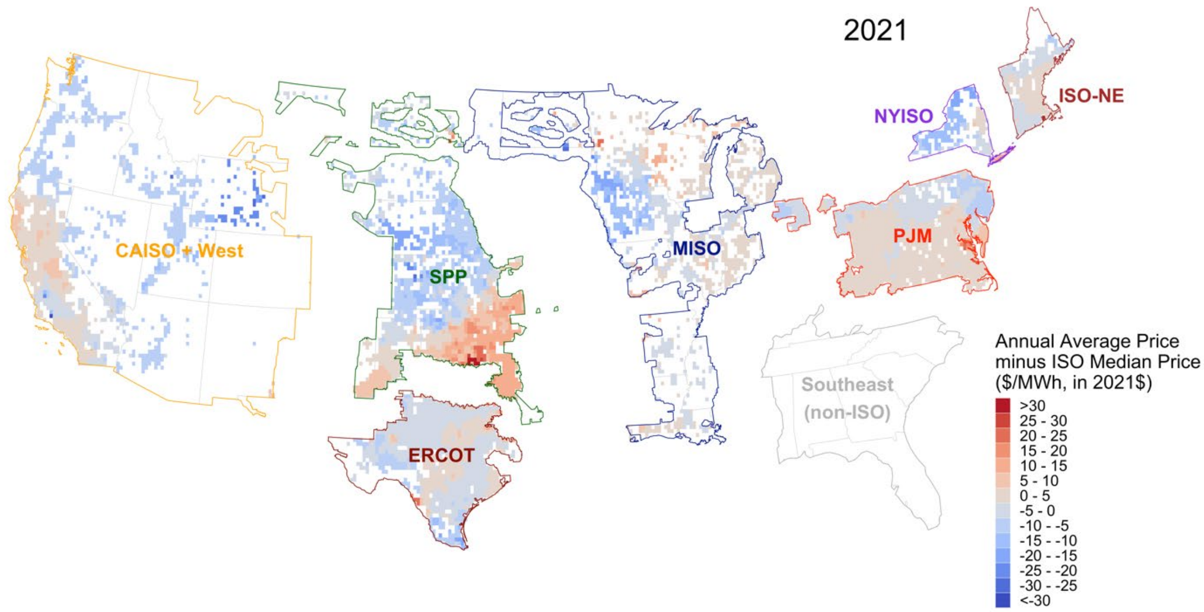
This analysis builds on past work; for example, DOE (2020) examined congestion in wholesale markets using RTO/ISO-reported congestion costs. These reported congestion costs are presented only at the region-wide level. They do not provide insight on where congestion is most costly within each region, nor do they provide insight on the value of interregional transmission. Additionally, RTO/ISO-reported congestion metrics are challenging to compare to each other because each RTO/ISO has a different approach for calculating these metrics. DOE (2020) also examined transmission line usage rates in the western United States, finding high usage on some transmission lines. This market price analysis goes beyond past work by analyzing and identifying congestion across all nodes within each region and providing a metric to examine the value of interregional transmission. In this analysis, we examine price differences within and across energy markets to understand trends in congestion and the implications for transmission expansion. The analysis reported here as well as additional details can be found in the Millstein et al. (2022a).

IV.b.1. Regional Price Differences

Congestion has created clear gradients in electricity prices across each major wholesale market region. These spatial gradients can be observed in Figure IV-4, which shows how the 2021 annual average price at each node differs from the median annual average price across all nodes in a region. For example, prices are low in northern SPP and high in southern SPP, prices are low in western MISO and higher in eastern MISO, and prices are low in the eastern portion of the West/CAISO region,[26] but higher in California, especially near population centers. A north/south pricing gradient in New York Independent System Operator (NYISO) and ISO–New England (ISO-NE) is also apparent. New transmission between low- and high-priced regions would allow load in high-priced markets to draw energy from a larger set of generators and lower electricity costs in high-priced regions. The extent to which high prices could be reduced depends on the magnitude of available generation made accessible by the new transmission. Goggin (2021) explored the potential for interregional transfer during recent extreme weather events, such as the February 2021 cold weather event (frequently referred to as Winter Storm Uri). Goggin (2021) found that while transfer across regions would have been limited by lack of

[26] Wholesale electricity price datasets are not readily available for the non-RTO West and can create challenges in evaluating congestion along the eastern edge of the Western Interconnection. See Section IV.c for further discussion.

available generation during certain hours, substantial transfers across existing lines did help to limit price spikes in multiple regions and additional transmission capacity would have allowed for even greater reduction to price spikes during many extreme weather events.



Source: Lawrence Berkeley National Laboratory (Millstein et al. 2022b).

Note: Each RTO/ISO is treated as a separate region, except CAISO and the larger western region, which are treated as a single region. Nodal price analysis does not provide full geographic coverage of congestion through the non-RTO western region (particularly in New Mexico and Colorado but also in portions of other states). Similarly, the analysis provides no coverage of non-ISO regions in the Southeast. Also, note that small price differences of $0-5/MWh may be due to losses rather transmission congestion.

Figure IV-4. Price difference between nodal average price and the regional median price in 2021.

An alternative approach to defining congested regions is to identify locations with price spikes (noticeably high or low hourly prices relative to prices across a region). Of particular interest are locations that have large price spikes across many years, which could indicate insufficient transmission infrastructure (FERC 2017), or insufficient local generation. To determine locations with consistent price spikes, we used another approach FERC developed—the Market Price Differential metric (FERC 2017). The Market Price Differential highlights locations with persistently low- or high-price spikes over many years.[27]

In contrast to the price gradients shown in Figure IV-4, the Market Price Differential metric shows only a subset of all nodes, which allows identification of discrete locations that would benefit from transmission. For example, Figure IV-5 shows discrete pockets of low- and high-priced nodes across the eastern region. Of particular note are the low-priced pockets centered on the Oklahoma and Kansas border, collocated with substantial wind resources. Similarly low-

[27] More information on the methods used here and summary data are available in the Supplemental Material.

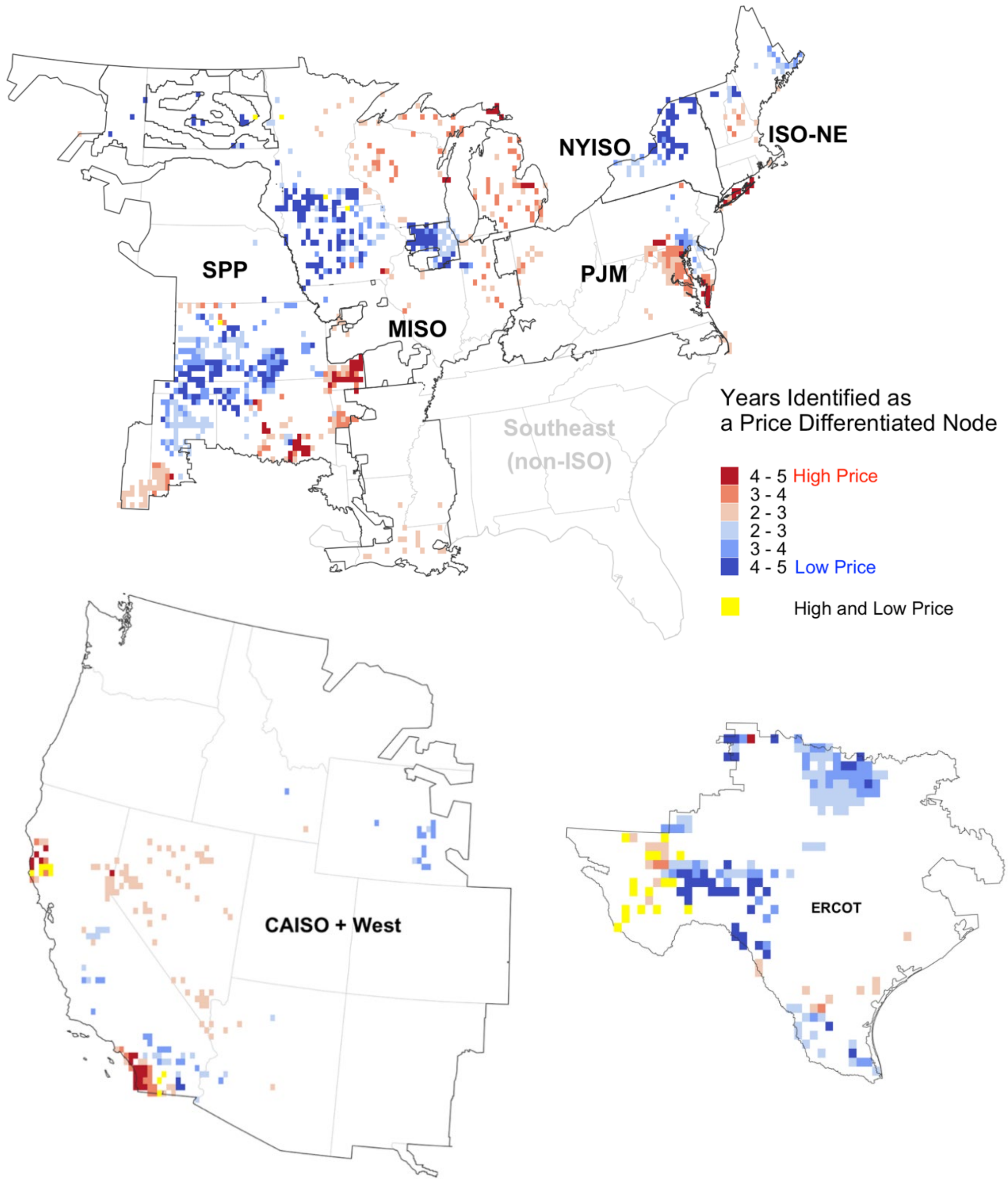
priced pockets can be found near wind resources in MISO in Iowa and Minnesota, and in PJM in Illinois. High-priced regions are identified in New York City and Long Island, in PJM near Washington DC, and in eastern SPP. A full list of high-and low-priced regional "pockets" is presented in Table IV-2. Transmission to any of these high-priced locations could help lower prices in those regions. Other strategies (e.g., energy efficiency or new low-cost energy supply resources) could also help lower localized high prices. The specific solutions that work for each locality might be unique to that community.

Note that Figure IV-5 combines the ISOs in the Eastern Interconnection. Alternatively, one can calculate the Market Price Differential metric within each ISO individually. Doing so largely identifies the same set of congested nodes as the interconnection-wide calculation depicted in the figure.[28] That the pattern of congested locations does not meaningfully differ between the individual ISO analysis and the combined region analysis suggests that the extreme prices in each ISO remain extreme within the context of the entire Interconnection.

The western region has fewer congested areas identified by the Market Price Differential metric (Figure IV-5) compared with the many different pockets of congestion identified across the Eastern Interconnection. For the non-RTO West, however, this finding is more a function of lack of wholesale electricity price data than a depiction of actual operating conditions (see Section IV.c for further discussion). Most notable is the congestion limiting energy transfer into the populated area along the southern coast of California from the nearby inland region east of the coast. Additional congestion is observed in coastal northern California and in Wyoming. There is some additional indication of congestion in Nevada, but this is found for only 2 out of 5 years, in most cases. We note that geographic coverage of the western region is sparse for the metrics shown in Figure IV-4 and Figure IV-5. Additional analysis of congestion in the western region is discussed in Section IV.c.

Pockets of congestion are also identified in ERCOT (Figure IV-5). In ERCOT, low-price regions are identified in the northern, western, and southern areas of the state. Few high-priced nodes are identified to be consistently high priced for more than 2 years. This indicates that the location of high-priced nodes has varied by year in ERCOT, while low-cost nodes have been more consistent over time.

[28] See Supplemental Material for a comparison between the calculations when each ISO is considered in isolation.



Source: Lawrence Berkeley National Laboratory (Millstein et al. 2022b).

Note: The Market Price Differential metric was calculated while treating the Eastern Interconnection as a single combined region (ISO boundaries are provided for reference). The metric is calculated independently each year; nodes are highlighted when they are identified for 2 or more years. Only a subset of nodes is identified as high- or low-priced nodes, and white space indicates either no nodes in that location or existing nodes were not identified as high- or low-priced (for reference, Figure IV-4 shows all nodes).

Figure IV-5. Low- and high-priced nodes identified by the Market Price Differential metric. Top: RTOs/ISOs within the Eastern Interconnection. Bottom left: CAISO and the WEIM. Bottom right: ERCOT.

Table IV-2. High- and low-priced regions identified within the wholesale markets of the Eastern Interconnection, the Western Interconnection, and ERCOT. Regions are defined based on a regional concentration of nodes identified with the Market Price Differential metric.

Region	Eastern Interconnection	Western Interconnection	ERCOT
Low-priced regions	Southern and Western KS OK/TX Panhandles Southwest and Central IA Southern MN Northeast IL Southeast PA Upstate NY North VT / NH	Mojave Desert CA Eastern WY	Northern TX Western TX Southern TX
High-priced regions	Southeast MO Southern OK Northwest WI Eastern and UP MI Eastern MD / VA Delmarva Peninsula MD & DE Long Island NY	Southern Coast CA Northern Coast CA	

IV.b.2. Interregional Price Differences

Although the regional calculation of the Market Price Differential metric (Figure IV-5) provided some indication of the need for interregional transmission, we can more directly assess the value of transmission across regions and Interconnections by determining the average hourly difference in pricing between regional hubs. Part of the value of new transmission is determined by energy arbitrage, that is, the difference in price between two locations.[29] Transmission provides additional value not included within this energy arbitrage value, such as providing capacity value, improving grid reliability and security, helping reduce emissions by facilitating greater deployment of wind and solar resources, and potentially improving resilience to extreme weather and unexpected events. Nevertheless, the energy arbitrage value is an important part of the total transmission value and provides an approach for ranking different transmission connections.

Figure IV-6 shows the average hourly difference in energy price between a selected set of pricing nodes. Nodes that are a “hub” or “zone” were most representative of the larger region. Compared to other locations, hub nodes have high trading volume. Transmission between ISOs was generally more valuable than transmission within ISOs. In the first half of 2022, 2021, and on average between 2012 and 2020, the highest value links were between SPP and its neighbors and ERCOT and its neighbors, and across the northeast. Note that prices during the 2nd half of 2022 were not examined here as they were not yet available at the time of writing.

[29] Large hourly price differences across regions suggest transmission value but do not perfectly quantify the marginal transmission energy value between regions because market rules for nodal price formation vary by region. Thus, results here should be interpreted as suggestive, but not a definitive measure of value.

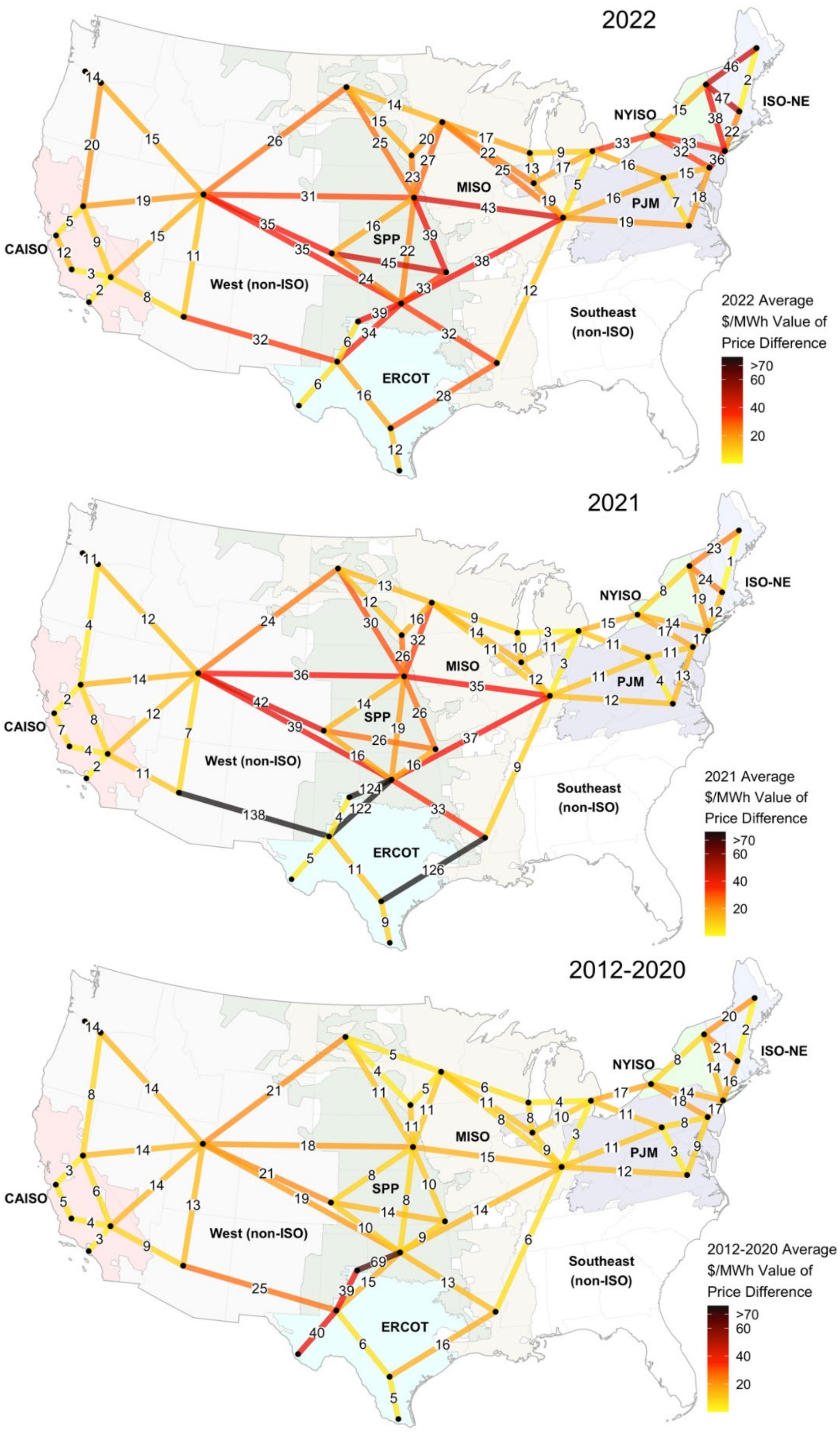
Exploring the time trends of these links reveals that the value of interregional transmission to SPP and to ERCOT has been increasing over time.[30]

The marginal value of transmission increased substantially in 2021 and the first half of 2022 compared to prior years (e.g., compare the two panels of Figure IV-6). This increase broadly tracks the overall increase in energy prices observed since 2021. Compared to the 2012 – 2020 average, 2022 saw broad increases in transmission value across most regions. In many locations, values in 2021 were similar to values in the first of 2022, except for the impact of extreme weather. For example, average nodal electricity prices in ERCOT and SPP were 3.9 and 1.9 times higher in 2021 than in 2019, respectively (2021 is compared to 2019 rather than 2020 to avoid comparison to the low 2020 prices caused by COVID). In other regions, 2021 electricity prices increased by 1.5 times or less between those same years (the increase was only 1.2 times in CAISO). Thus, it is not surprising that the 2021 value of transmission between SPP and other regions, and the value between ERCOT and other regions, increased by the more than the increase seen between the remaining U.S. regions. In SPP and ERCOT, extreme weather (i.e., Winter Storm Uri) produced a price spike in February 2021 (Levin et al. 2022). This period was characterized by extremely high prices in ERCOT and SPP (in the thousands of dollars per MWh), which were not observed in neighboring regions.[31] The period of extreme prices in February 2021 was limited primarily to SPP and ERCOT and demonstrates an important value of transmission: the ability to address regionally concentrated extreme weather impacts on electricity prices. The high prices found in ERCOT in 2021 may also have been reduced had certain regulatory changes already been implemented, including requirements for weatherization for generation resources and lower peak price limits. While 2021 reflects discreet, high-cost events in SPP and ERCOT, it is not clear that other regions are at lower risk from such events in the future, and therefore would benefit less from interregional investment.

A challenge to determining the value of transmission in regard to extreme events is how much each stakeholder should invest in new transmission for the “insurance” value of reducing future extreme event costs. Attribution of value is challenging because each power sector stakeholder’s potential benefits depend on the characteristics of future, unpredictable extreme weather events. Work is ongoing to quantify the value of resilience against extreme weather impacts when weighing the cost of new transmission investments against the benefits they provide (FERC 2022; Pfeifenberger 2022).

[30] Further analysis of time trends is presented in Millstein et al. (2022a).

[31] Wholesale price patterns can be investigated with the ReWEP tool, see Millstein et al. (2022b)



Source: Lawrence Berkeley National Laboratory (Millstein et al. 2022b).

Figure IV-6. Average hourly difference in price between selected hub and zonal nodes within and across regions for the first half of 2022 (top), 2021 (middle) and for 2012–2020 (bottom).

IV.b.3. Concentration of transmission congestion value during high value hours and extreme events

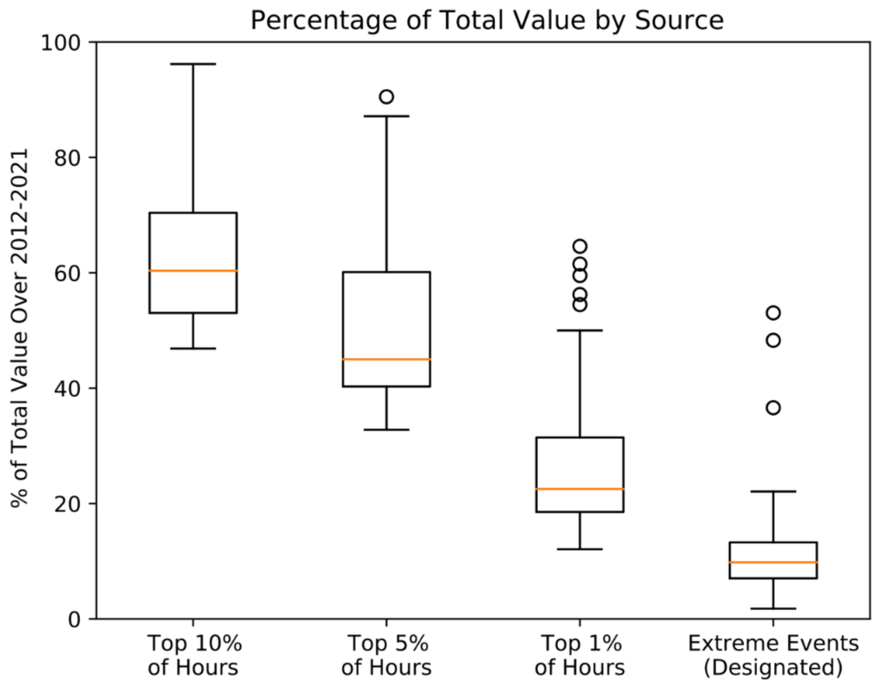
Transmission value can be affected by relatively infrequent but challenging conditions on the electricity system. Some examples of these conditions include fluctuations in uncertain variables for either short-term or long-term periods (e.g., fuel price volatility, inaccurate demand forecasts, inaccurate renewable forecasts), extreme weather events (e.g. heat wave, winter storm), exceptional levels of electricity demand, and infrastructure failures (in transmission or generation equipment, for example). Correlation of the above conditions can lead to particularly high system congestion. In this section the portion of total transmission congestion value attributable to high value hours or extreme conditions is analyzed.

Two approaches are used to identify extreme conditions or high value hours: In the first approach, literature and NERC reports are used to identify specific time periods of grid stress and extreme weather events.[32] Congestion value over these types of events is tabulated and together the events are referred to as 'designated events.' In the second approach, the value at each potential transmission link is calculated each hour and ranked, and the portion of total value contained in the top 1%, 5%, and 10% of hours (sorted by value) is tabulated. This second approach assumes that, though there was not necessarily a named weather event or infrastructure outage during all these top hours, the very fact that the price differential is so high indicates that an infrequent set of conditions exists. These conditions may not require emergency action by the ISO, and in fact may be an infrequent condition that occurs during standard operational conditions but occur during a period in which the market faces extreme price differences. The first and second approaches identify a somewhat overlapping set of hours, but the subsequent analysis is designed to prevent any 'double counting' issues where relevant.

For each transmission link as established in Figure IV-6, the total value over the study period was calculated, along with the value of the top 10%, 5%, and 1% of hours (in which these hours have been determined separately for each link). An important finding here is that a small portion of hours accounts for roughly half the value. Specifically, in the median case, the top 5% of hours account ~50% of value (*see* Figure IV-7). The top 1% of hours account for 20 to 30% of total value. Designated extreme events produce 10% to 20% of value (and account for ~5% of total hours). This indicates that many of the most valuable hours for transmission fall outside the set of designated extreme events, and instead occur during more standard operational conditions that were not flagged in the process used to designate extreme events.

Overall, this analysis highlights the importance of properly representing challenging grid conditions, including explicitly representing extreme weather events, fuel-price volatility, generation and load uncertainty, and geographic market resolution, when estimating or modeling the congestion value of transmission. Additional discussion and details can be found in Millstein et al. (2022a).

[32] Details can be found in Millstein et al. 2022a



Source: Lawrence Berkeley National Laboratory (Millstein et al. 2022a).

Note: The distribution reflects the spread across the set of links shown in Figure IV-6.

Figure IV-7. The portion of transmission congestion value derived from selected conditions over 2012 – 2022.

IV.c. Qualified Paths

For the non-RTO Western Interconnection, evaluating congestion can be a challenge because of a lack of wholesale electricity price data. Instead, information on congestion management, particularly along the eastern edge of the Western Interconnection, can be obtained from transmission operators and the WECC.

When congestion occurs along the West Coast, which can be frequent as demonstrated by the Market Price Differential analyses in the preceding sections, unscheduled energy from the Northwest flows through Wyoming, Colorado, New Mexico, and Arizona. This energy flow, referred to as loop flow, can create significant congestion and reliability challenges along the eastern edge of the Western Interconnection (*see* Figure IV-8).

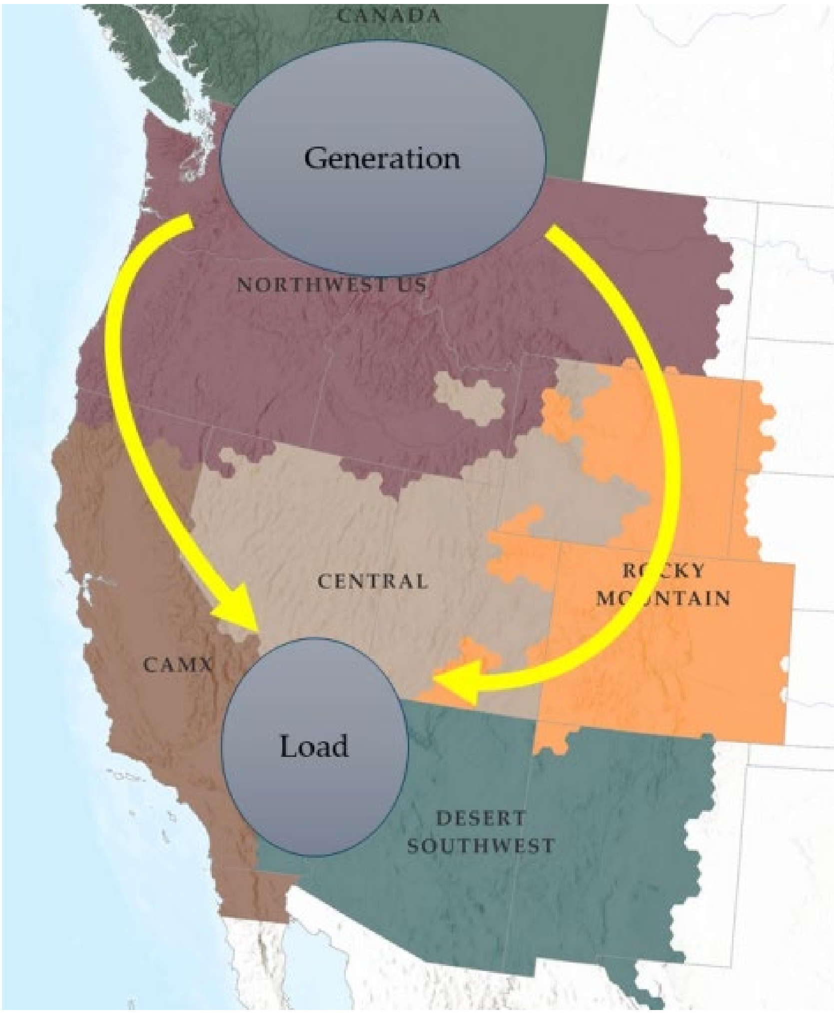
In response, the Western Interconnection uses the WIUFMP. The WIUFMP is a FERC-filed tariff that provides a mechanism for reliability entities to mitigate flows on Qualified Paths to reliable levels.[33]

[33] The WIUFMP FERC tariff is available at www.wecc.org/Reliability/FERC%20Accepted%20WIUFMP%20March%2011%202016.pdf.

Qualified Paths in the West designate transmission with the highest levels of congestion. Four of the approximately 50 paths in the Western Interconnection were identified as qualified paths. Path 66 (California), Path 36 (Wyoming-Colorado), Path 30 (Colorado-Utah), and Path 31 (Southern Colorado-Northern New Mexico) are bottlenecks of limited transmission to deliver power from the Northwest to the highly populated Desert Southwest (SPP 2020). These paths are listed in Table IV-3. Figure IV-9 shows these paths and many major paths in the Western Interconnection. The parallel nature of the Qualified Paths creates simultaneous interactions between the eastern and western portions of the Western Interconnection that can create reliability risks. Historically, the West has leveraged specific phase shifting transformers, also referred to as Qualified Controllable Devices, to redirect flows to manage unscheduled flow.

Phase shifters were a cost-effective alternative to additional transmission for many years, but their effectiveness is decreasing as the industry transitions away from tradition thermal generators to renewable energy resources. Much of the existing high-voltage transmission system was constructed around thermal generators. Utility-scale renewable resources are in different locations relative to existing transmission infrastructure. This has implications for transmission loading and can create incremental unscheduled flows on certain transmission segments, including the qualified paths.

In addition to the phase shifters, thermal generators have traditionally been leveraged as tools to manage congestion. Generator output can be increased or decreased on either side of affected transmission segments, which can aid in alleviating constraints. Given the number of thermal generator retirements, incrementing and decrementing generation is not as available as a tool for congestion management. This increases the reliance on the phase shifters, which were not designed to manage the changes in transmission flows developing on the system.



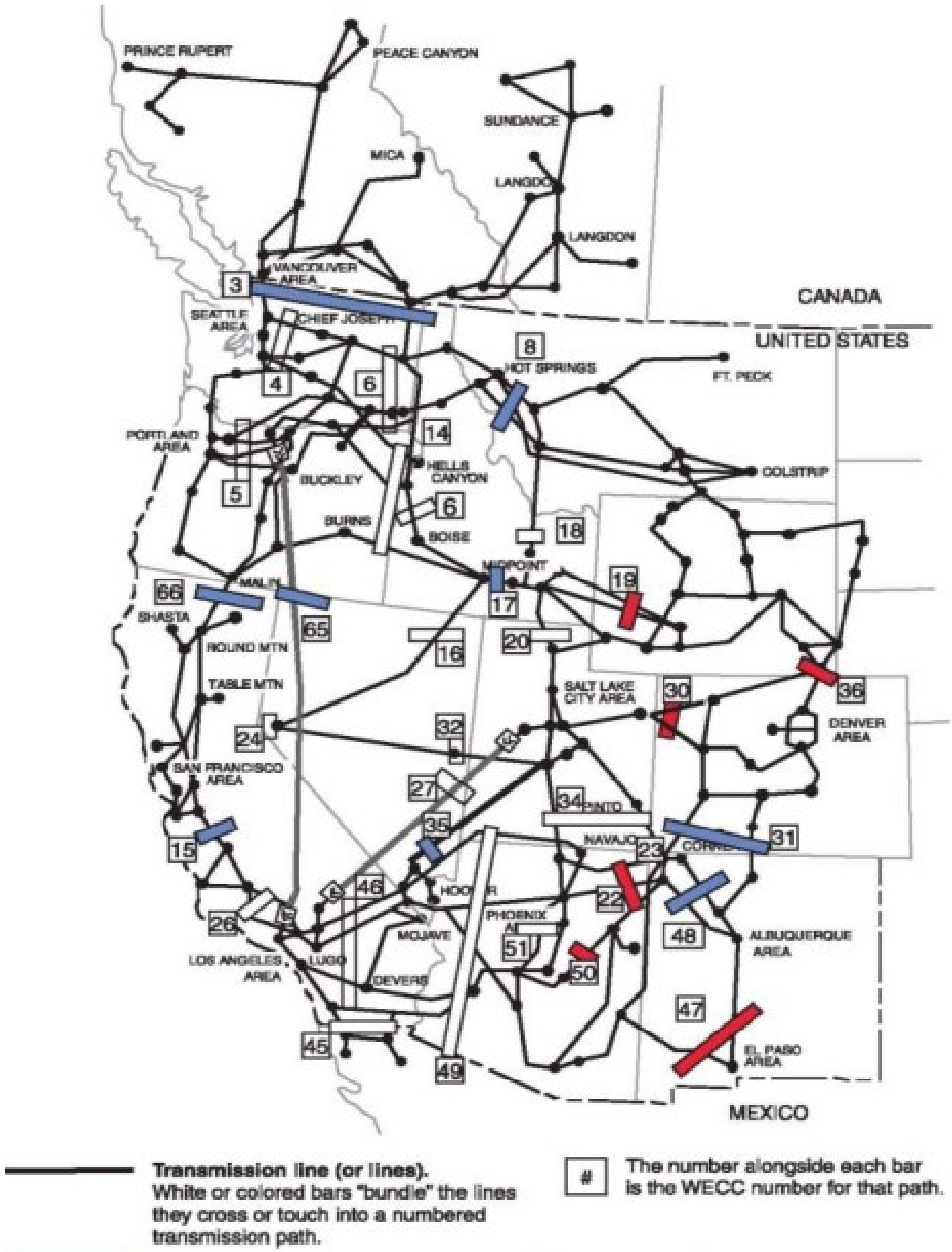
Source: WECC August 2020 Heatwave Event Analysis Report. March 2021; https://www.wecc.org/Reliability/August%202020%20Heatwave%20Event%20Report.pdf.

Figure IV-8. Loop flow in the Western Interconnection.

Table IV-3. Qualified paths and path operators in the Western Interconnection.

Qualified Path	Path Operator
Path 66 – California Oregon Interface (COI)	CAISO
Path 30 – TOT1A	Western Area Power Administration (WAPA)
Path 31 – TOT2A	WAPA
Path 36 – TOT3	WAPA

Source: Qualified Paths and path operators in the Western Interconnection from SPP at [https://spp.org/documents/58826/current%20list%20of%20qualified%20devices%20&%20paths_062520.pdf.](https://spp.org/documents/58826/current%20list%20of%20qualified%20devices%20&%20paths_062520.pdf)



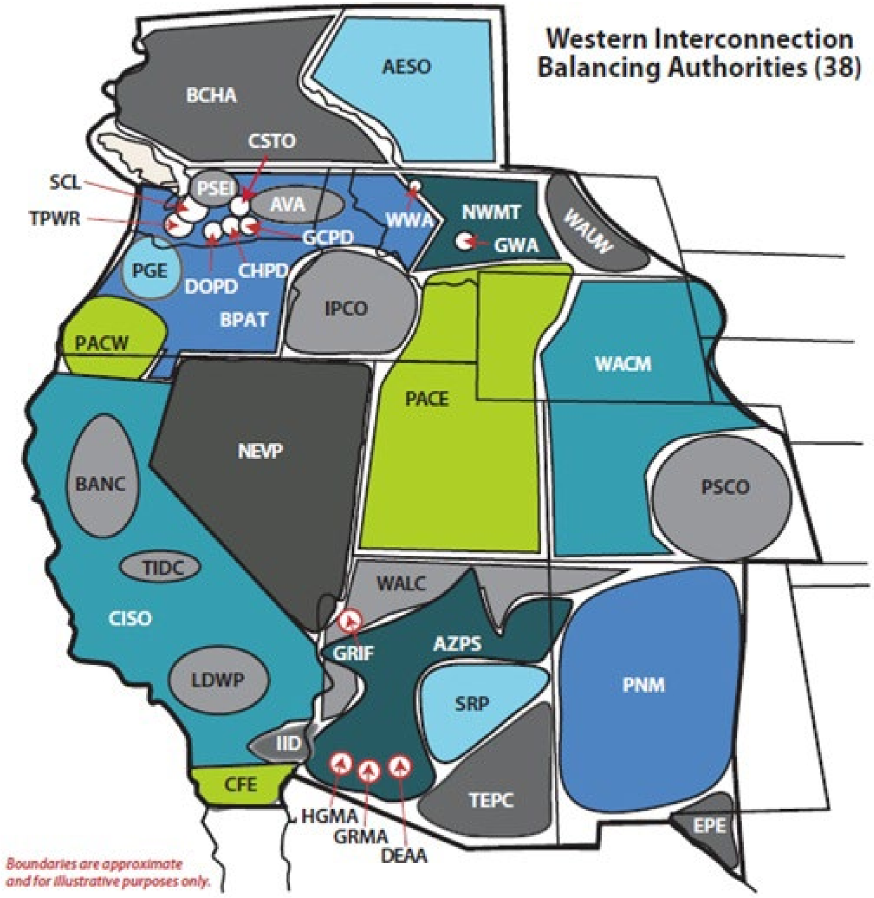
Source: Western Electricity Coordinating Council (WECC). See also: https://www.wecc.org/Reliability/TAS_PathReports_Combined_FINAL.pdf.

Figure IV-9. Paths in the Western Interconnection.

Additional transmission and expanded market structures to price and manage congestion are potential solutions to congestion challenges in the non-RTO West. The need for additional transmission capacity will become increasingly acute as transmission flow patterns continue to change due to additions of variable energy resources, thermal generator retirements, and drought-induced reductions in hydropower generation. Of critical importance is that changes made to the transmission system on the western edge of the Western Interconnection (CA, OR, WA) can have significant implications for transmission system operations on the eastern edge of the Western Interconnection (WY, CO, NM) because of the unscheduled loop flow described previously. This reliability and economic consideration is system wide. As the transmission system is expanded along the West Coast, transmission upgrades also might be necessary along the eastern edge of the Western Interconnection to protect system reliability across the entire West. Interconnection-wide power flow analyses and system impact studies will be essential in the study processes.

The non-RTO West faces unique challenges because it currently consists of 38 separate Balancing Authority (BA) areas, each operated by a different BA, shown in Figure IV-10. BAs are NERC-registered entities subject to strict NERC requirements to balance supply and demand in their respective footprints in real time. They meet these demands through extensive manual coordination with generators and transmission owners/operators within their footprints, along with communications with neighboring BAs and the regional Reliability Coordinators. The RTOs use a system known as Security Constrained Economic Dispatch to automatically adjust generation outputs in response to real-time system congestion, a base functionality not used by the BAs. The manual processes used in the non-RTO West to adjust generation were reasonably effective when net load (demand less variable generation) was straightforward to forecast. The fragmented BA model, however, is becoming increasingly difficult to manage.

Another factor associated with the non-RTO West is that interregional transmission is exceptionally difficult to plan or develop due to a lack of centralized planning processes and codified cost allocation mechanisms. As a result, the transmission development that does occur is not optimized from a regional reliability or economic perspective.



Source: WECC, Loads and Resources Methods and Assumptions. 2014; https://www.wecc.org/Reliability/2014LAR_MethodsAssumptions.pdf.

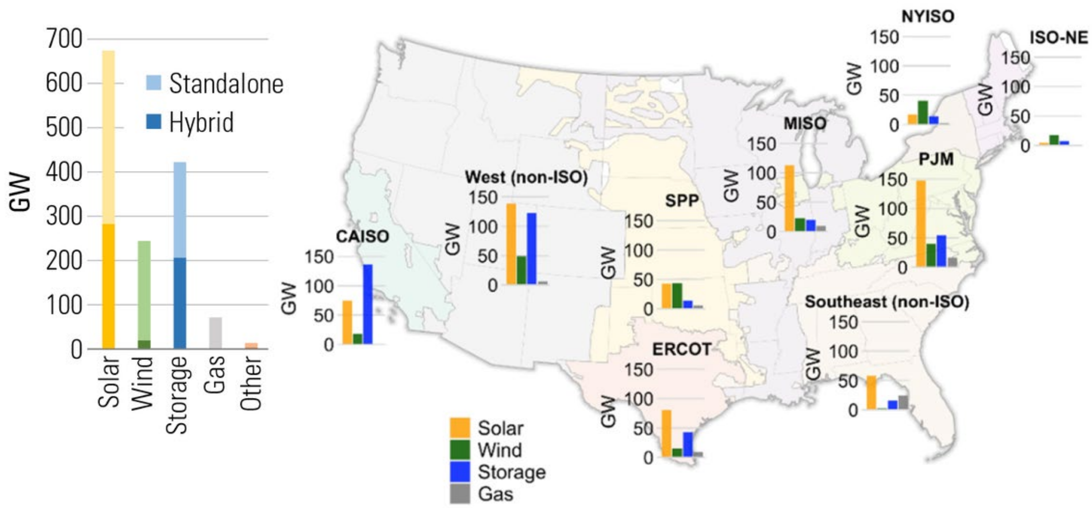
Note: Boundaries are approximate and for illustrative purposes only.

Figure IV-10. WECC Balancing Authorities.

IV.d. Interconnection Queues

Data from generation interconnection queues also demonstrate the growing need for new transmission infrastructure.

The latest compilation of data from Lawrence Berkeley National Laboratory shows that a record amount of new generation and storage capacity has applied for interconnection (DOE 2022a; Rand et al. 2022). More than 1,400 GW was sitting in clogged interconnection queues at the end of 2021, the majority of which was solar, wind, and storage (Figure IV-11). The enormous amount of solar, wind, and storage in the interconnection queues demonstrates that market and economic trends will lead to continued shifts in the Nation's resource mix, requiring a different approach to transmission planning and development. As shown later in this report (§VI), studies have repeatedly shown that given the Nation's changing resource mix, a least-cost power grid requires enhanced transmission links within and among regions.



Source: Lawrence Berkeley National Laboratory at https://www.energy.gov/sites/default/files/2022-04/Queued%20Up%E2%80%A6But%20in%20Need%20of%20Transmission.pdf.

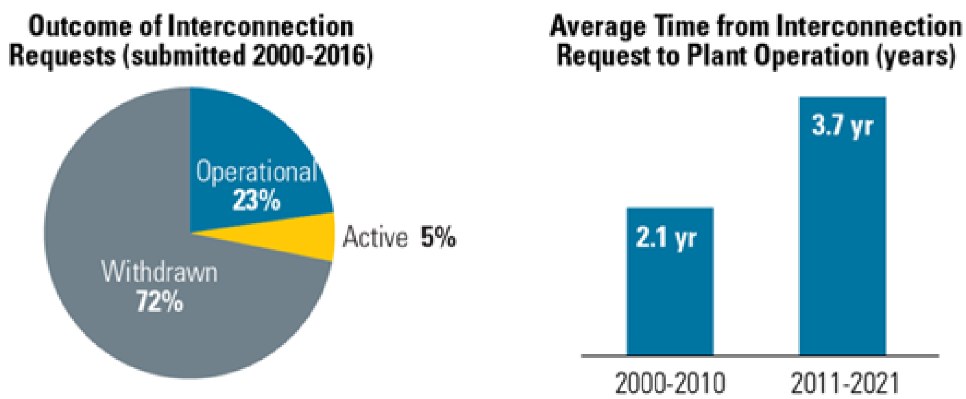
Note: Hybrid plants are those paired with one or more other type of generation or storage

Figure IV-11. Power plants seeking transmission connection by type (left) and mapped to region (right).

The duration between an interconnection request and commercial operation has increased: Among the regions with available data, the typical duration from an interconnection request to commercial operation increased from ~2.1 years for projects built in 2000–2010 to ~3.7 years for those built in 2011–2021 (Figure IV-12). The average duration from a request to a signed agreement has also increased in some regions and, on average, nationally for those regions where such data are available. High withdrawal rates are also evident: 72 percent of projects that sought interconnection between 2000 and 2016 subsequently withdrew their requests.

There are numerous drivers of these trends. While lack of access to transmission is a major barrier, there are many potential reasons that proposed power plants do not always move rapidly to the construction phase. Some projects in the queues are more exploratory in nature, in part driven by uncertainty in the scope and cost of necessary transmission upgrades and the extended timelines associated with the current interconnection process—often leading to withdrawals and successive restudies. Other challenges include securing land, permits, community support, power purchasers and financing, as well as unanticipated changes to project economics and available policy incentives.

