U.S. House Committee on Energy and Commerce
Subcommittee on Energy, Climate, and Grid Security
“Oversight of FERC: Adhering To A Mission Of Affordable And Reliable Energy For America”
[June 13, 2023]

1. Letter to Chair Duncan and Ranking Member DeGette from Electricity Transmission Competition Coalition, June 12, 2023, submitted by the Majority.
2. North American Electric Reliability Corporation, “2023 Summer Reliability Assessment” May 2023, submitted by the Majority.
3. Energy Transition in PJM: Resource Retirements, Replacements & Risks, February 24, 2023, submitted by the Majority.
4. North American Electric Reliability Corporation, “2022 Long-Term Reliability Assessment” December 2022, submitted by the Majority.
5. A General Electric International, Inc. and NRDC report entitled, “Economic, Reliability, and Resiliency Benefits of Interregional Transmission Capacity” 2023, submitted by Rep. Peters
6. A Lawrence Berkeley National Laboratory fact sheet entitled, “The Latest Market Data Show that the Potential Savings of New Electric Transmission was Higher Last Year than at Any Point in the Last Decade” February 2023, submitted by Rep. Peters.
7. A U.S. Department of Energy study entitled, “National Transmission Needs Study” February 2023, submitted by Rep. Peters.
8. A Grid Strategies LLC study entitled, "Transmission Makes the Power System Resilient to Extreme Weather” July 2021, submitted by Rep. Peters.
9. A Grid Strategies LLC study entitled, “The Value of Transmission During Winter Storm Elliott” February 2023, submitted by Rep. Peters.
10. An IEEE study entitled, “The Value of Increased HVDC Capacity Between Eastern and Western U.S. Grids: The Interconnections Seam Study” May 2022, submitted by Rep. Peters.
11. An article from The Economist entitled “Expensive Energy May Have Killed More Europeans Than COVID-19 Last Winter” May 10, 2023, submitted by the Majority.
12. Letter to FERC Chairman Glick and Commissioners regarding the Gas Transmission Northwest Xpress project, October 21, 2022, submitted by Rep. Fulcher.

Electricity Transmission Competition Coalition

June 12, 2023

The Honorable Jeff Duncan
Chairman
Subcommittee on Energy, Climate, & Grid Security
Committee on Energy and Commerce
U.S. House of Representatives
Washington, DC 20515

The Honorable Diana DeGette
Ranking Member
Subcommittee on Energy, Climate, & Grid Security
Committee on Energy and Commerce
U.S. House of Representatives
Washington, DC 20515

Re: Comments for the Record on Hearing on "Oversight of FERC: Adhering to a Mission of Affordable and Reliable Energy for America"

Dear Chairman Duncan and Ranking Member DeGette:

America's electricity consumers reach out to ask for your support in reminding the Federal Energy Regulatory Commission (FERC) that their core mission under the Federal Power Act is to protect electricity consumers[1] from unjust and unreasonable rates, and that you do not support the FERC backtracking on competitive bidding of transmission projects as their current Notice of Proposed Rulemaking (NOPR)[2] contemplates. Below are examples of ten competitively bid projects that demonstrate significant cost savings.

Competitive bidding of new FERC jurisdictional transmission projects reduces electricity costs for consumers, is sound anti-inflationary policy, and is a bipartisan conclusion. Under both Presidents Trump and Biden, the Department of Justice (DOJ) has challenged state incumbent preference laws (also known as rights of first refusal laws) that seek to circumvent FERC's existing requirements for transmission competition.[3] Last year, the DOJ, this time joined by the Federal Trade Commission (FTC), reiterated that stance in comments on the NOPR's proposal to significantly abandon transmission competition.[4]

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[1] Federal Power Act

[2] "Building for the Future Through Electricity Regional Transmission Planning and Cost Allocation and Generator Interconnection," Notice of Proposed Rulemaking, April 21, 2022. Although the NOPR was initiated under the former Chair, it remains pending.

[3] 5th Circuit brief

[4] Federal Trade Commission, DOJ Urge FERC to Preserve Robust Wholesale Electricity Markets | Federal Trade Commission, www.ftc.gov

FERC's Order No. 1000, issued over a decade ago, found that transmission competition was essential to the FERC's duty to determine just and reasonable rates and that eliminating contractual preferences in tariffs or agreements under federal jurisdiction was in the public interest. The FERC's pronouncement about the benefits of competition on transmission rates proved correct as savings from competed projects are significant and consistent with studies that have shown that competition could reduce the cost of transmission projects by up to 40 percent.[5] Yet only three percent of all transmission investment since Order No. 1000 has been competitively awarded because of a lack of FERC enforcement of Order No. 1000 and incumbent electricity utility lobbying efforts at the state level. With one study suggesting the United States may need to spend $2.1 trillion by 2050 to build-out the transmission grid, time is of the essence and your voice is essential now.

As Members of Congress focused on common sense measures for the public benefit, we ask that you lend your voice, and ultimately that of the entire Committee on Energy and Commerce, to remind the FERC that consumers come first, even during times of transition and that more transmission competition is the right direction, not less. The cost reductions from projects that have been competitively bid across the country show just how out of step the FERC's transmission planning NOPR is on this critical issue. We urge you to tell the FERC that transmission competition is essential to their mission and just and reasonable rates.

Sincerely,

Paul N. Cicio
Paul N. Cicio
Chair
Electricity Transmission Competition Coalition
https://electricitytransmissioncompetitioncoalition.org/

cc: House Committee on Energy and Commerce

[5] Brattle Group: Cost Savings Offered by Competition in Electric Transmission, https://www.brattle.com/wp-content/uploads/2021/05/16726_cost_savings_offered_by_competition_in_electric_transmission.pdf
Even a 25 percent savings would save consumers an estimated $525 billion by 2050. More specifically, reports indicate that competitive bidding processes could yield savings as follows: MISO (Midwest region): 15-28 percent cost savings; Southwest region (Southwest Power Pool): 50-58 percent savings; and Mid-Atlantic (PJM) region: 60-67 percent savings.

TRANSMISSION PROJECTS COMPETITIVELY BID

Hiple to IN/MI State Border 345 kV Competitive Transmission Project
Location: Indiana/Michigan
Year: Approved in 2023
Operator: Midcontinent Independent System Operator (MISO)
Builder: Republic Transmission, LLC
*The winning bid was 26% less expensive than MISO's estimate.[6]

Northern Maine Transmission Line and Renewable Energy Projects
Location: Northern Maine
Year: Approved in 2022
Operator: ISO New England Grid
Builder: LS Power Base & Longroad Energy
**Savings:* $1.08 billion
https://www.prnewswire.com/news-releases/ls-power-grid-maine-selected-to-build-transmission-solution-to-deliver-renewable-energy-from-northern-maine-301660502.html

Larrabee Tri-Collector Solution (LTCS) Project
Location: New Jersey
Year: Selected in 2022
Operator: PJM Interconnection
Builder: Mid-Atlantic Offshore Development (MAOD), Jersey Central Power & Light (JCP&L)
**Potential Savings:* $900 million
https://www.nj.gov/bpu/newsroom/2022/approved/20221026.html

Empire State Line
Location: Western New York
Year: Energized in mid-2022
Operator: New York Independent System Operator (NYISO)
Builder: NextEra Energy Transmission New York
**Potential Savings:* $500 Million
https://www.governor.ny.gov/news/governor-hochul-announces-commissioning-empire-state-transmission-line

Minco-Pleasant Valley-Draper Transmission Project
Location: Oklahoma
Year: Awarded in 2022
Operator: Southwest Power Pool (SPP)
Builder: NextEra Energy Transmission Southwest, LLC
**Potential Savings:* $26 million
https://www.prnewswire.com/news-releases/nextera-energy-transmission-awarded-minco-pleasant-valley-draper-transmission-line-project-by-spp-301534600.html

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[6] *NOTE: Each project cost savings observed are from RTO estimates to the selected winning bids and may understate the savings attributable to competition, considering incumbent-only final project costs in the absence of competition typically surpass initial RTO cost estimates.

Wolf Creek to Blackberry Transmission Project
Location: Kansas-Missouri
Year: Awarded in 2021
Operator: Southwest Power Pool (SPP)
Builder: NextEra Energy Transmission Southwest, LLC
**Potential Savings:* $58 million
https://www.prnewswire.com/news-releases/nextera-energy-transmission-awarded-wolf-creek-blackberry-transmission-line-project-by-spp-301409361.html

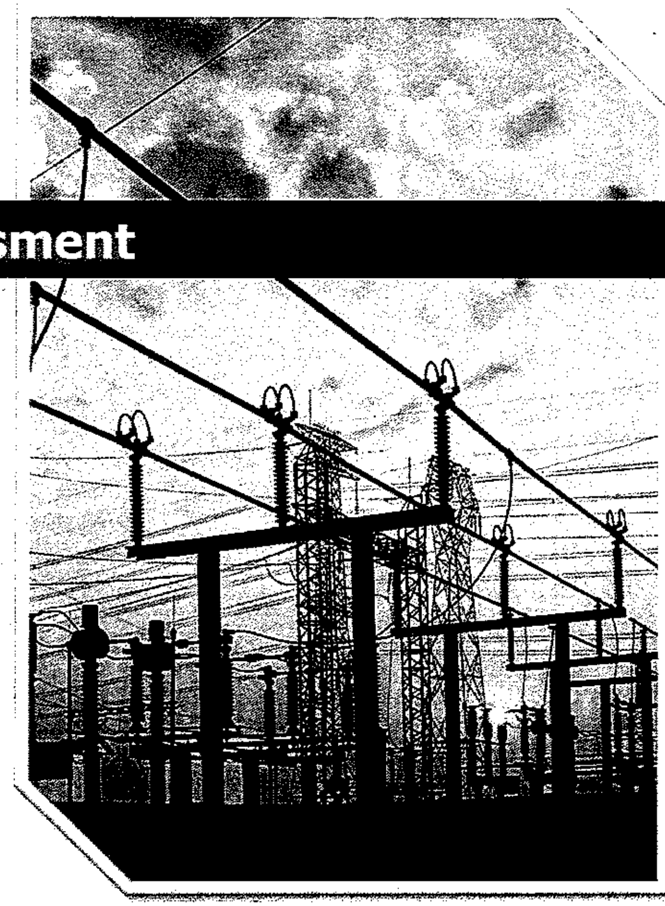
Central East Energy Connect
Location: Central New York
Year: 2021
Operator: NYISO
Builder: LS Power Grid New York and the New York Power Authority (NYPA)
**Potential Savings:* $200 Million
https://www.tdworld.com/overhead-transmission/article/21166855/first-5mile-section-of-central-east-energy-connect-transmission-line-complete

Harry Allen-Eldorado Project
Location: California
Year: 2016
Operator: California Independent System Operator (CAISO)
Builder: LS Power
The project was completed under budget in 2020, with an estimated cost savings of up to 29% compared to estimates for the project had it not been competitively bid.
**Potential Savings:* $203 Million
https://www.transmissionhub.com/articles/2020/08/ls-power-harry-allen-to-eldorado-line-energized-aug-12.html

Artificial Island Project
Location: New Jersey
Year: Completed in 2020
Operator: PJM Interconnection (PJM)
Builder: LS Power
**Potential Savings:* $591 Million
https://insidelines.pjm.com/artificial-island-project-nears-completion/

Duff-Coleman Line Project
Location: Southern Indiana and Western Kentucky
Year: 2016
Operator: Midcontinent Independent System Operator (MISO)
Builder: Republic Transmission
The final cost of the project was 10%-17% lower thanks to competitive bidding.
**Potential Savings:* $10 Million

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION



2023 Summer Reliability Assessment

May 2023

2023 Summer Reliability Assessment Video

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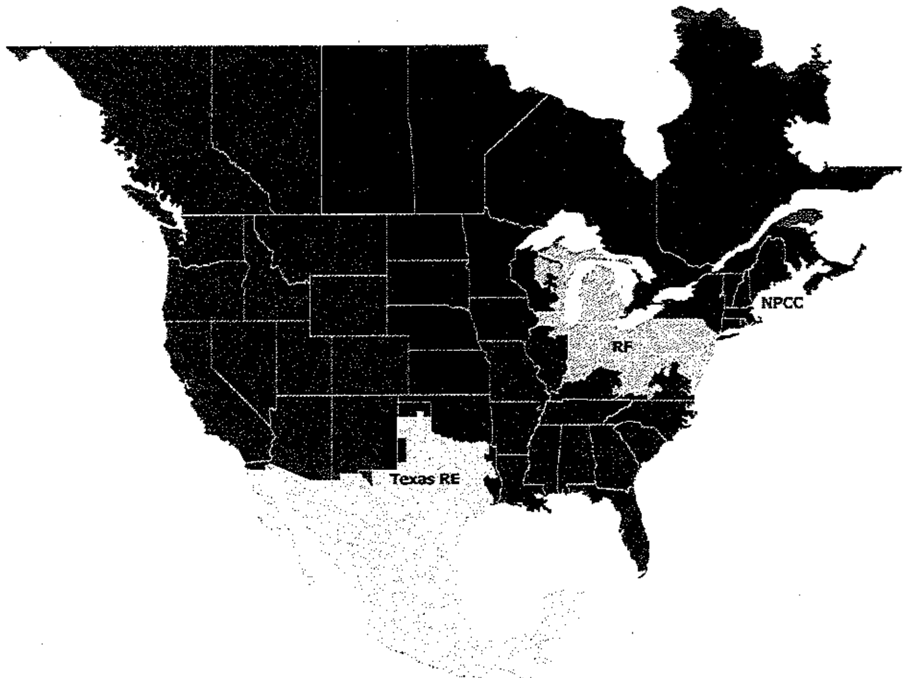
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entities as shown on the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators (TO/TOP) participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About this Assessment

NERC's *2023 Summer Reliability Assessment* (*SRA*) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming summer season. In addition, the *SRA* presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might affect the reliability of the BPS. The reliability assessment process is a coordinated reliability evaluation between the NERC Reliability Assessment Subcommittee, the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas. This report reflects an independent assessment by NERC and the ERO Enterprise and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to take necessary actions to ensure BPS reliability. This report also provides an opportunity for the industry to discuss plans and preparations to ensure reliability for the upcoming summer period.

Key Findings

NERC's annual SRA covers the upcoming four-month (June–September) summer period. This assessment provides an evaluation of generation resource and transmission system adequacy as well as energy sufficiency to meet projected summer peak demands and operating reserves. This includes a deterministic evaluation of data submitted for peak net demand hour and peak risk hour as well as results from recently updated probabilistic analyses. Additionally, this assessment identifies potential reliability issues of interest and regional topics of concern. While the scope of this seasonal assessment is focused on the upcoming summer, the key findings are consistent with risks and issues that NERC has highlighted in the *2022 Long-Term Reliability Assessment* and other earlier reliability assessments and reports.

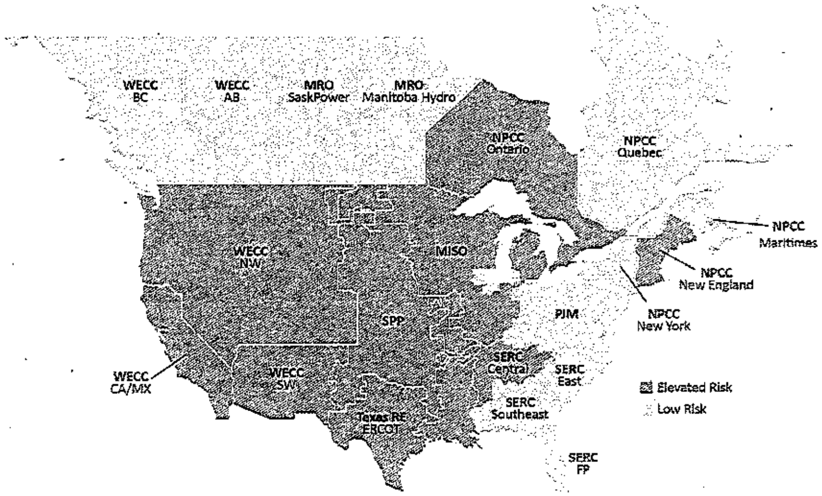
The following findings are NERC's and the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as potential operational concerns that may need to be addressed for the 2023 summer.

Resource Adequacy Assessment and Energy Risk Analysis

All areas are assessed as having adequate anticipated resources for normal summer peak load and conditions (see **Figure 1**). However, the following areas face risks of electricity supply shortfalls during periods of more extreme summer conditions. This determination of elevated risk is based on analysis of plausible scenarios, including 90/10 demand forecasts and historic high outage rates as well as low wind, solar photovoltaic (PV), or hydro energy conditions:

- **Midcontinent ISO (MISO):** The risk of being unable to meet reserve requirements at peak demand this summer in MISO is lower than in 2022 due to additional firm import commitments and lower peak demand forecast. MISO is expected to have sufficient resources, including firm imports, for normal summer peak demand. Wind generator performance during periods of high demand is a key factor in determining whether there is sufficient electricity supply on the system to maintain reliability. MISO can face challenges in meeting above-normal peak demand if wind generator energy output is lower than expected. Furthermore, the need for external (non-firm) supply assistance during more extreme demand levels will depend largely on wind energy output. Results of MISO's capacity auction have not been released at the time of this assessment, and these could change MISO's firm resources for the summer.
- **NPCC-New England:** Anticipated resources in New England are projected to be lower than in 2022 but are expected to remain sufficient for meeting operating reserve requirements at normal peak demand. Operating procedures for obtaining emergency resources or non-firm supplies from neighboring areas are likely to be needed during more extreme demand or low resource conditions.
- **NPCC-Ontario:** Planned nuclear outage for refurbishment have reduced the electricity supply resources serving the province. Additionally, load growth is contributing to a constrained transmission network during high-demand conditions that may not be able to deliver sufficient supply to the Windsor-Essex area in the southwest part of the province. Additional generator outages or extreme demand can lead to reserve shortages and a need to seek non-firm imports. Ontario could potentially see a significant increase in reliance on imports this summer under both normal peak (50/50) and extreme (90/10) demand scenarios.
- **SERC-Central:** Compared to the summer of 2022, forecasted peak demand has risen by over 950 MW while growth in anticipated resources has been flat. The assessment area is expected to have sufficient supply for normal peak demand while demand-side management or other operating mitigations can be expected for above-normal demand or high generator-outage conditions.
- **Southwest Power Pool (SPP):** Reserve margins have also fallen in SPP as a result of increasing peak demand and declining anticipated resources. Like MISO, the energy output of SPP's wind generators during periods of high demand is a key factor in determining whether there is sufficient electricity supply on the system. SPP can face energy challenges in meeting extreme peak demand or managing periods of thermal or hydro generator outages if wind resource energy output is below normal.
- **Texas (ERCOT):** The area is experiencing strong growth in both resources and forecasted demand. ERCOT added over 4 GW of new solar PV nameplate capacity to the ERCOT grid since 2022. Additionally, load reductions from dispatchable demand response programs have grown by over 18% to total 3,380 MW. ERCOT's peak demand forecast has also risen by 6% as a result of economic growth. Resources are adequate for peak demand of the average summer; however, dispatchable generation may not be sufficient to meet reserves during an extreme heat-wave that is accompanied by low winds.
- **U.S. Western Interconnection:** Resources across the area are sufficient to support normal peak demand. However, wide-area heat events can expose the WECC assessment areas of California/Mexico (CA/MX), Northwest (NW), and Southwest (SW) to risk of energy supply shortfall as each area relies on regional transfers to meet demand at peak and the late afternoon to evening hours when energy output from the area's vast solar PV resources are diminished. Within the Western Interconnection, entities are planning to install over 2 GW of new battery energy storage systems, which can help reduce energy risks from resource variability. Wildfire risks to the transmission network, which often accompany these wide-area heat events, can limit electricity transfers and result in localized load shedding.

All other areas have sufficient resources to manage normal summer peak demand and are at low risk of energy shortfalls from more extreme demand or generation outage conditions. Anticipated Reserve Margins meet or surpass the Reference Margin Level, indicating that planned resources in these areas are adequate to manage the risk of a capacity deficiency under normal conditions. Furthermore, based on risk scenario analysis in these areas, resources and energy appear adequate. **Figure 1** below summarizes the risk status for all assessment areas.



Seasonal Risk Assessment Summary	
High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Low	Sufficient operating reserves expected

Figure 1: Summer Reliability Risk Area Summary

Other Reliability Issues

- **Stored supplies of natural gas and coal are at high levels, but industry is monitoring for potential generator fuel delivery risks.** The natural gas supply and infrastructure is vitally important to electric grid reliability, even as renewable generation satisfies more of our energy needs. Fuel supply and delivery infrastructure must be capable of meeting the ramp rates of natural-gas-fired generators as they balance the system when solar generation output declines. Likewise, owners and operators of some coal-fired generators in the U.S. Southeast report challenges in arranging coal replenishment due to mine closures and transport delays. Consequently, some Balancing Authorities (BA) continue to employ coal-conservation measures that began in late 2022 in order to maintain sufficient stocks for peak months.
- **New environmental rules that restrict power plant emissions will limit the operation of coal-fired generators in 23 states, including Nevada, Utah, and several states in the Gulf Coast, mid-Atlantic, and Midwest.** The U.S. Environmental Protection Agency's (EPA) Good Neighbor Plan, finalized on March 15, 2023, ensures that affected states meet the Clean Air Act's "Good Neighbor" requirements by reducing pollution that significantly contributes to problems attaining and maintaining the EPA's health-based air quality standard[1] for ground-level ozone (i.e., smog) in downwind states.[2] Coal and natural-gas-fired generators in states affected by the Good Neighbor Plan will likely meet tighter emissions restrictions primarily by limiting hours of operation in this first year of implementation rather than through adding emissions control equipment. RCs in summer-peaking areas typically are not able to authorize extended outages to upgrade systems during this summer season in order to ensure sufficient resources for high demand. The final rule approved by the EPA includes provisions designed to give grid owners and operators flexibility to help maintain reliability, including allowance-trading mechanisms. Consequently, RCs, BAs, and GOs will need to be vigilant for emissions rule constraints that affect generator dispatchability and the potential need for emission allowance trades or waivers to meet high demand or low resource conditions. State regulators and industry should have protocols in place at the start of summer for managing emergent requests.
- **Low inventories of replacement distribution transformers could slow restoration efforts following hurricanes and severe storms.** The electric industry continues to face a shortage of distribution transformers as a result of production not keeping pace with demand. A survey by the American Public Power Association revealed that many utilities have low levels of emergency stocks that are used for responding to natural disasters and catastrophic events.[3]

[1] This standard is known as the 2015 Ozone National Ambient Air Quality Standards (NAAQS)
[2] https://www.epa.gov/csapr/good-neighbor-plan-2015-ozone-naaqs#summary

[3] https://www.publicpower.org/periodical/article/appa-survey-members-shows-distribution-transformer-production-not-meeting-demand

Asset sharing programs used by utilities provide visibility and voluntary equipment sharing to maximize resources; however, electricity customers may experience delayed restoration of power following storms as crews must work to obtain new equipment. New efficiency standards for distribution transformers proposed by the U.S. Department of Energy could further exacerbate the transformer supply shortages.[4]

- **Supply chain issues present maintenance and summer preparedness challenges and are delaying some new resource additions.** Difficulties in obtaining sufficient labor, material, and equipment as a result of broad economic factors has affected preseason maintenance of transmission and generation facilities in North America. These supply chain issues have led some owners and operators to delay or cancel maintenance activities that are typically performed to ensure facilities are ready for summer conditions. Additionally, GOs in some areas that were preparing to interconnect new generation are facing delays that will prevent some from being available to meet expected peak summer demand. This includes areas in the U.S. Southeast and the U.S. part of the Western Interconnection (see **Regional Assessments Dashboards** for details). These supply chain issues can exacerbate concerns in elevated risk areas (**Figure 1**) and add challenges to operators across the BPS. Should project delays emerge, affected GOs and TOs must communicate changes to BAs, TOPs, and RCs so that impacts are understood and steps are taken to reduce risks of capacity deficiencies or energy shortfalls.
- **Winter precipitation is expected to improve the water supply for hydro generation in parts of the U.S. West, but low water levels on major reservoirs remain a concern for electricity generation.** Significant amounts of rainfall and high elevation snow are expected to help replenish reservoirs and maintain river flows that provide energy for most of California's hydroelectric facilities. However, reservoirs at the largest hydro facilities in the U.S. West, including Washington's Grand Coulee Dam and the Hoover Dam on the Arizona-Nevada border, remain at historic low levels, potentially limiting hydroelectric energy output. Power from these plants is used throughout the U.S. Western Interconnection.
- **Unexpected tripping of wind and solar PV resources during grid disturbances continues to be a reliability concern.** NERC has analyzed multiple large-scale disturbances on the BPS that involved widespread loss of inverter-based resources (IBR). In 2021 and 2022, the Texas Interconnection experienced widespread IBR loss events, like those previously observed in the California area. Similarly, four additional solar PV loss events occurred between June and August 2021 in California. In 2022, ERCOT required GOs to submit mitigation plans, and corrective measures are being implemented in 2023. In March 2023, NERC issued the *Inverter-Based Resource Performance Issues Alert* to GOs of Bulk Electric System (BES) solar PV generating resources.[5] As a Level 2 alert, it contains recommended actions for GOs of grid-connected solar PV resources, including steps to coordinate protection and controller settings, so that the resources will reliably operate during grid disturbances.
- **Curtailment of electricity transfers to areas in need during periods of high regional demand is a growing reliability concern.** During energy emergencies and periods of transmission system congestion, RCs and BAs may curtail area transfers for various reasons using established procedures and protocols. While the curtailments alleviate an issue in one part of the system, they can contribute to supply shortages or effect local transmission system operations in another area. Two recent extreme temperature events highlight the effect of transfer curtailments on area supply needs during energy emergencies. During the September 2022 wide-area heat dome, a BA in the WECC-SW assessment area declared an energy emergency when the neighboring assessment area, California Independent System Operator (CAISO), curtailed transfers in order to meet the high demand within their own area. During Winter Storm Elliott, firm exports were curtailed from PJM during a period of widespread energy emergencies in the U.S. Eastern Interconnection.

  For the summer of 2023, several areas identified as having capacity or energy risks are relying on imports of electricity supplies. These areas include MISO, NPCC-Ontario, SERC-Central, and the assessment areas in the U.S. Western Interconnection. A wide-area heat event that severely affects regional demand or generator availability presents an added concern in areas that are dependent on imports for managing high electricity demand.
- **In addition to the risk items identified in the Key Findings, resource outages will continue to present challenges in many areas during "near-peak" demand conditions that occur in spring and fall.** Many parts of North America experience elevated temperatures that extend beyond the summer (June–September) months into periods when BPS equipment owners and operators historically scheduled outages for maintenance. Increasingly, BAs are facing resource constrained periods during shoulder months as unseasonable temperatures coincide with generator unavailability. Careful attention to long-term weather forecasts and the potential for unusual heat patterns in the shoulder months is important to inform the need for more conservative outage coordination periods.

[4] https://www.energy.gov/articles/doe-proposes-new-efficiency-standards-distribution-transformers

[5] https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC%20Alert%20R-2023-03-14-01%20Level%202%20-%20Inverter-Based%20Resource%20Performance%20Issues.pdf

Recommendations

To reduce the risk of electricity shortfalls on the BPS this summer, NERC recommends the following:

- RCs, BAs, and TOPs in the elevated risk areas identified previously in the key findings should take the following actions:
  - Review seasonal operating plans and the protocols for communicating and resolving potential supply shortfalls in anticipation of potentially extreme demand levels
  - Employ conservative generation and transmission outage coordination procedures commensurate with long-range weather forecasts to ensure adequate resource availability
  - Engage state or provincial regulators and policymakers to prepare for efficient implementation of demand side management mechanisms called for in operating plans
- GOs with solar PV resources should implement recommendations in the inverter-based resource performance issues alert that NERC issued in March 2023.
- RCs, BAs, and GOs in states affected by the new Good Neighbor Plan should be familiar with its provisions for ensuring electric reliability and have protocols in place to act to preserve generation resources when necessary to support periods of high demand. State regulators and industry should have protocols in place at the start of summer for managing emergent requests.

Discussion

Summer Temperature and Drought Forecasts

Peak electricity demand in most areas is directly influenced by temperature. Weather officials are expecting above normal temperatures for much of the United States while Canada is largely expected to see normal or below-normal average temperatures (see **Figure 2**). In addition, drought conditions continue across much of the western half of North America, resulting in unique challenges to area electricity supplies and potential impacts on demand.[6] Assessment area load forecasts account for many years of historical demand data, often up to 30 years, to predict summer peak demand and prepare for more extreme conditions. Above average seasonal temperatures can contribute to high peak demand as well as an increase in forced outages for generation and some BPS equipment. Effective preseason maintenance and preparations are particularly important to BPS reliability in severe or prolonged periods of above-normal temperatures.

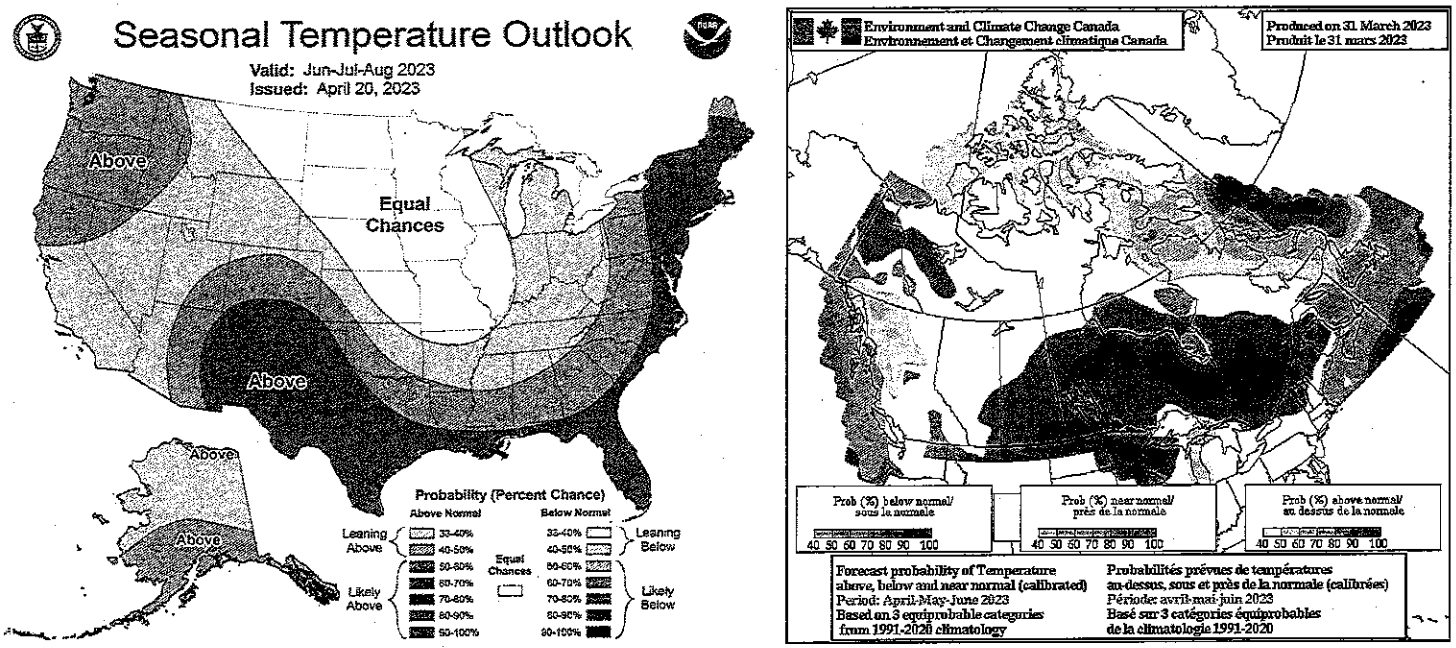


Figure 2: United States and Canada Summer Temperature Outlook[7]

[6] See North American Drought Monitor: https://www.ncdc.noaa.gov/temp-and-precip/drought/nadm/maps
[7] Seasonal forecasts obtained from U.S. National Weather Service and Natural Resources Canada: https://www.cpc.ncep.noaa.gov/products/predictions/long_range/ and https://weather.gc.ca/saisons/prob_e.html

Wildfire Risk Potential and BPS Impacts

Normal or below-normal fire risk is projected for much of the U.S. West at the beginning of the summer; in contrast, Florida, West Texas, and Central Canada project above-normal fire risks for the beginning of summer (see **Figure 3**). BPS operation can be impacted in areas where wildfires are active as well as areas where there is heightened risk of wildfire ignition due to weather and ground conditions. Above normal fire risk is projected for much of Canada throughout the summer.

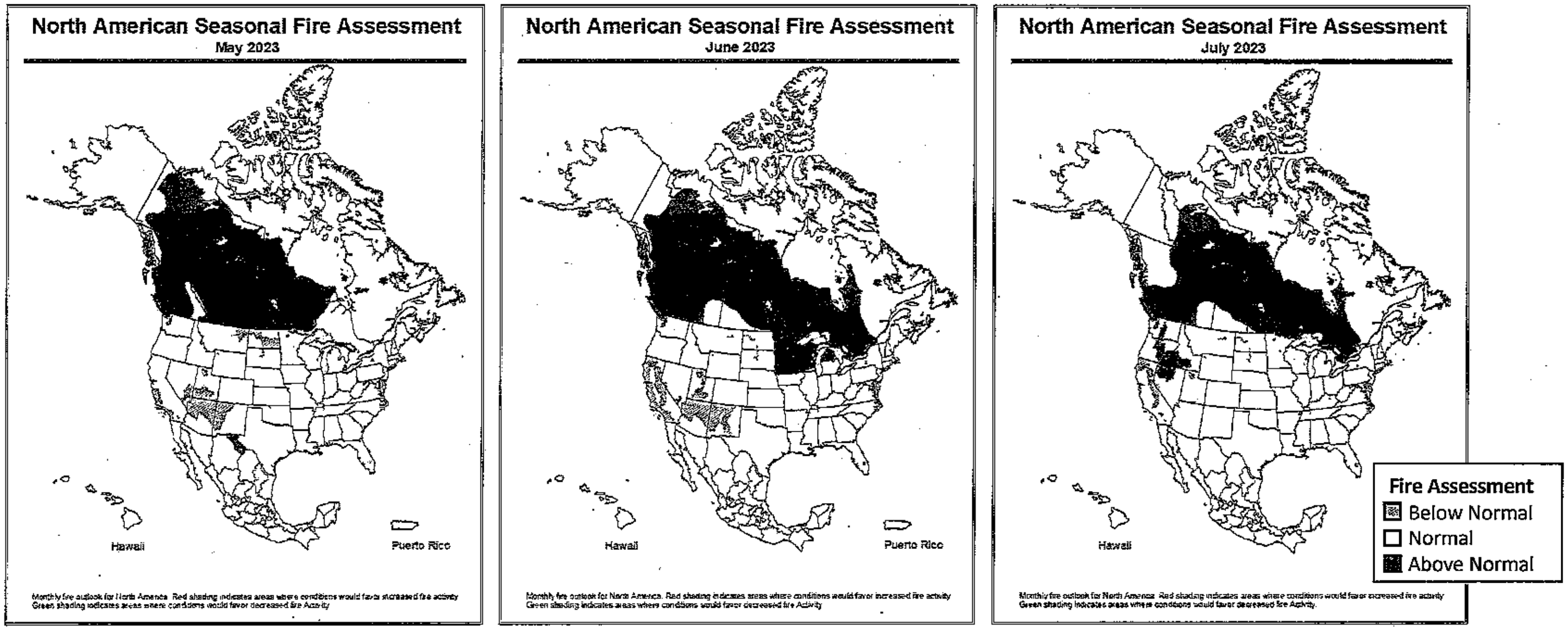


Figure 3: North American Seasonal Fire Assessment for May through July 2023[8]

Wildfire prevention planning in California and some states in the U.S. Northwest include power shut-off programs in high fire-risk areas. When conditions warrant implementing these plans, power lines (including transmission-level lines) may be preemptively de-energized in high fire-risk areas to prevent wildfire ignitions. Other wildfire risk mitigation activities include implementing enhanced vegetation management, equipment inspections, system hardening, and added situational awareness measures. In January 2021, the ERO published the *Wildfire Mitigation Reference Guide*[9] to promote preparedness within the North American electric power industry and share the experiences and practices from utilities in the Western Interconnection.

[8] *See North American Seasonal Fire Assessment and Outlook*, May 2023. Subsequent updates at this link will include August and September: https://www.predictiveservices.nifc.gov/outlooks/NA_Outlook.pdf
[9] See the NERC *Wildfire Mitigation Reference Guide*, January 2021: https://nerc.com/comm/RSTC/Documents/Wildfire%20Mitigation%20Reference%20Guide_January_2021.pdf

Risk Assessments of Resource and Demand Scenarios

Seasonal risk scenarios for each assessment area are presented in the **Regional Assessments Dashboards** section. The on-peak reserve margin and seasonal risk scenario chart in each dashboard provide potential summer peak demand and resource condition information. The reserve margins on the right side of the dashboard pages provide a comparison to the previous year's assessment. The seasonal risk scenario charts present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. The assessment areas determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized in the seasonal risk scenario charts; see the **Data Concepts and Assumptions** for more information about these dashboard charts.

The seasonal risk scenario charts can be expressed in terms of reserve margins: In **Table 1**, each assessment area's Anticipated Reserve Margins are shown alongside the reserve margins for a typical generation outage scenario (where applicable) and the extreme demand and resource conditions in their seasonal risk scenario.

Highlighted in orange are the areas identified as having resource adequacy or energy risks for the summer in the **Key Findings** section's discussion. The typical outages reserve margin is comprised of anticipated resources minus the capacity that is likely to be in maintenance or forced outage at peak demand. If the typical maintenance or forced outage margin is the same as the Anticipated Reserve Margin, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions margin includes all components of the scenario and represents the most severe operating conditions of an area's scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

In addition to the peak demand and seasonal risk hour scenario charts, the assessment areas provided a resource adequacy risk assessment that was probability-based for the summer season. Results are included in the Highlights section of each assessment area's dashboard and summarized in the **Probabilistic Assessment** section. The risk assessments account for the hour(s) of greatest risk of resource shortfall. For most areas, the hour(s) of risk coincide with the time of forecasted peak demand; however, some areas incur the greatest risk at other times based on the varying demand and resource profiles. Various risk metrics are provided and include loss of load expectation (LOLE), loss of load hours (LOLH), expected unserved energy (EUE), and the probabilities of energy emergency alert (EEA) occurrence.

Table 1: Seasonal Risk Scenario On-Peak Reserve Margins

Assessment Area	Anticipated Reserve Margin	Anticipated Reserve Margin with Typical Outages	Anticipated Reserve Margin with Higher Demand, Outages, Derates in Extreme Conditions
MISO	23.0%	4.3%	-6.9%
MRO-Manitoba	29.1%	25.6%	13.1%
MRO-SaskPower	29.1%	12.8%	-1.9%
NPCC-Maritimes	49.7%	39.3%	20.2%
NPCC-New England	17.7%	7.0%	-3.9%
NPCC-New York	30.3%	17.0%	9.9%
NPCC-Ontario	14.0%	14.0%	8.6%
NPCC-Québec	37.1%	37.1%	37.1%
PJM	31.9%	23.4%	8.4%
SERC-Central	18.0%	9.6%	6.4%
SERC-East	19.1%	16.0%	9.0%
SERC-Florida Peninsula	26.6%	19.9%	12.8%
SERC-Southeast	39.6%	36.4%	33.8%
SPP	24.6%	14.3%	-4.0%
Texas RE-ERCOT	23.0%	16.5%	-1.6%
WECC-AB	24.8%	21.9%	8.1%
WECC-BC	28.9%	28.8%	-5.4%
WECC-CA/MX	35.0%	29.0%	-11.9%
WECC-NW	28.5%	22.5%	-12.9%
WECC-SW	19.5%	15.8%	-6.8%

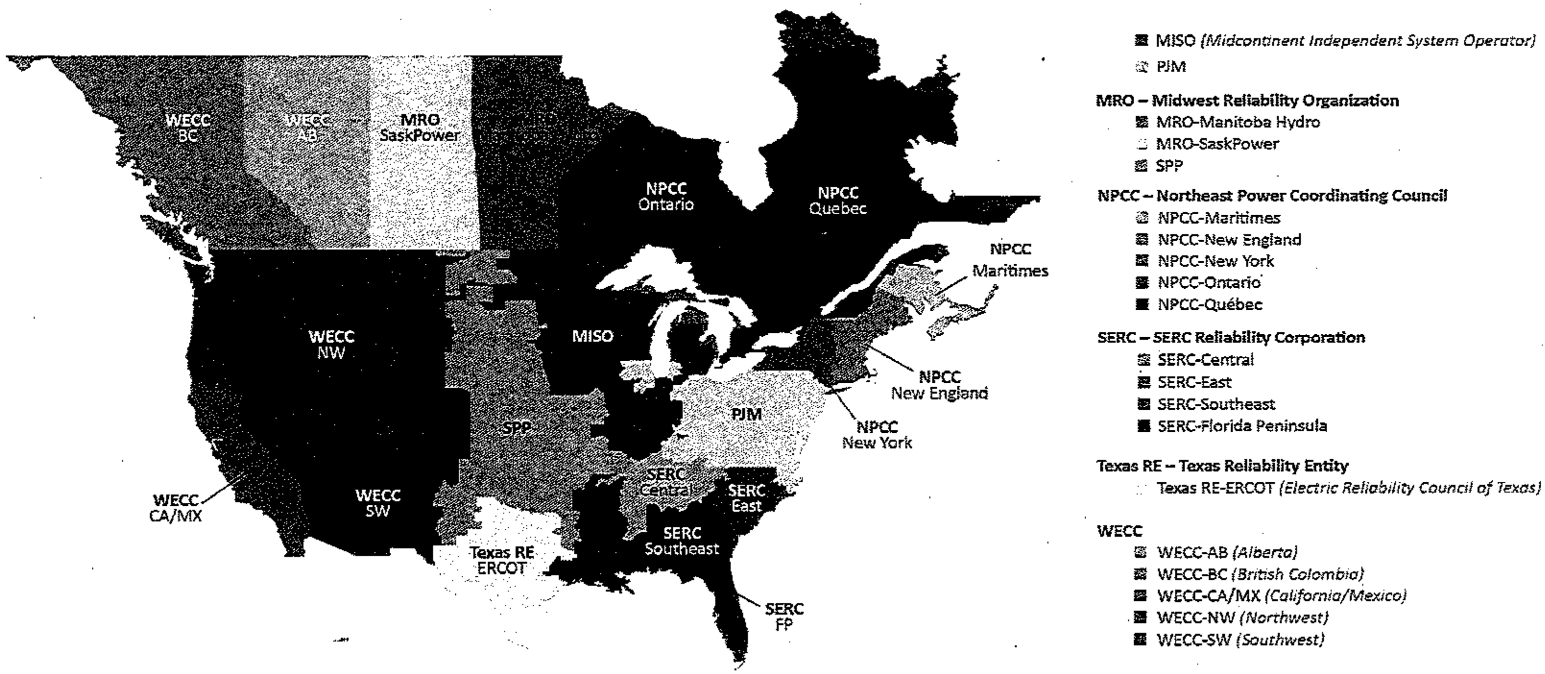
Extreme generation outages, low resource output, and peak loads similar to those experienced in wide area heat events and the heat domes experienced in western parts of North America during the last three summers are ongoing reliability risks in certain areas for the summer of 2023. When forecasted resources in an area fall below expected demand, BAs would need to employ operating mitigations or EEA to obtain the capacity and energy necessary to meet extreme peak demands. **Table 2** describes the various EEA levels and the circumstances for each.

Table 2: Energy Emergency Alert Levels

EEA Level	Description	Circumstances
EEA 1	All available generation resources in use	• The BA is experiencing conditions where all available generation resources are committed to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required contingency reserves. • Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
EEA 2	Load management procedures in effect	• The BA is no longer able to provide its expected energy requirements and is an energy deficient BA. • An energy deficient BA has implemented its operating plan(s) to mitigate emergencies. • An energy deficient BA is still able to maintain minimum contingency reserve requirements.
EEA 3	Firm Load interruption is imminent or in progress	• The energy deficient BA is unable to meet minimum contingency reserve requirements.

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. Guidelines and definitions are in the **Data Concepts and Assumptions** table. On-Peak Reserve Margin bar charts show the Anticipated Reserve Margin compared to a Reference Margin Level that is established for the areas to meet resource adequacy criteria. Prospective Reserve Margins can give an indication of additional on-peak capacity but are not used for assessing adequacy. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left blue column shows anticipated resources (from the **Demand and Resource Tables**), and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand (from the **Demand and Resource Tables**) and the extreme summer peak demand determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources. Adjustments may include reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools (if any) that are available during scarcity conditions but have not been accounted for in the SRA reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios. In addition, results from a probability-based resource adequacy assessment are shown in the Highlights section of each dashboard. Methods varied by assessment area and provided further insights into the risk conditions forecasted for the summer period.



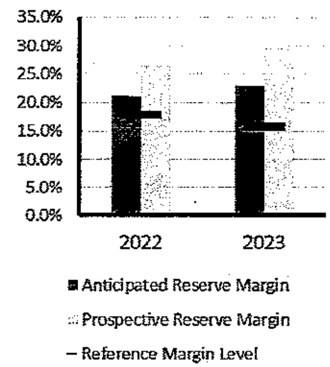
MISO

MISO is a not-for profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy, reliability, and operating reserve markets that consist of 36 local BA and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

Highlights

- Demand forecasts and preliminary resource data indicate that MISO is at risk of operating reserve shortfalls during periods of high demand or low resource output. MISO's resources are projected to be lower than in the summer of 2022 while net internal demand has also decreased. Firm transmission imports for this summer have significantly increased; this has resulted in a higher Anticipated Reserve Margin (ARM) of 23% (on an installed capacity basis) compared to 21% last summer. MISO's capacity auction has not concluded at the time of this assessment, which could lead to some change to MISO's firm resources for the summer.
- MISO conducted its annual probabilistic LOLE analysis and determined a 2023 Reference Margin Level (RML) of 15.9% results in an LOLE of 1 day in 10 years. MISO's RML declined from 17.9% in 2022 to 15.9% in 2023 based on the newly implemented seasonal capacity construct and associated modeling improvements that include seasonal outage rates and other enhancements. Comparing the increased ARM to the lower RML indicates improved reliability from the LOLE base case at 1 day in 10 years.
- Performance of wind generators during periods of high electricity demand is a key factor in determining whether system operators need to employ operating mitigations, such as maximum-generation declarations and energy emergencies. MISO has over 30,300 MW of installed wind capacity; however, the historically-based on-peak capacity contribution is 5,488 MW.

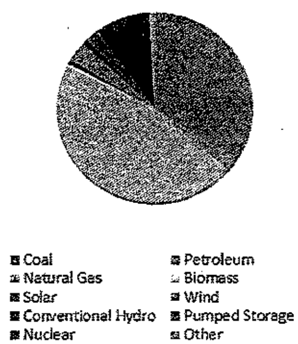
On-Peak Reserve Margin



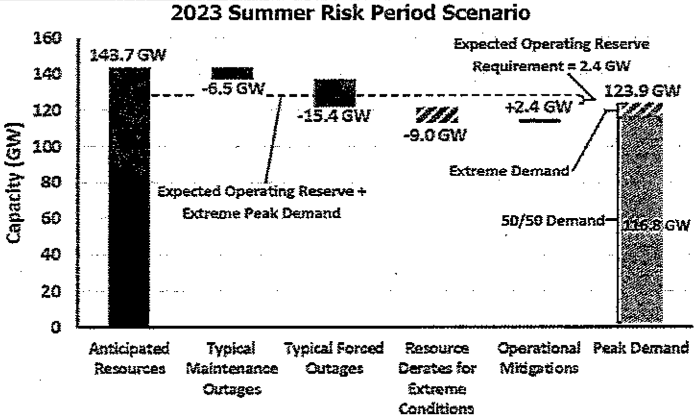
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., load modifying resources and energy transfers from neighboring systems) and EEAs. Emergency declarations that can only be called upon when available generation is at maximum capability are necessary to access load modifying resources (demand response) when operating reserve shortfalls are projected.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

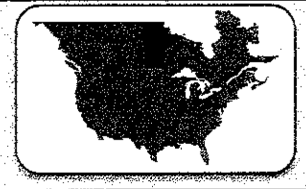
Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Maintenance Outages: Rolling five-year summer average of maintenance and planned outages

Forced Outages: Five-year average of all outages that were not planned

Extreme Derates: Maximum historical generation outages

Operational Mitigations: A total of 2.4 GW capacity resources available during extreme operating conditions



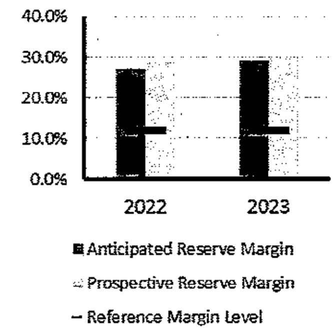
MRO-Manitoba Hydro

Manitoba Hydro is a provincial Crown Corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro is a leader in providing renewable energy and clean-burning natural gas Manitoba Hydro provides electricity to approximately 608,500 electric customers in Manitoba and provides approximately 293,000 customers with natural gas in Southern Manitoba. The service area is the province of Manitoba which is 251,000 square miles Manitoba Hydro is winter peaking. Manitoba Hydro is its own Planning Coordinator (PC) and BA. Manitoba Hydro is a coordinating member of MISO. MISO is the RC for Manitoba Hydro.

Highlights

- Manitoba Hydro is not anticipating any operational challenges and/or emerging reliability issues in its assessment area for the summer of 2023.
- The Anticipated Reserve Margin for the summer of 2023 exceeds the 12% Reference Margin Level.
- Six of the seven units at Keeyask Generating Station (hydroelectric) have reached commercial operation status. The remaining unit (Keeyask Unit 6) is listed as a Tier 1 capacity resource as it is operating but awaiting official commercial operation status.
- The 2022 probabilistic work indicated the annual probabilistic indices for the Manitoba Hydro system for 2024 of 29 MWh per year of EUE. Given comparable supply and demand balance, the 2024 EUE is a reasonable estimate for all of 2023.