As such, these trends partly reflect strong growth in interconnection requests and a diversity of underlying project-level and queue management issues. Yet there is also recognition that trends in interconnection queues are impacted by limited existing transmission infrastructure and transmission upgrade costs that, in many cases, the interconnecting generator must bear (DOE 2022a). Specifically, developers often incur costs not only to connect to the existing transmission system but must also provide up-front capital costs needed to upgrade the broader, high-voltage transmission grid, which provides benefits to those behind them in the queue. Interconnection costs are increasing, especially for these broader network upgrades (Caspary et al. 2021; Gorman et al. 2019). The specifics of cost allocation for these network upgrades vary regionally, but evidence is mounting that some of these network upgrades paid by interconnecting generators provide system-wide benefits (ICF 2021). Assigning the costs of these broader network upgrades to the first generator in line can cause those projects to drop out, even though those upgrades could facilitate additional interconnecting generators further down the queue.



Source: Lawrence Berkeley National Laboratory at https://www.energy.gov/sites/default/files/2022-04/Queued%20Up%E2%80%A6But%20in%20Need%20of%20Transmission.pdf.

Figure IV-12. Indicators of the challenges facing transmission interconnection, planning, and construction.

As described in a recent FERC Notice of Proposed Rulemaking (FERC 2022), these challenges are partly related to an increasing portion of overall transmission investment occurring through these interconnection agreement processes, which could result in less cost-effective transmission deployment. FERC suggests the piecemeal approach to transmission deployment occurring with the interconnection agreement process will not benefit from the economies of scale that would accompany a full regional transmission planning process. FERC notes that improved transmission planning and additional investment in the bulk-power transmission network will be needed to optimize the overall power grid and would be an effective means to address the increasingly long interconnect queue times (FERC 2022).

IV.e. Conclusions

A review of historical transmission system data from 2011 to 2020 provides information about the state of the grid today. Regional entities spent between \$0.19 and \$5.29 per MWh of load on new transmission in the past decade, on average. These investments resulted in a national total of over 34,000 circuit-miles of newly constructed or rebuilt transmission lines rated above 100 kV. Of these, over 22,000 circuit-miles were higher capacity lines rated at least 345 kV. Most of these investments were made in the first half of the decade, with transmission investments steadily declining since 2015.

Wholesale market prices in the RTOs/ISOs provides insight into where transmission congestion currently exists. Several regions of the country have had either consistently high or consistently low electricity prices over the past 3–5 years. Increased transmission access to persistently high-priced regions provides one way to lower prices for those consumers. Regions of high prices exist in Southeast MO, Southern OK, Northwest WI, Eastern and UP MI, Eastern MD/VA, Delmarva Peninsula MD and DE, Long Island NY, Southern Coast CA, and Northern coast CA. These regional and interregional transmission links have significant potential economic value from reducing congestion and expanding opportunities for trade. Extreme conditions and high-value periods play an outsized role in this value of transmission, with 50% of transmission's congestion value coming from only 5% of hours.

Examining differences in simultaneous market prices across the United States provides additional insight into the value of transmission during real-time operations. The greatest transmission value is found by connecting regions in the middle of the continent with their more eastern or western neighbors, particularly by connecting the three different transmission interconnections. The highest value is found by connecting ERCOT to the Southwest region of the Western Interconnection, followed by connecting ERCOT with the Eastern Interconnection. There is also significant value in connecting SPP with the Mountain region of the Western Interconnection and with MISO to the east. The value of these interregional connections has been growing over the past five years of data considered. Identifying the best nodal locations to make these connections requires additional engineering analysis which considers downstream system upgrades to support increased energy transfers.

In the non-RTO west, heavy traffic of energy moving from the Northwest into load centers in California and the Southwest causes congestion. As of the publication of this report, the most congested paths are between Oregon and California and between Colorado and its three neighbors in the Western Interconnection, Wyoming, Utah, and New Mexico. This congestion results in reliability concerns for the entire western system, particularly as the generation fleet is replaced due to age, climatic changes (e.g., severe drought conditions), and advancing technologies. Additional transmission is one solution to addressing these concerns.

A review of the power plants currently awaiting interconnection agreements in different parts of the country suggests the generation mix will continue to shift toward more wind, solar, and battery storage technologies. Generation resources with strong technical and economic potential located far from the existing transmission system – notably wind energy – require building new transmission to bring these low-cost resources to load (Brooks 2022). Storage technologies can help fortify the transmission system, helping ensure that the transmission built will be more highly utilized, as discussed in the next section.

V. Review of Existing Studies: Current and Future Needs

This literature review surveys nearly 50 recent reports to highlight the historical and anticipated drivers, benefits, and challenges of expanding the Nation's electric transmission infrastructure. The literature includes reports from the National Laboratories, academia, consultants, and industry that incorporate quantitative and qualitative measures of electricity transmission needs, such as increased reliability, dollars of investment, cost savings, circuit-miles of transmission, grid outages, and many others. We chose reports 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. Table V-1 lists the reports we reviewed.

Transmission expansion leads to numerous benefits discussed throughout the reports, such as system resilience, reliability, and economic benefits. Many other historical and anticipated drivers of transmission are explored in the literature, including reliability, resilience, curtailment, congestion, resource adequacy, and electrification of end use devices.

Additionally, an opportunity exists to advance energy justice goals in transmission planning. Transmission planning studies could prioritize renewable energy in areas that have had greater cumulative burdens associated with fossil dependence, energy burden, environmental and climate hazards and socio-economic vulnerabilities. Storage, microgrids and other non-wire alternatives could also be prioritized in areas with greater cumulative burdens. For infrastructure related to transmission lines, which historically have prioritized placement in low-cost lands, high cumulative burden should be an indicator to avoid those areas. The Department has created a suite of tools to identify areas with increased vulnerability (*see* accompanying text box).

Expanded transmission should mitigate existing harms and increase benefits to frontline communities

DOE work on Energy Justice

The Department has developed an Energy Justice Dashboard, which provides a map with several equity layers to show which low-income communities are facing the worst air pollution or public health risks at the census tract level. The Energy Justice Dashboard also overlays energy burden — a key indicator of energy justice that shows how much households spend on energy bills as a portion of their income. The Department has also conducted some analysis and identified areas with high cumulative burdens using 36 vulnerability indicators.

Dept. of Energy, Office of Economic Impact and Diversity, Energy Justice Dashboard (BETA), https://www.energy.gov/diversity/energy-justice-dashboard-beta.

Dept. of Energy, Office of Economic Impact and Diversity, Energy Justice Mapping Tool - Disadvantaged Communities Reporter, https://energyjustice.egs.anl.gov.

facing high energy burden, longer-duration outages, and higher levels of environmental hazards. Expanded transmission along with storage and other non-wire alternatives could create avenues for frontline communities to have access to community-owned renewable generation projects which could decrease costs, reduce air pollutants that cause adverse health impacts, and advance energy democracy. (Clack et al. 2020) Recent literature identifies the challenges of meeting these needs, notably the fragmented approach to permitting and siting, complex planning, the need for improved quantification of benefits in cost allocation, and various other barriers.

Table V-1. List of all studies considered in this section.

Study Title	Author(s)	Publication Date	Publisher	Funding Source(s)
Solar Futures Study	Ardani, Denholm, Mai, Margolis, O'Shaughnessy, Silverman, Zuboy	Sept. 2021	DOE	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	N/A
WECC 2038 Scenarios Reliability Assessment	Bailey, Mignella	May. 2020	Western Electricity Coordinating Council	N/A
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
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, U.S. DOE, Office of Energy Efficiency and Renewable Energy's Wind Energy Technologies Office, Water Power Technologies Office, Solar Energy Technologies Office, The Government of Mexico
Renewable Energy Resource Assessment Information for the United States	Brooks	Mar. 2022	DOE, Office of Energy Efficiency and Renewable Energy	N/A
The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System	Brown, Botterud	Jan. 2021	Joule	MIT Energy Initiative
20-Year Transmission Outlook	California ISO	Jan. 2022	California ISO	N/A

Study Title	Author(s)	Publication Date	Publisher	Funding Source(s)
A Plan for Economy-Wide Decarbonization of the United States	Clack, Choukulkar, Coté, McKee	Oct. 2021	Vibrant Clean Energy	N/A
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
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	N/A
EIPC State of the Grid Report – 2021	Eastern Interconnection Planning Collaborative	Dec. 2021	Eastern Interconnection Planning Collaborative	N/A
Oregon Clean Energy Pathways Analysis	Evolved Energy Research	June 2021	Evolved Energy Research	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
Transmission Makes the Power System Resilient to Extreme Weather	Goggin, Michael, Grid Strategies LLC	Jul. 2021	American Council on Renewable Energy	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	N/A

Study Title	Author(s)	Publication Date	Publisher	Funding Source(s)
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
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, U.S. DOE. Office of Energy Efficiency and Renewable Energy Wind Energy Technologies Office, U.S. DOE, Office of Energy Efficiency and Renewable Energy Water Power Technologies Office, and U.S. DOE, Office of Energy Efficiency and Renewable Energy Office of Strategic Analysis
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, 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	U.S. DOE, Office of Electricity, Advanced Grid Research Program
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
Techno-Economic Renewable Energy Potential on Tribal Lands	Milbrandt, Heimiller, Schwabe	July 2018	National Renewable Energy Laboratory	DOE, Office of Indian Energy Policy and Programs

Study Title	Author(s)	Publication Date	Publisher	Funding Source(s)
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
MISO's Long Range Transmission Planning to address the Reliability Imperative: Tranche 1 Portfolio	MISO Energy Transmission Planning Team	Sept. 2022	MISO	N/A
State of the Market Report for PJM	Monitoring Analytics, LLC	Mar. 2022	Monitoring Analytics, LLC	N/A
2021 Long-Term Reliability Assessment	NERC	Dec. 2021	North American Electric Reliability Corporation	N/A
2022 State of Reliability Report	NERC	Jul. 2022	North American Electric Reliability Corporation	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
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	N/A
2020 Assessment of the ISO New England Electricity Markets	Patton, LeeVanSchaick, Chen, Naga, Coscia	Jun. 2021	Potomac Economics	N/A
Transmission Planning and Benefit-Cost Analyses	Pfeifenberger	Apr. 2021	The Brattle Group	N/A
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

Study Title	Author(s)	Publication Date	Publisher	Funding Source(s)
The 2035 Report	Phadke, Paliwal, Abhyankar, McNair, Paulos, Wooley, O'Connell	Jun. 2020	Goldman School of Public Policy, University of California, Berkeley	MacArthur Foundation
2020 State of the Market Report for MISO Electricity Markets	Potomac Economics	May 2021	Potomac Economics	N/A
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, Thompson, Mohan, Jung, Peng, Hess, Li	Feb. 2021	Midcontinent Independent System Operator	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
Grid-Enhancing Technologies: A Case Study on Ratepayer Impact	DOE	Feb. 2022	DOE	N/A
Regulatory Evolution for a Decentralized Electric Grid: State of Performance-based Ratemaking in the U.S.	Wang, Crawford	Jun. 2019	Wood Mackenzie	N/A
State of the Market Report 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	N/A
A 2030 United States Macro Grid	Xu, Olsen, Xia, Livengood, Hunt, Li, Smith	Jan. 2021	Breakthrough Energy Sciences	N/A

V.a. Reliability

Grid reliability is a major driver of local transmission need, as cited in Brinkman et al. (2021), Clack et al. (2020b), and NERC (2021). MISO (2022) notes that the transformational changes occurring in the industry necessitate the identification of transmission solutions to ensure continued grid reliability and cost-effective transmission investments that will serve future needs. NERC (2021) refers to reliability as *the* major driver of transmission projects, claiming 64 percent of future circuit-miles, followed by variable renewable integration and economics/congestion. Transmission installations driven by reliability concerns experienced the largest increase between the 2020 and 2021 NERC Long-Term Reliability Assessments. NERC notes, in New England specifically, that transmission expansion has improved both reliability and resilience.

Bloom et al. (2020) identify transmission expansion across the interconnections as a way to reduce generation capacity required for reliable grid operations because diversifying load and generation across large geographic areas increases operating flexibility. Breakthrough Energy Sciences (2021) further concludes that high-voltage direct current (HVDC) connections that span interconnection seams enable generation from renewables to be shared more readily between interconnections. The authors argue that given existing assumptions about the future, sizable transmission additions are necessary to ensure system reliability.

Overbye et al. (2021) evaluate the potential to synchronize the Eastern and Western Interconnections using a combination of high-voltage alternating current (HVAC) and AC-DC-AC converter stations spanning the interconnection seam. The study assesses stability issues that could arise with synchronization and finds that generator governor action could result in asymmetrical responses under contingency conditions. In the event of a generator loss contingency in the WECC, approximately 80 percent of the lost power will flow from east to west because the Eastern Interconnection has almost four times the load of the WECC. The authors conclude that the interface joining two such grids would need reinforcing to handle the possible increase in flow that would occur under contingency conditions.

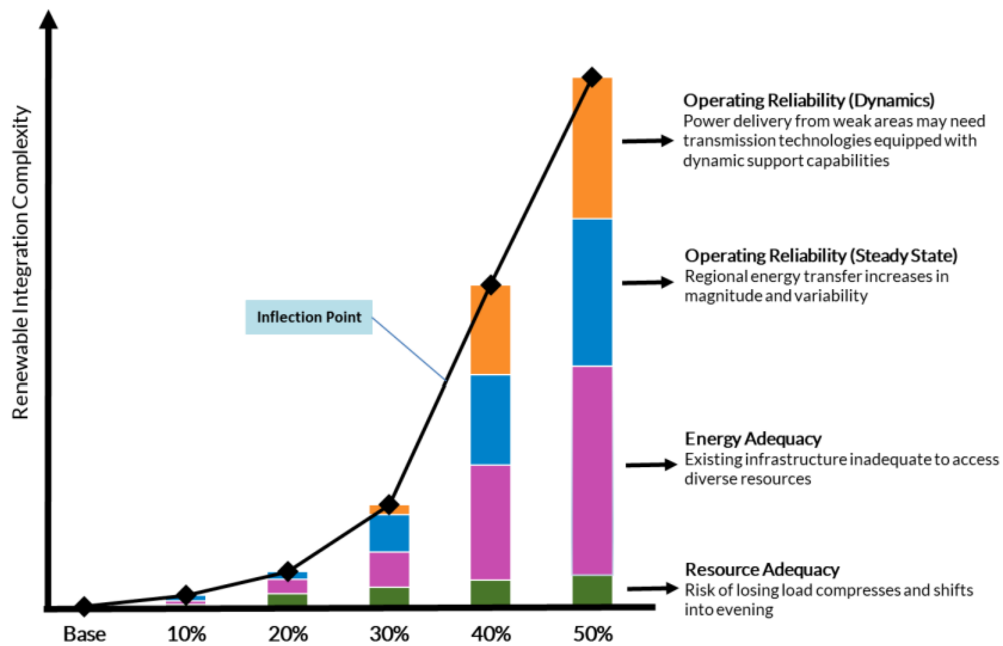
In the Clack et al. (2020b) modeling study of renewable energy development and emission reductions in the Eastern Interconnection, the authors find that investing in transmission can promote access to low-cost renewable energy without compromising system reliability. Clack et al. (2020b) determine that with a strong transmission network, the bulk power system can operate reliably even with high penetration of renewable generation, where wind and solar would supply 82 percent of electricity by 2050. The researchers argue that continental-scale transmission, expanding from the Western Interconnection to the Eastern Interconnection to ERCOT and Canada, can improve reliability by capturing even greater geographic diversity of generation resources.

Pfeifenberger (2021) asserts that recent efforts to replace aging transmission infrastructure create an opportunity to build a more robust, reliable grid, while efficiently using existing rights-of-way. For offshore systems, Pfeifenberger et al. (2020b) state that an offshore grid designed and built with the capability of a networked system will improve reliability and reduce curtailments when transmission outages occur.

Furthermore, part of meeting robust grid reliability standards is the flexible capability of the grid. Brinkman et al. (2021) and Brown and Botterud (2020) state that operational flexibility can come from transmission, especially interregional transmission. Ardani et al. (2021) similarly claim that transmission expansion is required to make the grid more flexible. Pfeifenberger (2021) claims that "a more flexible and robust grid provides 'insurance value' by reducing the risk of high-cost (short- and long-term) outcomes due to inadequate transmission."

Prabhaker et al. (2021) describe MISO's Renewable Integration Impact Assessment (RIIA), which examines the issues of, and possible solutions for, increasing installed amounts of wind and solar in MISO's footprint and surrounding regions. Prabhaker et al. (2021) conclude that the effort required to plan for, support, and operate new resources reliably as they are integrated with the grid (termed "integration complexity," which corresponds to additional costs) substantially increases at renewable penetration levels beyond 30 percent of annual load served, as shown in Figure V-1.

MISO's Long Range Transmission Planning (LRTP) initiative (2022) also references its RIIA study and assesses reliability risks looking 10-20 years into the future to identify the transmission investments needed to enable regional delivery of energy. It discusses the development of a collection of related initiatives that address the growing risks and solutions required to enable member resource plans and strategies. The LRTP considers a portfolio of regional transmission solutions to addressing the future energy needs rather than an incremental approach to reliability planning. LRTP projects deliver benefits by addressing future reliability issues and avoiding the costs of future upgrades that would have been required absent the portfolio.



Source: MISO's Renewable Integration Impact Assessment (RIIA), Feb 2021; https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf.

Figure V-1. Additional operational effort is needed to maintain system reliability as renewable generation levels (x-axis) increase. The MISO transmission system maintains reliability up to 30 percent renewable energy generation without significant additional operational support.

As discussed in NERC (2021), areas such as California, Texas, and the U.S. Northwest that rely on variable energy resources or imports to meet demand during peak or high-risk periods face higher risk of load curtailment during extreme conditions. MISO and the U.S. Southwest are approaching similar conditions in the near-term (NERC 2021). Extreme heat in 2021 impacted the Northwest grid, causing localized power outages (NERC 2022a). Transmission outages also occur due to wildfires, particularly in California and the Western U.S., that are exacerbated by extreme heat and drought. NERC (2022a) reported only one major system outage due to wildfires in 2021.

In New England, Texas, California and the Southwest, heavy reliance on natural gas for energy generation poses a risk to winter reliability (NERC 2021) (NERC 2022a). During extreme cold events, gas demand for residential and commercial heating peaks and shortages in gas supply for electricity generation can occur. Likewise, electricity outages can lead to gas shortages as electricity is required to operate the natural gas delivery system (NERC 2022a).

Additionally, FERC et al. (2021) and NERC (2022a) assess the impact of the severe cold weather event that occurred between February 8 and 20, 2021 on the reliability of the bulk electricity system in Texas and the Plains and Delta regions. The extreme cold temperatures and freezing precipitation led to outages, derates, or failures to start at 1,045 individual generation units, resulting in severe capacity shortage. For at least two consecutive days, the average generation not available at ERCOT was about 34,000 MW. At its peak, ERCOT shed firm load of 20,000 MW.

As FERC et al. (2021) note, unlike other regional markets like MISO and SPP that were also affected by the severe cold weather event, ERCOT has very limited interconnections with its neighbors. ERCOT can only import just over 1,000 MW over its ties to its neighbors, which significantly affected its ability to make up for the region's capacity shortage. FERC et al. (2021) recommend ERCOT conduct a study to evaluate the benefits of additional ties with the Eastern Interconnection, the Western Interconnection, or Mexico. The benefits could include increased import capability to help address capacity shortages during emergencies and improved black start capability.[34] Improving import capability would therefore help improve the overall reliability of the ERCOT system.[35]

The high electricity prices which resulted from the blackouts in ERCOT had a major impact on the congestion value of transmission calculated by Millstein et al. in (2022a). As discussed in Section IV.b, Millstein et al. calculated hourly transmission congestion values between different links in the contiguous United States from 2012 to 2021. They find that very few hours (5%) account for a large portion of transmission value and that a small number of extreme events (1 – 3 over ten years) contributed meaningfully to the total 10-year value of a particular link. This indicates that one lens with which to view transmission value is that of 'insurance' against the high costs of faced during extreme grid conditions, extreme events, or other factors (such as unexpected deviations from forecasted conditions). With insurance, as with some other benefits, attribution of value between different power sector stakeholders is challenging because each stakeholder's potential benefits depend on the characteristics of future extreme grid conditions or weather events that are unpredictable. The attribution of this complex value is another challenge that faces transmission planners as they strive to weigh the costs and benefits of transmission expansion projects. Transmission planners run the risk of understating the benefits of regional and interregional transmission if extreme conditions and high-value periods are not adequately considered. (Millstein et al. 2022a)

[34] Black start capabilities can be improved locally without the need for additional interregional transmission. FERC et al. (2021) additionally recommend a joint study on the winter preparedness of ERCOT's existing black start capabilities.

[35] FERC et al. (2021) describes a situation on February 15, 2021, when ERCOT was possibly less than 5 minutes from a total blackout.

V.b. Resource Adequacy

The need for new transmission to support resource adequacy is mentioned repeatedly throughout the literature. Patton et al. (2021) assert that new transmission capacity can provide substantial resource adequacy benefits, as new lines enable more flexible generation sharing, reducing the need for new generation. Brinkman et al. (2021) note that transmission is needed in the near-term for resource adequacy, and more importantly in the long-term, with the increase in clean energy resources. Brinkman et al. (2021) also conclude that transmission expansion can provide economic benefits and improve reliability of the grid by maintaining resource adequacy. MISO (2022) similarly notes that its LRTP portfolio will expand transfer, which will, in certain situations, increase the ability for a utility to use a new or existing resources from another part of the MISO region rather than constructing generation locally to meet resource adequacy obligations.

Ardani et al. (2021) and Bloom et al. (2020) similarly indicate that expanding transmission is an important aspect of resource adequacy in some regions to access diverse resources from around the country. Connecting geographically diverse resources can help lower costs by reducing the need for excess generating capacity. Ardani et al. (2021) also argue that distributed energy resources (DERs) can offset the need for some transmission resources in ensuring resource adequacy. Breakthrough Energy Sciences (2021) assert that given current assumptions about the future, substantial transmission investments will be necessary to ensure reliable renewable generation deliverability and system adequacy.

Novacheck et al. (2021) emphasize that even during extreme events of low wind and solar output, variable resources can contribute to resource adequacy via interregional coordination and bidirectional trading of power through the transmission system. Although the historical high-impact weather events considered in this report did not lead to new operational or resource adequacy concerns for an electricity system with high variable energy penetration, the report does note that milder versions of these weather events of increasing frequency can result in prolonged periods of low variable energy availability. For example, wind generation tends to decrease during periods of prolonged cold weather after a cold front moves through an area. These periods can pose challenges to resource adequacy as solar output is typically already lower during the winter months. Similarly, moderate heat waves accompanied by persistent high pressure can depress wind generation during evening net load peak. Expanding transmission to integrate geographically diverse, variable energy resources can reduce these risks, lower capacity reserve margins, and reduce system costs. Resource adequacy studies do not fully consider these milder weather events, however, and therefore current planning to ensure enough generation and transmission infrastructure exist to meet load is insufficient.

ISO-NE (2022) similarly found in their Future Grid Reliability Scenarios (FGRS) that mild weather events can pose significant challenges to maintaining electrical grid reliability under a high variable energy future. The FGRS reliability analyses showed whether the simulation-generated generation resource mixes had either excess or insufficient capacity to serve load. ISO-NE found that resource adequacy analysis overestimates the reliability of renewables during the hours of highest risk, suggesting more nuanced modeling of renewables is required to fully assess reliability under a high-renewables system. While fixed output values used in the resource adequacy analysis for solar and wind are sufficient for today's system, that assumption was no longer adequate in high variable renewable Scenarios where widespread wind lulls and cloudy weather become more impactful (ISO-NE 2022).

ISO-NE's FGRS (2022) implemented a resource adequacy reliability analysis using the tool that determines the ISO's installed capacity requirement. The work of FGRS showed that the results from one type of analyses could inform the inputs to other types of analyses. In the FGRS, a variety of modeling and analysis types were utilized iteratively to get the most meaningful combination of economic and engineering analyses. These analyses were used to explore what conditions will likely present operational or reliability issues under future Scenarios. Specifically, once FGRS identified a shortfall of units in the resource adequacy analysis, it re-simulated other portions of the analyses with sufficient supply resources to meet resource adequacy criteria. Without dispatchable units, a significantly large build-out of renewables is required. The FGRS analysis also finds that resource diversity is critical. In cases where only a single unit type was added, future scenarios either did not meet reliability criteria or required what may be infeasible quantities of those resources. The FGRS also explored a few resource mixes that used diverse combinations of onshore and offshore wind, solar, battery storage, or hypothetical dispatchable emission-free resources to meet resource adequacy criteria. This diversity reduced the need for new renewable and storage resources by up to 17,000 MW. This analysis also shows that resource adequacy criteria can be met by a variety of resource mixes but that dispatchable resources are particularly effective at meeting these criteria.

In their modeling to assess the reliability of the electric system with increasing levels of wind and solar in MISO's footprint and surrounding regions, Prabhaker et al. (2021) find no transmission solutions were needed for resource adequacy due to over-builds in renewable capacity at up to 30 percent wind and solar penetration. Beyond 40 percent, Prabhaker et al. (2021) find that new transmission is necessary. Resource adequacy remains a low portion of overall operational support (see Figure V-1).

As discussed previously, FERC et al. (2021) note that ERCOT's limited interconnections with its neighbors significantly affected its ability to make up for the capacity shortage experienced during the severe cold weather event of February 2021. MISO and SPP also reached transmission limits on imports during the February 2021 severe cold weather event, though neither region was as severely affected as ERCOT (FERC et al. 2021). MISO and SPP were less impacted given the strength of their connections with adjacent neighbors who were unaffected by the storm. Improving transfer capability ties with neighboring regions will increase ERCOT's ability to import power to address capacity shortages when its system is stressed under emergency conditions.

However, FERC et al. (2021) also comment that MISO and SPP would have been limited in their ability to increase imports to ERCOT during this event—had additional transfer capacity ties been available—without increased import capability with *their* adjacent neighbors in the Eastern Interconnection. The coincidence scarcity of generation resources among ERCOT's immediate neighbors during this event calls into question the value of increased transfer capability limits without an accompanying increase in multiregional transfer capability, thereby making the power grid larger than the weather systems that impact it.

NERC (2021) find that generation retirements over the next few years in MISO will result in capacity shortfalls as early as 2024 without additional generation or import transfer capacity additions. By 2026 MISO's reserve margin capacity shortfalls will be an estimated 3 GW (NERC 2021). NERC stresses that resource adequacy and energy sufficiency measures need to be urgently implemented in the area. MISO planners have similarly predicted capacity shortfalls in previous iterations of the Organization of MISO States - MISO survey (NERC 2021). While the shortfalls ultimately have not yet occurred, the continued identification of capacity shortfalls as a concern for the MISO region emphasizes the persistent need for resource adequacy measures such as new transmission.

Regions in the Western Interconnect face even more immediate concerns as current resources are insufficient to meet demand during wide-spread heat events, particularly without resource diversity to complement the loss of solar photovoltaic generation in the late afternoon. NERC (2021) estimates the Northwest could see 23 load-loss hours in 2022 and Southwest has potential for load-loss hours starting in 2024. NERC further estimates that California could face up to 10 hours of load loss beginning in 2022 and 75,000 MWh of unserved energy as soon as 2024 given the extreme heat events considered in their analysis. By 2026, California will experience an estimated 3 GW of capacity shorfalls. NERC notes that resource adequacy concerns in California are exacerbated by the planned retirement of the Diablo Canyon nuclear generation facility. Additional transfer capacity is one means to make up these reserve margin shortfalls, so long as neighboring regions have excess generation to export at the time of need.

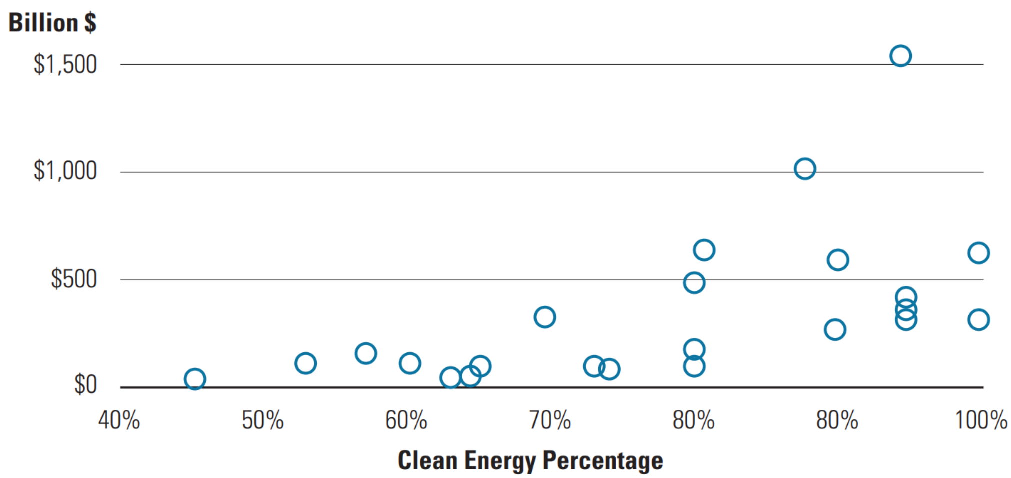
FERC et al. (2021) recommend that adjacent Reliability Coordinators, BAs, and Transmission Operators perform bidirectional power transfer studies to determine constraints that could occur when importing or exporting power between neighboring regions during an emergency that spans multiple Reliability Coordinator/BA areas. NERC (2021) makes a similar recommendation recognizing that resources planners in the Western Interconnect are increasingly reliant on external transfers to meet capacity reserve margins. This dependence on import capacity will require coordinated resource adequacy and transmission planning.

V.c. Clean Energy

Many reports surveyed cite access to clean energy resources for electricity production as a significant driver of transmission need. Numerous sources, including Brinkman et al. (2021), Bloom et al. (2020), Novacheck et al. (2021), Ardani et al. (2021), Cole et al. (2021), Clack et al. (2020b), FERC (2020), MISO (2022), MISO and SPP (2022), Breakthrough Energy Sciences (2021), and Pfeifenberger (2021), discuss the need for expanded transmission infrastructure at the national and international levels to take advantage of the diversity of generation resources.

Increasing the diversity of both resource fuel-type and resource geographic location improves the electric system's ability to produce affordable, reliable energy while increasing the operational flexibility and reliability of the grid. The reviewed reports name other important benefits of integrating clean energy generation, such as lowered electricity prices and system costs, avoided climate damages, and air quality improvements for frontline communities.

Several studies cite a need for significant transmission expansion as clean energy penetration increases. Most of these studies, including NERC (2021), indicate that expanding transmission will especially improve the integration of variable energy resources. Interconnecting transmission across regions enables the system to take advantage of the geographic and temporal diversity of energy generation, particularly from wind and solar resources, for which abundant production in one region can help compensate for low production in another in times of need. Figure V-2 shows growing transmission investments associated with increasing clean energy generation.



Source: DOE, Queued Up and In Need of Transmission, at https://www.energy.gov/sites/default/files/2022-04/Queued%20Up%E2%80%A6But%20in%20Need%20of%20Transmission.pdf.

Figure V-2. Summary of transmission investments estimated by several studies that enable differing levels of clean energy generation.

Clack et al. (2020b) demonstrate that expanding transmission infrastructure to access low-cost renewable energy is a reliable, cost-effective way to reduce emissions, increase consumer savings, and stimulate electric-sector employment. The authors find that significant amounts of new high-capacity transmission will be required regardless of the cost of renewables. In contrast, Phadke et al. (2020) find that low-cost generation technologies can reduce the amount of interregional transmission needed to connect high-quality renewable resource areas to load regions, which are often distant from one another. The authors explain that improved technology can access lower-quality resources and storage sited closer to load (Phadke et al. 2020).

Studies such as Ardani et al. (2021), Bloom et al. (2020), and others also find a need for significant transmission expansion with increasing clean energy penetration. In a decarbonization scenario targeting a 95 percent reduction in emissions on the U.S. electric grid from 2005 levels by 2035, Ardani et al. (2021) show that by 2050, transmission capacity expands by 60 percent (86,000 GW-mi)[36] relative to a reference scenario. Additionally, Cole et

[36] Gigawatt-mile (GW-mi) is not a commonly used unit in the industry, but is the unit used by capacity expansion modeling results. For comparison, a 100-mile 345kV rated transmission line has an estimated carrying capacity of

al. (2021) analyze scenarios of a wide range of power system futures and find, overall, that scenarios with higher levels of emission abatement correlate with higher levels of renewable generation deployment and increased levels of transmission development.

Clack et al. (2020b) find modeling scenarios with strong carbon reduction policies result in approximately 140,000 GW-mi of new interstate transmission, whereas scenarios with weak carbon reduction policies for cases with high solar and high wind deployment result in approximately 100,000 GW-mi and 70,000 GW-mi of new transmission, respectively. Clack et al. (2020b) also show that the amount of transmission capacity required for integration varies with the type of technology. Moving from weak to strong carbon cases under the high solar deployment case results in greater incremental transmission investment compared with moving from weak to strong carbon cases under the high wind deployment case, presumably because increased solar deployment in the Southeast requires additional transmission capacity to export excess solar production during the daytime and to export wind production at night.

Breakthrough Energy Sciences (2021) investigates the renewable generation and transmission requirements needed to achieve 70 percent clean energy for the U.S. electric grid by 2030 by modeling different transmission designs. The authors modeled four distinct transmission designs that included AC only and combined AC and HVDC transmission upgrades. In all cases, AC capacity relative to current capacity increases from about 23 percent to 36 percent. The broader reach of the design with a new 16-line HVDC network connecting all three interconnections with no change in existing HVDC converter station capacity enables southeastern U.S. states to import power from elsewhere in the country. Regardless of transmission design, the authors find that certain U.S. transmission corridors require large capacity upgrades. These common upgrades, approximately 56 terawatt-miles (TW-mi), make up at least half of upgrades for each design. Common upgrades are found in the Southeast, the Midwest, and across Texas. Additionally, HVDC connections that span interconnection seams enable generation from renewables to be shared more readily between interconnections, which makes renewable generation less variable and more reliable. The HVDC network can also reduce the cost of resources required to meet clean energy goals. For example, the need for transmission upgrades in the Eastern Interconnection is reduced because the Western Interconnection exports more clean energy (primarily solar) to the Eastern Interconnection.

In a scenario with constrained carbon dioxide emissions (80 percent reduction in carbon emissions from 2005 levels in the United States and Mexico, and 92 percent reduction in Canada by 2050), Brinkman et al. (2021) find even more transmission is necessary because variable resource costs are higher, forcing transmission buildout to more resource-rich regions farther from load centers. The authors note that their findings do not demonstrate that it is impossible to achieve renewable contribution levels or reliable future grids without extensive new transmission builds, but rather that those scenarios, if feasible, would come at a higher cost. In their modeling to estimate the system cost of electricity in a 100 percent renewable U.S. power system, Brown and Botterud (2020) conclude that transmission capacity expansion

860 MW, equivalent to 86 GW-mi (NRRI 1987). And a 200-mi 500kV line has a carrying capacity of 1,320 MW, equivalent to 264 GW-mi (NRRI 1987). See Table VI-2 for a comparison of carrying capacities and nominal voltage ratings for different length transmission lines.

and better coordination between regions can reduce the cost of decarbonization by almost half compared to a case with no interstate or interregional transmission investments, reinforcing the idea that decarbonizing without increasing transmission will be more costly.

In the WECC assessment on the requirements to meet clean energy goals by 2040 in the Western Interconnection, Bailey (2022) emphasize that transmission constraints are of significant concern at a 100 percent clean energy level and additional transmission investments should be considered early because new lines take many years to plan, site, approve, and build. Larson et al. (2021) argue that planning, siting, and construction of new lines should be a priority in the 2020s to meet the large need for new transmission projected for the 2030s.

Hildebrandt et al. (2021) identify a series of transmission system improvements to integrate the expected generation resources from California's Senate Bill 100 (California Legislature 2018), which sets a target that 100 percent of California's retail electricity be met by renewable and zero-carbon sources by 2045. Hildebrandt et al. (2021) estimate the cost of transmission investments to integrate renewable resources at $30.5 billion, comprising $10.74 billion in upgrades to the existing CAISO footprint, $8.11 billion for offshore wind (OSW) integration, and $11.65 billion for out-of-state wind integration. The author's report that accommodating 4.7 GW of wind resources from Wyoming and 5.2 GW from New Mexico will require additional incremental transmission builds. Hildebrandt et al. (2021) also show the importance of addressing transmission infrastructure needs in California, stating that rapid increases in renewables are outpacing projections: CAISO's 2020–2021 transmission plan was based on the addition of 1,000 MW per year of new resources, while the forthcoming 2022–2023 transmission plan is expected to be based on 4,000 MW per year.

The MISO and SPP Joint Targeted Interconnection Queue (JTIQ) Study discussed in MISO and SPP (2022), recommends a five[37]-project JTIQ portfolio of transmission projects that enables the interconnection of large amounts of predominantly renewable generation near the seam of the two regions. The JTIQ Portfolio resolves constraints that enable MISO to interconnect over 28 GW of additional generation near the seam, and SPP estimates it could interconnect over 53 GW of additional generation near the seam.

In MISO's RIIA, Prabhaker et al. (2021) conclude that renewable penetration beyond 50 percent in the MISO region can be achieved with coordinated action. The assessment identifies new and changing risks and system needs, including insufficient transmission capacity. Furthermore, transmission infrastructure investments, especially the higher voltage lines, increase with increasing renewable penetration. Expansion of new transmission lines rated 161 kV and below is highest at the 30 percent renewable penetration level at 1,700 circuit-miles, decreasing to 500 circuit-miles at 50 percent penetration (incremental additions). On the other hand, expansion of new transmission lines rated 230 kV and higher ranges from 700 circuit-miles at 20 percent penetration to 6,000 circuit-miles at 50 percent penetration. In addition, new HVDC lines were identified at 30 percent and higher penetration levels.

[37] The number of projects included in the MISO JTIQ portfolio has now been reduced from seven to five, since two of the projects were moved into the MISO LRTP portfolio.

NERC (2021) highlights that increased use of electrical inverters—which are required to connect many renewable energy resources to the grid—can lead to reliability concerns unless precautions are taken. System reliability concerns may arise from low inertia, unstable voltage, low fault currents, and unpredictable behavior of inverter-based resources during grid disturbances without appropriate precautions. In 2021, both Texas and California experienced the loss of widespread solar photovoltaic generation due to abnormal operation of inverters (NERC 2022a). Transmission planning, reliability studies, interconnection requirements, and operational control of the transmission system are crucial to account for the unique behavior of inverters on the power grid (NERC 2021) (NERC 2022a).

Dimanchev et al. (2020) note that meeting existing state climate policy targets in New York and New England will likely require the nearly complete decarbonization of electricity generation. To that end, consideration is being given to expanding imports of hydropower from neighboring Québec, Canada. According to their study, in a low-carbon future it is optimal to shift the utilization of the existing hydropower and transmission assets away from facilitating one-way export of electricity from Canada to the U.S. and toward a two-way trading of electricity to balance intermittent U.S. wind and solar generation (Dimanchev et al., 2020). They find doing so can reduce power system cost by 5-6% depending on the level of decarbonization. The cost-optimal use of Canadian hydropower is as a complement, rather than a substitute, to deploying low-carbon technologies in the U.S. Expanding transmission capacity enables greater utilization of existing hydropower reservoirs as a balancing resource, which facilitates a greater and more efficient use of wind and solar energy.

Jones et al. (2020) similarly note in a regional analysis conducted for a Massachusetts study that Canadian hydropower is an essential element of regional balancing. In their study, bidirectional flow of electricity enabled the Québec hydropower system to transition into the role of a ‘battery’ storing excess wind and solar generation for the New England region. The use of hydropower system as storage depends on the timing of renewable production and demand on both sides of the U.S.-Canada border (Jones et al., 2020). Total net-imports into Massachusetts from Québec declined after 2035 in the analysis. The study estimates that an additional 4.1 to 7.1 GW of new transmisison capacity between Québec and New England would be required.

V.c.1. Offshore Wind

Several studies discuss the unique transmission challenges associated with offshore wind in bringing generated power across the sea to terrestrial terminals where it will be delivered to load. Pfeifenberger et al. (2020a) and Pfeifenberger et al. (2020b) evaluate offshore transmission planning approaches for New England and New York, respectively. They find that an offshore grid designed and built with the capability of a networked system will provide more benefits and will better facilitate the integration of OSW resources compared with each OSW resource connecting to the onshore grid through a dedicated generator lead line. Pfeifenberger et al. (2020a) and Pfeifenberger et al. (2020b) find that designing and building the offshore grid with the capability of a networked system will improve reliability and reduce curtailments when transmission outages occur.

Pfeifenberger et al. (2020a) indicate that New England has already contracted for 3,112 MW of OSW. The next 3,600 MW of OSW could still be developed under the status quo with each developer constructing a generator-led line to an onshore point of interconnection. However, this existing approach is likely to lead to substantial onshore system upgrade needs far sooner than assumed. Selected projects connecting to the Cape Cod grid already face up to $787 million in onshore transmission upgrades and continuing this approach in the next set of generation procurements could lead to an additional $1.7 billion in onshore upgrades (Pfeifenberger et al. 2020a). This conclusion emphasizes the possible need for new infrastructure and coordinated planning.

ISO-NE's First Cape Cod Resource Integration Study (2021) identifies the transmission upgrades necessary to enable the interconnection of proposed new offshore wind resources to Cape Cod, Massachusetts. This study found that a new 345 kV line would enable another 1,200 MW of proposed OSW resources to interconnect. This system upgrade would supplement the already-estimated 1,600 MW of proposed Cape Code OSW generation that have completed their interconnection impact studies. This 2,800 MW of total new offshore wind generation demonstrates the significant amounts of resource economic potential

DOE work on Offshore Wind Transmission

The Department initiated a two-year Atlantic Offshore Wind Transmission Study in 2021. The study evaluates multiple pathways to reach offshore wind goals through coordinated transmission solutions along the U.S. Atlantic Coast under various combinations of electricity supply and demand while supporting grid reliability and resilience and ocean co-use. Researchers from that National Renewable Energy Laboratory and the Pacific Northwest National Laboratory will conduct this study by creating multiple scenarios of interstate, interregional transmission topologies (size, shape, and location of lines) through 2030 and 2050.

National Renewable Energy Laboratory, Atlantic Offshore Wind Transmission Study, https://www.nrel.gov/wind/atlantic-offshore-wind-transmission-study.html.

and associated necessary interconnections are much higher than that anticipated when planning the area's current grid infrastructure. Under the integration program, ISO-NE has developed rules that provide a process for identifying common infrastructure and avoiding instances of queue backlog which can materialize when such circumstances are present.

Additionally, ISO New England (2020) analyzes the impacts of high penetrations of OSW for 2030 without improved regional transmission. They find that spillage—a means of curtailing generation output specific to wind generation—increases with increasing OSW penetration from 2.4 TWh in the reference case to 21.3 TWh in the 12,000 MW OSW penetration scenario. ISO-New England concludes that avoiding transmission-related spillage might require further transmission expansion. In the unconstrained case, wherein the New England transmission system is modeled as a single-bus system in which transmission has essentially unlimited capacity, spillage is slightly lower across OSW penetration levels compared with the constrained case.

Given the complexities of integrating offshore wind along both within New England and along the Atlantic coast, the Department initiated an Atlantic Offshore Wind Transmission Study in 2021 to analyze how different coordinated transmission solutions enable offshore wind energy deployment along the U.S. Atlantic Coast (*see* accompanying text box).

Evolved Energy Research considers the complexities of integrating offshore wind along the Pacific Coast in (2021). The authors note that a substantial portion of investment in Oregon OSW is needed to meet both the State's current 2050 economy-wide target of 80% emissions reductions below 1990 levels and to enable exports of low-cost, high capacity-factor clean electricity to other Western states. The 20 GW of OSW projected to be built over 15 years would require a rapid scale-up of new supply chains and production capacity. A regionally integrated power grid is critical to enabling Oregon to take advantage of out-of-state clean energy resources, export power to other states, and efficiently plan for grid reliability. Regional grid integration will also be key to efficient decarbonization throughout the West.

V.c.2. Clean energy on tribal lands

Renewable energy technologies provide opportunities for diversification, energy independence, environmental sustainability, and new revenue streams for Native American Tribes, Alaska Native villages, and Alaska Native Corporations (Milbrandt, Heimiller, and Schwabe 2018). Many tribal lands are in areas that have abundant renewable energy, such as wind, solar, and biomass. Over 9% of the nationally available renewable energy resource is found within 10 miles of federally recognized Tribal lands (Brooks 2022).

In Milbrandt, Heimiller, and Schwabe (2018), the authors estimate the technical and economic potential for renewable energy development on tribal lands to support American Indian Tribes and Alaska Natives in decision-making as they evaluate technologies, potential scales of development, and economic viability. The resources analyzed include wind, solar photovoltaic and concentrating solar power systems, woody biomass, biogas, geothermal, and hydropower. The analysis shows that the utility-scale technical potential of these resources on tribal lands is approximately 6.5% of the total national technical potential. By comparison, federally recognized tribal lands make up approximately 5.8% of the contiguous U.S. land area (Milbrandt, Heimiller, and Schwabe 2018).

Milbrandt, Heimiller, and Schwabe (2018) find the economic potential[38] for tribal land-based wind exceeds 1 GW, which could produce more than 3 TWh annually. For utility-scale photovoltaic systems, there is more than 61 GW of economic potential, which could produce nearly 116 TWh of electricity annually. There is potential for distributed wind and solar in almost all tribal areas, however in low-resource areas the resulting levelized cost of energy is high and might not be competitive with grid electricity prices. Broadly, tribal lands in the western United States and the Plains regions contain high quality resource potential for wind, even at lower turbine hub heights. In the eastern and southeastern United States, wind opportunities are more limited. Increased solar resource availability makes distributed solar photovoltaic systems more productive for Tribes in the southern United States. Other renewable technologies did not show positive economic potential on tribal lands based on the set of assumptions used in Milbrandt, Heimiller, and Schwabe (2018).

Access to the transmission system is required to bring the economically viable generation resources to market. Where some tribal lands are well covered by the transmission system, some have limited or no access to high-voltage lines. The Department has funded the Geospatial Energy Mapper to locate potential areas of low carbon energy development. This tool also includes an interactive map of the existing transmission system and tribal lands to see where overlaps do and do not exist (*see* accompanying text box). Figure V-3 shows example outputs of the transmission system near the Tohono O'odham and the Houma tribal lands using the Geospatial Energy Mapper tool. Similar maps could be made using the tool for anywhere in the contiguous United States.

Resources that did not show economic potential in Milbrandt, Heimiller, and Schwabe (2018) should be revisited as the relative costs of renewable energy technology and market prices change. This constantly changing cost profile is particularly important in determining the relative value of renewable energy

DOE work on Mapping Energy Resources

The Department has funded the development of the Geospatial Energy Mapper (GEM) tool at Argonne National Laboratory. GEM provides mapping data and analysis tools for planning energy infrastructure in a geographic context. GEM is an interactive web-based decision support system that allows users to locate areas with high suitability for clean power generation and potential energy transmission corridors in the United States.

Argonne National Laboratory, Geospatial Energy Mapper (GEM), https://gem.anl.gov/.

[38] Where *technical potential* defines the amount of energy of a particular resource that could be converted into electricity given current technologies, the *economic potential* defines the amount that is financially viable to convert given technology costs and projected project revenue.

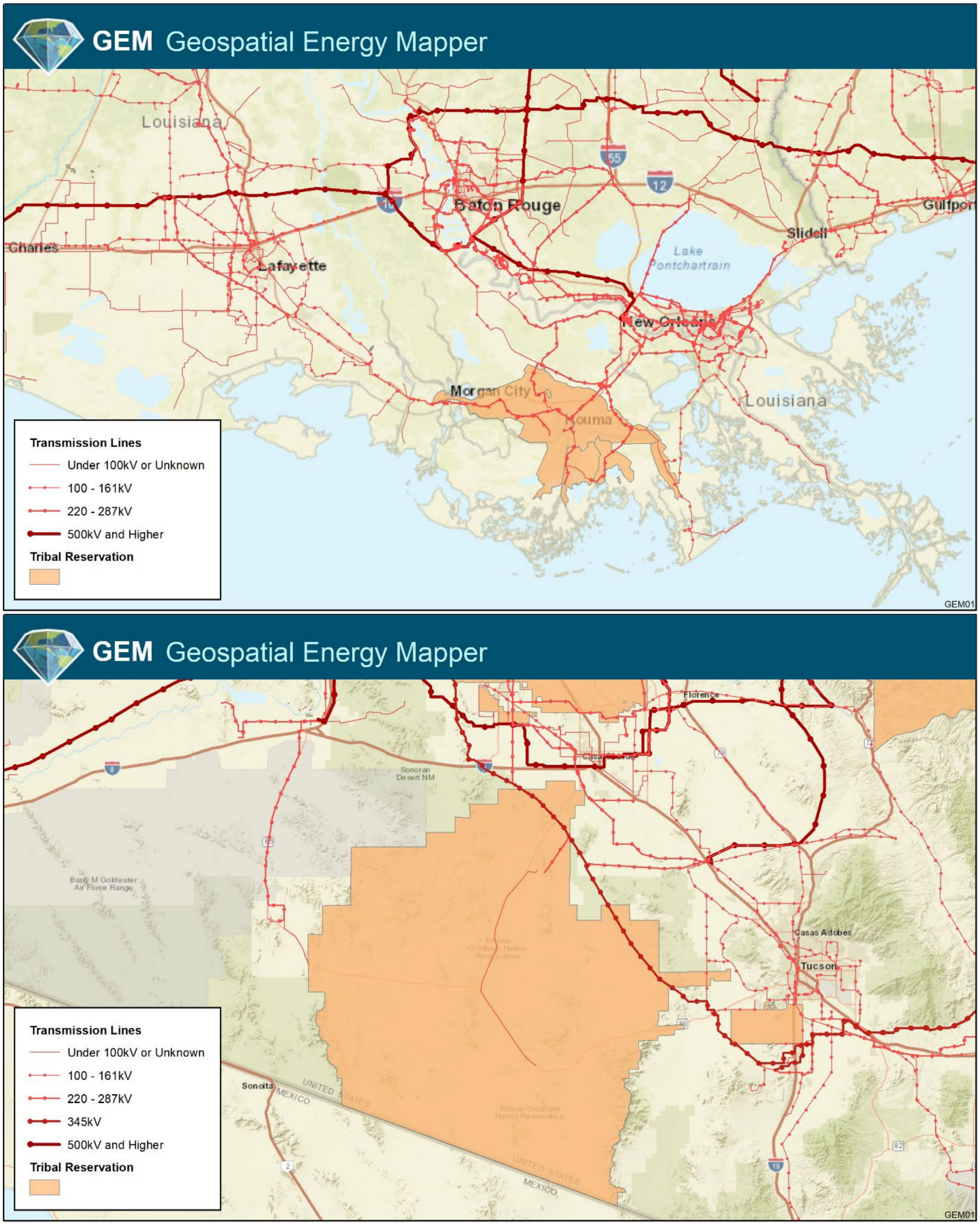
compared to other replacement sources of energy (Milbrandt, Heimiller, and Schwabe 2018). Future improvements to economic potential assessments on tribal lands include incorporating both in-region and out-of-region transmission costs and other policy drivers such as energy independence, reliability, environmental benefits, renewable portfolio standards, and any sensitivities to tax-oriented policies.

V.d. Congestion

Congestion is another major indicator of transmission need. Over one third of the reviewed reports discuss congestion as a driver of new transmission infrastructure, including Ardani et al. (2021), Pfeifenberger (2021), FERC (2020), and NERC (2021). MISO (2022) relies on congestion and fuel cost savings as another one of many quantified benefits gained from the projects proposed in their LRTP Tranche 1 Portfolio. The congestion value of transmission calculated by Millstein et al. in (2022a) discussed in Section IV.b is derived from the value of allowing a lower cost set of generators to meet load and by increasing operational flexibility through reduced congestion and increased interregional trade. Thus, value can also be thought of as the potential to reduce system cost through reducing congestion. In other words, properly accounting for the full suite of values that derive from transmission is critical toward building a least-cost electricity system.

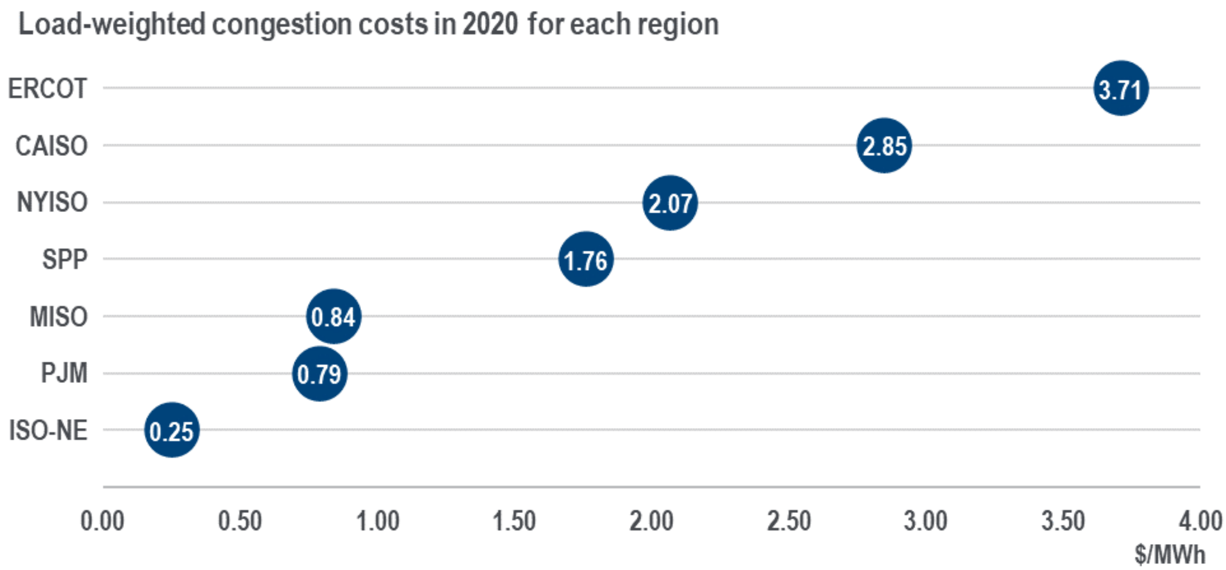
FERC (2020) similarly indicates that transmission investments can improve the competition of lowest-cost resources in wholesale markets by reducing congestion, noting that transmission investments have been rising for the past 20 years. In unconstrained cases, where the transmission system is modeled as a single-bus system in which transmission has unlimited capacity, no wholesale market price separation exists (ISO-NE 2021). New deployment of transmission, along with storage and other non-wire alternatives (discussed further in Section V.h), can alleviate congestion. If a transmission facility is being considered for the sole purposes of alleviating congestion, the cost of the project would need to be less than the congestion costs which are alleviated for the project to be financially viable.

This section discusses congestion found in each region, primarily using utility industry and market monitor reports in each area. Market monitor reports discuss costs incurred in each market due to transmission congestion. A summary of 2020 load-weighted congestion costs in each market from the reviewed market monitor reports is shown in Figure V-4. Load-weighted congestion costs are highest in CAISO and ERCOT.



Source: Created by Jim Kuiper at Argonne National Laboratory using the Geospatial Energy Mapper tool (2022).

Figure V-3. Overlap of the existing transmission system with the Houma (top) and Tohono O'odham (bottom) tribal lands.



Source: Data from ISO New England, Internal Market Monitor (2021, p. 120), Patton et al. (2021, p. 26), Market Monitoring Unit (2021, p. 198), Monitoring Analytics, LLC. (2021, p. 69), Potomac Economics (2021b, p. 59), Hildebrandt et al. (2021, p. 195 for DA and p. 111 for RT congestion), and Potomac Economics (2021c, p. 47). MISO system load calculated from MISO Regional Actual Load.[39] ERCOT system load taken from ERCOT's website.[40]

Note: Factors considered in calculating the congestion cost may vary from region to region, and therefore these load-weighted congestion costs represent best estimates and are presented for comparison purposes.

Figure V-4. 2020 load-weighted net congestion cost by region.

V.d.1. New England

Potomac Economics (2021a), in its 2020 assessment of the ISO-NE electricity markets, found that ISO-NE has very low congestion compared with other RTOs because of significant transmission investments over the past decade. As a result of these investments, however, the region has relatively high transmission service cost. ISO-NE experiences about 10 percent–20 percent of the congestion levels in other RTOs as a result of these large transmission investments (Potomac Economics 2021a). New transmission likely will not be needed in the near-term to alleviate congestion internal to the ISO-NE system. NERC (2021) also states that transmission expansion in New England has improved reliability and resilience, reduced air emissions, and lowered wholesale electricity market costs by nearly eliminating congestion.

Potomac Economics (2021a), however, describes the effect of transmission limitations on import capability in certain parts of the ISO-NE region. The assessment states that the combined lower Southeastern Massachusetts (SEMA) and eastern Rhode Island area is import

[39] See MISO Market Datafiles at https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/?msclkid=4b84e37ad14311ec991446d23bc026ef#nt=%2FMarketReportType%3ASummary%2FMarketReportName%3AHistorical%20Daily%20Forecast%20and%20Actual%20Load%20by%20Local%20Resource%20Zone%20(xls)&t=10&p=0&s=MarketReportPublished&sd=desc

[40] See ERCOT 2020 Demand and Energy Report at https://www.ercot.com/news/presentations/2020

constrained, and further transmission maintenance outages can reduce import capability from New Hampshire to Maine and increase reliability commitments in Maine.

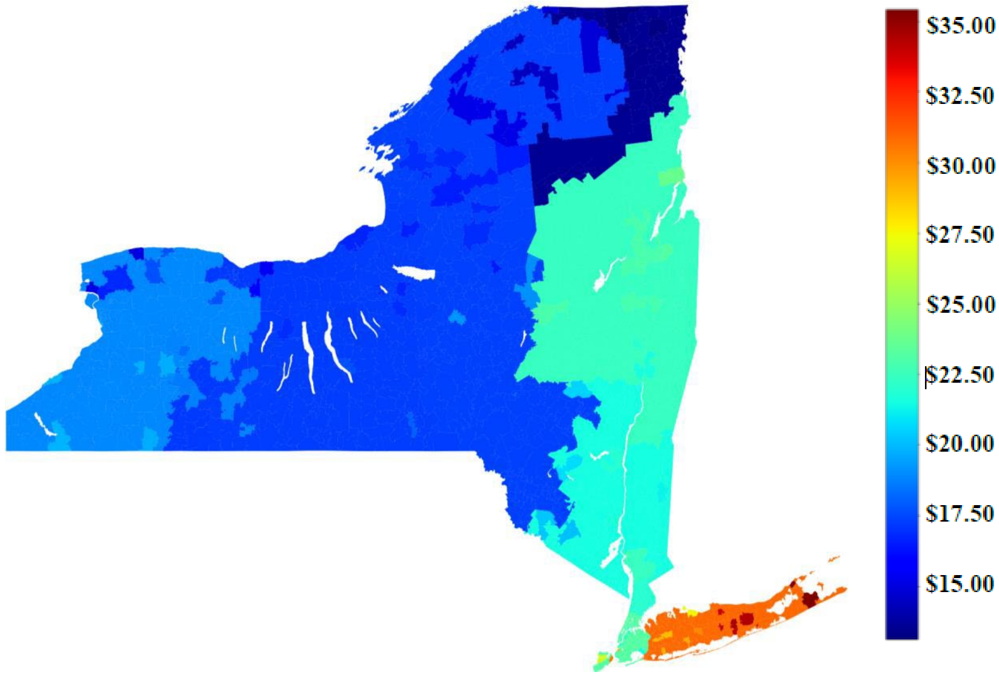
Additionally, ISO-NE (2020) notes that transmission enables low-cost resources to produce more energy, lowering wholesale electricity prices for several subareas. However, the report also mentions that increased congestion occurs on the SEMA/Rhode Island transmission interface from oversupply of wind generation to serve load outside the SEMA and Rhode Island areas. Interconnecting load centers in Connecticut and Massachusetts can alleviate this challenge. Further transmission expansion could be needed to avoid transmission-related wind curtailment, some of which can be avoided by developing resources near load centers. ISO-NE (2021) states that building extensive low production cost generation in one area, rather than near load centers, increases congestion, creating a need for new transmission.

V.d.2. New York

In NYISO's 2020 State of the Market Report, Patton et al. (2021) report that the COVID-19 pandemic reduced demand and had a larger effect on commercial customers than other customers. Thus, the decline in load was more pronounced downstate, which reduced congestion from upstate to downstate. Energy prices ranged from an average of $13.28/MWh in the North Zone to $28.03/MWh in Long Island due to transmission congestion and losses. However, congestion overall declined relative to 2019 due to lower load levels from the pandemic and lower natural gas prices. Day-ahead congestion revenues fell 31 percent, from $433 million in 2019 to $297 million in 2020, the lowest level since NYISO began operation. Still, the Central-East interface, which usually accounts for the largest congestion, continued that trend in 2020, with 39 percent of total day-ahead congestion value. Top congested corridors included the West Zone (19 percent), Long Island (17 percent), and New York City (8 percent). Average 2020 real-time energy prices and congestion in NYISO are shown in Figure V-5.

Transmission outages and other factors that limit transmission capability resulted in day-ahead congestion shortfalls. The most significant was the lengthy outage of the Sprainbrook-East Garden City 345 kV circuit. Outages on Cross Sound and the Neptune lines also caused significant congestion on Long Island. Further, transmission outages related to the construction of the Moses-Adirondack Smart Path Reliability Project resulted in reduced transfer capability out of the North Zone.

NYISO also improved the efficiency of scheduling and pricing in some areas by reducing the use of out-of-merit actions to manage constraints on low-voltage lines. In 2018, NYISO started incorporating some 115 kV constraints in the market software, reducing out-of-merit generation actions used to manage these constraints from 260 days in the West Zone in 2018 to 13 in 2020 and from 130 in the Capital Zone to 8.



Source: Potomac Economics, State of the Market Report for NYISO 2020, at https://www.potomaceconomics.com/wp-content/uploads/2021/05/NYISO-2020-SOM-Report.pdf

Figure V-5. Real-Time Energy Prices and Congestion in NYISO in 2020.

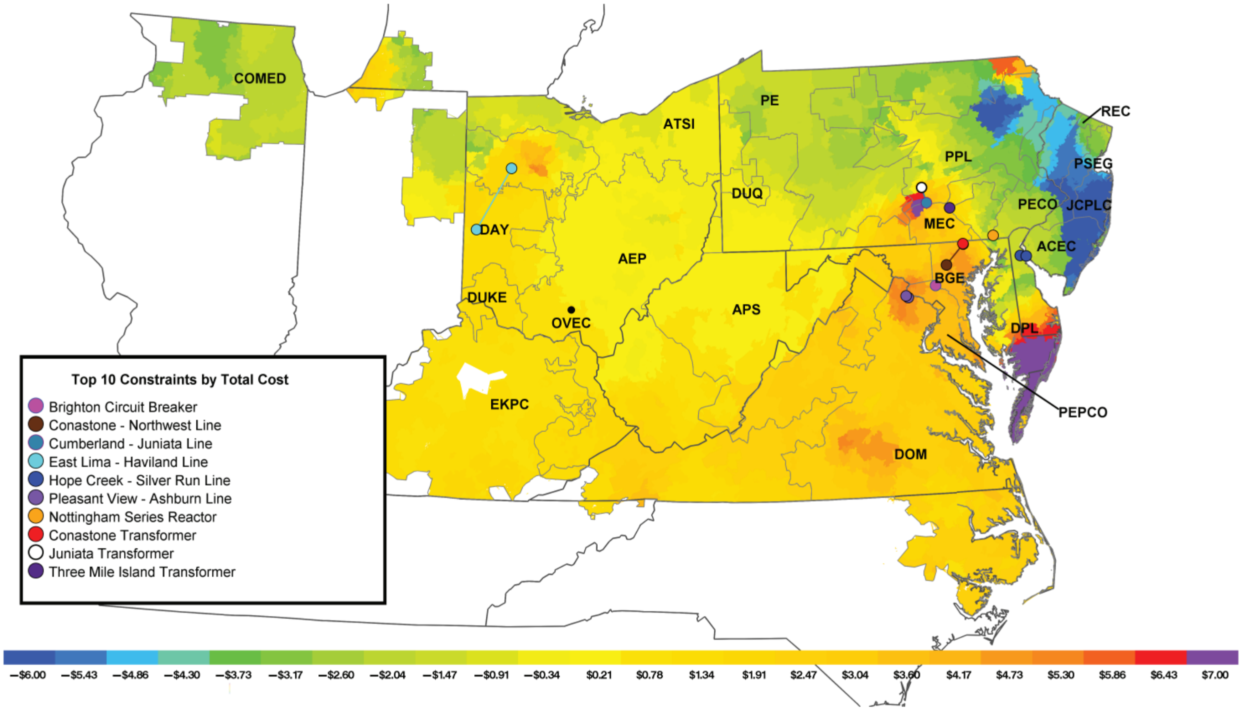
V.d.3. Mid-Atlantic

In PJM's 2021 State of the Market Report, Monitoring Analytics (2022) records that total congestion costs increased in 2021, from $528.7 million in 2020 to $995.3 million in 2021, an approximately 88.2 percent increase. The top ten facility constraints with regionwide impact are shown in Figure V-6 along with average 2021 congestion costs in the PJM region. A portion of this congestion associated with these constraints are a result of scheduled transmission outages during approved upgrades.

Monitoring Analytics (2022) also provides information on transmission constraint shadow prices, which represent the marginal change in total production cost from relieving a constraint by 1 MW and can signal congestion on certain lines. The average shadow price of PJM's internal transmission constraints almost doubled, from $92.23 in 2020 to $183.04 in 2021. For the first time since 2007, the cost of the transmission price component was more than the capacity price component for the wholesale price (on a per MWh basis), which shows a need for transmission upgrades within PJM to reduce congestion.

Monitoring Analytics (2022) also describes the impact of TLRs in PJM and its neighbors. According to the report, the impact of TLRs issued by PJM decreased in 2021, compared with 2020. PJM issued two Level 3a or higher TLRs each in 2020 and 2021, but no related curtailments occurred in 2021, compared with 1,789 MWh of curtailments in 2020. Monitoring Analytics (2022) indicates, however, that curtailments related to MISO and NYISO TLRs increased. The number of curtailments MISO issued decreased from 93 in 2020 to 75 in 2021, but curtailments increased from 58,520 MWh to 70,231 MWh, respectively. Monitoring

Analytics (2022) adds that NYISO issued three Level 3a or higher TLRs in 2021 compared with two in 2020. Related curtailments increased from 1,030 MWh in 2020 to 27,754 MWh in 2021. As described in Section III.d, TLRs only partially describe the congestion in RTOs where real-time transmission congestion is predominantly managed in the wholesale electricity markets.



Source: Monitoring Analytics, LLC. 2021 Annual State of the Market Report for PJM, Volume 2, Section 11: Congestion and Marginal Losses, page 593.
https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2021.shtml.

Figure V-6. Location of the top 10 constraints by total congestion costs: 2021 ($/MWh).

V.d.4. Midwest and Delta

In MISO's 2020 State of the Market Report, Potomac Economics (2021b) records that congestion costs increased because of increased wind output, generation and transmission outages, and the impact of Hurricane Laura in MISO South, highlighting the importance of increased resilience. Potomac Economics (2021b) reports that MISO's Regional Directional Transfer Limit[41] was frequently binding from south to north because of higher-than-normal temperatures in MISO Midwest. Flows were correlated to wind in other months. All wind resources within MISO are currently located in the MISO Midwest area, so flows are north to south when wind is high and in the reverse direction when wind is low. The ability to shift the quantity and direction of flows provides significant value to customers, suggesting that the desire for grid flexibility encourages the need for new energy transfers. Similarly, these findings highlight the need for increased access to a more diverse generation portfolio, which can be achieved through additional interregional transmission interconnections.

[41] The transfer capability limit on flows between MISO and SPP.

Despite lower gas prices and transmission upgrades in MISO, the value of real-time congestion rose by 26 percent to $1.2 billion in 2020 relative to 2019. Although congestion in the South and Central regions fell, congestion in the North region more than doubled due to increased wind output. The use of conservative static ratings and limitations of MISO's authority to coordinate outages contributed to higher than optimal real-time congestion. MISO has no authority to deny or postpone planned outages, even if such action would result in significant economic benefits. The Independent Market Monitor recommends that MISO file for increased authority to coordinate planned transmission and generation outages to reduce unnecessary economic costs.

According to Potomac Economics (2021b), congestion also affected MISO's interchange with neighboring markets. Congestion on MISO's Market-to-Market (M2M) constraints increased 37 percent in 2020 to $530 million (45 percent of all congestion in MISO) relative to 2019. The M2M processes for markets such as MISO and PJM are joint, real-time coordination processes that allow the regions to efficiently and cost effectively manage constraints that both regions affect. MISO uses M2M processes to manage congestion on MISO constraints that are also affected by generation in PJM and SPP (and vice versa). High wind along the seams with SPP and generator retirements contributed to a 400 percent increase in M2M payments ($80 million net payment) from MISO to SPP. The market monitor recommends measures to improve the M2M coordination and reduce M2M congestion costs.

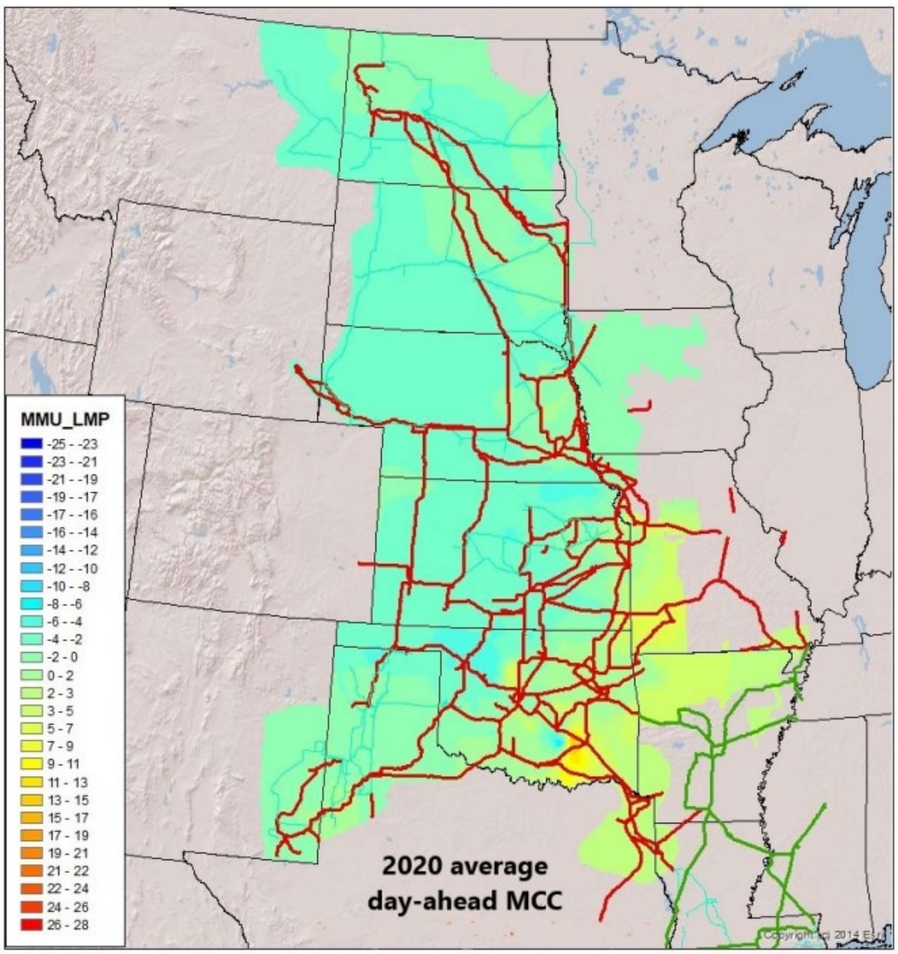
In addition, Potomac Economics (2021b) describes the negative impact of TLR on the MISO market. TLR is used as a congestion management method. TLRs called by the Independent Electricity System Operator of Ontario resulted in curtailments of large amounts of power from PJM to MISO, creating price spikes in MISO. Potomac Economics (2021b) also finds that Tennessee Valley Authority (TVA) generation could have relieved $63 million in congestion costs from TLR constraints and similarly identifies $43 million in congestion costs from TLR constraints that Associated Electric Cooperative Inc. generation could relieve economically. The market monitor recommends that MISO coordinate with TVA and the Independent Electricity System Operator of Ontario to develop mitigation measures.

In MISO and SPP's JTIQ Study (2022), RTOs recommend a five-project transmission portfolio that relieves constraints in both markets, enables the interconnection of large amounts of renewable generation near the seam, and provides other significant benefits. The portfolio relieves 48 reliability constraints across both markets. The JTIQ Portfolio resolves constraints that allow MISO to interconnect over 28 GW of additional generation near the seam, while SPP estimates it would be able to interconnect over 53 GW of additional generation. The JTIQ study suggests that increasing interconnections will reduce grid constraints and improve performance. MISO's LRTP Tranche 1 Portfolio (2022) identifies 7 projects that would generate $13.1 billion adjusted production cost[42] savings in congestion and fuel savings benefits over a 20-year period.

[42] See more at the MISO Adjusted Production Cost Calculation White Paper.

V.d.5. Plains

In SPP's 2020 State of the Market Report, Market Monitoring Unit (2021) records that congestion due to high wind generation and transmission limitations affected 2020 pricing in some locations. The southeastern corner of SPP, including eastern Kansas, southwestern Missouri, and southeastern Oklahoma experienced the highest congestion costs. Figure V-7 shows a map of average 2020 day-ahead congestion costs, as reflected in the marginal congestion component of the locational marginal price. Net congestion costs totaled over $442 million because of high wind generation and transmission limitations. Congestion costs in 2020 were 8 percent lower than those in 2019. Price differences between SPP North and SPP South hubs remained relatively small in 2020 ($0.23/MWh average day-ahead price difference) because of reduced congestion resulting from transmission expansion and a milder summer in the southern region. Transmission upgrades have increased transmission capability for wind-producing regions and reduced prices in previously congested regions.



Source: SPP State of the Market 2020.

Figure V-7. Average day-ahead marginal congestion cost map in SPP in 2020.

In addition, SPP experienced an increase in M2M payments from MISO. Total payments from MISO were $82.8 million in 2020, compared with $17.5 million in 2019. The Market Monitoring

Unit has recommended evaluating the processes and mechanisms between SPP and MISO through a joint study addressing the inefficiencies between the two markets. As MISO's wind penetration continues to increase, SPP's M2M flowgates would continue to be affected and potentially lead to an increase in the M2M payments from MISO. The M2M coordination study estimates a reduction of $35 million in annual congestion costs by automating processes that promptly identify and activate constraints in SPP and MISO's M2M systems.

SPP Market Monitoring Unit (2021) also indicates that underfunding of transmission congestion rights in SPP can affect the ability to use them to mitigate the effect of congestion.

Transmission projects in the regional transmission plan will address four of the top ten congested flowgates. The 2021 Integrated Transmission Planning Assessment performed by SPP could identify projects that address four additional flowgates.

V.d.6. California and the West

Hildebrandt et al. (2021) describe the impact of congestion in CAISO. Transmission constraints and greenhouse gas compliance costs resulted in CAISO's having higher prices than the rest of the WEIM. CAISO's Annual Report on Market Issues and Performance identifies congestion in both the day-ahead and 15-minute markets in 2020. Locational price differences because of congestion in both the day-ahead and 15-minute markets increased in 2020, particularly as a result of constraints associated with major transmission congestion on lines between Northern and Southern California and on those connecting CAISO and the Pacific Northwest.

Congestion on interties across all markets (day-ahead, 15-minute, and 5-minute) increased by 74 percent from $152 million in 2019 to $263 million in 2020. This increase was primarily due to increased congestion on the two major interties linking CAISO with the Pacific Northwest, where total congestion charges tripled to $236 million in 2020 relative to 2019 as a result of increased import congestion frequency on the interties during the third quarter. In California overall, congestion resulted in higher prices in SCE ($0.95/MWh or 2.66 percent) and SDG&E ($1.67/MWh or 4.53 percent), and lower prices in PG&E (-$1.47/MWh or -$0.41 percent). Constraints that contributed the most to price separation between the three load zones were the Path 26 nomogram, the Midway-Vincent #2 500 kV line, and the Quinto-Los Banos 230 kV line.

The effect of emerging trends on future interregional transmission capacity utilization in the Western Interconnection, based on the WECC 2028 Scenario Reliability Assessment (Bailey and Mignella 2020) is summarized in Figure V-8. The figure shows the top 15 highly utilized WECC paths in the 2038 Reference Case and four scenarios examined in the WECC study. Because of the displacement of coal generation, the Western Interconnection becomes more dependent on the Basin and the Southwest regions to meet energy needs, and the Rocky Mountain region switches from a net exporter to a net importer.

Demand in California continues to dominate the Western Interconnection. Transmission paths with high utilization include those that facilitate transfers from the Basin and Southwest to California and the Rocky Mountain region and those that support transfers from the Northwest to California. The increase in solar generation in California has resulted in bidirectional flows on some of these congested paths, sending energy in the opposite direction when solar production within California is high. Path congestion occurs during periods of heavy ramping or during energy deficiency periods in California. While periods of congestion are shorter now given the bidirectional nature of power flows, they are of increased criticality for reliability (Lauby 2022).

Most of the paths with high utilization are common to at least three scenarios. More than half of the paths are expected to be highly utilized in the near- to mid-term, as shown in the 2028 Anchor Data Set modeling results, but the level of utilization of these paths is expected to increase significantly by 2038.

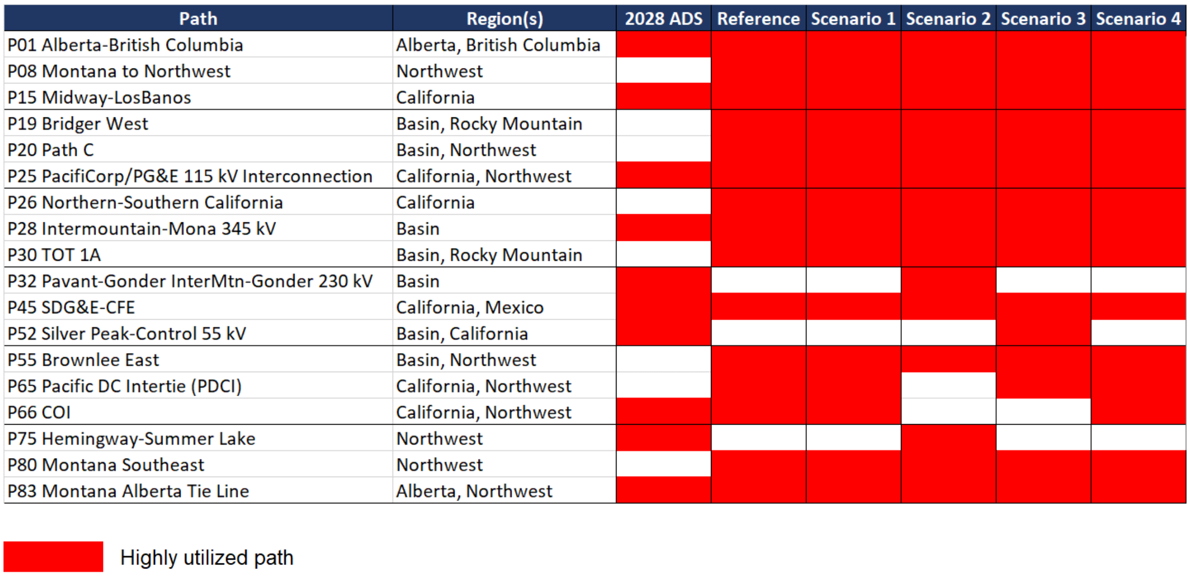


Figure V-8. Summary of WECC 2038 Scenario Reliability Assessment.

V.e. Curtailment

About a dozen of the reviewed reports, including Brown and Botterud (2020), Clack et al. (2020b), Breakthrough Energy Sciences (2021), Bailey (2022), and FERC (2020), mention transmission expansion as an effective means of avoiding or reducing renewable generation curtailment. Several reports maintain that curtailment is primarily caused by generation oversupply and transmission constraints. Curtailment is often cited as a concern, as it may challenge objectives to efficiently integrate renewables to reach electric sector decarbonization goals, realize the full benefits of renewable generation investments, and achieve further pollution reduction. Breakthrough Energy Sciences (2021) notes, however, that some amount of curtailment is inevitable—even with a perfect transmission network—because of the patterns of solar and wind availability.

In a study examining the potential economic value of increasing power transfers between the Eastern Interconnection and Western Interconnection, Bloom et al. (2020) model four different transmission designs that include HVDC transmission expansion co-optimized with generation investments and AC transmission investments. The authors report that the curtailment of renewable generation ranges from 11 percent to 15 percent, with congestion on AC transmission lines as the main driver. They note, however, that understanding the tradeoffs among curtailment, transmission, and other options requires additional analysis. Pfeifenberger (2021) quantifies curtailment reductions, estimating that for grids with 10 percent–60 percent renewable generation, regional diversification through the transmission grid results in curtailment reductions ranging from 45 percent to 90 percent.

Ardani et al. (2021) further state that curtailed solar and wind represent low-cost, zero-carbon power that can be used to supply new demand or produce low-carbon fuel. Using this curtailed energy, however, will require co-locating solar resources and low-carbon fuel production, developing adequate transmission connections, or identifying new demand resources that can make economic use of the variable curtailed solar. The report also notes that curtailment occurring during the operation of renewably fueled combustion turbines is an indication of transmission congestion, which demonstrates the critical role of transmission in achieving a least-cost mix of resources.

Clack et al. (2020b) find that expanding continental-scale transmission across the eastern and western United States tied to ERCOT and Canada can also help reduce curtailment through greater geographic diversity of resources. Additionally, the authors note that electrification could help reduce curtailment if resource dispatch and wholesale electricity markets are coordinated.

Prabhaker et al. (2021) demonstrate transmission solutions substantially decrease wind energy curtailments at 40 percent and 50 percent renewable penetration levels in MISO. The report notes that because transmission solutions have a lower effect on curtailment reductions at 50 percent renewable penetration level, transmission solutions have potentially diminishing returns at higher penetration scenarios.

V.f. Resilience

Novacheck et al. (2021) demonstrate how transmission is needed for resilience during certain weather events. The authors explain that risks posed by regional icing and cold temperature shutdowns, although rare, can be mitigated by local gas generation dispatch and interregional transmission, either individually or in concert. Novacheck et al. (2021) find that the operational and resource adequacy issues caused by the historical high-impact weather events considered in their report, such as the 2014 polar vortex that impacted the Midwest and the northeastern United States, were not further exacerbated by a higher penetration of VERs on the electricity system. They did find, however, that milder versions of these weather events resulted in concerns when periods of low VER availability were prolonged. The authors note that expanding transmission to create geographically diverse, clean energy resources can reduce these risks, suggesting that transmission can increase grid reliability in the face of risks posed by future weather events. Nevertheless, NERC (2021) suggests adopting policies that promote hardening of electric generation, transmission facilities, and fuel supplies to reduce risks to electricity reliability from extreme winter weather events.

Goggin (2021) similarly invetsigates through review of recent severe weather events what, if any, value additional transmission would have provided to the power grid during such events.

During the Texas heat wave of 2019, the study found that an additional 1 GW transmission tie to the Southeast could have saved Texas consumers nearly $75 million. As summer heat waves become more frequent and severe, the value of transmission for delivering needed electricity supplies from regions that are less affected will grow.

During the February 2021 cold weather event, Goggin (2021) found that each additional 1 GW of transmission ties between the Texas power grid and the Southeastern U.S. could have saved nearly $1 billion, while keeping the heat on for hundreds of thousands of Texans. With stronger transmission ties, both the Plains and Delta regions also could have avoided power outages while saving consumers in excess of $100 million with an additional 1 GW of transmission ties to power systems to the east (Goggin 2021).

During the "Bomb Cyclone" cold snap across the Northeast in December 2017-January 2018, the affected regions—New England, New York, and the Mid-Atlantic region—could have saved $30-40 million for each GW of stronger transmission ties among themselves or to other regions (Goggin 2021). These regions routinely switched between importing and exporting as the most severe cold migrated among the regions over the course of the three-week event, demonstrating that transmission benefits all users across broad geographic areas. In addition, one GW of stronger transmission ties between eastern and western PJM, the grid operator for much of the region between the Mid-Atlantic and Chicago, would have provided over $40 million in net benefits during this event. Likewise, the "polar vortex" event in the Midwest in 2019 was notable for illustrating how transmission expansion benefits multiple interconnected regions. As the extreme cold moved eastward from the Midwest to the Mid-Atlantic, operators were able to switch the direction of power flow to serve customers in need. (Goggin 2021)

FERC (2020) also reports that high-voltage transmission can improve the reliability and resilience of the transmission system by enabling utilities to share generating resources, enhancing the stability of the existing transmission system, aiding with restoration and recovery after an event, and improving frequency response and ancillary services. Following disruptive events, high-voltage transmission lines help with restoration and recovery by serving power from black start units once enough generation is operational. Additionally, high-voltage transmission lines help maintain a consistent frequency and enhance the stability of interconnected transmission by dampening interarea modes of oscillation.

A resilient transmission system can withstand many simultaneous maintenance-based or forced outages during even moderate electricity demand conditions. That is especially important as scheduling outages becomes more difficult with an aging transmission system. The number of transmission facilities and associated components in need of maintenance often exceed a utility's ability to service them in a timely manner. This backlog of maintenance requests leads transmission owners to develop risk-based asset management techniques to prioritize the most critical assets (BPA 2022).

In MISO's 2020 State of the Market Report, Potomac Economics (2021b) reports that transmission issues arose due to generation and transmission outages and the impact of Hurricane Laura in MISO South. Laura damaged the Entergy transmission system and isolated load in southwestern Louisiana and the eastern parts of Texas that are in MISO South, forcing more than 6 GW of generation out of service. More than 500 MW of firm load was curtailed as a result (Potomac Economics 2021b).

NERC (2022a) comments on the widespread outages in the Delta, Southeast, Texas, and Florida regions due to recent hurricanes, most notably Hurricane Ida in 2021. Over 1.2 million customers lost power and over 210 transmission lines were out of service due to Ida (NERC 2022a). The impacts of Hurricanes Laura and Ida emphasizes the importance of improving resilience and hardening transmission infrastructure.

NERC (2022a) notes that the ability of the power grid to withstand and recover from extreme events is increasingly important as the intensity and frequency of severe weather grows due to climate change. Interregional transmission investments will help improve system resilience by enabling access to diverse generation resources across different climatic zones.

V.g. Electrification

Another major driver of transmission investments identified in a handful of studies is electrification of end-use demand. Electrifying technologies and systems that currently run on fossil fuel sources, such as vehicles and heat pumps, is important in enabling economywide decarbonization to mitigate the impacts of climate change; improving local air quality that impacts human health, particularly for frontline communities; and providing grid system balancing.

ISO-New England's FGRS (2022) notes that, in addition to changes in electricity supply, regional goals and legislation regarding heating and transportation will also change the way electricity is used throughout New England over the next decade and beyond. Heating and transportation will become further electrified. Policy initiatives to replace building heating systems currently powered by wood, oil, propane, or natural gas to electricity will have a significant impact to the power grid. Replacing these building heating systems with electric-powered air-source or ground-source heat pumps will significantly increase the total demand on the New England grid. The replacement of gas and diesel-powered vehicles with electric vehicles will also increase overall system demand. Heating and electrification demand envisioned one of the FGRS's future scenarios is an exponential increase from current trends. In addition to the overall increase in demand, daily electrical system demand patterns will also change.

Brinkman et al. (2021) simulate a scenario representing the electrification of heating, transportation, and other end-use energy demands in North America so that electricity loads in 2050 are nearly double those in 2020. The result is significantly more transmission investments, with the greatest increase in investments at the intranational level. Under this scenario, transmission expansion within the contiguous United States is approximately 195 GW, over three times the business-as-usual scenario. Expansion between the United States and Mexico is approximately 8 GW and between the United States and Canada is approximately 20 GW.

NREL's Solar Futures Study (Ardani et al. 2021) came to a similar conclusion, finding in its scenario with extensive solar and wind deployment and increased electrification that transmission capacity expansion is 56,000 GW-mi by 2035 (39 percent increase relative to 2020 system) and 129,000 GW-mi by 2050 (90 percent increase relative to 2020 system). Larson et al. (2021) model various scenarios, with high-voltage transmission capacity additions ranging from over 94,000 GW-mi in the reference case to over 813,000 GW-mi in the high electrification, high variable renewables case. This results in a range of total capital transmission investments of $0.95 trillion to $3.6 trillion, respectively, stressing the role that electrification plays in driving transmission need.

FERC (2020) similarly reports on Brattle Group estimates that, in the future, increased electrification will stimulate substantially more transmission investment than historical levels. The Brattle Group study quantified these transmission needs, finding that the United States will need an average transmission investment of $3–$7 billion per year through 2030 due to electrification, on top of maintenance and renewable integration investments.

Clack et al. (2021) remind us that investments in the distribution system, and not just the transmission system, will be crucial in high electrification futures. In Clack et al. (2021), the largest share of cost in 2050 is distribution system investments, which are required to address system needs due to economywide electrification.