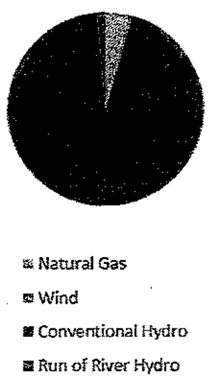
On-Peak Reserve Margin



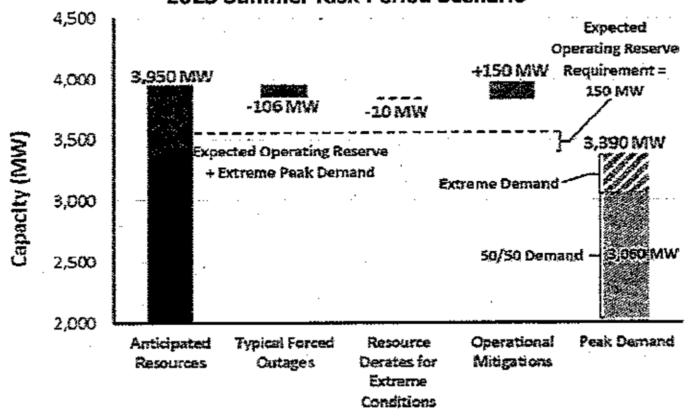
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

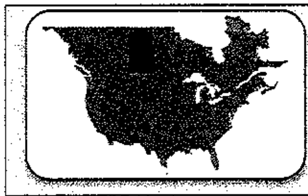
Demand Scenarios: (50/50) Demand with allowance for Extreme Demand based on extreme summer weather scenario of 37 C (99 F)

Forced Outages: Typical forced outages

Extreme Derates: Summer wind capacity accreditation of 18.1% of nameplate rating based on MISO seasonal analysis

Normal hydro generation expected for this summer.

Operational Mitigations: Utilize Curtailable Rate Program to manage peak demand; utilize operating reserve if additional measures required



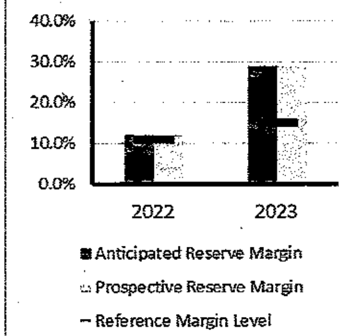
MRO-SaskPower

MRO-SaskPower is an assessment area in the Saskatchewan province of Canada. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and a population of approximately 1.1 million. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the PC and RC for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan BES and its Interconnections.

Highlights

- Summer reserve margins in Saskatchewan are higher than in 2022 due to the addition of new wind resources, fewer scheduled generator outages, and lower forecasted peak demand.
- Saskatchewan is a winter-peaking region but also experiences high load in summer during extreme hot weather.
- SaskPower conducts an annual summer joint operating study with Manitoba Hydro and prepares operating guidelines for any identified issues. Inputs from the Western Area Power Administration are included in the study.
- Results from SaskPower's probabilistic analysis indicate that the expected number of hours with operating reserve deficiency for the 2023 summer season (June to September) is 0.21 hours. The month with the highest probability of EEA is September (0.07 hours). The risk of operating reserve shortage during peak load times or EEAs could increase if large generation forced outage combined with planned maintenance outages occurs during peak load times in June, July, August, and September months.
- In case of extreme electricity demand from high temperatures combined with large generation forced outages, SaskPower would use available demand response programs, short-term power transfers from neighboring utilities, and short-term load interruptions if necessary.
- The Reference Reserve Margin was updated to adequately assess energy risks, such as due to changing resource mix, and to align with NERC recommended RRM.

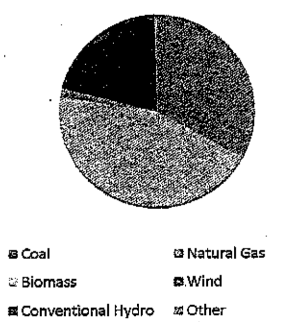
On-Peak Reserve Margin



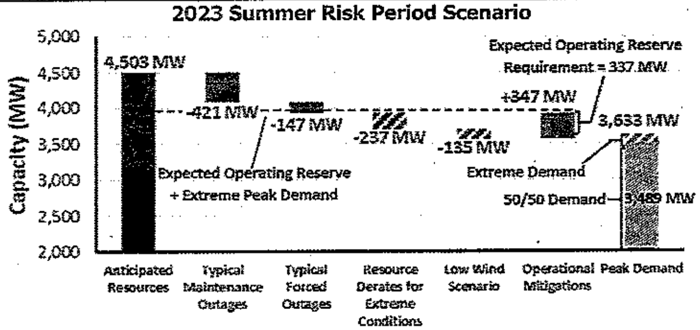
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and above-normal scenario based on peak demand with lighting and all consumer loads

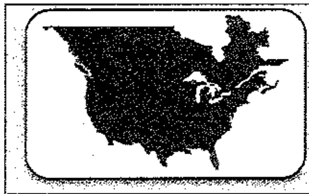
Maintenance Outages: Average of planned maintenance outages for the last three summers less future planned outages (already considered in Anticipated Resources)

Forced Outages: Estimated by using SaskPower forced outage model

Extreme Derates: Estimated resources unavailable in extreme conditions

Low Wind Scenario: 33% reduction in nameplate capacity for temperatures between 35° C and 40° C

Operational Mitigations: Estimated non-firm imports and stand-by generators on 2–7 day notice



NPCC-Maritimes

The Maritimes assessment area is a winter-peaking NPCC area that contains two BAs. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, and Prince Edward Island, and the northern portion of Maine, which is radially connected to the New Brunswick power system. The area covers 58,000 square miles with a total population of 1.9 million.

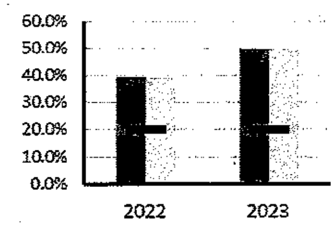
Highlights

- The Maritimes area has not identified any operational issues that are expected to impact system reliability. If an event were to occur, there are emergency operations and planning procedures in place. All of the area's declared firm capacity is expected to be operational for the summer. As part of the planning process, dual-fuel units will have sufficient supplies of heavy fuel oil on-site to enable sustained operation in the event of natural gas supply interruptions.
- Based on an NPCC Probabilistic Assessment, minimal amounts of cumulative LOLE (<0.03 days/period), LOLH (<0.11 hours/period), or EUE (<5 MWh/period) were estimated over the May–September summer period for all modeled scenarios. The Maritimes area is winter peaking. The analysis included simulation of a base case (normal 50/50 demand and expected resources) and a highest peak load scenario as well as a low-likelihood, reduced resource case. This reduced resource case considered the impacts of wind capacity being derated by half during July and August due to calm weather, natural-gas-fired units being derated by half in July and August due to supply disruptions (dual-fuel units assumed to revert to oil) as well as reduced transfer capabilities. The highest load level results were based on the two highest load levels of the seven modeled, having approximately a combined 7% chance of occurring.

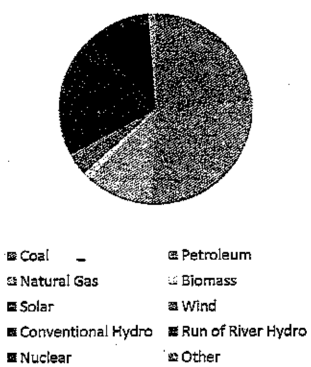
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs.

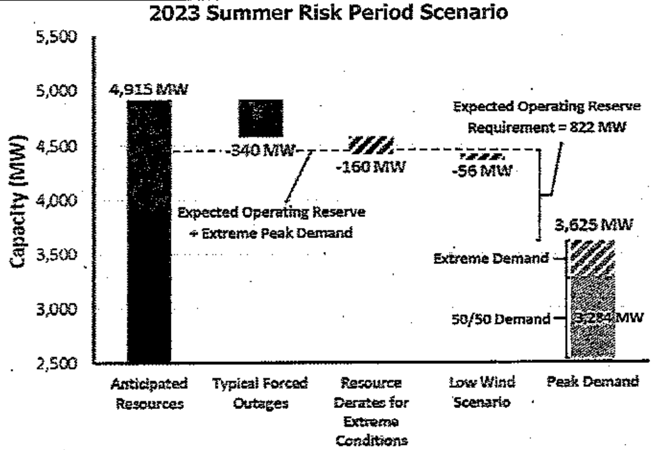
On-Peak Reserve Margin



On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (above 90/10) extreme demand forecast

Forced Outages: Based on historical operating experience

Extreme Derates: A low-likelihood scenario resulting in an additional 50% derate in the remaining capacity of both natural gas and wind resources under extreme conditions

NPCC-New England

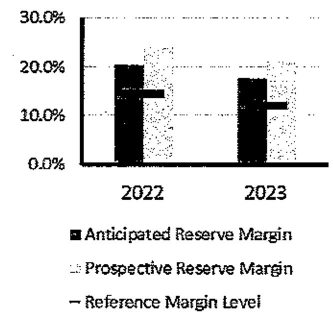
NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont that is served by ISO New England (ISO-NE) Inc. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS.

The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

Highlights

- Reserve margins in New England are projected to be lower this summer due to less existing-certain capacity and firm imports. The New England area expects to have sufficient capacity to meet the 2023 summer peak demand forecast. As of April 4, 2023, The New England area expects to have sufficient resources to meet the 2023 summer peak demand forecast of 24,664 MW, for the weeks beginning June 4 through week beginning September 10, 2023, with the lowest projected net margin of 231 MW (0.9%) during the week of June 25, 2023. The 2023 summer demand forecast takes into account the demand reductions associated with energy efficiency, load management, behind-the-meter photovoltaic (BTM-PV) systems, and distributed generation.
- Based on an NPCC Probabilistic Assessment, ISO-NE may rely on limited use of its operating procedures that are designed to mitigate resource and energy shortages during the summer. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios except the severe low-likelihood case. This reduced resource case with the highest peak load scenario resulted in a small estimated cumulative LOLE risk (0.12 days/period) with associated LOLHs (0.4 hours/period) and EUE (175 MWh/period) with the highest risk occurring in June. This scenario is based exclusively on the two highest load levels with a 7% chance of occurring and a low resource case consisting of extended summer maintenance across NPCC and reduced imports from PJM.

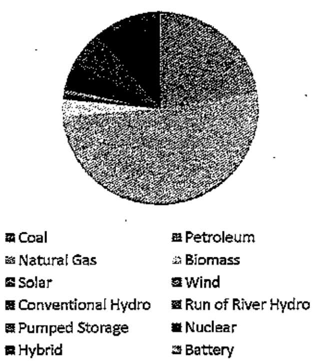
On-Peak Reserve Margin



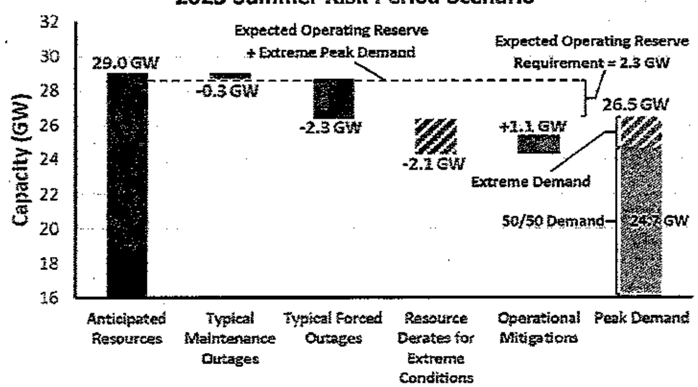
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios with local operating procedures. Extreme summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, appeals) and EEAs. As noted above, the risk of load shedding is low.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Peak net internal demand (50/50) and (90/10) extreme demand forecast

Maintenance & Forced Outages: Based on historical weekly averages

Extreme Derates: Represent a case that is beyond the (90/10) conditions based on historical observation of force outages, additional reductions for generation at risk due to operating issues at extreme hot temperatures, and other outage causes reported by generators

Operational Mitigations: Based on load and capacity relief assumed available from invocation of ISO-NE operating procedures

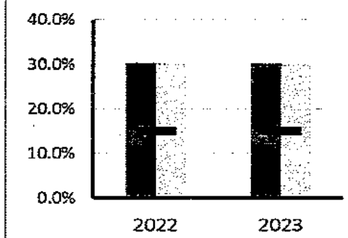
NPCC-New York

NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. The NYISO is the only BA within the state of New York. The BPS encompasses over 11,000 miles of transmission lines, 760 power generation units, and serves 20.2 million customers. For this SRA, the established Reference Margin Level is 15%. Wind, grid-connected solar PV, and run-of-river totals were derated for this calculation. However, New York requires load-serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council. New York State Reliability Council approved the 2022–2023 IRM at 20.0%.

Highlights

- NYISO is not anticipating any operational issues in the New York control area for the upcoming summer. Adequate capacity margins are anticipated, and existing operating procedures are sufficient to handle any issues that may occur.
- A number of combustion turbine generators will be retiring before or during this summer as a result of the New York State Department of Environmental Conservation Peaker Rule. Retirements in 2023 include 16 MW of natural-gas-fired, 53 MW of oil-fired, and 558 MW of dual-fueled generation. New generation includes 556 MW of land-based wind, 90 MW of new solar PV (coming in the third quarter), and 136 MW of new offshore wind generation (coming in the third quarter). Overall, the rule is expected to lead to the retirement of approximately 1,600 MW of capacity by 2025.
- Based on an NPCC Probabilistic Assessment, NYISO may rely on limited use of its operating procedures that are designed to mitigate resource and energy shortages during the summer. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios except the severe low-likelihood case. This reduced resource case with highest peak load scenario resulted in a small estimated cumulative LOLE risk (0.5 days/period) with associated LOLH (1.1 hours/period) and EUE (525 MWh/period) with the highest risk in June and August. This scenario is based exclusively on the two highest load levels with a 7% chance of occurring and a low resource case consisting of extended summer maintenance across NPCC and reduced imports from PJM.

On-Peak Reserve Margin

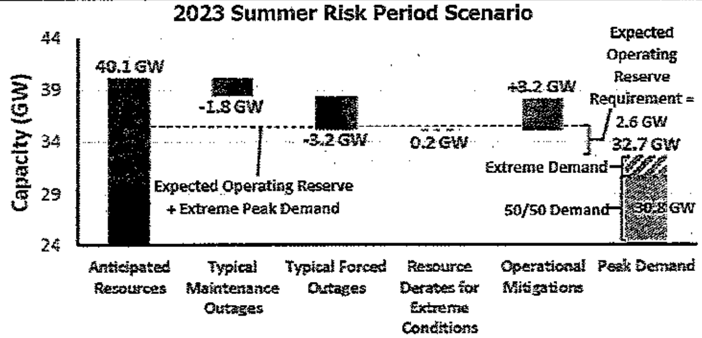


Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix

2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) extreme demand forecast

Maintenance Outages:

Forced Outages: Based on historical 5-year averages

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 3.3 GW based on operational/emergency procedures in area emergency operations manual

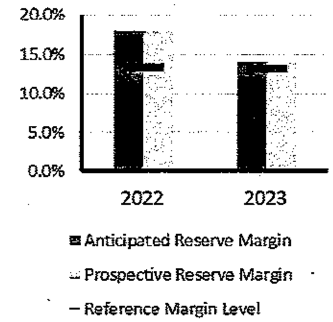
NPCC-Ontario

NPCC-Ontario is an assessment area in the Ontario province of Canada. The Independent Electricity System Operator (IESO) is the BA for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of more than 14 million. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

Highlights

- Ontario has entered a period during which generation and transmission outages will be increasingly difficult to accommodate. The IESO expects these conditions to persist for the foreseeable future. IESO is strongly encouraging market participants to plan ahead and coordinate with IESO to ensure planned outages can be appropriately scheduled.
- Under both normal and extreme weather conditions, Ontario may rely on imports and outage management for a significant number of weeks during the 2023 summer assessment period primarily as a result of coincident generator outages. Should market participants be unable to reschedule certain outages during this period, Ontario may have to rely on more than 2,000 MW of non-firm supply from other areas and/or additional operating actions to ensure reliability.
- Based on an NPCC Probabilistic Assessment, Ontario is expected to need only limited use of its operating procedures that are designed to mitigate resource and energy shortages during the summer. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios except the severe low-likelihood cases, which resulted in small LOLH (0.3 hours). These results model import availability and indicate that Ontario will be able to obtain the necessary supplies from neighbors over a range of most conditions, but there is a risk during extreme demand and low resource periods.
- The ongoing transmission outage at the New York–St. Lawrence interconnection continues to impact import and export capacity between Ontario and New York. This issue is expected to be resolved by the end of the fourth quarter of 2023.

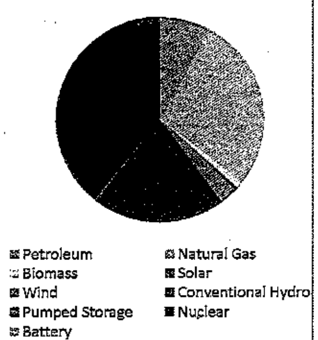
On-Peak Reserve Margin



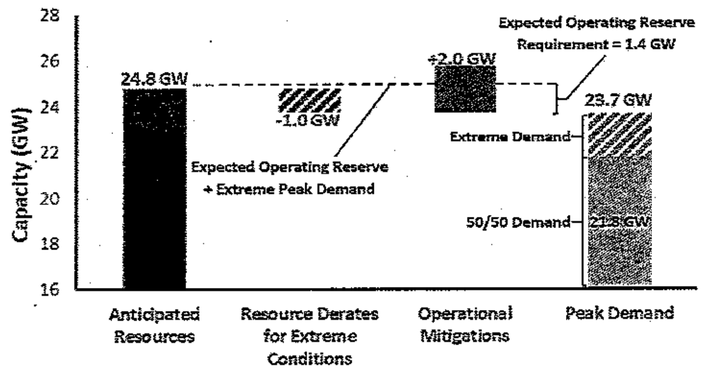
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load or extreme outage conditions could result in the need to employ operating mitigations (i.e., demand response and non-firm transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



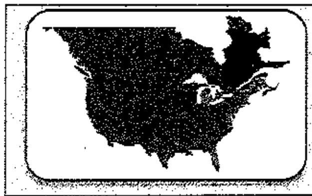
Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50 Forecast) and highest weather-adjusted daily demand based on 31 years of demand history

Extreme Derates: Derived from weather-adjusted temperature rating of thermal units and adjustments to expected hydro production for low water conditions

Operational Mitigations: Imports anticipated from neighbors during emergencies



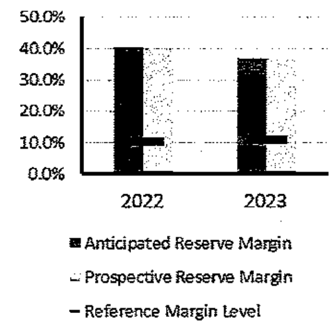
NPCC-Québec

The Québec assessment area (Province of Québec) is a winter-peaking NPCC area that covers 595,391 square miles with a population of 8 million. Québec is one of the four Interconnections in North America; it has ties to Ontario, New York, New England, and the Maritimes; consisting of either high voltage direct current ties, radial generation, or load to and from neighboring systems.

Highlights

- The Québec area forecasted summer peak demand (excluding April, May, and September) is 22,859 MW during the week of August 13, 2023, with a forecasted net margin of 7,202 MW (31.5%). No particular resource adequacy problems are forecasted, and the Québec area expects to be able to provide assistance to other areas up to the transfer capability available.
- In the Québec RC area, most transmission line, transformer, and generating unit maintenance is done during the summer period. Internal transmission outage plans are assessed to meet internal demand, firm sales, expected additional sales, and additional uncertainty margins. They should not impact inter-area transfer capabilities with neighboring systems. During the 2023 summer operating period, some maintenance outages are scheduled on the interconnections. Maintenance is coordinated with neighboring RC areas so as to leave maximum capability to summer-peaking areas.
- Based on an NPCC Probabilistic Assessment, Québec is expected to need only limited use of its operating procedures designed to mitigate resource and energy shortages during the summer. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios, including the severe low-likelihood cases.

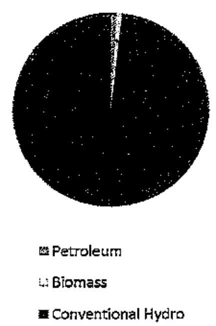
On-Peak Reserve Margin



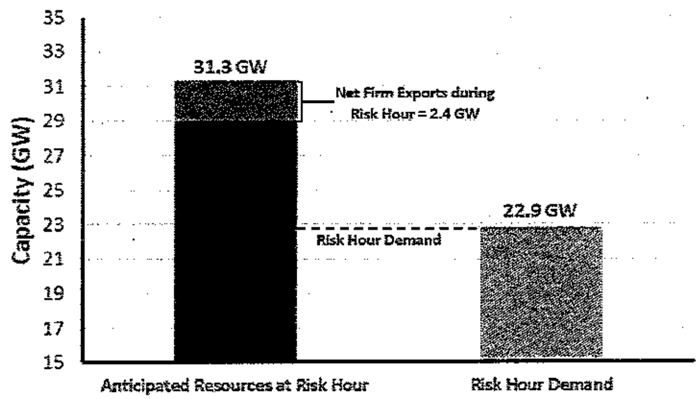
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario

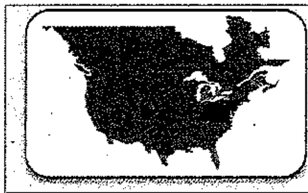


Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenario: Net internal demand (50/50) and (90/10) demand forecast

Net Firm Transfers: Anticipated exports to neighbors during the risk hour



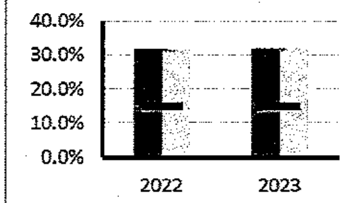
PJM

PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM serves 65 million customers and covers 369,089 square miles. PJM is a BA, PC, Transmission Planner, Resource Planner, Interchange Authority, TOP, Transmission Service Provider, and RC.

Highlights

- PJM expects no resource problems over the entire 2023 summer peak season. Installed capacity is over twice the PJM reserve requirement necessary to meet the 1-day-in-10-years LOLE criterion.
- The 2022 PJM reserve requirement study used to establish the target installed reserve margin of 14.9% analyzed a wide range of load scenarios (low, regular and extreme) as well as multiple scenarios for system-wide unavailable capacity due to forced outages, maintenance outages, and ambient derations. Due to the rather low penetration of limited and variable resources in PJM relative to PJM's peak load, the hour with most loss of load risk remains the hour with highest forecasted net peak demand.
- No other reliability issues are expected.

On-Peak Reserve Margin

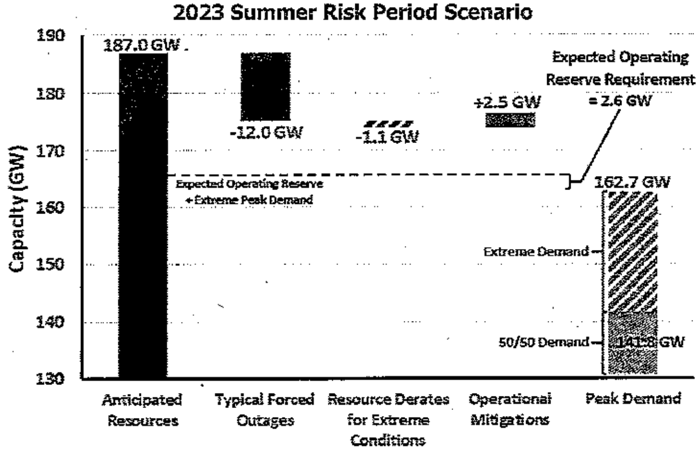


Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix

2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Based on historical data and trending

Extreme Derates: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 2.5 GW based on operational/emergency procedures

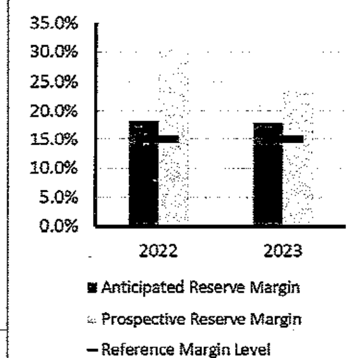
SERC-Central

SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission (FERC) approved delegation agreements with NERC. SERC-Central is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities (PA), and 6 RCs.

Highlights

- Entities in SERC-Central have not identified any potential reliability issues for the upcoming summer season. Entities anticipate having adequate system capacity for the upcoming summer season and are equipped to address unexpected short-term issues by leveraging diverse generation portfolios and spot purchases from the power markets when necessary.
- Non-economic dispatch (out of merit) of available coal-fired generators ahead of the upcoming summer season is anticipated in order to build inventory and limit consumption of fuel and consumables for plant operations and mitigate supply and transportation challenges during the summer.
- Each entity continues to work collaboratively to ensure reliability for its area within SERC and to promote reliability and adequacy across the entire SERC Regional Entity.
- Entities continue to participate actively in the SERC Near-Term and Long-Term Working Groups among others. These working groups help the entities identify and address emerging and potential reliability impacts on transmission and resource adequacy along with transfer capability.
- Probabilistic analysis indicates negligible risk for resource shortfall. The 2022 study found negligible LOLH and EUE during summer months for a similar resource mix and demand levels.

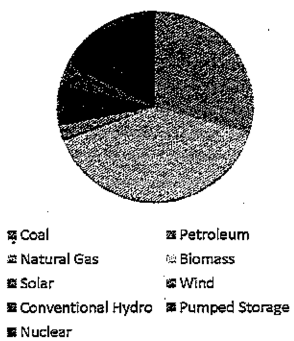
On-Peak Reserve Margin



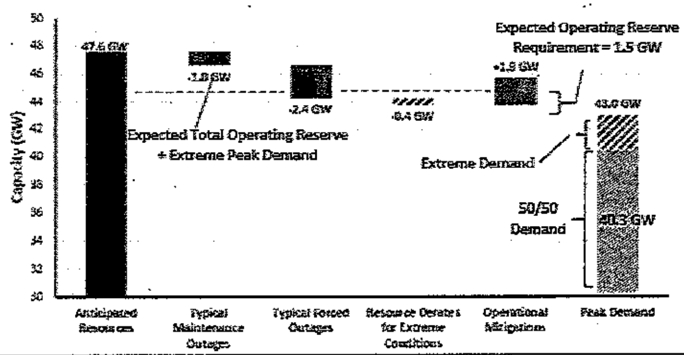
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

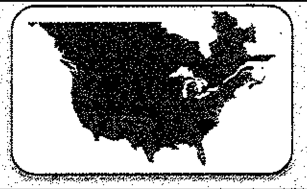
Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 1.9 GW based on operational/emergency procedures

SERC-East



SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer-peaking area, SERC-East is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 PAs, and 6 RCs.

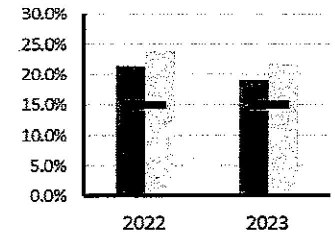
Highlights

- SERC-East is transitioning to a hybrid-peaking (both summer and winter peaking) area as solar PV reduces summer peak demand and electrification of heating drives up winter peak demand.
- Entities have not identified any emerging reliability issues or operational concerns for the upcoming summer season.
- Entities continue to perform resource studies to ensure resource adequacy to meet the summer peak demand and to maintain reliability to the system.
- Entities continue to participate actively in the SERC Near-Term and Long-Term Working Groups. These groups identify emerging and potential reliability impacts on transmission and resource adequacy along with transfer capability.
- Probabilistic analysis shows a low risk for resource shortfall during the months of July and August. The 2022 study found LOLH of 0.005 hours and EUE of 2.381 MWh during summer months for a similar resource mix and demand levels.

Risk Scenario Summary

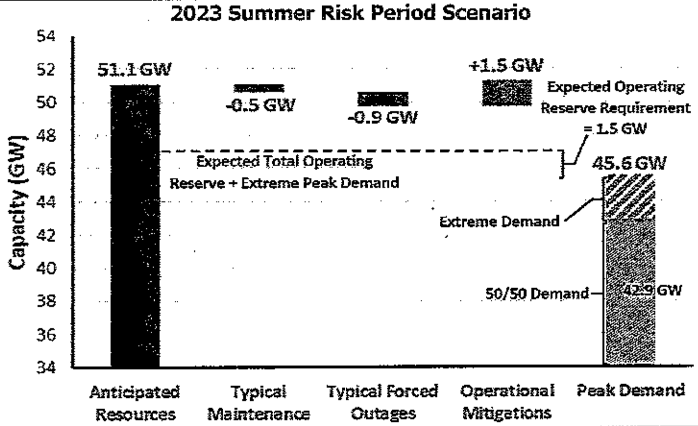
Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margin



On-Peak Fuel Mix

2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 1.5 GW based on operational/emergency procedures

SERC-Florida Peninsula

SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six companies across North America that are responsible for the work under FERC approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 PAs, and 6 RCs.

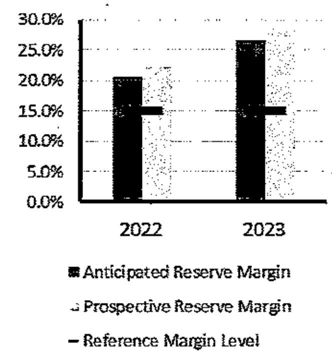
Highlights

- Entities have not identified any emerging reliability issues or operational concerns for the upcoming summer season.
- Entities continue to perform resource studies to ensure resource adequacy to meet the summer peak demand and to maintain system reliability.
- Entities continue to participate actively in the SERC Near-Term and Long-Term Working Groups. These groups identify emerging and potential reliability impacts on transmission and resource adequacy along with transfer capability.
- SERC probabilistic analysis indicates negligible risk for resource shortfall. The 2022 study found negligible LOLH and EUE during summer months for a similar resource mix and demand levels

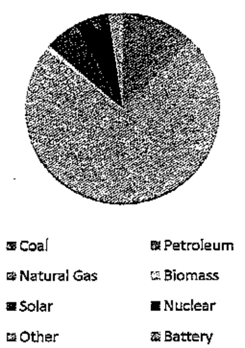
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

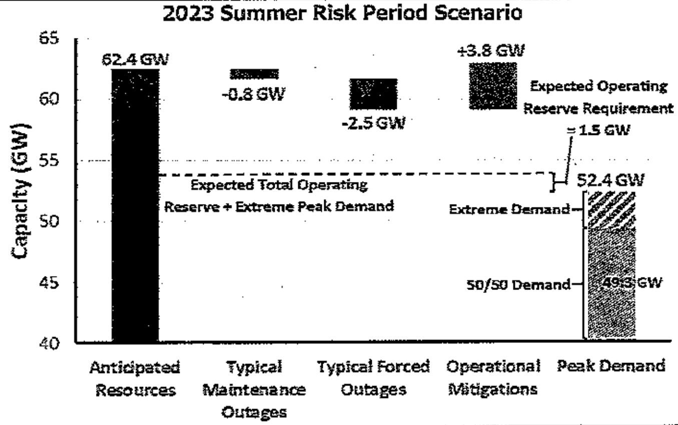
On-Peak Reserve Margin



On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast) .

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 3.8 GW based on operational/ emergency procedures

SERC-Southeast

SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six companies across North America that are responsible for the work under FERC approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the southeastern and central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities, and 6 RCs.

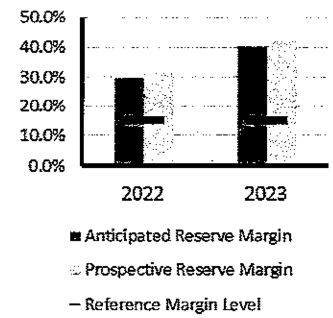
Highlights

- Entities have not identified any emerging reliability issues for the upcoming summer season that will impact resource adequacy.
- The available system capacity for the upcoming summer season meets or exceeds the reserve margin target. Reliability is supported by a diverse fuel mix, firm natural gas contracts, and power purchases.
- Entities continue to participate actively in the SERC near-term and long-term working groups. These groups identify emerging and potential reliability impacts on transmission and resource adequacy along with transfer capability.
- Probabilistic analysis indicates almost no risk for resource shortfall.

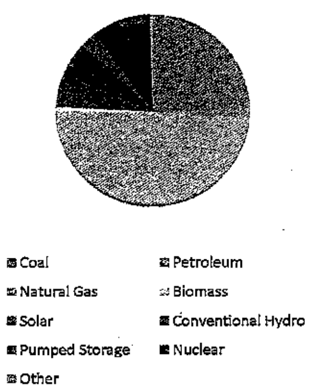
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

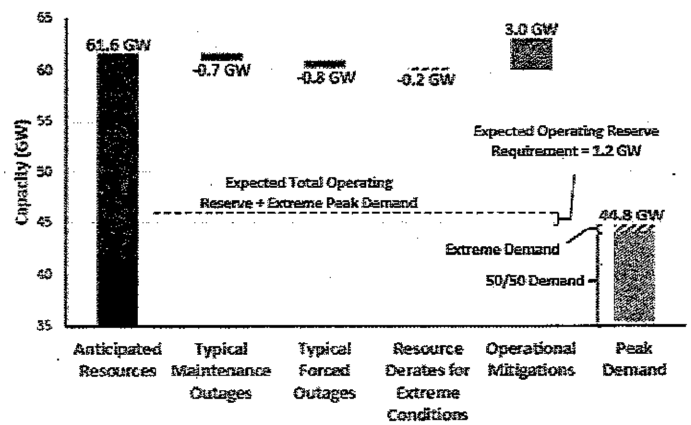
On-Peak Reserve Margin



On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

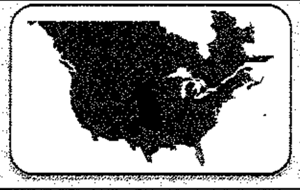
Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 3.0 GW based on operational/ emergency procedures



SPP

SPP PC footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the Planning Coordinator footprint, which touches parts of the Midwest Reliability Organization Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.

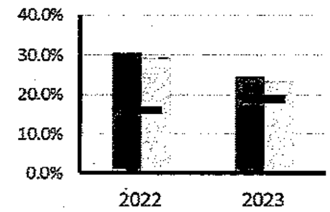
Highlights

- At this time, SPP projects a low likelihood of any emerging reliability issues impacting the area for the 2023 summer season.
- BA generation capacity deficiency risks remain depending on wind generation output levels and unanticipated generation outages in combination with high load periods.
- SPP performed a statistical analysis of risk of energy emergencies for the upcoming summer based on historical data. They found it likely that operators would use part of the 2 GW operating reserves and issue EEA1 and EEA2 level approximately one day each summer; it is likely that operators would deplete all operating reserves approximately once every five summers, resulting in an EEA3.
- Using the current operational processes and procedures, SPP will continue to assess the needs for the 2023 summer season and will adjust as needed to ensure that real-time reliability is maintained throughout the summer time frame.

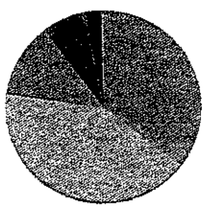
Risk Scenario Summary

Expected resources are sufficient to meet operating reserve requirements under normal peak-demand and outage scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e. demand response and transfers from neighboring systems) and EEAs.

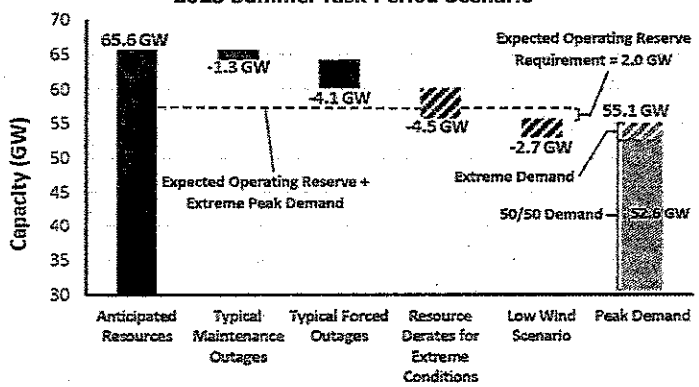
On-Peak Reserve Margin



On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand is a 5% increase from net internal demand

Maintenance & Forced Outages: Represent 5-year historical averages; calculated from SPP's generation assessment process

Extreme Derates: Additional unavailable capacity from operational data at high demand periods

Low Wind Scenario: Derates reflecting a low-wind day in the summer

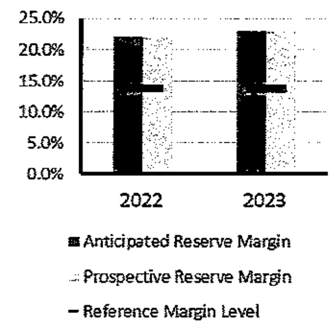
Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) is the ISO for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer-peaking. It covers approximately 200,000 square miles, connects over 52,700 miles of transmission lines, has over 1,100 generation units, and serves more than 26 million customers. Texas RE is responsible for the RE functions described in the Energy Policy Act of 2005 for ERCOT. On November 3, 2022, the Public Utility Commission of Texas issued an order directing ERCOT to assume the duties and responsibilities of the Reliability Monitor for the Texas power grid.

Highlights

- Given an Anticipated Reserve Margin of 23% and Reference Reserve Margin of 13.75%, ERCOT expects to have sufficient operating reserves in expected normal summer system conditions.
- Solar PV nameplate capacity expected for the 2023 summer season is 4.4 GW higher than the forecast amount reported for the 2022 SRA.
- Several generator owners in the ERCOT area indicated they could run out of NOx emission allowances by July 2023 under U.S. EPA's Good Neighbor Plan. Texas filed a motion to stay the EPA's regulatory action. A delay in implementation has alleviated these concerns. ERCOT's probabilistic risk assessment indicates a low probability of energy emergency conditions during the summer peak load period, but the risk increases into the early evening hours due reductions of solar PV generation. There is a 4% probability that ERCOT will declare an EEA1 during the expected daily peak load hour increasing up to 19% probability at the highest risk hour ending at 8:00 p.m.
- System stability and strength stemming from the growth of IBRs remains a concern. ERCOT is also experiencing large increases in renewable production curtailments due to transmission constraints, and these curtailments are increasingly occurring at solar PV sites.

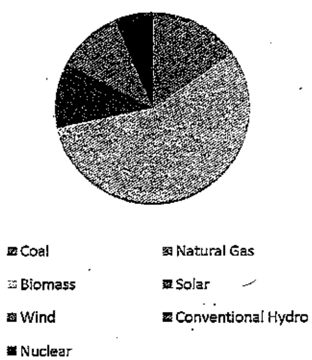
On-Peak Reserve Margin



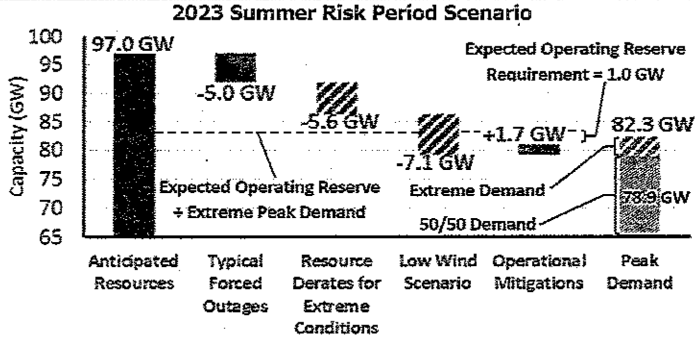
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal and extreme peak-demand scenarios. Extreme generator outages combined with low-wind output during extreme peak demand could result in the need to employ operating mitigations such as demand response, EEAs, and localized load shedding.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

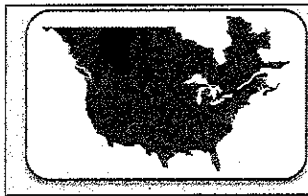
Demand Scenarios: Net internal demand (50/50) and extreme demand represents weather conditions 2% worse than summer peak in 2011

Forced Outages: Based on the 95th percentile of historical averages of forced outages for June through September weekdays, hours ending 3:00–8:00 p.m. local time for the last three (2019–2021) summer seasons

Low Wind Scenario: Based on the 10th percentile of historical averages of hourly wind for June through September, hours ending 1:00–9:00 p.m. local time

Extreme Derates: Based on the 95th percentile of historical averages of forced outages for June through September weekdays, hours ending 3:00–8:00 p.m. local time for the last five (2019–2021) summer seasons

Operational Mitigations: Additional capacity from switchable generation and additional imports



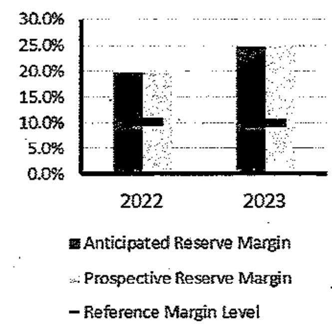
WECC-AB

WECC-AB (Alberta) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of Alberta, Canada. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

Highlights

- The Western Interconnection is experiencing heightened reliability risks heading into the summer of 2023 due to increased supply-side shortages along with the ongoing drought impacts in some areas, continued wildfire threats, and expanding heat wave events.
- There is 35% less coal-fired generator capacity in Alberta compared to last summer (446 MW). Resource additions include 554 MW of natural-gas-fired generation, 336 MW of new solar PV resources, and 1,350 MW of new wind generation.
- Based on a WECC Probabilistic Assessment, the WECC-AB assessment area had negligible LOLH and EUE.
- Alberta is expected to have sufficient resource availability to meet demand and cover reserves on the peak hour at 4:00 p.m. under a summer peak defined as a one-in-ten probability at the 90th percentile with any combination or accumulation of derates.

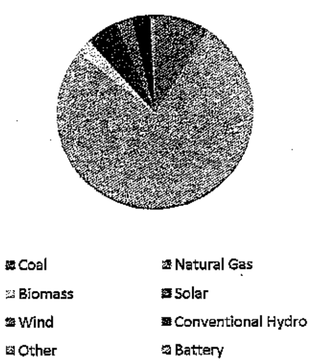
On-Peak Reserve Margin



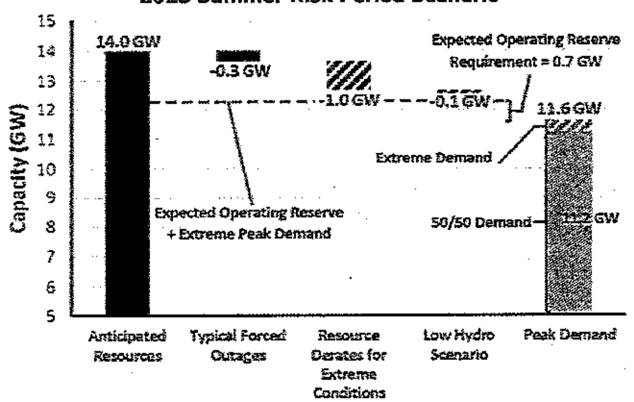
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

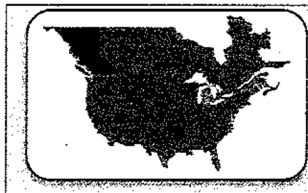
Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Typical Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) point of resource performance distribution

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions



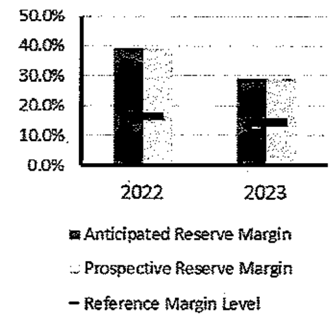
WECC-BC

WECC-British Columbia (BC) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of British Columbia, Canada. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

Highlights

- The Western Interconnection is experiencing heightened reliability risks heading into the summer of 2023 due to increased supply-side shortages along with the ongoing drought impacts in some areas, continued wildfire threats, and expanding heat wave events.
- BC shows adequate reserve margins to meet demand under extreme conditions.
- Based on a WECC Probabilistic Assessment, the WECC-BC assessment area had negligible LOLH and EUE.
- BC is expected to have sufficient resource availability to meet demand and cover reserves on the peak hour at 4:00 p.m., under a summer peak defined as a one-in-ten probability at the 90th percentile with any combination or accumulation of derates.

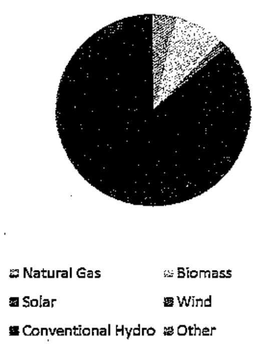
On-Peak Reserve Margin



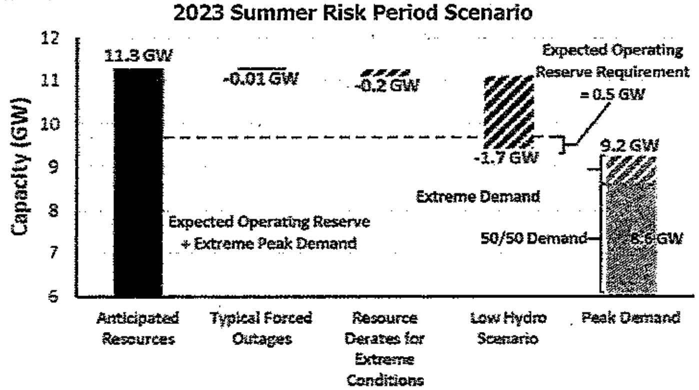
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under the extreme peak demand and outage scenarios studied.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) resource performance distribution at peak hour

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions

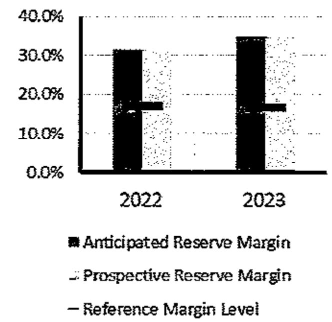
WECC-CA/MX

WECC-CA/MX is a summer-peaking assessment area in the WECC Regional Entity that includes parts of California, Nevada, and Baja California, Mexico. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

Highlights

- The Western Interconnection is experiencing heightened reliability risks heading into the summer of 2023 due to increased supply-side shortages along with the ongoing drought impacts in some areas, continued wildfire threats, and expanding heat wave events.
- CA/MX shows adequate reserve margins under expected conditions on the peak hour. However, increased risk occurs during the hours after peak demand and into the evening due to the variability of energy availability. CA/MX is typically reliant on imports during these periods.
- Based on a WECC Probabilistic Assessment, WECC-CA/MX is projected to have negligible-to-low amounts of LOLH (<0.5 hours) this summer. Variation in LOLH is attributable to the amount of Tier 1 resources that connect before the later months.
- CA/MX is expected to have sufficient resource availability to meet demand and cover reserves on the peak hour at 4:00 p.m. under a summer peak defined as a one-in-ten probability at the 90th percentile with any combination or accumulation of derates.
- For the peak riskiest hour ending 8:00 pm (four hours later than the peak) under an extreme summer peak load, CA/MX would need to rely on increased imports to maintain adequate reserves. Under expected net internal demand for the same riskiest hour (not an extreme summer peak for that hour), any of the typical outages or extreme derates would also cause a need for increased reliance on imports.

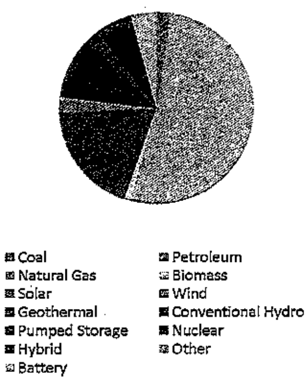
On-Peak Reserve Margin



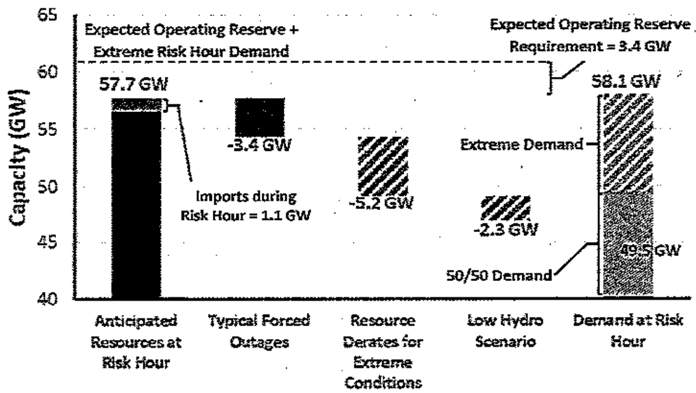
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios studied.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

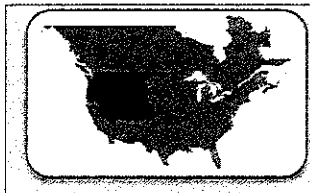
Risk Period: Highest risk for unserved energy at 8:00 p.m. local time as solar PV output is diminished and demand remains high

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Estimated using market forced outage model

Extreme Derates: On natural gas units based on historic data and manufacturer data for temperature performance and outages

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions



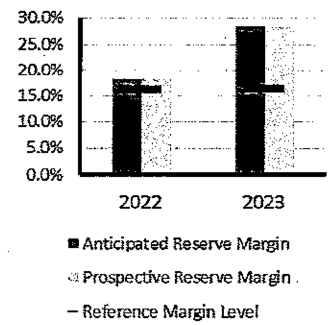
WECC-NW

WECC-NW is a summer-peaking assessment area in the WECC Regional Entity. The area includes Colorado, Idaho, Montana, Oregon, Utah, Washington, Wyoming and parts of California, Nebraska, Nevada, and South Dakota. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

Highlights

- The Western Interconnection is experiencing heightened reliability risks heading into the summer of 2023 due to increased supply-side shortages along with the ongoing drought impacts in some areas, continued wildfire threats, and expanding heat wave events.
- NW shows adequate reserve margins under expected conditions on the peak hour. However, NW shows increased risk a few hours later during the peak riskiest hour, due to the variability of energy availability later in the evenings. NW would be reliant on increased imports.
- Based on a WECC Probabilistic Assessment, the WECC-NW assessment area had negligible LOLH and EUE.
- WECC-NW would need to rely on imports to maintain adequate reserves on the peak riskiest hour (five hours later at 9:00 p.m.) under an extreme summer peak load and either extreme thermal or extreme hydro derates or any combination of two other extreme derate scenarios.