V.h. Non-Wire Alternatives

Some of the reviewed reports consider transmission needs that could be met by both non-wire alternatives and traditional wires solutions. Strategic planning to site storage and generation close to load centers could help mitigate need for traditional transmission wires. For example, distributed energy resources—and even conventional generation with carbon capture, use and sequestration technologies—could help meet demand locally. Demand response is another technology with the potential to limit electricity demand when transmission is constrained. Implementing these generation- and demand-based solution would require careful planning from both utilities, and state and local officials to ensure resource adequacy and minimize risks. Energy storage, DERs, grid-enhancing technologies (GETs), and microgrids are examples of non-wire transmission solutions that can serve some of the same purposes as traditional wires and are discussed in more detail below.

V.h.1. Energy Storage

Energy storage can serve as a grid asset to support higher degrees of variable energy on the system by shifting load across hours or days, smoothing seasonal peaks, and providing grid services. Prabhaker et al. (2021) find that pairing storage with renewables and transmission helps optimize grid operations in MISO. Without adequate transmission capacity, however, storage might not contribute sufficiently to achieving penetration targets. In their storage sensitivity modeling, Prabhaker et al. (2021) indicate that even with large additions of storage to the MISO system, there is a limited change to transmission needs. More specifically, their modeling shows that beyond an incremental 12.1 GW of 6-hour storage at 40 percent renewable penetration, there is little change to transmission needs. In contrast, Bailey (2022) finds that adding battery storage resources can help offset the need for new transmission expansion in integrating renewables onto the grid.

Furthermore, Clack et al. (2020b) demonstrate that storage complements transmission by using battery storage to increase the utilization of transmission lines. Jorgenson et al. (2022) also find that storage increases utilization of some transmission lines (quantified by the amount of observed congestion), while reducing the congestion observed on other lines. Exactly how storage impacts nearby transmission by increasing or decreasing usage depends on the local conditions.

For instance, in New England large quantities of new energy storage, primarily batteries, could be used as a solution to maintain grid reliability in a renewable-dominant landscape (ISO-NE 2022). The ISO-NE (2022) analysis found that modeling storage with the objective of price arbitrage did not fully address the needs of the overall future power grid. Current reliability models may not be able to capture long dispatch periods and the reserve services that storage is able to provide, which will become increasingly important in with larger penetrations of variable energy resources.

V.h.2. Distributed Energy Resources

Clack et al. (2020a; 2020b; 2021) and other studies comment on the role of distributed energy resources[43] in a clean electricity system. Clack et al. (2020a) use a model that allows for the incorporation of a detailed representation of the distribution system and disaggregation of DER technologies, providing insights into the interface of the distribution and transmission systems. Their model enables comparisons between scenarios with a traditional planning approach augmented with DER co-optimization and scenarios that exclude DER co-optimization (Clack et al. 2020a).

Clack et al. (2020a) also evaluate the potential value of DERs in lowering costs across the electricity system and promoting clean electricity goals. The study models four scenarios – a business-as-usual scenario with and without DER co-optimization and a clean energy standard scenario also with and without DER co-optimization. The authors find that transmission expands at a similar rate in all scenarios until 2035. In the clean energy standard scenarios, transmission expands rapidly after 2035, when significant changes in generation resource mix required to meet clean energy goals start to occur. Additionally, the study finds that DER co-optimization results in key geographic differences in the location of transmission builds. Compared to scenarios without DER co-optimization, scenarios with DER co-optimization require higher transmission buildout in the states in the southeast to help integrate VERs. A similar trend, though to a lesser extent, occurs in the states in the southwest that have higher solar generation. States in the northeast require a higher buildout of transmission in scenarios without DER co-optimization to support utility scale generation developed in those scenarios. In general, total transmission expansion is similar in the two business-as-usual scenarios. In the clean energy standard scenarios, total transmission expansion is slightly higher in the scenario with DER co-optimization. Incorporating DER co-optimization results in 85,000 GW-mi of new transmission builds, compared to 75,000 GW-mi without DER co-optimization. The study notes

[43] While each study referenced here may have slightly different definitions, we define *distributed energy resources* here as any electricity generation resource connected to distribution system facilities with nominal ratings of less than 100 kV.

that the model does not simply replace transmission with DER, but rather removes transmission that is no longer economic and builds transmission in areas where it is more economic and supports grid decarbonization.

Investments in the distribution system are also crucial. Co-optimizing distribution system improvements with utility-scale generation contributes to significant reductions in distribution system costs. Co-optimizing the expansion of the distribution grid and development of DERs reduce total resource costs—mostly distribution system costs—by $109 billion by 2030 and $515 billion by 2050, compared with a scenario that considers only utility-scale solar generation (Clack et al. 2021).

Clack et al. (2021) run a scenario with utility-scale and distribution system co-optimization in which DERs can grow to meet net-zero emissions in the U.S. economy by 2050. They find that all states except Montana and Oregon significantly increase interstate transmission capacity. The largest new transmission buildout is in the northeastern United States, whereas the WECC region has lower buildout. Although transmission buildouts are still required, Ardani et al. (2021) demonstrate that because DERs can provide the same services as utility-scale PV, they offset the need for generation and transmission resources to maintain resource adequacy.

V.h.3. Grid-Enhancing Technologies

GETs are a suite of solutions available to manage transmission congestion and increase line utilization rates by increasing the capacity of the existing transmission system. Beyond congestion relief, GETs provide several system benefits, including situational awareness to enable safer real-time operations, asset deferral while longer-term solutions are implemented, increased grid resilience, and asset health monitoring (DOE 2022b). GETs deployment can also improve the reliability of the existing transmission system, which can serve as an economical alternative to transmission expansion in certain scenarios. The several types of GETs include dynamic line rating (DLR), power flow controllers (PFCs), dynamic transformer ratings, and topology optimization (DOE 2022b).[44]

DLRs use sensing devices and algorithms to collect real-time weather data or other information on conditions that affect the operation of a transmission line and calculate the ampacity[45] of a conductor more accurately. This enables operators to better model the true thermal limits of the line at any given moment using near-real time conditions. Often, the use of DLR technology yields greater capacity than static line ratings, and thus provides an opportunity to safely use the existing transmission system more efficiently (DOE 2022b). Potomac Economics (2021b) also identifies concerns with the use of conservative static ratings in the MISO region. They estimate significant benefits would result from the use of adjusted ambient line ratings and recommend that MISO improve the flexibility of its systems and processes to enable more dynamic and accurate line ratings.[46]

[44]Energy storage is also sometimes identified as a GET, although it is discussed separately in this Needs Study.
[45] The maximum amount of current that a wire can safely carry.
[46] Ambient-adjusted rating uses ambient air temperature to adjust line ratings over time.

PFCs are a set of technologies that reroute power away from overloaded, congested lines onto underutilized, less congested lines in the network. PFCs operate by adjusting physical properties of the line. Along with DLRs and other GETs, PFCs provide another important tool for optimizing the use of the current network (DOE 2022b).

Both DLRs and PFCs are the focus of the 2022 study released by the U.S. Department of Energy: *Grid-Enhancing Technologies: A Case Study on Ratepayer Impact*. This study models the impact of GETs on a region in NYISO under three generation scenarios: a scenario with the renewables currently in service in NYISO, a second scenario with 3 GW of additional solar capacity and 4 GW of additional wind capacity from the NYISO Interconnection Queue, and a third scenario with the required renewable generation to achieve 70 percent renewable generation by 2030. The report outlines customer benefits that could be realized by implementing DLRs and PFCs in these scenarios, including annual avoided curtailment savings ranging from $1.7 million from applying DLR to $9.1 million from deploying DLR, PFCs, and a new substation. Although the study finds that line reconductoring and adding a new substation (traditional upgrades) could yield the highest savings in avoided curtailment, these upgrades are also expensive and time consuming to implement. GETs can yield high curtailment savings at a lower cost than traditional wires solutions in some cases in the near-term, and therefore can be an efficient use of ratepayer funds (DOE 2022b). The study also outlines recommendations for the further deployment of GETs across different parts of the system.

V.h.4. Microgrids

Microgrids serve as an effective platform for integrating DERs and reducing costs and emissions while bolstering the resilience of the Nation's electricity system. The value of microgrids has grown with FERC Order 2222, under which the DERs that are aggregated and optimized in microgrids can participate in wholesale energy markets and can realize more of their maximum potential benefits (DOE 2022b).

The full value of microgrids can be categorized into bulk system services (generation capacity, contingency reserves, etc.), transmission and distribution services (congestion relief, upgrade deferral, etc.), and customer services (demand charge management, reliability, etc.). One utility has characterized 14 unique value streams in planning and using microgrids for benefits now and into the future (Lightner et al. 2021). As of mid-2019, 19 states and the District of Columbia had either adopted or were actively exploring adoption of performance-based ratemaking structures to incentivize utilities to use resources beyond traditional generation to meet capacity needs and achieve high rates of reliability (Wang and Crawford 2019).

With expanding deployments of DERs, microgrids play an increasingly important role as a non-wire alternative solution to provide power to meet local loads while supporting grid performance objectives (e.g., reliability, resilience, ancillary services). By doing so, microgrids help defer or avoid the need to build new power lines and can allow communities to have greater control over energy resources. DOE envisions microgrids as building blocks of the future grid that will accelerate the transformation toward more distributed and flexible architecture in a socially equitable and secure manner (DOE 2021).

V.i. Barriers to Transmission Development

The reviewed literature also identifies various challenges to meeting the transmission needs discussed above. Multiple studies specify siting of high-voltage lines as one major challenge, indicating that developers often must navigate multiple state processes and local and federal government requirements. As detailed in FERC (2020), developers are often required to navigate multiple state processes as well as federal and local requirements. To obtain a Certificate of Public Convenience and Necessity[47], developers of multistate projects must demonstrate that their project is in the public interest in each state. Criteria used to make determinations may differ in each state and may even be inconsistent. For example, some states may focus on intrastate benefits and costs only, while others may also take into account or even require interstate, regional, or national benefits and costs. Further, some states may require broad environmental and economic benefits and costs, while others may consider specific policy goals. The Department funds the Regulatory and Permitting Information Desktop (RAPID) toolkit as a resource to catalog these many differences (*see* accompanying textbox).

As stated in Breakthrough Energy Sciences (2021), differences in planning and permitting processes of the state and local authorities along the path of a transmission line makes this a major hurdle. FERC (2020) and Breakthrough Energy Sciences (2021) further indicate that obtaining approvals in each state also may be difficult because many states focus on intrastate burdens and benefits. A line that does not directly connect resources within a state might not receive permits required to traverse the state.

Additionally, developers face hurdles during the planning process, where differing drivers of transmission needs or siloed consideration of the

DOE work on Regulation and Permitting

The Department funds the Regulatory and Permitting Information Desktop (RAPID) Toolkit, which provides information about federal, state, and local permitting and regulations for utility-scale renewable energy and transmission projects. Developed and maintained by the National Renewable Energy Laboratory, the toolkit makes permitting information easily accessible from a single site by providing links to permit applications, processes, manuals, and other related resources.

National Renewable Energy Laboratory, The RAPID Toolkit: Facilitating Utility-Scale Renewable Energy Development, https://www.nrel.gov/state-local-tribal/blog/posts/the-rapid-toolkit-facilitating-utility-scale-renewable-energy-development.html.

OpenEI, RAPID Bulk Transmission Toolkit, https://openei.org/wiki/RAPID/BulkTransmission.

[47] Certificates of Public Convenience and Necessity go by different names in each state, but are generally granted by state public service commissions to indicate than an infrastructure project is deemed in the public interest and therefore is entitled to specific rights, such as eminent domain or rate-basing costs among all customers.

multiple benefits of transmission may exclude valuable projects or complicate their path to construction. Conflicts also arise over cost allocation, as quantifying and determining who receives the benefits is especially challenging. FERC (2020) adds that the planning and permitting process might further complicate transmission development because in addition to state laws, the project may also be subject to local and federal review. For example, local review may be required for authorizations such as zoning permits and high-voltage transmission lines that cross federal lands may require permits from federal agencies that have different information needs and decision criteria. Overall, NERC (2021) describes high-voltage transmission expansion as time consuming and often involving significant siting challenges.

Furthermore, land acquisition is described as a challenge in transmission development in Ardani et al. (2021). Capacity expansion models, like those used in Section 6, try to capture this challenge by significantly increasing the input cost assumptions of transmission development. In their modeling, Cole et al. (2021) increased transmission costs by a factor of five in some scenarios to capture the challenges of siting new lines. These increased costs are meant, in part, to capture the capital cost increases of undergrounding significant portions of transmission lines.

FERC (2020) and Breakthrough Energy Sciences (2021) suggest co-locating transmission in transportation corridors to help mitigate some siting and land acquisition issues. FERC (2020) indicates, however, that there are barriers to such co-location. Some state laws prohibit or in other ways restrict the co-location of transmission in highway rights-of-way. Co-location may also increase costs if the highway does not run in the direction compatible with the project. Further, electrical interference can affect the protection systems of oil and gas pipelines and accelerate corrosion, and the induced currents from high voltage lines can also affect railroad signaling systems. These issues could limit co-location of transmission in pipeline or railroad rights-of-ways. Finally, additional safety and security concerns arise when facilities are co-located. Incidents related to one facility can affect the co-located facility due to the physical proximity.

Some challenges relate to energy justice issues. Ardani et al. (2021) suggest that community engagement will be key in addressing siting concerns and making equitable siting decisions. Ardani et al. (2021) add that transmission infrastructure can raise local opposition because of possible perceived negative impacts on property and the environment. Increased community engagement will be crucial for addressing local concerns and making equitable siting decisions. Historically, marginalized communities have had a disproportionate share of the cost and burdens of transmission network expansion.

V.j. Conclusions

Altogether, the studies reviewed in this section signify a pressing need to expand electric transmission—driven by the need to improve grid reliability, resilience, and resource adequacy, enhance renewable resource integration and access to clean energy, decrease energy burden, support electrification efforts, and reduce congestion and curtailment. These indicators of transmission need are recurrent across the reviewed reports, demonstrating their prevalence despite distinct study regions, modeling tools, and industries.

The need to integrate clean energy resources into the grid underlies the majority of reviewed studies across the range of study authors, in the context of decarbonization and electricity price and energy cost reductions. Transmission expansion is needed to interconnect renewable generation often located in remote areas and deliver energy to load centers where it is needed. Energy justice considerations should be included in transmission planning scenarios to relieve high energy burdens and high cumulative burdens. Expanding interregional transmission capacity enables the system to take advantage of the geographic and temporal diversity of energy resources, so that abundant production in one region can help compensate for low production in other areas, which improves the electric system's ability to produce affordable, reliable energy while increasing the operational flexibility of the grid. Utilizing increased geographic diversity of resources also reduces curtailment, thereby more efficiently integrating renewables to reach clean energy and decarbonization goals, realizing the full benefits of renewable generation investments, and achieving further pollution reduction. More specifically, increasing access to remote renewable resources results in benefits from avoided health impacts, avoided climate damage costs, and general air quality improvements.

Further, with aims toward economywide decarbonization, some reports demonstrate an even greater need for increased transmission buildout to support electricity demand increases due to electrification. As Brinkman et al. (2021) show, demand for electricity could double by 2050 relative to 2020 levels as a result of electrification, driving new investments in interregional transmission.

Another key theme reoccurring across the literature is reliability as a major driver of transmission projects. Expanding transmission capacity improves the ability of the bulk power system to respond to emergencies. Several reports find that interregional and continental-scale connections can improve reliability by capturing even greater geographic diversity of generation resources. Similarly, new transmission can also support resource adequacy, as new lines enable more flexible generation sharing, reducing the need for new generation.

Transmission is also key to bolstering grid resilience. Several authors mention the benefits of transmission in reducing weather risks by allowing utilities to share generating resources, enhancing the stability of the existing transmission system, aiding with restoration and recovery after an event, and improving frequency response and ancillary services. One case in which transmission likely would have improved grid resilience was during the severe cold weather event that occurred in February 2021 in Texas and the South Central United States (FERC et al. (2021). FERC et al. (2021) suggest that ERCOT evaluate the benefits of additional ties with neighboring interconnections to improve import and black start capabilities.

Additionally, congestion was also expressed as an indicator of transmission need throughout the literature. Several market reports also acknowledged that new or upgraded transmission reduced congestion in the region or was anticipated to.

VI. Capacity Expansion Modeling: Anticipated Future Need

The U.S. power supply is undergoing a rapid transformation, motivated by evolving market conditions, geopolitical conflicts, and the increasing penetration of new generation and transmission technologies. Given the long development time for high voltage power lines, the Nation's transmission needs should be defined as much by anticipated future need as current need. Congress has also directed that the Department consider expected future congestion and constraints in this study.

Planning the future power system requires knowing changing market conditions and consumer demand behavior. Capacity expansion modeling is a common tool used to estimate what the power demand and generation mix will be in future years. To accommodate many potential futures—for example, how many end use appliances will be electrified? what will be the adoption rate of advanced nuclear technologies? —capacity expansion modelers consider multiple scenarios under a range of feasible assumptions.

Once future power system scenarios and input modeling assumptions have been established, capacity expansion models make generation, storage, and transmission investment decisions by optimizing for the lowest capital and operations costs, system wide. In finding this cost-optimal capacity mix, the models do consider hourly energy dispatch constraints and some essential grid reliability services, such as resource adequacy. [48] The models will optimize around all possible technology combinations and choose the least expensive solutions in each geographic zone. The resulting transmission needs for each region given the most cost-optimal solutions found for all scenarios are presented here.

The capacity expansion modeling studies used here are national in scope and capture a wide range of likely future power sector characteristics. Given the rapid transformation of the power sector, there is value in considering how a diversity of generation and demand futures will impact the transmission system. Scenario-based transmission planning can capture large uncertainty in how the generation and demand sectors will change 20 or more years into the future. Capacity expansion modeling studies differ from many industry-led studies, which respond to regional, near-term transmission needs by identifying specific transmission projects as solutions (Pfeifenberger et al. 2021).

The values presented here are zonal estimates of the amount and general geographic location of future transmission need. The precise characteristics and nodal locations of specific transmission projects to accommodate generation and load changes would be determined by additional engineering analysis performed by the transmission planners (as described in the Introduction). Additionally, any one of these transmission additions may require associated system upgrades to support increased energy transfers and, as such, the zonal estimates reported here may underestimate total required system builds. These downstream analyses are

[48] The energy and reserve services considered by each capacity expansion model can be found in the referenced model documentation.

critical to the transmission planning process to ensure reliable operation of the grid but are out of scope for the analysis presented here. Because of their near-term focus, industry-led studies tend to be less speculative about the characteristics of the future power system. Section V reviews the results of many of these studies but given the mismatch in modeling scope, the results of the reviewed industry studies are not included in this analysis.

The Department is currently undertaking a National Transmission Planning Study to bridge the gap between national, long-term capacity expansion modeling studies and regional, near-term transmission planning studies (*see* accompanying text box). The National Transmission Planning Study is conducting downstream engineering analysis of candidate transmission projects which result from capacity expansion modeling. Future iterations of the Needs Study may include the results of the National Transmission Planning Study.

This section describes future power system scenarios that six capacity expansion studies considered and the resulting amount of new transmission each study modeled. Section VI.a provides a high-level overview of all model scenarios considered in this analysis and explains how we categorized the scenarios for presentation of results. This section also includes an explanation of non-wire technologies considered by the scenarios. Sections VI.b and VI.c present the resulting new transmission needed to meet changes in electricity demand and other power sector constraints of each region. Section VI.b presents the regional transmission expansion results, followed by interregional transfer capacity expansion results in Section VI.c. International transfers are presented in Section VI.d. The transmission expansion results shown here are model outputs that illustrate the amount of anticipated transmission investments needed to meet a large range of power sector futures. Given the diversity of demand-side, generation and transmission solutions to future power sector needs, ranges of results are shown.

DOE work on National Transmission Planning

The Department is conducting the National Transmission Planning Study to identify transmission solutions that will provide broad-scale benefits to electric customers; inform regional and interregional transmission planning processes; and identify interregional and national strategies to accelerate decarbonization while maintaining system reliability.

Dept. of Energy, Grid Deployment Office, National Transmission Planning Study, https://www.energy.gov/gdo/national-transmission-planning-study.

VI.a. Included Studies and Scenarios

We analyze the anticipated transmission results of over 200 scenarios from six capacity expansion modeling studies published since 2020.[49] The scenarios represent different potential futures for the Nation's power sector, all of which result in different assumptions about future electricity demand and the resulting deployment of transmission. Four of the six studies were performed by researchers at the National Renewable Energy Laboratory (Ardani et al. 2021; Brinkman et al. 2021; Cole et al. 2021; Denholm et al. 2022), one study from Princeton University researchers (Larson et al. 2021), and the final from researchers at the Massachusetts Institute of Technology (Brown and Botterud 2020). These studies and results from their core scenarios were reviewed in Section V. Table VI-1 summarizes the six studies discussed here at a high level; a more detailed summary of and the specific treatment of transmission in each study can be found in the Supplemental Material.

Table VI-1. Summary of six reports used in this analysis.

Report	Driving Perspective	Temporal	Geographic	Included Modeling	Scenarios
Mass. Institute of Technology *The Value of Inter-Regional Coordination and Transmission in Decarbonizing the U.S. Electricity System* Brown and Botterud (2020)	Considers costs associated with different transmission coordination and expansion cases, given 100% renewable energy system	<u>Scope</u> 2040 <u>Resolution</u> CEM: single year modeled	<u>Scope</u> Contiguous U.S. <u>Resolution</u> State	• CEM: custom co-optimized, linear capacity planning and dispatch model	6 core scenarios: • No new transmission, no inter-state coordination • No new transmission, regional coordination (PA–AC) • New state transmission, regional coordination (PA+AC) • New state transmission, national coordination (USA–AC–DC) • New regional transmission, national coordination (USA+AC–DC) • New regional AC & DC transmission, national coordination (USA+AC+DC) Plus 48 sensitivities
NREL *North American Renewable Integration Study* Brinkman et al. (2021)	Considers impacts on power sector if transmission and generation planning conducted jointly with USA, Canada, and Mexico	<u>Scope</u> 2010–2050 <u>Resolution</u> CEM: 2-yr PCM: 5-min RA: hourly	<u>Scope</u> Continental <u>Resolution</u> Approx. nodal	• Capacity expansion modeling (ReEDS) • Production Cost Modeling (PLEXOS) • Resource Adequacy (PRAS)	4 core scenarios: • Business-as-usual • Low-cost variable generation • Carbon constrained • Electrification Plus 38 sensitivities

[49] Several other studies with anticipated future transmission expansion results reviewed in Section V were considered for inclusion in this analysis. Because of data issues (errors found in results, only preliminary results available to wider public, etc.), those studies were excluded from this analysis.

Report	Driving Perspective	Temporal	Geographic	Included Modeling	Scenarios
NREL *Standard Scenarios* Cole et al. (2021)	Considers possible future power sector scenarios, given different technology costs and system conditions and adoption levels	Scope 2022–2050 Resolution CEM: 2-yr PCM: hourly	Scope Contiguous U.S. Resolution Approx. BA	• Demand side modeling (dGEn) • Capacity expansion modeling (ReEDS) • Production Cost Modeling (PLEXOS)	3 core scenarios: • No New Policy • 95% by 2050 • 95% by 2035 Plus 47 sensitivities
NREL *Solar Futures Study* Ardani et al. (2021)	Considers role of solar energy, distributed energy, and electrification, given power sector decarbonization	Scope 2020–2050 Resolution CEM: 2-yr PCM: hourly RA: hourly	Scope Contiguous U.S. Resolution Approx. BA	• Capacity expansion modeling (ReEDS) • Production Cost Modeling (PLEXOS) • Resource Adequacy (PRAS)	3 core scenarios: • Reference • Decarbonization • Decarbonization + Electrification Plus 6 sensitivities
Princeton University *Net Zero America* Larson et al. (2021)	Economy-wide net-zero emissions by 2050; implications for land use, capital mobilization, jobs, air pollution assessed for different net-zero energy system pathways	Scope 2020–2050 Resolution CEM: 5-yr	Scope Contiguous U.S. Resolution State (transmission outputs)	• Demand side modeling (EP) • Capacity expansion modeling for power and fuels sectors (RIO)	6 core scenarios: • Reference • High electrification (E+) • Less high electrification (E−) • Less high electrification, high biomass (E−B+) • High electrification, less high variable energy resources (E+RE−) • High electrification, 100% renewable energy by 2050 (E+RE+)
NREL *Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035* Denholm et al. (2022)	Considers different pathways to achieve 100% clean electricity by 2035 and net-zero emissions by 2050	Scope 2020–2050 Resolution CEM: 2-yr	Scope Contiguous U.S. Resolution Approx. BA	• Demand side modeling (dGEn) • Capacity expansion modeling (ReEDS)	4 core scenarios: • All options • Infrastructure renaissance • Constrained Siting • No carbon capture & sequestration Plus 122 sensitivities

VI.a.1. Scenario grouping

Figure VI-1 shows the combination of clean energy generation[50] and electricity demand assumptions for all study scenarios in 2040. The two outer histograms show the scenario counts

[50] Clean energy generation for purposes of grouping scenarios is defined as all solar energy (concentrating solar power, utility-scale photovoltaic systems, rooftop photovoltaic systems), land-based wind, offshore wind,

with respect to clean energy penetration (x-axis) and total annual load (y-axis) individually. The center contour plot shows the scenario counts for both clean energy penetration and total load, considered together. A single point on the contour plot indicates the amount of clean energy and load assumed for a single scenario. Red shading contours indicate where many datapoints are clustered. The darker the shading, the more scenarios have that level of clean energy penetration and total load. The open diamond indicates the clean energy penetration (38.6 percent) and total annual load (3,974 TWh) in 2021 (EIA 2022a). Any scenarios to the right of the diamond indicate an increase in total clean energy penetration in 2040 compared to today's levels. Any scenarios above the diamond indicate a growth in total annual load compared to today's load.

Three general groups of scenarios emerge from the contour plot, as shown by the outermost contour line in Figure VI-1. Using the contours as a guide, linear thresholds are applied to categorize scenarios into three groups:

- **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 percent) and 80 percent 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 percent in 2040.
- **High/High:** high load growth above 7,000 TWh and high clean energy penetration above 80 percent in 2040.

All studies considered scenarios with different utility, state, and federal policies modeled, including "no policy" scenarios where changes in resource mix and load are driven by market forces only, "existing policy" scenarios that consider any relevant utility, state and federal policies in place at the time of the study, and "new policy" scenarios that would require new state or federal power sector policies (compared to the existing policies at the time of the study) to enable the modeled power sector changes. It is important to note that modeling for all studies was performed before the passage of the bipartisan Infrastructure Investment and Jobs Act of 2021 and the Inflation Reduction Act of 2022. It is anticipated that these laws will have dramatic impacts on future generation and demand that were not modeled among the "existing policy" scenarios presented here. Transmission solutions will be needed to accommodate the generation and load changes enabled by financial incentives included in both laws.

The Moderate/Moderate scenario group most closely represents the evolution of the power system had IIJA and IRA not been enacted. The Moderate/High group best represents the future power system that will be enabled by current (as of the publication date of this Needs Study) utility, local, state, and federal policies, including the large advances in generation

hydropower, nuclear, hydrogen-based technologies, biomass energy, coal and natural gas plants paired with carbon capture and sequestration, and landfill gas plants. Please refer to source documentation of each study to understand the specific generation mixes considered and modeled in each.

technologies enabled by IRA.[51] The High/High group represents the future power system where new clean energy and electrification of demand-side energy policies are enacted. The first two groups include scenarios from all six studies. The final group includes only scenarios from Brown and Botterud (2020) (single scenario) and Denholm et al. (2022) studies, as these studies considered the largest load growth due to electrification. Additional information about study scenarios and each scenario group is found in the Supplemental Material.

Only a few scenarios that fall outside these general categories—notably those where load growth from high electrification outpaces clean energy technology deployment—were considered by some studies (*see* Figure VI-1). Given the small sample size of scenarios outside the three categories identified here, they are not considered in this analysis. Furthermore, scenarios that disallowed building of interregional transmission were excluded from this analysis. The Supplemental Material provides a description of the excluded scenarios.

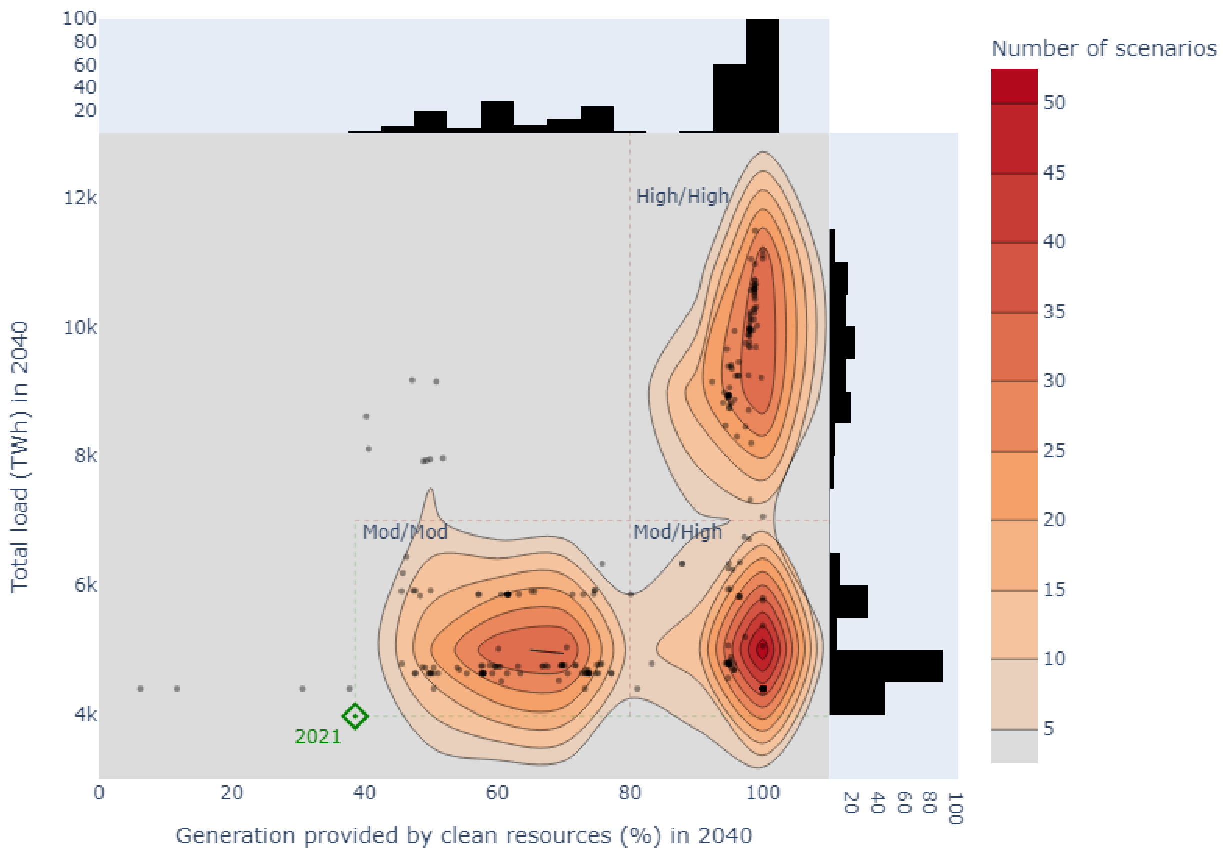
VI.a.2. Treatment of non-wire alternative transmission solutions

Section V.h outlines several alternative transmission solutions to traditional wires. These solutions can include strategically placed generation near load centers, grid-enhancing technologies, energy storage, distributed energy resources. Any of these solutions could help lower, but are unlikely to eliminate, the need for new transmission infrastructure ("poles and wires"). There is some inclusion of these solutions in the capacity expansion modeling results analyzed here. Notably, the grid reliability services provided by NWAs are not captured in capacity expansion modeling, but their value in reducing overall system costs are captured.

There are several different combinations of solutions to meet regional electricity demands, for example, co-locating generation and storage units, siting generation close to load, and siting generation far from load with long transmission lines connecting the two. Capacity expansion models will make the least cost choice among these combinations.

Grid-enhancing technologies are not explicitly modeled in the studies considered here. The transmission results presented do not preclude the use of GETs, however. For example, dynamic line ratings enable operators to make better use of the fully carrying capacity of existing transmission lines. When capacity expansion models find that new GW or GW-miles of transmission capacity is needed in a particular region, this could be met, at least in part, by increasing the carrying capacity of existing grid infrastructure already within the region. Additional engineering analysis performed by planners is needed to determine the best technologies and locations of the available transmission solutions to meet the needs identified here.

[51] Several studies anticipate that IRA will enable power sector carbon dioxide emissions to reduce by 70%-86% in 2030 compared to 2005 emissions (DOE 2022c) (Jenkins et al. 2022) (Larsen et al. 2022) (Mahajan et al. 2022) (Roy et al. 2022). This most closely aligns with the power sector carbon dioxide emissions enabled by scenarios in the Moderate/High scenario group. The spread of 2003 carbon emissions reductions (compared to 2005 levels) for scenarios are used in this analysis are 30%-72% for the Moderate/Moderate group, 70%-80% (with two scenarios around 50%) for the Moderate/High group, and 80% for the High/High group. More details about the carbon emission reductions reached by all scenarios are found in the Supplemental Material.



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 2022a). Thresholds separating the three scenario groups are shown as dashed lines, and each scenario group is labeled.

Figure VI-1. Counts of study scenarios describing the amount of clean energy generation (as percentage of total annual generation) and the total annual load in 2040.

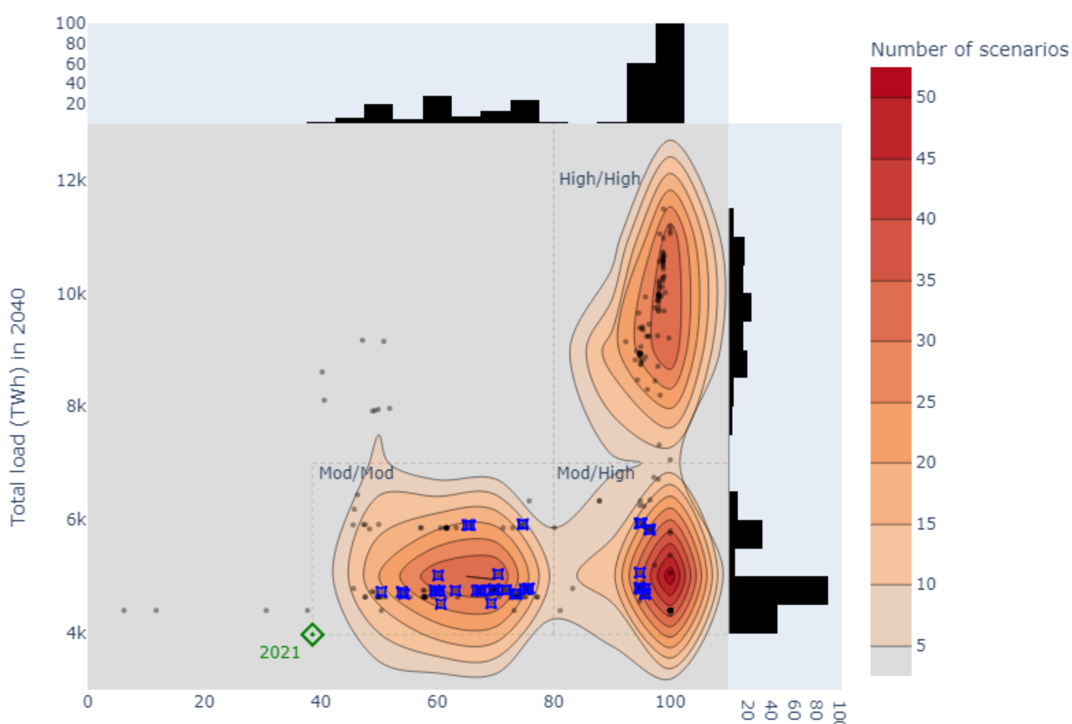
Energy storage resources enable a more efficient use of the grid. All studies except Larson, et al. (2021) co-optimized future capacity expansion of diurnal, stand-alone storage[52] among their respective suites of generation resources. The location of any new storage facilities chosen by the models could be near generation or at key locations in the transmission network where their energy arbitrage and reserve services are most beneficial. All studies found large growth in energy capacity of storage technologies, notably batteries, under numerous scenarios to meet future power system changes. Storage capacity is found to increase from 1GW of installed capacity in 2020 (EIA 2022) to between 25GW and 325GW in 2040 across all scenarios considered by Cole et al. (2021). Brown and Botterud (2020) find increased deployment of 3.5TWh to 11.5TWh of storage energy by 2040, with more storage necessary to balance a less coordinated grid. Storage is found to be increasingly important for grid reliability with increased demand from electrification (Ardani, et al. 2021).

[52] Storage technologies considered include pumped hydro and between 2- and 12-hour durations of battery storage. *Standard Scenarios* also considered hybrid photovoltaic solar + battery storage systems, which are included as the contribute to solar generation and not storage generation here.

As described in Section V, Vibrant Clean Energy's 2020 report "*Why Local Solar for All Costs Less*" study (C. Clack, 2020) considers the economic and social impacts of increased adoption of distributed energy resources (DER), namely distribute solar photovoltaic systems. Vibrant Clean Energy compares the results of two high DER scenarios to business-as-usual scenarios to measure those impacts. These scenarios consider approximately 200 and 300 TWh of annual distributed solar production, respectively, in 2040.

There are 47 scenarios in this analysis which exceed 200 TWh of distributed solar generation in 2040; nine are from the *Solar Futures Study* and 38 are from the *Standard Scenarios s*tudy. Fourteen of these scenarios are in Moderate/High scenario group, and the remaining are in the Moderate/Moderate scenario group. The 47 scenarios are shown as blue boxes in Figure VI-2. All high DER contribute to the overall statistical results of their respective groups, provided in the Supplemental Material.

High DER scenarios do not necessarily result in lower transmission or transfer capacity builds than other scenarios. Nearly half of the high DER scenarios in the Moderate/Moderate group result in higher-than-average 2040 transmission deployment compared to all scenarios in that group. The high DER scenarios in the Moderate/High group have lower-than-average 2040 transmission deployment compared to all scenarios in that group but are not the minimum builds of the group. As found in (C. Clack, 2020), new transmission needed to accommodate high distributed energy resources will be regionally dependent.



Note: (See Figure V-1) Blue boxes indicate scenarios with at least 200 TWh of annual energy production from DERs.

Figure VI-2. 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 with high DER scenarios indicated.

VI.b. Within Region Transmission Deployment

All studies calculated the amount of new transmission deployment within a region modeled to meet different future scenarios.[53] Given the diversity of future scenarios considered, a range of results is presented in Figure VI-3 through Figure VI-6.

Transmission deployment is presented here as the increase in carrying capacity (GW or TW) of a modeled power line multiplied by the length (miles) of the line. Quantifying power lines as GW-mi or TW-mi is a convenient unit for capacity expansion models but is not a common practice in industry. Transmission planners and developers quantify power lines by their nominal voltage rating (kilovolts, kV) multiplied by the length (miles) of the line. In general, the higher the voltage rating and the shorter the power line, the more carrying capacity it has. Table VI-2 from NRRI (1987) provides approximate conversions between nominal voltage ratings and distances to carrying capacity for AC transmission lines. By these conversions, a 100-mile, 345kV rated line is equivalent to 86 GW-mi.

Table VI-2. Approximate power carrying capabilities (MW) of uncompensated AC transmission lines at different voltage ratings and lengths from NRRI (1987).

Nominal Voltage (kV) → Line Length (miles) ↓	138	161	230	345	500	765
50	145	195	390	1260	3040	6820
100	100	130	265	860	2080	4660
200	60	85	170	545	1320	2950
300	50	65	130	420	1010	2270
400	NA	NA	105	335	810	1820
500	NA	NA	NA	280	680	1520
600	NA	NA	NA	250	600	1340

A summary of median new transmission deployment (in TW-mi) is presented in Table VI-3 for 2030, 2035, and 2040. The values represent the cumulative new transmission—calculated as nominal carrying capacity—deployed by the stated year, less the modeled 2020 system. The approximate amount of transmission that currently exists in each region from Denholm et al. (2022) is provided in Table VI-3 for reference.

Table VI-3, Figure VI-4, and Figure VI-5 show the model results of new transmission deployment within each region for each scenario group in 2030, 2035, and 2040. The range of results is skewed right for almost all regions, indicating that a minority of scenarios show very high transmission builds. For this reason, the interquartile range (IQR) (middle 50 percent of result distribution) and the median are shown in these figures for each region separately.

[53] Because the estimation of transmission miles used in the NREL *North American Renewable Integration Study* is from a vintage version of the ReEDS model, which underestimated mileage, those results are not used here. NREL is constantly updating their ReEDS model. Information the model can be found in the Supplemental Information.

Table VI-3. Median new transmission deployment in all study scenarios in 2030, 2035, and 2040 for all regions.

Region	2020 TW-mi	Scenario Group	New in 2030		New in 2035		New in 2040	
			TW-mi	% Growth	TW-mi	% Growth	TW-mi	% Growth
California	4.29	Mod/Mod	0.06	1.5%	0.07	1.6%	0.08	1.8%
		Mod/High	0.09	2.1%	0.12	2.8%	0.12	2.9%
		High/High	0.05	1.1%	0.16	3.7%	0.23	5.4%
Mountain	3.48	Mod/Mod	1.46	42.1%	1.66	47.9%	1.86	53.5%
		Mod/High	2.28	65.5%	3.14	90.4%	2.88	82.9%
		High/High	3.12	89.7%	6.00	173%	7.69	221%
Northwest	15.24	Mod/Mod	0.03	0.2%	0.04	0.3%	0.08	0.5%
		Mod/High	0.07	0.4%	0.54	3.5%	0.00	0.0%
		High/High	0.62	4.1%	4.71	30.9%	8.54	56.1%
Southwest	5.66	Mod/Mod	0.41	7.3%	0.63	11.2%	0.78	13.7%
		Mod/High	0.93	16.5%	1.87	33.0%	0.81	14.3%
		High/High	2.75	48.7%	6.69	118%	7.64	135%
Texas	6.43	Mod/Mod	2.78	43.2%	4.35	67.7%	5.68	88.3%
		Mod/High	6.04	93.9%	9.00	140%	9.60	149%
		High/High	3.33	51.8%	7.27	113%	8.72	136%
Delta	3.36	Mod/Mod	0.01	0.2%	0.15	4.6%	0.40	12.0%
		Mod/High	0.39	11.5%	1.65	49.2%	1.37	40.8%
		High/High	2.98	88.7%	7.76	231%	8.79	262%
Florida	2.97	Mod/Mod	0.00	0.0%	0.08	2.7%	0.15	5.0%
		Mod/High	0.06	2.1%	0.81	27.3%	1.04	35.1%
		High/High	0.01	0.3%	0.73	24.4%	1.04	34.9%
Mid-Atlantic	14.60	Mod/Mod	0.56	3.9%	0.96	6.5%	1.11	7.6%
		Mod/High	1.09	7.5%	3.28	22.5%	3.61	24.7%
		High/High	2.49	17.1%	8.84	60.5%	11.69	80.1%
Midwest	11.92	Mod/Mod	1.13	9.5%	2.26	19.0%	3.40	28.5%
		Mod/High	3.71	31.2%	13.34	112%	16.22	136%
		High/High	7.73	64.8%	20.70	174%	23.40	196%
New England	1.94	Mod/Mod	0.02	0.9%	0.03	1.6%	0.05	2.4%
		Mod/High	0.05	2.5%	0.10	5.2%	2.72	140%
		High/High	0.37	18.9%	2.44	126%	2.98	154%

Region	2020 TW-mi	Scenario Group	New in 2030		New in 2035		New in 2040	
			TW-mi	% Growth	TW-mi	% Growth	TW-mi	% Growth
New York	0.82	Mod/Mod	0.00	0.0%	0.00	0.0%	0.00	0.0%
		Mod/High	0.00	0.0%	0.00	0.0%	0.06	7.6%
		High/High	0.10	12.5%	0.38	46.1%	0.41	50.4%
Plains	6.97	Mod/Mod	1.56	22.4%	2.93	42.1%	3.93	56.3%
		Mod/High	3.52	50.5%	8.32	119%	6.31	90.5%
		High/High	6.88	98.7%	28.47	408%	31.26	449%
Southeast	8.90	Mod/Mod	0.55	6.2%	1.09	12.2%	1.58	17.7%
		Mod/High	2.83	31.8%	6.82	76.6%	6.04	67.9%
		High/High	2.68	30.1%	9.11	102%	11.46	129%

Note: Scenarios are split into three scenario groups defined by underlying characteristics of the modeled power sector. Both new transmission in TW-mi and percent growth from the estimated 2020 system are shown. The 2020 existing system for each region is taken from (Denholm et al. 2022).

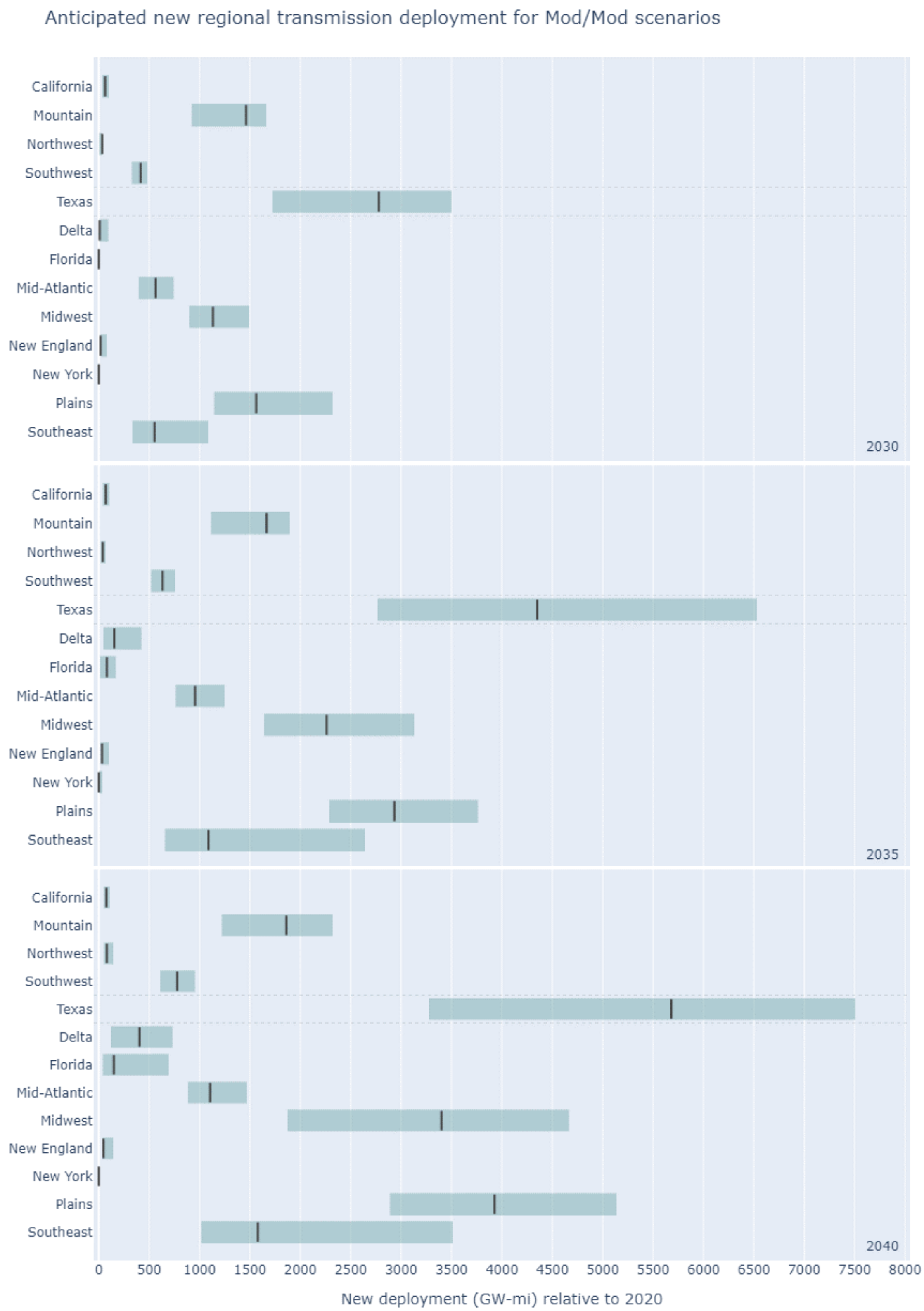
Figure VI-3 shows the transmission results for the Moderate/Moderate scenario group, which defines a power system without the IIJA and IRA enacted. Studies consistently find that the largest transmission expansion will take place in Texas to meet future power sector changes across all years. In 2035, the median transmission expansion in Texas is 4,350 GW-mi, nearly 70 percent of its 2020 size. Transmission is expanded more in the Mountain region (2035 median of 1,660 GW-mi, nearly 50 percent current size) than other regions in the Western Interconnection. In the Eastern Interconnection, modeling results show the most transmission expansion in the Southeast (1,090 GW-mi, 12 percent growth by 2035), Midwest (2,260 GW-mi, 19 percent growth), and Plains (2,930 GW-mi, 42 percent growth).

Figure VI-4 shows the results for the Moderate/High scenario group, which, at the time of publication, is the most likely power sector future given recently enacted laws. The regional trends are similar in this scenario group as the previous, with the largest transmission expansion again occurring in the Texas, Mountain, Southeast, Midwest, and Plains regions. These regions also have large IQRs of expansion results compared to other regions. The median transmission expansion in 2035 in Texas is 9,000 GW-mi, a 140 percent growth compared to the 2020 system. Scenario results suggest that the transmission system in the Mountain, Plains, and Midwest regions will double in size by 2035 to meet the power sector needs modeled in this scenario group (2035 median expansion values of 3,140 GW-mi, 8,320 GW-mi, and 13,340 GW-mi, respectively). These results demonstrate the heavy reliance on clean energy in the middle of the contiguous United States that must be connected to a reinforced power grid to serve load centers.

Figure VI-5 shows the results for the High/High scenario group, which will not be realized without additional state and federal policies. This group results in the most transmission expansion, necessary to meet the high electrification scenarios in this group. Additional transmission in the Midwest and Plains greatly exceeds that of all other regions under the high load growth scenarios, again pointing to the large reliance on transmission to access low-cost generation in the middle of the United States. The Southeast and Delta regions also experience large transmission builds—a doubling and tripling of the 2020 system, respectively—in this scenario group compared to the lower load growth scenarios.

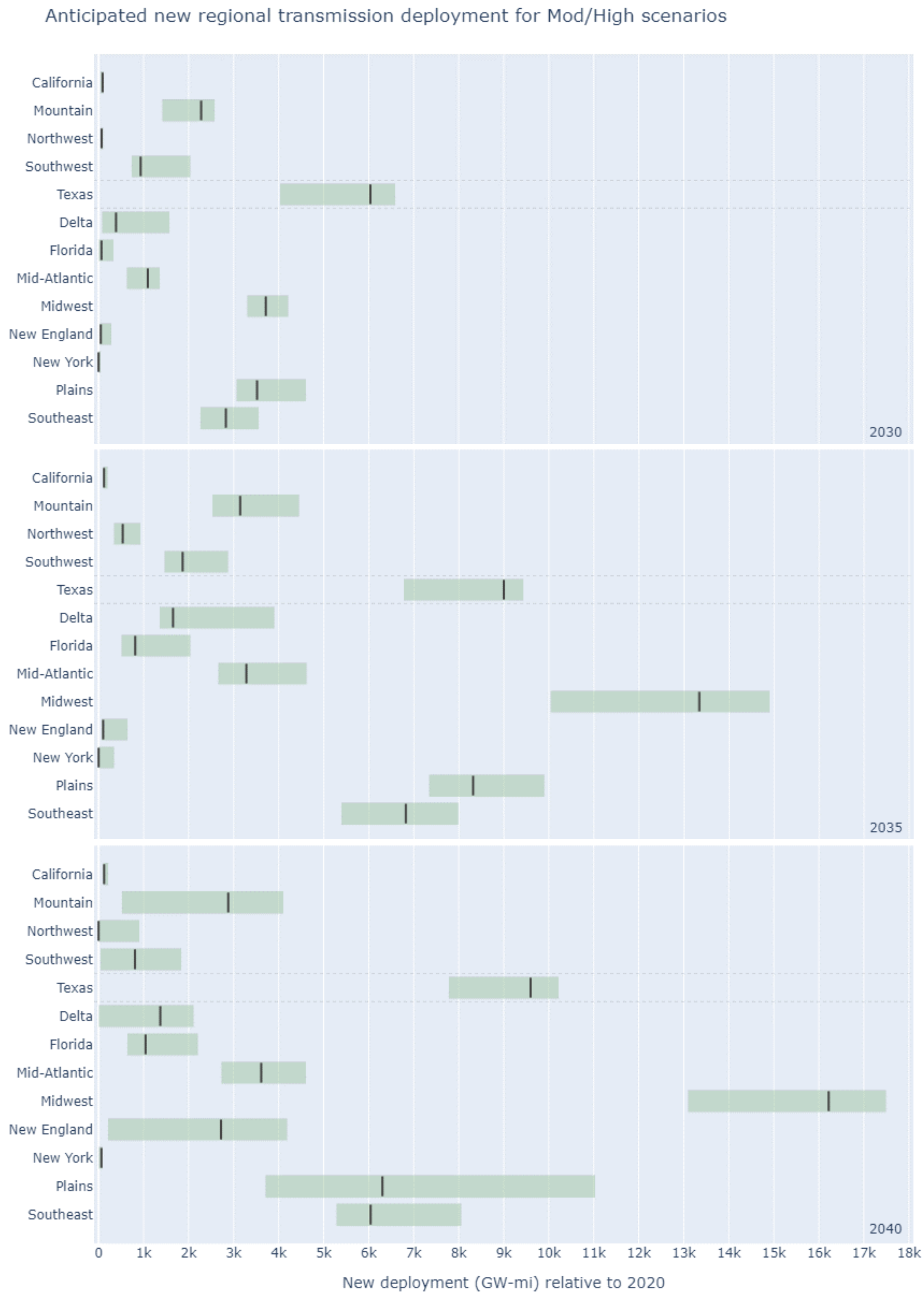
NERC collects data on 10-year projections of bulk power system as part of its annual Long-Term Reliability Assessment process (NERC 2021). These data include the near-term transmission development plans in each NERC assessment area. An initial comparison.[54] of these plans through 2030 against the Moderate/Moderate and Moderate/High scenario group modeling results is shown in Figure VI-6. The planned transmission development of many regions—including New England, New York, Florida, and California—exceed the range of anticipated transmission need in both scenario groups in 2030. All other regions fall hundreds of GW-mi of new transmission short of capacity expansion model results.

[54] Utility transmission plans for transmission lines rated equal to or above 100kV with a status of "under construction" or "planned" in the NERC data are considered. The Midwest and Delta regions have been combined, as NERC data are provided for MISO. Similarly, the Northwest and Mountain regions have been combined, as NERC data are provided for NWPP/RMRG (now WPP).



Note: New transmission relative to the 2020 system (from Denholm et al. 2022) of each study is shown for 2030 (top), 2035 (middle), and 2040 (bottom). Median and IQR for all scenarios in each region shown.

Figure VI-3. Regional transmission deployment for all Moderate/Moderate scenarios.

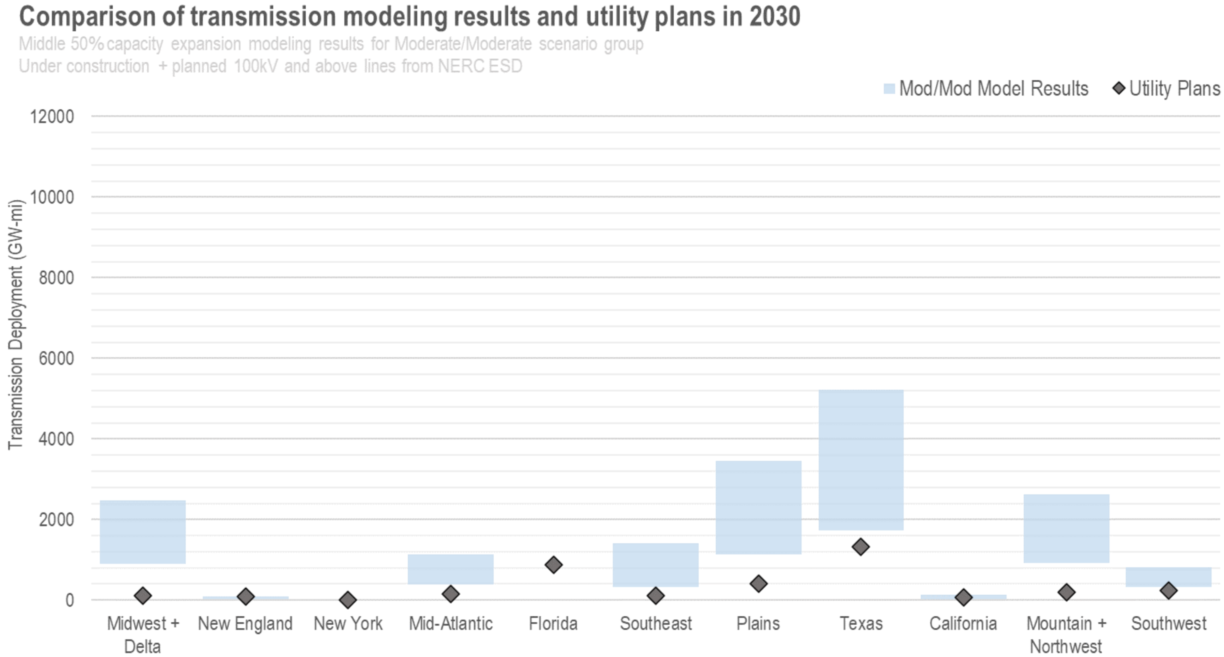


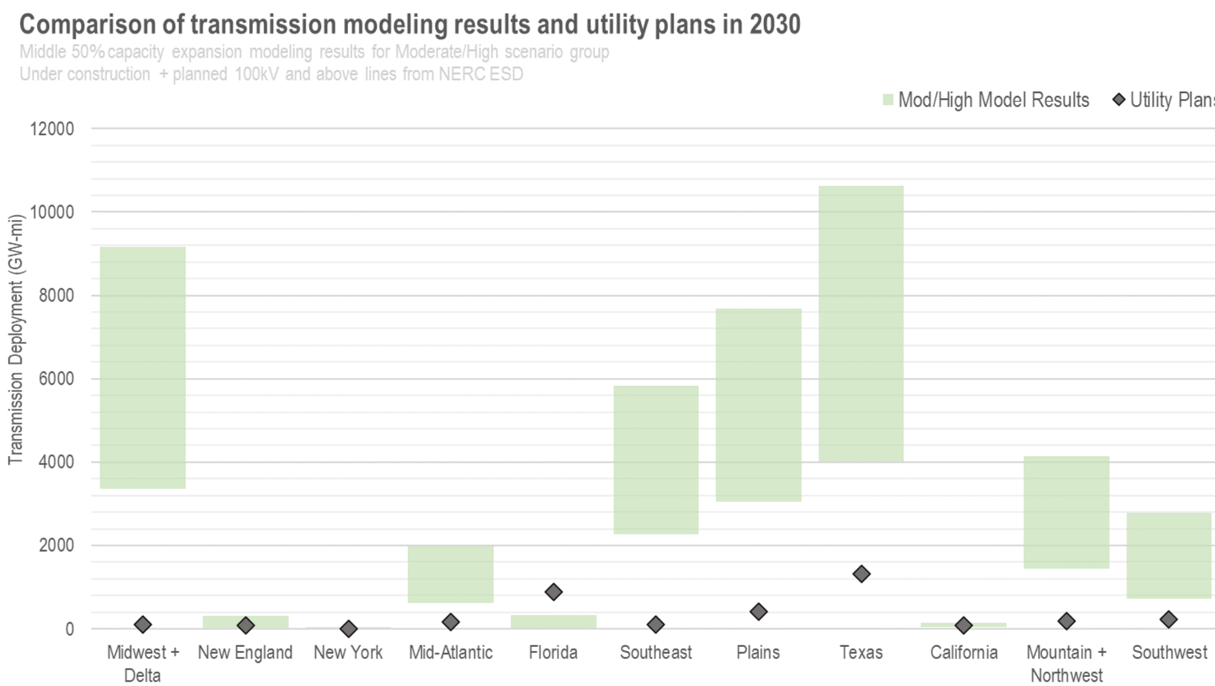
Note: New transmission relative to the 2020 system (from Denholm et al. 2022) of each study is shown for 2030 (top), 2035 (middle), and 2040 (bottom). Median and IQR for all scenarios in each region shown.

Figure VI-4. Regional transmission deployment for all scenarios in the Moderate/High scenario group.

Note: New transmission relative to the 2020 system (from Denholm et al. 2022) of each study is shown for 2030 (top), 2035 (middle), and 2040 (bottom). Median and IQR for all scenarios in each region shown.

Figure VI-5. Regional transmission deployment for all scenarios in the High/High scenario group.





Source: Utility plan data includes all planned projects and projects under construction above 100 kV from NERC (2020). This data does not include transmission approved by the planners since 2021.

Note: New transmission model results relative to the 2020 system (from Denholm et al. 2022).

Figure VI-6. Comparison of utility transmission development plans with IQR of capacity expansion modeling results for the Moderate/Moderate (top) and Moderate/High (bottom) scenario groups.

VI.c. Interregional Transfer Capacity

Whereas the previous set of results focused on new transmission deployment *within* a region to meet growing clean energy and load, this section focuses on new transfer capacity needed *between* regions. Increased transfer capacity (the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines or paths between those areas under specified system conditions) and, relatedly, capacity (the ability to transfer power without causing facility overloads under contingency, generally referred to in the sum of the thermal ratings of the transmission tie lines between two entities) has many benefits: regional grid reliability is strengthened by the diversity of generation provided by interregional transfers, regions need to import electricity when they cannot meet growing demand with local generation or when the combination of remote generation and interregional transmission has lower overall system costs than local generation, or a combination of these.

Transfer capacity differs from transmission deployment results in the previous section by focusing on the amount of power that new or upgraded lines can move between neighboring regions, regardless of the length of the lines that make that connection across boundaries. For that reason, transfer capacity results are shown as GW of power between regions, instead of as GW-mi of new transmission lines. The amount of transfer capacity needed between regions to support different futures was calculated by all studies except Larson et al. (2021), which reported deployment only in capacity-miles and not capacity alone.

A summary of the median new transfer capacity results modeled for all scenario groups in 2030, 2035, and 2040 is presented in Table VI-4. The approximate amount of transfer capacity that currently exists among all regions is provided for reference. We use data from Denholm et al. (2022) to approximate the existing transfer capacities between regions, as it is the most up to date of all studies. There may be some links between regions absent from this table if they were not considered by the modelers. For example, transfers between the Texas and Delta regions were only considered by Brown and Botterud (2020) and therefore do not show up for all years. In addition, the potential creation of an offshore transmission system to support Atlantic offshore wind generation may allow the New England and Mid-Atlantic regions to share direct transfers without needing to transfer through the terrestrial New York system.

Table VI-4. Median new transfer capacity estimated by all study scenarios in 2030, 2035 and 2040 for all regions.

Region	2020 GW	Scenario Group	New in 2030		New in 2035		New in 2040	
			GW	% Growth	GW	% Growth	GW	% Growth
California – Mountain	2.12	Mod/Mod	0.31	14.7%	0.96	45.4%	1.80	84.8%
		Mod/High	0.58	27.3%	1.87	88.1%	4.97	235%
		High/High	1.21	57.0%	2.75	130%	4.31	204%
California – Northwest	5.15	Mod/Mod	0.00	0.0%	0.00	0.0%	0.00	0.0%
		Mod/High	0.00	0.0%	0.13	2.5%	0.00	0.1%
		High/High	0.25	4.8%	1.28	24.9%	1.94	37.7%

Region	2020 GW	Scenario Group	New in 2030		New in 2035		New in 2040	
			GW	% Growth	GW	% Growth	GW	% Growth
California – Southwest	5.23	Mod/Mod	0.00	0.0%	0.14	2.7%	0.22	4.3%
		Mod/High	0.05	0.9%	0.31	5.9%	5.09	97.3%
		High/High	1.90	36.4%	5.31	102%	6.89	132%
Mountain – Northwest	12.7	Mod/Mod	0.00	0.0%	0.09	0.7%	0.51	4.0%
		Mod/High	1.08	8.5%	3.30	26.0%	0.00	0.0%
		High/High	6.25	49.2%	25.7	202%	39.2	308%
Mountain – Southwest	4.06	Mod/Mod	0.04	0.9%	0.09	2.2%	0.38	9.5%
		Mod/High	0.37	9.1%	1.65	40.6%	1.70	41.7%
		High/High	2.08	51.2%	5.24	129%	6.06	149%
Delta – Texas	0.00	Mod/Mod					22.2	
		Mod/High					48.3	
		High/High					106.7	
Mountain – Plains	0.92	Mod/Mod	0.36	39.1%	0.94	102%	1.40	152%
		Mod/High	0.79	85.4%	2.64	287%	11.9	1290%
		High/High	6.10	663%	19.3	2100%	29.2	3170%
Plains – Southwest	0.40	Mod/Mod	0.69	172%	1.16	290%	1.48	370%
		Mod/High	2.53	631%	3.66	914%	13.1	3280%
		High/High	5.54	1380%	13.0	3240%	14.4	3600%
Plains – Texas	0.82	Mod/Mod	0.02	3.0%	0.49	60.0%	0.91	111%
		Mod/High	1.15	140%	9.84	1200%	14.6	1780%
		High/High	14.3	1750%	28.9	3520%	34.9	4260%
Delta – Midwest	3.00	Mod/Mod	0.00	0.0%	0.00	0.0%	0.00	0.0%
		Mod/High	0.00	0.0%	0.00	0.0%	0.00	0.0%
		High/High	0.10	3.2%	0.91	30.4%	1.32	44.2%
Delta – Plains	4.76	Mod/Mod	0.00	0.0%	0.35	7.4%	0.73	15.3%
		Mod/High	4.89	103%	19.7	414%	0.00	0.0%
		High/High	20.7	434%	48.5	1020%	55.3	1160%
Delta – Southeast	5.92	Mod/Mod	0.00	0.0%	0.00	0.0%	0.00	0.0%
		Mod/High	0.92	15.6%	5.10	86.2%	10.7	181%
		High/High	10.1	171%	33.9	572%	37.7	637%
Florida – Southeast	3.60	Mod/Mod	0.00	0.0%	0.00	0.0%	0.00	0.0%
		Mod/High	0.00	0.0%	1.14	31.6%	7.20	200%
		High/High	0.87	24.2%	10.6	295%	12.9	360%

Region	2020 GW	Scenario Group	New in 2030		New in 2035		New in 2040	
			GW	% Growth	GW	% Growth	GW	% Growth
Mid-Atlantic – Midwest	21.7	Mod/Mod	1.10	5.1%	2.39	11.0%	2.65	12.2%
		Mod/High	9.87	45.5%	33.8	156%	21.9	101%
		High/High	42.4	196%	103	475%	119	550%
Mid-Atlantic – New York	2.00	Mod/Mod	0.00	0.0%	0.29	14.7%	0.81	40.6%
		Mod/High	0.00	0.0%	2.43	122%	14.8	742%
		High/High	2.03	102%	8.24	412%	12.7	634%
Mid-Atlantic – Southeast	7.07	Mod/Mod	0.19	2.6%	0.51	7.3%	1.50	21.3%
		Mod/High	2.78	39.3%	6.86	97.1%	12.5	177%
		High/High	4.36	61.7%	9.88	140%	12.2	173%
Midwest – Plains	12.1	Mod/Mod	1.35	11.2%	3.14	26.0%	3.62	30.1%
		Mod/High	7.99	66.3%	21.1	175%	23.0	191%
		High/High	24.6	204%	88.0	731%	98.7	819%
Midwest – Southeast	8.27	Mod/Mod	0.00	0.0%	0.00	0.0%	0.00	0.0%
		Mod/High	1.28	15.4%	4.46	53.9%	6.23	75.3%
		High/High	10.3	125%	34.4	416%	39.9	483%
New England – New York	2.03	Mod/Mod	1.46	71.7%	2.84	140%	2.90	142%
		Mod/High	1.53	75.1%	5.19	255%	11.4	559%
		High/High	3.96	195%	17.0	835%	21.4	1050%

Note: Scenarios are split into three scenario groups defined by underlying characteristics of the modeled power sector. Both new capacity need in GW and percent growth from the estimated 2020 system are shown. The 2020 existing national system for each region is taken from Denholm et al. (2022). Transfers between Delta and Texas appear only in 2040 because transfers between these two regions were modeled only by Brown and Botterud (2020), which considered transmission results in 2040.

Figure VI-7 through Figure VI-9 show the amount of transfer capacity (in GW) needed between all regions for each of the three scenario groups in 2030, 2035, and 2040. Like the previous set of results, the IQR (middle 50 percent of distribution) and the median of all results are shown in these figures for each regional transfer separately. Common statistical values can be found in the Supplemental Material for each scenario group.

Four transfers in the figures below—Delta to Texas, Mountain to Plains, Plains to Texas, and Plains to Southwest—represent increased transfer across the three interconnections. Importantly, these transfer capacities are modeled as increased DC-AC-DC intertie connections, like those connections that already exist between the interconnections.

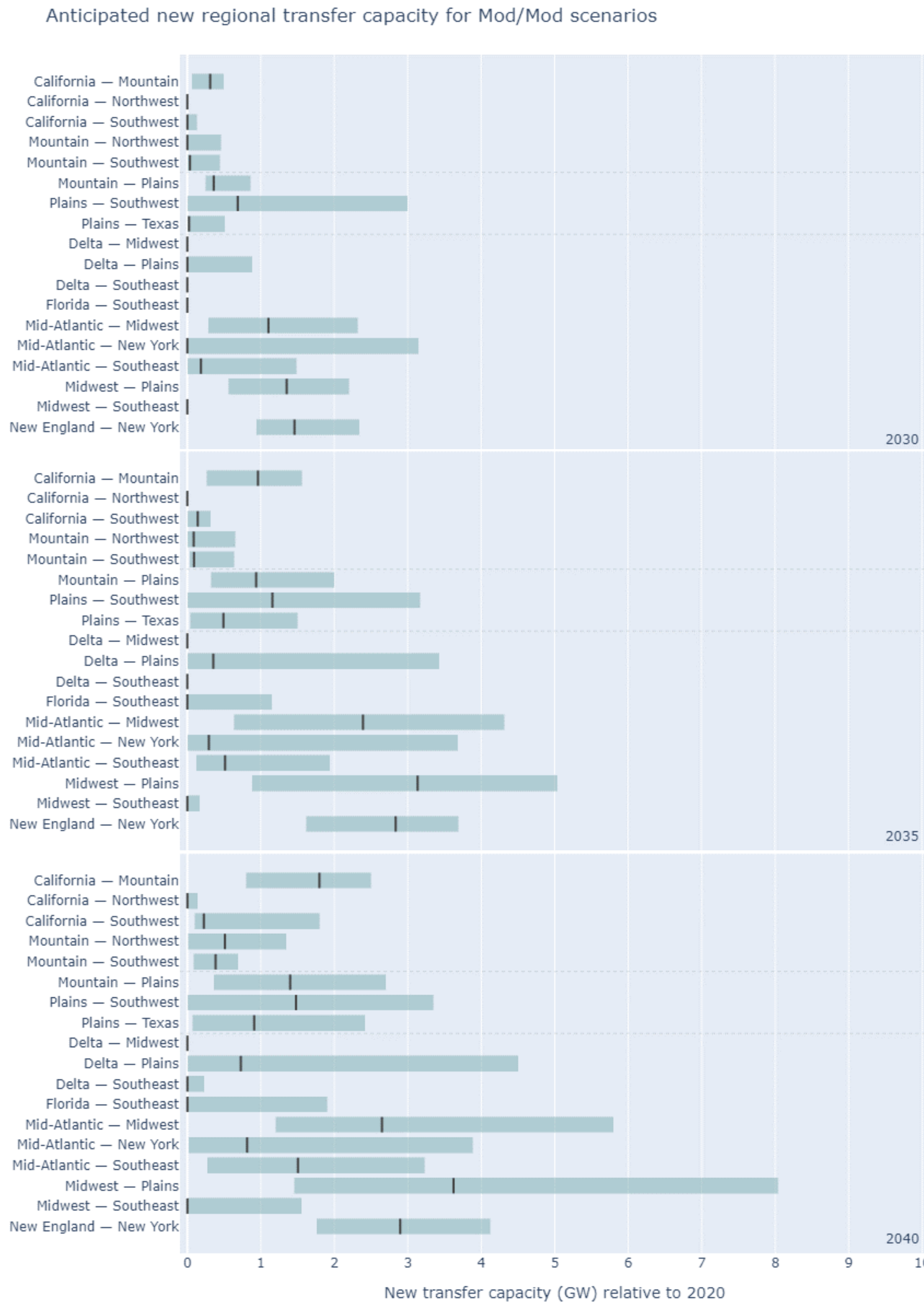
Figure VI-7 shows the regional transfers for the Moderate/Moderate scenarios in 2030, 2035, and 2040, which defines a power system without the IIJA and IRA enacted. These results are relatively low, indicating that local generation within a region can meet regional demand needs for modeled scenarios in this group. There is moderate transfer capacity expansion in the northern half of the Eastern Interconnection. Highest transfers are found between New

England and New York (2035 median of 2.8 GW, 140 percent growth) and between the Midwest and Plains (2035 median of 3.1 GW, 26 percent growth). Models show a range of increased transfer between the Eastern and Western Interconnections through the Plains and Southwest. In 2040, the median new transfer capacity between these two regions is 1.5 GW, a small absolute number but a nearly 370 percent increase from the current transfer capacity.

Figure VI-8 shows the regional transfers for the Moderate/High scenarios in 2030, 2035, and 2040, which, at the time of publication, is the most likely power sector future given recently enacted laws. Capacity transfers in the Eastern Interconnection continue to dominate in this scenario group, but with increased expansion in new regions. Although new transfer capacity continues to grow between New York and New England and between the Plains and Midwest, higher clean energy generation results in cost-effective transfers between other regions compared to the last group. Median transfers between the Delta and the Plains grow five-fold from 2020 and 2035, adding 20 GW of new transfer capacity. The highest median transfer capacity is found between the Mid-Atlantic and the Midwest (34 GW in 2035), likely to move low-cost clean generation in the Plains and Midwest regions onto the Mid-Atlantic. Cross-interconnection transfers between Texas and its eastern neighbors grow dramatically in this scenario group. In 2040, an estimated 15 GW of new transfer capacity could be built cost effectively between Texas and the Plains and an estimated 48 GW between Texas and the Delta region.

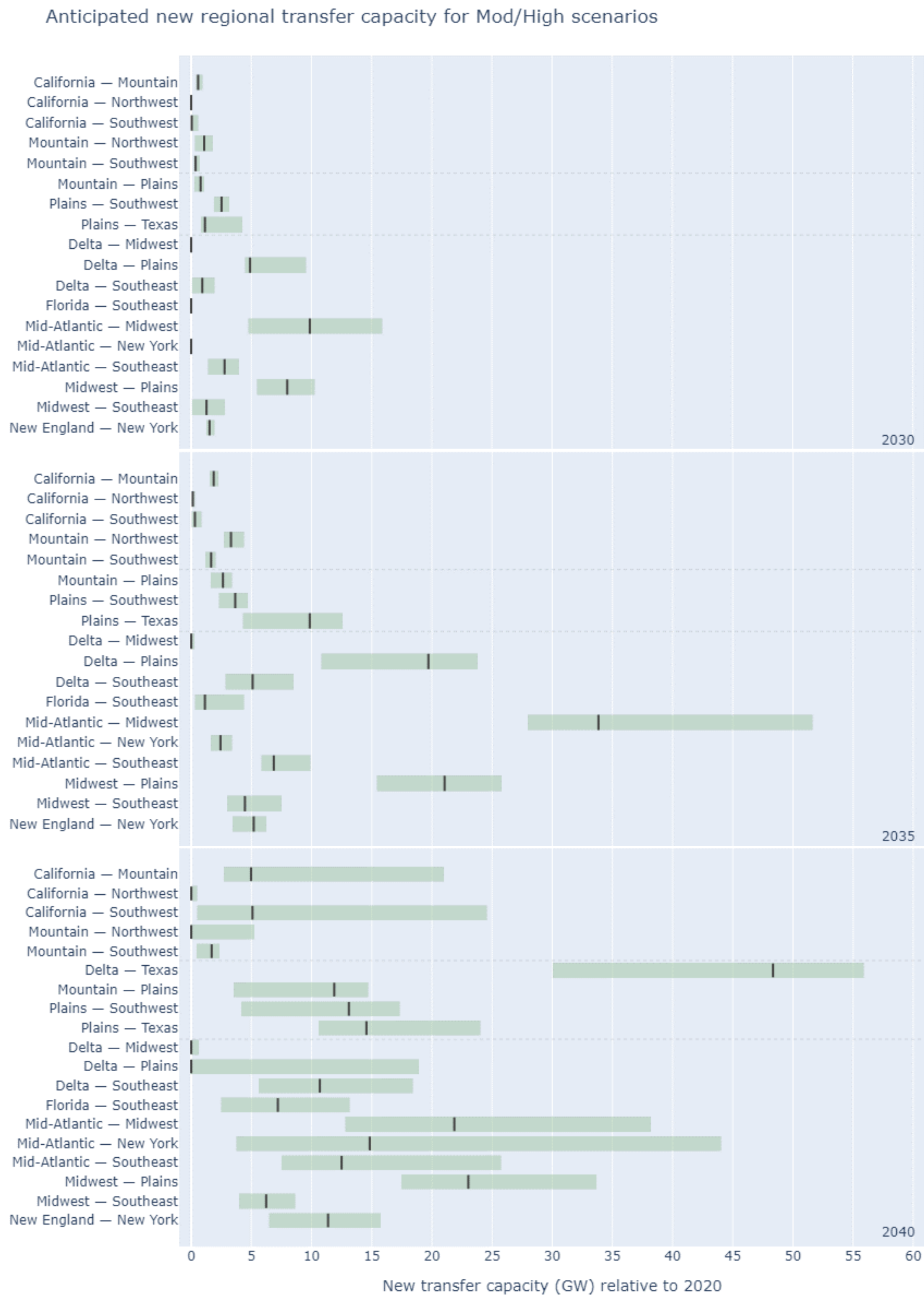
Figure VI-9 shows the regional transfers for the High/High scenarios in 2030, 2035, and 2040, which will not be realized without additional state and federal policies. Estimated transfer capacity between regions quadruples in the high load growth scenarios compared to the Moderate/High scenario group. An increasingly interconnected grid increases reliability, especially in high clean energy and high load futures (Bloom et al. 2020; Brown and Botterud 2020; Denholm et al. 2022), and that is reflected in these results of increased sharing among all regions. Transfer capacities between the Midwest, Plains, and their adjacent neighbors dominate in this scenario group, as increased access to low-cost generation in the middle of the country become more important to meet high demand. Increased transfers between the interconnects also grow dramatically in this scenario group.

Notably, while the above findings indicate a more modest need for increased interregional transmission, other studies demonstrate contrasting findings. For example, in Jones et al. (2020), a regional analysis conducted for a Massachusetts-sponsored study, modeling suggested that an additional 4.1 to 7.1 gigawatts of capacity between Québec and New England would be required to achieve the state’s net-zero emissions target. While the estimates range across different studies using different assumptions and modeling tools, together they indicate some estimates may be low.



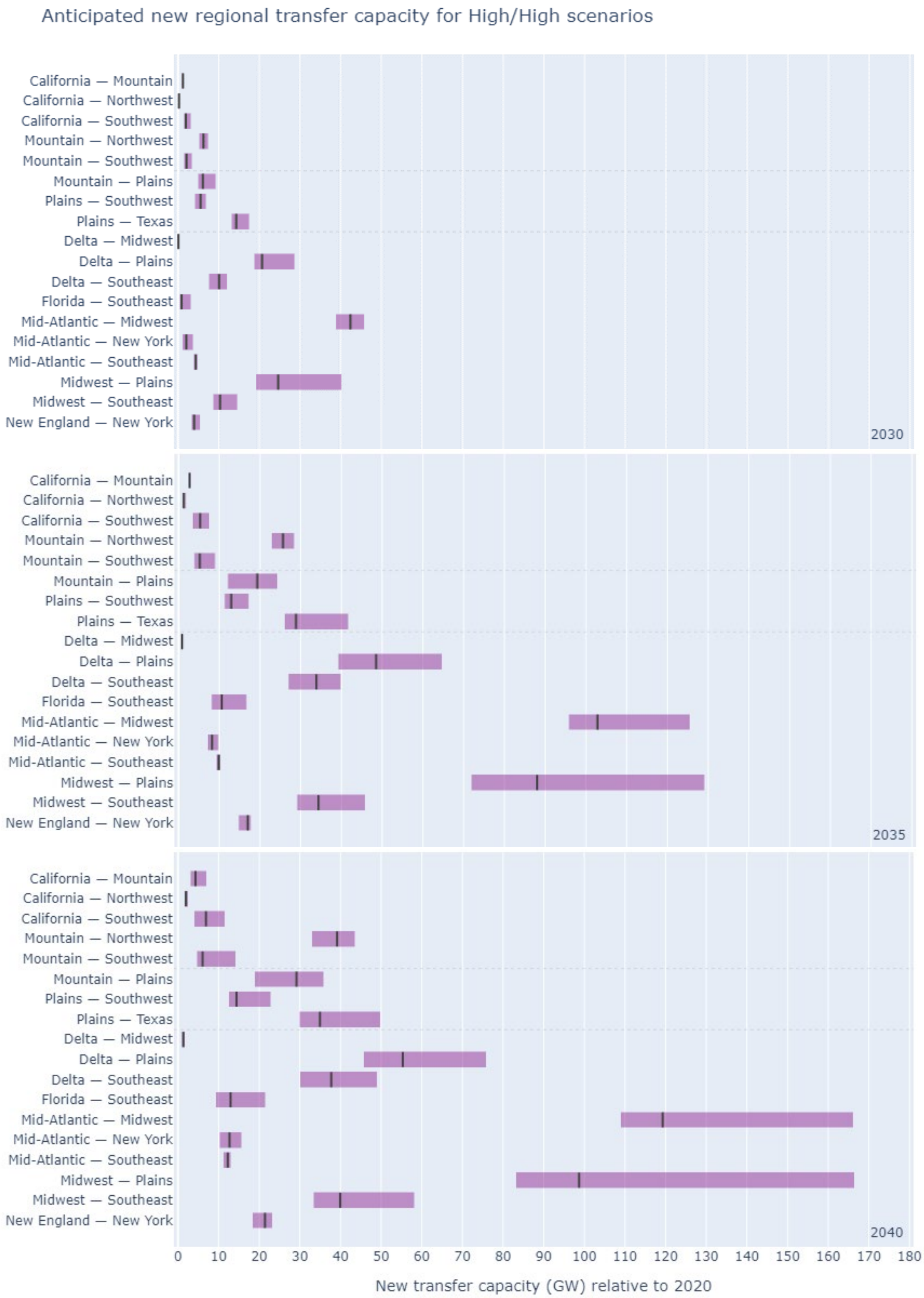
Note: New transmission relative to the 2020 system (from Denholm et al. 2022) of each study is shown for 2030 (top), 2035 (middle), and 2040 (bottom). Median and IQR for all scenarios in each region shown.

Figure VI-7. Interregional transfer capacity for all scenarios in the Moderate/Moderate scenario group.



Note: New transmission relative to the 2020 system (from Denholm et al. 2022) of each study is shown for 2030 (top), 2035 (middle), and 2040 (bottom). Median and IQR for all scenarios in each region shown.

Figure VI-8. Interregional transfer capacity for all scenarios in the Moderate/High scenario group.



Note: New transmission relative to the 2020 system (from Denholm et al. 2022) of each study is shown for 2030 (top), 2035 (middle), and 2040 (bottom). Median and IQR for all scenarios in each region shown.

Figure VI-9. Interregional transfer capacity for all scenarios in the High/High scenario group.

International Transfers

VI.d. International Transfers

The *North American Renewable Integration Study* calculated international transfers between the United States and Canada or Mexico. These transfers are shown separately in Figure VI-10 for 2030, 2035, and 2040. Scenarios with international transfers fell exclusively into the Moderate/Moderate scenario group. For that reason, results shown in this section could be compared with regional transfers of the Moderate/Moderate scenario group in the preceding section. Consistent with results, international transfers are expected to increase above that shown here, given clean energy and load growth enabled by currently enacted policies, including the IIJA and IRA.

A summary of the modeled transfer capacities across international borders in future years is presented in Table VI-5. The approximate amount of transfer capacity that currently exists among all border regions from Brinkman et al. (2021) is provided in Table VI-5 for reference.

In general, the range of international transfer capacities is about half the range of anticipated national transfers resulting from moderate clean energy and moderate load growth (Figure VI-7). The greatest increase in international transfers is between Texas and Tamaulipas, Mexico, reaching 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 around 1 GW (2035 median) with their Canadian provisional neighbors.

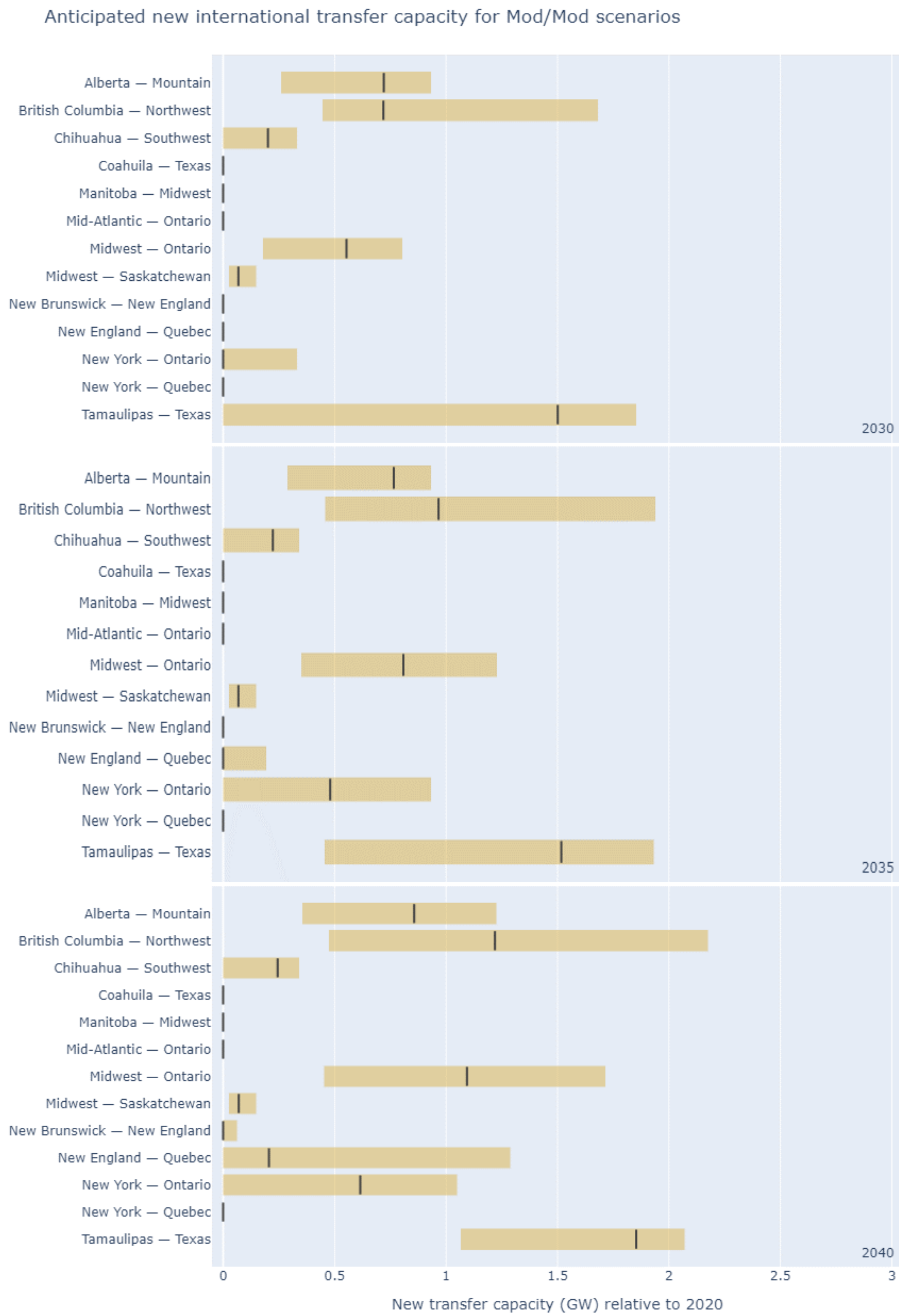
Appreciable international transfer capacities between Canada and New York and New England do not arise until 2040 in Brinkman et al. (2021). For comparison, an anticipated 1.8 to 4.1 GW of new transfer capacity (IQR) is modeled between New England and New York in 2040 in the analogous Moderate/Moderate scenario group (Figure VI-7). The U.S. regional transfer results include scenarios from the studies that did not consider growth in international transfers, putting increased reliance on the national transfers between regions that cannot otherwise share with their international neighbors. That national 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 U.S. 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 gigawatts of capacity between Québec and New England would be required to meet existing state clean energy targets.

Table VI-5. Median international transfer capacities estimated by Brinkman et al. (2021) in 2030, 2035, and 2040.