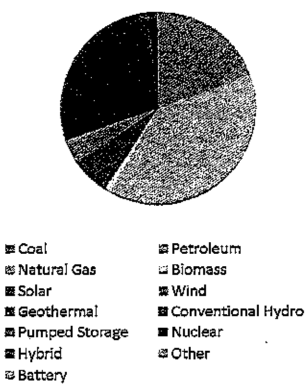
On-Peak Reserve Margin



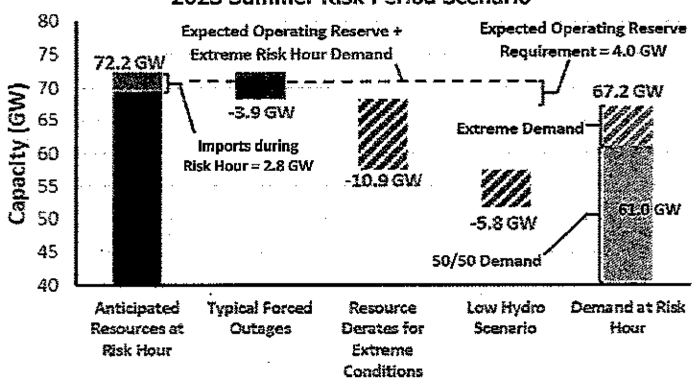
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios.

On-Peak Fuel Mix

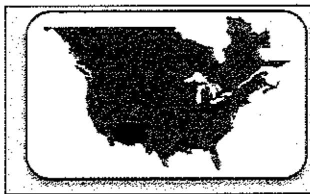


2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

- **Risk Period:** Highest risk for unserved energy at 9:00 p.m. local time as solar PV output is diminished and demand remains high
- Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour
- Forced Outages: Average seasonal outages
- Extreme Derates: Using (90/10) scenario
- Low Hydro Scenario: Reduced hydro availability resulting from drought conditions



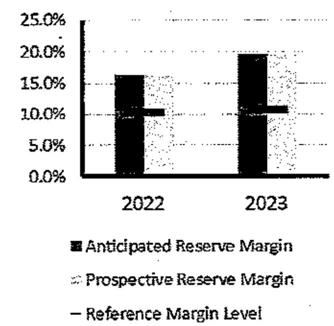
WECC-SW

WECC-SW is a summer-peaking assessment area in the WECC Regional Entity. It includes Arizona, New Mexico, and part of California and Texas. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada as well as the northern portion of Baja California in Mexico and all or portions of the 14 Western United States in between.

Highlights

- The Western Interconnection is experiencing heightened reliability risks heading into the summer of 2023 due to increased supply-side shortages along with the ongoing drought impacts in some areas, continued wildfire threats, and expanding heat wave events.
- WECC-SW shows adequate reserve margins to meet demand under extreme conditions.
- Based on a WECC Probabilistic Assessment, the WECC-SW assessment area had negligible LOLH and EUE.
- WECC-SW is expected to have sufficient resource availability to meet demand and cover reserves on the peak hour at 5:00 p.m. under a summer peak defined as a one-in-ten probability at the 90th percentile with any combination or accumulation of derates.

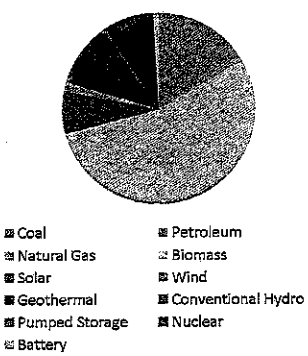
On-Peak Reserve Margin



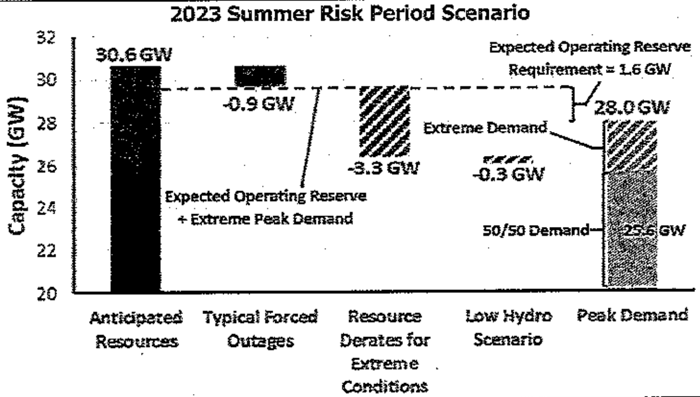
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand (5:00 p.m. local)

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions

Data Concepts and Assumptions

The table below explains data concepts and important assumptions used throughout this assessment.

General Assumptions
• Reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
▪ Adequacy is the ability of the electricity system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
▪ Operating reliability is the ability of the electricity system to withstand sudden disturbances, such as electric short-circuits or unanticipated loss of system components.
• The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
• All data in this assessment is based on existing federal, state, and provincial laws and regulations.
• Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
• *2022 Long-Term Reliability Assessment* data has been used for most of this 2023 summer assessment period augmented by updated load and capacity data.
• A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.
Demand Assumptions
• Electricity demand projections, or load forecasts, are provided by each assessment area.
• Load forecasts include peak hourly load[10] or total internal demand for the summer and winter of each year.[11]
• Total internal demand projections are based on normal weather (50/50 distribution[12]) and are provided on a coincident[13] basis for most assessment areas.
• Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.
Resource Assumptions
Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. Because the electrical output of variable energy resources (e.g., wind, solar PV) depends on weather conditions, their contribution to reserve margins and other on-peak resource adequacy analysis is less than their nameplate capacity.
Anticipated Resources: • **Existing-Certain Capacity:** Included in this category are commercially operable generating unit or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the summer season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or where energy-only markets exist, unit must be a designated market resource eligible to bid into the market. • **Tier 1 Capacity Additions:** This category includes capacity that either is under construction or has received approved planning requirements. • **Net Firm Capacity Transfers (Imports minus Exports):** This category includes transfers with firm contracts.

[10] *Glossary of Terms* used in NERC Reliability Standards
[11] The summer season represents June–September and the winter season represents December–February.
[12] Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.
[13] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval; this is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC and FRCC calculate total internal demand on a noncoincidental basis.

Prospective Resources: Includes all anticipated resources plus the following:

Existing-Other Capacity: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.

Reserve Margin Descriptions

Planning Reserve Margin: This is the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage.

Reference Margin Level: The assumptions and naming convention of this metric vary by assessment area. The Reference Margin Level can be determined using both deterministic and probabilistic (based on a 0.1/year loss of load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing a Reference Margin Level is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increase demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, a Reference Margin Level is established by a state, provincial authority, ISO/RTO, or other regulatory body. In some cases, the Reference Margin Level is a requirement. Reference Margin Levels may be different for the summer and winter seasons. If a Reference Margin Level is not provided by an assessment area, NERC applies 15% for predominately thermal systems and 10% for predominately hydro systems.

Seasonal Risk Scenario Chart Description

Each assessment area performed an operational risk analysis that was used to produce the seasonal risk scenario charts in the Regional Assessments Dashboards. The chart presents deterministic scenarios for further analysis of different resource and demand levels: The left blue column shows anticipated resources, and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand and the extreme summer peak demand—both determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources, such as the following:

- Reductions for typical generation outages (i.e., maintenance and forced outages that are not already accounted for in anticipated resources)
- Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions that result in reduced thermal generation output)
- Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions

Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable.

The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Furthermore, the effects from extreme events can also be examined by comparing resource levels after applying extreme-scenario derates and/or extreme summer peak demand.

Resource Adequacy

The Anticipated Reserve Margin, which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecast peak demand.[14] Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. All assessment areas have sufficient Anticipated Reserve Margins to meet or exceed their Reference Margin Level for the 2023 summer as shown in Figure 4.

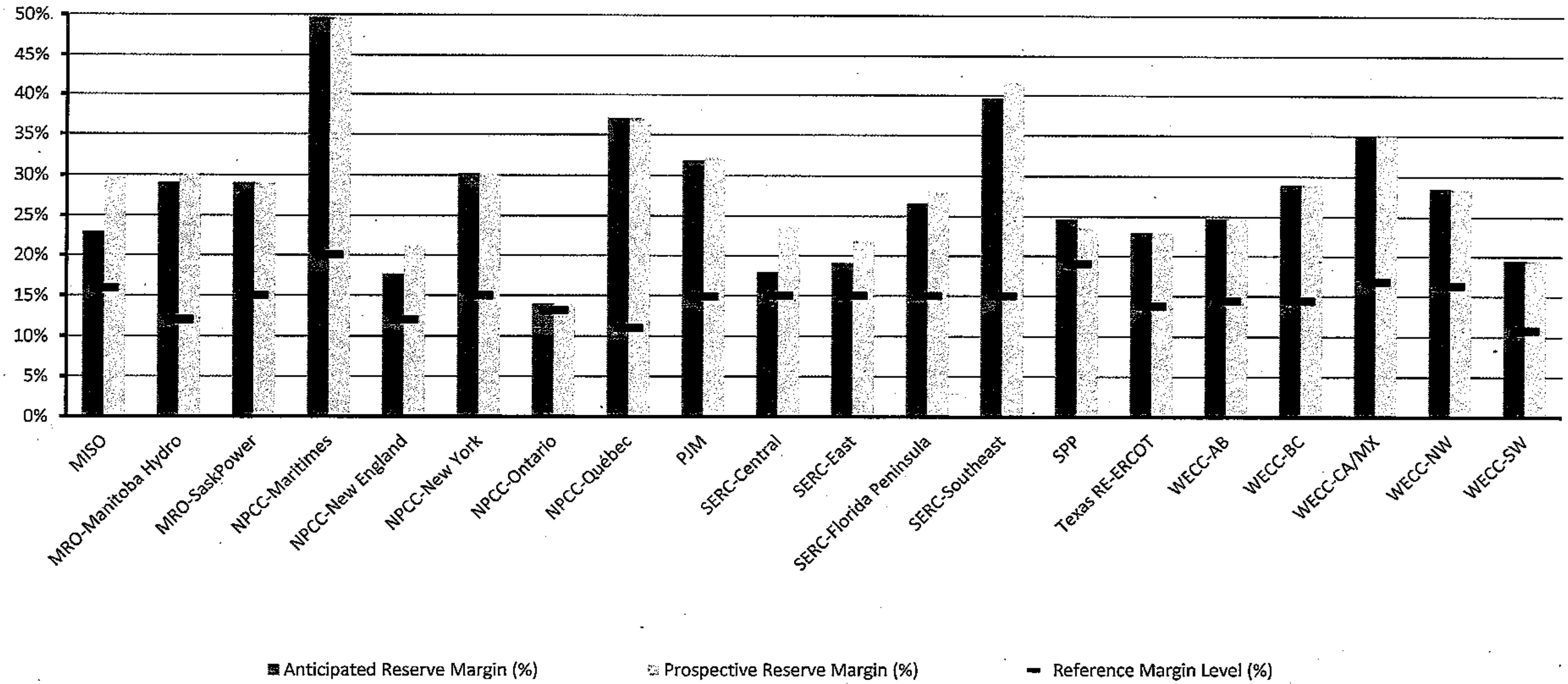
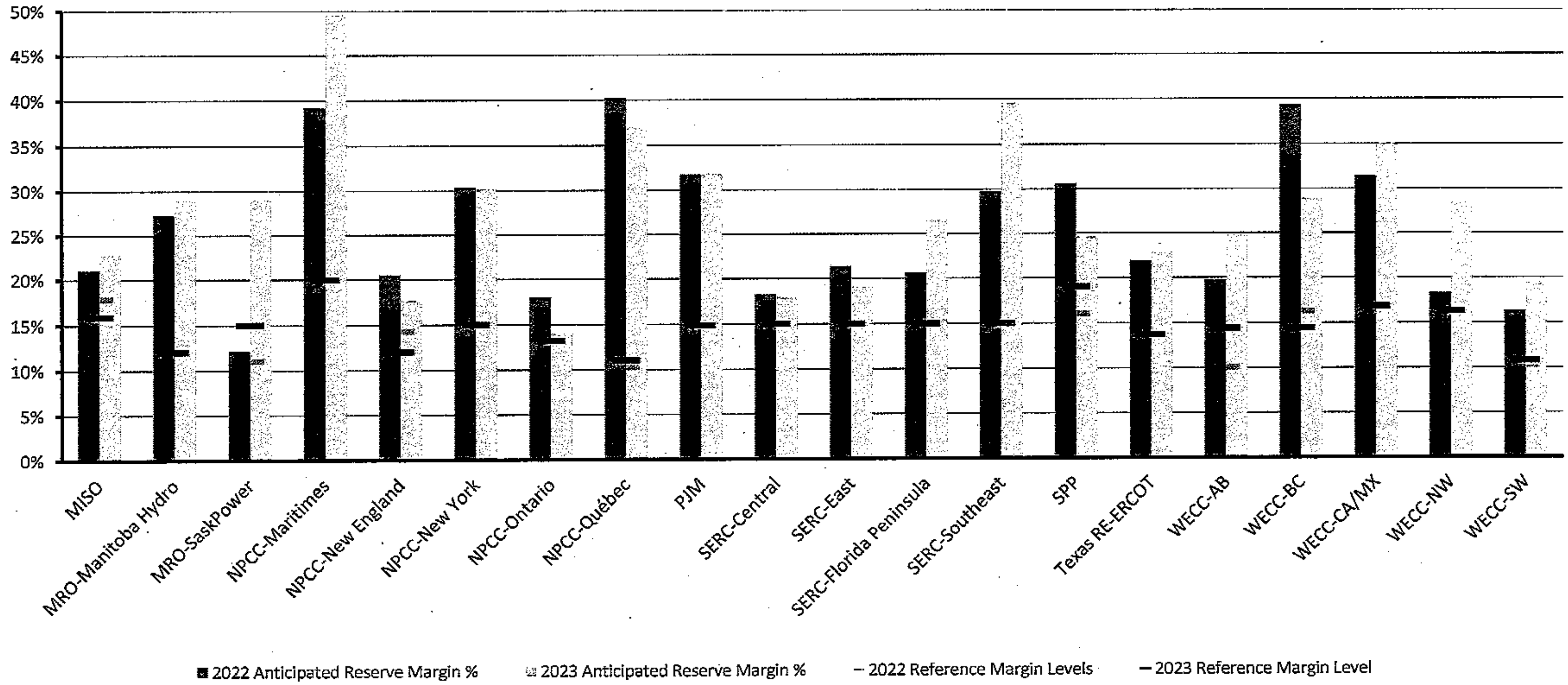


Figure 4: Summer 2023 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[14] Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during electrical peak loads for the season. Prospective resources are those that could be available but do not meet criteria to be counted as anticipated resources. Refer to the Data Concepts and Assumptions section for additional information on Anticipated/Prospective Reserve Margins, anticipated/prospective resources, and Reference Margin Levels.

Changes from Year-to-Year

Figure 5 provides the relative change in the forecast Anticipated Reserve Margins from the 2022 summer to the 2023 summer. A significant decline can indicate potential operational issues that emerge between reporting years. NPCC-Ontario, SPP and WECC-BC have noticeable reductions in anticipated resources with NPCC-Ontario close to falling below its Reference Margin Level for the 2023 summer. NPCC-Ontario is experiencing ongoing nuclear refurbishments and recent retirements will make it difficult to accommodate unplanned generator or transmission outages. NPCC-Ontario will rely on demand response and transfers from neighbors during a higher load scenario to avoid load interruption. The lower Anticipated Reserve Margins for NPCC-Maritimes, NPCC-Québec, SERC-C, and WECC-AB do not present reliability concerns on peak for this upcoming summer. Additional details for each assessment area are provided in the **Data Concepts and Assumptions** and **Regional Assessments Dashboards** sections.



Note: The areas that only have one bar have the same Reference Margin Level for both years.

Figure 5: Summer 2022 and Summer 2023 Anticipated Reserve Margins Year-to-Year Change

Net Internal Demand

The changes in forecasted Net Internal Demand for each assessment area are shown in **Figure 6.**[15] Assessment areas develop these forecasts based on historic load and weather information as well as other long-term projections.

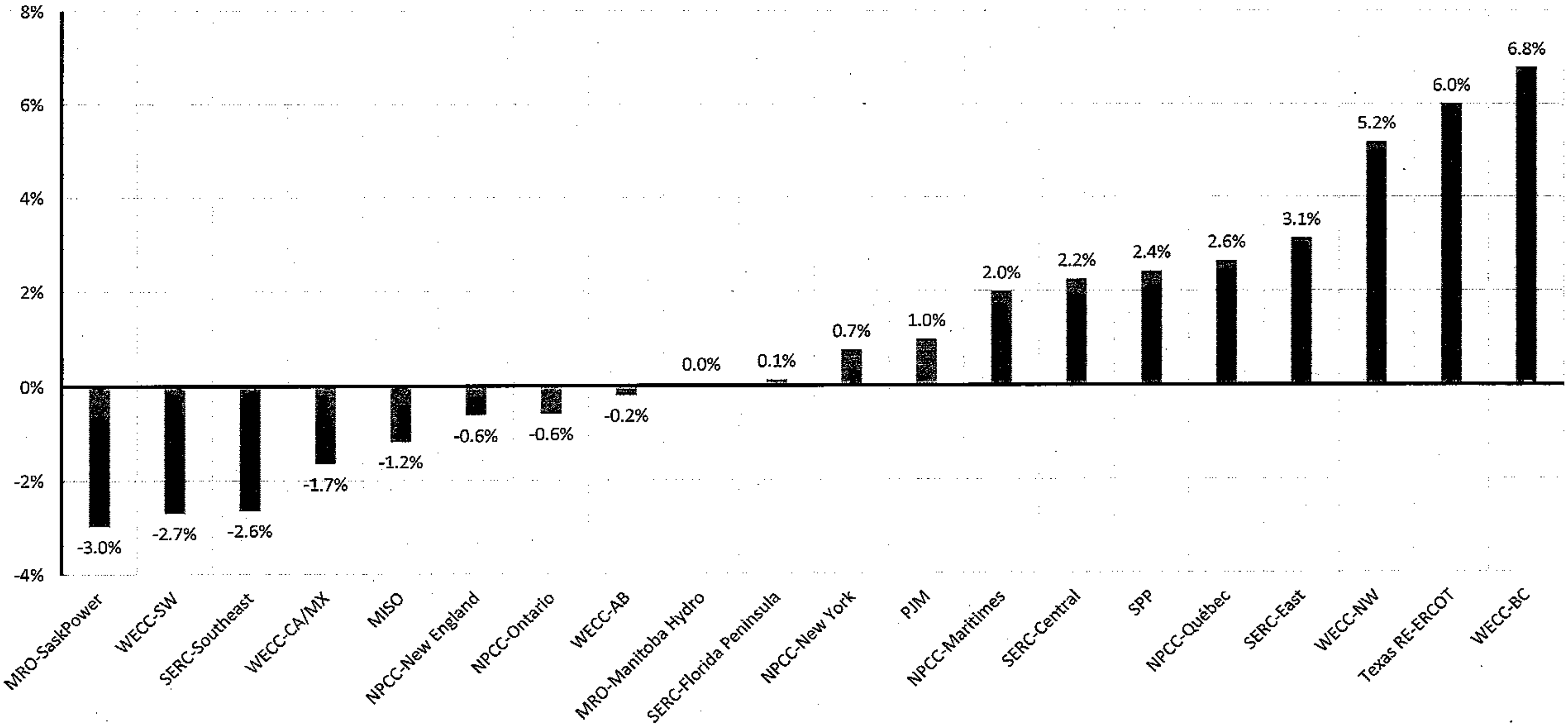


Figure 6: Change in Net Internal Demand—Summer 2022 Forecast Compared to Summer 2023 Forecast

[15] Changes in modeling and methods may also contribute to year-to-year changes in forecasted net internal demand projections.

Demand and Resource Tables

Peak demand and supply capacity data—resource adequacy data—for each assessment area are as follows in each table (in alphabetical order).

MISO			
Demand, Resource, and Reserve Margins	2022 SRA	2023 SRA	2022 vs. 2023 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	124,506	123,728	-0.6%
Demand Response: Available	6,287	6,903	9.8%
Net Internal Demand	118,220	116,825	-1.2%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	141,844	140,650	-0.8%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,353	3,018	123.1%
Anticipated Resources	143,197	143,668	0.3%
Existing-Other Capacity	669	668	-0.1%
Prospective Resources	149,756	151,579	1.2%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	21.1%	23.0%	1.8
Prospective Reserve Margin	26.7%	29.7%	3.1
Reference Margin Level	17.9%	15.9%	-2.0

MRO-Manitoba Hydro			
Demand, Resource, and Reserve Margins	2022 SRA	2023 SRA	2022 vs. 2023 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	3,059	3,060	0.0%
Demand Response: Available	0	0	-
Net Internal Demand	3,059	3,060	0.0%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	5,523	5,731	3.8%
Tier 1 Planned Capacity	186	91	-50.9%
Net Firm Capacity Transfers	-1,816	-1,872	3.1%
Anticipated Resources	3,893	3,950	1.5%
Existing-Other Capacity	44	34	-23.4%
Prospective Resources	3,937	3,984	1.2%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	27.3%	29.1%	1.8
Prospective Reserve Margin	28.7%	30.2%	1.5
Reference Margin Level	12.0%	12.0%	0.0

MRO-SaskPower			
Demand, Resource, and Reserve Margins	2022 SRA	2023 SRA	2022 vs. 2023 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	3,656	3,539	-3.2%
Demand Response: Available	60	50	-16.7%
Net Internal Demand	3,596	3,489	-3.0%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	3,743	4,213	12.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	290	290	0.0%
Anticipated Resources	4,033	4,503	11.7%
Existing-Other Capacity	0	0	-
Prospective Resources	4,033	4,503	11.7%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	12.2%	29.1%	16.9
Prospective Reserve Margin	12.2%	29.1%	16.9
Reference Margin Level	11.0%	15.0%	4.0

NPCC-Maritimes			
Demand, Resource, and Reserve Margins	2022 SRA	2023 SRA	2022 vs. 2023 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	3,475	3,612	3.9%
Demand Response: Available	255	328	28.6%
Net Internal Demand	3,220	3,284	2.0%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	4,419	4,834	9.4%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	64	81	26.6%
Anticipated Resources	4,483	4,915	9.6%
Existing-Other Capacity	0	0	-
Prospective Resources	4,483	4,915	9.6%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	39.2%	49.7%	10.4
Prospective Reserve Margin	39.2%	49.7%	10.4
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New England			
Demand, Resource, and Reserve Margins	2022 SRA	2023 SRA	2022 vs. 2023 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	25,300	25,111	-0.7%
Demand Response: Available	483	447	-7.5%
Net Internal Demand	24,817	24,664	-0.6%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	28,626	27,997	-2.2%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,292	1,030	-20.3%
Anticipated Resources	29,918	29,027	-3.0%
Existing-Other Capacity	911	872	-4.3%
Prospective Resources	30,829	29,899	-3.0%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	20.6%	17.7%	-2.9
Prospective Reserve Margin	24.2%	21.2%	-3.0
Reference Margin Level	14.3%	12.0%	-2.3

NPCC-Ontario			
Demand, Resource, and Reserve Margins	2022 SRA	2023 SRA	2022 vs. 2023 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	22,546	22,439	-0.5%
Demand Response: Available	666	687	3.1%
Net Internal Demand	21,880	21,752	-0.6%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	25,648	24,575	-4.2%
Tier 1 Planned Capacity	24	9	-61.5%
Net Firm Capacity Transfers	150	223	48.5%
Anticipated Resources	25,822	24,807	-3.9%
Existing-Other Capacity	0	0	-
Prospective Resources	25,822	24,807	-3.9%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	18.0%	14.0%	-4.0
Prospective Reserve Margin	18.0%	14.0%	-4.0
Reference Margin Level	13.3%	13.2%	0.0

NPCC-New York			
Demand, Resource, and Reserve Margins	2022 SRA	2023 SRA	2022 vs. 2023 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	31,765	32,049	0.9%
Demand Response: Available	1,170	1,226	4.8%
Net Internal Demand	30,595	30,823	0.7%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	37,431	37,216	-0.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	2,465	2,932	18.9%
Anticipated Resources	39,896	40,148	0.6%
Existing-Other Capacity	0	0	-
Prospective Resources	39,896	40,148	0.6%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	30.4%	30.3%	-0.1
Prospective Reserve Margin	30.4%	30.3%	-0.1
Reference Margin Level	15.0%	15.0%	0.0

NPCC-Québec			
Demand, Resource, and Reserve Margins	2022 SRA	2023 SRA	2022 vs. 2023 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	22,271	22,859	2.6%
Demand Response: Available	0	0	-
Net Internal Demand	22,271	22,859	2.6%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	33,542	33,690	0.4%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-2,304	-2,353	2.1%
Anticipated Resources	31,238	31,337	0.3%
Existing-Other Capacity	0	0	-
Prospective Resources	31,238	31,337	0.3%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	40.3%	37.1%	-3.2
Prospective Reserve Margin	40.3%	37.1%	-3.2
Reference Margin Level	10.3%	11.0%	0.7

PJM			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	148,938	149,059	0.1%
Demand Response: Available	8,527	7,288	-14.5%
Net Internal Demand	140,411	141,771	1.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	184,837	186,540	0.9%
Tier 1 Planned Capacity	10	0	-100.0%
Net Firm Capacity Transfers	124	463	273.4%
Anticipated Resources	184,971	187,003	1.1%
Existing-Other Capacity	0	0	-
Prospective Resources	185,095	187,466	1.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	31.7%	31.9%	0.2
Prospective Reserve Margin	31.8%	32.2%	0.4
Reference Margin Level	14.9%	14.9%	0.0

SERC-East			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	42,883	43,889	2.3%
Demand Response: Available	1,298	1,008	-22.3%
Net Internal Demand	41,585	42,881	3.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	49,380	50,452	2.2%
Tier 1 Planned Capacity	486	0	-100.0%
Net Firm Capacity Transfers	612	624	2.0%
Anticipated Resources	50,478	51,076	1.2%
Existing-Other Capacity	1,097	1,182	7.8%
Prospective Resources	51,575	52,258	1.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	21.4%	19.1%	-2.3
Prospective Reserve Margin	24.0%	21.9%	-2.2
Reference Margin Level	15.0%	15.0%	0.0

SERC-Central			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	41,267	42,223	2.3%
Demand Response: Available	1,841	1,910	3.7%
Net Internal Demand	39,426	40,313	2.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	47,424	46,964	-1.0%
Tier 1 Planned Capacity	0	93	-
Net Firm Capacity Transfers	-795	1,068	-
Anticipated Resources	46,629	47,556	2.0%
Existing-Other Capacity	4,808	2,313	-51.9%
Prospective Resources	51,437	49,868	-3.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	18.3%	18.0%	-0.3
Prospective Reserve Margin	30.5%	23.7%	-6.8
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	52,172	52,195	0.0%
Demand Response: Available	2,932	2,898	-1.2%
Net Internal Demand	49,240	49,297	0.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	56,571	60,074	6.2%
Tier 1 Planned Capacity	2,540	1,742	-31.4%
Net Firm Capacity Transfers	300	589	96.3%
Anticipated Resources	59,411	62,405	5.0%
Existing-Other Capacity	847	776	-8.4%
Prospective Resources	60,258	63,181	4.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.7%	26.6%	5.9
Prospective Reserve Margin	22.4%	28.2%	5.8
Reference Margin Level	15.0%	15.0%	0.0

SERC-Southeast			
Demand, Resource, and Reserve Margins	2022 SRA	2023 SRA	2022 vs. 2023 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	47,258	46,127	-2.4%
Demand Response: Available	1,946	2,010	3.3%
Net Internal Demand	45,312	44,117	-2.6%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	59,828	59,559	-0.4%
Tier 1 Planned Capacity	1,514	2,865	89.3%
Net Firm Capacity Transfers	-2,524	-815	-67.7%
Anticipated Resources	58,818	61,609	4.7%
Existing-Other Capacity	859	908	5.7%
Prospective Resources	59,677	62,517	4.8%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	29.8%	39.6%	9.8
Prospective Reserve Margin	31.7%	41.7%	10.0
Reference Margin Level	15.0%	15.0%	0.0

SPP			
Demand, Resource, and Reserve Margins	2022 SRA	2023 SRA	2022 vs. 2023 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	52,040	53,468	2.7%
Demand Response: Available	658	842	27.9%
Net Internal Demand	51,382	52,626	2.4%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	67,245	65,821	-2.1%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-144	-238	65.0%
Anticipated Resources	67,101	65,583	-2.3%
Existing-Other Capacity	0	0	-
Prospective Resources	66,554	65,036	-2.3%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	30.6%	24.6%	-6.0
Prospective Reserve Margin	29.5%	23.6%	-5.9
Reference Margin Level	16.0%	19.0%	3.0

Texas RE-ERCOT			
Demand, Resource, and Reserve Margins	2022 SRA	2023 SRA	2022 vs. 2023 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	77,317	82,307	6.5%
Demand Response: Available	2,856	3,380	18.3%
Net Internal Demand	74,461	78,927	6.0%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	89,603	94,580	5.6%
Tier 1 Planned Capacity	1,199	2,445	103.9%
Net Firm Capacity Transfers	20	20	0.0%
Anticipated Resources	90,822	97,045	6.9%
Existing-Other Capacity	0	0	-
Prospective Resources	90,850	97,073	6.9%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	22.0%	23.0%	1.0
Prospective Reserve Margin	22.0%	23.0%	1.0
Reference Margin Level	13.75%	13.75%	0.0

WECC-AB			
Demand, Resource, and Reserve Margins	2022 SRA	2023 SRA	2022 vs. 2023 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	11,228	11,206	-0.2%
Demand Response: Available	0	0	-
Net Internal Demand	11,228	11,206	-0.2%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	11,926	13,759	15.4%
Tier 1 Planned Capacity	1,082	227	-79.0%
Net Firm Capacity Transfers	437	0	-100.0%
Anticipated Resources	13,445	13,986	4.0%
Existing-Other Capacity	0	0	-
Prospective Resources	13,445	13,986	4.0%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	19.7%	24.8%	5.1
Prospective Reserve Margin	19.7%	24.8%	5.1
Reference Margin Level	10.1%	9.9%	-0.2

WECC-BC			
Demand, Resource, and Reserve Margins	2022 SRA	2023 SRA	2022 vs. 2023 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	8,088	8,636	6.8%
Demand Response: Available	0	0	-
Net Internal Demand	8,088	8,636	6.8%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	11,266	11,135	-1.2%
Tier 1 Planned Capacity	3	0	-100.0%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	11,269	11,135	-1.2%
Existing-Other Capacity	0	0	-
Prospective Resources	11,269	11,135	-1.2%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	39.3%	28.9%	-10.4
Prospective Reserve Margin	39.3%	28.9%	-10.4
Reference Margin Level	16.3%	14.4%	-1.9

WECC-CA/MX			
Demand, Resource, and Reserve Margins	2022 SRA	2023 SRA	2022 vs. 2023 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	57,269	56,356	-1.6%
Demand Response: Available	844	862	2.2%
Net Internal Demand	56,425	55,494	-1.7%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	70,791	69,408	-2.0%
Tier 1 Planned Capacity	3,381	5,522	63.3%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	74,172	74,930	1.0%
Existing-Other Capacity	0	0	-
Prospective Resources	74,172	74,930	1.0%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	31.5%	35.0%	3.6
Prospective Reserve Margin	31.5%	35.0%	3.6
Reference Margin Level	16.9%	16.8%	-0.1

WECC-SW			
Demand, Resource, and Reserve Margins	2022 SRA	2023 SRA	2022 vs. 2023 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	26,720	25,992	-2.7%
Demand Response: Available	399	380	-4.7%
Net Internal Demand	26,321	25,612	-2.7%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	28,249	26,206	-7.2%
Tier 1 Planned Capacity	1,369	1,655	20.9%
Net Firm Capacity Transfers	1,002	2,747	174.2%
Anticipated Resources	30,620	30,608	0.0%
Existing-Other Capacity	0	0	-
Prospective Resources	30,620	30,608	0.0%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	16.3%	19.5%	3.2
Prospective Reserve Margin	16.3%	19.5%	3.2
Reference Margin Level	10.2%	10.8%	0.6

WECC-NW			
Demand, Resource, and Reserve Margins	2022 SRA	2023 SRA	2022 vs. 2023 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	63,214	66,366	5.0%
Demand Response: Available	1,104	1,038	-6.0%
Net Internal Demand	62,110	65,328	5.2%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	70,154	76,587	9.2%
Tier 1 Planned Capacity	798	2,350	194.5%
Net Firm Capacity Transfers	2,517	5,004	98.8%
Anticipated Resources	73,469	83,941	14.3%
Existing-Other Capacity	0	0	-
Prospective Resources	73,469	83,941	14.3%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	18.3%	28.5%	10.2
Prospective Reserve Margin	18.3%	28.5%	10.2
Reference Margin Level	16.1%	16.3%	0.2

Variable Energy Resource Contributions

Because the electrical output of variable energy resources (e.g., wind, solar PV) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. The following table shows the capacity contribution of existing wind and solar PV resources at the peak demand hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS. For NERC's analysis of risk periods after peak demand (i.e., U.S. assessment areas in WECC), lower contributions of solar PV resources are used because output is diminished during evening periods.

BPS Variable Energy Resources by Assessment Area									
	Wind			Solar			Hydro		
Assessment Area / Interconnection	Nameplate Wind	Expected Wind	Expected Share of Nameplate (%)	Nameplate Solar PV	Expected Solar PV	Expected Share of Nameplate (%)	Nameplate Hydro	Expected Hydro	Expected Share of Nameplate (%)
MISO	30,373	5,488	18%	7,499	3,750	50%	4,884	4,688	96%
MRO-Manitoba Hydro	259	47	18%	-	-	0%	6,220	5,548	89%
MRO-SaskPower	615	203	33%	30	-	0%	851	797	94%
NPCC-Maritimes	1,212	255	21%	4	-	0%	1,315	1,183	90%
NPCC-New England	1,448	186	13%	2,914	1,163	40%	3,565	2,472	69%
NPCC-New York	2,879	331	12%	179	84	47%	6,731	5,067	75%
NPCC-Ontario	4,943	771	16%	478	126	26%	8,985	5,185	58%
NPCC-Québec	3,880	-	0%	10	-	0%	40,307	32,974	82%
PJM	10,923	1,688	15%	5,169	2,984	58%	3,027	3,027	100%
SERC-Central	1,206	564	47%	885	511	58%	4,967	3,315	67%
SERC-East	-	-	0%	1,475	1,473	99%	3,064	3,013	98%
SERC-Florida Peninsula	-	-	0%	7,724	4,534	59%	-	-	0%
SERC-Southeast	-	-	0%	5,305	4,647	88%	3,242	3,288	101%
SPP	32,028	4,500	14%	440	378	86%	5,465	4,996	91%
Texas RE-ERCOT	30,938	10,293	33%	15,958	12,509	78%	563	477	85%
WECC-AB	3,619	309	9%	1,165	763	65%	894	416	47%
WECC-BC	747	137	18%	2	1	50%	16,519	10,124	61%
WECC-CA/MX	9,362	1,111	12%	21,975	14,489	66%	13,957	4,606	33%
WECC-SW	2,994	593	20%	3,493	1,411	40%	1,202	844	70%
WECC-NW	20,296	3,968	20%	9,270	5,062	55%	41,860	22,752	54%
EASTERN INTERCONNECTION	85,886	14,032	16%	32,102	19,649	61%	52,316	42,578	81%
QUÉBEC INTERCONNECTION	3,880	-	0%	10	-	0%	40,307	32,974	82%
TEXAS INTERCONNECTION	30,938	10,293	33%	15,958	12,509	78%	563	477	85%
WECC INTERCONNECTION	37,018	6,118	17%	35,905	21,726	61%	74,432	38,742	52%
INTERCONNECTION TOTAL:	157,722	30,443	19%	83,975	53,885	64%	167,618	114,771	68%

Probabilistic Assessment

Regional Entities and assessment areas provided a resource adequacy risk assessment that was probability-based for the summer season. Results are included in the Highlights section of each assessment area's dashboard and summarized in the table below. The risk assessments account for the hour(s) of greatest risk of resource shortfall. For most areas, the hour(s) of risk coincide with the time of forecasted peak demand; however, some areas incur the greatest risk at other times based on the varying demand and resource profiles. Various risk metrics are provided and include LOLE, LOLH, EUE, and the probabilities of EEA occurrence.

Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight From Assessment**
MISO	Annual probabilistic LOLE study	MISO's RML decreased from 17.9% in 2022 to 15.9% for Summer 2023. The change results from implementing seasonal forced outages and probabilistic distributions of non-firm imports. Operating mitigations are needed in extreme peak summer conditions.
MRO-Manitoba	Verification of NERC 2022 Probabilistic Assessment (2022 ProbA)	The 2022 ProbA results indicate 29 MWh per year of EUE for 2024. Given comparable supply and demand balance, the 2024 EUE is a reasonable estimate for all of 2023. EUE for summer is less than the annual EUE.
MRO-SaskPower	Probability-based capacity adequacy assessment	Results indicate that the expected number of hours with operating reserve deficiency for the 2023 summer season (June to September) is 0.21 hours. September is the month with highest risk.
NPCC	NPCC conducted an all-hour Probabilistic Assessment that consisted of a base case and several more severe scenarios examining low resources, reduced imports, and higher loads. The highest peak load scenario has a 7% probability of occurring.	The assessment forecasts that the NPCC Regional Entity will have an adequate supply of electricity this summer. Necessary strategies and procedures are in place to deal with operational challenges and emergencies as they may develop. Results of the probabilistic analysis by assessment area are below.
NPCC-Maritimes		NPCC's assessment results indicate that Maritimes is likely to use a combination of imports and operating procedures to mitigate resource shortages this summer. Cumulative LOLE (<0.03 days/summer), LOLH (<0.11 hours/summer), or EUE (<5 MWh/summer) were estimated over the May–September summer for all modeled scenarios.
NPCC-New England		NPCC's assessment results indicate that ISO-NE may rely on limited use of its operating procedures to mitigate resource and energy shortages during the summer. The reduced resource case with the highest peak load scenario resulted in a small estimated cumulative LOLE risk (0.12 days/period) with associated LOLHs (0.4 hours/period) and EUE (175 MWh/period) with the highest risk occurring in June. This scenario is based exclusively on the two highest load levels with a 7% chance of occurring and a low resource case consisting of extended summer maintenance across NPCC and reduced imports from PJM.
NPCC-New York		NPCC's assessment results indicate that NYISO may rely on limited use of its operating procedures to mitigate resource and energy shortages during the summer. The reduced resource case with the highest peak load scenario resulted in a small estimated cumulative LOLE risk (0.5 days/summer) with associated LOLH (1.1 hours/summer) and EUE (525 MWh/summer). The highest risk is in June and August.
NPCC-Ontario		NPCC's assessment results indicate that Ontario is likely to use a combination of imports and operating procedures to mitigate resource shortages this summer. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios, including the severe low-likelihood cases. These results indicate that Ontario will be able to obtain necessary supplies from neighbors over a range of conditions.

Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight From Assessment**
NPCC-Québec		Québec is expected to need only limited use of its operating procedures designed to mitigate resource and energy shortages during the summer. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios, including the severe low-likelihood cases.
PJM	Based on 2022 PJM Reserve Requirement Study (RRS)	PJM is expecting a low risk of resources falling below required operating reserves. PJM forecasts a 29% installed reserve margin, well above the target of 14.9%. Due to the low penetration of variable energy resources in PJM relative to PJM's peak load, the hour with most loss of load risk remains the hour with highest forecasted demand.
SERC	Verification of NERC 2022 ProbA Results	The 2022 Base Case results indicated adequate resources for the SERC Region as a whole with an observed LOLE of 0.03 days/year for the year 2024. Trends from 2022 to 2023 indicate little change in study results, so SERC does not anticipate resource adequacy risk for the upcoming summer season.
SERC-Central		Probabilistic analysis indicates no risk for resource shortfall.
SERC-East		Probabilistic analysis shows low risk for July and August with EUE of 2.38 MWh and LOLH 0.005 hours.
SERC-Florida Peninsula		SERC Probabilistic analysis indicates no risk of resource shortfall.
SERC-Southeast		Probabilistic analysis indicates almost no risk of resource shortfall.
SPP	Statistical analysis of the Summer 2022 real time data; Operational process and procedures	Potential risk of using operating reserves and EEA1 or EEA2 is 1 day per summer. Risk of EEA3 is 0.2 days per summer. Risks is associated with low wind generation output levels or unanticipated generation outages in combination with high load periods.
Texas RE-ERCOT	ERCOT's Summer 2023 Probabilistic Assessment	There is a 4% probability that ERCOT will declare an EEA1 during the expected daily peak load hour; increasing up to 19% probability at the highest risk hour and ending at 8:00 p.m.
WECC	The 2022 Western Assessment of Resource Adequacy provides the most recent probability-based resource adequacy risk assessment for Summer 2023 across WECC's areas.	The Western Interconnection is experiencing heightened reliability risks heading into Summer 2023 due to increased supply-side shortages and fuel constraints along with the ongoing drought impacts in some areas, continued wildfire threats, and expanding heat wave events. The installation of new resources for the summer and the availability of the imports, especially during wide-area heat events, affects resource adequacy for the U.S. assessment areas. The reliability and resource adequacy of the Western Interconnection depends on the ability to move power throughout the footprint.
WECC-AB		Alberta is expected to have sufficient resource availability to meet demand and cover reserves on the peak hour at 4:00 p.m. under a summer peak defined at the 90th percentile with any combination or accumulation of derates.
WECC-BC		BC is expected to have sufficient resource availability to meet demand and cover reserves on the peak hour at 4:00 p.m. under a summer peak defined at the 90th percentile with any combination or accumulation of derates.
WECC-CA/MX		WECC-CA/MX is projected to have negligible-to-low amounts of LOLH (<0.5 hours) this summer with variation attributable to the amount of Tier 1 resources that connect before the later months. Resources are sufficient to meet demand and cover reserves on the peak hour at 3:00

Probability-Based Risk Assessment		
Assessment Area	Type of Assessment	Results and Insight From Assessment
		p.m. under a summer peak defined at the 90th percentile with any combination or accumulation of derates. However, there is increased risk of insufficient reserves at later hours (up to 8:00 p.m.) due to the variability of energy resource output. Imports to the area are required to cover these risk periods; however, regional resource availability and transmission constraints can affect external assistance during wide area heat events.
WECC-NW		WECC-NW assessment area is projected to have negligible LOLH and EUE this summer with planned resource additions and normal transfer availability. However, some LOLH (<0.1) and EUE (<400 MWh) is anticipated during above-normal demand periods if new resource are delayed or external transfers are disrupted. WECC-NW would rely on imports to maintain adequate reserves on the during the risk hours from 4:00–9:00 p.m. under extreme summer peak load and low-resource conditions (e.g., extreme thermal or extreme hydro derates or combinations of other low energy output scenarios.)
WECC-SW		WECC-SW assessment area is projected to have negligible LOLH and EUE this summer with planned resource additions and normal transfer availability. However, some LOLH (<0.1) and EUE (<150 MWh) is anticipated during above-normal demand periods if new resource are delayed or external transfers are disrupted.

Errata

May 2023

- The Risk Scenario Summaries for SERC-Central and SERC-East were corrected (page 23 and page 24)

Energy Transition in PJM:
Resource Retirements, Replacements & Risks

Feb. 24, 2023

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Contents

Executive Summary

Driven by industry trends and their associated challenges, PJM developed the following strategic pillars to ensure an efficient and reliable energy transition: facilitating decarbonization policies reliably and cost-effectively; planning/operating the grid of the future; and fostering innovation.

PJM is committed to these strategic pillars, and has undertaken multiple initiatives in coordination with our stakeholders and state and federal governments to further this strategy, including interconnection queue reform, deployment of the State Agreement Approach to facilitate 7,500 MW offshore wind in New Jersey, and coordination with state and federal governments on maintaining system reliability while developing and implementing their specific energy policies.

In light of these trends and in support of these strategic objectives, PJM is continuing a multiphase effort to study the potential impacts of the energy transition. The first two phases of the study focused on energy and ancillary services and resource adequacy in 2035 and beyond. This third phase focuses on resource adequacy in the near term through 2030.[1]

Maintaining an adequate level of generation resources, with the right operational and physical characteristics[2], is essential for PJM's ability to serve electrical demand through the energy transition.

Our research highlights four trends below that we believe, in combination, present increasing reliability risks during the transition, due to a potential timing mismatch between resource retirements, load growth and the pace of new generation entry under a possible "low new entry" scenario:

- The growth rate of electricity demand is likely to continue to increase from electrification coupled with the proliferation of high-demand data centers in the region.
- Thermal generators are retiring at a rapid pace due to government and private sector policies as well as economics.
- Retirements are at risk of outpacing the construction of new resources, due to a combination of industry forces, including siting and supply chain, whose long-term impacts are not fully known.
- PJM's interconnection queue is composed primarily of intermittent and limited-duration resources. Given the operating characteristics of these resources, we need multiple megawatts of these resources to replace 1 MW of thermal generation.

[1] See Energy Transition in PJM: Frameworks for Analysis | Addendum (2021), and Energy Transition in PJM: Emerging Characteristics of a Decarbonizing Grid | Addendum (2022).

[2] See previous work on Reliability Products and Services, including PJM's Evolving Resource Mix and System Reliability (2017), Reliability in PJM: Today and Tomorrow (2021), Energy Transition in PJM: Frameworks for Analysis | Addendum (2021), and work completed through the RASTF and PJM Operating Committee (2022).

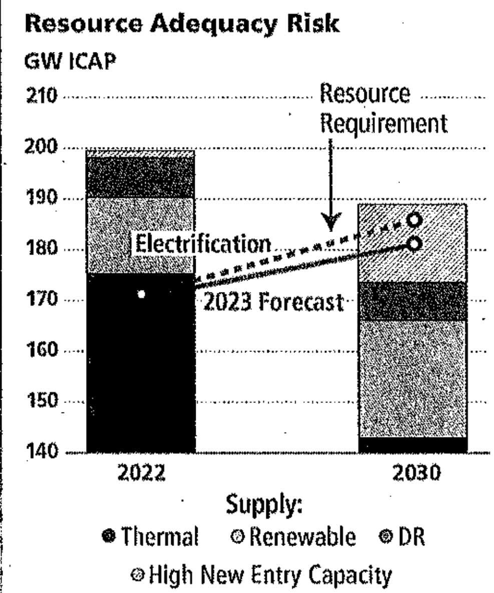
The analysis also considers a "high new entry" scenario, where this timing mismatch is avoided. While this is certainly a potential outcome, given the significant policy support for new renewable resources, our analysis of these long-term trends reinforces the importance of PJM's ongoing stakeholder initiatives, including capacity market modifications, interconnection process reform and clean capacity procurement, and the urgency for continued, combined actions to de-risk the future of resource adequacy while striving to facilitate the energy policies in the PJM footprint.

The first two phases of the energy transition study assumed that PJM had adequate resources to meet load.

In this this third phase of this living study, we explore a range of plausible scenarios up to the year 2030, focusing on the resource mix "balance sheet" as defined by generation retirements, demand growth and entry of new generation.

The analysis shows that 40 GW of existing generation are at risk of retirement by 2030. This figure is composed of: 6 GW of 2022 deactivations, 6 GW of announced retirements, 25 GW of potential policy-driven retirements and 3 GW of potential economic retirements. Combined, this represents 21% of PJM's current installed capacity[3].

In addition to the retirements, PJM's long-term load forecast shows demand growth of 1.4% per year for the PJM footprint over the next 10 years. Due to the expansion of highly concentrated clusters of data centers, combined with overall electrification, certain individual zones exhibit more significant demand growth – as high as 7% annually.[4]



The projections in this study indicate that it is possible that the current pace of new entry would be insufficient to keep up with expected retirements and demand growth by 2030.

On the other side of the balance sheet, PJM's New Services Queue consists primarily of renewables (94%) and gas (6%). Despite the sizable nameplate capacity of renewables in the interconnection queue (290 GW), the historical rate of completion for renewable projects has been approximately 5%. The projections in this study indicate that the current pace of new entry would be insufficient to keep up with expected retirements and demand growth by 2030. The completion rate (from queue to steel in the ground) would have to increase significantly to maintain required reserve margins.

In the study, we also consider generation entry beyond the queue using projections from S&P Global. Those projections indicate that, despite eroding reserve margins, resource adequacy would be maintained if the influx of renewables materializes at a rapid rate and gas remains the transition fuel, adding 9 GW of capacity. The analysis performed at the Clean Attribute Procurement Senior Task Force (CAPSTF) also suggests that further gas expansion is economic and competitive.[5]

[3] Unless otherwise noted, thermal capacity values are expressed in ICAP, without adjustment for EFORd.

[4] PJM Load Forecast Report, January 2023.

[5] CAPSTF Analysis, Initial Results; Emmanuele Bobbio, Sr. Lead Economist – Advanced Analytics, PJM, Dec. 16, 2022.

Balance Sheet Summary (2022–2030)

Retirements	New Entry Wind/Solar[6]	New Entry Standalone Storage	New Entry Thermal	Load Growth
40 GW **60% Coal** **30% Natural Gas** **10% Other**	**Low =** 48 GW-nameplate / 8 GW-capacity **High =** 94 GW-nameplate / 17 GW-capacity	**Low =** 3 GW **High =** 4 GW	**Low =** 4 GW **High =** 9 GW	**2023 Forecast =** 11 GW **Electrification Forecast =** 13 GW

Unless otherwise noted, thermal capacity values are expressed in ICAP, without adjustment for EFORd.

For the first time in recent history, PJM could face decreasing reserve margins should these trends continue. The amount of generation retirements appears to be more certain than the timely arrival of replacement generation resources and demand response, given that the quantity of retirements is codified in various policy objectives, while the impacts to the pace of new entry of the Inflation Reduction Act, post-pandemic supply chain issues, and other externalities are still not fully understood.

The findings of this study highlight the importance of PJM's ongoing stakeholder initiatives (Resource Adequacy Senior Task Force, Clean Attribute Procurement Senior Task Force, Interconnection Process Subcommittee), continued efforts between PJM and state and federal agencies to manage reliability impacts of policies and regulations, and the urgency for coordinated actions to shape the future of resource adequacy. The potential for an asymmetrical pace in the energy transition, in which resource retirements and load growth exceed the pace of new entry, underscores the need to enhance the accreditation, qualification and performance requirements of capacity resources.

The composition and performance characteristics of the resource mix will ultimately determine PJM's ability to maintain reliability. It is critical that all PJM markets effectively correct imbalances brought on by retirements or load growth by incentivizing investment in new or expanded resources.

[6] Includes hybrid projects with battery storage

Background

Resource adequacy is the ability of the electric system to supply the aggregate energy requirements of electricity to consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of generation and transmission facilities. To achieve the goal of resource adequacy, PJM maintains an Installed Reserve Margin in excess of the forecast peak load that achieves a loss-of-load expectation (LOLE) of one day in 10 years. This LOLE standard is consistent with that prescribed in the ReliabilityFirst Corporation standard for planning resource adequacy.[7]

Long-term reliability and resource adequacy are addressed through the combined operation of PJM's electricity markets, and in particular the capacity market, called the Reliability Pricing Model (RPM). Each PJM member that provides electricity to consumers must acquire enough power supply to meet demand, not only for today and tomorrow, but for the future. Members secure these capacity resources for future energy needs through a series of base and incremental capacity auctions, as well as Fixed Resource Requirement plans.