Region	2020 GW	Scenario Group	New in 2030		New in 2035		New in 2040	
			GW	% Growth	GW	% Growth	GW	% Growth
Alberta – Mountain	0.00	Mod/Mod	0.72		0.77		0.86	
British Columbia – Northwest	3.15	Mod/Mod	0.72	22.8%	0.97	30.7%	1.22	38.7%
Chihuahua – Southwest	0.20	Mod/Mod	0.20	101%	0.22	112%	0.24	122%
Coahuila – Texas	0.04	Mod/Mod	0.00	0.0%	0.00	0.0%	0.00	0.0%
Manitoba – Midwest	3.20	Mod/Mod	0.00	0.0%	0.00	0.0%	0.00	0.0%
Mid-Atlantic – Ontario	0.00	Mod/Mod	0.00		0.00		0.00	
Midwest – Ontario	1.85	Mod/Mod	0.55	29.9%	0.81	43.7%	1.09	59.1%
Midwest – Saskatchewan	0.17	Mod/Mod	0.07	41.5%	0.07	41.5%	0.07	42.5%
New Brunswick – New England	1.00	Mod/Mod	0.00	0.0%	0.00	0.0%	0.00	0.0%
New England – Quebec	4.40	Mod/Mod	0.00	0.0%	0.00	0.0%	0.21	4.7%
New York – Ontario	2.15	Mod/Mod	0.00	0.0%	0.48	22.3%	0.62	28.6%
New York – Quebec	2.00	Mod/Mod	0.00	0.0%	0.00	0.0%	0.00	0.0%
Tamaulipas – Texas	0.55	Mod/Mod	1.50	270%	1.52	273%	1.85	334%

Note: Scenarios fall exclusively into the Moderate/Moderate scenario group. New capacity need in GW and percent growth from the estimated 2020 system is shown. The 2020 existing national system for each region is taken from Brinkman et al. (2021).



Note: New transmission relative to the 2020 system (from Denholm et al. 2022) shown for 2030 (top), 2035 (middle), and 2040 (bottom). Median and IQR for all scenarios in each region shown.

Figure VI-10. International transfer capacity for all Brinkman et al. (2021) scenarios, which fell exclusively into the Moderate/Moderate scenario group.

VI.e. Conclusions

Increased transmission deployment helps regions meet growing demand needs reliably and cost effectively by connecting generation to demand. Increased transfer capacities among regions enables regions to share electricity effectively, improving system reliability and providing access to low-cost clean energy generated far from load centers (Brinkman et al. 2021; Brown and Botterud 2020). Several different generation technologies will contribute to meeting the Nation's growing electricity and clean energy demands. Which generation technologies are built where will be driven by market changes, policy decisions, and social and geopolitical concerns. The analysis of capacity expansion modeling work presented in this Needs Study shows that all combinations of new generation will require increased transmission deployment to remove expected constraints and congestion that would negatively impact consumers and bring new generation to market, but to differing degrees. Capacity expansion modeling studies help quantify the range of new transmission needed to meet future demand.

Capacity expansion modeling shows the national power grid needs to increase 10 percent by 2030 and 23 percent by 2040 (median results) to meet a future with moderate load and clean energy growth. The future power system described by this scenario group has less load and clean energy growth than that projected to be enabled by state and federal laws enacted since 2021. Regions in greatest need of cost-effective transmission growth are those in the middle of the country, including the Texas, Mountain, Plains, and Midwest regions. Transfer capacity needs between regions remain low under these moderate scenario conditions, needing to grow 5 percent in 2030 (median 5.5 GW) and 40 percent in 2040 (median 41 GW). Increased transfer capacity among neighbors in the Eastern Interconnection show that cost savings and reliability benefits can be realized for regions sharing electricity, even in moderate growth futures.

In future scenarios with moderate load but high clean energy assumptions—in line with the future power sector enabled by all currently enacted laws, including the bipartisan Infrastructure Investment and Jobs Act of 2021 and the Inflation Reduction Act of 2022—both transmission deployment and transfer capacities need to increase nationwide. Median model results suggest 47,300 GW-mi of new transmission will be needed nationwide by 2035 to meet the scenario conditions of this group, a 57 percent growth in today's transmission system. Regions in greatest need of transmission growth are the Southeast, Texas, Plains, and Midwest. In comparison with current utility plans for transmission development by 2030, many regions—including New England, New York, Florida, and California—either meet or exceed the range of anticipated transmission need.

Whereas total median interregional transfer capacities across the United States were just over 13 GW in the Moderate/Moderate scenario group in 2035, this number increases to over 120 GW in the Moderate/High scenario group. Several regions would benefit from increased connectivity with their neighbors as clean energy deployment increases to over 80 percent annual generation. Studies show a large growth in transfer capacity between all regions adjacent to the Plains, including across the three interconnections. Large amounts of low-cost generation potential exist in the middle of the country and accessing this generation through increased transmission is cost effective for neighboring regions.

The need for transmission growth is even greater in future scenarios that have high load and high clean energy assumptions. The range of deployment results in this scenario group is also large, highlighting that the mix of generation and power sector technologies that enable both high load and clean energy growth vary significantly in their needs for additional transmission support. In 2030, median results suggest 30,000 GW-mi of new transmission is needed to meet the demands of these scenarios. By 2040, new transmission deployment is projected between 100,000 and 185,000 GW-mi (115,000 GW-mi median), a doubling in size of today's transmission system. The value in sharing electricity interregionally continues to increase in futures with high demand and clean energy growth. Median study results anticipate new transfer capacities of 157 GW in 2030 (154 percent growth compared to today's system) and 655 GW in 2040 (644 percent growth) nationwide.

VII. Process for Preparing the Draft 2023 National Transmission Needs Study

This section reviews the process the Department followed to prepare this draft study. It describes the Department's consultation with states, Tribes, and regional entities pursuant to Section 216(a) of the Federal Power Act (FPA), as amended (16 U.S.C. §824p(a)(1)).

As directed by the FPA, as amended, the Department consulted with states, Tribes, and regional entities in preparing this study from July through November 2022. Consultation took the form of circulating a "notification letter" to give entities at least 30 days' notice that the "consultation draft" would be sent to them for review and feedback, then subsequently distributing the "consultation draft" of the National Transmission Needs Study to each state (including points of contact from state energy offices, Governors offices, utility commissions chairs, and state public utility commission groups for multi-state ISOs), Tribes, and regional entities (including transmission reliability and planning entities) in the continental US, along with an invitation to provide written comment on the draft or to meet with DOE staff, in person or by phone, to convey comments. In addition, DOE briefed the states, Tribes, and regional entities via a series of six webinars on the consultation draft, with one webinar open to all consultation draft recipients and the other five targeted at each entity type in partnership with a convening group to help with amplification of the webinar (e.g., DOE partnered with the National Association of State Energy Offices for the webinar targeted at state energy offices). Appendix A-1 contains a list of entities that submitted written or verbal comments on the consultation draft of the study, and an overview summary of the comments received. Appendix A-2 contains a detailed "comment matrix" that documents each individual comment received and the manner in which the Department resolved each comment.

APPENDIX A-1: List of Entities that Provided Comments on the Consultation Draft of the Study and Comment Overview

The Department received 23 comment submissions from 20 entities over the course of the consultation period. Fifteen parties submitted written comments while eight parties either requested general information or provided verbal comments by phone or during webinars held to discuss the consultation draft. Three entities submitted both written comments and provided verbal comments. Table A-1.1 below contains the list of 20 entities that submitted comments.[55]

Table A-1.1: List of commenting entities

Commenter Name	Commenter Type
ReliabilityFirst	Regional Reliability Entity
Western Electricity Coordinating Council (WECC)*	Regional Reliability Entity
Connecticut Department of Energy and Environmental Protection*	State Energy Office
Illinois Commerce Commission (ICC)	State Regulatory Commission
Minnesota Public Utilities & Minnesota Department of Commerce	State Regulatory Commission
ISO New England (ISO-NE)	ISO/RTO
PJM Interconnection, L.L.C (PJM)	ISO/RTO
Iowa Utilities Board (IUB)	State Regulatory Commission
Electric Reliability Council of Texas, Inc. (ERCOT)	ISO/RTO
New England States Committee on Electricity (NESCOE)	Regional State Committee
Southeastern Regional Transmission Planning (SERTP)	Regional Transmission Planning Entity
Virginia Department of Energy	State Energy Office
Oregon Department of Energy*	State Energy Office
Midwest Reliability Organization (MRO)	Regional Reliability Entity
Delaware Public Service Commission	State Regulatory Commission
South Carolina Office of Regulatory Staff*	State Regulatory Commission
Pilar Thomas*	Quarles & Brady (Tribal Webinar Participant)
Ho-Chunk*	Tribe
Ahtna*	Alaska Native Corporation
Choctaw Nation*	Tribe

[55] An asterisk (*) indicates an entity requested general information or provided verbal comments in lieu of, or in addition to, written comments.

The 23 submissions were composed of approximately 172 individual comments, which can be grouped into seven comment issue categories, as summarized in Table A-1.2.

Table A-1.2: Counts by comment issue

Comment Issue Description	Total Comments
Requests/suggestions to expand discussion	61
Edits/suggestions for clarity or consistency	47
Note of factual error or incorrect conclusion drawn from analysis	15
Other general comments	28
Comments related to legal issues	12
Suggestions related to organization and structure	3
Request for general information about Needs Study	6

APPENDIX A-2: Comment Matrix

The detailed "comment matrix" below documents each individual comment received over the course of the consultation period in order to adequately consider each comment. The matrix contains the following information: (1) the section the comment references, (2) the sentence(s) the comment references, (3) commenter name, (4) relevant verbatim excerpt of comment, and (5) Department resolution.

Table A-2. All comments received on consultation draft of National Transmission Needs Study and associated resolution.

No	Section	Sentence	Commenter	Comment/Question	Resolution
1	ES	General comment.	WECC	*Regarding organization and flow, there were some areas that we'd like to highlight. The content found in the conclusion (page 93) would be more appropriate to include in the Executive Summary—rather than breaking down the information regionally—due to it being more consistent with the rest of the report.*	We did add high-level national summaries to the Executive Summary and moved all regional summaries into their own section. The following was added to the executive summary: "A review of historical transmission system data from 2011 to 2020 provides insight into key indicators that demonstrate the need for more transmission infrastructure. These indicators include an overall decrease in historical transmission investment, regional and interregional wholesale electricity price differentials, and a record amount of new generation and storage capacity in interconnection queues across the county. Regional entities spent between $0.19 and $5.29 per MWh of annual load on new transmission in the past decade, on average. These investments resulted in a national total of over 34,000 circuit-miles of newly constructed or rebuilt transmission lines rated above 100 kV. Most of these investments were made in the first half of the decade, with transmission investments steadily declining since 2015. Wholesale market prices in the RTOs/ISOs also provides insight into where transmission congestion currently exists. Several regions of the country have had either consistently high or consistently low electricity prices over the past 3–5 years. Extreme conditions and high-value periods play an outsized role in this value of transmission, with 50% of transmission's congestion value coming from only 5% of hours. Finally, a review of the power plants currently awaiting interconnection agreements in different parts of the country suggests the generation mix will continue to shift toward more wind, solar, and battery storage technologies. "A review of recently published power systems studies to highlight the historical and anticipated drivers, benefits, and challenges of expanding the Nation's electric transmission infrastructure. Altogether, the studies reviewed signify a pressing need to expand electric transmission—driven by the

					need to improve grid reliability, resilience, and resource adequacy, enhance renewable resource integration and access to clean energy, support electrification efforts, and reduce congestion and curtailment. Interregional transmission investments will help improve system resilience by enabling access to diverse generation resources across different climatic zones. In addition to changes in electricity supply, regional goals and legislation regarding heating and transportation will also change the way electricity is used throughout the country over the next decade and beyond. Heating and transportation will become further electrified, which will significantly increase the total demand on the national grid and overall system demand. In addition to the overall increase in demand, daily electrical system demand patterns will also change. "Analysis of anticipated future transmission and transfer capacity need was performed for several different power sector scenarios across three different future years. According to capacity expansion model results, the largest growth of transmission will be needed in the Texas, Mountain, Southeast, Midwest, and Plains regions. The largest growth in interregional transfer capacity occurs between the Plains and Midwest, the Midwest and the Mid-Atlantic, and between New York and New England. New connections between the three interconnections are also shown to grow significantly. "
2	ES	"Each summary includes a brief description and indicator of general need followed by potential approaches to address the need."	WECC	*… the following statement may not match the coinciding section that follows; rather it instead details a need followed by indicators of the need.* *a. "Each summary includes a brief description and indicator of general need followed by potential approaches to address the need."(page iii)*	Sentence modified to strike rest of sentence after "…indicator of general need."
3	ES	"DOE broadly defines a transmission need to be an upgrade to or a new transmission facility—including non-wire alternatives— that would optimally be built to improve reliability and resilience of the power system; alleviate transmission congestion on an annual basis; alleviate transmission congestion during real-time operations; alleviate power transfer capacity limits between	ReliabilityFirst	*This definition of a "transmission need" or "new transmission facility" is harder to follow in the body of the report due to using GW-Mile and GW of transfer capability terminology. It is somewhat difficult to conceptualize the idea of Giga-Watt Miles (GW-mi). When thinking of adding transmission lines, system planners typically think of it as having to be purposeful, taking into account parallel paths constraints, essential reliability services items (i.e. voltage, etc.) and the physical location of load pockets. This analysis seems to consider adding transmission without considering these additional items. We believe they are needed.*	Emphasis on how this analysis differs from the engineering analysis performed during transmission planning was added to the introduction of Section VI: "The values presented here are zonal estimates of the amount and general geographic location of future transmission need. The precise characteristics and nodal locations of specific transmission projects to accommodate generation and load changes would be determined by additional engineering analysis performed by the transmission planners. Additionally, any one of these transmission additions may require associated system upgrades to support increased energy transfers and, as such, the zonal estimates reported here may

		neighboring regions; deliver new, cost-effective generation to high-priced demand; and to meet projected future generation, electricity demand, or reliability requirements."			underestimate total required system builds. These downstream analyses are critical to the transmission planning process to ensure reliable operation of the grid, but are out of scope for the analysis presented here. Because of their near-term focus, industry-led studies tend to be less speculative about the characteristics of the future power system. Section V reviews the results of many of these studies but given the mismatch in modeling scope, the results of the reviewed industry studies are not included in this analysis." The following was added to Section VI.a.2: "Additional engineering analysis performed by planners is needed to determine the best technologies and locations of the available transmission solutions to meet the needs identified here." Additionally, GDO added a paragraph, table and reference to section VI.b. to describe the differences between GW-mi units of capacity expansion models and kV-mi units more familiar in industry: "Transmission deployment is presented here as the carrying capacity (GW or TW) of a modeled power line multiplied by the length (miles) of the line. Quantifying power lines as GW-mi or TW-mi is a convenient unit for capacity expansion models but is not a common practice in industry. Transmission planners and developers quantify power lines by their nominal voltage rating (kilovolts, kV) multiplied by the length (miles) of the line. In general, the higher the voltage rating and the shorter the power line, the more carrying capacity it has. Table VI-2 from NRRI (1987) provides approximate conversions between nominal voltage ratings and distances to carrying capability for AC transmission lines. By these conversions, a 100 mile, 345kV rated line is equivalent to 86 GW-mi. "Table VI 2. Approximate power carrying capabilities (MW) of uncompensated AC transmission lines at different voltage ratings and lengths from NRRI (1987)."
4	ES	"DOE broadly defines a transmission need to be an upgrade to or a new transmission facility—including non-wire alternatives— that would optimally be built to improve reliability and resilience of the power system; alleviate transmission congestion on an	ReliabilityFirst	*The executive summary mentions non-transmission solutions being on option. It is not clear how optimally located generation additions would count against a value presented in GW-mi. In addition, the non-wire alternatives could include construction of new reliable resources close to the load centers thereby reducing the transmission needs.*	These solutions are included in the results already. The capacity expansion models used in Section VI look for the least expensive combinations of generation and transmission. We added Section VI.a.2. "Treatment of non-wires alternative transmission solutions" to clarify how generation near load, energy storage, and DERs are all incorporated in the capacity expansion modeling results. This section includes information about the number of scenarios in which NWAs were considered.

		annual basis; alleviate transmission congestion during real-time operations; alleviate power transfer capacity limits between neighboring regions; deliver new, cost-effective generation to high-priced demand; and to meet projected future generation, electricity demand, or reliability requirements.”			The use of generation near loads as an NWA was added to section V.h. See resolution to comment 120.
5	ES	n/a	Illinois Commerce Commission	*While the Study highlights a range of findings, identifies system needs and summarizes a plethora of prior studies, it stops short of providing a strong recommendation or blueprint for developing a robust transmission system. Perhaps the Study will allow industry participants to refocus their priorities and/or push for general improvements that, over time, will result in meaningful improvements to the transmission grid. For example, the Midwest section of the Study suggests that MISO is likely better off addressing the transfer capability constraints between its south and central regions by first improving transmission between MISO North and SPP and then from SPP to MISO South, rather than by initially focusing on the MISO North to MISO South constraint. This suggestion is contrary to MISO's current efforts to address the MISO North/South constraint directly in Tranche 4 of its long-range transmission planning efforts and has prompted ICC Staff to reconsider MISO's plan.*	Thank you for your comments. As stated in the Executive Summary, “This study prescribes no particular solutions to issues faced by the Nation's power sector. Rather, it establishes findings of need in order for industry and the public to suggest best possible solutions for alleviating them in a timely manner.” It is our hope that States and industry will use this document to suggest meaningful transmission solutions to the identified needs.
6	ES	“DOE broadly defines a transmission need to be an upgrade to or a new transmission facility—including non-wire alternatives— that would optimally be built to improve reliability and resilience of the power system; alleviate transmission congestion on an annual basis; alleviate transmission congestion during real-time operations; alleviate power transfer capacity limits between neighboring regions; deliver new, cost-effective generation to high-priced demand;	ReliabilityFirst	*Growing the transmission system has the potential to create a new set of challenges for the system operators. As more transmission is added, and more generation of small mass is added (i.e. wind farms, solar), it is going to be difficult to control system voltage. In light load periods, line loading may drop (increase in line charging) to a point where there are not enough units to absorb all of the excess Vars. Therefore adding transmission may result in the need for more reactors, which is inherently inefficient. These are things to keep in mind during the process.*	Please see resolution to comments 46 and 99. Additionally, we added the following to Section IV.c. to clarify the use of phase shifters to manage unscheduled flows: “Phase shifters were a cost-effective alternative to additional transmission for many years, but their effectiveness is decreasing as the industry transitions away from tradition thermal generators to renewable energy resources. Much of the existing high-voltage transmission system was constructed around thermal generators. Utility-scale renewable resources are in different locations relative to existing transmission infrastructure. This has implications for transmission loading and can create incremental unscheduled flows on certain transmission segments, including the qualified paths.

		and to meet projected future generation, electricity demand, or reliability requirements.”			“In addition to the phase shifters, thermal generators have traditionally been leveraged as tools to manage congestion. Generator output can be increased or decreased on either side of affected transmission segments, which can aid in alleviating constraints. Given the number of thermal generator retirements, incrementing and decrementing generation is not as available as a tool for congestion management. This increases the reliance on the phase shifters, which were not designed to manage the changes in transmission flows developing on the system.”
7	ES	“DOE broadly defines a transmission need to be an upgrade to or a new transmission facility—including non-wire alternatives— that would optimally be built to improve reliability and resilience of the power system; alleviate transmission congestion on an annual basis; alleviate transmission congestion during real-time operations; alleviate power transfer capacity limits between neighboring regions; deliver new, cost-effective generation to high-priced demand; and to meet projected future generation, electricity demand, or reliability requirements.”	Minnesota Department of Commerce and the Minnesota Public Utilities Commission	*We understand the primary purpose of this study is not to designate specific National Interest Electric Transmission Corridors. The draft executive summary does, however, identify some major transmission needs in each region. It is somewhat unclear what criteria were used to select these transmission needs. We understand developing specific reliability and transfer capacity definitions and related criteria would be difficult in this context. One idea that may help, though, is to develop a more precise definition of “transmission need.”* *It may be helpful organizationally to specifically point out in the introduction that what we currently have are a variety of problems with the existing electricity system, such as large price differentials, barriers to meeting carbon reduction goals, and the related long interconnection queues. That existing situation is described in Chapter IV.* *Then “need” might be described as the requirement to maintain reliability and increase transfer capacity in various regions if we are to reduce these problems to an acceptable level in the future and meet carbon reduction goals, as described in Chapters V and VI. The priority problems highlighted in the executive summary could then be selected using some more specific, but perhaps non-quantitative criteria. Tying the chapters together in this way might make the information more useful for users to identify priorities.*	DOE has amended the definition of “transmission need” in the draft Needs Study to mean the existence of present or expected electric transmission capacity constraints or congestion in a geographic area. This definition more closely aligns with the statutory direction in Section 216(a)(1) of the FPA. The draft Needs Study continues to acknowledge that geographic areas where transmission needs exist could benefit from an upgraded or a new transmission facility. However, DOE maintains that this Needs Study does not intend to prescribe particular solutions to the issues faced by the Nation’s power sector. Regarding support for NIETC designations, although the Needs Study will inform potential decisions to designate NIETC, Section 216(a)(2) of the FPA provides that DOE may also base such designations on other information relating to transmission capacity constraints and congestion. Prior to issuing the next report mandated by Section 216(a)(2) of the FPA, DOE intends to engage in further process and collect additional information for purposes of potential NIETC designations. Lastly, DOE reiterates that in addition to its authority to designate NIETC, the Needs Study will inform DOE as it coordinates the use of other authorities, such as implementing various provisions of the Infrastructure Investment and Jobs Act and Inflation Reduction Act, and funding related to electric transmission.
8	ES	General comment.	WECC	*The subregional breakdowns (beginning on page v), appear to contain identical ‘Indicators’ across the Western Interconnection. Perhaps, it would be better suited as one comprehensive statement for all regions and then state the “Needs” broken down by each region.*	Please see resolution to comment 1

9	ES	"Alleviate congestion between California and the Northwest. Transmission path 66 at the intersection of the Northwest, California, and Mountain." and "Alleviate congestion on three Qualified Paths within the region. Transmission paths 30, 31, and 36, which align with Colorado's borders to the west, south, and north, respectively, are congested Qualified Paths."	WECC	*…we are uncertain whether these paths are indeed congested. The challenge with these paths is the unscheduled flow due to the nature of Western Interconnection and the associated reliability risks.*	Replaces "Alleviate congestion" with "Alleviate unscheduled flows" in both sentences. Struck congestion from both the first and second sentences. To be consistent, made the same changes above to the "California" subsection in the Executive Summary.
10	ES	"Congestion costs increased considerably from 2020 to 2021 in the Mid-Atlantic region, surpassing energy costs. (§V.d)" and "Top congestion constraints are in the eastern portion of the Mid-Atlantic region near the borders of Maryland, Delaware, Pennsylvania, and New Jersey. Large price differentials occur in this part of the region. (§IV.b & §V.d)"(§IV.b & §V.d)"	PJM	*A significant portion of the higher congestion noted in the Report is associated with multiple transmission outages in support of approved upgrades. As a result, the congestion listed should not necessarily be considered a persistent level of congestion in the Mid-Atlantic. Moreover, the Transource Project 9A would have addressed a significant amount of the identified congestion but siting of that project was denied by the Pennsylvania PUC resulting in continued congestion. Additionally, higher gas prices result in higher magnitude of the congestion dollars.*	Sentence added at the end of first paragraph of section V.d.3: "A portion of this congestion associated with these constraints are associated with scheduled transmission outages during approved upgrades." Regarding Transource Project 9A, DOE appreciates that transmission projects currently under development could address some of the needs identified in the Study. Without insight into all projects currently under development and how they may address these needs, we are declining to identify specific projects as solutions to these needs in the Study. We hope the Study will help industry prioritize solutions to the identified Needs.
11	ES	"Anticipate between 2,700 and 4,600 GW-mi (median 3,300 GW-mi, 23 percent relative to 2020 system) in 2035 to meet moderate load and high clean energy futures. Current utility plans for transmission development in the Mid-Atlantic do not meet anticipated need. (§VI.b)"	PJM	*The Report should make clear that existing PJM planning, both reliability and market efficiency, anticipates future load growth and congestion. Multiple transmission upgrades will be or have already been approved in accordance with PJM planning requirements/processes to address future load growth during this period. PJM is happy to review this with the authors but is concerned the Report does not depict the full role of PJM planning which is designed to address potential load growth.*	The following was added to Section 1 on current planning processes: "Transmission planning by designated Planning Authorities is driven by FERC Order 1000 tariff provisions which have traditionally been based on siloed processes that use tailored deterministic models to protect existing service obligations. In aggregate, these assessments are intended to be comprehensive in evaluating the reliability, economic and public policy requirements of the future power system. Many of these plans are primarily focused on compliance with NERC and local reliability standards with very limited scopes and planning horizons. These assessments typically are performed to

					ensure that future system will address expected reliability needs for select futures which reflect known resources changes, such as resource retirement or modification commitments, as well as executed generation interconnection agreements and approved transmission service requests.”
12	ES	“High dependence on natural gas power poses a risk to winter reliability. (§V.a)”	ISO-NE	*This statement is not complete. High dependence on natural gas for electricity generation alone does not pose a risk to winter reliability. New England has a constrained gas supply system and therefore, during periods of extreme cold, New England does not have sufficient pipeline infrastructure to meet the region’s demand for natural gas for both home heating and power generation. This situation leaves the region reliant on deliveries of liquefied natural gas – a globally-traded commodity, as well as in season replenishment of oil supplies*	Modified sentence in New England and California subsections in the ES: “A constrained natural gas system poses a risk to winter reliability when demand for gas is high for both heating and electricity.” Also modified Texas subsection of the ES: “A constrained natural gas system poses a risk to winter reliability, particularly in the absence of winter hardening investments and when demand for gas is high for both heating and electricity.”
13	ES	“Improve onshore transmission system reliability by designing a networked transmission system for offshore wind generation. (§V.c)”	ISO-NE	*This statement appears to be based on a number of non-ISO-NE studies. These studies only show the benefits of offshore transmission, without comparing them to other alternatives such as strengthened onshore transmission.*	Added ISO-NE’s First Cape Cod Resource Integration Study (2021) and as well as ISO-NE’s 2021 Economic Study: Future Grid Reliability Study Phase 1 (2022) to several places in Section V. Modified sentence to “A well-designed offshore transmission system can integrate offshore wind generation without compromising reliability of the onshore transmission system.”
14	ES	“Increased transmission maintenance outages elsewhere in New England can increase reliability commitments in Maine given regional transmission limitations. (§V.d)”	ISO-NE	*This statement is based on a relatively small number of hours during which maintenance outages occur, and no analysis is provided of the benefits of avoiding these commitments vs. the costs of new transmission to avoid them.*	Sentence removed from Executive Summary, but kept discussion in section V.
15	ES	“Reduce generation curtailments by increasing transmission system for offshore wind generation in several States. (§V.c & V.d)”	ISO-NE	*The ISO-NE study that was used to support this statement shows that generation curtailment is only slightly lower in an unconstrained-transmission scenario than in a constrained-transmission study. The statement in the consultation draft is not supported by any cost/benefit analysis of the costs of new transmission vs. the benefits of reduced curtailment.*	Statement was removed.
16	ES	“The real-time, interregional value of transmission between New York and New England was higher than the value of transmission within New England and has been increasing over the past several years. (§IV.b)”	ISO-NE	*This is an accurate statement, but this is driven more by minimal price differences within New England than by large price differences between New England and New York.*	Sentence modified: “The real-time, interregional value of transmission between New York and New England has been increasing over the past several years.”

17	ES	"Anticipate between 3.4 and 6.3 GW (median 5.2 GW, 255 percent relative to 2020 system) new transfer capability needed with New York in 2035 to meet moderate load and high clean energy futures. (§VI.c)"	ISO-NE	*This finding is based on capacity expansion modeling similar to that performed in the National Transmission Planning Study (NTPS). Drawing conclusions from this modeling is premature.*	Because the capacity expansion modeling used here and that used in the NTP Study are so similar, we anticipate the NTP Study will find similar levels of transmission is needed. The most important value of the NTP Study is the power flow and reliability studies that will be conducted on candidate transmission projects resulting from the capacity expansion modeling. We agree the NTP Study will have very useful conclusions and hope those results and can discussed in the next iteration of the Needs Study. We have added the following to the introduction of Section VI to clarify this point further: "The Department is currently undertaking a National Transmission Planning Study to bridge the gap between national, long-term capacity expansion modeling studies and regional, near-term transmission planning studies (*see* accompanying text box). The National Transmission Planning Study is conducting downstream engineering analysis of candidate transmission projects which result from capacity expansion modeling. Future iterations of the Needs Study may include the results of the National Transmission Planning Study."
18	ES	Plains summary	Iowa Utilities Board	*The Plains section of the Executive Summary offers certain amounts of GW-mile for meeting transmission needs. It may be beneficial to consider the possibility of future storage capacity collocated with wind and/or solar generation, which may minimize the need for additional wind or solar generation projects.*	Only one study used in Section VI considered co-location of solar and battery storage, but several did co-optimize for the growth of utility-scale storage (which could be placed wherever is most optimal, including near solar and wind sites). We added Section VI.a.2. "Treatment of non-wires alternative transmission solutions" to clarify how generation near load, energy storage, and DERs are all incorporated in the capacity expansion modeling results.
19	ES	Midwest summary	Iowa Utilities Board	*The Midwest section of the Executive Summary offers amounts of GW for transmission needed and states that congestion is higher in the Dakotas, Minnesota and Iowa. DOE should consider the Joint Transmission Interconnection Queue projects planned between MISO and SPP, which intends to alleviate congestion for a foreseeable future in this seam's region. Iowa, particularly, is on the seam and will be the site of one of these projects.*	The JTIQ portfolio is already mentioned in the literature review sections V.c. and V.d.4. While the Department recognizes that these projects, if built, will contribute to meeting the stated need, we choose not to add them to as solutions to the capacity expansion model results in section VI. Without insight into all projects currently under development in each region and how they may address the stated needs, including only this portfolio will skew the results for other regions.
20	ES	"Generation retirements in MISO could result in capacity shortfalls as early as 2024. (§V.b)"	ReliabilityFirst	*This may be a timing issue and when the date was grabbed for this assessment, but the 2022 NERC Long-term Reliability Assessment now indicates the shortfall happening in 2023. Should this be adjusted or the wording changed since these have the potential to change?*	Regrettably, GDO is unable to address this particular comment at this time given the timing mismatch of the 2022 NERC LTRA publication date. Perhaps after the LTRA report is published we can address this in the next Needs Study iteration.

21	ES	"Generation retirements in MISO could result in capacity shortfalls as early as 2024. (§V.b)"	Midwest Reliability Organization	*NERC's 2022 Long-term Reliability Assessment, being released mid-December, indicates this happening in 2023. Should this be updated for NERC's updated assessment? Not sure if this report will be released before NERC's LTRA. There may be other references in the other regions that may need to be updated for NERC's most recent LTRA.*	See resolution to comment 20
22	ES	"Generation retirements in MISO could result in capacity shortfalls as early as 2024. (§V.b)"	Midwest Reliability Organization	*See earlier comment with regard to NERC's 2022 LTRA.*	See resolution to comment 20
23	ES	"Congestion costs increased considerably from 2020 to 2021 in the Mid-Atlantic region, surpassing energy costs. (§V.d)"	Delaware Public Service Commission	*On page xiii, the Needs Study indicates congestion costs surpassed energy costs in the Mid-Atlantic region in 2021. We find no corresponding reference to support that assertion in the Needs Study.*	This reference can be found in the first section of V.d.3: "In PJM's 2021 State of the Market Report, Monitoring Analytics (2022) records that total congestion costs increased in 2021, from $528.7 million in 2020 to $995.3 million in 2021, an approximately 88.2 percent increase."
24	ES	"Increase in transmission deployment to meet projected generation and demand growth."	Delaware Public Service Commission	*On page xiv, regarding the recommendation, "Increase in transmission deployment to meet projected generation and demand growth", it is not clear if the Needs Study considers the offshore wind initiatives of various Mid-Atlantic states and corresponding transmission upgrades, and how those upgrades may impact congestion and any other required transmission build out in the region as energy begins to flow from east to west.*	Offshore wind is included as a possible generation source in many of the capacity expansion models used to support this statement. This is listed in footnote 45 in section VI.a.1. The discussion of offshore wind in Section V.c.1 has been significantly expanded to identify specific onshore grid upgrades which would be required to accommodate offshore wind.
25	I	"DOE undertakes this Needs Study to identify high-priority national transmission needs—specifically, to identify where new or upgraded transmission facilities could promote greater grid reliability and resilience; relieve expected future constraints and congestion driven by deployment of clean energy consistent with federal, state, and local policy and with consumer preferences; accommodate higher electric demand as a result of building and transportation electrification; and address insufficient transfer capability across regions."	ReliabilityFirst	Commenter highlights "Where new or upgraded transmission facilities" and comments: *We suggest using a qualifier here such as "**general areas where** new or upgraded transmission facilities could promote greater reliability and resilience,", given that this study doesn't specify where facilities are specifically needed.*	Please see the resolution to comment 7 where "transmission need" is redefined.

26	III	"The Western Electricity Coordinating Council (WECC) WIUFMP was used for the first time in this Needs Study to identify congested areas in the Western Interconnection."	WECC	*We recommend adjusting the following statement accordingly since the Western Interconnection Unscheduled Flow Mitigation Plan (WIUFMP) is managed by the individual entities and their Reliability Coordinators.* *a. "The Western Interconnection Unscheduled Flow Mitigation Plan (WIUFMP) was used for the first time in this Needs Study to identify congested areas in the Western Interconnection." (page 5)*	Sentence modified: "The Western Interconnection Unscheduled Flow Mitigation Plan (WIUFMP) was used for the first time in this Needs Study to identify congested areas in the Western Interconnection."
27	III	"The Western Electricity Coordinating Council (WECC) WIUFMP was used for the first time in this Needs Study to identify congested areas in the Western Interconnection."	WECC	*We believe it may add greater clarification expanding on "The Western Interconnection Unscheduled Flow Mitigation Plan," (page 5) by describing the limited number of paths that this may affect; there are only four paths involved in WIUFMP of the approximately 50 paths that are defined in the Western Interconnection.*	Added the following sentence to section IV.c: "Four of the approximately 50 paths in the Western Interconnection were identified as qualified paths."
28	III.a	"Transmission also helps reduce congestion and losses, which leads to economic benefits in the form of reduced electricity prices, reduced system costs, and reduced reserve margin requirements."	Midwest Reliability Organization	*Transmission expansion in itself does not reduce capacity reserve margin. It enables reduced margin requirements by providing a network where there is more assurance of deliverability of generation resources from an area rich with generation to one that is deficient. Reduced margin requirements are more so dependent on generation capacity being installed and available.*	Sentence modified to remove portion related to reduced reserve margin requirements. Additional sentence added specific to resource adequacy: "Transmission also helps reduce congestion and losses, which can lead to economic benefits in the form of reduced electricity prices and reduced system costs. Relatedly, diversity in load, generation, and weather patterns within and between regions imply that resource adequacy can typically be improved with increased transmission infrastructure, so long as regional planners guard against shifting resource adequacy responsibilities to neighboring regions that face inter-dependent risks."
29	III.a	"Transmission also helps reduce congestion and losses, which leads to economic benefits in the form of reduced electricity prices, reduced system costs, and reduced reserve margin requirements."	ReliabilityFirst	*If you add more transmission in an area where lines are loaded close to Surge Impedance Loading, it may not necessarily reduce losses or "system costs". In some cases, excess transmission may result in the need to add shunt reactors, which may negate the cost savings and increase losses.* Commenter also highlights "reduced" and comments: *There is a wide range of process and assumptions used in reserve margin calculations. Having this here and having this too large could create a new risk of interdependency on neighboring systems, etc. Is that a new risk that we want to introduce?*	See resolution to comment 28

30	III.a	"A more robust transmission system supports the electrification of end-use devices which presently rely on fossil fuel combustion, resulting in environmental benefits in the form of improved indoor air quality and avoided adverse health effects."	Midwest Reliability Organization	*As written this limits electrification to buildings (reference to indoor air quality). Electrification of transportation is currently accelerating faster than electrification of buildings and will have a bigger near-term impact to air quality. Suggest removing the inclusion of "indoor" as to not limit the topic of electrification.*	Sentence modified to remove "indoor."
31	III.a	"Without an underlying network of transmission lines, delivery of large amounts of power from utility-scale power generation installations to consumers is not possible."	ReliabilityFirst	*Consider rewording to the following: "An underlying network of transmission lines facilitates the delivery of large amounts of power from utility-scale power generation installations to consumers."* *It is possible to deliver large amounts of power from utility-scale power generation installations, but requires the location of such resources to reside adjacent to consumers (not cost effective).*	Sentence modified: "An underlying network of transmission lines facilitates the delivery of large amounts of power from utility-scale power generation installations to consumers."
32	III.a	"In addition to the transmission network, other transmission solutions such as non-wires alternatives and grid enhancing technologies, can be employed to improve the efficiency of the grid, improve power quality, or enable power delivery at lower costs."	ReliabilityFirst	Commenter highlights "enhancing" and comments: *In Section V.h grid enhancing technologies are defined as being one of the non-wire alternatives, consider looking at the way this is worded.*	Sentence modified to remove "and grid enhancing technologies."
33	III.a	"Many energy resources are currently within backlogged interconnection queues and a well- planned transmission system can help hasten connection of those resources to the grid."	ReliabilityFirst	Redline edits remove "a well-planned transmission system" and adds the following: *Many energy resources are currently within backlogged interconnection queues and <u>a more efficient transmission study process that ensure the Essential Reliability Services are included</u> can help hasten connection of those resources to the grid.*	Modified sentence: "Many energy resources are currently within backlogged interconnection queues and <u>a</u> more efficient transmission study process that ensure the Essential Reliability Services are included can help hasten connection of those resources to the grid." Footnote added referencing 2016 NERC sufficiency guidelines, which has also been added as a resource in the references section.
34	III.a	"In areas with high renewable penetration, transmission buildout can reduce renewable generation curtailment and improve the output of renewable resources."	ReliabilityFirst	*This circumstance impacts generators of all fuel source types. Suggest changing "renewable" to "resource", then strike the second reference to "renewable" in the sentence.* Commenter also highlights the section of sentence after the comma and comments: *In many cases the fossil fuels are the load following units that lowered due to their dispatchability and cost and not the renewables Consider adjusting this language.*	Modified sentence to replace first two instances of "renewable" with "resource" and struck final "renewable."

35	III.a	"A more robust transmission system supports the electrification of end-use devices which presently rely on fossil fuel combustion, resulting in environmental benefits in the form of improved indoor air quality and avoided adverse health effects."	ReliabilityFirst	Commenter highlights "transmission" and comments: *This would likely require investment and upgrade of the local distribution systems as well. To be fair and it does not appear anyone is talking about the lower voltages and impact there. Should that be added here?*	Modified to "…robust transmission system—along with associated upgrades to the distribution system—supports the electrification…"
36	III.b	"This study evaluates national transmission needs. For purposes of this document, we consider a *transmission need* to be an upgrade to or a new transmission facility—including non-wire alternatives—that would optimally be built to address present or expected future transmission congestion or transmission capacity constraints."	ReliabilityFirst	*Per the reference to "non-wire alternatives", sometimes the economic solution is to make the existing resources more reliable.*	Included sentence in section V.h.3: "GETs deployment can also improve the reliability of the existing transmission system, which can serve as an economical alternative to transmission expansion in certain scenarios."
37	III.b	"This study evaluates national transmission needs. For purposes of this document, we consider a *transmission need* to be an upgrade to or a new transmission facility—including non-wire alternatives—that would optimally be built to address present or expected future transmission congestion or transmission capacity constraints."	ReliabilityFirst	Commenter also highlights "study evaluates" and comments: *Upon review we did not see any reference in the document that specified the type of studies that would be performed to identify "optimal" solutions. This seems like it would be a difficult thing to determine based on all the different measures of project benefits. Consider adding that for a complete picture of the assessment.*	Please see the resolution to comment 7 where "transmission need" is redefined.
38	III.b	"As a result, operators are forced to reroute power through less optimal paths and use more expensive generation, such as conventional fossil fuels, while curtailing renewables to safely meet customer demand."	Midwest Reliability Organization	*Suggest removing "such as conventional fossil fuels" as expensive generation is not limited to just fossil fuels. Further replace "renewables" with "less expensive generation" since it isn't always true that renewables are being curtailed. Congestion always results in less expensive generation being curtailed, and more expensive generation being increased, regardless of fuel type.*	Removed "such as conventional fossil fuels" and replaced "renewables" with "less expensive resources."

39	III.b	"As a result, operators are forced to reroute power through less optimal paths and use more expensive generation, such as conventional fossil fuels, while curtailing renewables to safely meet customer demand."	ReliabilityFirst	*It would be helpful to cite data from the study to support this statement.*	The passage has been modified to: "As a result, power is rerouted through less optimal paths to use more expensive generation while curtailing less expensive generation to safely meet customer demand. This process occurs either manually through operator intervention or automatically via Security Constrained Economic Dispatch."
40	III.b	"A constraint on the transmission system that may drive transmission congestion could refer to…"	ReliabilityFirst	*Later in the report a reference is made to the MISO Central to MISO South transmission constraint being binding much of the time. That constraint is a Contract Path constraint, and does not fit either of these two definitions used here. Consider adding one to fit this path.*	A third bullet was added: "A transfer limitation established to manage flows in accordance with coordination agreements."
41	III.b	"Reliability standards specify the tolerances around the nominal levels."	ReliabilityFirst	Commenter highlights "Reliability standards" and comments: *Typically the ISO/RTO and utilities set these thresholds. Not sure the word standard is right here. Consider using the term "Operating Limits, which are set by equipment owner/operators, specify the...."*	Sentence modified: "Operating Limits, which are set by equipment operators, specify the tolerances around the nominal levels."
42	III.b	"We define it here to be a suboptimal limit of transfer of electric power on the grid, including those that reduce operational reliability of the power system; power transfer capability limits between neighboring regions that reduce resilience or increase production costs; and limits on the ability of new, cost-effective generation to be delivered to high-priced demand."	ReliabilityFirst	Commenter highlights "demand" and comments: *Recommend removing the word "new" here. By using LMP as a measure of transmission congestion, it appears as though there is an association that transmission constraints limit the ability of all cost-effective generation to be delivered to high-priced demand. Without knowing why the congestion happened this could be misleading.*	Please see the resolution to comment 7 where "transmission need" is redefined.
43	III.b	"While transmission congestion (and the related but not identical transmission constraint) have industry standard definitions, transmission capacity constraints do not."	SERTP	*The Draft Study specifically cites to FPA section 216 as its authority, but then undertakes a very broad analysis of "transmission needs" rather than the statutorily specified study of "electric transmission capacity constraints or congestion." The Draft Study states that a "transmission need" for purposes of the study is an upgrade or new transmission facility that would be built to address "present or expected future transmission congestion or transmission capacity constraints." The Draft Study presents a definition of "transmission congestion" tied to a "constraint on the transmission system" but then states that while "transmission congestion (and the related but not identical transmission constraint) have industry*	Please see the resolution to comment 7 where "transmission need" is redefined and Section 216 authority is clarified. Please also see resolution to comment 11 regarding existing planning processes.

				standard definitions, transmission capacity constraints do not." Based upon this purported ambiguity, DOE adds very broad criteria that greatly expand DOE's definition of transmission need to encompass matters that have been traditionally considered resource/generation/integrated resource planning ("IRP") planning and not transmission planning	
44	III.d.1	"Congestion costs are directly affected by transmission investment."	Iowa Utilities board	*The IUB does not believe that all transmission investments impact congestion. For example, investment can be made to replace aging infrastructure or increase resiliency, meanwhile keeping capacity the same. In the third paragraph in section III.d.1., we suggest removing or revising the sentence, "Congestion costs are directly affected by transmission investment."*	Removed sentence.
45	IV	"Additional transmission could remove or reduce the variation in prices caused by congestion, allowing lower-cost energy to reach high demand areas."	ReliabilityFirst	*As cited in section III.d.1 RTO/ISO Congestion Management Practices, changes in system topology, changes in load/demand or resources in areas all have and can impact congestion. Congestion is a signal to market on where resources, but the system conditions need to be accounted for as well.*	Thank you for the comment. We believe this concern is appropriately caveated using the language "could remove or reduce" in the highlighted sentence.
46	IV	"Examining price differences between RTOs/ISOs can also help identify valuable transmission opportunities. Interregional transmission might be a better option than within- region transmission because load and generation patterns across regional markets are less temporally correlated than within different subregions of a single market."	ReliabilityFirst	*Historic data identifies historic needs. However as the resource mix changes (i.e. coal and natural gas generation retirements take place and or are accelerated) flows on the transmission system will most likely change. As a result the historic performance and data used might not be a good indicator of future performance. Study and analysis of these new installations are needed.*	While it is true that resource mix changes will change power flow and congestion, GDO respectfully disagrees that historic data therefore is not relevant to current impacts. Recent historic trends are capturing the resource mix changes that will continue into the near future. More detail was added to highlight the importance of the regional transmission planning processes which do study these impacts. See resolution to comments 3 & 11. In addition, the following was added to Section 1: "Transmission planning is becoming more difficult and complex with the adoption and integration of new distributed and variable resources which affect the performance and capabilities required at the bulk power system. Advanced transmission technologies are being incorporated on the grid to enhance asset utilization, mitigate curtailments of renewable resources which in many cases has energy storage capabilities, and better manage congestion patterns that may not be considered in existing planning processes. Although it may be a paradigm shift compared to traditional operations, leveraging technology to increase an operator's visibility and understanding of power system flows and capabilities on critical components should actually improve grid security, not jeopardize reliability."

47	IV	"FERC suggests that the "piecemeal" approach to transmission deployment that occurs with the interconnection agreement process will not benefit from the economies of scale that would accompany a full regional transmission planning process (FERC 2022)."	ReliabilityFirst	Commenter highlights "full regional transmission planning process" and comments: *PJM and MISO both perform regional RTO Planning studies and inter-regionally as well. SPP does the same with MISO. Consider looking into these processes and include that here.*	See resolution to comments 11 and 19.
48	IV	"FERC suggests that the "piecemeal" approach to transmission deployment that occurs with the interconnection agreement process will not benefit from the economies of scale that would accompany a full regional transmission planning process (FERC 2022)."	Midwest Reliability Organization	*SPP and MISO have a Joint Targeted Interconnection Queue Study that is inter-regional planning. Consider mentioning this process here to showcase the value of inter-regional planning.*	See resolution to comments 11 and 19.
49	IV	n/a	Oregon DOE	*Sec. IV – <u>Historical Data - Lack of wholesale price data in non-RTO regions & Qualified Paths</u>: We appreciate GDO's recognition that assessing transmission congestion in the non-RTO West based on historical wholesale electricity price data can be a particular challenge. Relative to regions with RTOs, the predominance of BPA and vertically integrated utilities puts downward pressure on the annual volume of energy that gets transacted in the wholesale markets of the non-RTO West, leading to a relative lack of wholesale electricity price data. Because of this, we found the Qualified Paths sub-section, including the discussion of loop flows, the constraints of having 38 fragmented BAs, and the lack of centralized transmission planning, particularly useful.*	Thank you for your comments. We are glad the Study is proving useful.
50	IV	"Section IV.a reviews the past decade of transmission investments in each U.S. region using metrics as outlined in the *2017 Transmission Metrics Report* (FERC 2017)."	ReliabilityFirst	*This reference is 5 years old and the grid has changed a lot with respect to infrastructure and resource additions. With all the change consider adding text to reflect that change has taken place and needs to be accounted for.*	DOE believes no further clarification is required. Section IV states that the study "…reviews the past decade of transmission investments in each U.S. region *using* metrics as outlined in the 2017 Transmission Metrics Report (FERC 2017)." (Emphasis added). Section IV.a further clarifies: "FERC presented data from 2008 to 2015 in its metrics report (FERC 2017); *we consider the decade of investments from 2011 to 2020*." (Emphasis added).
51	IV.a	"Transmission investments are inherently lumpy."	ReliabilityFirst	Commenter highlights "lumpy" and comments:	Changed to "Transmission investments are inherently 'lumpy,' or unevenly distributed."

				Suggest replacement of the term "lumpy" with a more technical term (e.g., back end loaded).	
52	IV.a	"To account for this lumpiness, we present temporal trends using rolling averages, which differ from the metrics FERC has developed."	ReliabilityFirst	*Suggest to replace "lumpiness" with "non-distributed representation".*	Changed to "To account for this "lumpiness," or unevenly-distributed representation."
53	IV.a	"The proportion of project circuit- miles installed by non-incumbent transmission developers has steadily decreased from 40 percent in 2013 to less than 2 percent in 2020."	ReliabilityFirst	*How does this correlate to actual and forecasted load growth for each area? Within some areas of North America, all-time peak demand numbers were experienced prior to 2015 paired with large amounts of generation retirements due to EPA MATS. This may have led to overall increased investment in transmission infrastructure during that timeframe. Thus, creating an increased demand that allowed more opportunities for non-incumbent developers.*	Load during this decade was relatively flat in all regions. Where regional load did fluctuate, that was balanced by commensurate load changes in other regions such that national load was flat. The average national annual load from 2011-2020 was 4006 TWh, with a minimum of 3955 TWh in 2013 and maximum of 4128 TWh in 2014. We considered adding both regional and national load data to the referenced figure, but due to its flatness the figure did not add any value.
54	IV.a	Figure IV-2	WECC	*Regarding the first graph on page 22, it would be helpful to clearly define incumbent vs. non-incumbent entities.*	Sentence introducing figure IV-2 revised: "Incumbent transmission developers, or entities that develop transmission within their own retail distribution footprint, have always dominated project development space nationwide. The proportion of project circuit-miles installed by non-incumbent transmission developers, or entities that do not have a retail distribution footprint or that are public utilities developing transmission outside of their footprint, has steadily decreased from 40 percent in 2013 to less than 2 percent in 2020."
55	IV.a	discussing resource adequacy concerns in the Northwest, Southwest, California, Plains, Midwest, Delta, and Texas	SERTP	*Another concern with the Draft Study's conclusions on the need for significant interregional/interface facilities is that such "solutions" could allow certain regions to shift their resource adequacy responsibilities to neighboring regions, exacerbating existing resource adequacy problems and ultimately increasing reliability risks to all. For example, the Draft Study identifies several regions that are predicted to experience resource adequacy problems or that are likely to experience complications associated with not having sufficient dispatchable resources/high renewable penetration. While interregional transfer capability may temporarily, or in isolated instances, alleviate these complications, resource adequacy as a whole cannot fully and finally be resolved through transmission –it is, after all, a resource issue. If those regions do not directly address those problems internally but instead expand their interface ties, then those regions are merely exporting their problems to neighboring regions…this concern of allowing regions*	See resolution to comments 11 and 28. Joint coordinated planning has worked in the past to accommodate seasonal diversity exchanges between regions in the past. While it may be a challenge, more coordinated joint planning will be required in the future for a decarbonized grid to be affordable for consumers.

				with resource adequacy problems to shift those problems to their neighbors appears borne out by the Draft Study's Table VI-3, which seems to indicate that current low-cost regions, such as the Southeast, would have to bear significant upgrade costs to enable its neighbors to "lean on" the Southeast. While there could be some benefits from geographic and resource diversity, it cannot come at the cost of encouraging regions to disregard their own respective resource adequacy. ….In sum, there may be better alternatives to the massive build-out of interfaces as forecasted in the Draft Study. These include regions addressing their problems with internal upgrades (which could be transmission or supply-or demand-side alternatives). The Draft Study, however, appears to give no consideration to the possibility of other, more cost-effective or efficient alternatives. For example, for the Southeast, the Draft Study specifically forecasts that 5,400-8,000 GW-mi of new transmission is needed but fails to consider whether there are more cost-effective or efficient or reliable alternatives.	
56	IV.b.1	"New transmission between low- and high-priced regions would allow load in high-priced markets to draw energy from a larger set of generators and lower electricity costs in high-priced regions."	ReliabilityFirst	*Please keep in mind the system conditions that initiated the congestion needs to be accounted for. In most cases this is true only to the extent that there are additional low priced resources available in the low priced market and the limitation is between the same two areas. Otherwise, the economic benefit may be a wash with prices in the two markets becoming the same, somewhere between the low and high priced resources.*	Added text to the Study, including new citation: "The extent to which high prices could be reduced depends on the magnitude of available generation made accessible by the new transmission. Goggin (2021) explored the potential for interregional transfer during recent extreme weather events, such as Winter Storm Uri. Goggin (2021) found that while transfer across regions would have been limited by lack of available generation during certain hours, substantial transfers across existing lines did help to limit price spikes in multiple regions and that additional transmission capacity would have allowed for even greater reduction to price spikes during many extreme weather events."
57	IV.b.1	"Of particular interest are locations that have large price spikes across many years, which could indicate insufficient transmission infrastructure (FERC 2017)."	ReliabilityFirst	*Or indicate where resource should be installed to ease the congestion.*	Added the text: " or insufficient local generation."
58	IV.b.1	"High-priced regions are identified in New York City and Long Island, in PJM near Washington DC, and in eastern SPP."	ReliabilityFirst	Commenter highlights "New York City and Long Island" and comments: *Under the current planning processes, and if plans remain unchanged, New York and Long Island will be receiving enough offshore wind that could potentially reverse the direction of flows in that area. Installing more transmission capability for imports may not be needed. Instead an excess may*	Added a caveat to mention offshore wind could potentially impact prices: "Note that new offshore wind development could also potentially reduce high prices found in New York City and Long Island, and in New Jersey." Though we added a new caveat calling out offshore wind, we had already included text which addresses the point made about

				exists. The New Jersey may face the same issue. Careful planning analysis is needed to ensure additions and enhancements are made reliably. Commenter also highlights "Washington DC" and comments: *Recently, State Regulators rejected a project to increase transmission capability into Washington DC area. As mentioned above these higher prices are an signal and encourage new lower priced resources to be built near the loads, in this case Washington DC.*	Washington DC.: "Other strategies (e.g., energy efficiency or new low-cost energy supply resources) could also help lower localized high prices."
59	IV.b.1	"In SPP and ERCOT, extreme weather produced a price spike in February 2021 (Levin et al. 2022)."	Electric Reliability Council of Texas, Inc. (ERCOT)	*The draft study identifies a number of benefits associated with additional connections between Texas and other regions of the country. For example, the study notes that the increased transfer capability would help address capacity shortages under emergency conditions like those that occurred during the February 2021 cold weather event. The study also identifies Texas as one of the regions with the most cost-effective transmission growth. However, the economic, reliability, and resiliency benefits identified in the study for Texas cannot be achieved by implementing only certain projects identified as providing the highest value. Rather, the benefits depend on additional proposed transfer capability being built between other regions. As the draft study notes on page 47, "the coinciden[t] scarcity of generation resources among ERCOT's immediate neighbors during [the February 2021 cold weather event] calls into question the value of increased transfer capability limits without an accompanying increase [in] multiregional transfer capability . . . ." Any analysis of improvements would therefore need to consider the costs of building all of these facilities—not just a select few facilities that the study identifies as having the highest value.*	In section IV.b.2, we changed figure IV-6 to show three different time periods rather than only two. The time periods are now: 2012-2020, 2021, and 1H-2022. The impact of this change is to slightly deemphasize 2021. This allows readers to see transmission value for periods that do not include 2021, as well as for 2021 on its own. This is important because it shows that while 2021 did include extremely high values, there were relatively high values for interregional transfers into ERCOT during other years as well (just not as extreme as due to winter storm Uri). Regarding the dependence of benefits at certain locations on the increase in multiregional transfer capability, the benefits here were calculated independently of each other, so the economic benefits are not dependent on the other connections. That said, it is important to note that generation resource limitations in neighboring regions, for example, in SPP during portions of the winter storm Uri, could limit the value of some of the connections below what was found simply through examining historical LMP price differences. We expanded discussion of this limitation (overall generation available across multiple regions) in response to comment 56.
60	IV.b.1	Figure IV-4	ISO-NE	*Price differences between nodes may not be a good indicator of congestion, especially when differences are relatively small (on the order of $0-5/MWh). Locational Marginal Prices (LMPs) often differ by a few dollars across New England due to loss factors, rather than congestion. It appears that many of the price differences in New England are fairly small, and may be related to losses rather than congestion.*	We agree. We open the discussion of the section "IV.b. Market Price Differentials" by pointing out that price differential between locations depend both on congestion and losses, but that congestion is usually much larger than losses. We have added text to the note associated with Figure IV-4 that states: "Also, note that small price differences of $0-5/MWh may be due to losses rather transmission congestion."
61	IV.b.2	General comment.	CT Energy Office	*Thank you for section IV.b.2. If we want state energy officers and RTO staff to see the value of interregional transmission we need material like this. I would actually even try to emphasize more how interregional transfers can improve reliability in the face*	Thank you for your comment. We are glad the Study is already proving useful. See resolutions to comment 58 and 62 for expanded discussion on the value of

				of weather extremes and in system recovery. With the 2003 Blackout, it was the HVDC Cross Sound cable that was used to restore Long Island.	interregional connections during extreme events.
62	IV.b.2	(map)	Electric Reliability Council of Texas, Inc. (ERCOT)	*However, the study fails to account for data that may skew the overall historical trend. The most obvious example is the use of 2021 price data for ERCOT and SPP.* *The February 2021 winter storm was a statistical outlier by any metric. Some analyses suggest this storm was a 1 in 100 or even a 1 in 130-year event for the Texas region.* *The extreme weather produced equally extreme market pricing outcomes, as energy costs in ERCOT in 2021 were six times higher than in 2020 due to the February 2021 winter storm. Such anomalous results should not be expected to reoccur with any regularity.* *The study does not consider recent market pricing changes, including a $4,000/MWh reduction in the system-wide offer cap, that would alter the value of transmission between ERCOT and other regions if a similar loss of generation were to occur today. The study also fails to consider the various regulatory reforms undertaken that would lessen the likelihood of such anomalous price events, including adoption of rules requiring weatherization of generators and critical gas infrastructure …. Furthermore, an ongoing market re-design will alter future market outcomes and therefore impact many of the conclusions found in the study.*	These are good points. As mentioned in the resolution to comment 59, we have expanded figure IV-6 to include more time periods that are independent of 2021. This helps to show how unique the values were in 2021. The new time periods also show that there were relatively high values for the interregional links into ERCOT (compared to the value of other interregional links) in the time periods other than 2021, just not as extreme as in 2021. We also have added a specific mention of other possible responses to winter storm Uri, including reducing the price cap level and requiring weatherization through regulation.
63	IV.b.2	Figure IV-6	ReliabilityFirst	*Which side of each line segment is the high price and low price? Washington DC was highlighted as being a high price area, but the lines to Washington DC are all yellow (low average value).*	In this analysis we did not look at the direction of high to low price at each link. We also did not exactly measure the transmission value into DC, we looked at transmission value to a hub in PJM that was near DC, but not exactly in DC itself. So, some of the difference that is seen between Figs IV-5 and IV-6 may be that prices in DC may be a little different than the nearby hub prices. Additionally, having high price spikes does not guarantee that transmission will be hugely valuable into a specific location, as the spikes may be limited in total number of hours. The Figure IV-5 is more of a way to screen for potential valuable locations, rather than a specific analysis of transmission value.
64	IV.b.2	"While 2021 reflects discreet, high-cost events in SPP and ERCOT, it is not clear that other regions are at lower risk from such events in the future, and therefore would benefit less from	ReliabilityFirst	Commenter highlights '2021 reflects discreet, high-cost events in SPP and ERCOT" and comments: *In February, there was a large number of limitation coupled with unit outages across the southwest that played a role in this. Wide area planning and analysis is needed to ensure additions and enhancements are made in the appropriate areas.*	We have added a sentence to point out that other changes beyond transmission could help address some of these issues, specifically regulations to require weatherization of generation resources: "The high prices found in ERCOT in 2021 may also have been reduced had certain regulatory changes already been implemented, including requirements for

		interregional investment."			weatherization for generation resources and lower peak price limits."
65	IV.b.3	"Designated extreme events produce 10% to 20% of value (and account for ~5% of total hours). This indicates that many of the most valuable hours for transmission fall outside the set of designated extreme events, and instead occur during more standard operational conditions that were not flagged in the process used to designate extreme events."	Iowa Utilities Board	*The third paragraph in section IV.b.3. states: "Designated extreme events produce 10% to 20% of value (and account for ~5% of total hours). This indicates that many of the most valuable hours for transmission fall outside the set of designated extreme events, and instead occur during more standard operational conditions that were not flagged in the process used to designate extreme events." It may be helpful to expand the analysis to determine what historical events are more impactful to transmission congestion compared to extreme weather events.*	Great point. We are actively study this topic right now, we'll be able to publish something on this in 2023.
66	IV.b.3	"Overall, this analysis highlights the importance of properly representing challenging grid conditions, including explicitly representing extreme weather events, fuel-price volatility, generation and load uncertainty, and geographic market resolution, when estimating or modeling the congestion value of transmission. Additional discussion and details can be found in Millstein et al. (2022a)."	ReliabilityFirst	*This analysis seems to indicate that basing large-scale transmission infrastructure on historical market pricing values does not produce a correlation to reliability associated with extreme events. In short, transmission infrastructure targeted to reduce market congestion may not mitigate risks associated with wide-area reliability events.*	It is certainly likely that reliability value and market congestion value are spatially correlated, but they are unlikely to be exactly correlated, thus we are suggesting the importance of accounting for challenging grid conditions when calculating congestion value, and not only when calculating reliability value.
67	IV.c	"The parallel nature of the Qualified Paths creates simultaneous interactions between the eastern and western portions of the Western Interconnection that can create significant reliability risks."	WECC	*We agree that this could create reliability risks, however, the severity of the risk will depend on the system conditions. We suggest removing the word "significant.*	Removed "significant" from sentence.
68	IV.c	"Historically, the West has leveraged specific phase shifting transformers, also referred to as Qualified Controllable Devices, to redirect flows to manage congestion."	WECC	*We recommend using the phrase "unscheduled flow" rather than "congestion"*	Replaced "congestion" with "unscheduled flow."

69	IV.c	"The Bas cannot automatically adjust generation in response to system congestion, which is a base functionality of the Security Constrained Economic Dispatch employed by all RTOs."	WECC	Redline edit suggestion to capitalize "Bas." Also notes: *The statement…may benefit from greater clarification because BAs certainly do adjust generation in non-RTO regions.*	Capitalized "BAs". Modified referenced sentence and following sentence to read: "The RTOs use a system known as Security Constrained Economic Dispatch to automatically adjust generation outputs in response to real-time system congestion, a base functionality not used by the BAs. The manual processes used in the non-RTO West to adjust generation were reasonably effective when net load (demand less variable generation) was straightforward to forecast."
70	IV.d	"As shown later in this report, studies have repeatedly shown that given the Nation's changing resource mix, a least-cost power grid requires enhanced transmission links within and among regions."	ReliabilityFirst	Commenter highlights "studies" and comments: *Suggest adding a citation to where this is referenced later in the report.*	Added hyperlink to section (VI) within sentence: "As shown later in this report (§VI), studies have repeatedly shown…"
71	IV.d	"High withdrawal rates are also evident: 72 percent of projects that sought interconnection between 2000 and 2016 subsequently withdrew their requests."	ReliabilityFirst	Commenter highlights "requests" and comments: *Recommend adding why these withdrawals happen. In many cases developers load the queues and then select where they can profit the most, leaving the planners with re-study and analysis as the queue constantly is changing.*	New paragraph added to clarify this point: "There are numerous drivers of these trends. While lack of access to transmission is a major barrier, there are many potential reasons that proposed power plants do not always move rapidly to the construction phase. Some projects in the queues are more exploratory in nature, in part driven by uncertainty in the scope and cost of necessary transmission upgrades and the extended timelines associated with the current interconnection process—often leading to withdrawals and successive restudies. Other challenges include securing land, permits, community support, power purchasers and financing, as well as unanticipated changes to project economics and available policy incentives." The opening sentences of the following paragraph were modified to: "As such, these trends partly reflect strong growth in interconnection requests and a diversity of underlying project-level and queue management issues. Yet there is also recognition that trends in interconnection queues are impacted by limited existing transmission infrastructure and transmission upgrade costs that, in many cases, the interconnecting generator must bear (DOE 2022a)."
72	IV.d	"Importantly, evidence is also mounting that some of these network upgrades provide system-wide benefits (ICF 2021)."	ReliabilityFirst	*It should be noted that various wholesale markets handle this cost allocation process differently, which includes cost sharing or reimbursement from all connected generators that have an impact to the need of the new infrastructure, thus allowing all connections benefiting from the reinforcement to share in the cost.*	Sentence modified to: "The specifics of cost allocation for these network upgrades vary regionally, but evidence is mounting that some of these network upgrades paid by interconnecting generators provide system-wide benefits (ICF 2021)."

				Also, the inverse of this statement is true as well. As conventional generation retires, transmission owners will likely be responsible for system reinforcements that provide additional wide-area benefits beyond their intended design. Using Figure IV-3 in this report, Reliability-based investment has on average been greater than 50% of total investment since 2015. Has this investment in turn reduced potential High Capacity and Economic costs?	
73	IV.d	"Recognition is growing that improved transmission planning and additional investment in the bulk-power transmission network will be needed to optimize the overall power grid and would be an effective means to address the increasingly long interconnect queue times."	ReliabilityFirst	*Keep in mind much of this analysis was with the low cost fossil fire units in place. Once they are retired the scenarios examined may look very different. As a result, this is only true if one of the following remains constant: 1) end-use customer demand within the market area; or 2) total resources within the market area (as referenced in III.d.1 RTO/ISO Congestion Management Practices). This analysis did not evaluate impacts of increased electrification on these high-priced regions or potential generation retirements and the continued effectiveness of large-scale system reinforcements.* *Recommend changing this sentence from "recognition is growing" to, "FERC has recognized". Additionally, the RTOs do studies and analysis across the seams to ensure economic and reliability enhancements are made. Consider adding that as well.*	Sentence revised to begin with: "FERC notes that improved…" and was FERC report was re-cited.
74	IV.e	"Regions of high prices exist in Southeast MO, Southern OK, Northwest WI, Eastern and UP MI, Eastern MD/VA, Delmarva Peninsula MD and DE, Long Island NY, Southern Coast CA, and Northern coast CA. "	ReliabilityFirst	Commenter highlights "Delmarva" and comments: *If more infrastructure is being considered, allowing the RTOs to perform their analysis should aid in the correct placement of these Facilities.*	We agree planners and utilities have the best insight into their systems. The following was added to Section 1: "The National Transmission Needs Study is not meant to displace the transmission reliability or planning responsibilities of the Reliability Coordinators and Planning Authorities, but rather help to inform and drive effective regional and interregional planning to properly assess the value of transmission and the ability of a robust transmission plan to lower overall delivered energy prices to consumers. The National Transmission Needs Study will evolve with time and must incorporate the findings of industry and other government initiatives to determine a consensus long-range national plan for the bulk electric power system. It's critically important that utilities have a primary role in transmission expansion planning since they own and operate the facilities which integrate and deliver capacity and energy to address consumer needs. Transmission owners/operators understand the remaining life in aging assets and local needs that are unique to their system's footprint."

75	IV.e	"The highest value is found by connecting ERCOT to the Southwest region of the Western Interconnection, followed by connecting ERCOT with the Eastern Interconnection."	ReliabilityFirst	*Depending on where the interconnection is made additional infrastructure may be needed along with system upgrades beyond the interconnection point to accommodate the transfers of energy. A cost benefit analysis would need to be done to assess the best economic alternative. In addition, the 2021 event also included issues where existing resources and resource supply lines were not prepared for extreme cold weather. Suggest adding that here.*	The following was added to the reference paragraph in section IV.e: "Identifying the best nodal locations to make these connections requires additional engineering analysis which considers downstream system upgrades to support increased energy transfers." Regarding weatherization of supply, see resolution to comments 62 and 64.
76	IV.e	"Wind and solar generation require building of new transmission to bring these low-cost resources to load."	ReliabilityFirst	*This study references analysis that indicates wind is directly tied to increased transmission costs while solar is directly tired to increased battery storage costs. Suggest the removal of solar from this statement and citation of this analysis within this report.* *Also, if any new generation connecting to the system takes advantage of locations associated with recent generation retirements, there is a likelihood that interconnection costs could be reduced.*	Modified sentence to: "Generation resources with strong technical and economic potential located far from the existing transmission system—notably wind energy—require building new transmission to bring these low-cost resources to load." Added citation to: Brooks A. 2022. Renewable Energy Resource Assessment Information for the United States. Washington, DC: DOE, Office of Energy Efficiency and Renewable Energy.
77	IV.e	"This congestion results in reliability concerns for the entire western system, particularly as the generation fleet is replaced due to age, climatic changes, and advancing technologies."	Iowa Utilities Board	*In the fourth paragraph of section IV.e., the IUB suggests changing "climatic changes" to "climate change goals" for clarity in the sentence, "This congestion results in reliability concerns for the entire western system, particularly as the generation fleet is replaced due to age, climatic changes, and advancing technologies."*	Clarified "climatic changes" by modifying the sentence: "This congestion results in reliability concerns for the entire western system, particularly as the generation fleet is replaced due to age, climatic changes (e.g., severe drought conditions), and advancing technologies."
78	V	General comment. Table V-1 and section V.d4	Minnesota Department of Commerce and the Minnesota Public Utilities Commission	*…we suggest adding the MISO LRTP study to your evaluation of transmission needs. The results may provide important insights. The 2022 MISO LRTP study did include a resource expansion component, but may best fit in Chapter V, specifically Table V-1 and Section V.d4. The final MISO LRTP report is available at this link: MISO Long Range Transmission Planning Tranche 1*	MISO LRTP study has been incorporated throughout Chapter V.
79	V	General comment.	CT Energy Office	*Section V is a good list of the literature reviewed and I am familiar with a lot of them. I add this link to an article which itself has links to two other MIT articles that have been influential to staff here in New England and put forward a concept we are actively reviewing.* *https://news.mit.edu/2022/new-england-renewables-canadian-hydropower-0408*	A summary of and reference to "Two-Way Trade in Green Electrons: Deep Decarbonization of the Northeastern U.S. and the Role of Canadian Hydropower" has been added to Chapter V.
80	V	[Table V-1 rows 1-3]	NESCOE Gov Offices	*Recently, five of the New England states issued a joint Request for Information (RFI), "seeking comment on an initiative to integrate offshore wind and other resources in a cost-effective, reliable and efficient*	Thank you for this information. GDO hopes the RFI is successful, and we look forward to continued collaboration.

				manner—including opportunities to leverage federal funding for New England transmission investments under the federal Infrastructure Investment and Jobs Act (IIJA) and Inflation Reduction Act (IRA)." Along with the RFI, the states included a conceptual framework for a modular offshore wind integration plan, focused on identifying efficient, least-cost offshore transmission infrastructure solutions. This effort complements the Department's ongoing Atlantic Offshore Wind Transmission Study. Continued dialogue around and alignment of Department and regional work can help promote the timely and efficient consideration of further federal and regional efforts to advance both landside and offshore transmission solutions.	
81	V	[Table V-1 rows 1-3]	NESCOE Gov Offices	*We note that the New England specific studies considered in the draft NTS focus primarily on offshore wind development, including a 2019 Offshore Wind Integration Economic Study that NESCOE requested. Since that offshore study was completed, further work has been done that may provide insight into transmission needs related to offshore wind, particularly in southeastern Massachusetts and Rhode Island (SEMA/RI). In July 2021, ISO-NE completed the* ***First Cape Cod Resource Integration Study****, which identified the transmission upgrades necessary to enable the interconnection of 1,200 megawatts (MW) of offshore wind resources. The* ***Second Cape Cod Resource Integration Study*** *is currently underway, which is intended to build on the First Integration Study and identify transmission upgrades necessary to interconnect the remaining offshore wind resources. Together, these studies put a finer point on the potential transmission needs to interconnect offshore wind in Cape Cod and allow that generation to flow out of SEMA/RI. We recommend the Department consider including these recent studies in the NTS to enhance the analysis of transmission needs associated with offshore wind integration in New England.*	ISO-NE's First Cape Cod Resource Integration Study has been incorporated throughout Chapter V. The second has not been completed so it has not been incorporated.
82	V	n/a	Oregon DOE	*Sec. V – Existing Studies – If GDO is interested in additional reference material for the current Needs Study and/or future studies, Evolved Energy Research has performed several studies examining market and policy optimized build-outs of generation, storage, and transmission for different states and regions of the country, including the West and PNW. Particularly relevant to the West are the following studies, several of which highlight the market value that offshore wind can provide the West under current economy-wide*	Added reference to Oregon Clean Energy Pathways (2021) to Chapter V.

				decarbonization and clean electricity policies of western states (i.e., in the absence of a new policy specifically requiring the development of OSW): West-wide Power of Place (2022) – OSW Note: shows offshore wind as a cost-effective regional resource to supply significant clean power exports to Western states outside of Oregon beginning as early as the 2026-2030 timeframe under a high electrification scenario, growing to around 15 GW by 2050.West-wide Power of Place (2022) – OSW Note: shows offshore wind as a cost-effective regional resource to supply significant clean power exports to Western states outside of Oregon beginning as early as the 2026-2030 timeframe under a high electrification scenario, growing to around 15 GW by 2050. Oregon Clean Energy Pathways (2021) – OSW Note: shows offshore wind as a cost-effective regional resource beginning in 2035, growing to 20 GW by 2050.Oregon Clean Energy Pathways (2021) – OSW Note: shows offshore wind as a cost-effective regional resource beginning in 2035, growing to 20 GW by 2050. Washington State Energy Strategy Decarbonization Modeling (2020) - OSW Note: shows offshore wind off the west coast as early as 2025, growing to around 20 GW by 2050.Washington State Energy Strategy Decarbonization Modeling (2020) - OSW Note: shows offshore wind off the west coast as early as 2025, growing to around 20 GW by 2050. PNW Deep Decarbonization (2019)PNW Deep Decarbonization (2019)	
83	V.a	[discussing HVDC]	SERTP	*The Draft Study forecasts the need for a massive build-out of virtually all interface ties but does not give consideration to the corresponding vast amounts of local upgrades that would need to be made to accommodate expanding such ties by the projected gigawatts of capacity. To illustrate, and using HVDC lines as an example of expanded interregional capacity, such lines typically carry between 500 MW and 2000 MW of power. When transferring power across the HVDC line, the source end of the HVDC line would draw in up to 2000 MW of generation out of the system, acting like a 2000 MW load. The delivery end of the HVDC line would push 2000 MW of power into the receiving system, similar to adding 2000 MW of power, much like a large generation site. The existing transmission system is currently not designed to handle either the 2000 MW of generation being moved out of the system or the dumping of 2000 MW of generation into the system at the other end of the HVDC line. The existing*	Several references to the need for system upgrades to accommodate increased energy transfers have been added. See resolutions to comments 3 and 75.

				infrastructure would require major, costly expansion (in addition to the HVDC line itself) of the AC transmission system to accommodate this type of large transfer. Transmission planners would have to study the impacts of each one of these proposed HVDC lines and rebuild the existing transmission system to accommodate the Draft Study's forecasts.	
84	V.a	"Breakthrough Energy Sciences (2021) further concludes that high-voltage direct current (HVDC) connections that span interconnection seams enable generation from renewables to be shared more readily between interconnections, which makes renewable generation less variable and more reliable."	ReliabilityFirst	Commenter highlights "renewable generation less variable and more reliable" and comments: *We would advise caution here. Having access to a larger amount of variable resources does not always equate to better reliability. In fact more dependence on a variable resource under a contingency scenario could be more impactful and cause larger issues. This will need detailed study and analysis.*	Modified sentence to remove "…which makes renewable generation less variable and more reliable."
85	V.a	"82 percent of ERCOT's black start resources experienced an outage, derate, or failure to start."	ERCOT	*The draft DOE study states that 82 percent of ERCOT's black start resources experienced an outage, derate, or failure to start." This statement is misleading in that it implies ERCOT's Blackstart Plan was compromised. In fact, 10 of the 13 black start sites were available 100% of the hours during Uri. Most black start sites include primary and secondary blackstart units. Singular outages of either the primary or secondary unit at a Blackstart site would not have affected Blackstart Plan performance. The chart below shows the overall availability for these blackstart sites during the event. ERCOT designs its black start plan to be effective with expectation that not all sites may be available during an emergency.*	Removed this sentence, but left FERC et al. (2021) recommendation that increased interregional transfer capability could improve black start capabilities in the region. Added an additional footnote: "Black start capabilities can be improved locally without the need for additional interregional transmission. FERC et al. (2021) additionally recommend a joint study on the winter preparedness of ERCOT's existing black start capabilities."
86	V.a	n/a	WECC	*…there is a discussion about extreme events and heat impacting the NW and California regions. However, it is not clear as to how it impacts the rest of the Western Interconnection as described in the Executive Summary*	Both NERC (2021) and NERC (2022a) discuss the impacts of extreme weather, heat, and wildfire risk in all Western regions. These are discussed in section V.a and V.b.
87	V.b	"FERC et al. (2021) comment that had ERCOT been capable of increasing its imports, the amount that MISO and SPP could have imported likely would have decreased without increased import capability with their adjacent neighbors."	Iowa Utilities Board	*Could be restated for clarity.*	See resolution to comment 94

88	V.b	"Although historical high- impact weather events do not lead to new operational or resource adequacy concerns for an electricity system with high variable energy penetration, milder versions of these weather events of increasing frequency can result in prolonged periods of low variable energy availability."	Midwest Reliability Organization	*There have been past challenges with variable resources during severe cold weather events where wind resources shut down because of cold temperature cutouts. Example was the 2019 Polar Vortex in the upper Midwest where a large amount of wind was unavailable because of extreme cold weather.*	Sentence modified: "Although the historical high-impact weather events considered in this report did not lead to new operational or resource adequacy concerns for an electricity system with high variable energy penetration, the report does note that milder versions of these weather events of increasing frequency can result in prolonged periods of low variable energy availability."
89	V.b	"Although historical high- impact weather events do not lead to new operational or resource adequacy concerns for an electricity system with high variable energy penetration, milder versions of these weather events of increasing frequency can result in prolonged periods of low variable energy availability."	Midwest Reliability Organization	*Is there an example of what the milder versions of weather events with increased frequency are? It isn't obvious what type of weather events lead to prolonged periods of low variable energy availability.*	Added a few sentences: "For example, wind generation tends to decrease during periods of prolonged cold weather after cold front moves through an area. These periods can pose challenges to resource adequacy as solar output is typically already lower during the winter months. Similarly, moderate heat waves accompanied by persistent high pressure can depress wind generation during evening net load peak."
90	V.b	"Expanding transmission to integrate geographically diverse, variable energy resources can reduce these risks, lower capacity reserve margins, and reduce system costs."	Midwest Reliability Organization	*The more variable resources are added to the system, the lesser the accredited capacity will be from those resources. This theoretically would increase reserve margins assuming no other system changes. Further, transmission expansion in itself does not lower capacity reserve margin. There needs to be assurance of a generation resource delivered over the expanded transmission to an area deficient of gen capacity to effectively lower the reserve margin.*	See resolution to comment 28
91	V.b	NERC (2021) find that generation retirements over the next few years in MISO will result in capacity shortfalls as early as 2024 without additional generation or import transfer capacity additions.	Midwest Reliability Organization	*NERC's 2022 Long-term Reliability Assessment, being released mid-December, indicates this happening in 2023. Should this be updated for NERC's updated assessment? Not sure if this report will be released before NERC's LTRA.*	See resolution to comment 20
92	V.b	"FERC et al. (2021) recommend that adjacent Reliability Coordinators, BAs, and Transmission Operators perform bidirectional power transfer studies to determine constraints that could occur when importing or exporting	ReliabilityFirst	*If this moves forward a criteria will be needed to assess the adequate transfer capability values. Also keep in mind as was mentioned earlier, this could introduce a new risk whereby regions or areas become dependent on each other. The Heat Dome out west pointed out how big of risk that was and load needed to be shed.*	See resolution to comments 28 and 74.

		power between neighboring regions during an emergency that spans multiple Reliability Coordinator/BA areas."			
93	V.b	"This dependence on import capacity will require coordinated resource adequacy and transmission planning."	ReliabilityFirst	*Some RTOS already are doing this and coordinate this. It is call Load Deliverability. One RTO uses a 1 event in 25-year criteria for their analysis.*	See resolution to comments 11, 28 and 74.
94	V.b	"As FERC et al. (2021) note, MISO and SPP also reached transmission limits on imports during the February 2021 severe cold weather event, though neither region was as severely affected as ERCOT. FERC et al. (2021) further add that during certain other emergency conditions, MISO curtailed SPP's imports to avoid violating reliability limits."	Minnesota Department of Commerce and the Minnesota Public Utilities Commission	*While it is true that MISO did curtail SPP imports during the February 2021 winter event, we are concerned that this statement on its own may be misleading. That section of the FERC report also largely describes how MISO's and SPP's ability to transfer nearly 13,000 MW of power through their numerous ties with adjacent regions in the Eastern Interconnection helped to alleviate portions of their generation shortfalls with imports from areas that were not experiencing the extreme cold weather that week. We suggest adding this context to the final DOE Needs Study.* Commenters also note this applies to the following sentence in the ES: *"The MISO region was unable to import additional capacity during the February 2021 cold weather event, negatively impacting resource adequacy."*	This passage has been replaced with the following (modified of what was previously written): "As discussed previously, FERC et al. (2021) note that ERCOT's limited interconnections with its neighbors significantly affected its ability to make up for the capacity shortage experienced during the severe cold weather event of February 2021. MISO and SPP also reached transmission limits on imports during the February 2021 severe cold weather event, though neither region was as severely affected as ERCOT (FERC et al. 2021). MISO and SPP were less impacted given the strength of their connections with adjacent neighbors who were unaffected by the storm. Improving transfer capability ties with neighboring regions will increase ERCOT's ability to import power to address capacity shortages when its system is stressed under emergency conditions. "However, FERC et al. (2021) also comment that MISO and SPP would have been limited in their ability to increase imports to ERCOT during this event—had additional transfer capacity ties been available—without increased import capability with *their* adjacent neighbors in the Eastern Interconnection. The coincidence scarcity of generation resources among ERCOT's immediate neighbors during this event calls into question the value of increased transfer capability limits without an accompanying increase in multiregional transfer capability, thereby making the power grid larger than the weather systems that impact it."
95	V.b	"NERC (2021) find that generation retirements over the next few years in MISO will result in capacity shortfalls as early as 2024 without additional generation or import transfer capacity additions. By 2026 MISO's reserve margin capacity shortfalls will be an estimated 3 GW (NERC 2021). NERC	Minnesota Department of Commerce and the Minnesota Public Utilities Commission	*We suggest adding some additional context to this statement from the NERC report because NERC also indicates that a projected five year out capacity shortfall, although a concern, is not necessarily unexpected. Page 14 of the 2021 NERC Report also states the following:* *"A capacity shortfall of over 560 MW in 2024 would result if all of these unconfirmed retirements were to occur without additional new generation resources (on top of the 8 GW already in development for*	Few sentences added for more context: "MISO planners have similarly predicted capacity shortfalls in previous iterations of the Organization of MISO States (OMS) - MISO survey (NERC 2021). While the shortfalls ultimately have not yet occurred, the continued identification of capacity shortfalls as a concern for the MISO region emphasizes the persistent need for resource adequacy measures such as new transmission."

		stresses that resource adequacy and energy sufficiency measures need to be urgently implemented in the area."		*interconnection by 2024). MISO planners note that previous iterations of the Organization of MISO States (OMS)-MISO survey have also indicated future year shortfalls, and the survey results provide a mechanism for correction. The assessments provide a range of possible resource adequacy outcomes at a specific snapshot in time. Through coordination between MISO, member state utility commissions, and stakeholders*, past shortfall predictions have not come to pass."	
96	V.c	"Increasing the diversity of resources improves the electric system's ability to produce affordable, reliable energy while increasing the operational flexibility and reliability of the grid."	Midwest Reliability Organization	*Is this statement referring to the locational diversity of clean energy resources? Or is it referring to having a diverse set of resources from different fuel sources (wind, solar, natural gas, nuclear, coal, etc.)? As written, it could be read both ways so clarifying which is being referred to here would be beneficial.*	Sentence modified: 'Increasing the diversity of both resource fuel-type and resource geographic location improves the electric system's ability to produce…"
97	V.c-V.d	n/a	SERTP	*While the Draft Study emphasizes the value of additional transmission, since the scope of the Draft Study does not include specific cost ramifications, the Draft Study's assumed benefits are almost certainly overstated. For example, the Draft Study performs scenario analyses of several levels of renewable penetration to conclude that vast amounts of additional transmission capacity (i.e., gigawatts) are needed both internally and between transmission planning regions. The Draft Study does not, however, appear to weigh the costs associated with the specific benefits asserted, thereby calling into question whether net benefits would be provided or whether there may be more economic alternatives. The apparent narrow focus of the analysis calls into question the probative value of the projected transmission needs.*	See resolution to comments 3, 11 and 106.
98	V.c	"Clack et al. (2020b) find modeling scenarios with strong carbon reduction policies result in approximately 140,000 GW-mi of new interstate transmission, whereas scenarios with weak carbon reduction policies for cases with high solar and high wind deployment result in approximately 100,000 GW-mi and 70,000 GW-mi of new transmission, respectively."	ReliabilityFirst	*This is difficult to conceptualize. How many MW of retired generation is being considered by the different scenarios? How do you translate that into GW-mi of transmission build.*	Footnote was added to the first reference of "GW-mi" in the Executive Summary and Section V (when discussing results from Ardani et al. 2021) to clarify: "Gigawatt-mile (GW-mi) is not a commonly used unit in the industry, but is the unit used by capacity expansion modeling results. For comparison, a 100-mile 345kV rated transmission line has an estimated carrying capacity of 860 MW, equivalent to 86 GW-mi (NRRI 1987). And a 200-mi 500kV line has a carrying capacity of 1,320 MW, equivalent to 264 GW-mi (NRRI 1987). See Table VI 2 for a comparison of carrying capacities and nominal voltage ratings for different length transmission lines." Additionally, see resolution to comment 3
99	V.c	"NERC (2021) highlights that	ReliabilityFirst	*This statement indicates that building transmission does not address all the*	See resolution to comment 6.

		increased use of electrical inverters—which are required to connect many renewable energy resources to the grid—can lead to reliability concerns unless precautions are taken."		*reliability problems associated with renewables (i.e., Inverters), and we agree. If other problems such as low inertia, low fault currents, predictable performance during disturbances are not addressed, then no amount of transmission expansion is going to do any good.*	Added following sentence in paragraph: "System reliability concerns may arise from low inertia, unstable voltage, low fault currents, and unpredictable behavior of inverter-based resources during grid disturbances without appropriate precautions."
100	V.c	"These common upgrades, approximately 56 terawatt-miles (TW-mi), make up at least half of upgrades for each design."	WECC	*We recommend including an explanation on what "TW-mi" measures and why it was chosen.*	See resolution to comment 98
101	V.c	"In MISO and SPP's JTIQ Study (2022), RTOs recommend a seven-project transmission portfolio that relieves constraints in both markets, enables the interconnection of large amounts of renewable generation near the seam, and provides other significant benefits."	Minnesota Department of Commerce and the Minnesota Public Utilities Commission	*The number of projects included in the MISO JTIQ portfolio has now been reduced from seven to five, since two of the projects were moved into the MISO LRTP portfolio.*	Revised from "seven" to "five"
102	V.c.1	"In the unconstrained case, wherein the New England transmission system is modeled as a single-bus system in which transmission has essentially unlimited capacity, spillage is slightly lower across OSW penetration levels compared with the constrained case, which suggests a significant need for transmission expansion."	ISO-NE	*The section on offshore wind overstates the benefits of transmission, both onshore and offshore. The statement that "spillage is slightly lower across OSW penetration levels" (emphasis added) in an unconstrained case does not support "… a significant need for transmission expansion" (emphasis added) later in the same sentence.*	Revised sentence to end after "compared with the constrained case."
103		"Pfeifenberger et al. (2020a) indicate that only half of Maine's target OSW goal of 2,000 MW has been met primarily because of transmission constraints, which emphasizes the possible need for new infrastructure."	ISO-NE	*Additionally, Maine's 2,000 MW target mentioned in this section is related to onshore wind, not offshore wind, and thus is not relevant to this section.*	Revised to remove reference to Maine. Passage now begins: "Pfeifenberger et al. (2020a) indicate that New England has already contracted for 3,112 MW of OSW. The next 3,600 MW of OSW could still be developed under the status quo with each developer constructing a generator-led line to an onshore point of interconnection. However, this existing approach is likely to lead to substantial onshore system upgrade needs far sooner than assumed."
104	V.c.1	"Pfeifenberger et al. (2020a) indicate that only half of Maine's target OSW goal of 2,000 MW has been	CT Energy Office	*I think that is an error. I am sure that Maine has not acquired any OSW to date. I checked with my Maine contact, and he said:*	See resolution to comment 103

		met primarily because of transmission constraints, which emphasizes the possible need for new infrastructure.”		*“We have about 1,000 MW of onshore wind installed in Maine, and substantial amounts in the interconnection queue/potentially under contract. The 2009 Wind Energy Act established goals of 2,000 MW by 2015, 3,000 MW including 300 MW offshore by 2020, and 8,000 MW including 5,000 MW offshore by 2030. It sounds like the DOE report is conflating the generic 2015 goal with an OSW goal, but in any case, the numbers speak for themselves. There were not procurement mechanisms associated with these goals when they were established.”*	
105	V.d	Figure V-3	Iowa Utilities Board	*Figure V-3 shows relatively high congestion costs for NYISO and CAISO. However, later in the report, Table VI-2 shows that New York and California have relatively minimal estimated transmission buildout in the futures analysis. An explanation for this discrepancy may be appropriate.*	Capacity expansion models do not account for congestion occurring on the grid today. More explanation about capacity expansion models has been added to Section VI. See resolution to comment 133.
106	V.d.1	General comment	ISO-NE	*This section contains a statement that congestion creates a need for transmission expansion. However, there is no comparison of the cost of congestion with the cost of new transmission infrastructure. If the cost of new transmission significantly exceeds the cost saved through congestion reduction, it is not economically efficient to build new transmission. This is often the case in New England, where transmission costs are relatively high and congestion is lower than in other parts of the U.S.*	The following sentence was added to Section V.d: “If a transmission facility is being considered for the sole purposes of alleviating congestion, the cost of the project would need to be less than the congestion costs which are alleviated for the project to be financially viable.”
107	V.d.1	“Further, the Surowiec South interface in southern Maine has a transfer limit of 1,500 MW, which results in heavy constraints (ISO-NE 2020). This constraint causes price separation, with prices in Boston, New Hampshire, and SEMA higher than in Maine and the Bangor Hydro region (ISO-NE 2020).”	ISO-NE	*The last paragraph of this section mischaracterizes the findings of the ISO-NE 2019 Economic Study. The analysis by ISO-NE referenced here was part of an economic study looking at a specific set of possible future system conditions, not existing congestion. Additionally, the ISO-NE study states the following in footnote 33: “This study assumed a Surowiec South interface transfer limit of 1,500 MW. However, the Surowiec South interface transfer limit is expected to increase to 2,500 MW once NECEC and its associated transmission upgrades are in service.”1 Pointing to this interface as a source of congestion, without acknowledging the upcoming increases in interface capability, is misleading.*	Thank you for the clarification. This passage was removed.
108	V.d.2	Figure V-4	ReliabilityFirst	*The map on page 51 does not depict this type of difference in LMP (the lines on that map are yellow)* *Authors, please see – Pg 28, Fig IV-6*	We believe the data shown in Figs IV-4, IV-5, IV-6 and V-4 are consistent. In Fig. IV-6 the price differences between upstate New York and Manhattan are $14/MWh using 2012-2020 data, which is very similar to the ~$20/MWh price difference shown in Fig V-4 for 2020 data. The color legends between the two figures are not consistent as these are from different reports.