The capacity market ensures long-term grid reliability by procuring the appropriate amount of power supply resources needed to meet predicted energy demand up to three years in the future. These capacity resources have an obligation to perform during system emergencies, and are subject to penalties if they underperform. By matching generation with future demand, the capacity market creates long-term price signals to attract needed investments to ensure adequate power supplies. This exchange provides consumers with an assurance of reliable power in the future, while capacity resources receive a dependable flow of income to help maintain their existing capability, attract investment in new resources, and encourage companies to develop new technologies and sources of electric power.

Methodology

The size, composition and performance characteristics of the resource mix will determine PJM's ability to maintain reliability. This study explores a range of scenarios in the context of resource adequacy, focusing on the resource mix "balance sheet" as defined by demand growth, generation retirements and new entry of generation. Using the methodology described in this section, PJM evaluates the future of resource adequacy by estimating the amount of capacity required to cover load expectations versus expected capacity for the years 2023 through 2030.

The study's initial supply levels are 192.3 GW of installed capacity from generation resources and 7.8 GW of installed capacity from demand response capacity resources. The generation mix is approximately 178.9 GW of thermal resources and 13.3 GW of renewables and storage.[8]

[7] RFC Standard BAL-502-RF-03: Planning Resource Adequacy Analysis, Assessment and Documentation

[8] This value includes the capacity value of run-of-river hydro, pumped storage hydro, solar, onshore wind, offshore wind and battery energy storage.

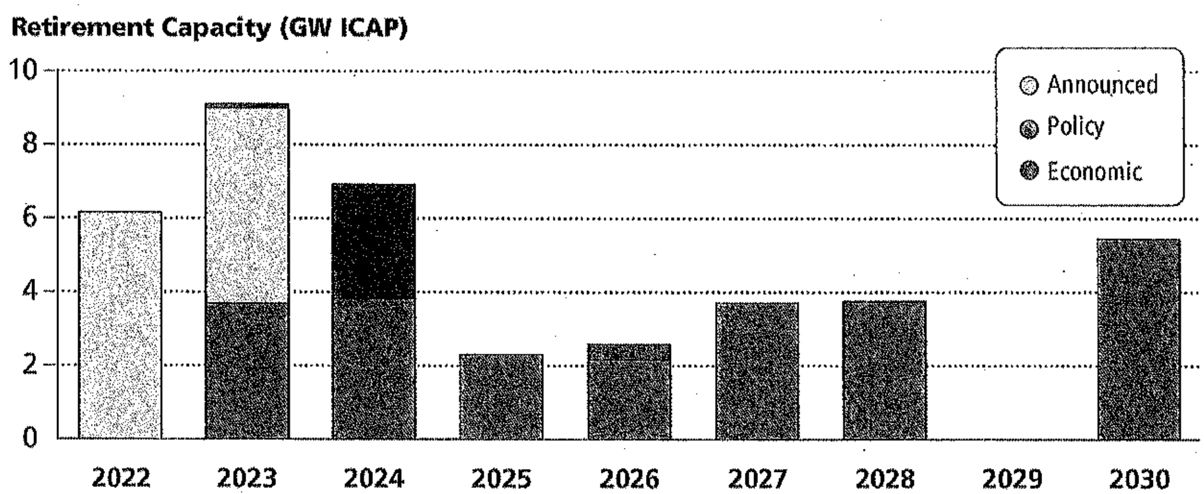
Supply Exits

PJM is undergoing a major transition in the resources needed to maintain bulk power grid reliability.

Historically, thermal resources have provided the majority of the reliability services in PJM. Today, a confluence of conditions, including state and federal policy requirements, industry and corporate goals requiring clean energy, reduced costs and/or subsidies for clean resources, stringent environmental standards, age-related maintenance costs, and diminished energy revenues are hastening the decline in thermal resources.

This study estimates anticipated retirements through 2030 by adding announced retirements with retirements likely as a result of various state and federal policies, and then with those at risk for retirement due to deteriorating unit economics. Potential policy-driven retirements, in this context, reflect resources that are subject to current and proposed federal and state environmental policies, in which it is conservatively assumed that the costs of mitigation and compliance could economically disadvantage these resources to the point of retirement. **Figure 1** highlights the 40 GW of projected generation retirements by 2030, which is composed of: 12 GW of announced retirements[9], 25 GW of potential policy-driven retirements[10] and 3 GW of potential economic retirements. Combined, this represents 21% of PJM's current installed capacity.[11] This section describes each category of potential retirements in more detail.

Figure 1. Total Forecast Retirement by Year (2022–2030)



[9] Includes 6 GW of 2022 retirements.

[10] Note that 7 GW of the 25 GW of supply with policy risk was also identified to have more immediate economic risk. The year that these 7 GW of potential policy retirements shown in **Figure 2** is based on timing identified in the economic analysis. In **Figure 4**, these 7 GW are shown in terms of the regulatory compliance timeline alone. The timeline of these potential quantities of resource retirements does not factor in any reliability "off-ramps" that may be included in established policies.

[11] In this study, PJM assumes that a resource that exits would not return to service in a future delivery year, even if operational conditions improve. Historically, a small percentage of retiring units would instead enter a "mothball" or standby state, in which the unit is put into a state where it may not operate for one or more years; however, in order to obtain an operating permit renewal, the mothballed unit would have to comply with the most recent environmental standards, likely requiring costly upgrades, making investing in newer, cleaner technologies more inviting.

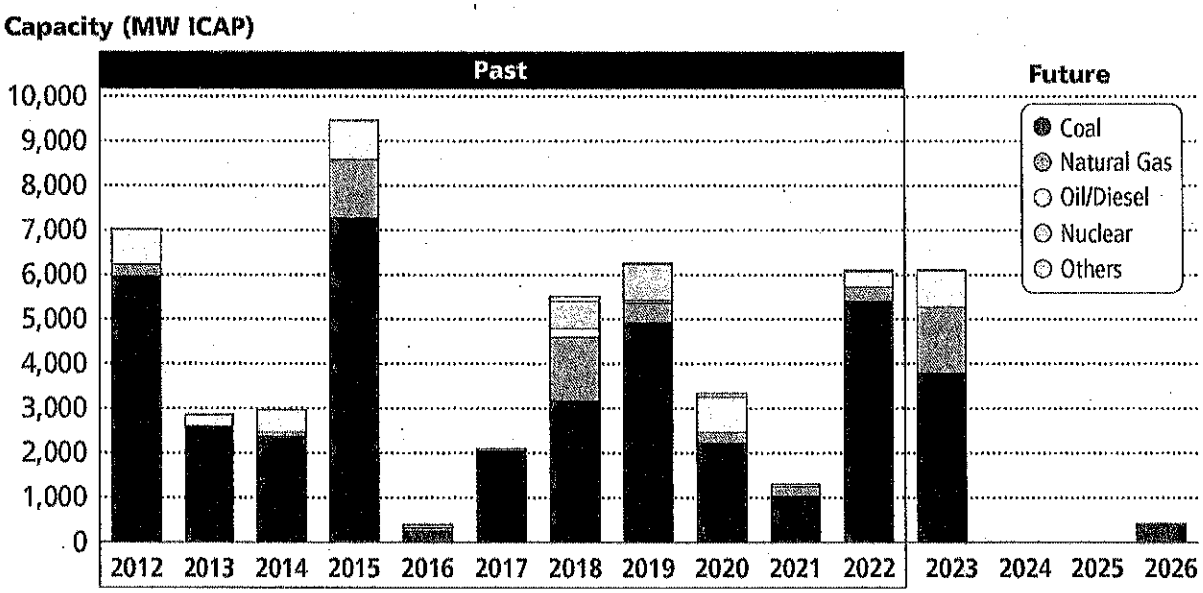
Announced Retirements

One of PJM's responsibilities is to ensure the continued reliability of the high-voltage electric transmission system when a generation owner requests deactivation. Through its Generation Deactivation process,[12] PJM identifies transmission solutions that allow owners to retire generating plants as requested without threatening reliable power supplies to customers. PJM may order transmission upgrades or additions built by transmission owners to accommodate the generation loss. PJM has no authority to order plants to continue operating. However, in some instances, to maintain reliability, PJM may formally request that a plant owner continue operating, subject to rates authorized by the Federal Energy Regulatory Commission (FERC), while transmission upgrades are completed.

Plant owners considering retirement must notify PJM at least two quarters before the proposed deactivation date. PJM and the transmission owners complete a reliability analysis in the subsequent quarter after notification to PJM. Generator retirements and any required system upgrades to keep the grid running smoothly are included in the PJM Regional Transmission Expansion Planning process and are reviewed with PJM members and stakeholders at the PJM Transmission Expansion Advisory Committee.

Between 2012 and 2022, 47.2 GW of generation retired in PJM, as detailed by fuel type in **Figure 2**. In 2022, approximately 6 GW of generation deactivated and an additional 5.8 GW announced ("future") deactivations over the 2023–2026 time frame. The deactivations are slightly above the 10-year average of 4.3 GW, but well under the historical annual peak of 9.5 GW in 2015. Coal-fired resources account for approximately 89% of retired capacity in 2022.

Figure 2. Past and Announced Future Retirements



[12] See process details in PJM Manual 14-D, Section 9, and tracking of deactivation requests at https://www.pjm.com/planning/services-requests/gen-deactivations.

Potential Policy Retirements

An analysis of federal and state policies and regulations with direct impacts on generation in the PJM region yielded the largest group of potential future retirements in this study.[13] As highlighted in **Figure 3**, the combined requirements of these regulations and their coincident compliance periods have the potential to result in a significant amount of generation retirements within a condensed time frame. These impacts will be reevaluated as these policies and regulations evolve. PJM will continue to work with both federal and state agencies on the development and implementation of environmental regulations and policies in order to address any reliability concerns.

Below are the policies and regulations included in the study:

EPA Coal Combustion Residuals (CCR): The U.S. Environmental Protection Agency (EPA) promulgated national minimum criteria for existing and new coal combustion residuals (CCR) landfills and existing and new CCR surface impoundments. This led to a number of facilities, approximately 2,700 MW in capacity, indicating their intent to comply with the rule by ceasing coal-firing operations, which is reflected in this study.

EPA Effluent Limitation Guidelines (ELG): The EPA updated these guidelines in 2020, which triggered the announcement by Keystone and Conemaugh facilities (about 3,400 MW) to retire their coal units by the end of 2028.[14] Importantly, but not included in this study, the EPA is planning to propose a rule to strengthen and possibly broaden the guidelines applicable to waste (in particular water) discharges from steam electric generating units. The EPA is expecting this to impact coal units by potentially requiring investments when plants renew their discharge permits, and extending the time that plants can operate if they agree to a retirement date.

EPA Good Neighbor Rule (GNR): This proposal requires units in certain states to meet stringent limits on emissions of nitrogen oxides (NOx), which, for certain units, will require investment in selective catalytic reduction to reduce NOx. For purposes of this study, it is assumed that unit owners will not make that investment and will retire approximately 4,400 MW of units instead. Please note that the EPA plans on finalizing the GNR in March, which may necessitate reevaluation of this assumption.

Illinois Climate & Equitable Jobs Act (CEJA): CEJA mandates the scheduled phase-out of coal and natural gas generation by specified target dates: January 2030, 2035, 2040 and 2045. To understand CEJA criteria impacts and establish the timing of affected generation units' expected deactivation, PJM analyzed each generating unit's publically available emissions data, published heat rate, and proximity to Illinois environmental justice communities and Restore, Reinvest, Renew (R3) zones. For this study, PJM focuses on the approximately 5,800 MW expected to retire in 2030.

[13] Policies impacting forward energy prices, such as the Regional Greenhouse Gas Initiative and Renewable Energy Credits, are implicitly included in economic analysis but are not explicitly included in analysis of policy-related retirements.

[14] See State Impact PA, Nov. 22, 2021. These facilities have not filed formal Deactivation Notices with PJM.

New Jersey Department of Environmental Protection CO_2 Rule: New Jersey's CO_2 rule seeks to reduce carbon dioxide (CO_2) emissions of fossil fuel-fired electric generating units (EGUs) through the application of emissions limits for existing and new facilities greater than 25 MW. Units must meet a CO_2 output-based limit by tiered start dates. The dates and CO_2 limits are:

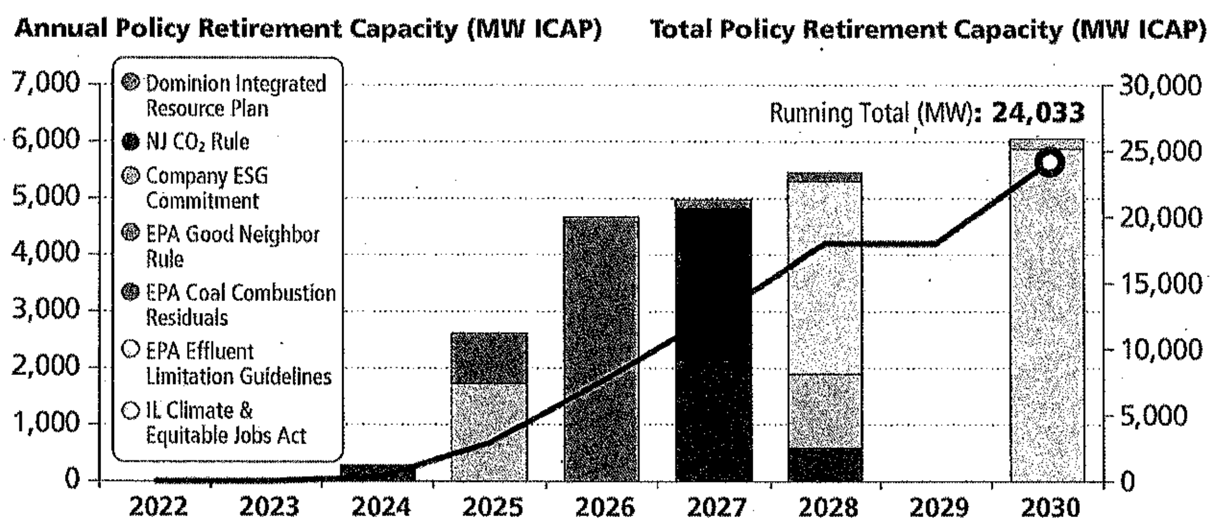
- June 1, 2024 – 1,700 lb/MWh
- June 1, 2027 – 1,300 lb/MWh
- June 1, 2035 – 1,000 lb/MWh

PJM used emissions data found in EPA Clean Air Markets Program Data to evaluate unit compliance. Where a unit's average annual emissions rate was greater than the CO_2 limit on the compliance date, the unit was assumed to be retiring. In this study PJM, estimated retirements at approximately 400 MW in 2024 and approximately 2,700 MW in 2027.

Dominion Integrated Resource Plan (IRP) commits to net zero carbon in its Virginia and North Carolina territory by 2050. PJM studied Dominion's Alternative Plan B retirement schedule, approximately 1,533 MW, for this analysis. Alternative Plan B proposes "significant development of solar, wind and energy storage resource envisioned by the VCEA," (Virginia Clean Economy Act of 2020), while maintaining natural gas generation for reliability, which is reflected in our analysis.

Company ESG (Environmental, Social, Governance) commitments are included where there is a commitment to retire resources per legal consent decree or other public statement. This includes the elimination of coal use and the retirement of the Brandon Shores, 1,273 MW, and Wagner, 305 MW, facilities in Maryland and the retirement of Rockport, 1,318 MW, in Indiana.

Figure 3. Potential Policy Retirements



Potential Economic Retirements

The third category of retirements in this study, beyond those formally announced and made likely by policy implementation, were identified through an analysis of revenue adequacy, the ability to economically cover going-forward costs from the wholesale markets. A net profit value was calculated for each existing generation resource using an estimate of future revenues and historical costs.

$$\begin{aligned} Net\ Profit = {} & (\ Gross\ Energy\ \&\ Ancillary\ Service\ Revenue - Production\ Costs\ ) \\ & + (\ Capacity\ Revenue\ ) - (\ Fixed\ Avoidable\ Costs\ ) \end{aligned}$$

The results reveal that a portion of the thermal fleet is at risk of becoming unprofitable in the coming years.

The capacity market's Variable Resource Requirement (VRR) represents the set of prices for which load is willing to procure additional supply beyond the minimum reliability requirement. There are three points in the sloped demand curve, the first of which is anchored at a price 1.5 times the Net Cost of New Entry (Net CONE). Should the auction clear at this price level, the auction result signals that demand is willing to pay for the construction of new supply, minus the expected energy revenues the resource should expect to earn in the energy markets. As such, it is important to align the revenue expectations for the marginal resources with forward revenues, especially under PJM's continually changing landscape of business rules.

Energy & Ancillary Services Revenue and Production Cost

This study used a scaling approach to estimate forward unit-specific energy and ancillary services (E&AS) revenues from historical energy and ancillary service revenues by applying the following:

$$Fwd\ Unit\ E\&AS\ Revenue = Hist\ Unit\ E\&AS\ Revenue * \frac{Fwd\ Reference\ E\&AS\ Revenue^{15}}{Hist\ Reference\ E\&AS\ Revenue} * \frac{Reference\ Avg\ Heat\ Rate}{Unit\ Avg\ Heat\ Rate}$$

For a given reference resource type, unit dispatch was simulated using both historical and forward energy hub-adjusted energy prices. For the equivalent production cost model, the relative ratio of revenues and heat rates indicate the net effects of both rising fuel costs and energy price revenue. A unit on the margin in the energy markets, typically a natural gas unit, would set a locational price near its short-run marginal costs. Infra-marginal units, potentially coal units, would receive higher revenues as price-taking resources, and thus may see increased profitability. This is reflected in the analysis, in which a reference coal unit's forward revenues increased an average of 139% over previous revenue estimates.

[15] The forward energy and ancillary services revenue calculation used in this study is the method that was developed for use in the Forward Net Energy & Ancillary Services Offset calculation originally developed in 2020, and filed as part of the most recent Quadrennial Review.

Capacity Revenues and Fixed Avoidable Costs

Unit-specific capacity revenues were calculated from prices and cleared quantities in the 2023/2024 Base Residual Auction (BRA). The study used the published 2023/2024 BRA Default Gross Avoidable Cost Rate (ACR) values as representative total fixed costs ($/MW-day) required to keep the generating plant available to produce energy. In other words, these are projected costs that could be avoided by the retirement of the plant. Avoidable costs represent operational factors like operations and maintenance labor, fuel storage costs, taxes and fees, carrying charges, and other costs not directly related to the production of energy. When available, unit-specific ACR values from the 2023/2024 BRA supply offer mitigation process were used, otherwise the class average Gross ACR was used.

Results and Estimated Impact

This study assumes that a simulated economic loss would result in a retirement of the resource at the next available delivery year in which the unit is not committed for capacity. As such, a unit with a revenue loss that did not clear in the 2023/2024 BRA would exit in 2023, while a unit with a revenue loss that cleared in the 2023/2024 BRA would exit in 2024. While units that do not clear a single BRA may remain energy-only resources, this conservative assumption was used to provide awareness.

The economic analysis identified approximately 10 GW of supply in immediate economic risk, of which 7 GW of supply is also affected by policy risk, and 3 GW of supply is economic risk only. In aggregate, 6 GW are steam resources, and 4 GW represent combustion turbines and internal combustion resources. Several of the units identified were older steam boilers that had once converted from coal-fired to natural gas fuel; these resources are less efficient than a modern heat-recovery steam generator in a combined cycle unit. Fifty-three percent of the resources identified for economic risk did not have a PJM capacity obligation in Delivery Year 2023/2024, either through the FRR process or market clearing.

Supply Entry

The composition of the PJM Interconnection Queue has evolved significantly in recent years, primarily increasing in the amount of renewables, storage, and hybrid resources and decreasing in the amount of natural gas-fired resources entering the queue. The PJM New Services Queue stands at approximately 290 ICAP GW of generation interconnection requests, of which almost 94% (271 ICAP GW) is composed of renewable and storage-hybrid resources.

Natural Gas Headwinds

In the last decade, resources in the PJM region have benefitted from the proximity to the Marcellus Shale, an area that extends along the Appalachian Mountains from southern West Virginia to central New York. Beginning around 2010, gas extraction from hydraulic fracturing transformed this region into the largest source of recoverable natural gas in the United States. This local fuel supply decreased the prices for spot market natural gas in much of the PJM region, and prices in the PJM region often trade at negative basis to the Henry Hub spot price.

The entry of natural gas resources in the PJM region peaked in 2018, with 11.1 GW of generation commercializing that single year. From 2019 to 2022, a total of 8.1 GW of natural gas generation began service, or about a third of the 23 GW observed from 2015–2018. Queue proposals have also declined; over the last three years, only 4.1 GW of new natural gas projects entered the queue, while 15.1 GW of existing queue projects withdrew.[16]

Recent movement in the natural gas spot markets across the U.S. and Europe add another degree of uncertainty to future operations. In 2022, European natural gas supply faced many challenges resulting from the war in Ukraine and subsequent sanctions against Russia. Liquefied natural gas (LNG) imports into the EU and the U.K. in the first half of 2022 increased 66% over the 2021 annual average,[17] primarily from U.S. exporters with operational flexibility. This international natural gas demand is a new competitor for domestic spot-market consumers, resulting in significantly higher fuel costs for PJM's natural gas fleet.

This study assumes that, of the approximately 17.6 GW of natural gas generation in the queue, only those that are proposed uprates of existing generation, or currently under construction, will complete.[18] This results in 3.8 GW of entry from under-construction natural gas resources to be completed for the 2023/2024 Delivery Year. While 12 GW of natural gas have reached a signed Interconnection Service Agreement (ISA) stage, it is unclear what percentage of this capacity may move forward. If significantly more natural gas capacity achieved commercial operation, it could help avoid reliability issues.

Renewable Transition

PJM's projected resource mix continues to evolve toward lower-carbon intermittent resources. Entry into the queue from renewable and storage resources has been growing at an annualized rate of 72% per year since 2018, or 199 GW of capacity entry versus 2.8 GW commercializing and 42.1 GW withdrawn. This influx of renewable projects has led to a joint effort between PJM and its stakeholders to enact queue reforms intended to clear the backlog of projects, improve procedures around permitting and site control, simplify analysis by clustering projects, and accelerate projects that don't require network upgrades. FERC approved the proposed package in November 2022, with expected implementation in 2023.

Commercial Probability and Expanding Beyond the Queue

PJM staff developed several forecasts of the rate by which projects successfully exit the queue (the "commercial probability" of reaching an *In-Service* state). Since 1997, the PJM New Services Queue has tracked proposed generation interconnection projects from their submittal and study stages to completion of an ISA and Wholesale Market Participation Agreement (WMPA) and construction. At any point in the process, a resource may withdraw from the queue, effectively ending its commercial viability.

[16] This capacity represents natural gas projects that were submitted prior to 2020 and withdrawn in the 2020–2022 time frame.

[17] Europe imported record amounts of liquefied natural gas in 2022, U.S. Energy Information Administration, June 14, 2022.

[18] Under construction includes the New Service Queue *Partially in Service – Under Construction* and *Under Construction* statuses.

The study utilized a logistical regression classification algorithm to predict the probability of a project reaching an *In-Service* entry (or *Withdrawn* exit) based on several properties of the project. A logistical regression searches for patterns within training datasets, resulting in a model that can forecast a probability of a result. After applying the logistical regression model for 10 years of historical project completion (Y-queue to present) without project stage, approximately 15.3 GW-nameplate/8.7 GW-capacity were deemed commercially probable out of 178 GW of projects examined.

The model results for thermal resources were reasonably in line with expectations. However, the model produced extremely low entry from onshore wind, offshore wind, solar, solar-hybrid and storage resources. The uncertainty of completion rates of newer resource types, like offshore wind, likely plays a role in these model outcomes. After adjusting the new renewable capacity by Effective Load Carrying Capability (ELCC) derations, this commercial probability analysis estimates net 13.2 GW-nameplate / 6.7 GW-capacity to the system by 2030, as shown in **Figure 4.**

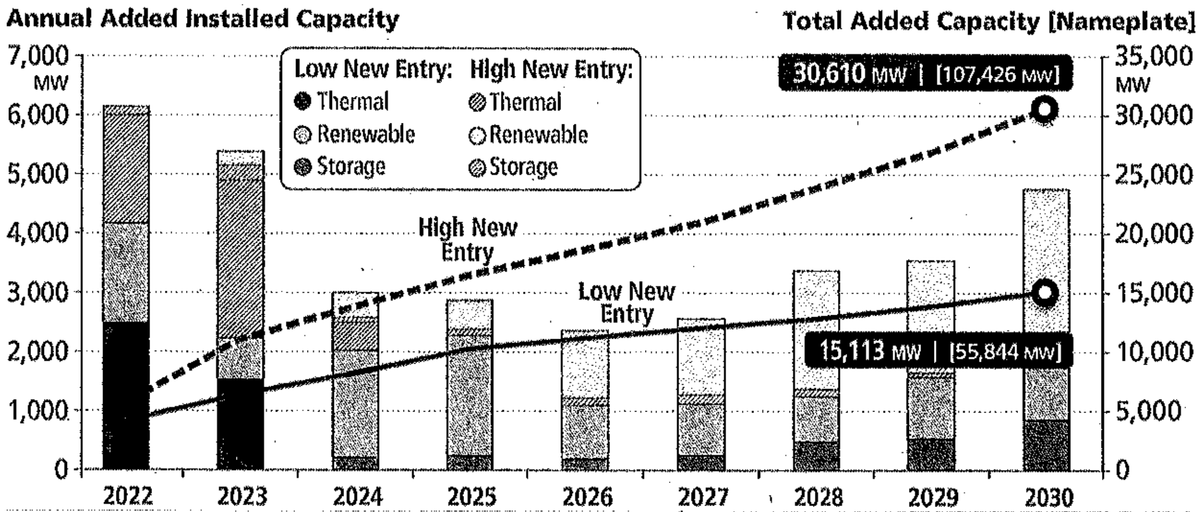
Given that this process may not capture recent policy changes and fiscal incentives toward renewable and storage development, and that the existing queue has fewer resources entered after 2026, PJM staff utilized two S&P Global Power Market Outlook analyses' generation expansion models. As estimates of future entry beyond the queue, these models are used to provide additional insight for the two scenarios: "Low New Entry" utilizes the "Planning Model,"[19] and "High New Entry" utilizes the "Fast Transition" model.[20] Based on these models, PJM added additional capacity to its commercial probability data in each scenario.

These forecasts of generation expansion are economic resource planning solutions, which take state RPS requirements and capacity margins into account to ensure new renewable builds. Over the study period, the Low New Entry scenario adds 42.6 GW-nameplate/8.4 GW-capacity to supply expectations, resulting in total entry of 55.8 GW-nameplate/15.1 GW-capacity. The High New Entry scenario adds 107 GW-nameplate/30.6 GW-capacity after ELCC derations. Net natural gas entry was approximately 5 GW, and renewables was 48.5 GW-nameplate/10.4 GW-capacity, as shown in **Figure 4.**

[19] S&P Global, North American Power Market Outlook, June 2022, planning model. This planning case incorporated effects from the 2021 Infrastructure Investment and Jobs Act, but not the 2022 Inflation Reduction Act.

[20] S&P Global, North American Power Market Outlook, Sept. 2022, Fast Transition model. This planning case assumes carbon net neutrality by 2050 through the IRA and additional policies, such as state clean energy policies, and as such assumes adjustments for increased electrification of heating, tax credits for renewable generation and higher levels of fossil retirements.

Figure 4. Forecast Added Capacity



Impact of Capacity Accreditation on Existing Renewables and Storage

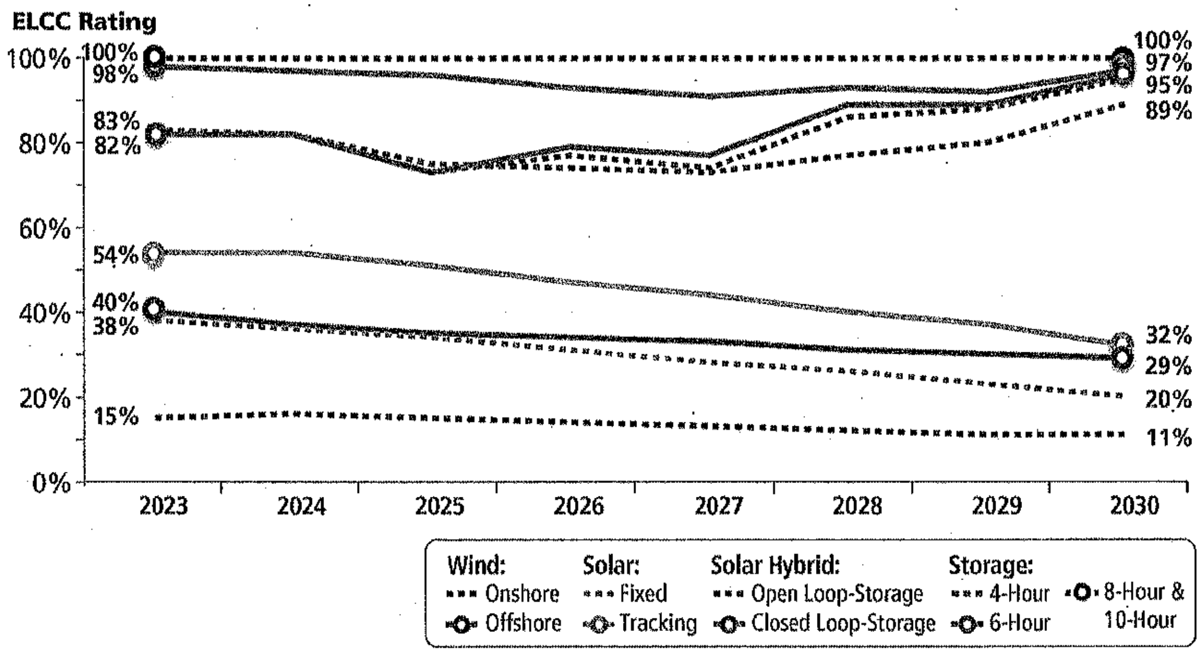
In July 2021, FERC accepted PJM's ELCC methodology for calculating unforced capacity values for intermittent and energy storage capacity resource classes. The ELCC analysis[21] examines load and resource performance uncertainty, and calculates an hourly loss-of-load probability (LOLP) to meet a one-in-10 year loss of load expectation (LOLE) adequacy criteria. The ELCC method examines the alignment of a given resource type's capacity to high risk hours, as well as the change in risk hours proportional to the changes in portfolio size. The adjustments to accredited capacity went into effect in the 2023/2024 BRA executed in June 2022.

This study examined the current renewable generation fleet for the impact of future changes in capacity accreditation. Today, there are approximately 3.5 GW of onshore wind and solar capacity resources participating in the RPM capacity market as intermittent resources. From 2022 to 2030, this accredited capacity is expected to decline by 1.2 GW to 2.3 GW due to portfolio effects resulting in the increase of entry from other intermittent renewable resources.[22] This adjustment is consistent with the renewable expectations presented in the December 2021 Effective Load Carrying Capability (ELCC) Report.

[21] Manual 20, Section 5: PJM Effective Load Carrying Capability Analysis

[22] Approximate nameplate needed to replace 1 MW of thermal generation: Solar – 5.2 MW; Onshore Wind – 14.0 MW; Offshore Wind – 3.9 MW. These are average values.

Figure 5. Effective Load Carrying Capability (ELCC) Rating by Resource Type



Demand Expectations

Load forecasting is an important part of maintaining the reliability of the bulk electric system. Forecasting helps PJM make decisions about how to plan and operate the bulk electric system in a reliable manner, and how to effectively administer competitive power markets. PJM's Resource Adequacy Planning Department publishes an annual Load Forecast Report, which outlines "long-term load forecasts of peak-loads, net energy, load management, distributed solar generation, plug-in electric vehicles and battery storage."

Along with the energy transition, PJM is witnessing a large growth in data center activity. Importantly, the PJM footprint is home to Data Center Alley in Loudoun County, Virginia, the largest concentration of data centers in the world.[23] PJM uses the Load Analysis Subcommittee (LAS) to perform technical analysis to coordinate information related to the forecast of electrical peak demand. In 2022, the LAS began a review of data center load growth and identified growth rates over 300% in some instances.[24] The 2023 PJM Load Forecast Report incorporates adjustments to specific zones for data center load growth, as shown in **Figure 5.**

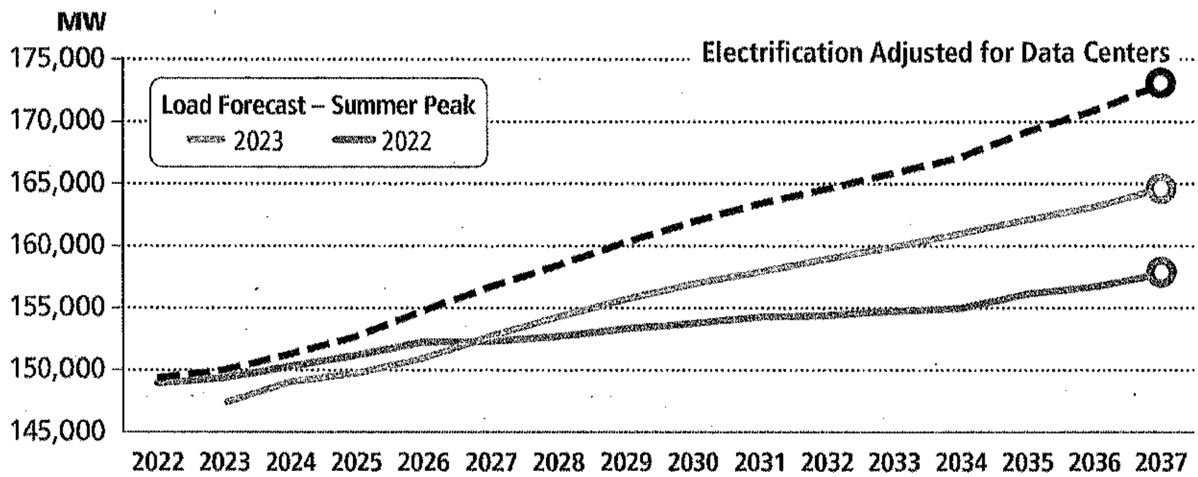
[23] See Loudoun County Department of Economic Development, 2023.

[24] Load Analysis Subcommittee: Load Forecast Adjustment Requests, Andrew Gledhill, Resource Adequacy Planning, Oct. 27, 2022

Additionally, PJM is expecting an increase in electrification resulting from state and federal policies and regulations. The study therefore incorporates an electrification scenario in the load forecast to provide insight on capacity need should accelerated electrification drive demand increases.[25] This accelerated demand increase is consistent with the methodology used in the Emerging Characteristics of a Decarbonizing Grid paper.[26] That paper found electrification to have an asymmetrical impact on demand growth, with demand growth in the winter, mainly due to heating, more than doubling that in the summer. This would move the bulk of the resource adequacy risk from the summer to the winter.

Figure 6 highlights how updated electrification assumptions and accounting for new data center loads have impacted the summer peak between the 2022 and 2023 forecasts.[27]

Figure 6. Impacts of Electrification and Data Center Load on Forecasts



What Does This Mean for Resource Adequacy in PJM?

PJM projects resource adequacy needs through the Reserve Requirement Study (RRS). The purpose of the RRS is to determine the required capacity or Forecast Pool Requirement for future years or delivery years based on load and supply uncertainty. The RRS also satisfies the North America Electric Reliability Corporation/ReliabilityFirst Adequacy Standard BAL-502-RFC-03, Planning Resource Adequacy Analysis, Assessment and Documentation, which requires that the Planning Coordinator performs and documents a resource adequacy analysis that applies a LOLE of one occurrence in 10 years. The RRS establishes the Installed Reserve Margin values for future delivery years. For this study PJM used the most recent 2022 RRS, as well as the 2021 RRS for comparison.

[25] Electrification assumptions are 17 million EVs, 11 million heat pumps, 20 million water heaters, 19 million cooktops in PJM by 2037, built on top of the 2022 Load Forecast.

[26] Energy Transition in PJM: Emerging Characteristics of a Decarbonizing Grid, May 17, 2022.

[27] 2023 Load Forecast Supplement, PJM Resource Adequacy Planning Department, January 2023.

Combining the resource exit, entry and increases in demand, summarized in **Figure 7**, the study identified some areas of concern. Approximately 40 GW PJM's fossil fuel fleet resources may be pressured to retire as load grows into the 2026/2027 Delivery Year. At current low rates of renewable entry, the projected reserve margin would be 15%, as shown in **Table 1.** The projected total capacity from generating resources would not meet projected peak loads, thus requiring the deployment of demand response. By the 2028/2029 Delivery Year and beyond, at Low New Entry scenario levels, projected reserve margins would be 8%, as projected demand response may be insufficient to cover peak demand expectations, unless new entry progresses at a levels exhibited in the High New Entry scenario. This will require the ability to maintain needed existing resources, as well as quickly incentivize and integrate new entry

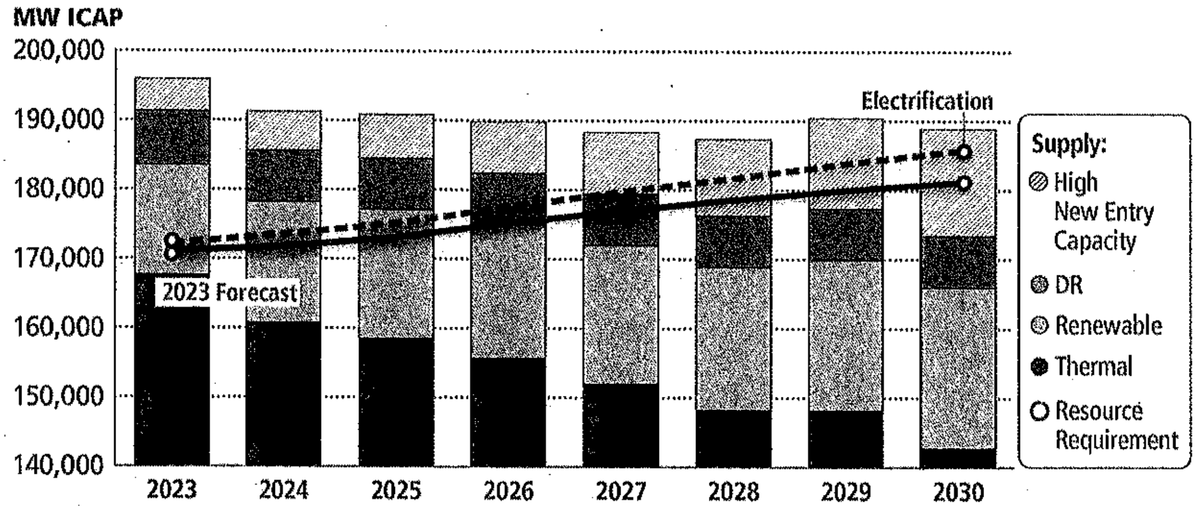
Table 1. Reserve Margin Projections Under Study Scenarios

Reserve Margin	2023	2024	2025	2026	2027	2028	2029	2030
Low New Entry								
2023 Load Forecast	23%	19%	17%	15%	11%	8%	8%	5%
Electrification	22%	18%	16%	13%	10%	7%	6%	3%
High New Entry								
2023 Load Forecast	26%	23%	21%	19%	17%	16%	17%	15%
Electrification	25%	22%	20%	18%	15%	14%	14%	12%

As witnessed during the rapid transition from coal resources to natural gas resources last decade, PJM markets provide incentives for capacity resources. The challenge will be integrating the level of additional resources envisioned to meet this demand, and therefore addressing issues such as resource capacity accreditation is critical in the near term. The low entry rates shown in our Low New Entry scenario are illustrative of recent completion history applied to the current queue. RTO capacity prices in recent auctions have been low for several delivery years, and capacity margins have historically reached around 28% of peak loads. As capacity reserve levels tighten, the markets will clear higher on the VRR curves, sending price signals to build new generation for reliability needs.

The 2024/2025 BRA, which executed in December 2022, highlighted another area of uncertainty. Queue capacity with approved ISAs/WMPAs is currently very high, approximately 35 GW-nameplate, but resources are not progressing into construction. There has only been about 10 GW-nameplate moving to in service in the past three years. There may still be risks to new entry, such as semiconductor supply chain disruptions or pipeline supply restrictions, which are preventing construction despite resources successfully navigating the queue process.

Figure 7. The Balance Sheet



For the first time in recent history, PJM could face decreasing reserve margins, as shown in **Table 1**, should these trends – high load growth, increasing rates of generator retirements, and slower entry of new resources – continue. The amount of generation retirements appears to be more certain than the timely arrival of replacement generation resources, given that the quantity of retirements is codified in various policy objectives, while the impacts to the pace of new entry of the Inflation Reduction Act, post-pandemic supply chain issues, and other externalities are still not fully understood.

The findings of this study highlight the importance of PJM's ongoing stakeholder initiatives (Resource Adequacy Senior Task Force, CAPSTF, Interconnection Process Subcommittee), continued efforts between PJM and state and federal agencies to manage reliability impacts of policies and regulations, and the urgency for coordinated actions to shape the future of resource adequacy.

The potential for an asymmetrical pace within the energy transition, where resource retirements and load growth exceed the pace of new entry, underscores the need for better accreditation, qualification and performance requirements for capacity resources.

The composition and performance characteristics of the resource mix will ultimately determine PJM's ability to maintain the reliability of the bulk electric system. Managing the energy transition through collaborative efforts of PJM stakeholders, state and federal agencies, and consumers will ensure PJM has the tools and resources to maintain reliability.

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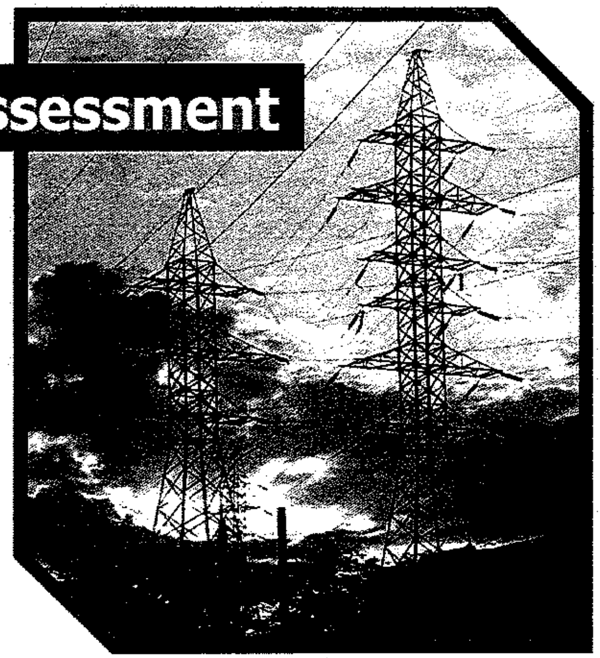

2022 Long-Term Reliability Assessment

December 2022

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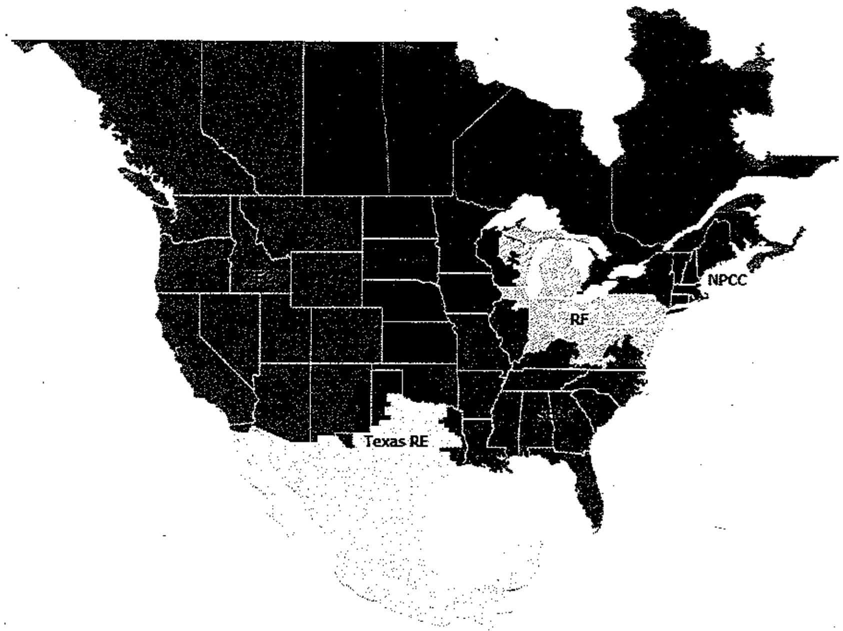
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities, is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entity boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities (LSE) participate in one Regional Entity while associated Transmission Owners/Operators participate in another. A map and list of the assessment areas can be found in the **Regional Assessments** section.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About this Assessment

NERC is a not-for-profit international regulatory authority with the mission to assure the reliability of the BPS in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the ERO for North America and is subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC, also known as the Commission) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the North American BPS and serves more than 334 million people. Section 39.11(b) of FERC's regulations provides that "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

Development Process

This assessment was developed based on data and narrative information NERC collected from the six Regional Entities (see **Preface**) on an assessment area (see **Regional Assessments**) basis to independently evaluate the long-term reliability of the North American BPS while identifying trends, emerging issues, and potential risks during the upcoming 10-year assessment period. The Reliability Assessment Subcommittee, at the direction of NERC's Reliability and Security Technical Committee (RSTC), supported the development of this assessment through a comprehensive and transparent peer review process that leverages the knowledge and experience of system planners, Reliability Assessment Subcommittee members, NERC staff, and other subject matter experts; this peer review process ensures the accuracy and completeness of all data and information. This assessment was also reviewed by the RSTC, and the NERC Board of Trustees (Board) subsequently accepted this assessment and endorsed the key findings.

NERC develops the Long-Term Reliability Assessment (LTRA) annually in accordance with the ERO's Rules of Procedure[1] and Title 18, § 39.11[2] of the Code of Federal Regulations,[3] also required by Section 215(g) of the Federal Power Act, which instructs NERC to conduct periodic assessments of the North American BPS.[4]

Considerations

Projections in this assessment are not predictions of what will happen; they are based on information supplied in July 2022 about known system changes with updates incorporated prior to publication. This *2022 LTRA* assessment period includes projections for 2023–2032; however, some figures and tables examine data and information for the 2022 year. This assessment was developed by using a consistent approach for projecting future resource adequacy through the application of the ERO Reliability Assessment Process.[5] NERC's standardized data reporting and instructions were developed through stakeholder processes to promote data consistency across all the reporting entities that are further explained in **Demand Assumptions and Resource Categories**. Reliability impacts related to cyber and physical security risks are not specifically addressed in this assessment; this assessment is primarily focused on resource adequacy and operating reliability. NERC leads a multi-faceted approach through NERC's Electricity-Information Sharing and Analysis Center (E-ISAC) to promote mechanisms to address physical and cyber security risks, including exercises and information-sharing efforts with the electricity industry.

The LTRA data used for this assessment creates a reference case dataset that includes projected on-peak demand and system energy needs, demand response (DR), resource capacity, and transmission projects. Data from each Regional Entity is also collected and used to identify notable trends and emerging issues. This bottom-up approach captures virtually all electricity supplied in the United States, Canada, and a portion of Baja California, Mexico. NERC's reliability assessments are developed to inform industry, policy makers, and regulators as well as to aid NERC in achieving its mission to ensure the reliability of the North American BPS.

[1] NERC Rules of Procedure - Section 803

[2] Section 39.11(b) of FERC's regulations states the following: "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

[3] Title 18, § 39.11 of the Code of Federal Regulations

[4] BPS reliability, as defined in the How NERC Defines BPS Reliability section of this report, does not include the reliability of the lower-voltage distribution systems that account for 80% of all electricity supply interruptions to end-use customers.

[5] *ERO Reliability Assessment Process Document*, April 2018: https://www.nerc.com/comm/PC/Reliability%20Assessment%20Subcommittee%20RAS%202013/ERO%20Reliability%20Assessment%20Process%20Document.pdf

Assumptions

In this *2022 LTRA*, the baseline information on future electricity supply and demand is based on several assumptions:[6]

- Supply and demand projections are based on industry forecasts submitted and validated in July 2022. Any subsequent demand forecast or resource plan changes may not be fully represented; however, updated data submitted throughout the report drafting time frame have been included where appropriate.
- Peak demand is based on average peak weather conditions and assumed forecast economic activity at the time of submittal. Weather variability is discussed in each Regional Entity's self-assessment.
- Generation and transmission equipment will perform at historical availability levels.
- Future generation and transmission facilities are commissioned and in service as planned, planned outages take place as scheduled, and retirements take place as proposed.
- Demand reductions expected from dispatchable and controllable DR programs will yield the forecast results if they are called on.
- Other peak demand-side management programs, such as energy efficiency (EE) and price-responsive DR, are reflected in the forecasts of total internal demand.

Reading this Report

This report is compiled into two major parts:

- A reliability assessment of the North American BPS with the following goals:
  - Evaluate industry preparations that are in place to meet projections and maintain reliability
  - Identify trends in demand, supply, and reserve margins
  - Identify emerging reliability issues
  - Focus the industry, policy makers, and the general public's attention on BPS reliability issues
  - Make recommendations based on an independent NERC reliability assessment process
- A regional reliability assessment that contains the following:
  - 10-year data dashboard
  - Summary assessments for each assessment area
  - Focus on specific issues identified through industry data and emerging issues
  - Identify regional planning processes and methods used to ensure reliability

[6] Forecasts cannot precisely predict the future. Instead, many forecasts report probabilities with a range of possible outcomes. For example, each regional demand projection is assumed to represent the expected midpoint of possible future outcomes. This means that a future year's actual demand may deviate from the projection due to the inherent variability of the key factors that drive electrical use, such as weather. In the case of the NERC regional projections, there is a 50% probability that actual demand will be higher than the forecast midpoint and a 50% probability that it will be lower (50/50 forecast).

Executive Summary

Introduction

This *2022 LTRA* is the ERO's independent assessment and comprehensive report on the adequacy of planned BPS resources to reliably meet the electricity demand across North America over the next ten years. This *2022 LTRA* also identifies reliability trends, emerging issues, and potential risks that could impact the long-term reliability, resilience, and security of the BPS.