109	V.d.3	General comment.	PJM	*The congestion data portrayed in the report is accurate. However, it should be noted that TLRs are not very relevant for PJM. Moreover, the TLR level is minimal compared to other RTOs because of our market-to-market coordination with the Midwest ISO.*	The following sentence was added to this passage: "As described in Section III.d, TLRs only partially describe the congestion in RTOs where real-time transmission congestion is predominantly managed in the wholesale electricity markets."
110	V.d.3	"Key constraints with regionwide impact included the Three Mile Island Transformer, Nottingham Series Reactor, Cumberland–Juniata Line, Conastone Transformer, and Brighton Circuit Breaker."	ReliabilityFirst	*Considered adding language around why these areas were impacted.*	Sentence was removed and instead readers are directed to the figure to see the top facility constraints. Additionally, see resolution to comment 10.
111	V.d.4	"All wind resources are currently in MISO Midwest, so flows are north to south when wind is high and in the reverse direction when wind is low."	ReliabilityFirst	Commenter highlights "All wind resource are currently in MICO Midwest" and comments: *Consider rewording to state "All wind resources within MISO are in the MISO Midwest area…."*	Modified sentence: "All wind resources within MISO are currently located in the MISO Midwest area, so flows are north to south when wind is high and in the reverse direction when wind is low."
112	V.d.4	"All wind resources are currently in MISO Midwest, so flows are north to south when wind is high and in the reverse direction when wind is low."	ReliabilityFirst	Commenter highlights "north to south" and comments: *It would be helpful to indicate where this flow shift is being measured.*	Unfortunately, the cited report does not provide this information.
113	V.d.4	First Paragraph	Iowa Utilities Board	*The first paragraph in section V.d.4 states that increased wind output, among other things, serves to highlight the importance of increased resilience. It could be noted that this might also highlight the need for a more diverse generation portfolio at a local or regional level.*	Sentence added at the end of first paragraph: "Similarly, these findings highlight the need for increased access to a more diverse generation portfolio, which can be achieved through additional interregional transmission interconnections."
114	V.f	n/a	Midwest Reliability Organization	*The majority of transmission investments occur within the planning authorities/RTOs footprint. Additional transmission capability is needed at the seams of RTOs to improve resilience.*	The following was added to section V.f: "Interregional transmission investments will help improve system resilience by enabling access to diverse generation resources across different climatic zones." This point is further supported by the addition of findings from Goggin 2021 in this same section.
115	V.f	"Novacheck et al. (2021) demonstrate how transmission is needed for resilience during certain weather events"	ReliabilityFirst	*There are many places weather is pointed out as being an issue for Transmission. Perhaps including more non-wire alternatives throughout would be helpful.*	While several of the studies referenced in this section were conduction considering wired transmission, the Department's use of "transmission" is technology-agnostic, where practical. See resolution to comment 120.
116	V.f	"The authors explain that risks posed by regional icing and cold temperature shutdowns, although rare, can be mitigated by local gas generation	Midwest Reliability Organization	*Should this be "and" or "or"? Either could be deployed independently to address resilience for icing or cold weather events. They could be deployed in combination as well but stating "and" here almost makes it seem like both are required to address resiliency, which isn't the case.*	Revised to "...local gas generation dispatch and interregional transmission, either individually or in concert."

		dispatch and interregional transmission."			
117	V.f	"Following disruptive events, high-voltage transmission lines help with restoration and recovery by serving power to black start units."	ReliabilityFirst	*High transmission lines typically deliver power from resources and Black Start Unit, not to them. Once there is enough generation up and running to handle the charging currents of the high voltage lines the islands that are formed are tied together with the high voltage lines. Consider rewording this.*	Sentence modified: "Following disruptive events, high-voltage transmission lines help with restoration and recovery by serving power from black start units once enough generation is operational."
118	V.f	The Southeast region is impacted by tornados and severe thunderstorms that can damage the transmission system. More than 270,000 customers suffered power outages in the Southeast due to the December 10, 2021 tornados in Kentucky and Tennessee (NERC 2022a).	SERTP	The Draft Study references the need for increased resilience due to hurricanes and tornados as a basis for the need for additional transmission in the Southeast. However, outages caused by these types of events are normally caused by damage to the distribution system, not the transmission system. Accordingly, the Draft Study statement that 270,000 customers in KY and TN suffered outages due to tornados and severe thunderstorms does not support DOE's conclusions about transmission need in the Southeast because those customer outages, for the most part, were not attributable to transmission outages. While December 2021 had the most severe tornado on record for that area, the loss of power was mostly due to buildings (that use power) being destroyed and distribution level outages. Defining National Corridors/NEITCs and/or significant transmission expansions would not have prevented the customer outages cited in the Draft Study.	Deleted two referenced sentences. The accompanying summary in the executive summary was also removed.
119	V.f	"In MISO's 2020 State of the Market Report, Potomac Economics (2021b) reports that transmission issues arose due to generation and transmission outages and the impact of Hurricane Laura in MISO South. NERC (2022a) comments on the widespread outages in the Delta, Southeast, Texas, and Florida regions due to recent hurricanes, most notably Hurricane Ida in 2021. Laura damaged the Entergy transmission system and isolated load in southwestern Louisiana and the eastern parts of Texas that are in MISO South, forcing more than 6 GW of	ReliabilityFirst	*Recommend splitting this into two paragraphs, one for Hurricane Laura's impacts and one for Hurricane Ida's impacts (easy to get them mixed up because they are both described together)*	Revised to the following: "In MISO's 2020 State of the Market Report, Potomac Economics (2021b) reports that transmission issues arose due to generation and transmission outages and the impact of Hurricane Laura in MISO South. Laura damaged the Entergy transmission system and isolated load in southwestern Louisiana and the eastern parts of Texas that are in MISO South, forcing more than 6 GW of generation out of service. More than 500 MW of firm load was curtailed as a result (Potomac Economics 2021b). "NERC (2022a) comments on the widespread outages in the Delta, Southeast, Texas, and Florida regions due to recent hurricanes, most notably Hurricane Ida in 2021. Over 1.2 million customers lost power and over 210 transmission lines were out of service due to Ida (NERC 2022a). The impacts of Hurricanes Laura and Ida emphasizes the importance of improving resilience and hardening transmission infrastructure."

		generation out of service. More than 500 MW of firm load was curtailed as a result (Potomac Economics 2021b). Over 1.2 million customers lost power and over 210 transmission lines were out of service due to Ida (NERC 2022a). The impacts of Hurricanes Laura and Ida emphasizes the importance of improving resilience and hardening transmission infrastructure. "			
120	V.h	General comment.	ReliabilityFirst	*Some suggestions to add to this section as examples of non-wires alternatives: Transmission Connected Solar generation near the load center, and conventional generation with carbon capture located near the load centers also are non-wire alternatives. Smart Loads that refuse to run when transmission is constrained might be another non-wires solution.*	Added the following to the introduction of section V.h. to clarify: "Strategic planning to site storage and generation close to load centers could help mitigate need for traditional transmission wires. For example, distributed energy resources—and even conventional generation with carbon capture, use and sequestration technologies—could help meet demand locally. Demand response is another technology with the potential to limit electricity demand when transmission is constrained. Implementing these generation- and demand-based solution would require careful planning from both utilities, and state and local officials to ensure resource adequacy and minimize risks." Additionally, we added Section VI.a.2. "Treatment of non-wires alternative transmission solutions" to clarify how generation near load, energy storage, and DERs are all incorporated in the capacity expansion modeling results.
121	V.h.1	n/a	Midwest Reliability Organization	*Consider explaining how or why storage works well with variable generation and how the transmission grid optimizes operation of storage.*	The following sentence was added to section V.h.1: "Energy storage can serve as a grid asset to support higher degrees of variable energy on the system by shifting load across hours or days, smoothing seasonal peaks, and providing grid services."
122	V.h.2	n/a	Midwest Reliability Organization	*What is the scope of DERs being discussed in this section? Is it inclusive of rooftop solar, utility scale solar? Consider defining what is included when referring to DERs.*	Added footnote: "While each study referenced here may have slightly different definitions, we define *distributed energy resources* here as any electricity generation resource connected to distribution system facilities with nominal ratings of less than 100 kV."
123	V.i	"More specifically, increasing access to remote renewable resources could result in millions to trillions of	ReliabilityFirst	Commenter highlights "millions to trillions" and comments: *Recommend citing a specific source related to cost here.*	See resolution to comment 124.

		dollars in benefits from avoided health impacts, avoided climate damage costs, and general air quality improvements."			
124	V.i	"More specifically, increasing access to remote renewable resources could result in millions to trillions of dollars in benefits from avoided health impacts, avoided climate damage costs, and general air quality improvements."	Midwest Reliability Organization	*This is a very broad range. Suggest removing reference to dollar amounts with such a broad range. The sentence still gets the message across without the inclusion of a dollar amount.*	Revised Sentence: "More specifically, increasing access to remote renewable resources results in benefits from avoided health impacts, avoided climate damage costs, and general air quality improvements."
125	V.i	"Similarly, new transmission can also support resource adequacy, as new lines enable more flexible generation sharing, reducing the need for new generation."	ReliabilityFirst	*As mentioned above generation sharing is a great reliability tool, but also has it limitations. If this is too large of a value it could introduce a dependency reliability risk.*	See resolution to comment 28
126	V.i	"The reviewed literature, however, also identifies various challenges to meeting the transmission needs discussed above. Multiple studies specify siting of high-voltage lines as one major challenge, indicating that developers often must navigate multiple state processes and local and federal government requirements. Siting criteria differ across states and might be inconsistent. Additionally, developers face hurdles during the planning process, as projects must meet mandatory reliability standards, might need to demonstrate they meet benefit and cost thresholds, and might also have to meet various state policy goals. Conflicts also arise over cost allocation, as quantifying and determining who	ReliabilityFirst	*We recommend dedicating a whole section of the report to this issue, as it is a big hurdle.*	Created new section V.i. Barriers to Transmission Development to elaborate on various issues identified related to siting, permitting, and planning.

		receives the benefits is especially challenging."			
127	VI	General comment.	ISO-NE	*Section VI is based on the same capacity expansion model used in the National Transmission Planning Study. It is premature to state that future transmission is "needed" before the NTPS is complete, and it would make more sense for the National Transmission Needs Study to incorporate the conclusions of the NTPS only after that study is complete and widely accepted.*	See resolution to comment 17
128	VI	stating that the results of industry-led studies "are not included in this analysis	SERTP	*At a high level, the SERTP Sponsors recommend that DOE make greater utilization of NERC-registered transmission planners and transmission owners that have the actual "duties to serve" and corresponding legal obligations to expand their respective transmission systems in an economic and reliable manner to meet the needs of their customers. In this regard, the SERTP Sponsors have concerns about the decision to rely solely on capacity modeling studies that use abstracted, generalized assumptions, disregarding industry-led regional studies based on actual operation of the grid. The Draft Study also relies heavily on existing studies performed by consultants, who are often funded by certain market participants. To better ground the study through the use of actual electric system forecasts, data, and established practices, the SERTP Sponsors recommend a higher utilization of the expertise afforded by the Eastern Interconnection Planning Collaborative ("EIPC"). The EIPC performs coordinated transmission planning among the transmission planners in the Eastern Interconnection, including both RTOs/ISOs and non-RTO/ISO transmission planners, and increased coordination with the EIPC would provide a more reliable study informed by transmission planners who have the needed experiential perspectives on the needs of the grid.*	The National Transmission Needs Study is not meant to displace the transmission reliability or planning responsibilities of these entities. See resolution to comments 3, 7 and 74.
129	VI	n/a	SERTP	*In reaching the Draft Study's conclusions in section VI, DOE utilizes NREL's ReEDS model. This model and software were developed by NREL for their own use, and is self-described as subject to misconstruction. Per NREL's website describing ReEDS: "ReEDS is a large, complex optimization model with many inputs, outputs, variables, and constraints. Understanding and appropriately using the model may take time and require some knowledge of optimization modeling. A typical model run includes hundreds of thousands or millions of variables and constraints and produces millions of outputs. Because of this complexity and size, it can be easy to misinterpret results or*	The engineering modeling done by transmission planners and the reliability organizations is critical to the safe operation of the power grid. The analysis presented in this chapter is not meant to replace those important industry studies. See resolution to comments 3, 17, and 74

				to ascribe more accuracy to certain model results than is merited." …DOE has apparently selected studies that employ load forecasts that are speculative in nature. In this regard, the Draft Study itself recognizes that "industry-led studies tend to be less speculative about the characteristics of the future power system" but as noted above, specifically chose not to include these less speculative, industry-led studies.	
130	VI.a	"These laws will have dramatic impacts on future generation and demand that were not modeled among the "existing policy" scenarios presented here."	ReliabilityFirst	Redline change to beginning of sentence: *It is anticipated that these laws will have…*	Revised to "It is anticipated that these laws will have…"
131	VI.b	Footnote 39	ReliabilityFirst	Commenter highlights the NREL study and comments: *Did this analysis include power flow and stability analysis? Recommend looking at the overall impact of the additions considered and ensuring that these additions under contingency analysis do not create more issues across the systems(s).*	GDO agrees that important engineering modeling is required following capacity expansion modeling to ensure safe operation of the grid. These modeling efforts are outside the scope of the analysis presented in this section. See resolution to comments 3 and 17.
132	VI.c	"Increased transfer capability (sometimes referred to transfer capacity) has many benefits: regional grid reliability is strengthened by the diversity of generation provided by interregional transfers, regions need to import electricity when they cannot meet growing demand with local generation or when the combination of remote generation and interregional transmission has lower overall system costs than local generation, or a combination of these."	SERTP	*The Draft Study states that transfer capability is sometimes referred to as transfer capacity. These are two very different concepts. Per the NERC Glossary of Terms, total transfer capability is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. Capability refers to the ability to transfer power without causing facility overloads under contingency. Capacity normally refers to the sum of the thermal ratings of the transmission tie lines between two entities. While indicative of the robustness of the interconnection, use of the term capacity fails to include constraints that are not tie lines. The terms capability and capacity, thus, are not interchangeable.*	The definition of transfer capability from EIA's Glossary of Terms (2022) is "the overall capacity of interregional or international power lines, together with the associated electrical system facilities, to transfer power and energy from one electrical system to another." Our use of this definition was footnoted in the highlighted sentence. We recognize this definition conflicts with NERC's. Given the structure of the models, the capacity expansion models used here are not able to run the analysis needed to quantify transfer capability as defined by NERC. To align with NERC's definition, we switch all references to "capability" in this section to "capacity." We remove the footnote which references EIA's definition of *transfer capability*. Additionally, the following footnotes were added to section III.d.: "*Transfer capability* is defined in NERC (2022b) as "The measure of the ability of interconnected electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines (or paths) between those areas under specified system conditions." "*Transfer capacity* also does not have an industry standard definition but does

					commonly refer to the sum of thermal limits of all transmission tie lines between two regions.”
133	VI.c	Table VI-3	ReliabilityFirst	*It would be helpful to include the direction, whether these are incremental or total values, whether it is with all facilities in service, and the first contingency values. Additional items that would be helpful: are the values based solely on thermal ratings or something more? Did each of the studies that are being averaged together do the calculations on the same basis and same assumptions?*	The following was added to Section VI.b ahead of this table: “The values represent the cumulative new transmission—calculated as nominal carrying capacity—deployed by the stated year, less the modeled 2020 system.” The following was added to the introductory material of Section VI: “Once future power system scenarios and input modeling assumptions have been established, capacity expansion models make generation, storage, and transmission investment decisions by optimizing for the lowest capital and operations costs, system wide. In finding this cost-optimal capacity mix, the models do consider hourly energy dispatch constraints and some essential grid reliability services—such as resource adequacy. The models will optimize around all possible technology combinations and choose the least expensive solutions in each geographic zone. The resulting transmission needs for each region given the most cost-optimal solutions found for all scenarios are presented here.” Other characteristics about how each study models the transmission system is available in the Supplemental Material. We add a note to point the reader there by adding the following to section VI.a: “Table VI 1 summarizes the six studies discussed here at a high level; a more detailed summary of and the specific treatment of transmission in each study can be found in the Supplemental Material.”
134	VI.d	General comment.	ReliabilityFirst	*Would a paragraph about needing State Department approval of international transmission expansion adds to the complexity of getting such projects approved, and in service?*	Please see resolution to comment 126.
135	VI.d	“Appreciable transfer capacities between Canada and New York and New England do not arise until 2040 in Brinkman et al. (2021).”	ReliabilityFirst	Commenter strikes extra “s” in the word “capacities.” Commenter also highlights “Appreciable transfer capacities” and comments: *The table below says that they are international transfer capacities, so suggest adding that word here.*	Revised to “Appreciable international transfer capacities...”
136	VI.d	[Tabl VI-4 row 10]	NESCOE Gov Offices	*Finally, NESCOE notes that the draft NTS indicates a modest need for increased international transmission between New England and Québec. Other studies, however, indicate that the draft NTS may underestimate possible future needs for such increased transmission capacity. For example, ISO-NE’s recent Future Grid Reliability Study found unlimited*	This study been incorporated into Sections V and VI. The following was added to the Executive Summary: “Increase transfer capacity with Canada to meet future load and generation growth. • Increased transfer capacity between New England and Canada will enable bidirectional

				bidirectional flows between ISO-NE and Québec "eliminated any curtailment of New England renewables and imports on existing tie-lines and [the New England Clean Energy Connect] while significantly decreasing natural gas production and emissions." In that study, the flows exceeded 10,700 MW. *Similarly, regional analysis conducted for a Massachusetts study found that an additional 4.1 to 7.1 gigawatts of capacity between Québec and New England would be required. While the estimates range across different studies using different assumptions and modeling tools, together they indicate that the estimates in the draft NTS may be low.* Evolved Energy Research, *Energy Pathways to Deep Decarbonization: A Technical Report of the Massachusetts 2050 Decarbonization Roadmap Study* (Dec. 2020), at 64, at.	flow of hydropower, wind, and solar generation between the regions, helping to meet State clean energy targets." The following was added to Section V.c: "Dimanchev et al. (2020) note that meeting existing state climate policy targets in New York and New England will likely require the nearly complete decarbonization of electricity generation. To that end, consideration is being given to expanding imports of hydropower from neighboring Québec, Canada. In a low-carbon future, it is optimal to shift the utilization of the existing hydrodower and transmission assets away from facilitating one-way export of electricity from Canada to the U.S. and toward a two-way trading of electricity to balance intermittent U.S. wind and solar generation (Dimanchev et al., 2020). They find doing so can reduce power system cost by 5-6% depending on the level of decarbonization. The cost-optimal use of Canadian hydropower is as a complement, rather than a substitute, to deploying low-carbon technologies in the U.S. Expanding transmission capacity enables greater utilization of existing hydropower reservoirs as a balancing resource, which facilitates a greater and more efficient use of wind and solar energy. Jones et al. (2020) similarly note in a regional analysis conducted for a Massachusetts study that Canadian hydropower is an essential element of regional balancing. In their study, bidirectional flow of electricity enabled the Québec hydropower system to transition into the role of a 'battery' storing excess wind and solar generation for the New England region. The use of hydropower system as storage depends on the timing of renewable production and demand on both sides of the U.S.-Canada border (Jones, et al., 2020). Total net-imports into Massachusetts from Québec declined after 2035 in the analysis. The study estimates that an additional 4.1 to 7.1 GW of new transmission capacity between Québec and New England would be required." The following was added to Section VI.d: "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 U.S. 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 gigawatts of capacity between Québec and New England would be required to meet existing state clean energy targets.”
137	VI.d	General comment.	ISO-NE	*The study does not include any additional ties between Canada and New England until 2040 (and only 210 MW in 2040, Table VI-4, pg.90). Some of the New England states have included new transmission connections with Canada to import clean energy as a part of their plan to decarbonize their energy supply. Failure to include these lines can have a significant effect on the needed interregional transfers between New York and New England. Although the last paragraph on pg. 89 states that additional international transfers may reduce the need for New York – New England transfers, readers will likely focus on the 3-6 GW value throughout the report and not factor in this comment.*	See resolution to comment 136
138	VI.e	“Shown in this Needs Study, all combinations of new generation will require increased transmission deployment to bring new generation to market, but to differing degrees.”	ReliabilityFirst	Commenter highlights “all combinations” and comments: *Nuclear at existing coal and gas generation sites may be an exception to this "all" statement. Also, if DER and microgrids win the cost battle, they also may require no new transmission.*	We leave this statement unchanged. The capacity expansion models found new transmission was needed even with high levels of DERs and large advances in nuclear technologies. Many of the model scenarios—notably those from the NREL studies—did continue to deploy natural gas solutions with CCS technologies. No studies found continued deployment of coal into the future. For a description of DER considerations among the scenarios, please see the newly added Section VI.a.2. For a description of the generation technologies considered among all capacity expansion studies, please refer to the reference model documentation.
139	VI.e	“Regions with the most cost-effective transmission growth are those in the middle of the country, including the Texas, Mountain, Plains, and Midwest regions.”	ReliabilityFirst	Redline addition: *“Regions with the <u>need for the</u> most cost-effective transmission growth are those in the middle of the country, including the Texas, Mountain, Plains, and Midwest regions.”*	Revised to “Regions in greatest need of cost-effective transmission...”
140	VI.e	“Transfer capacities between regions remain low under these moderate scenario conditions, needing to grow 5 percent in 2030 (median 5.5 GW) and 40 percent in 2040 (median 41 GW).”	ReliabilityFirst	Redline addition: *“Transfer capacities <u>needs</u> between regions remain low under these moderate scenario conditions, needing to grow 5 percent in 2030 (median 5.5 GW) and 40 percent in 2040 (median 41 GW).”*	Revised to “Transfer capacity needs between…”
141	VI.e	“Regions with the most transmission growth are the Southeast,	ReliabilityFirst	Redline addition:	Revised to “Regions in greatest need of transmission growth...”

		Texas, Plains, and Midwest."		*Regions with the <u>need for the</u> most transmission growth are the Southeast, Texas, Plains, and Midwest.*	
142	VI.e	"Large amounts of low-cost clean generation exist in the middle of the country and accessing this generation through increased transmission is cost effective for neighboring regions."	ReliabilityFirst	*Is this referring to existing or planned generation?*	This is meant to refer to generation potential, whether planned or currently unplanned. Sentence was modified to read "…generation potential…".
143	VI.e	"Transmission growth is even more ambitious in future scenarios that have high load and high clean energy assumptions."	ReliabilityFirst	Redline addition: *<u>The need for t</u>ransmission growth…*	Revised to "The need for transmission growth is even greater in future scenarios..."
144	n/a	n/a	New England States Committee on Electricity (NESCOE)	*ISO New England (ISO-NE) is currently working on the 2050 Transmission Study, initiated in response to the states' request for more visibility into longer-term system needs that account for the states' clean energy laws and mandates. The 2050 Transmission Study uses state-provided assumptions on load and resource mix to provide visibility into potential transmission needs to* *reliably meet demand in the 2035, 2040 and 2050 timeframes. The study will also consider possible solutions to address potential needs and provide transmission upgrade "roadmaps" that consider both constructability and cost.* *…* *Going forward, the Department should include the 2050 Transmission Study and subsequent ISO-NE studies under this provision of the tariff in its work to identify anticipated transmission capacity needs.*	Thank you for this information. GDO looks forward to seeing the results and incorporating them into a future iteration of the Needs Study.
145	n/a	n/a	ERCOT	*more connections would make ERCOT more susceptible to fast events like the January 2019 Eastern Interconnection event, which arguably put the entire Eastern Interconnection on the brink of a collapse. DOE should address these risks in the study.*	See resolution to comment 28
146	n/a	n/a	ERCOT	*The study should consider that Texas has already built more transmission than other regions.*	Added the following to Section IV.a in reference to Fig. IV-1: "Texas (ERCOT) built more transmission circuit miles than any other region in the first half of the decade."
147	n/a	n/a	SERTP	*DOE has expanded the scope of its studies from the statutorily mandated "transmission capacity constraints and congestion" analysis to one that is more akin to a future generation/resource study. In doing so, DOE intrudes into resource planning activities that extend well beyond the scope authorized by FPA section 216. the Draft Study could unlawfully open the way for FERC to authorize transmission projects*	Please see the resolution to comment 7 where "transmission need" is redefined and authority under Section 216 is clarified.

				predicated upon resource decisions made by the federal government (not the states, as prescribed in the FPA). Therefore, we recommend that DOE continue to perform a transmission assessment and not an expansive future generation study predicated upon theoretical resource assumptions. We further suggest that the accuracy of such transmission studies would be improved if DOE were to coordinate more closely with North American Electric Reliability Corporation- ("NERC") registered transmission planners and transmission owners. In the alternative, DOE should clarify that the Draft Study is not for FPA section 216 purposes and provide further explanations of the Draft Study's scope.	
148	n/a	October 25 Needs Study Webinar Slide 8	SERTP	*DOE broadly defines a transmission need to be...an upgrade to or a new transmission facility—including non-wire alternatives—that would optimally be built to...* *-improve reliability and resilience of the power system;* *-alleviate transmission congestion on an annual basis;alleviate transmission congestion during real-time operations;* ***-alleviate power transfer capacity limits between neighboring regions;*** ***-deliver new, cost-effective generation to high-priced demand; and*** ***-to meet projected future generation, electricity demand, or reliability requirements.*** *The last three criteria bolded above were not within the scope of the DOE's 2020 triennial transmission congestion study, which defined "transmission constraint and congestion" to consist of essentially the first three criteria quoted above. The new criteria have apparently been added to the scope of the Draft Study based upon Congress' recent addition of the term "capacity" before the word "constraint" in FPA section 216(a)(1). The addition of this word "capacity" apparently is being used to expand the scope of the Draft Study from being focused on transmission matters (i.e., the first three criteria quoted above) to also encompass resource/generation/IRP planning matters (i.e., the last three criteria quoted above).Indeed, a review of the Draft Study establishes that it primarily concerns DOE's projection of the addition of significant amounts of renewable generation.14Then, having assumed certain levels of specified generation resources based upon certain modeling scenarios, the Draft Study concludes, without any real explanation, that huge amounts (i.e., gigawatts) of additional transmission capacity are needed within and between*	Please see the resolution to comment 7 where "transmission need" is redefined and authority under Section 216 is clarified.

				essentially all transmission planning regions. *…* *Rather than DOE independently performing such de facto resource/generation/IRP planning, DOE should coordinate with NERC-registered transmission planners and transmission owners to utilize their load and supply-side and demand-side forecasts that incorporate the results of state-regulated IRP and resource procurement processes. This approach would allow for an accurate assessment of "electric transmission capacity constraints and congestion" in accordance with FPA section 216 as well as being consistent with the overall structure of the FPA. Further, the Draft Study incorporates studies that are predicated upon very aggressive clean energy and renewables assumptions that are not tied to federal mandates. With the Draft Study's resource forecasts predicated upon neither state-regulated forecasts nor federal mandates, the basis upon which DOE is incorporating such assumptions is unclear. Instead of DOE independently making such determinations, the better approach would be for DOE to use the "projected future generation, electricity demand, or reliability requirements" determined to be appropriate for transmission planning purposes by NERC-registered transmission planners and transmission owners–those having the responsibilities under FPA section 215 to do so–and which incorporate the results of state-regulated IRP and resource procurement processes.*	
149	n/a	n/a	SERTP	*The studies utilized by DOE predominantly use a zonal model. Compared to a nodal model, the use of a zonal model greatly underestimates the required transmission buildout that would be necessary. This characteristic means that the transmission build-out to support the Draft Study's increased inter-regional transfer capability is likely significantly underestimated*	The following was added to the introductory paragraphs of Section VI: "Additionally, any one of these transmission additions may require associated system upgrades to support increased energy transfers and, as such, the zonal estimates reported here may underestimate total required system builds." Likewise, see resolution to comment 3.
150	n/a	n/a	SERTP	*If a transmission needs study is to be performed, specific transmission planning studies to assess transmission expansion should be performed and not derived from a conglomeration of different types of studies. EIPC has begun discussing the preparation of a combined Eastern Interconnect study that will assess expected renewable generation and synchronous generation retirements as well as incorporating climate change transfer capability needs. This process includes:* *-building eastern interconnect models which include renewable generation in expected rural areas*	Thank you for your comments. The National Transmission Needs Study is not meant to displace the transmission reliability or planning responsibilities of these entities. See resolution to comments 3, 7, 74, and 106.

				-modeling expected synchronous generation retirements identifying extreme weather events -forecasting generation requirements in areas experiencing the extreme weather event -modeling transfers of power from areas not experiencing the SAME weather event to the areas experiencing the SAME extreme weather event; this step identifies the required transfer capability for extreme weather -identifying transmission constraints resulting from modeling the required transmission transfer capability requirements -identifying transmission needs to mitigate the transmission constraints which includes non-wires solutions where appropriate SERTP respectfully submits that this type of specific, engineering-based study, rather than an abstracted, aggregated meta-study, is more appropriate to determine transmission needs.	
151	n/a	n/a	CT Energy Office	*I think a couple of caveats early on in the document would be helpful. For example, in the Executive Summary, the draft refers to the need for increased transfer capability between NYISO and ISO-NE between 1.6 and 3.4 GW by 2035 but no mention is made about increased capacity to Quebec when New England already has two links to Quebec and two to New Brunswick that typically account for about 10-12% of our load. There are two potential new HVDC lines to Quebec (Clean Energy Link and NECEC) that would have a significant impact on the region and it looks a little odd (to New Englanders at least) that increased ties to Canada are not mentioned. You do have a brief comment on page 89 that the "U.S. regional transfers . . . did not consider growth in international transfers…." Just thinking that putting up front that this study is focused on U.S. regional transfers would address the issue which was the first question I asked myself when I read the Summary.* *Also, I read section VI.d to mean that if there were increased ties to Canada, that would reduce the NYISO-ISO-NE ties by an equivalent amount.* *Finally, staff here in CT has been looking at interregional ties to NYISO and PJM and has even talked to at least one staff in PJM about this. NY has a project (Beacon Wind) in the MA leasehold. CT and MA have projects in the same leasehold and the HVDC converters will all be reasonably close to each other. Meshing between the*	Regarding international transfers between New England and Canada, please see resolution to comment 136. You're reading of section IV.d. is correct. The following is already included in that section: "The U.S. regional transfer results include scenarios from the studies that did not consider growth in international transfers, putting increased reliance on the national transfers between regions that cannot otherwise share with their international neighbors. That national transfers might decrease commensurate with increased international transfers for a particular region is a reasonable expectation, all other resource operating characteristics on balance." The following was added to section VI.c to address additional offshore transfers: "There may be some links between regions absent from this table if they were not considered by the modelers. For example, transfers between the Texas and Delta regions were only considered by Brown and Botterud (2020) and therefore do not show up for all years. The potential creation of a submerged transmission system to support Atlantic offshore wind generation may allow the New England and Mid-Atlantic regions to share direct transfers without needing to transfer through the terrestrial New York system."

				Beacon Wind and Vineyard Wind and Park City Wind will allow for interregional transfers. But it is possible that NY and NJ may have converters in proximity to each other in the leases south of NY. If these were meshed it is possible to shift power from NJ to Boston.	
152	n/a	n/a	CT Energy Office	*…the draft mentions some of the issues with the constraints between Maine and the rest of New England. I note that there has been a recently approved 345 kV line from northern Maine bringing 1200 MW of onshore wind into the ISO-NE grid. Whether it gets funded and built is still up in the air and I also think that it should be considered an interregional transmission line because that portion of Maine (about 10,000 sq. miles) is actually part of the New Brunswick control center and they will have to pay a through and out transmission (TOUT) tariff to bring the power into ISO-NE.*	DOE appreciates that transmission projects currently under development will address some of the needs identified in the Study. Without insight into all projects currently under development and how they may address these needs, we are declining to identify specific projects in the Study. We hope the Study will help industry prioritize solutions to the identified Needs.
153	n/a	n/a	Virginia DOE	*Virginia Energy does have concerns that the Needs Study limits consideration of future scenarios as the content of the study relies mostly on references that focus on specific renewable technologies and decarbonization scenarios. Virginia encourages flexibility in the transmission planning process, one that incorporates innovation and presents considerations for a broad mix of clean energy technologies noticeably absent in the Draft…..Virginia Energy is concerned that while prescribing no particular solution, the Draft presents solutions that indeed focus on particular technology solutions. Furthermore, the Draft suggests large-scale transmission solutions that overlook other options such as non-wires alternatives. Distributed generation options are referenced but do not feature in the regional summaries and offer targeted solutions that will increase both reliability and resiliency. The proposed solutions otherwise require large-scale transmission projects burdened by increasingly challenging siting, permitting, and cost issues. Increasing baseload resources in or near transmission constrained areas will avoid the cost and reliability issues associated with long-range dispatch of what mostly amounts to intermittent power….For the Needs Study, Virginia recommends that DOE identifies or performs additional research that can examine a wider range of scenarios, including increased analysis of the threats to reliability posed by a high-level of intermittent generation in the energy stack and the risk of needs changing as new technologies emerge and become commercially viable. The latter issue presents the risk of stranded assets and other inefficiencies if the grid is upgraded*	Thank you for your comments. The National Transmission Needs Study is not meant to displace the transmission reliability or planning responsibilities of these entities. Regarding the role of transmission planners and how the analysis in this study differs from those activities, please see the resolutions to comments 3, 7, 11, 17, and 74. Regarding challenges to permitting and siting, please see resolution to comment 126. We added Section VI.a.2. “Treatment of non-wire alternative transmission solutions” to clarify how generation near load, energy storage, and DERs are all incorporated in the capacity expansion modeling results.

				based on an overly rigid expectation of future generation. This would be magnified if newer technologies render selected generation technologies obsolete.	
154	n/a	n/a	Electric Reliability Council of Texas, Inc. (ERCOT)	*Under established planning principles, a transmission project proposed under economic planning criteria may be justified only if the estimated benefits of the project exceed a measure of its estimated costs. If a project's benefits don't exceed that measure, the project cannot be justified under economic criteria. The draft study identifies substantial economic benefits of a number of new transmission facilities across the country, and in particular, projects linking Texas to the western United States and the "Plains" region. However, ERCOT has noted that the study does not address the cost of these projects, which in many cases is likely to be very substantial, given the contemplated scale. ERCOT therefore recommends that the DOE provide a more robust cost-benefit analysis with estimates of project costs so that the net benefit of these additions can be understood. Without such an analysis, ERCOT questions whether the study can establish an independent economic "need."* *In evaluating project costs, DOE should consider that adding substantial capacity between ERCOT and other regions (such as the 9.8 GW [median] recommended for connecting ERCOT to the Plains region by 20352) would require a number of new separate transmission lines, each limited to approximately 1.5 GW. This is because relying on a single point of interconnection to provide this transfer capability would result in a material increase in ERCOT's single largest contingency, which would in turn require a substantial increase in ERCOT's costs of ancillary services to counter the operational risk of losing the facility while it is importing or exporting. The costs of building these separate points of interconnection should be considered.* *…* *In addition to the costs of the identified transmission facilities, DOE's assessment should include consideration of other costs attributable to the proposed changes to the grid, which would include the following:* *• Additional transmission upgrades that may be needed to ensure sufficient grid strength and inertia* *• Changes in dispatch costs due to retirements of older or less efficient generation caused by the increased transfer capability*	Thank you for your comments. The National Transmission Needs Study is not meant to displace the transmission reliability or planning responsibilities of these entities. See resolution to comments 3, 7, 74, and 106.

				• Changes the increased transfer capability will have on the regional dispatch costs due to intermittency of renewable resources • Changes to operating reserve requirements due to increased reliance on intermittent resources • Potential changes to existing market designs and Texas state rules to manage interregional transfer	
155	n/a	n/a	PJM	*Although reference to prior analyses are helpful background, in PJM's view the study should be enhanced and revised by utilizing a more region-specific approach taking into account the notable changes in transmission topology, interconnection requests, changing public policies and demands on the grid that have occurred since the last congestion study in each of the regions that make up the Eastern and Western Interconnections. In that way, the study would have provided an appropriate update to the prior analyses of congestion and renewable deployment given all of the changes that have occurred since the 2006 and 2009 analyses. PJM recognizes that this is a considerable task and stands ready to assist the DOE in that effort. However, in reviewing the draft, it is hard to find the specific analysis that supports the study's findings—an issue that could provide grist for later legal challenges to the Secretary's actions that are being taken in reliance upon the study.*	Thank you for your comments. The National Transmission Needs Study is not meant to displace the transmission reliability or planning responsibilities of these entities. See resolution to comments 3, 7, and 74.
156	n/a	n/a	PJM	*PJM cautions against approaching this analysis based on a 'top down' analysis based on what appears to be an attempt at optimizing the deployment of renewables across the nation. The planning process is and always has been more of a 'bottom up' exercise…an approach which would start with consultation on each region's needs and exploration of the potential interregional solutions that would help meet the needs of that region and its neighbors would be a more realistic and actionable step that would complement rather than potentially conflict with today's fundamental planning approach. PJM stands ready to work with the authors on such an in-depth review and discussion in any future iterations of this report.*	Thank you for your comments. The National Transmission Needs Study is not meant to displace the transmission reliability or planning responsibilities of these entities. See resolution to comments 3, 7, and 74.
157	n/a	n/a	PJM	*Although the report makes certain conclusions about the need for increased interregional transfer capability, it is difficult to determine from the draft the basis for those conclusions other than if one approaches the matter starting with a top-down nationwide optimization of the placement of renewable generation. However, since such an approach is plainly not consistent with either the applicable law or regulations at the state and federal level,*	Thank you for your comments. The National Transmission Needs Study is not meant to displace the transmission reliability or planning responsibilities of these entities. See resolution to comments 3, 7, and 74.

				it will become difficult for the DOE to use the draft's findings concerning the level of needed interregional transfer capability as a basis for the designation of transmission corridors or investment of DOE funds. A more complementary approach which works with today's planning approaches is needed in this area. *The EIPC has recently talked with FERC Staff on undertaking a more specific analysis of Interregional Transfer Capability. In its Comments to the FERC NOPR, PJM proposed a phased process that would start with transmission planners, working with the labs, NERC and FERC to first develop common metrics and measurements to determine the appropriate level of interregional transfer capability and then setting up a process for each region to apply those metrics across its seams within the Eastern Interconnection to determine whether incremental transfer capability is needed across a particular seam to manage widespread disruptive events, such as widespread extreme temperatures or physical or cyberattacks on infrastructure. PJM would welcome the lab's involvement in that effort and has actually made that request to FERC in the context of its Transmission Planning NOPR Docket No. RM21-17-000.*	
158	n/a	n/a	PJM	*The draft Report argues that the lack of transmission capability is the primary cause of the delay in integrating lower emitting resources. PJM respectfully submits that this conclusion is entirely too sweeping and conclusory. Any future draft should recognize other extremely relevant factors including:* *ØPermitting challenges both for renewable resources and transmission;* *ØDelays by developers in deploying renewable resources…* *…In short, the planning process has kept up with the needs while planners and developers have run into problems in effectuating those plans through the siting process. This should be noted in the draft rather than the delays in renewable deployment being solely attributed to interconnection queue delays.*	Regarding delays met by generation developers please see resolution to comment 71. Regarding challenges to transmission permitting and siting, please see resolution to comment 126.
159	n/a	n/a	Ho-Chunk*	*Requesting general information about Needs study.*	No changes needed
160	n/a	n/a	Ahtna*	*Requesting general information about Needs study. Notes that Alaska has a huge transmission need.*	GDO appreciates that Alaska has unique electricity concerns. The Needs Study only considers the bulk transmission system in the contiguous U.S., and thus Alaska (and island

					States and territories) are not considered here.
161	n/a	n/a	Choctaw Nation*	*Seeking additional information about Needs study and what it will entail. Nation aspires to work with state and local partners to upgrade transmission lines throughout our reservation.*	No changes needed
162	n/a	n/a	Pilar Thomas, Quarles & Brady*	*Suggest that more resources related to energy development and transmission on tribal lands be included in the study. Suggest that maps of the transmission system overlaid with tribal lands would be very useful.*	Added section V.c.2 Clean Energy on Tribal Lands which includes two studies reviewing clean energy development on tribal lands: Milbrandt et al. (2018) and Brooks (2022). Also included example maps of the Geospatial Energy Mapper tool showing the transmission system on two tribal territories. These two Tribes were chosen as examples given their geographic diversity and differences in transmission coverage within each territory, but the tool includes the entire contiguous U.S.
163	n/a	n/a	SC Office of Regulatory Staff*	*Curious about how increased transfer capabilities were calculated and what that means for South Carolina.*	No changes needed
164	n/a	n/a	SC Office of Regulatory Staff*	*General questions about process for designating NIETCs and providing funding to developers or state for development within corridor. Questions included hypotheticals for designating NIETCs and about various DOE funding programs.*	No changes needed
165	n/a	n/a	SC Office of Regulatory Staff*	*Questions about how this relates to NTP Study.*	See resolution to comment 17
166	n/a	n/a	CT Energy Office*	*Concerns about interregional transfer between NY and New England shown and not New England and Canada. Note there is no place to put new transfers with NY. Note a need for Canadian Hydro to balance OSW energy.*	See resolution to comment 136
167	n/a	n/a	CT Energy Office*	*Also considering direct links between New England and Mid-Atlantic offshore, skipping NY entirely.*	See resolution to comment 151
168	n/a	n/a	CT Energy Office*	*New line just approved entirely within ME, but it connects Canadian grid to ISO-NE. Suggest considering the addition of this line to the Study.*	DOE appreciates that transmission projects currently under development will address some of the needs identified in the Study. Without insight into all projects currently under development and how they may address these needs, we are declining to identify specific projects in the Study. We hope the Study will help industry prioritize solutions to the identified Needs.
169	n/a	n/a	Oregon DOE*	*General review of Northwest results*	No changes needed
170	n/a	n/a	Oregon DOE*	*Note the high/high scenario group in Section VI better aligns with Oregon State clean energy and electrification targets.*	Thank you for this information. We will keep these results in the Study. Additionally, see resolution to comment 82 which discusses Oregon State targets.
171	n/a	n/a	WECC*	*Want more clarity around qualified paths and how it relates to more transmission*	See resolution to comment 9
172	n/a	n/a	WECC*	*GW-mi unit in CEM results section is confusing. Discussed ideas to better caveat this*	See resolution to comment 3

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