The findings in this 2022 LTRA are vitally important to understand the reliability risks to the North American BPS as it is currently planned and as it is being shaped by government policies, regulations, consumer preferences, and economic factors. Energy systems and the electricity grid are undergoing unprecedented change on a scope, scale, and speed that challenges the ability to foresee—and design for—their future states. This report contains future energy sufficiency metrics that serve as guideposts for the reliability of the North American electric grid on its current trajectory. It also describes the relevant trends that are propelling the grid's transformation and have the potential to alter the ability of the BPS to service the energy needs of communities and industries in North America.

Projected Area Supply Shortfalls

The **Resource Capacity and Energy Risk Assessment** section of this report identifies potential electricity supply shortfalls under normal and more severe conditions. NERC's assessment assumes the latest demand forecasts, resource levels, and area transfer commitments as well as accounts for expected generator retirements, resource additions, and demand-side resources.

High Risk Areas[7]

Most areas are projected to have adequate electricity supply resources to meet demand forecasts associated with normal weather. However, areas shown in red (high risk) in Figure 1 do not meet resource adequacy criteria, such as the 1-day-in-10 year load-loss metric during periods of the assessment horizon. This indicates that the supply of electricity for these areas is more likely to be insufficient in the forecast period and that more firm resources are needed. The following is a summary of the high-risk areas (details are discussed in later sections of this *2022 LTRA*):

- **In the Midcontinent Independent System Operator (MISO)** area, the previously-reported reserve margin shortfall has advanced by one year, resulting in a 1,300 MW capacity deficit for the summer of 2023. The projected shortfall continues an accelerating trend since both the *2020 LTRA* and the *2021 LTRA* as older coal, nuclear, and natural gas generation exit the system faster than replacement resources are connecting.
- **NPCC-Ontario** also continues to project a reserve margin shortfall in 2025 and beyond. The capacity deficit of 1,700 MW is driven by generation retirements and lengthy planned outages at nuclear units undergoing refurbishment.
- Resource additions in the **California/Mexico (CA/MX) part of WECC** are alleviating capacity risks, but energy risks persist. Planned reserve margins meet annual reserve margin targets for the duration of the 10-year horizon. However, overall variability in both the resource mix and demand profile contributes to shortfall risk periods, mainly in summer months around sunset, when expected supplies are not sufficient to meet the demand.

Elevated Risk Areas[8]

Extreme temperatures and prolonged severe weather conditions are increasingly impacting the BPS. Extreme weather impacts the system by increasing electricity demand and forcing generation and other resources off-line. While a given area may have sufficient capacity to meet resource adequacy requirements, it may not have sufficient availability of resources during extreme and prolonged weather events. Therefore, **long-duration weather events increase the risk of electricity supply shortfalls.**

In many parts of North America, peak electricity demand is increasing, and forecasting demand and its response to extreme temperatures and abnormal weather is increasingly uncertain. Electrification and distributed energy resource (DER) trends can be expected to further contribute to demand growth and sensitivity to weather patterns. Specifically, electrification of residential heating requires the system to serve especially high demand on especially cold days.

[7] An assessment area is deemed to be "high risk" by failing to meet the established resource adequacy target or requirement. The established resource adequacy target is not established by NERC, but instead by the prevailing regulatory authority or market operator. Generally, these targets/requirements are based on a 1 day/event load-loss in a 10-year planning requirement. High risk areas have a probability of load shed greater than the requirement/target. Simply said, high risk areas do not meet resource adequacy requirements.

[8] An assessment area is deemed to be "elevated risk" when it meets the established resource adequacy target or requirement, but the resources fail to meet demand and reserve requirements under the probabilistic or deterministic scenario analysis. The established resource adequacy target is not established by NERC, but instead the prevailing regulatory authority or market operator. Simply, elevated risk areas meet resource adequacy requirements, but they may face challenges meeting load under extreme conditions.

Electricity supplies can decline in extreme weather for many reasons. Generators that are not designed or prepared for severe cold or heat can be forced off-line in increasing amounts. Wide area weather events can also impact multiple balancing and transmission operations simultaneously that limit the availability of transfers. Fuel production or transportation disruptions could limit the amount of natural gas or other fuels available for electric generation. Wind, solar, and other variable energy resource (VER) generators are dependent on the weather.

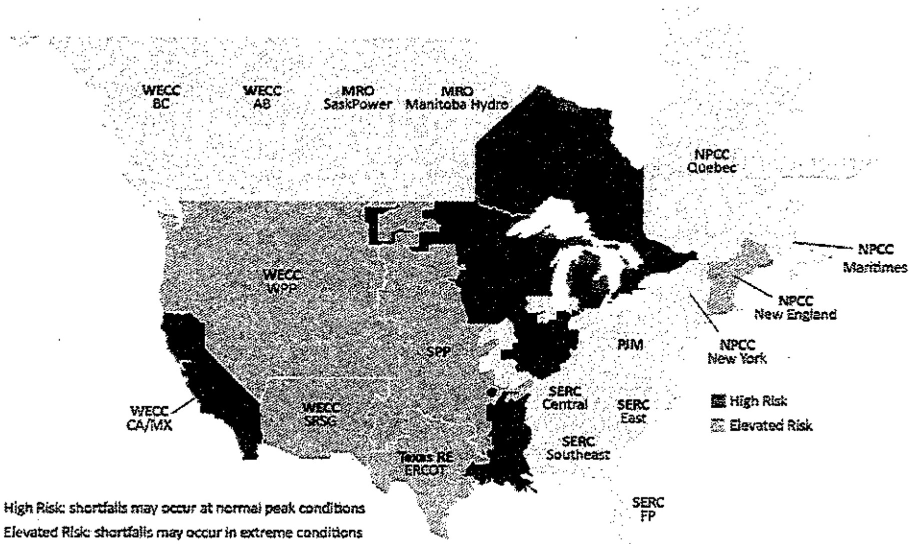


Figure 1: Risk Area Summary 2023–2027

Areas in orange (elevated risk) in Figure 1 meet resource adequacy criteria and have sufficient energy and capacity for normal forecasted conditions, but they are at risk of shortfall in extreme conditions:

- All three assessment areas in the **U.S. West—CA/MX, Western Power Pool (WPP), and the Southwest Reserve Sharing Group (SRSG)**—have increasing demand and resource mix variability. In normal conditions, the expected demand and resource variability is balanced across the area as excess supply from one part of the system is delivered through the transmission network to places where demand is higher than supply. However, more extreme summer temperatures that stress large portions of the Interconnection reduce the availability of excess supply for transfer while also reducing the transmission network's ability to transfer the excess.
- Reliability during extreme winter weather remains a concern in **Texas.** ERCOT's winter peak load varies substantially (as much as 12.5%) between the coldest temperatures of an average year and a more extreme year as might be experienced once per decade. A high number of forced outages of the thermal and wind generation fleet have been an issue in severe winter weather. Improved generator availability resulting from winter preparedness programs and reforms implemented by Texas regulators, ERCOT, and Generator Owners since February 2021 are expected to reduce the risk that electricity supplies will be insufficient during a severe winter storm.
- **SPP** is exposed to energy risks in ways that are similar to both Texas and the U.S. West. Severe weather in SPP is likely to cause high generator outages and poses a risk to natural gas fuel supplies. In addition, the penetration of wind generation makes the resource mix variable and exposed to insufficient energy during low wind periods.
- In **New England,** limited natural gas infrastructure can impact winter reliability due to increased heating demand and the potential for supply disruptions to generators. Liquefied natural gas facilities and sufficient generators with stored backup fuels are critical to electric reliability.

Continuing Resource Mix Changes and Implications for Reliability

This *2022 LTRA* contains the latest industry projections for generation and other resources, including DR, DERs, and the resulting Continuing Resource Mix Changes and Implications for Reliability found at this link. Highlights of these trends and the implications for reliability include the following:

- **Reliable Interconnection of Inverter-Based Resources:** Reliably integrating inverter-based resources (IBR), which include most solar and wind generation, onto the grid is paramount. Over 70% of the new generation in development for connecting to the BPS over the next 10 years is solar, wind, and hybrid (a generating source combined with a battery).
- **Accommodating Large Amounts of Distributed Energy Resources:** Preparing the grid to operate with increasing levels of distribution resources must also be a priority in many areas. Solar photovoltaic (PV) DERs are projected to reach over 80 GW by the end of this 10-year assessment, a 25% increase in projection since the *2021 LTRA*; a total of 12 assessment areas project to double the amount of DERs in their areas by 2032.

- **Managing the Pace of Generation Retirements:** As new resources are introduced and older traditional generators retire, careful attention must be paid to power system and resource mix reliability attributes. Within the 10-year horizon, over 88 GW of generating capacity is confirmed for retirement through regional transmission planning and integrated processes. Effective regional transmission and integrated resource planning processes are the key to managing the retirement of older nuclear, coal-fired, and natural gas generators in a manner that prevents energy risks or the loss of necessary sources of system inertia and frequency stabilization that are essential for a reliable grid.
- **Maintaining Essential Reliability Services:** The changing composition of the North American resource mix calls for more robust planning approaches to ensure adequate essential reliability services.[9] Retiring conventional generation is being replaced with large amounts of wind and solar; planning considerations must adapt with more attention to essential reliability services. As replacement resources are interconnected, these new resources should have the capability to support voltage, frequency, and dispatchability. Various technologies can contribute to essential reliability services, including variable energy resources; however, policies and market mechanisms need to reflect these requirements to ensure these services are provided and maintained. Regional transmission organizations, independent system operators, and FERC have taken steps in this direction, and these positive steps must continue.

Trends and Implications for Reliability

Demand Trends and Implications as well as **Transmission Development Trends and Implications** found at these links affect long-term reliability and the sufficiency of electricity supplies. Several key insights emerge from the latest industry data:

- **Peak Demand and Energy Growth:** Projected growth rates of electricity peak demand and energy in North America are increasing for the first time in recent years. Government policies for the adoption of electric vehicles (EVs) and other energy transition programs have the potential to significantly influence demand. Demand-side management programs, including conservation, EE, and DR continue to offset demand and contribute to load management. Where rapid transition is proposed, early alignment and coordination on energy and infrastructure are needed.
- **Insufficient Transmission for Large Power Transfers:** Transmission development projections remain near the averages of the past five NERC LTRAs. There has been some increase in the number of miles of transmission line projects for integrating renewable generation over the next 10 years compared to the *2021 LTRA* projections. Transmission investment is important for reliability and resilience as well as the integration of new generation resources.
- **Emerging Electrification Challenges:** Several emerging issues and trends have the potential to impact future long-term projections of demand and resources. In addition to EV and electrification issues, cryptocurrency mining may have a notable impact on demand and resources in some areas. Resource development may be significantly altered by supply chain issues and differ from projections used in this *2022 LTRA*. Notable emerging issues and their potential implications are discussed in this report.

Conclusions and Recommendations

The energy and capacity risks identified in this assessment underscore the need for reliability to be a top priority for the resource and system planning community of stakeholders. Planning and operating the grid must increasingly account for different characteristics and performance in electricity resources as the energy transition continues. General actions for industry and policymakers to address the reliability risks described in this *2022 LTRA* include the following:

- Manage the pace of generator retirements until solutions are in place that can continue to meet energy needs and provide essential reliability services
- Include extreme weather scenarios in resource and system planning
- Address IBR performance and grid integration issues
- Expand resource adequacy evaluations beyond reserve margins at peak times to include energy risks for all hours and seasons
- Increase focus on DERs as they are deployed at increasingly impactful levels
- Mitigate the risks that arise from growing reliance on just-in-time fuel for electric generation and the interdependent natural gas and electric infrastructure
- Consider the impact that the electrification of transportation, space heating, and other sectors may have on future electricity demand and infrastructure

Specific *LTRA* recommendations are provided on the following page and in the appropriate sections of this report.

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[9] Essential Reliability Services: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/ERS%20Abstract%20Report%20Final.pdf

Reducing the Risk of Insufficient Energy

The impact of wide-area and long-duration extreme weather events, such as the February 2021 South Central U.S. cold weather event and the August 2020 Western U.S. wide-area heat event, have underscored the need to consider extreme scenarios for resource planning. Energy risks emerge when weather-dependent generation is impacted by abnormal atmospheric conditions or when extreme conditions disrupt fuel supplies. In areas with a high dependence on VERs and natural-gas-fired generation, Prospective Reserve Margins (PRM) are not sufficient for measuring resource adequacy:

- Industry and regulators should conduct all-hours energy availability analyses for evaluating and establishing resource adequacy and include extreme condition criteria in integrated resource planning and wholesale market designs.
- The ERO and industry should prioritize the development of Reliability Standard requirements to address energy risks in operations and planning. NERC's Reliability Standards Project 2022-03 should be closely monitored, and stakeholder experts should contribute to developing effective requirements for entities to assess energy risks and implement corrective actions in all time horizons.
- State and provincial regulators and independent system operators (ISO)/regional transmission operators (RTO) should have mechanisms they can employ to prevent the retirement of generators that they determine are needed for reliability, including the management of energy shortfall risks.
- Regulatory and policy-setting organizations should use their full suite of tools to manage the pace of retirements and ensure that replacement infrastructure can be timely developed and placed in service. If needed, the Department of Energy should use its 202(c) authority as called upon by electric system operators.
- Resource planners and policymakers must pay careful attention to the pace of change in the resource mix as well as update capacity and energy risk studies (including all-hours probabilistic analysis) with accurate resource projections.

Planning and Adapting for IBRs and DERs

IBRs, including most solar and wind as well as new battery or hybrid generation, respond to disturbances and dynamic conditions based on programmed logic and inverter controls. The tripping of BPS-connected solar PV generating units and other control system behavior during grid faults has caused a sudden loss of generation resources over wide areas in some cases. As areas become more reliant on IBRs for their electricity generation, it is critically important to reduce risks from IBR performance issues. Likewise, explosive growth in DERs underscores the need to incorporate them into system planning:

- The ERO and Industry should take steps to ensure that IBRs operate reliably and the system is planned with due consideration for their unique attributes. NERC has developed an IBR strategy document to address IBR performance issues that illustrates current and future work to mitigate emerging risks in this area.[10] Regulators, industry-standards-setting organizations, trade forums, and manufacturers each have a role to play to address IBR performance issues.
- Industry should increase its focus on the technical needs for the BPS to reliably operate with increased amounts of DERs. Growth promises both opportunities and risks for reliability. Increased DER penetrations can improve local resilience at the cost of reduced operator visibility into loads and resource availability. Data sharing, models, and information protocols are needed to support BPS planners and operators. DER aggregators will also play an increasingly important role for BPS reliability in the coming years. Increasing DER participation in wholesale markets should be considered in connection with potential impacts to BPS reliability, contingency selection, and how any reliability gaps might be mitigated.

Addressing the Reliability Needs of Interdependent Electricity and Natural Gas Infrastructures

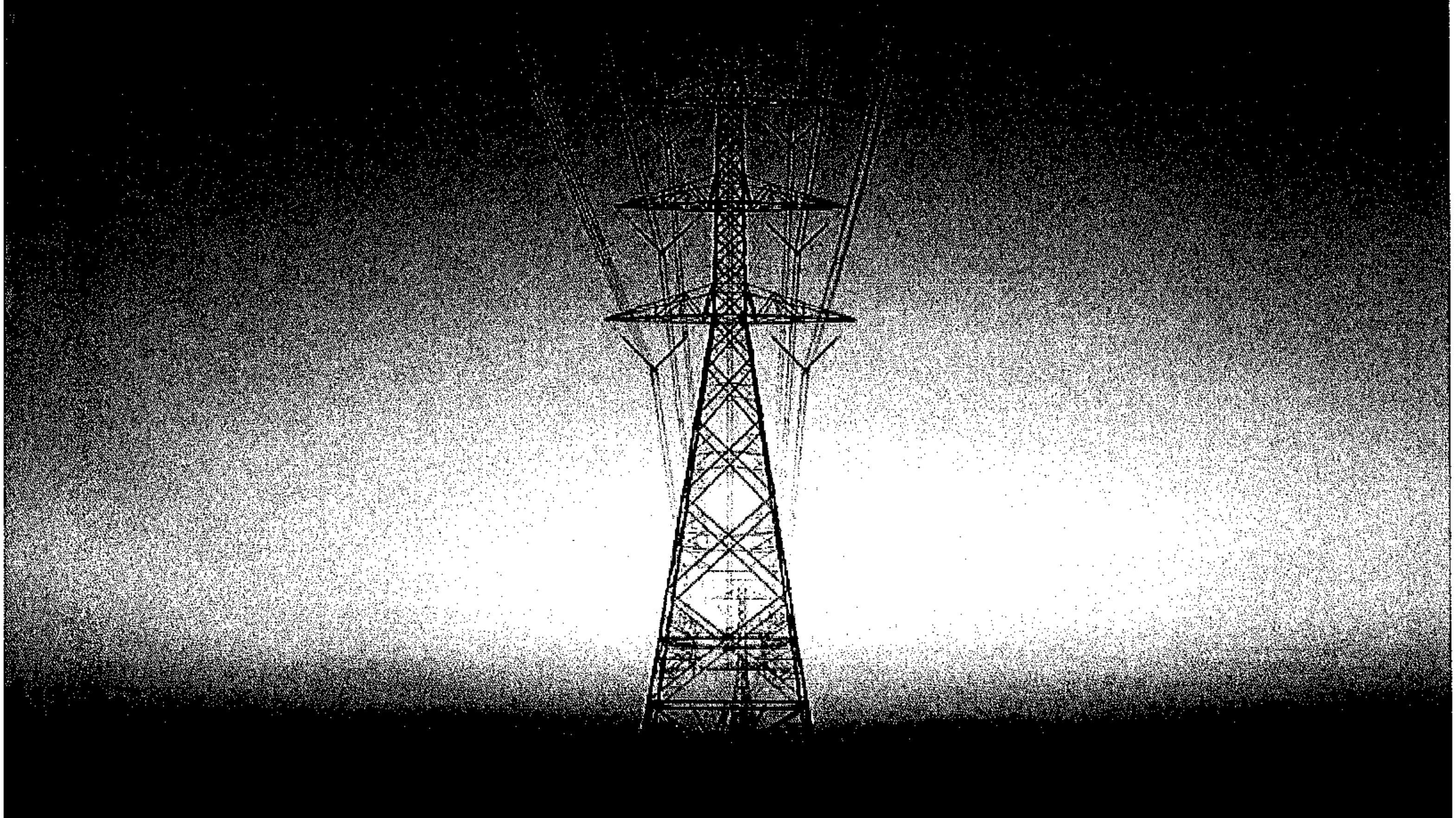
Natural gas is an essential fuel for electricity generation that bridges the reliability needs of the BPS during this period of energy transition. As natural-gas-fired generation continues to increase, vulnerabilities associated with natural gas delivery to generators can potentially result in generator outages. Energy stakeholders must urgently act to solve reliability challenges that arise from interdependent natural gas and electricity infrastructure:

- ERO and Industry planners should enhance guidelines for assessing and reducing risks through system and resource planning studies and develop appropriate Reliability Standards requirements to ensure corrective actions are put in place.
- Regulators and other energy stakeholders must also take steps to promote coordination on interdependencies. The forum convened by the North American Energy Standards Board is one such important action that should be broadly supported.[11]

[10] https://www.nerc.com/comm/Documents/NERC_IBR_Strategy.pdf
[11] https://www.nerc.com/news/Pages/-FERC,-NERC-Encourage-NAESB-to-Convene-Gas-Electric-Forum-to-Address-Reliability-Challenges.aspx

Economic, Reliability, and Resiliency Benefits of Interregional Transmission Capacity

Case Study Focusing on the Eastern United States in 2035



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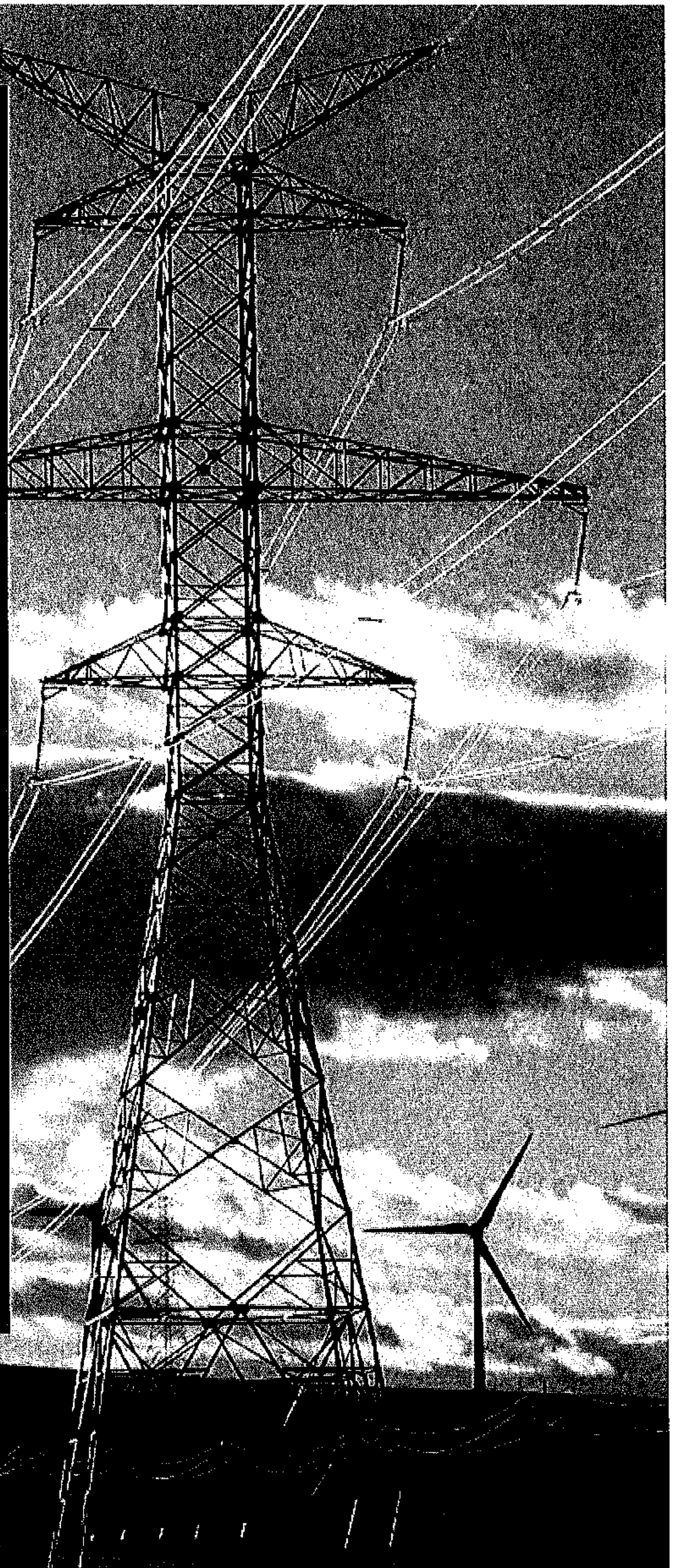

FOREWORD

This report was written on behalf of, and funded by, the Natural Resources Defense Council (NRDC). It was prepared by General Electric International, Inc. (GEII), acting through its Energy Consulting group, based in Schenectady, New York. Questions and any correspondence concerning this document should be referred to:

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Relevant Engineering Terms & Acronyms

AC / DC	Alternating Current / Direct Current
EI	Eastern Interconnection
FRCC	Florida Reliability Coord
FERC	Federal Energy Regulatory Commission
GE MAPS	GE Multi Area Production Simulation
GW / MW	Gigawatt / Megawatt
Hz	Hertz
ISONE	Independent System Operator of New England
kV	Kilovolts
LMP	Locational marginal price
MISO	Midcontinent Independent System Operator
MMBtu	Metric Million British Thermal Units
NYISO	New York Independent System Operator
PJM	Pennsylvania New Jersey Maryland Regional Transmission Organization
POI	Point of Interconnection
PV	Present value
SCR	Short circuit Current Ratio
SERC (E, SE, N)	Southeastern Electric Reliability Council (East, Southeast, North)
SPP	Southwest Power Pool

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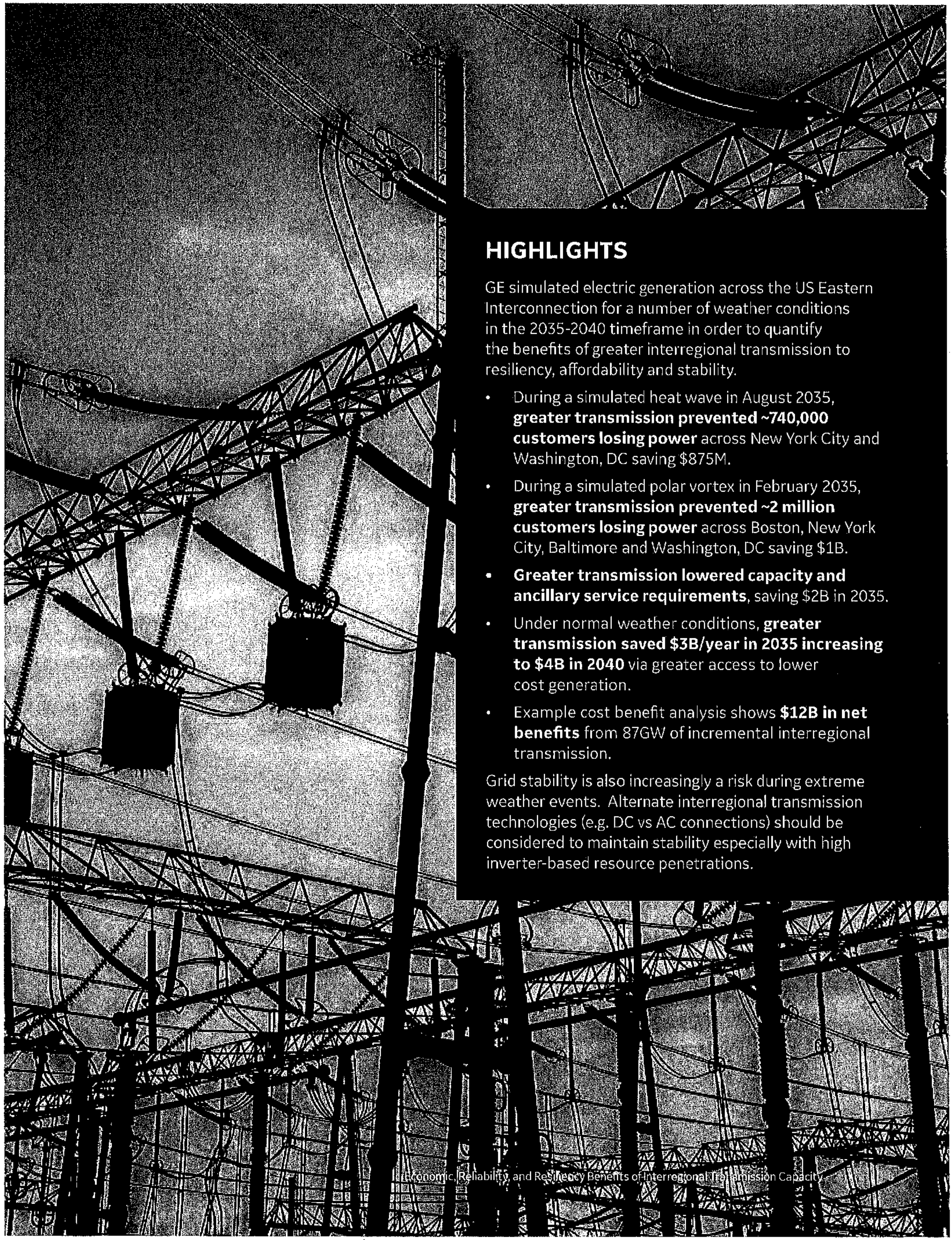


HIGHLIGHTS

GE simulated electric generation across the US Eastern Interconnection for a number of weather conditions in the 2035-2040 timeframe in order to quantify the benefits of greater interregional transmission to resiliency, affordability and stability.

- During a simulated heat wave in August 2035, **greater transmission prevented ~740,000 customers losing power** across New York City and Washington, DC saving $875M.
- During a simulated polar vortex in February 2035, **greater transmission prevented ~2 million customers losing power** across Boston, New York City, Baltimore and Washington, DC saving $1B.
- **Greater transmission lowered capacity and ancillary service requirements**, saving $2B in 2035.
- Under normal weather conditions, **greater transmission saved $3B/year in 2035 increasing to $4B in 2040** via greater access to lower cost generation.
- Example cost benefit analysis shows **$12B in net benefits** from 87GW of incremental interregional transmission.

Grid stability is also increasingly a risk during extreme weather events. Alternate interregional transmission technologies (e.g. DC vs AC connections) should be considered to maintain stability especially with high inverter-based resource penetrations.

1 EXECUTIVE SUMMARY

The United States electric grid is in a state of transition. The country is shifting towards lower carbon sources while facing more frequent extreme weather events that challenge the ability to keep the lights on. Greater grid flexibility is the key to reliable decarbonization in the face of uncertainty. One of the most cost-efficient forms of flexibility while maintaining resiliency is greater reliance on interregional imports and exports of electricity.

GE Energy Consulting (GE) knows the value of interregional flexibility from its own study experience. Back in our 2010 Western Wind and Solar Integration Study, GE and the National Renewable Energy Laboratory (NREL) identified the value of higher inter-regional flexibility to support California's decarbonization goals. This work helped support the 2014 launch of the Western Energy Imbalance Market that is operating today and has enabled over $2B in gross benefits across its 17 members.

In this study, we broaden our perspective to ask and illustrate the more general question: What are the benefits of interregional transmission? Answering this question should be based on the three types of ratepayer benefits:

1 Resiliency

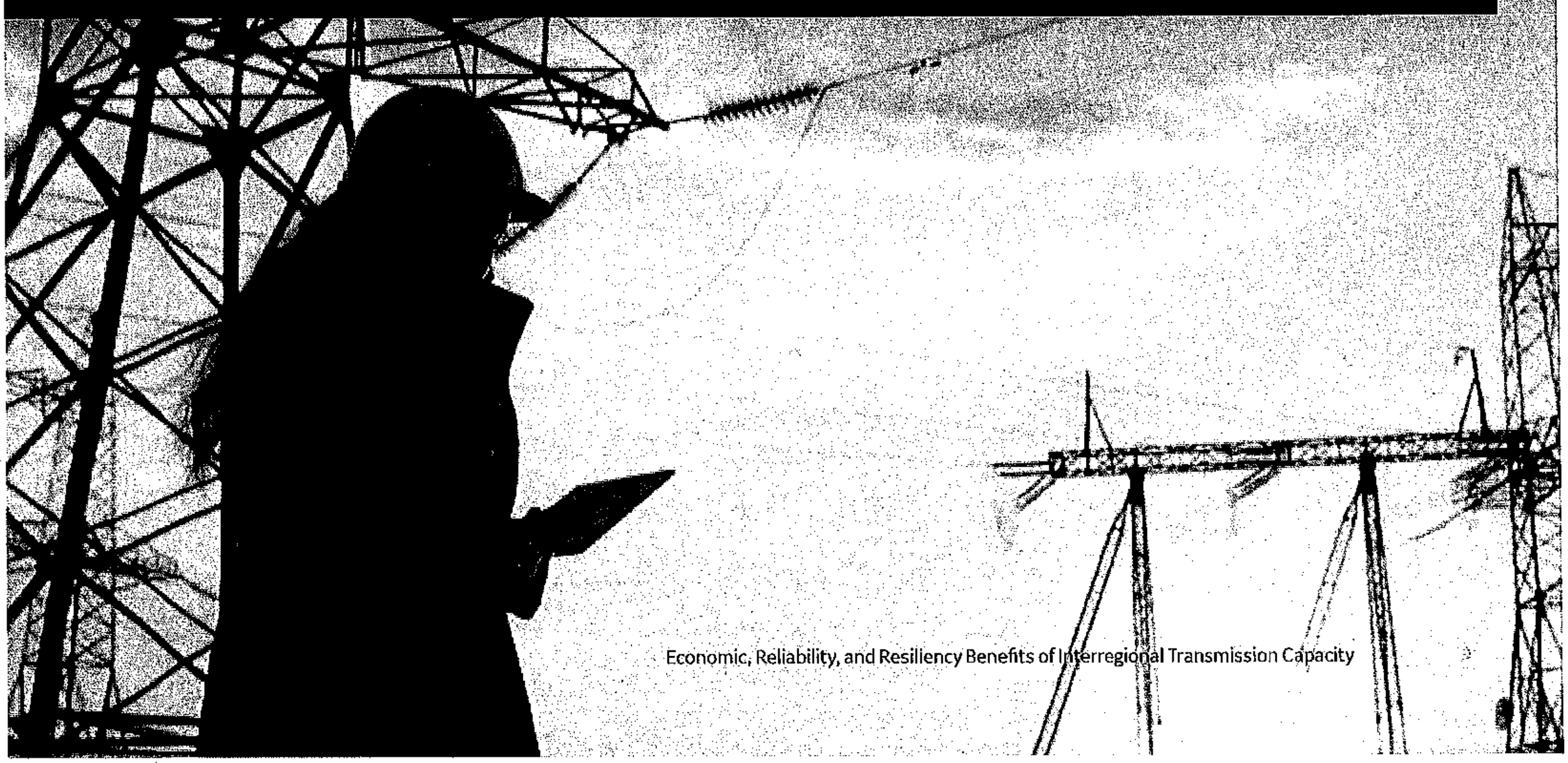
Interregional transmission expansion can lower the overall capacity required given grid uncertainty. In the face of frequent and extreme weather events, interregional transmission expansion can allow access to generation that otherwise would not have been accessible and minimizes the likelihood (or in the worst case, the impact) of shedding load (i.e., blackouts). In addition, a reduction in overall generating capacity is needed as interregional capacity takes advantage of diversity in load shapes.

2 Affordability

Interregional transmission expansion allows ratepayers with expensive generation to access generation from areas with less expensive generation. By enabling greater transmission access to these low-cost resources, ratepayers with more expensive generation can benefit.

3 Stability

With the shifting generation mix comes increased reliance on inverter-based resources. Interregional capacity can strengthen voltage, which is especially important for regions with large amounts of high inverter-based resources. Interregional transmission can reduce the amount of generation capacity that is required for meeting such stability needs.



In this study, GE modeled generation differences between a transmission-constrained and an unconstrained transmission grid to estimate the resiliency, economic and stability benefits. **GE found that fully unconstraining the transmission system in the Eastern Interconnection (EI) would result in limited to no loss of load during extreme weather events and $12 billion in net benefits.** GE believes these benefits are conservative due to a number of factors including:

- Study evaluated average power flows between regions rather than maximum power flows;
- Study assumed all regions maintained resource adequacy, and for estimating capacity and ancillary service savings, assumed a flat reserve margin rather than conducting a loss-of-load-expectation analysis;
- Many assumptions in GE's production cost model were locked in place in April 2022 to maintain the integrity of the comparative analysis conducted for this study. Had the study included 2022 updates to load forecasts, which incorporated more aggressive electrification assumptions by Independent System Operators, and most recent natural gas price forecasts, GE believes the benefits would have been higher.

Nevertheless, the benefits of interregional transmission are significant and are highlighted in this study.

GE also recognizes that the production cost modelling conducted for this study assumes rational economic behavior and that all stakeholders in the Eastern Interconnect would utilize the increased transmission capacity by increasing exports and imports to and from neighboring regions. There are a number of operational and planning limitations which could limit the realization of potential benefits of increased interregional transmission. Examples of limitations could include operational governance of the commitment and dispatch decisions of imports and exports in both day-ahead and real-time markets; planning requirements limiting imports to serve a regional grid in all but the most limited circumstances; and sharing of resources to meet reserve margins across multiple jurisdictions. This study is designed to exemplify the benefits of increased interregional transmission and does not specifically address potential barriers to those benefits.

2 METHODOLOGY & ANALYSIS

GE utilized the following approach based on interregional power flow needs and benefits across three sources of value:

1 Resiliency

That level of interregional transmission enables load to be served during expected extreme weather events across the Eastern Interconnection?

2 Affordability

What level of interregional transmission enables the most economic use of generation to serve load across the Eastern Interconnection?

3 Stability

Should interregional transmission include attributes beyond the size of AC transmission capacity? Given that grid stability is increasingly a factor during extreme weather events, how should interregional transmission address this concern?

In the following sections, GE outlines its evaluation methodology for each of these three areas and illustrate its use with an example analysis focused on the Eastern Interconnection of the United States.

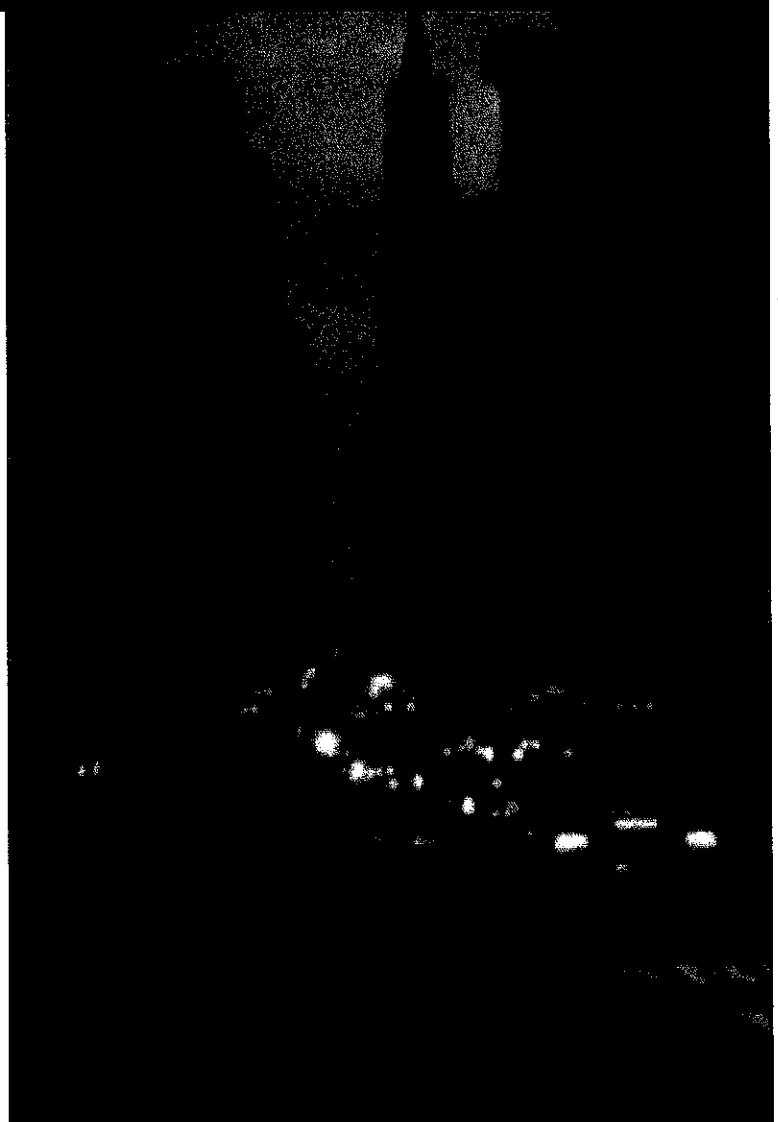
2.1 Benefits of incremental interregional transmission for increased resilience

2.1.1 Methodology

2.1.1.1 Formulate future system base assumptions

Future interregional supply-demand scenarios form the foundation of the simulations GE proposes to determine the benefits of interregional transmission. Many planners focus their simulations on their own region with limited or simplified consideration of the neighboring regions. However, in order to accurately assess the benefits of interregional transmission, a full grid model of the interregional system in question needs to be in place with future assumptions regarding variables such as:

1. Generation mix, additions & retirements
2. Annual load growth
3. Hourly load profile
4. Hourly renewables profiles
5. Generation cost assumptions including plant-level fuel costs
6. Interregional nodal transmission system and its constraints



New York City blackout after Hurricane Sandy, October 2012

2.1.1.2 Formulate future resilience conditions

For extreme weather uncertainty, GE proposes developing uncertainty scenarios to test for the amount of incremental transmission needed given potential load spikes, generation outages, or fuel shortages. For the case study presented, GE simulated individual scenarios. Ideally, GE recommends a more detailed stochastic analysis of the impacts from these variables if additional study funding becomes available. These requirements would be calculated on a pool-to-pool basis for each pool across the United States.

Given that recent grid events have highlighted adequacy risks across every type of resource (e.g., frozen cooling water, gas supply outages, transmission outages, extreme temperatures), the study team suggests that this type of analysis would:

- **Broaden the potential sources of failure** (e.g., non-electric sources of failure such as gas supply outage)
- **Test new weather extremes** (e.g., extreme temperatures driving extreme load peaks)
- **Test coincidence of failures** (e.g., extreme temperatures during gas supply failure, or cyber-attacks across multiple resources simultaneously)

2.1.1.3 Simulate future extreme-weather system performance with constrained vs unconstrained transmission

With the resilience conditions established, GE proposes simulating system performance under the following two transmission conditions:

1. Condition 1: **Constrained transmission.** This will allow the determination of the average power flow amounts between pools utilizing the existing/planned transmission system.
   Output metric: Average constrained power flows for each pool-to-pool interface.
2. Condition 2: **Unconstrained transmission.** For this simulation, GE suggests removing the MW limits associated with transmission flows. By removing the transmission line limits, the average power flows between pools can be determined to serve load most economically across the EI.
   Output: Average unconstrained power flows for each pool-to-pool interface.

Utilizing simulations under both the constrained and unconstrained EI conditions allows us to calculate the amount of transmission necessary to ensure resiliency:

Resilience incremental interregional transmission requirement

= Max across resilience scenarios [Average unconstrained power flows

- Average constrained power flows]

Equation 1 - Formula for calculating the resilience incremental interregional transmission requirement.

2.1.2 Example analysis for the US Eastern Interconnection

GE used the methodology above to estimate the amount of incremental transmission needed for the EI in 2035 to demonstrate resiliency benfits.

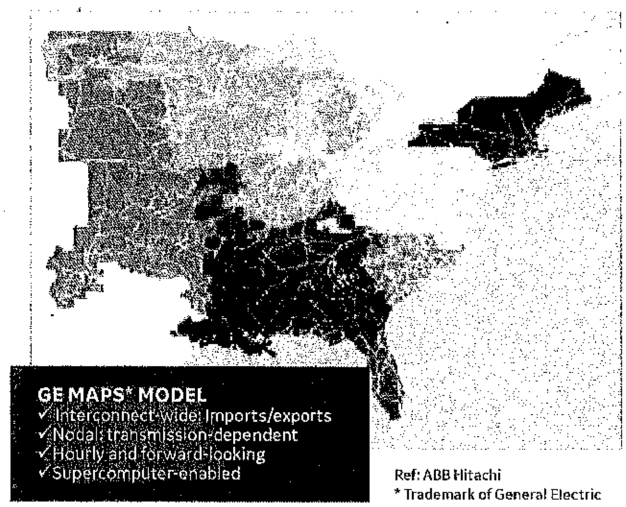


Figure 1 - GE simulation approach used GE MAPS to simulate the hourly dispatch across the EI in 2035.

GE simulated hourly dispatch across the EI in GE MAPS. Please refer to Section 4 for a summary of the assumptions used.

2.1.3 Example resilience analysis: Load shedding is mitigated via expanded transmission

2.1.3.1 Extreme Weather Events

Two weather events—a summer heat wave and a polar vortex—were simulated. Ideally, a broader range of resilience conditions would be considered either through many scenarios or using stochastic analysis. Such a broad range of grid conditions was considered beyond the scope of this analysis. However, the two extreme weather examples simulated here show the value of greater interregional transmission.

GE designed two extreme weather events to be simulated in this example:

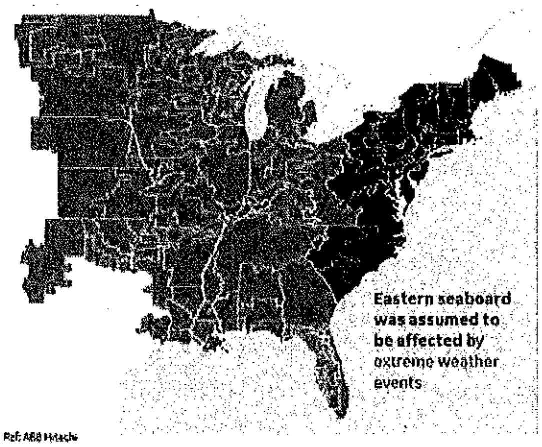
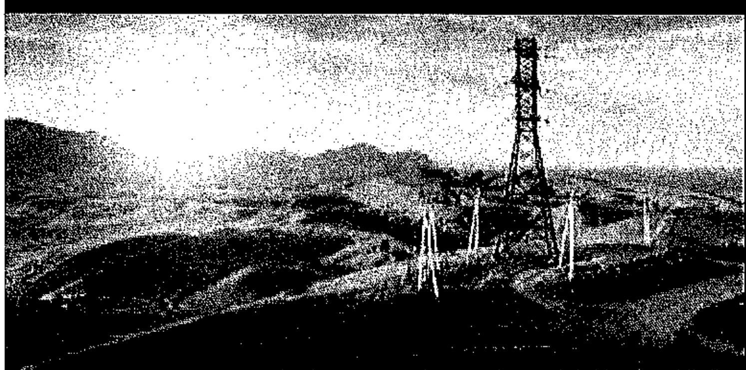


Figure 2 - For this example analysis, GE assumed that the Eastern seaboard was affected by the two extreme weather events we designed.

2035 Summer Heat wave

This event was modeled after the three-day summer heat wave of August 2018 where load along the East Coast was ~30% higher than average due to extreme heat. For this simulated event, GE therefore assumed an hourly load shape that was 30% higher than our assumed normal weather hourly load shape for the weekdays 8/15/2035 through 8/17/2035. For the days before and after the event, GE assumed hourly load was 10% higher than normal.



2035 Polar Vortex

This event was modeled after the February 2014 Polar Vortex event where East Coast load was ~40% higher than normal along with generation outages due to the cold. Winter loads are generally lower than summer loads, but the coincidence of generation outages adds another resiliency challenge. For this simulated polar vortex event, GE assumed:

- **Higher hourly load:** The hourly load shape was 40% higher than our assumed normal weather hourly load shape for the weekdays 2/14/2035 through 2/16/2035. For the days before and after the event, we assumed hourly load was 10% higher than normal.
- **Generation outages:** GE assumed ~15% generation outages across all fuel types due to winter conditions.
- **Gas price spikes:** Due to higher heating loads, the example also assumed gas prices spike to $40/ MMBTU due to supply shortages.

2.1.3.2 Heat wave analysis: Unconstraining transmission eliminates loss of load

In this example heat wave, GE simulated the EI under both a constrained and an unconstrained transmission system. The results of this simulation are shown in Figure 3.

Figure 3 shows average locational marginal prices (LMPs) across the EI during the 3 heat wave days in August 2035 for both the constrained and unconstrained conditions. In the constrained transmission case, regional LMPs across the EI spike to greater than $300/MWH in the New York City and Washington, DC metropolitan areas whereas given the greater access to generation in the unconstrained transmission case, prices remain tempered at ~$60/MWH. The arrows connecting each pool in Figure 3 denotes the average power flow size and direction between pools. As Figure 4 shows, in the unconstrained case, average power flows are significantly larger than in the constrained case. These larger average power flows enable more levelized prices.

More importantly, in the constrained case shown in Figure 3, given the increase in load and in transmission constraints, 35 GWh of power is lost, which is equivalent to ~740,000 customers losing power across New York City (~600,000 customers) and Washington, DC (~140,000 customers). Assuming $25k/MWH loss of load cost, this loss of load event equates to $875M. **By unconstraining the transmission system, these load losses are eliminated.**

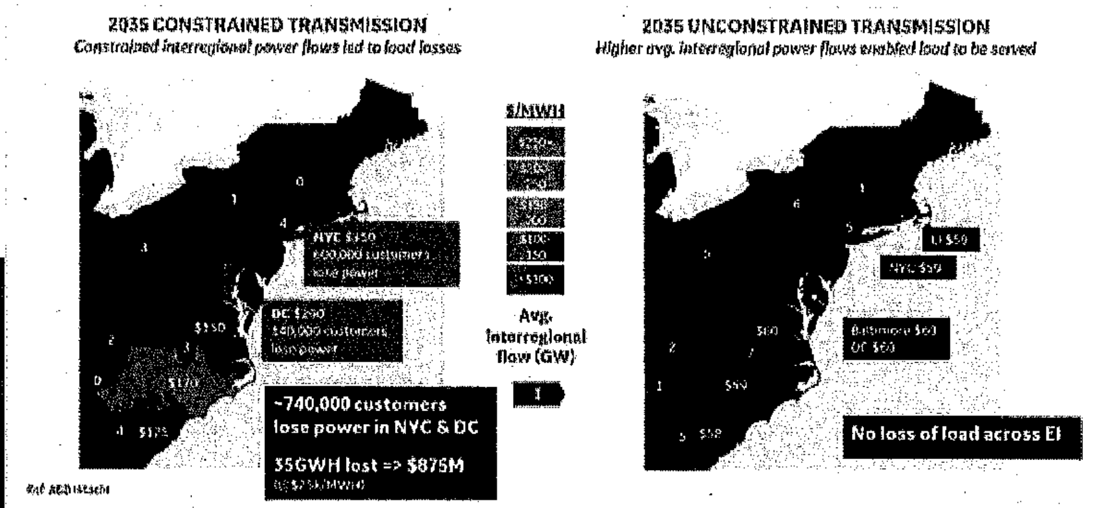


Figure 3 – Results of 2035 simulated heat wave: ~740,000 customers lost power in the constrained transmission case. These load losses were eliminated in the unconstrained transmission case via greater interregional power flows as shown.

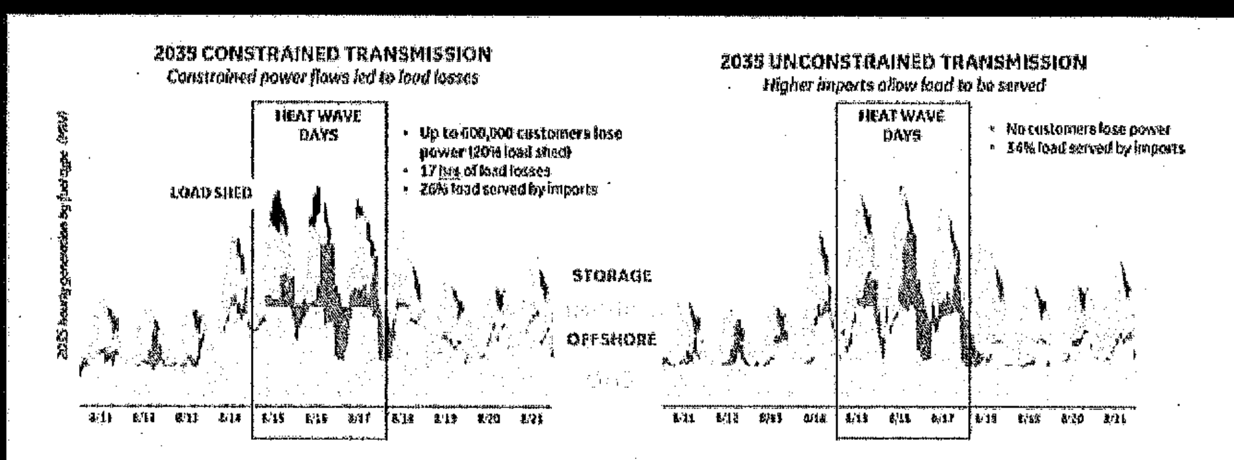


Figure 4 – Hourly New York City generation mix during the 2035 simulated heat wave: ~600,000 customers (20% of total load) lost power for 17 hours in the constrained transmission case. These load losses were eliminated in the unconstrained transmission case via greater interregional imports.

To examine the nature of the load shedding in more detail, Figure 4 shows the mix of generation that serve New York City during the simulated heat wave across both transmission cases. In both cases most of the load needs for these simulated days in August 2035 are served by natural gas, offshore wind, energy storage, and imports.

On August 15-17 of the simulated heat wave, load increases by 30% versus those days in a normal August. In the constrained case, as load increases, we start to see load shedding during peak hours since transmission constraints prevent additional generation to serve New York City with imports at ~26% of load. These load losses represent up to ~20% of load or approximately 600,000 customers without power for 17 hours. However, the unconstrained case shows there is zero load shedding and 34% of load is now served by imports given the increased amount of transmission.

GE then calculated the interregional transmission needed between each pool based on the results of the heat wave simulations as shown in Figure 5. The left of Figure 5 shows the average power flows between each pool for the constrained and unconstrained cases. The interregional transmission needed for each pool-to-pool connection would is calculated as the difference in the average power flows between the constrained and unconstrained cases. GE then assigned the transmission requirement to the pool importing the power as shown on the right side of Figure 5. The net result is 27GW of total interregional transmission requirement across the 9 pools shown with PJM bearing the largest requirement. Although this total figure may seem large at first, when looking at this requirement as a percentage total peak load, it is fairly small. For example, PJM's requirement of ~7GW represents ~4% of its 2035 peak load.

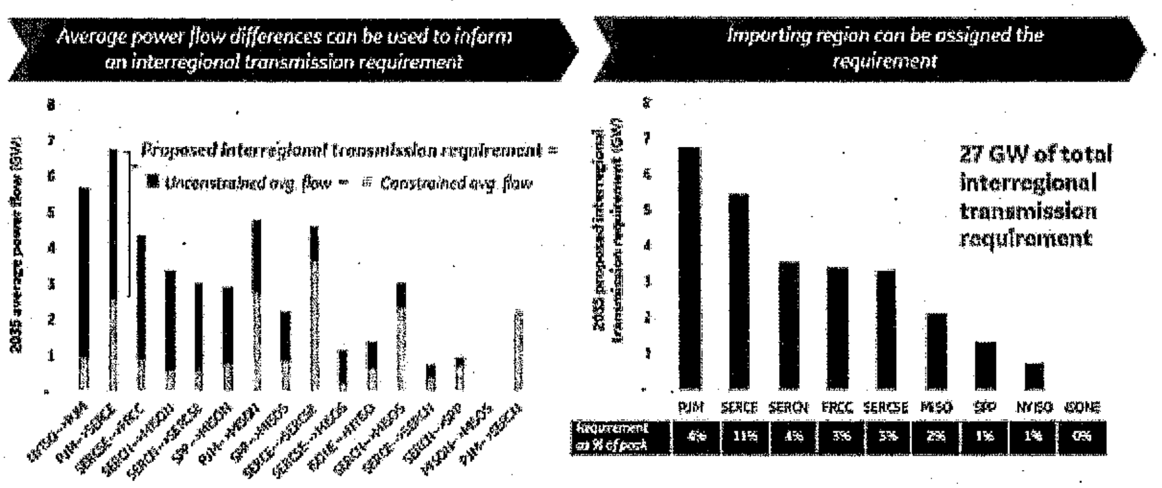


Figure 5 – Interregional transmission requirement given the average interregional power flow differences between the constrained and unconstrained heat wave simulations. The requirement is first defined based on the power flows between each pool and then the requirement is allocated to the pool importing the power.

2.1.3.3 Polar vortex analysis: Unconstraining transmission eliminates load losses

A similar analysis was performed in an example polar vortex case where electric system reliability is challenged not only by higher load, but also by generation outages, and fuel price spikes as outlined in Section 2.1.3.1. GE again simulated the EI under both a constrained and an unconstrained transmission system in order to inform the amount of incremental interregional transmission that is needed. The results of this simulation are shown in Figure 6.

Figure 6 shows average locational marginal prices (LMPs) across the EI during the 5 days of cold in February 2035 for both the constrained and unconstrained conditions. In the constrained transmission case, regional LMPs across the EI spike to greater than $500/MWH in the New York City, Washington, DC and Baltimore metropolitan areas whereas in the unconstrained transmission case, given the greater access to generation, prices do not spike as high. It is valuable to highlight here that the unconstrained simulations did not change transmission pathways into Canada. As a result, prices in the Northeast remain high in the unconstrained case though they are lower than the constrained case. The arrows connecting each pool in Figure 6 denotes the average power flow size and direction between pools. In the unconstrained case, shown on the right of Figure 6, these average power flows are significantly larger than in the constrained case. These larger average power flows enable more levelized prices.

More importantly, in the constrained case shown in Figure 6, given the increase in load combined with generation outages, fuel price hikes and the constraints in the transmission system to deliver more power, 35GWH of power is lost which is equivalent to ~2 million customers losing power across the largest Northeast metropolitan areas. Assuming $25k/MWh loss of load cost, this loss of load event equates to $875M. By unconstraining the transmission system, these load losses are eliminated.

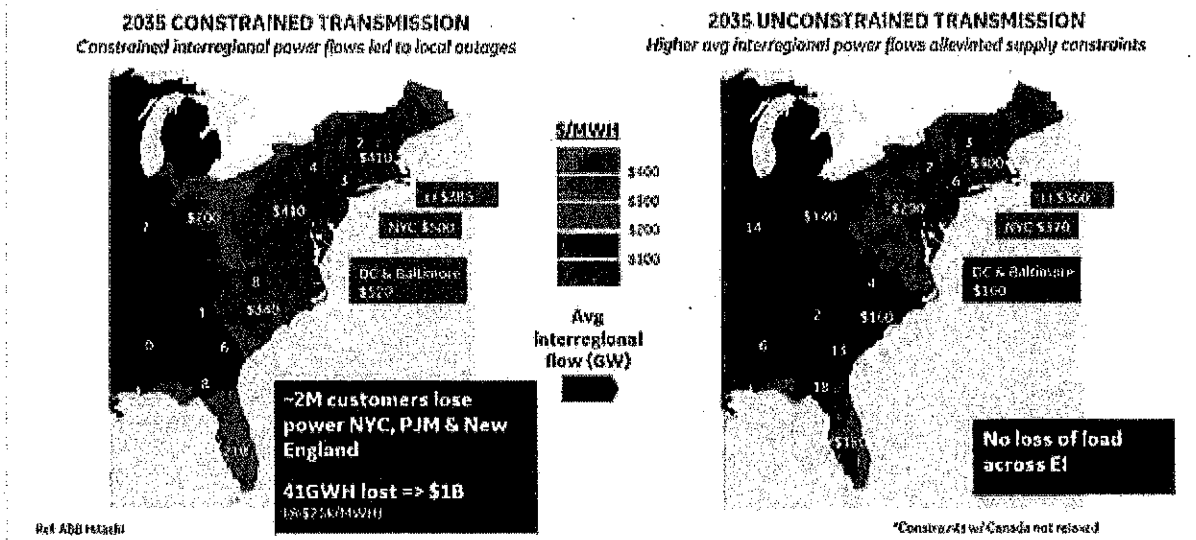


Figure 6 – Results of 2035 simulated polar vortex event: ~2 million customers lost power in the constrained transmission case. These load losses were eliminated in the unconstrained transmission case via greater interregional power flows as shown.

Greater transmission during a simulated polar vortex in February 2035, **prevented ~2 million customers losing power** across Boston, New York City, Baltimore and Washington, DC **saving $1B.**

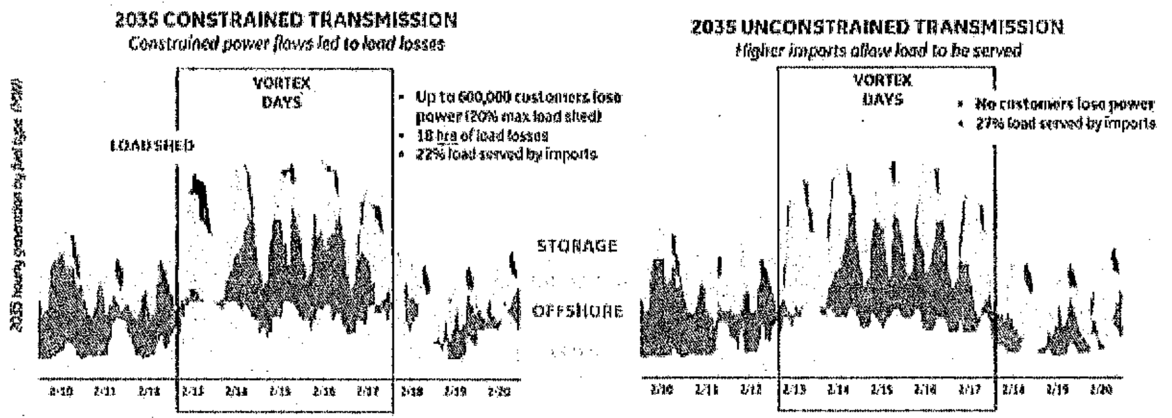
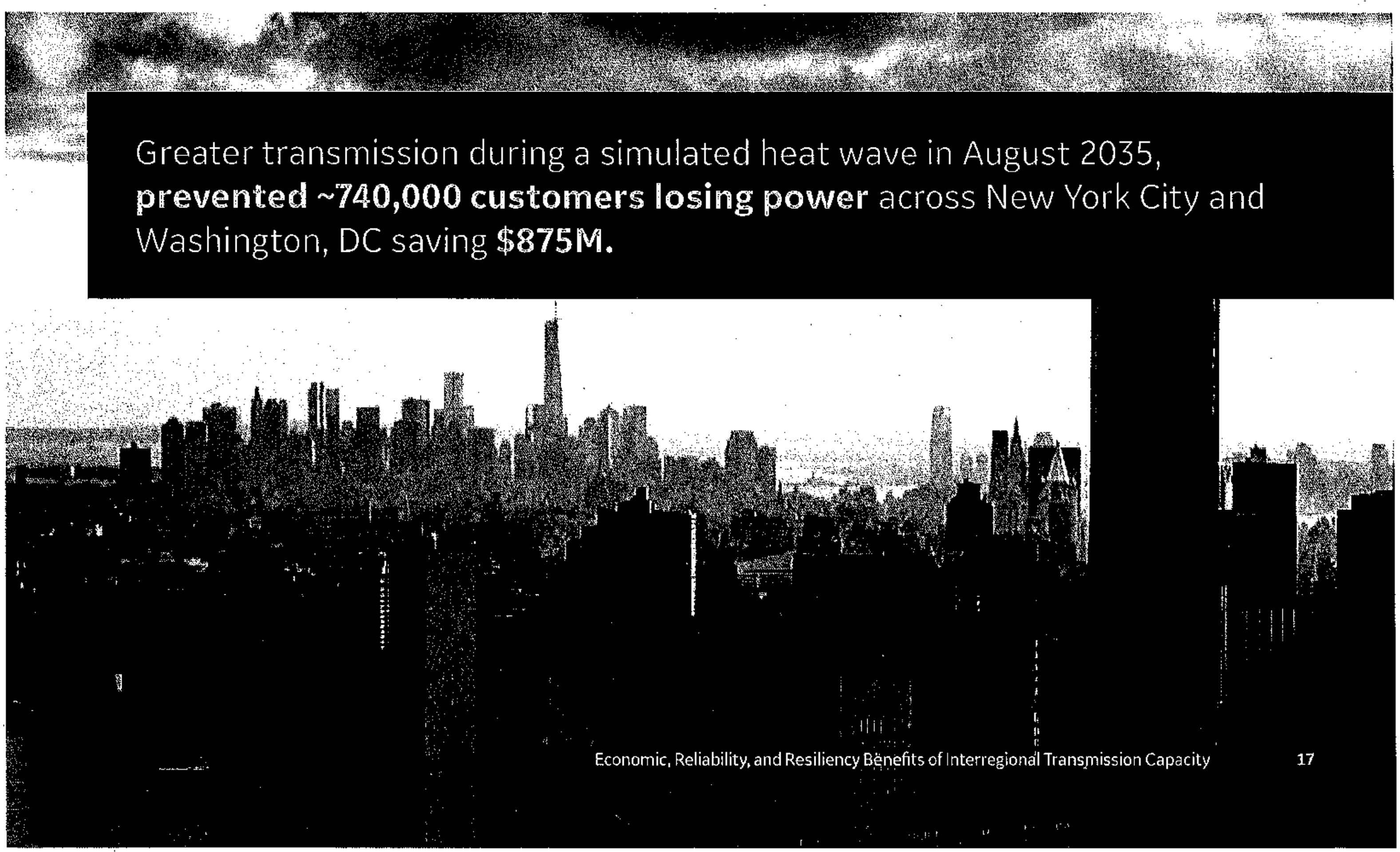


Figure 7 – Hourly New York City generation mix during the 2035 simulated polar vortex: ~2 million customers (20% of total load) lost power for 18 hours in the constrained transmission case. These load losses were eliminated in the unconstrained transmission case via greater interregional imports.

To examine the nature of the load shedding in more detail, Figure 7 shows the mix of generation that serve New York City during the simulated polar vortex across both transmission cases. In both cases most of the load needs for these simulated days in February 2035 are served by gas, offshore and imports.

On February 13-17 of the simulated polar vortex, ~15% of generation incurs forced outages while load increases by 40% versus those days in a normal February. In the constrained case, as load increases, load shedding occurs, especially during peak hours of February 13 since offshore wind generation is low that day and transmission constraints prevent additional generation from serving New York City, capping imports at ~22% of load. These load losses represent up to ~20% of load or approximately 600,000 customers without power for 18 hours. However, the unconstrained case results in zero load shedding, and 27% of load is now served by imports given greater transmission.



Greater transmission during a simulated heat wave in August 2035, **prevented ~740,000 customers losing power** across New York City and Washington, DC saving **$875M.**

Greater interregional transmission lowered US Eastern Interconnection capacity and ancillary service requirements, **saving $2B in 2035.**

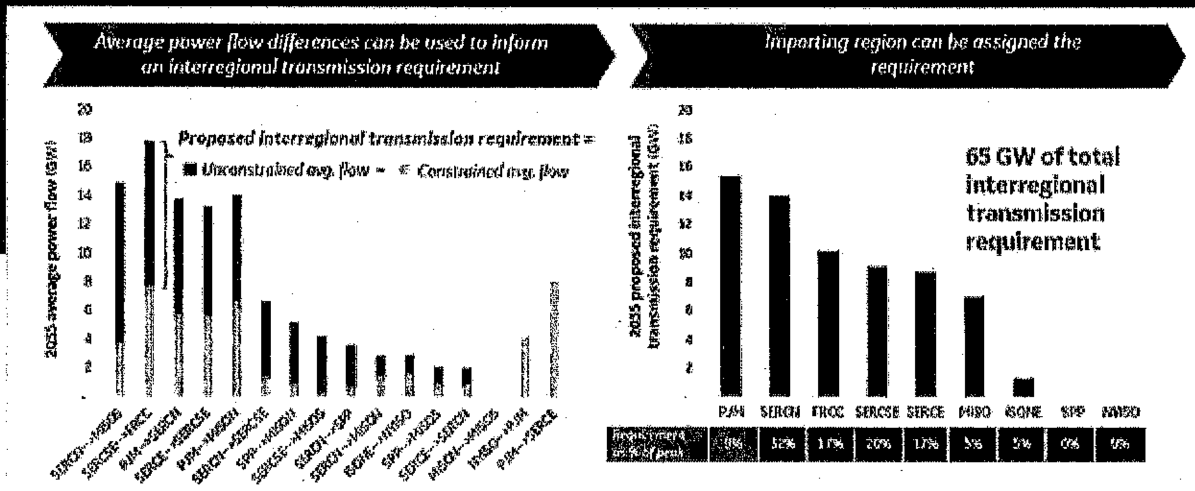


Figure 8 – Interregional transmission requirement given the average interregional power flow differences between the constrained and unconstrained polar vortex simulations. The requirement is first defined based on the power flows between each pool and then the requirement is allocated to the pool importing the power.

GE then calculated the amount of interregional transmission needed between each pool based on the results of the polar vortex simulations as shown in Figure 8. The left side of Figure 8 shows the average power flows between each pool for the constrained and unconstrained cases. The interregional transmission capacity for each pool-to-pool connection is calculated as the difference in the average power flows between the constrained and unconstrained cases. The incremental transmission is then assigned to the pool importing the power as shown on the right side of Figure 8. The net result is 65GW of total interregional transmission requirement across the 9 pools shown with PJM bearing the largest amount. While this total may seem large, when calculated as a percentage total peak load, this requirement is relatively small. For example, PJM's amount of ~15GW represents ~9% of its 2035 peak load. However, the transmission capacity needed for the Southeast are generally more significant as a percentage of load.

2.1.3.1 Calculating the total incremental interregional transmission needed for summer and winter resiliency

Now that the interregional incremental transmission requirement for each weather scenario has been determined, the total transmission needed to maintain for resilience can be calculated. As outlined in Equation 1, the total transmission needed for each pool-to-pool connection will be the maximum across both the summer and winter weather scenarios, as depicted in Figure 9.

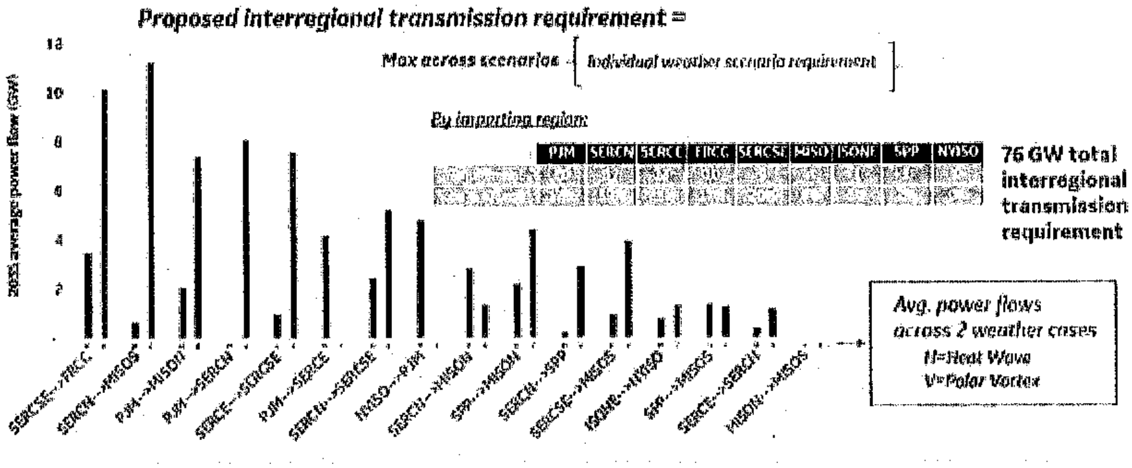
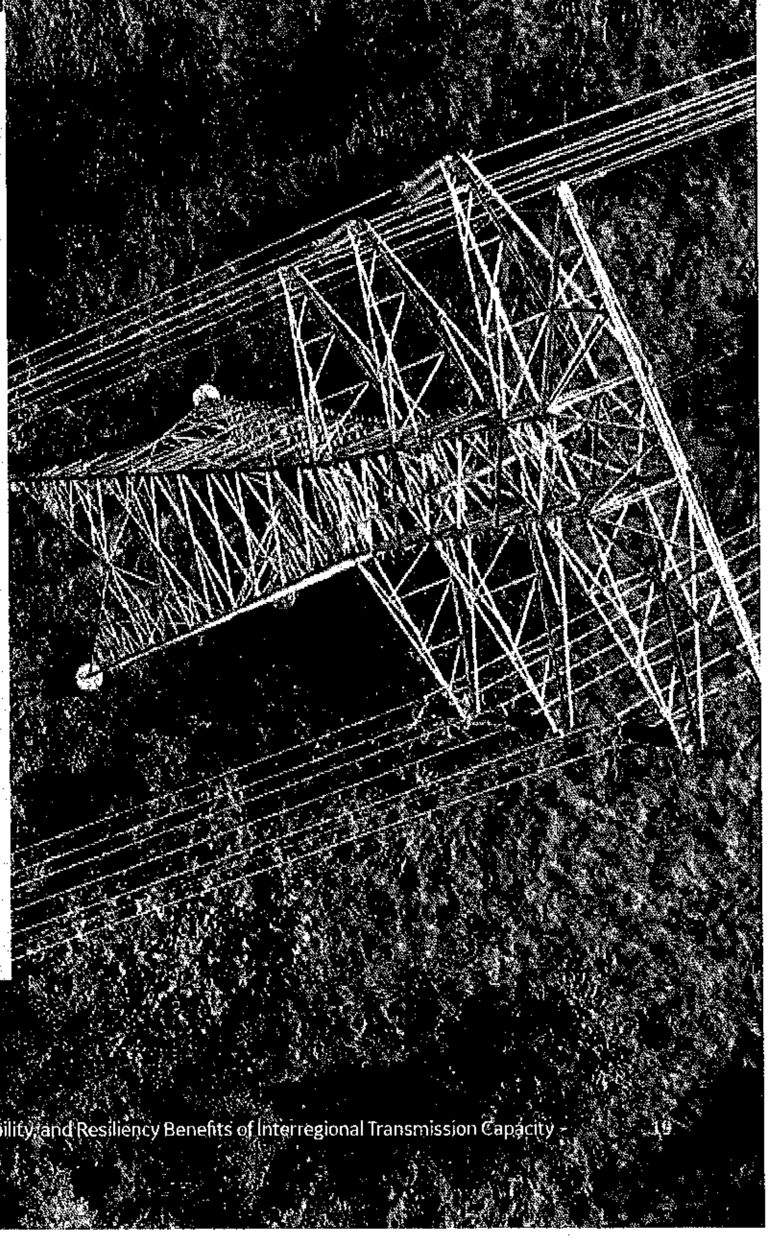


Figure 9 – The total resilience interregional transmission requirement will be determined by considering the average power flows across the weather scenarios. In our example, we determined each pool-to-pool requirement by selecting the max requirement from the two weather scenarios. Ideally, a broader range of weather scenarios would be considered.

The amount of transmission needed is then assigned to the pool importing the power as shown in the inset table in Figure 9. The net result is 76 GW of total transmission across the 9 pools shown, with PJM bearing the largest need. PJM's need of ~20GW represents ~12% of its 2035 peak load. However, the transmission needed for the Southeast are generally more significant as a percentage of load, ranging from 20% to 39%.

2.1.3.2 Greater interregional transmission lowers the capacity and ancillary service requirements, saving $2B in 2035

GE proceeded to evaluate the economic benefit associated with more interregional transmission through lower requirements for capacity and ancillary services. Looking at capacity first, the capacity requirement for the constrained case was calculated based on the reserve margin targets for each pool from GE MAPS and applied to the peak load of 2035 load forecast. In the 2035 forecast year for the EI, the peak load for each pool can occur at different times of the year. While the forecast for all of the pools in 2035 remained summer peaking, the hour in which the peak load occurred varied by each pool. The capacity requirement by pool was then summed for the entire EI for a total constrained case capacity requirement estimate of 700 GW, as outlined in Table 1 (next page).



Pool	Date/Time	Peak Hour Load	Target RM	Target Capacity
FRCC	9 Aug 17:00	59,509	20.0%	71,411
ISONE	3 Aug 15:00	25,797	13.6%	29,303
MISO North	3 Aug 15:00	97,075	16.8%	113,384
MISO South	6 Aug 15:00	32,758	16.8%	38,262
NYISO	16 Aug 15:00	31,868	18.9%	37,892
PJM	3 Aug 15:00	160,684	15.5%	185,590
SERCE	8 Aug 15:00	51,164	15.0%	58,839
SERCN	7 Aug 15:00	42,592	15.0%	48,980
SERCSE	8 Aug 15:00	44,679	15.0%	51,381
SPP	6 Aug 15:00	57,444	12.0%	64,337
Total EI		**603,571**	**15.9%**	**699,379**

Table 1: Constrained Case Peak Load by Pool and the corresponding total Capacity Target.

For the unconstrained case, the capacity requirement was calculated based on the EI peak load (summed load across all pools) which occurs on August 3, 2035, at 2:00 p.m. The reserve margin for the EI is estimated as the weighted average (by load) for each pool or 15.8%. In all likelihood, the planned reserve margin for the entire EI would likely be lower, based on the increased diversity of pooled resources represented by the EI, meaning the savings in capacity reported here is conservative and likely to be much higher. Assuming a weighted average of 15.8%, this results in a peak hour load of 586 GWs and a reserve capacity of 680 GW, or a capacity savings of 20 GW over the constrained case.

The capacity savings of 20 GW in the unconstrained case equates to a net capacity savings of $2 billion based on a net cone of $104/kw-year for a simple cycle gas turbine. The net cone is based on current GE MAPS assumptions and is consistent with prices published for capacity markets in the U.S. The results are presented in Figure 10.

New York City during blizzard conditions

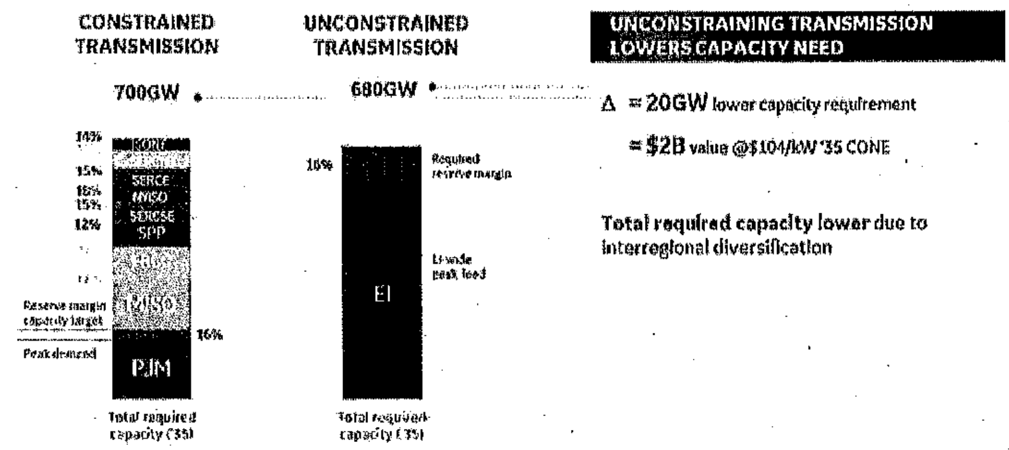


Figure 10 – The economic benefit of greater interregional transmission can be quantified by calculating the capacity requirement for the constrained and unconstrained cases. Given the interregional diversification of load that results from unconstraining transmission between pools, the total capacity requirement is 20GW less than in the unconstrained case resulting in an estimated $2B in savings.

To estimate the potential ancillary service savings in the unconstrained case, GE calculated the amount of generation capacity which was dispatched to serve peak load in both scenarios. This was calculated as the dispatched capacity for thermal and other dispatchable (or non-renewable generation) during the peak hour plus the renewable generation (wind and solar) and imports for the same hour.

This equates to 605 GW of available resources in the constrained case compared to 601 GW in the unconstrained case, for a reserves (ancillary services) savings of 4 GW (see Table 2, below).

Note that there was slightly higher renewable generation in the unconstrained case due to the elimination of curtailments relative to the constrained case of 1.2 GW during the peak hour. Furthermore, as expected, the unconstrained case benefits from an additional 9.4 GW of imports as compared to the constrained case.

Constrained Case	FRCC	ISONE	MISO North	MISO South	NYISO	PJM	SERCE	SERCN	SERCSE	SPP	Total
Committed Dispatchable Capacity	47,420.07	16,445.90	82,973.52	32,544.79	19,187.40	139,698.83	42,639.47	39,256.95	46,483.82	47,688.81	514,339.57
Renewable Generation	6,599.58	8,320.37	13,065.93	719.35	16,515.41	24,313.89	5,751.33	1,114.05	3,134.34	6,580.78	86,115.03
Imports	(307.65)	3,339.81	1,605.89	(1,601.36)	(2,386.09)	312.30	1,980.97	1,957.53	(3,724.63)	3,409.70	4,586.48
Total	53,712.00	28,106.08	97,645.34	31,662.79	33,316.73	64,325.02	50,371.76	42,328.54	45,893.53	57,679.29	605,041.09
Peak Hour Load	52,618.12	25,797.39	97,075.48	31,280.39	30,283.05	60,683.73	49,072.80	41,360.44	42,513.15	55,975.51	586,660.07
	2.1%	8.9%	0.6%	1.2%	10.0%	2.3%	2.6%	2.3%	8.0%	3.0%	3.1%
Unconstrained Case	**FRCC**	**ISONE**	**MISO North**	**MISO South**	**NYISO**	**PJM**	**SERCE**	**SERCN**	**SERCSE**	**SPP**	**Total**
Committed Dispatchable Capacity	47,555.67	18,253.10	82,611.72	35,132.79	20,027.26	136,675.04	35,399.31	37,431.85	45,182.74	41,844.13	500,113.62
Renewable Generation	6,599.58	8,320.37	13,065.93	719.35	17,674.73	24,313.89	5,751.33	1,114.05	3,134.34	6,580.78	87,274.35
Imports	(443.25)	2.88	1,993.10	(4,259.96)	(6,232.12)	3,388.94	8,994.75	3,782.63	(2,484.72)	9,240.68	13,982.94
Total	53,712.00	26,576.35	97,670.75	31,592.19	31,469.87	164,377.88	50,145.38	42,328.54	45,832.36	57,665.59	601,370.91
Peak Hour Load	52,618.12	25,514.50	97,075.48	31,280.39	29,925.61	160,683.73	49,072.80	41,360.44	42,513.15	55,975.51	586,019.73
	2.1%	4.2%	0.6%	1.0%	5.2%	2.3%	2.2%	2.3%	7.8%	3.0%	2.6%
Reserve Saving	(0.00)	1,529.73	(25.40)	70.60	1,846.86	(52.86)	226.38	(0.00)	61.17	13.70	3,670.18

Table 2: Operational Reserves savings between the Constrained and Unconstrained cases of 4 GW.

The benefit of lower spinning reserves is estimated to be $50 million/year based on average ancillary services prices for PJM in 2021 of $1.51/MWh.

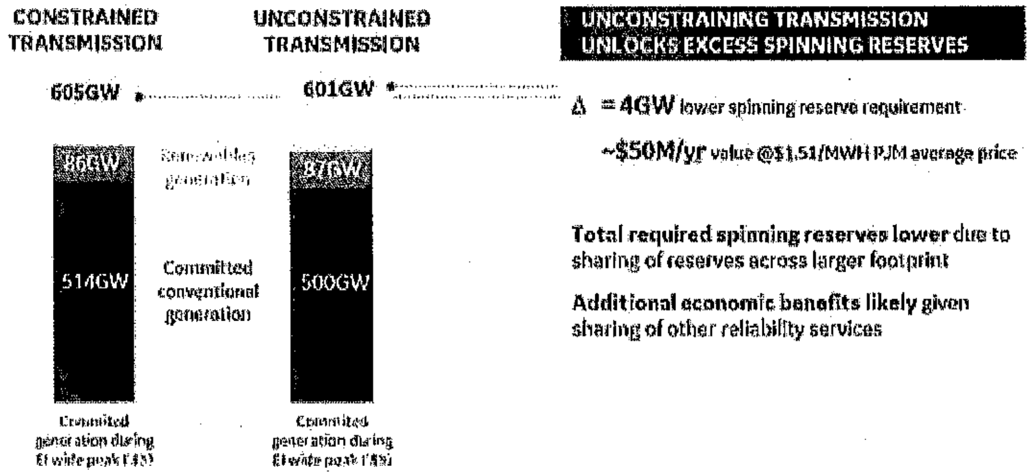


Figure 11 – Estimated economic benefit of greater interregional transmission from operational reserves savings of 4GW in the Eastern Interconnect between the constrained and unconstrained cases.

2.2 Benefits of incremental interregional transmission for increased affordability

2.2.1 Methodology

In order to quantify a potential minimum incremental interregional transmission capacity requirement for more affordable power usage, GE proposes simulating future system dispatch under the following two conditions:

1. *Condition 1:* **Constrained transmission.** This will allow the determination of the average power flow amounts between pools utilizing the existing/planned transmission system.
   Output metric: **Average constrained power flows** for each pool-to-pool interface.
2. *Condition 2:* **Unconstrained transmission.** For this simulation, GE suggests removing the MW limits associated with transmission flows. By removing the transmission line limits, we can determine the average power flows between pools in order to most economically serve load across the EI. This approach assumes that inter-regional transmission needs are coordinated with intra-regional needs.
   Output: **Average unconstrained power flows** for each pool-to-pool interface.

Utilizing simulations under both the constrained and unconstrained EI conditions allows an "affordability incremental interregional transmission requirement" to be calculated as follows:

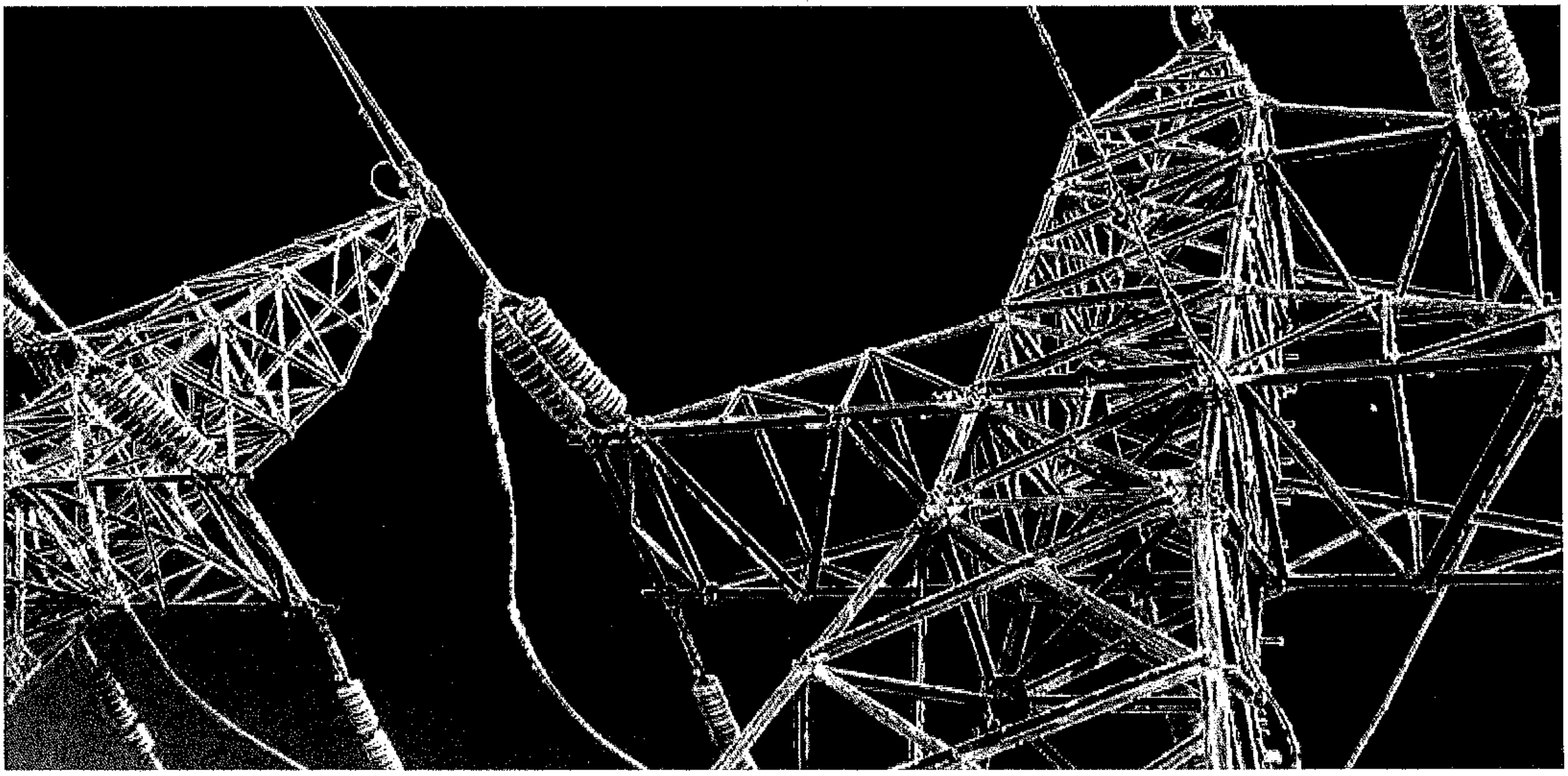
Affordability incremental interregional transmission requirement

= Average unconstrained power flows - Average constrained power flows

Equation 2 - Formula for calculating the affordability incremental interregional transmission requirement.

This requirement would be calculated on a pool-to-pool basis across the United States. Costs for the required resources could be allocated to the pool importing the power.

Greater interregional transmission enabled **access to lower cost generation saving $3B/year in 2035** increasing to $4B in 2040.



2.2.2 Example affordability analysis: Greater interregional transmission enables access to lower cost generation saving $3B/year in 2035

Another benefit of increased interregional transmission is greater access to lower cost wholesale power sources. To estimate this, GE again simulated a constrained and unconstrained transmission system and simulated hourly dispatch across the EI using GE MAPS. Please refer to Section 4 for a summary of the assumptions used in the GE simulation performed here.

Figure 12 shows average locational marginal prices (LMPs) across the EI in 2035 for both the constrained and unconstrained conditions. By comparing the cases, there is significantly less price variation in the unconstrained versus constrained case. The arrows connecting each pool in Figure 12 denote the average power flow size and direction between pools. In the unconstrained case, these average power flows were significantly larger than in the constrained case. These larger average power flows enabled the resultant price smoothing. By allowing cheaper generators to serve more load, transmission enables $3-4 billion in production cost savings in the unconstrained case versus the constrained case.

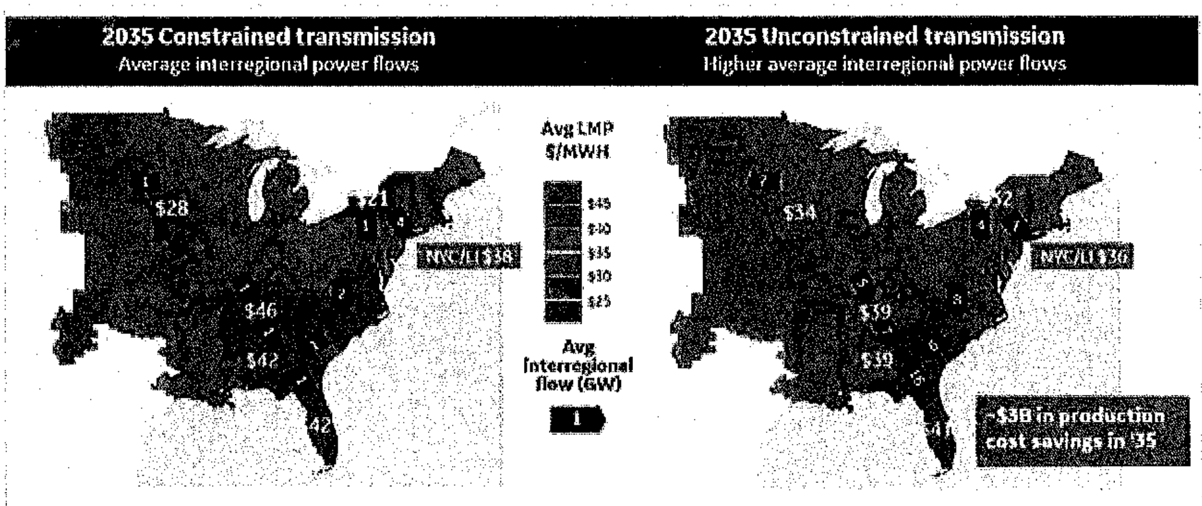


Figure 12 - Results of GE simulations to assess the affordability incremental interregional transmission requirement.

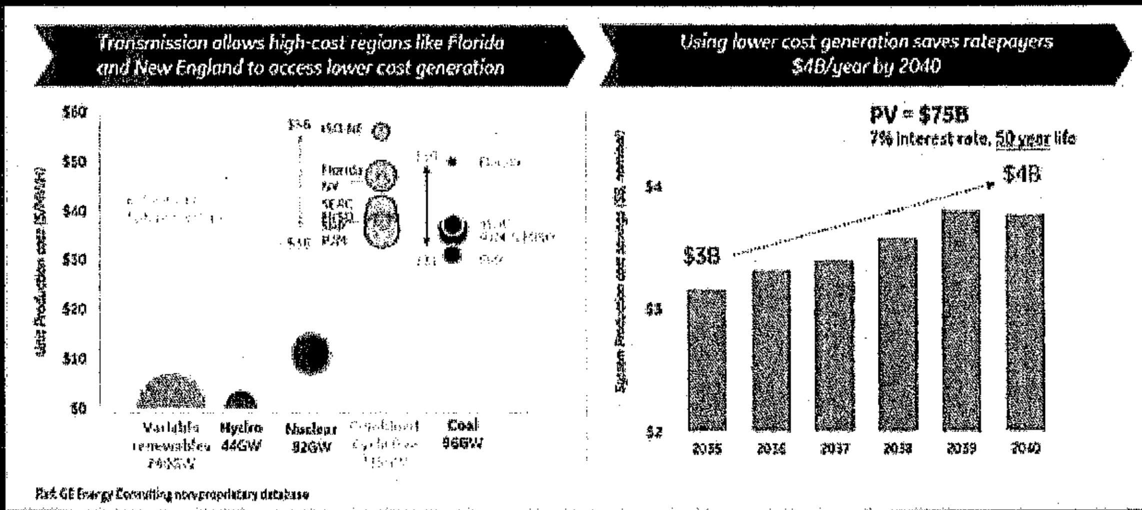


Figure 13 - Production costs vary by fuel type and location. Unconstraining transmission allows regions with high generation costs access to lower cost resources. The result is annual production cost savings of $4B by 2040.

The $3-4 billion in production cost savings enabled by unconstrained transmission in 2035 is due to the locational variation in generation cost across the EI combined with the higher average power flows enabled by the transmission system. As Figure 13 shows, generation production costs vary by fuel type and location. The highest costs of generation were generally in New England and the Southeast where the costs of delivered gas and coal are higher than other parts of the EI. By unconstraining the EI transmission system, regions with high generation costs could access a wide range of lower cost generation from other parts of the EI.

As Figure 13 shows, such savings from access to lower cost generation increases from $3 billion in 2035 to $4 billion by 2040. Such an increase in savings is driven by a sharp increase in load over the same time period given factors like electrification. Assuming a 50-year life for transmission assets, the annual savings translates into a $75 billion present value.

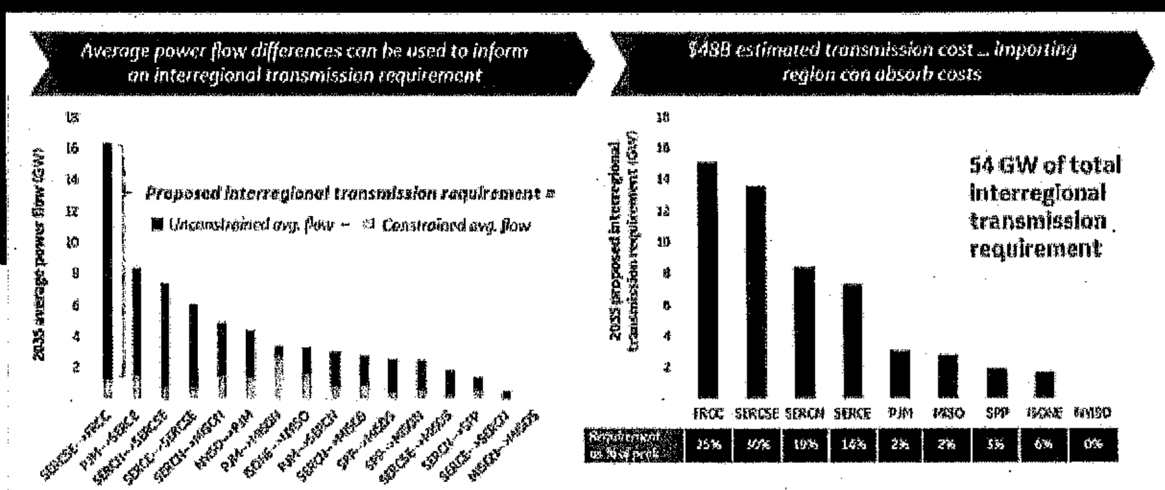
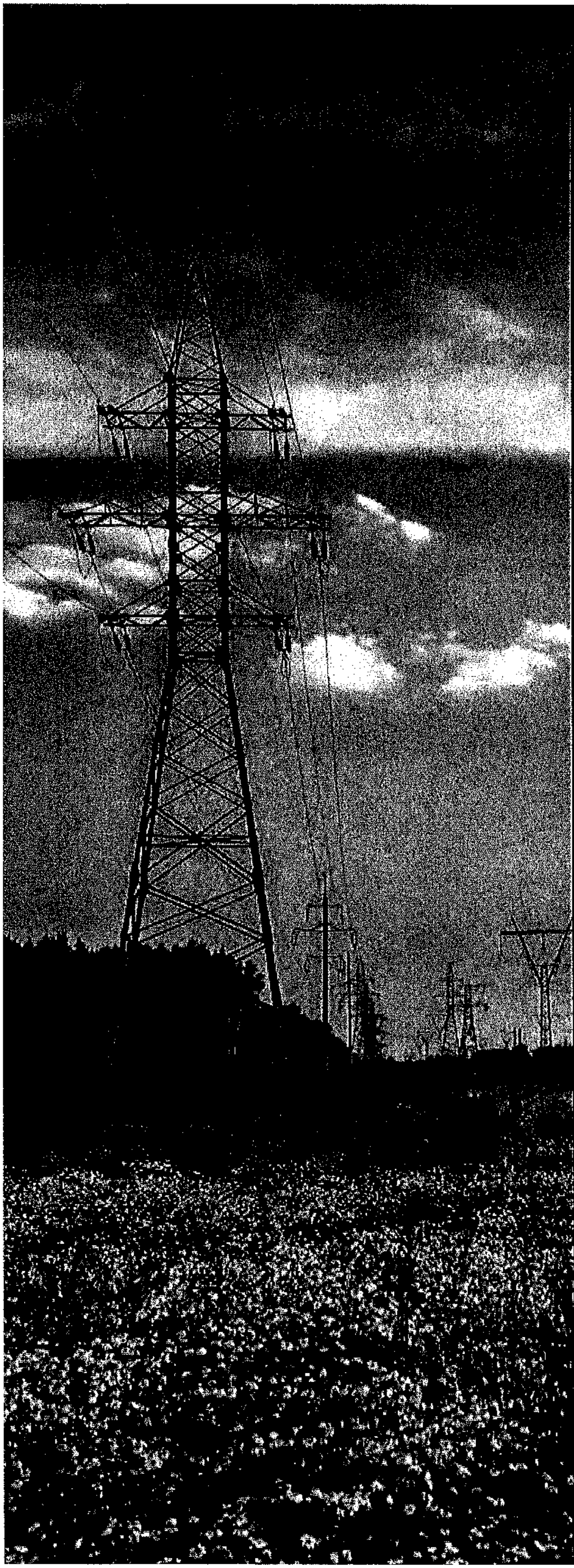


Figure 14 - Proposed incremental interregional transmission requirement can be calculated on a pool-to-pool basis where the requirement can be assigned and cost-allocated to the pool importing the power.

The left side of Figure 14 illustrates the difference in capacity between the constrained and unconstrained average power flow by power pool. Please note that the average power flow levels shown in the graph here correspond to the same average power flows represented by the arrows in Figure 12. Given that the Southeast has some of the highest generation costs, it is not surprising that it has the highest need for interregional transmission.

The amount of incremental interregional transmission needed is assigned to individual pools based on the pool importing the power. The results are shown on the right side of Figure 14. It also shows the need on a % of peak load basis as well. Again, for the Southeast, the need is highest given its relatively high generation costs.



2.3 Total interregional transmission requirement across resilience & affordability

2.3.1 Methodology

Previous sections have evaluated separately the resiliency and economic benefits of interregional transmission. This section considers how to incorporate both benefits in an evaluation. This decision essentially boils down into the question: "How resilient should the system to be?" If a fully resilient system is needed, the greater of the resilience and affordability need as outlined by Equation 3 should be used.

> ***Total incremental interregional transmission requirement***
>
> *= Resilience incremental interregional transmission requirement*
>
> *+ If greater than zero [Affordability incremental interregional transmission requirement*
>
> *- Resilience incremental interregional transmission requirement]*

Equation 3 - Formula for calculating the total incremental interregional transmission requirement across resilience & affordability.

2.3.2 Determining the total incremental interregional transmission need for resiliency and affordability results in 87GW of transmission

Assuming the methodology outlined in Equation 2 is used, returning to the example analysis, each of the pool-to-pool transmission capacity requirements as shown in Figure 15 would be calculated. This shows that for each pool-to-pool requirement, there is a component from the resiliency need and a component from the affordability need. The total incremental interregional transmission needed for individual pools based on the pool importing the power can be calculated. The results are shown on the right side of Figure 15. The need on a % of peak load basis is shown as well. Again, for the Southeast, the need for interregional transmission is highest given its relatively high generation costs combined with the GE assumptions around extreme weather impact.

> Example cost benefit analysis shows **$12B in net benefits** from 87GW of incremental interregional transmission.

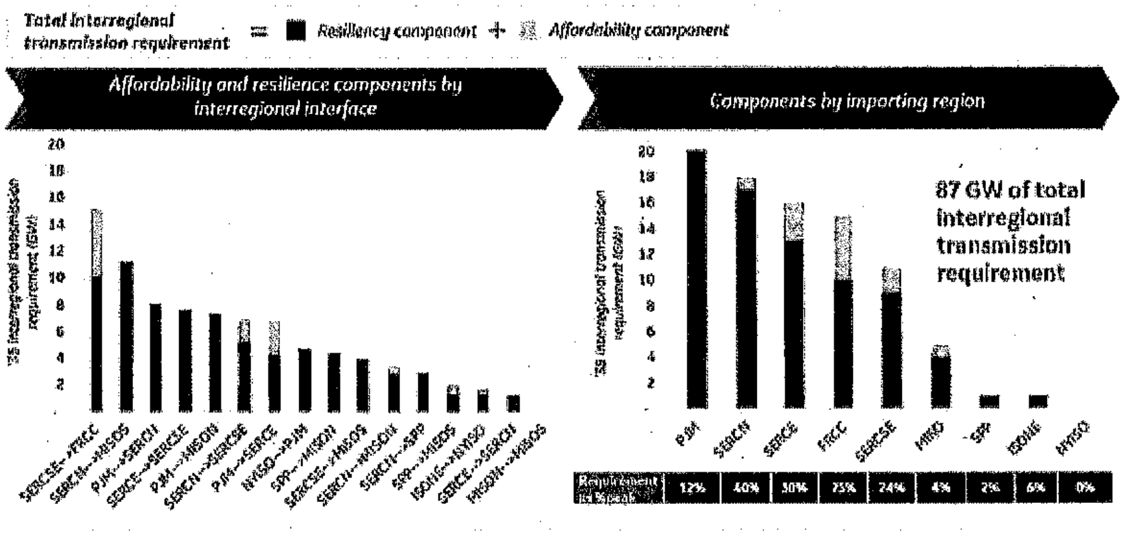


Figure 15 - Proposed incremental interregional transmission need can be calculated on a pool-to-pool basis where the requirement can be assigned and cost-allocated to the pool importing the power.

2.3.3 Example cost benefit analysis shows $12 billion in net benefits

Now that the total incremental interregional transmission need for each region has been determined, the total net benefits by summarizing the total costs and total benefits can be calculated. For the example analysis presented, the costs and benefits are summarized in Figure 16.

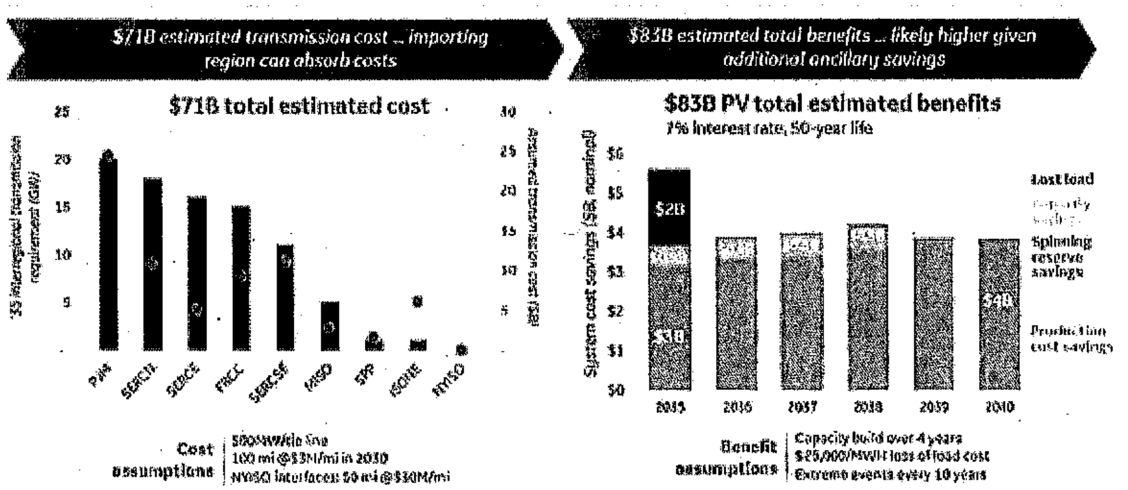


Figure 16 – Cost-benefit analysis showing $12B in net benefits given $71B in total estimated transmission costs and $83B in total estimated benefits.

The left side of Figure 16 summarizes a $71 billion cost estimate for the 87GW of incremental interregional transmission determined in Section 2.5. This estimate is based on some broad assumptions for the purpose of illustrating this methodology. The cost assumptions are outlined on the left side of Figure 16.

The right side of Figure 16, summarizes $83 billion in total benefits across the four areas of benefit discussed throughout this example analysis. The majority of the benefits come from the annual production cost savings given the more cost-efficient use of generation, but significant benefits also stem from loss of load, capacity cost, and spinning reserve savings.

The net result of this example cost-benefit analysis is $12 billion in net benefits. This net benefit can potentially be used to invest in intra-regional transmission to enable the benefits outlined here. As noted earlier, this estimate of benefits is likely conservative and could be much higher.

However, to realize the full benefits of expanded transmission, even of this conservative estimate, one would have to coordinate both intra-regional and inter-regional planning as well as operational norms to increase imports and exports between regions.

2.4 Benefits of interregional transmission for increased grid stability

The proposed methodology was focused on the adequacy part of grid resiliency: does the system have enough generation to meet load given extreme weather events? However, as the grid is evolving to include greater diversity of technologies such as synchronous machines, inverter-based resources, transmission assets, distributed generation, and load resources, unwanted equipment interactions often referred to as "stability risks" are increasingly becoming important in ensuring future reliability of the electric power grid.

While a system can be adequate in terms of having enough generation, it can still be unstable given the mix of resources. In the face of extreme weather, for example, a lightning strike can result in unstable fluctuations in voltage or frequency leading to unwanted behavior or tripping of generation equipment. Such trips can have cascading effects as well. NERC regularly summarizes examples of such events.

The analysis so far assumes interregional AC transmission interconnection only. However, there may be reasons to consider alternate reinforcements like DC interconnections to ensure system stability.

For this analysis, GE utilized the following screening methodology:

Test: Is the grid stable assuming the incremental interregional requirement is AC? A stable system would have to pass each of the following criteria:

Grid stability is also increasingly a risk during **extreme weather events. Alternate transmission technologies** (e.g. DC vs AC connections) should be considered to maintain grid stability under extreme weather pressure **with high inverter-based resource penetrations.**

- **Weak grid?** Does grid voltage remain stable after grid disturbances (e.g., lightning strike, generator trip, equipment switching) or does voltage collapse resulting in cascading outages? Short circuit ratio screening methodology is an industry standard test of grid strength. If the short circuit ratios above are low (e.g., <3), the grid is too weak to maintain stable voltage and reinforcements are required. AC interregional transmission may help improve grid strength, but if improvements are not sufficient, additional reinforcements like DC technology or condensers may be necessary.
- **Stable frequency?** Does frequency recover after a large grid disturbance (e.g., lightning strike, generator trip) or does frequency collapse resulting in cascading outages? Screening for this risk involves assessing the amount of headroom (i.e., ability to increase power output) generators have in order to respond and recover from a loss of a large power station. If headroom is low in one region, and transmission constraints limit access to other regions, then interregional transmission may help open up the opportunity to share headroom across a wider footprint to support stable frequency.
- **Small signal instabilities?** Are there unwanted resonances that could result in generator outages? Screening for this risk involves identifying low order grid resonances caused by areas of long undersea cable or series compensated transmission corridors. This screening may be done through investigation of system topology, frequency-impedance scans and grid EMT (electromagnetic transients) modeling to uncover risks of unwanted power swings and tripping of areas of the grid. This methodology may also be used to determine the risks / benefits of DC vs. AC interregional transmission.

If all pass: The AC requirement is sufficient for stability risks.

If any fail: There could be stability risks that interregional reinforcements could help mitigate. Deeper analysis is needed to determine systemic risk and mitigation methodology.

2.4.1 Example analysis: Even with significant AC interregional reinforcement, Eastern seaboard grid remains weak--interregional DC may be preferred for resiliency

For this example, GE calculated the short circuit current ratio (SCR) for three pockets of ISO-NE, NYISO, and PJM where significant levels of offshore wind are projected.

Short circuit current ratio (SCR) is an industry-standard metric for assessing the strength of the grid's voltage. In general, an SCR above 10 is considered strong and a transmission voltage of 230kV, for example, will remain within acceptable limits despite grid disturbances such as lightening or unit trips. An SCR below 3 is considered weak. In a weak grid, a transmission voltage of 230kV, for example, may fluctuate outside of acceptable limits during grid disturbances such as extreme weather, resulting in generation tripping offline to avoid damage.

Figure 17 summarizes the results of our SCR analysis for the constrained and unconstrained transmission cases. In the constrained case, given the assumed penetration of offshore wind into ISO-NE, NYISO, and PJM, the SCR is weak across all three RTO pockets. In addition, the SCR at the offshore wind plant locations are all weak as well. The net result is that the grid in the constrained case is too weak to maintain a stable voltage during both normal operations and after extreme weather disturbances.

For the unconstrained case, it was assumed the needed amounts of incremental interregional AC transmission calculated in Section 2.5 would connect these three RTO pockets. GE then recalculated the SCR. Figure 17, shows how in the unconstrained case, the increased AC interregional transmission improved the SCR for each of the three RTO pockets versus the constrained case. However, while there was an improvement in SCR from 2 to 4 or 5, depending on the location, it still may not be enough to result in a stable grid. In addition, the SCR at the offshore wind plant locations all remained weak as well due to their distant electrical proximity and the high concentration of IBR in one area. The net result is that, while interregional transmission marginally improved the grid strength across regions, the grid in the unconstrained case is likely still too weak to be stable during both normal operations and extreme weather disturbances.

In such a circumstance, if PJM, ISO-NE, and NYISO were to incorporate an interregional transmission requirement assuming AC interregional transmission alone, certain benefits could be lost that would be provided by alternative transmission technologies such as DC ties. The control instabilities and voltage fluctuations associated with weak AC grids could be mitigated with properly coordinated VSC-HVDC technology and offshore wind plants. By building out DC versus AC interregional transmission, the grid strength risks identified here could be mitigated.

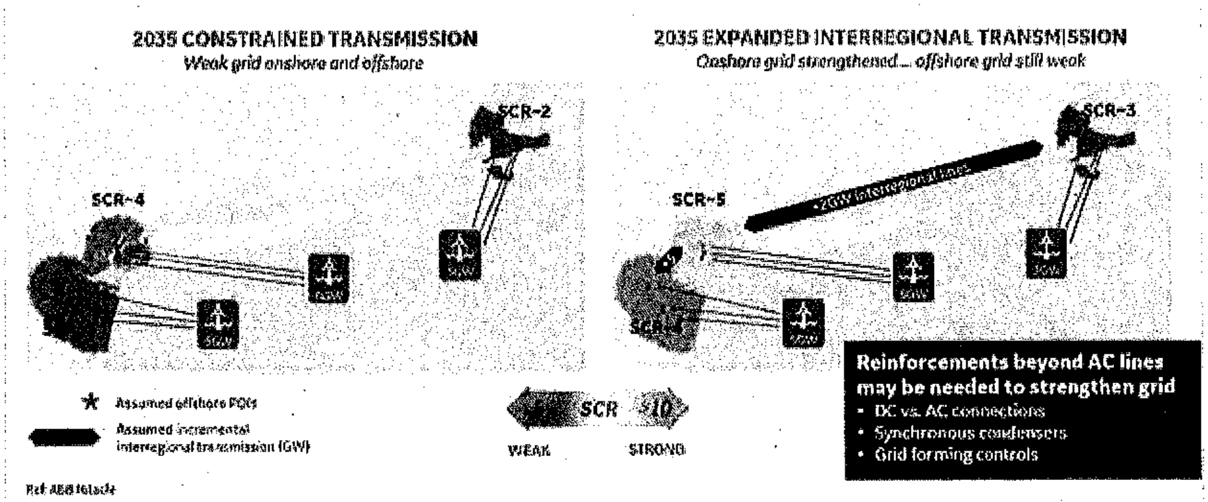
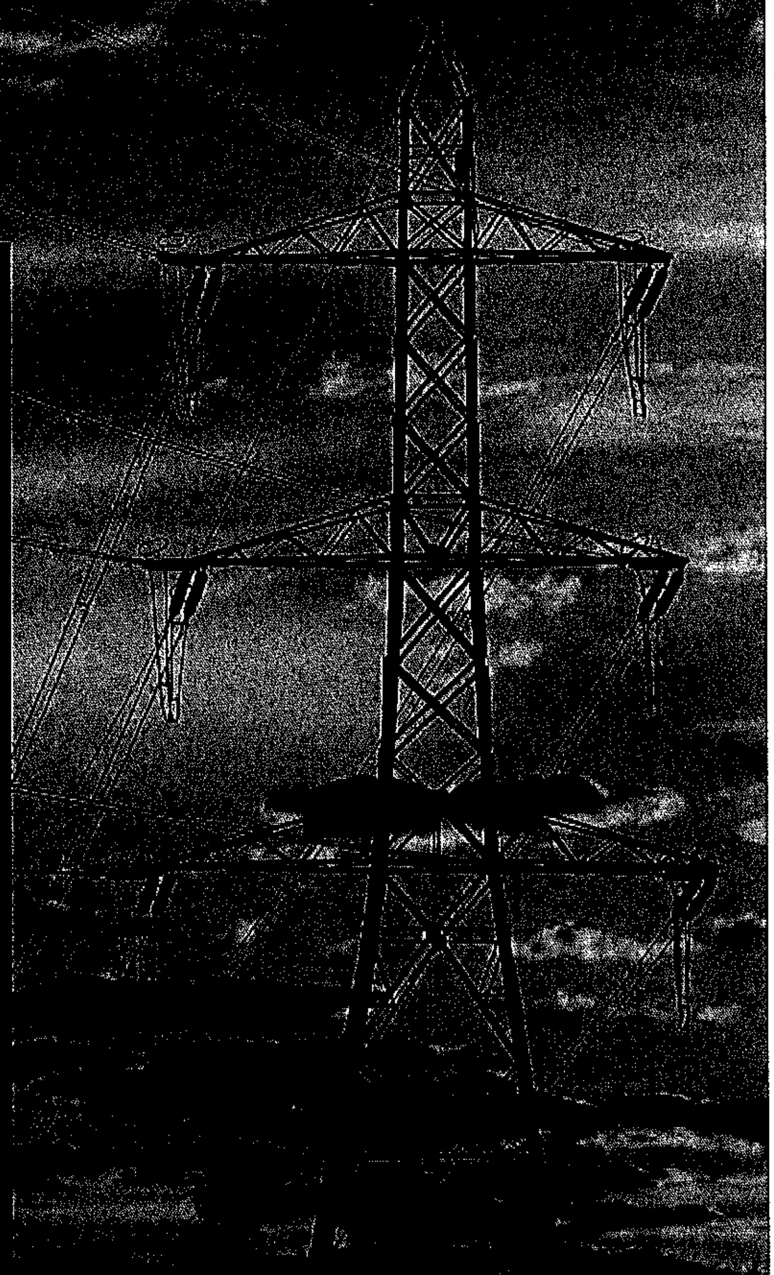


Figure 17 – Short circuit current (SCR) analysis for pockets of ISO-NE, NYISO, and PJM where the mix of resources may result in grid weakness. AC interregional transmission helps strengthen the grid but additional interregional reinforcements like DC transmission could provide greater stability benefit.



3 CONCLUSIONS

This report illustrates the broad range of benefits of expanded interregional transmission. GE determined the incremental interregional transmission needed via an increase in average power flows enabled by unconstraining transmission across normal and extreme weather events. These example simulations showed that:

- **Greater incremental interregional transmission can avoid load shedding during multiple types of extreme weather events.** In the example cases presented, power losses due to extreme weather cost $875 million - $1 billion.
- **Greater incremental interregional transmission enabled ~$3-4 billion/year production cost savings** under normal weather conditions.
- **More interregional transmission could result in upwards of $12 billion in net benefits.** Although costs for more intra-regional transmission are not included in this estimate, this net benefit estimate is likely low as noted earlier in this analysis.
- **Grid stability is increasingly a factor in grid resiliency.** An AC interregional transmission capacity requirement can increase grid stability, but alternate technologies may provide greater stability benefit such as DC transmission ties.

4 APPENDIX

4.1 Study assumptions

GE Energy Consulting continuously updates its North American MAPS databases, including the Eastern Interconnect database used for this study. Primary updates like load forecasts typically are incorporated in the late spring or early summer after the relevant Independent System Operators publish their updated forecasts. Similarly, GE Energy Consulting employs a separate production cost model for the natural gas price forecasts for North America, which is primarily updated in the summer.

Once the study for NRDC started in April, GE froze a version of the MAPS database to maintain consistent results throughout the study. As such, the MAPS database used for this analysis was limited to the primary assumptions implemented for the previous year 2021, including load forecasts and fuel forecasts, meaning the sharp increase in natural gas and coal prices were not captured in this analysis. This limitation was communicated to the NRDC team at the beginning of the study. Incorporating more recent load and fuel price forecasts would not have had a significant impact on the primary results of this study, and if anything, would further increase the benefits of interregional transmission.

4.1.1 Load assumptions

Load assumptions for this study were based on updates completed in 2021. GE Energy Consulting utilizes detailed load forecasts published, where available, by each independent system operator, including, for example, the ISO New England's Forecast Report of Capacity, Energy, Loads and Transmission (CELT Report) and NYISO's Gold Book. For those regions without published forecasts, GE Energy Consulting uses regression analysis with US GDP forecasts to create annual peak and energy forecasts.

It should be noted that the load forecasts developed in 2021, including those published by ISO New England and NYISO, did not include projected future changes to loads like electrification of space heating and more extensive adoption of electric vehicles. These changes in load forecasts were evident in updates recently published in 2022. As a result, most of the load assumptions for the year 2035, which was a focal point of this study, did not include changes from a summer to winter peaking system as might have been expected. It is likely that if this study had begun later this year, the new load forecast would have exemplified more of this shift in electrification and would further increased the financial benefits of interregional transmission in the polar vortex case.

Figure 18 below highlights the load assumptions graphically for the individual pools of the Eastern Interconnect. The load growth continues at roughly 1% per annum.

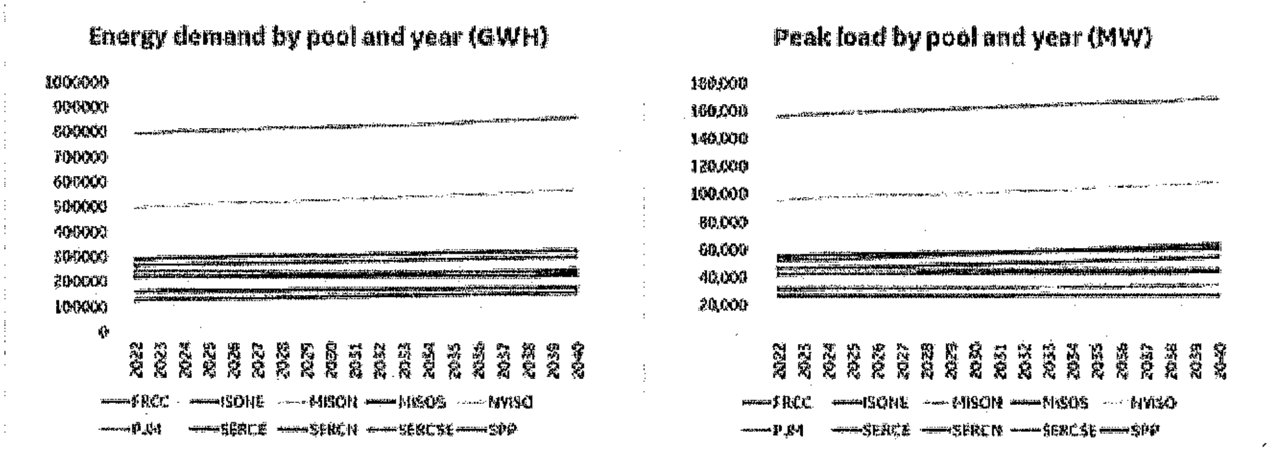
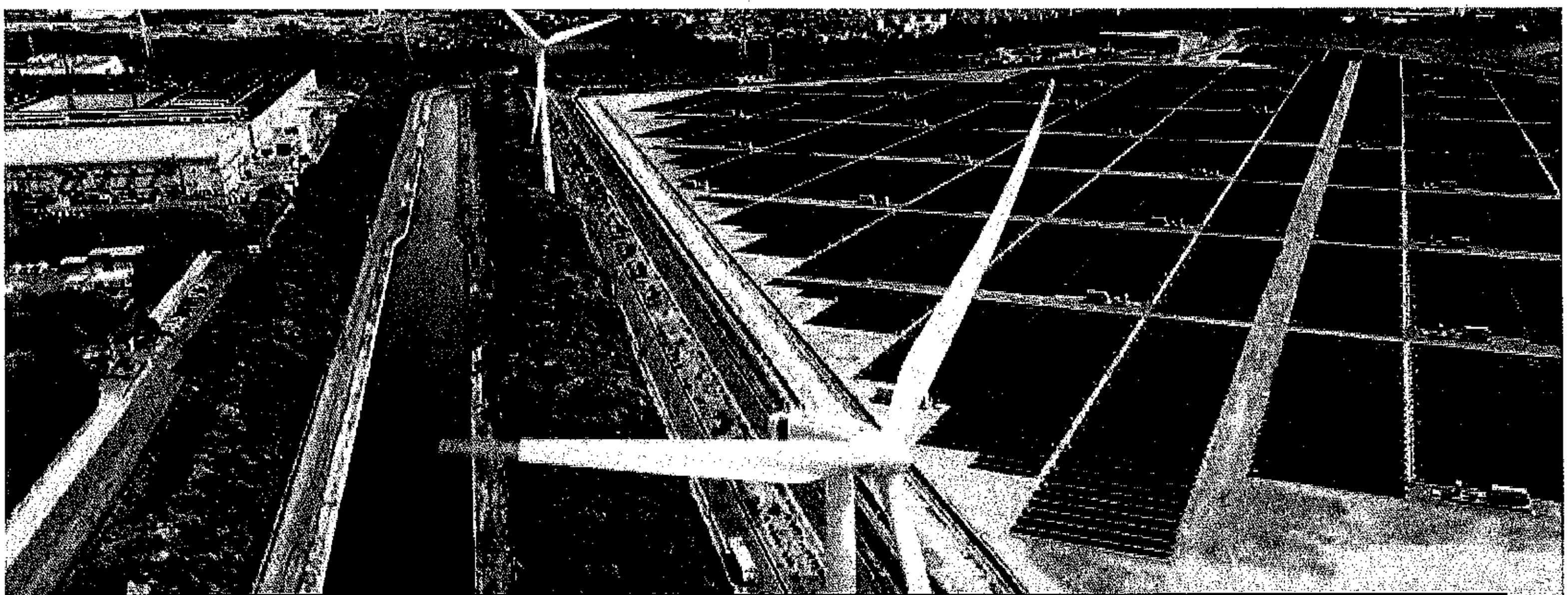


Figure 18 GE load growth assumption across pools ~1%/year ... steeper growth 2040+. GE Energy Consulting load assumptions based on RTO-issued forecasts.



4.1.2 Generation assumptions

Generation capacity depends on timely updates to generator additions (expansion or new unit builds) and retirements. Typically, utilities will announce the expected retirements of their large base load generators several years in advance, including large coal fired generators. GE regularly incorporates these announcements as part of the planned capacity additions and retirements.

In addition, GE evaluates state policies such renewable energy requirements into generation capacity forecasts. To highlight this (see Figure 19 below), GE has forecasted the addition of 28 GWs of offshore wind generation to the Eastern Interconnect between 2023 and 2035 despite the fact that this is a nascent technology in the U.S. with less than 100 MW of installed operating capacity as of this writing. This is similarly true for our forecasts of solar generation, increasing nearly 150% between 2023 and 2040 and coal capacity declining by 50% over the same horizon.

GE expects that these capacity forecasts will change even over the next year. A recent publication by DOE in May 2022, expects 40 GW of offshore wind is in active development, an increase of 13.5% over its 2021 report. While GE regularly updates its wind and solar forecasts to match the best data available and recognizes the rapidly shifting environment to decarbonize the grid, it is reasonable to expect continued operation of some of the thermal fleet.

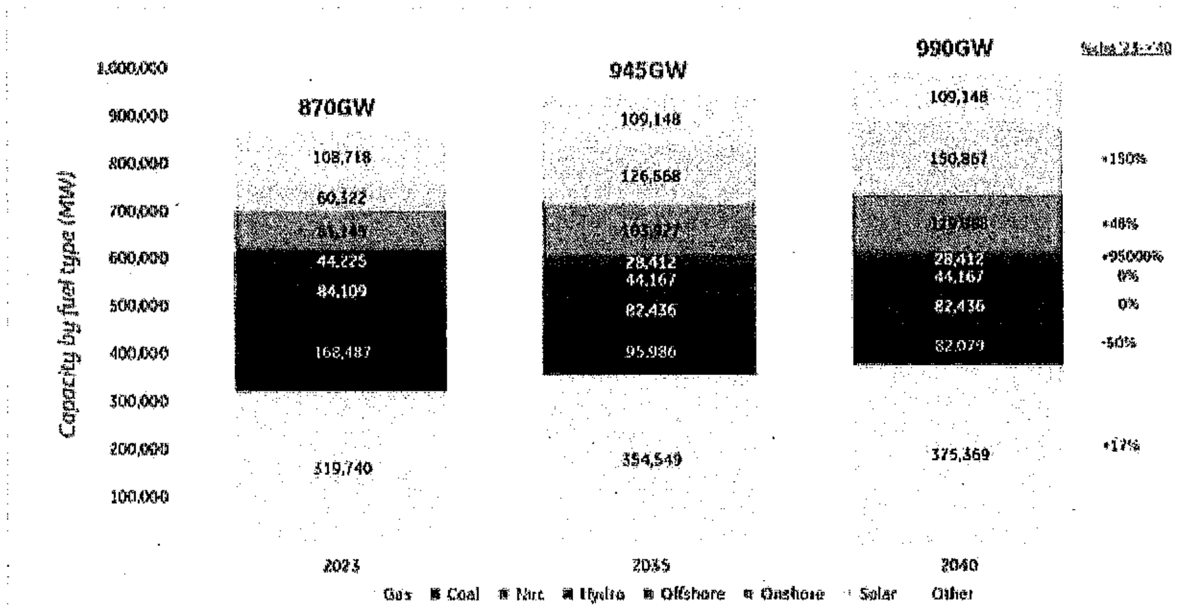
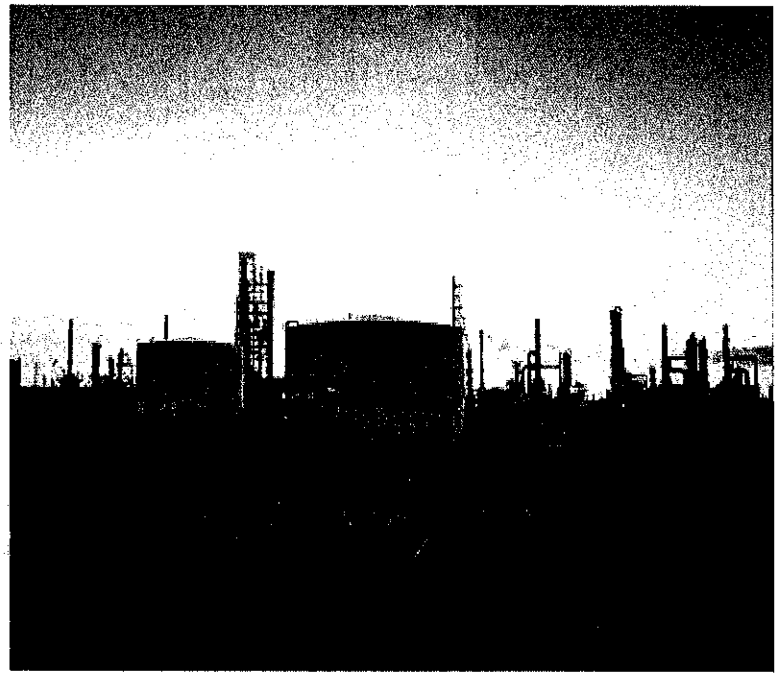


Figure 19: GE Generation capacity forecast assumptions summarized for years 2023, 2035 and 2040. As expected, the fastest capacity additions are wind and solar renewables while coal generation declines over the same horizon.

4.1.3 Fuel price assumptions

GE Energy Consulting uses a fundamentals model to forecast natural gas prices in North America. As noted previously, those updated natural gas forecasts for 2022 were not available when GE started this study and froze all assumptions.

While recent price spikes in both electricity, coal and natural gas prices could have a significant impact on this analysis, current real long-range price forecasts predict natural gas prices will fall to below $4.00/ mmBTU (in 2021 $) in 2030 and remain there, with some minor deviations, until 2050. While the near term price of natural gas is significantly higher in 2022 due to a number of factors, as noted earlier, the longer term prices have increased only marginally. Also, higher natural gas prices will only increase the benefits of interregional transmission.



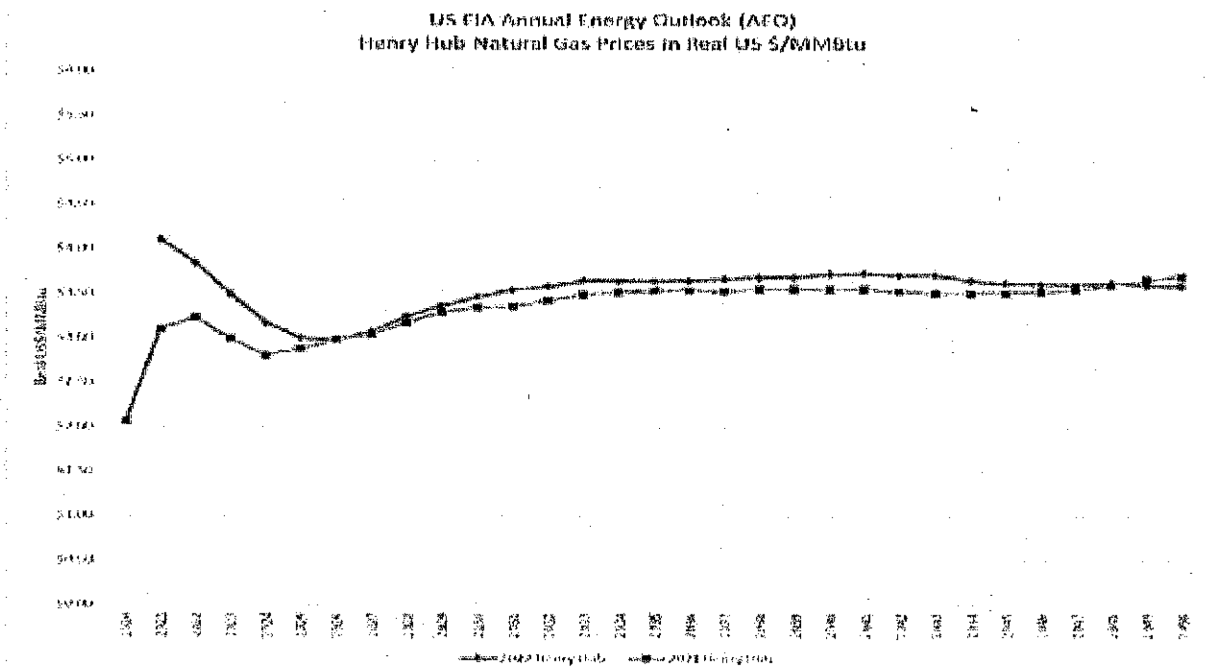


Figure 20: Henry Hub Natural Gas price comparison EIA AEO 2022 vs 2021forecasts (real US$/MMBtu).

GEA35221 (10/2022)

February 2023

The Latest Market Data Show that the Potential Savings of New Electric Transmission was Higher Last Year than at Any Point in the Last Decade

Dev Millstein, Ryan Wiser, Seongeun Jeong, Julie Mulvaney Kemp
Lawrence Berkeley National Laboratory

In 2022, additional transmission could have reduced electric system costs by more than in any year from 2012 through 2021. Generally high electricity prices coupled with extreme weather events and other factors helped drive the high value for transmission. Transmission congestion-relief values were high in many regions in 2022, with a number of interregional links reaching $200 to $300 million per 1000 MW of transmission capacity (or $23 to $34 per MWh). Additionally, wholesale pricing patterns during winter storm Elliott at the end of 2022 illustrate the role of transmission in helping manage periods of grid stress. In this factsheet, we analyze the latest data and describe what energy pricing patterns tell us about the state of the U.S. power market and the possible value of additional transmission infrastructure.

Introduction

We build on our past research, focusing on locational price arbitrage as one signal of the value of transmission expansion. The difference in wholesale electricity prices between two locations largely represents the cost of congestion or, conversely, a key potential value of new transmission. While the congestion-based value of transmission analyzed here represents one of the largest sources of transmission value, transmission provides other benefits that we do not measure (including, for example, reliability, resiliency, and emission-reduction benefits). Underlying the congestion-based transmission benefits that are the focus of this factsheet is the simple concept that transmission enables a lower cost set of generators to meet load than would otherwise be available.

Our prior work focused on the period 2012-2021 and concluded that existing transmission planning approaches run the risk of understating the economic value of new transmission. We found that wholesale power prices exhibit stark geographic differences and that increased transmission across many regional and interregional transmission links would have substantial economic value. We further found that transmission congestion value varies by year and is correlated with the national average of wholesale electricity prices. Extreme conditions and high-value periods have an outsized role in driving this value, though named extreme weather events oftentimes do not play as large a role as more-normal, but infrequent conditions, such as infrastructure outages or demand forecast misses. Data from 2022 largely confirm and strengthen these findings. Additionally, wholesale pricing patterns during winter storm Elliott at the end of 2022 illustrate the role of transmission in helping manage periods of grid stress.

Key Findings

High transmission value (or equivalently, cost savings) existed in most regions in 2022. We calculate two metrics of the potential price-arbitrage value of transmission across a set of 64 location pairs (Figure 1). The first metric represents the average hourly price spread in 2022 across each pair of locations and ranged between $3/MWh and $58/MWh (top image). The second metric represents the 2022 value of a hypothetical 1000 MW line connecting the two locations and ranged from $29 million to $505 million per year (bottom image). Most, but not all, links with an annual value above $200 million per 1000 MW were interregional links. However, many regional links had 2022 values between $100 and $200 million per 1000 MW. These estimates are based on location specific marginal energy prices only, and thus represent a marginal value calculation; additional context and limitations are described at the end of this factsheet.

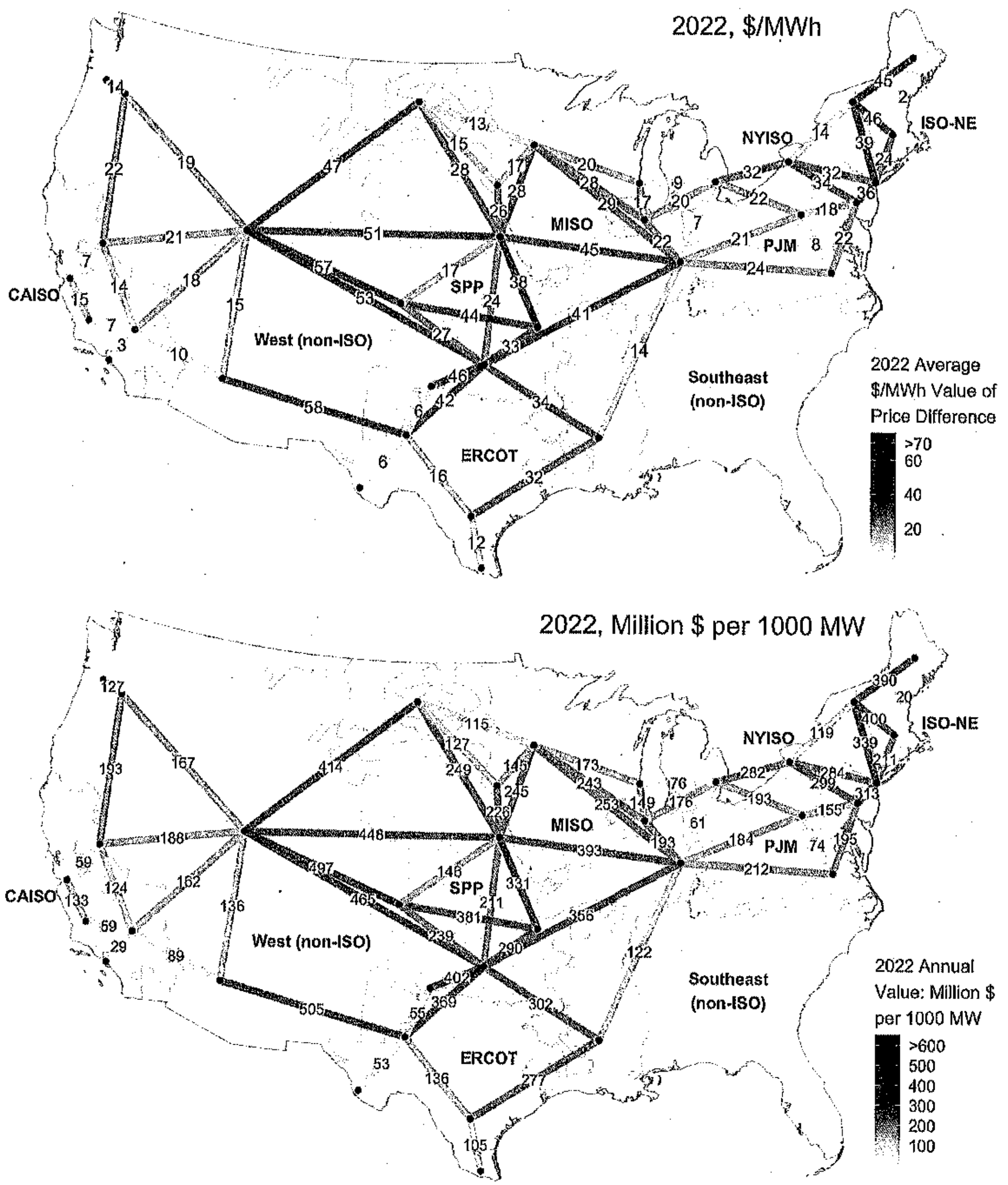


Figure 1. High transmission value is observed in many regions in 2022.
Top panel: The average absolute value of the hourly difference in prices across each link. Bottom panel: the annual cumulative value of a hypothetical 1000 MW transmission link. These values are marginal (applying to the next unit of transmission) and based only on hourly energy price arbitrage. Note that we were unable to analyze transmission value where pricing data was limited or not available, for example in the non-ISO Southeast region.

Transmission value was higher last year than at any point in the last decade. Across the set of 64 links the mean value was $220 million per 1000 MW (or $25/MWh) and the median value was $193 million per 1000 MW (or $22/MWh). Compared to previous years studied (2012 – 2021), both the mean and the median value of links reached new heights in 2022 (Figure 2).

The median and mean price differences across different years (left and right of Figure 2, respectively) provide insight into the geographic scale of events causing high transmission values. The median value was significantly higher in 2022 than any other year, indicating that the increase in transmission value last year was a broad phenomenon across most of the U.S. and not specific to any one region. The increase in transmission value across so many locations is suggestive of a cause that is national in nature, such as increased average energy prices in 2022. In contrast, high mean values without corresponding high median values (such as in 2018 and 2021) indicate that certain events can drive extremely high transmission value in isolated regions. In 2021, for example, winter storm Uri drove high values for interregional transmission into SPP and ERCOT, but had less impact on other regions of the U.S.

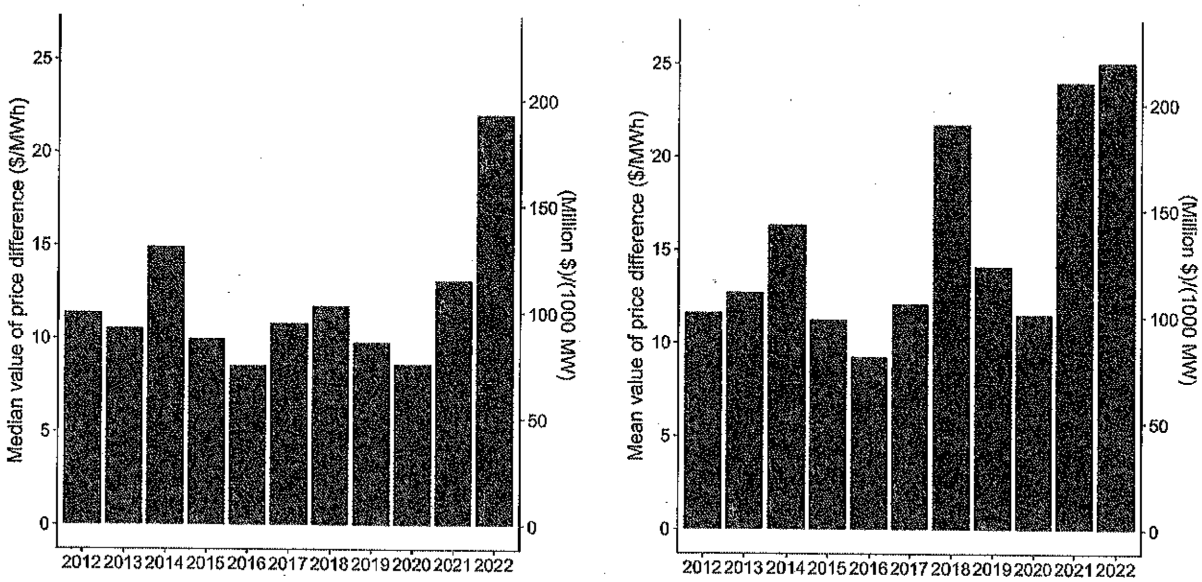


Figure 2. Transmission value was higher in 2022 than in past years in the study period.
Median (left) and mean (right) value of transmission links across the set of 64 links. Note that the set of links in the early years is smaller due to data constraints.

Transmission value was concentrated in a small portion of total hours. This was true in past years as well as in 2022. For the typical link in 2022 (calculated as the median value across the 64 links), 50% of total value was derived from only 10% of the hours, and 37% of total value was derived from only 5% of the hours (Figure 3). Compared to past years, value was slightly less concentrated in time. For example, from 2012 – 2021, a typical link derived 50% of value from only 5% of hours (not 10% as in 2022). The finding that value was less concentrated in time in 2022 is also consistent with generally higher wholesale electricity prices leading to higher values across all hours. Higher average prices increase transmission values because price volatility and spatial differences in price tend to increase with average prices.

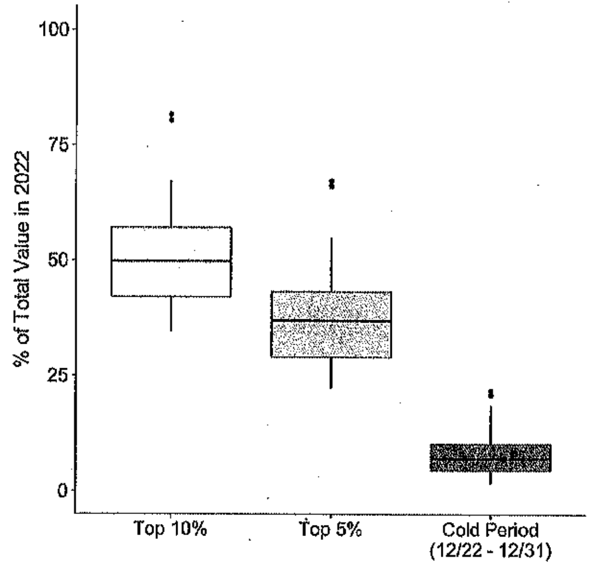


Figure 3. Transmission value was concentrated in a small fraction of total hours.
The most valuable 5% and 10% of hours accounted for a substantial portion of total annual transmission value as shown above. The box and whisker format shows the spread of the data across the full set of 64 links in the study.

Wholesale pricing patterns during winter storm Elliott illustrate the role of transmission in helping manage periods of grid stress. During the final week of 2022, in which this storm gripped the country, the typical link derived 7% of its total annual value (Figure 3). However, total annual value was more closely tied to the storm in certain regions. Figure 4 shows the percentage of annual value for each link derived from winter storm Elliott. The storm boosted transmission values in MISO, PJM, and the Northeast, such that for many links in these regions this short period provided 10% to 22% of total annual value.

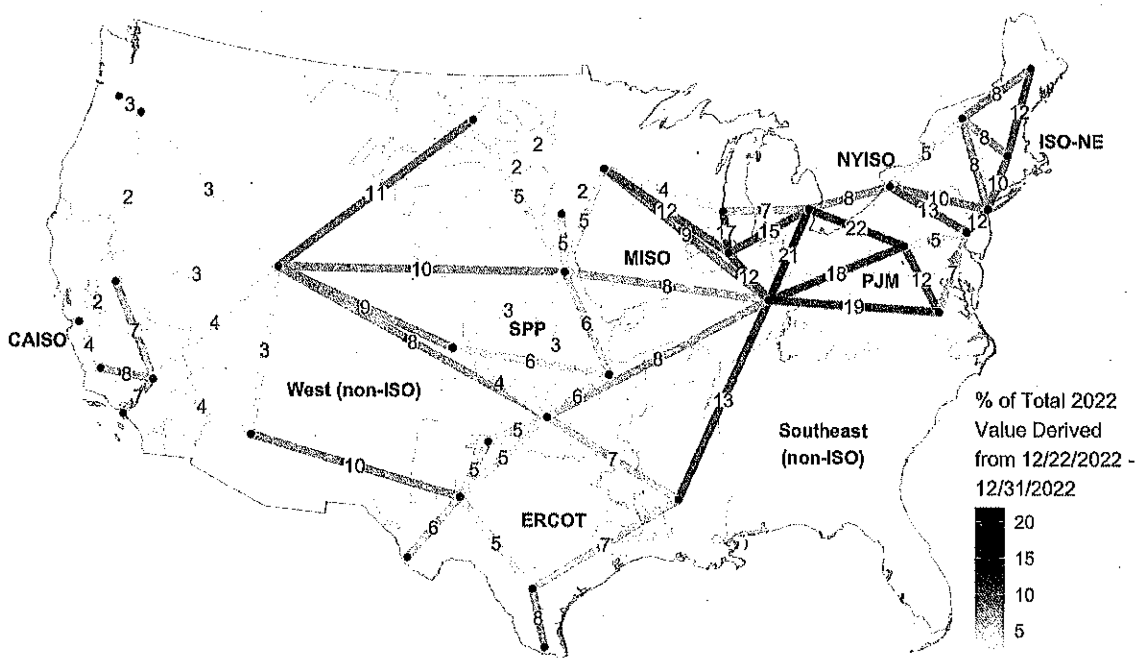


Figure 4. Winter storm Elliott provided a substantial portion of total transmission value in some regions of the country.
The value from this event illustrates the role of transmission in managing the economic and physical risks of such incidences.

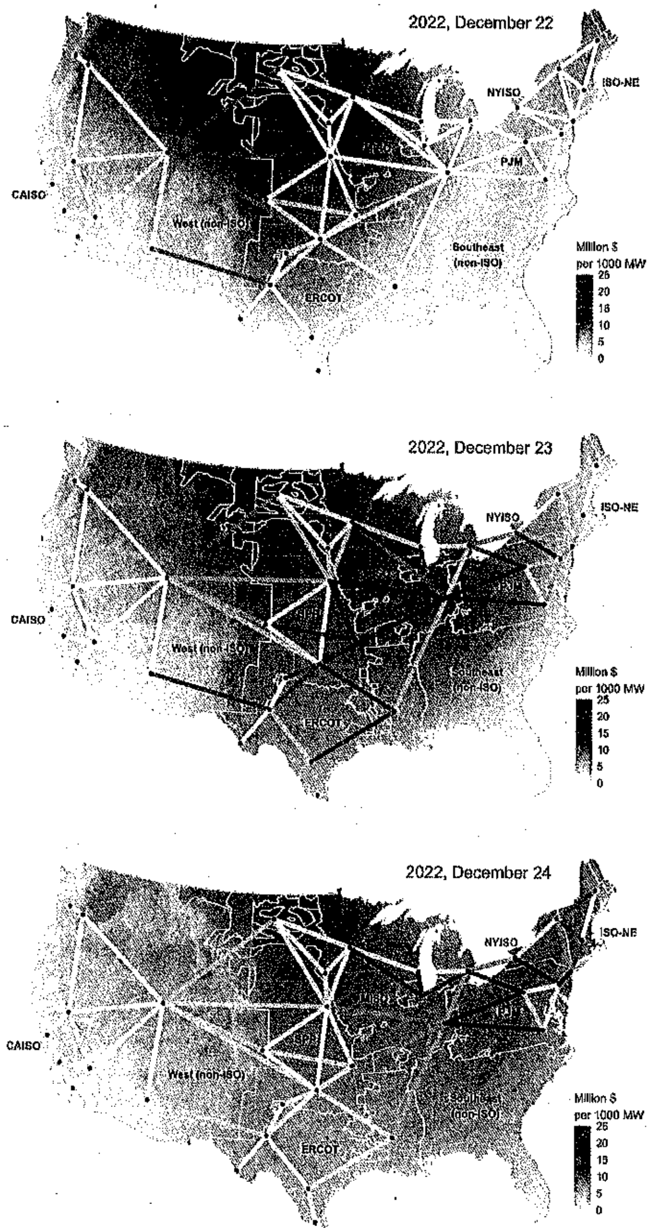


Figure 5. Transmission value moved east with cold surface temperatures December 22nd – 24th. *The value shown above is calculated as a total for each day (central time). Darker blue colors indicate colder surface temperatures.*

The cold weather associated with winter storm Elliot moved first south through the Midwest and then eastward. Transmission value largely followed this path with the highest value links pointing into the center of the storm and shifting over time (Figure 5). Most of the high value links highlighted in Figure 5 are interregional, showing the particular value of interregional links in helping to mitigate costs during extreme weather.

Transmission values in 2022 further illustrate the challenge assessing the full benefits of new grid infrastructure. Transmission congestion-relief values were unusually high in 2022. The value patterns demonstrate the sensitivity of transmission value to overall wholesale electricity prices (and thus to natural gas prices) and to rare events (weather, as identified, as well as the other 10% of high value hours that accounted for 50% of value). In as much as transmission planning studies do not adequately take into account uncertainties in weather, natural gas prices, and other factors, they may deeply understate the possible value of new transmission.

Key Limitations

Prices in wholesale energy markets represent the cost of the next unit of generation (i.e., they are marginal prices), and thus the transmission value metric we calculate represents the value of the next unit of transmission. What this means is that the transmission value is subject to saturation effects – i.e., as more transmission is added to the system the value of additional transmission would decline. When we calculated the value of new transmission with 1,000 MW of capacity we assumed that there were no saturation effects, and it is likely that in some locations our transmission value estimate would be more applicable to a smaller capacity addition than a full 1,000 MW. On the other hand, many of the locations chosen are 'hub' nodes, representing prices over a region, and thus may not be as sensitive to saturation effects as a more localized pocket of demand. For context, PJM load peaked at over 130,000 MW during December 23, 2022. An additional consideration is that some of the difference in prices between locations is due to electric line losses, though typically losses are much smaller than congestion costs. Also, some differences in prices between regions are due to market structure and agreements rather than true lack of transmission capacity; these structural costs are also generally small compared to potential value of added transmission. Finally, the value calculated here only represents a small portion of total transmission value (it does not include reliability, resiliency, and emission benefits). The transmission value calculated here is most similar to 'production cost' benefits, which have been found to account for roughly half of total transmission value in a number of 'multi-value' transmission studies. Finally, understanding both value and costs are critical to planning for new transmission, our research here aims to inform transmission value estimates, but it does not address transmission cost estimates.

Conclusions

This study finds that additional regional and interregional transmission would have had significant economic value in 2022, larger than any year 2012 – 2021. This update for year 2022 supports past results that indicated many existing transmission planning approaches are likely understating the economic value of new transmission infrastructure. In part, this is because roughly half of the marginal value of transmission in providing congestion relief occurs during extreme grid conditions and high-value periods that are not always adequately modeled or considered by transmission planners. These periods are natural features of actual market operations. As such, this and our earlier study highlights the need for planners to more-comprehensively assess the value of transmission under both normal and extreme conditions. We plan to produce more in depth research on these topics later this year. Stay tuned!

Acknowledgements

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U.S. DEPARTMENT OF ENERGY

National Transmission Needs Study

Draft for Public Comment

February 2023

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)

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[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.

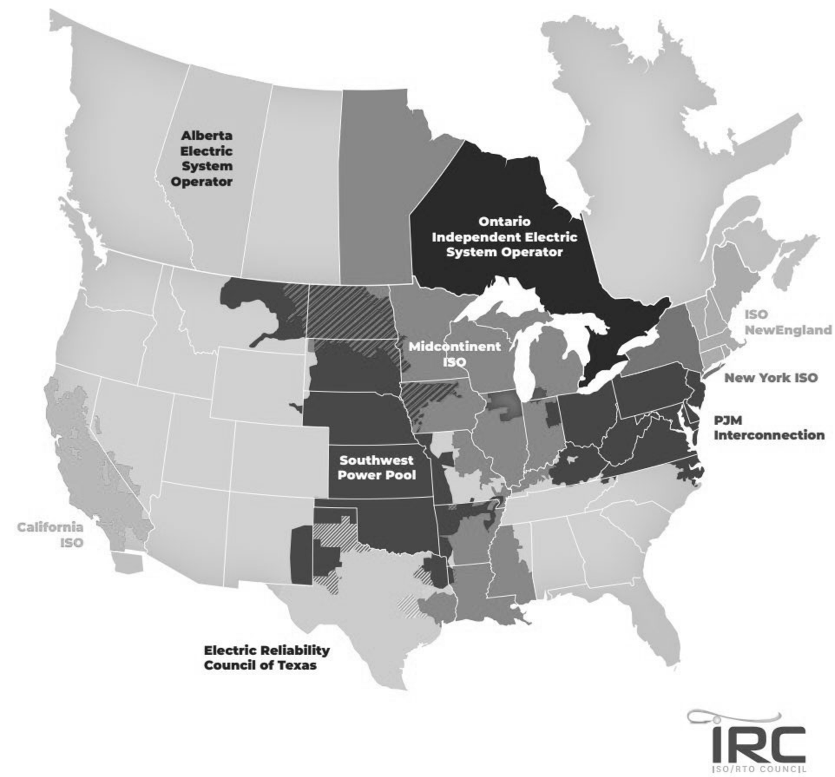
Transmission capacity constraint. While *transmission congestion* (and the related but not identical *transmission constraint)* have industry standard definitions, *transmission capacity constraints* do not. We define it here to be a suboptimal limit of transfer of electric power on the grid, including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



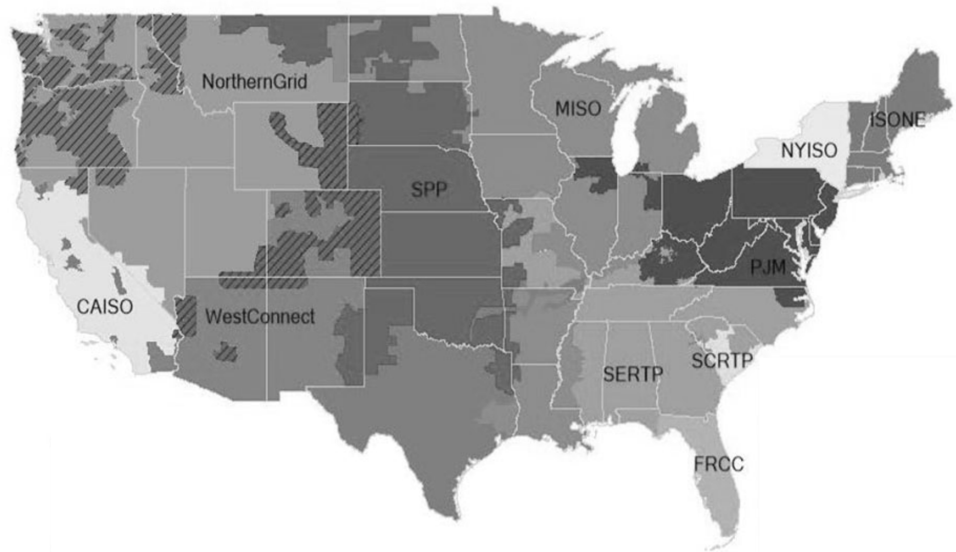
Source: ISO/RTO Council, at https://isorto.org/.

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."

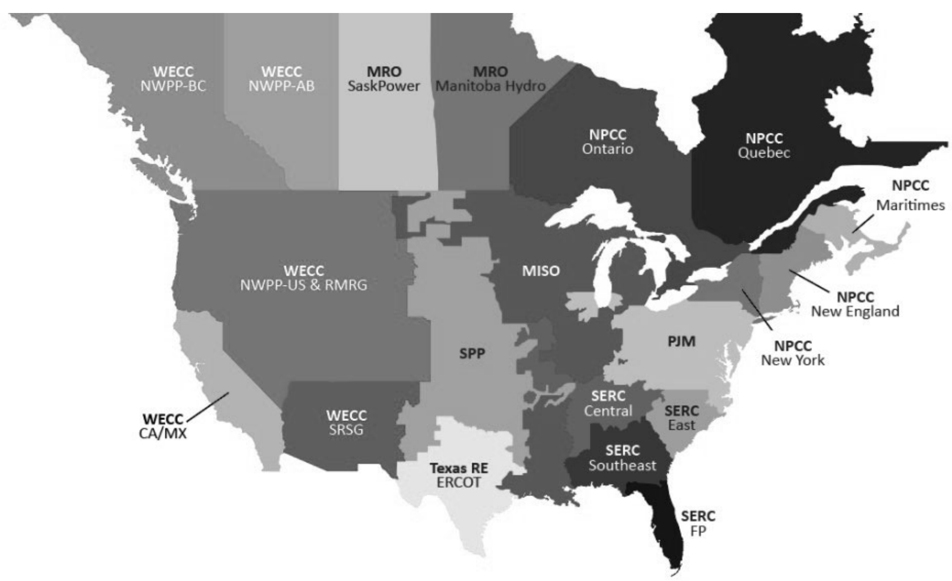
[22] Transfer capacity does not have an industry standard definition but does commonly refer to the sum of thermal limits of all transmission tie lines between two regions.



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.

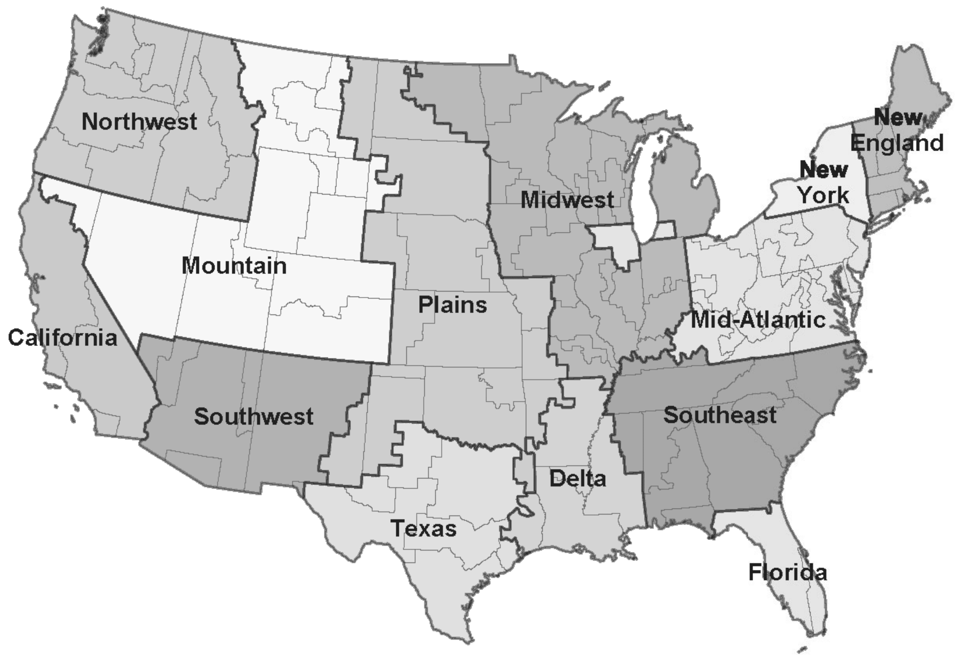
This study organizes transmission need results by geographic region, to the extent possible. If data sources are specific to an RTO/ISO, Order 1000, or NERC assessment area, the appropriate regional entity name also is used. For example, the wholesale market prices that underlie the analysis presented 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.

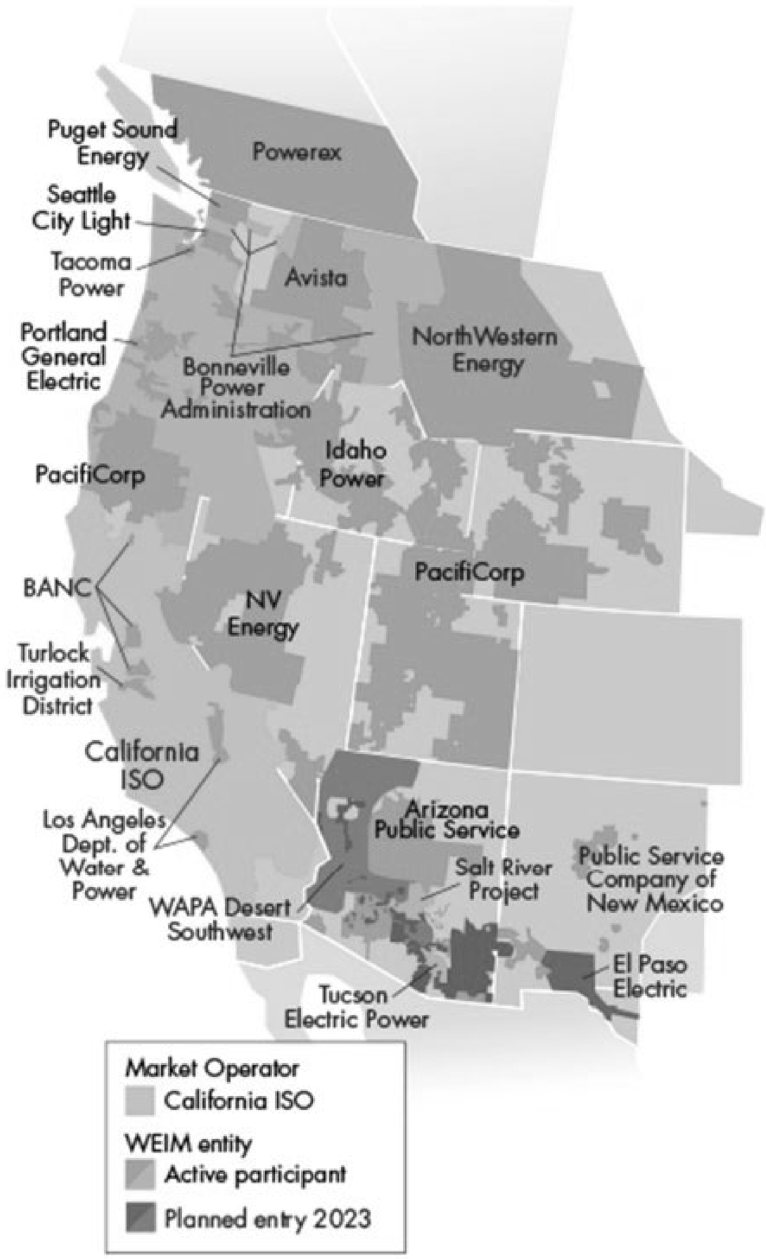
ATC directly reflects how close operation is to a transmission constraint. An ATC value of zero means no further requests for transmission services can be accepted, because no additional flows of electricity can be accommodated without violating a reliability limit.

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/

Licensed with permission from the California ISO. Any statements, conclusions, summaries or other commentaries expressed herein do not reflect the opinions or endorsement of the California ISO.

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.

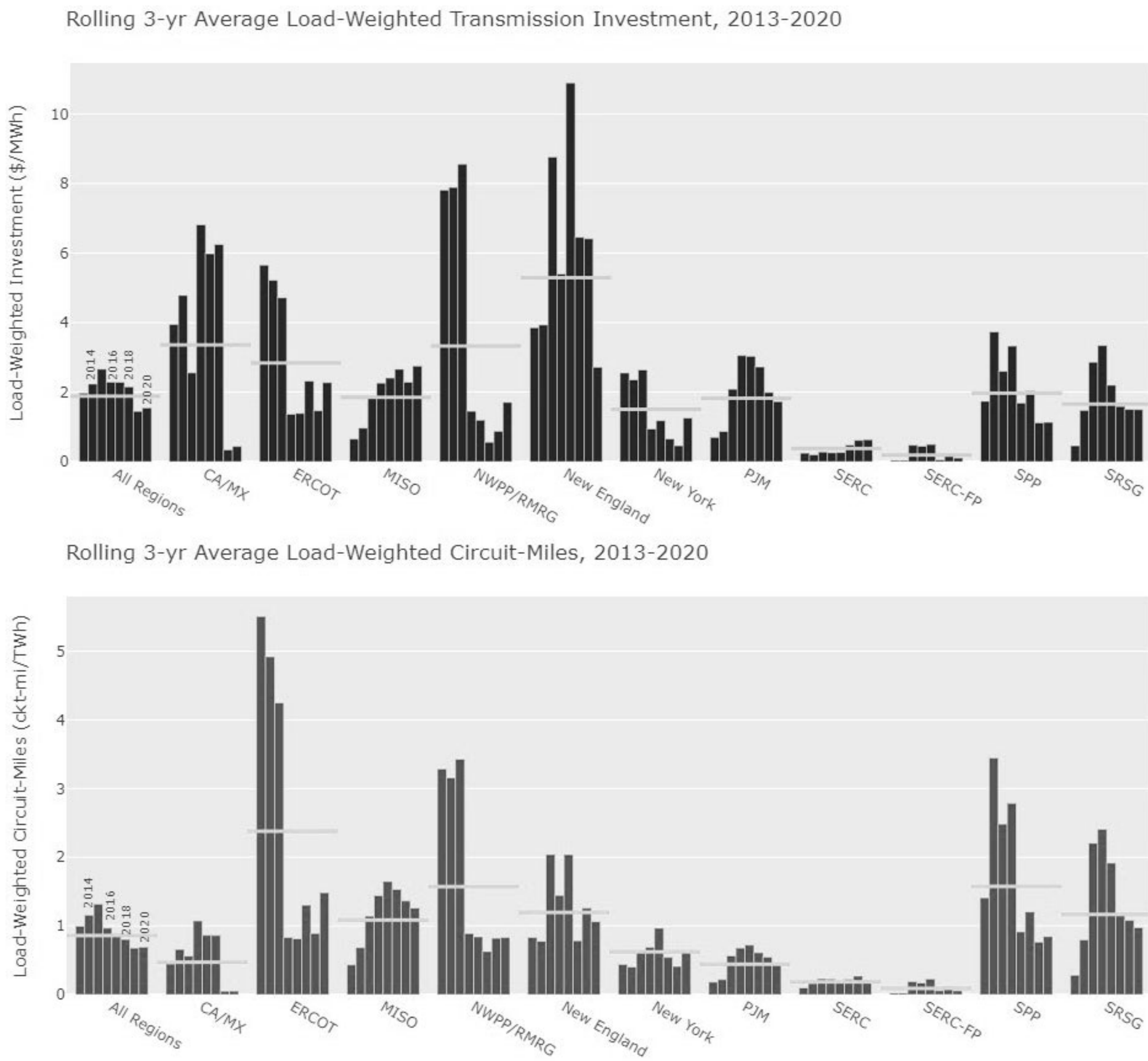
Transmission investments are inherently "lumpy," or unevenly distributed. Many projects that have been in development for several years might all be energized in the same year, giving the appearance of large investments during that single year without acknowledgement of when projects first entered the 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).

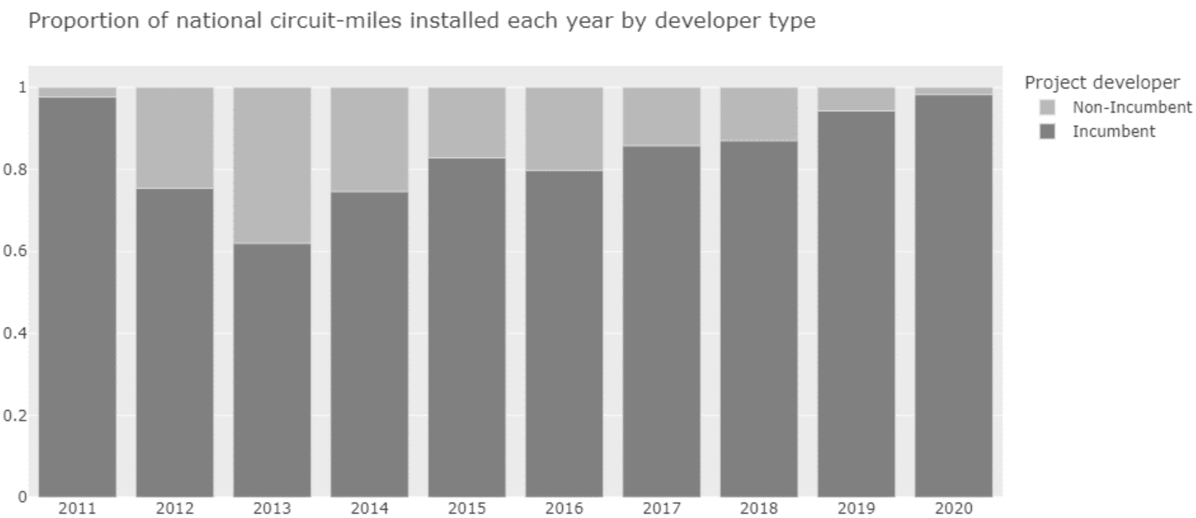
Table IV-1. Qualitative trends in new transmission investments between 2011 and 2020 for each region and for the United States as a whole. Decadal mean of both load-weighted transmission investments and circuit-miles for new transmission rated over 100 kV and energized in each year of the decade are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

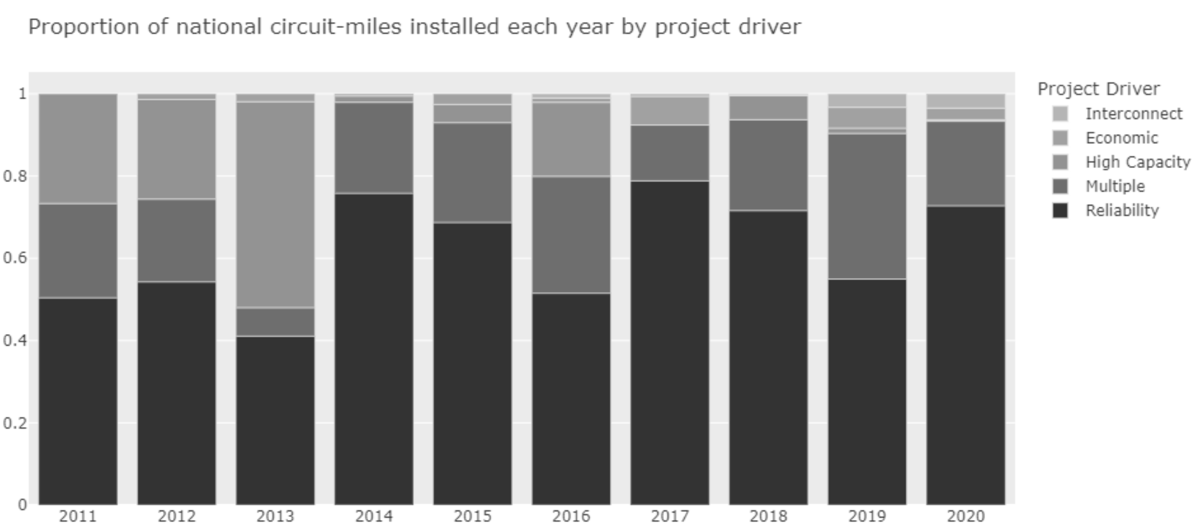
Figure IV-3 shows the primary driver for all transmission projects (rated above 100 kV) energized between 2011 and 2020 across the United States. New transmission projects can be a response to a single, or combination of drivers, including a specific reliability need, the opportunity to realize far-reaching 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.

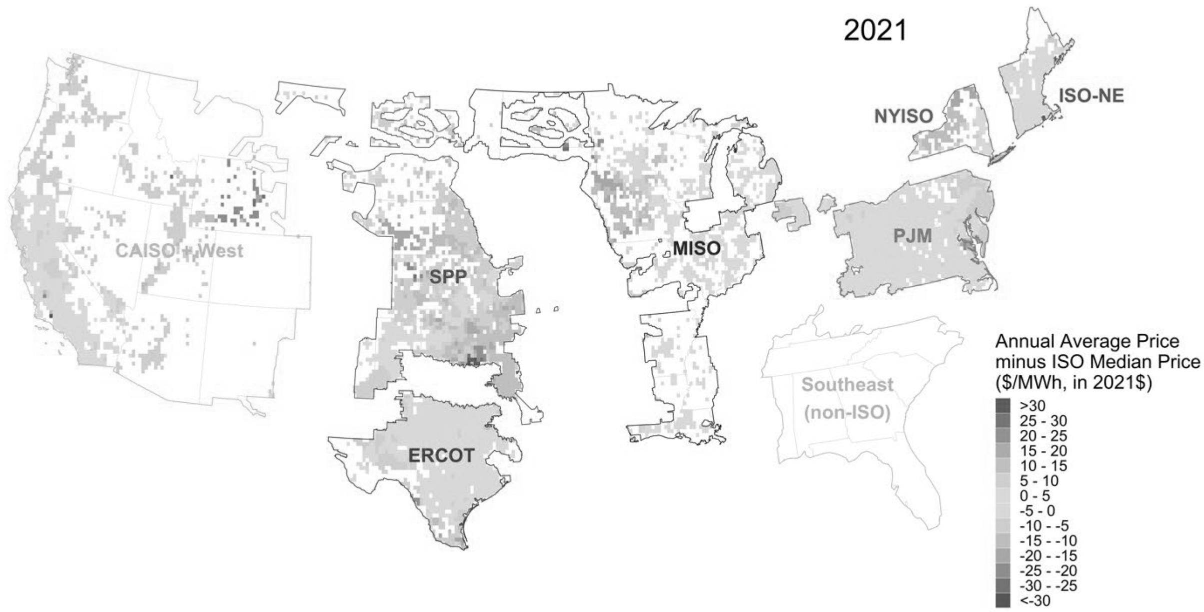
This analysis builds on past work; for example, DOE (2020) examined congestion in wholesale markets using RTO/ISO-reported congestion costs. These reported congestion costs are presented only at the region-wide level. They do not provide insight on where congestion is most costly within each region, 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.

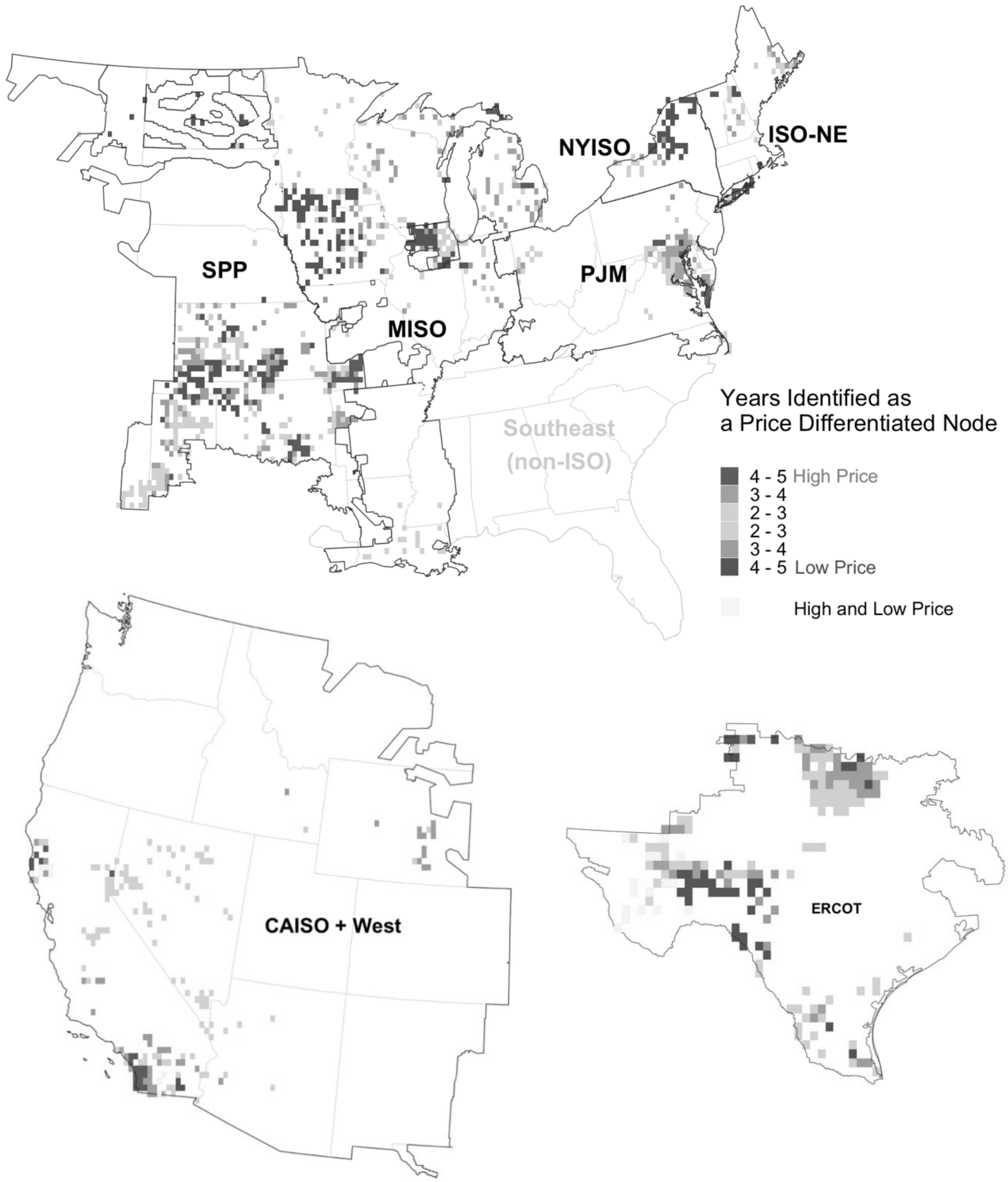
priced pockets can be found near wind resources in MISO in Iowa and Minnesota, and in PJM in Illinois. High-priced regions are identified in New York City and Long Island, in PJM near Washington DC, and in eastern SPP. A full list of high-and low-priced regional “pockets” is presented in Table IV-2. 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.

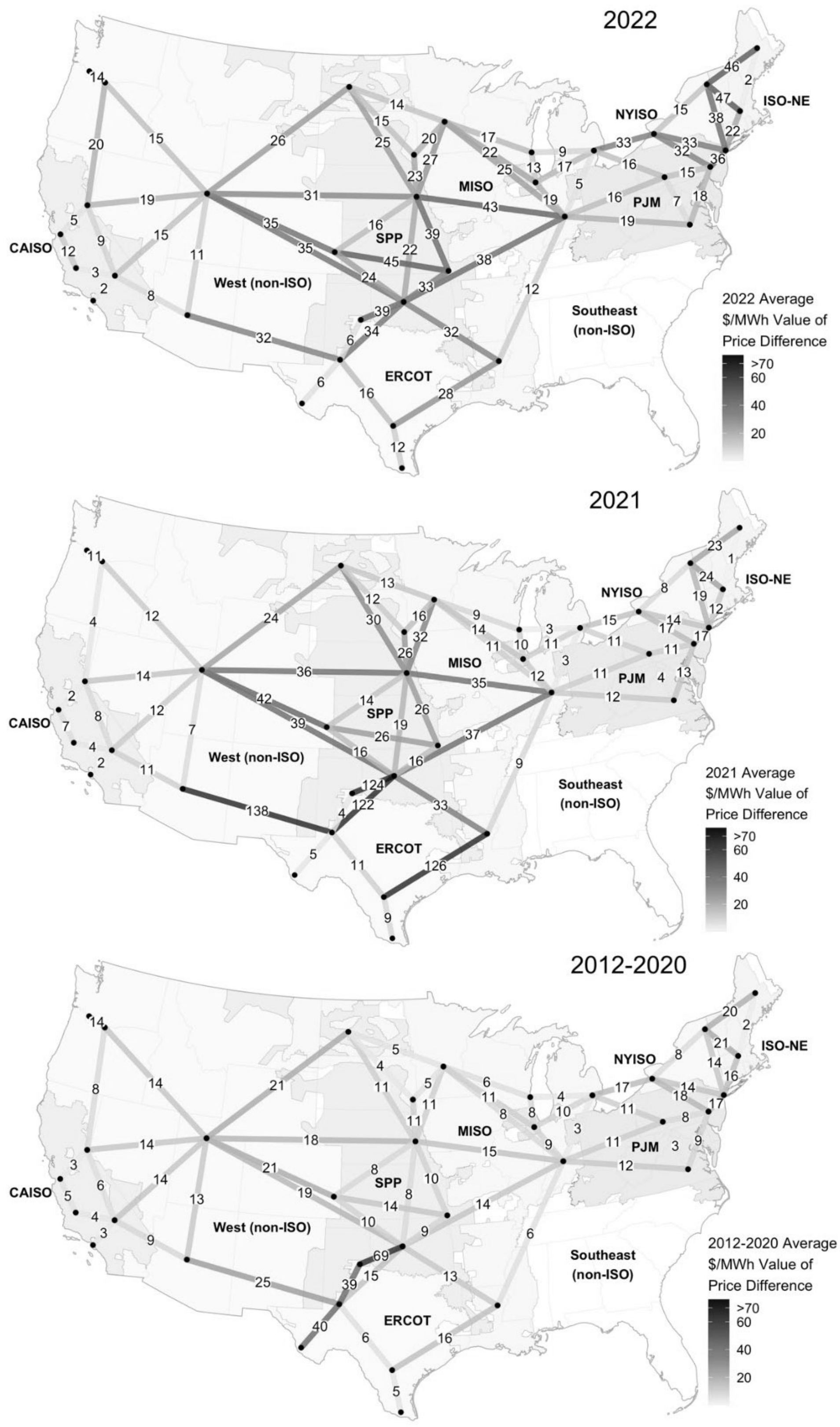
Exploring the time trends of these links reveals that the value of interregional transmission to SPP and to ERCOT has been increasing over time.[30]

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

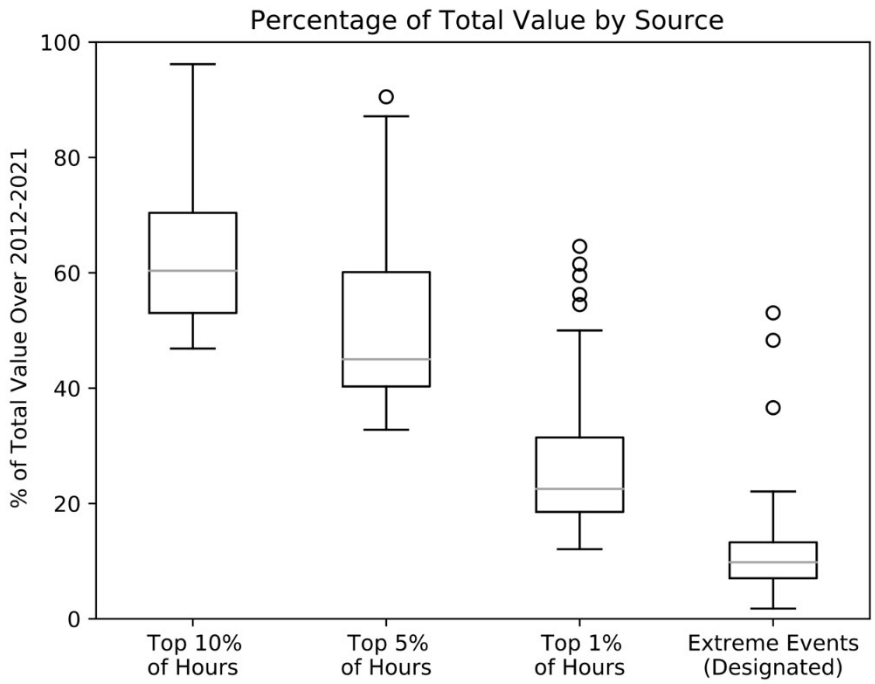
Transmission value can be affected by relatively infrequent but challenging conditions on the electricity system. Some examples of these conditions include fluctuations in uncertain variables for either short-term or long-term periods (e.g., fuel price volatility, inaccurate demand forecasts, inaccurate 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).

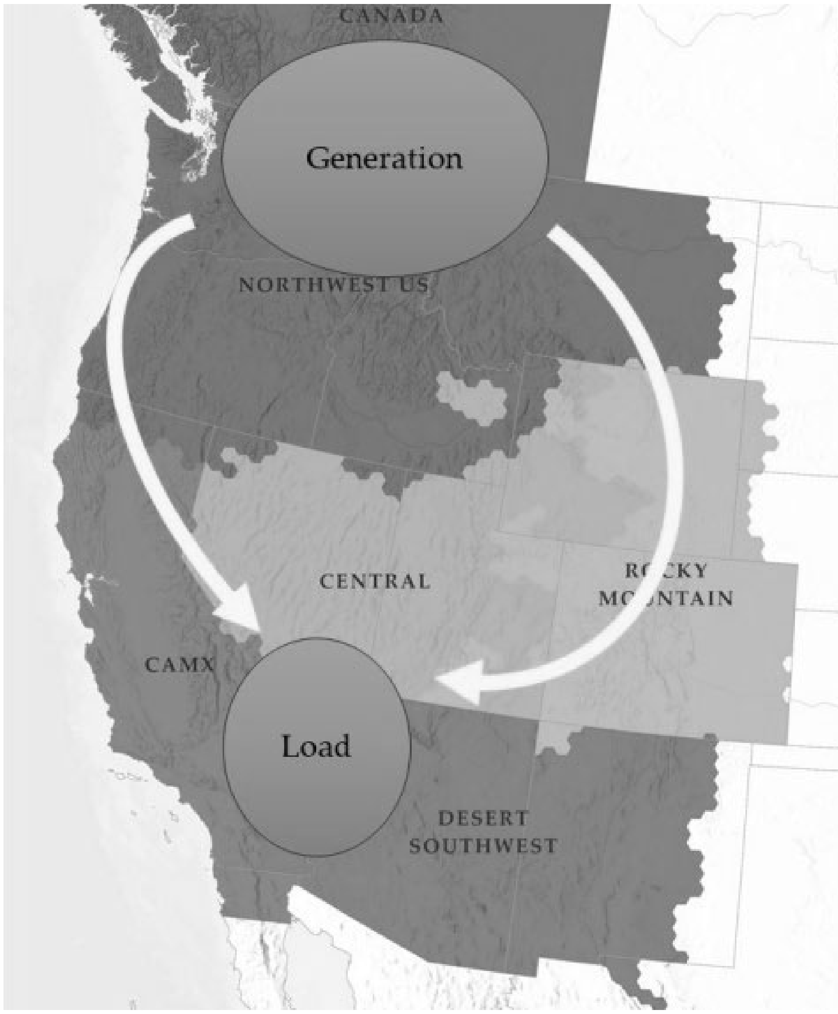
In response, the Western Interconnection uses the WIUFMP. The WIUFMP is a FERC-filed tariff that provides a mechanism for reliability entities to mitigate flows on Qualified Paths to reliable levels.[33]

[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.



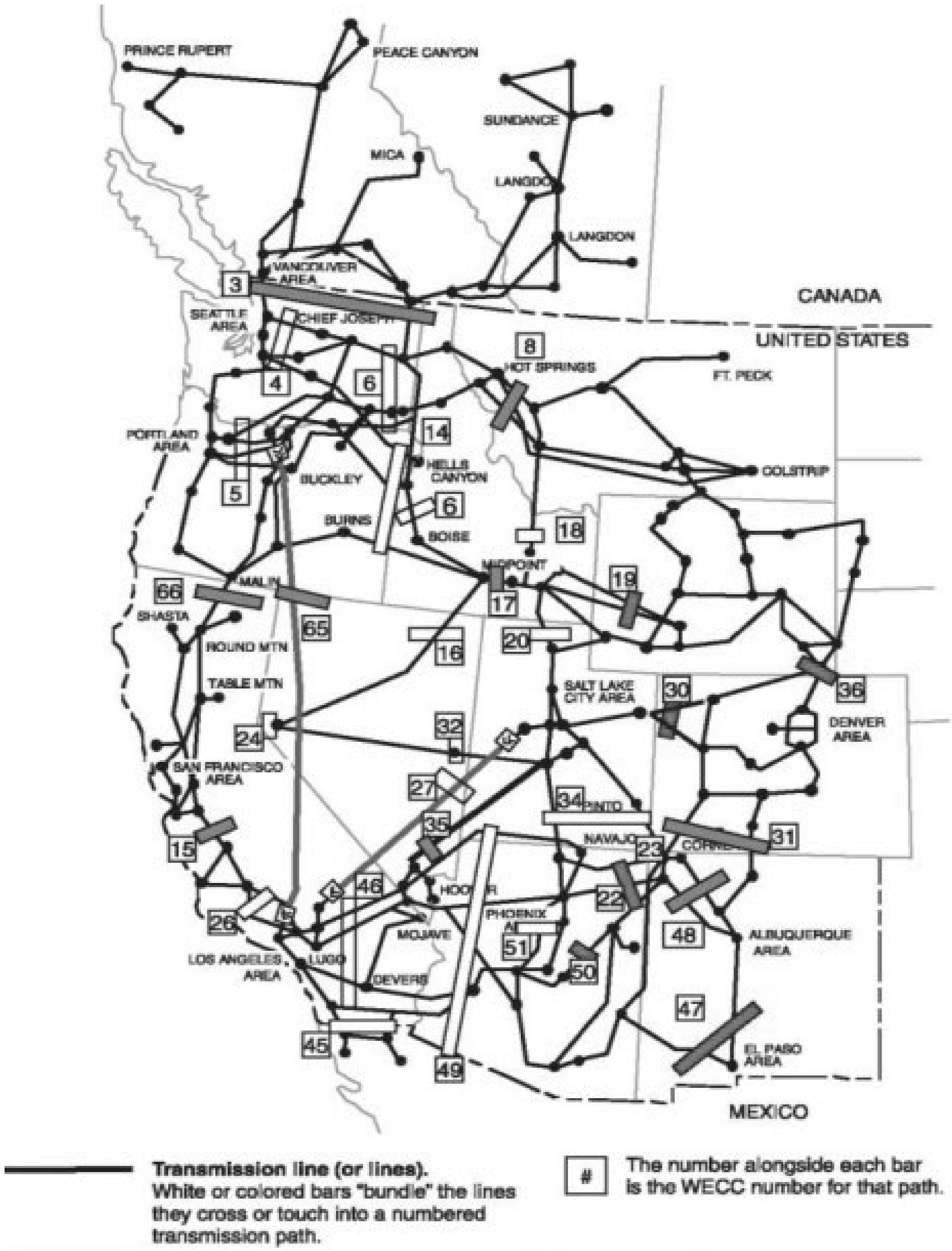
Source: WECC August 2020 Heatwave Event Analysis Report. March 2021; https://www.wecc.org/Reliability/August%202020%20Heatwave%20Event%20Report.pdf.

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.



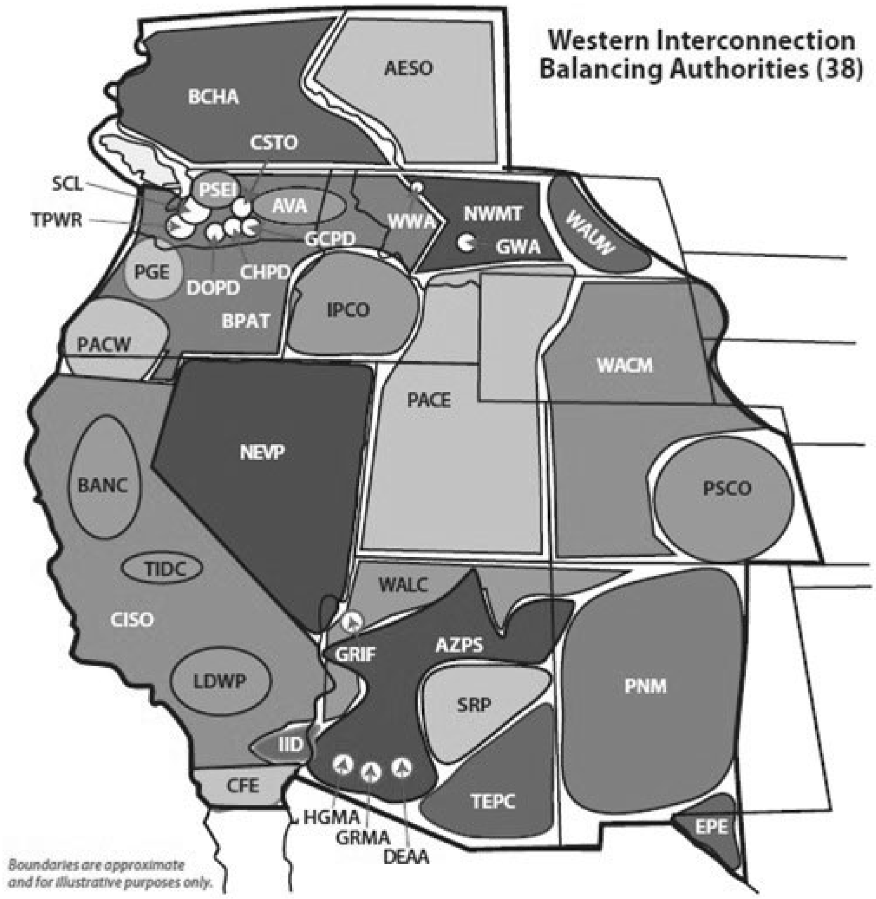
Source: Western Electricity Coordinating Council (WECC). See also: https://www.wecc.org/Reliability/TAS_PathReports_Combined_FINAL.pdf.

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.

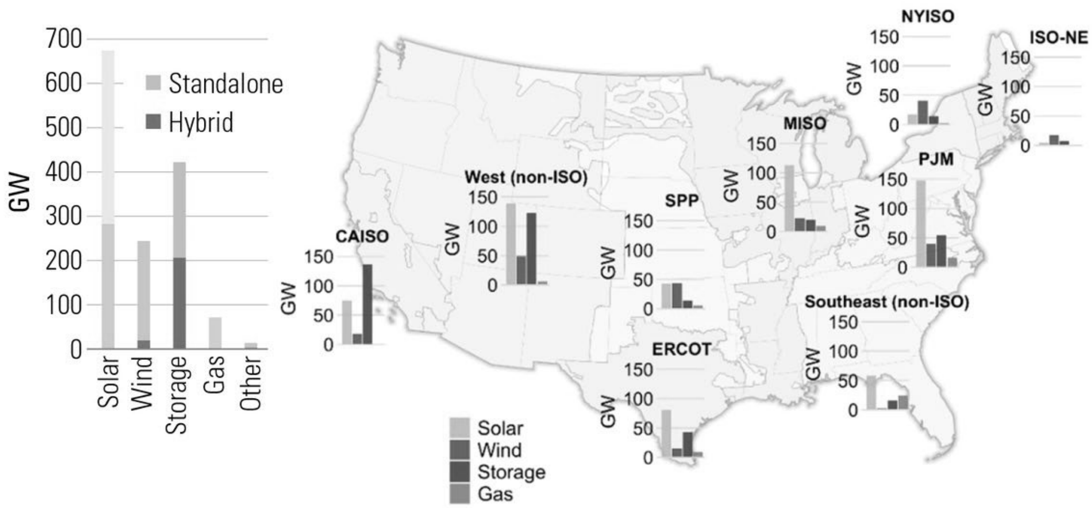
Note: Boundaries are approximate and for illustrative purposes only.

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.

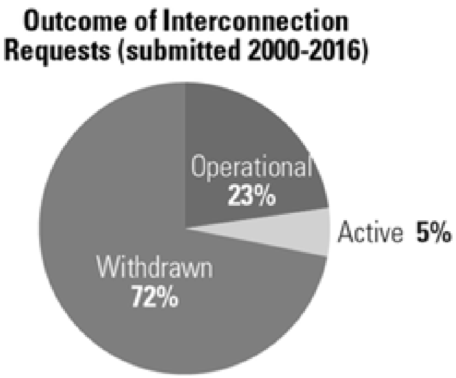
Note: Hybrid plants are those paired with one or more other type of generation or storage

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.

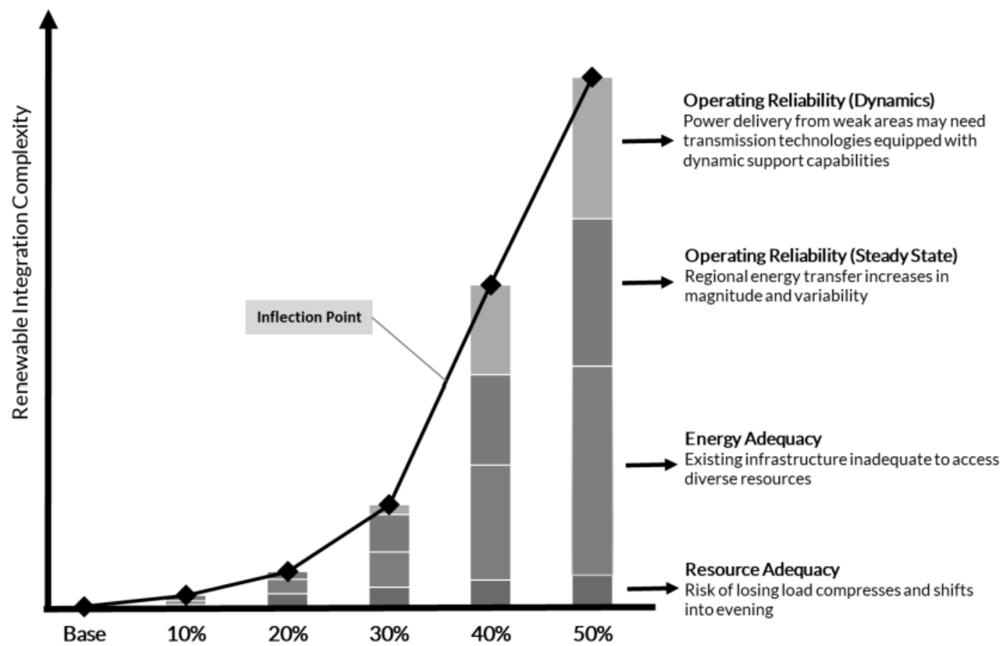
In the Clack et al. (2020b) modeling study of renewable energy development and emission reductions in the Eastern Interconnection, the authors find that investing in transmission can promote access to low-cost renewable energy without compromising system reliability. Clack et al. (2020b) determine that 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.

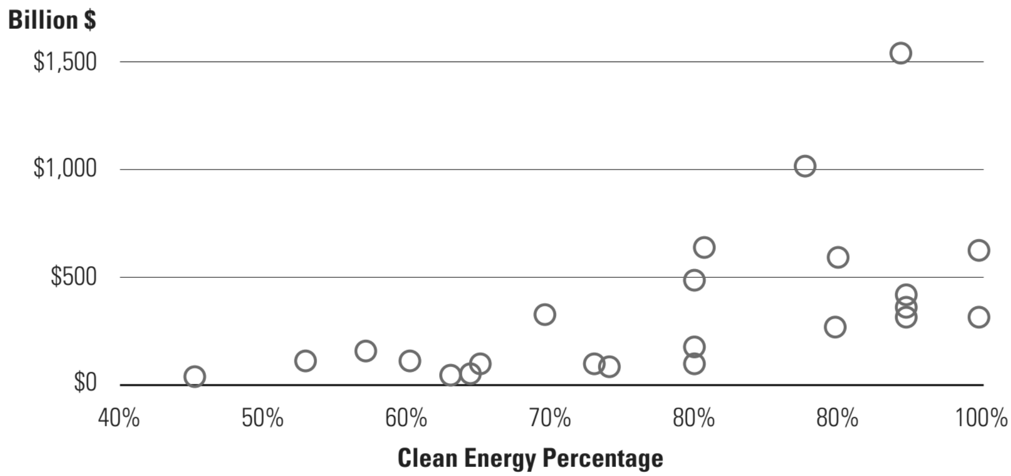
FERC et al. (2021) recommend that adjacent Reliability Coordinators, BAs, and Transmission Operators perform bidirectional power transfer studies to determine constraints that could occur when importing or exporting power between neighboring regions during an emergency that spans multiple Reliability 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.

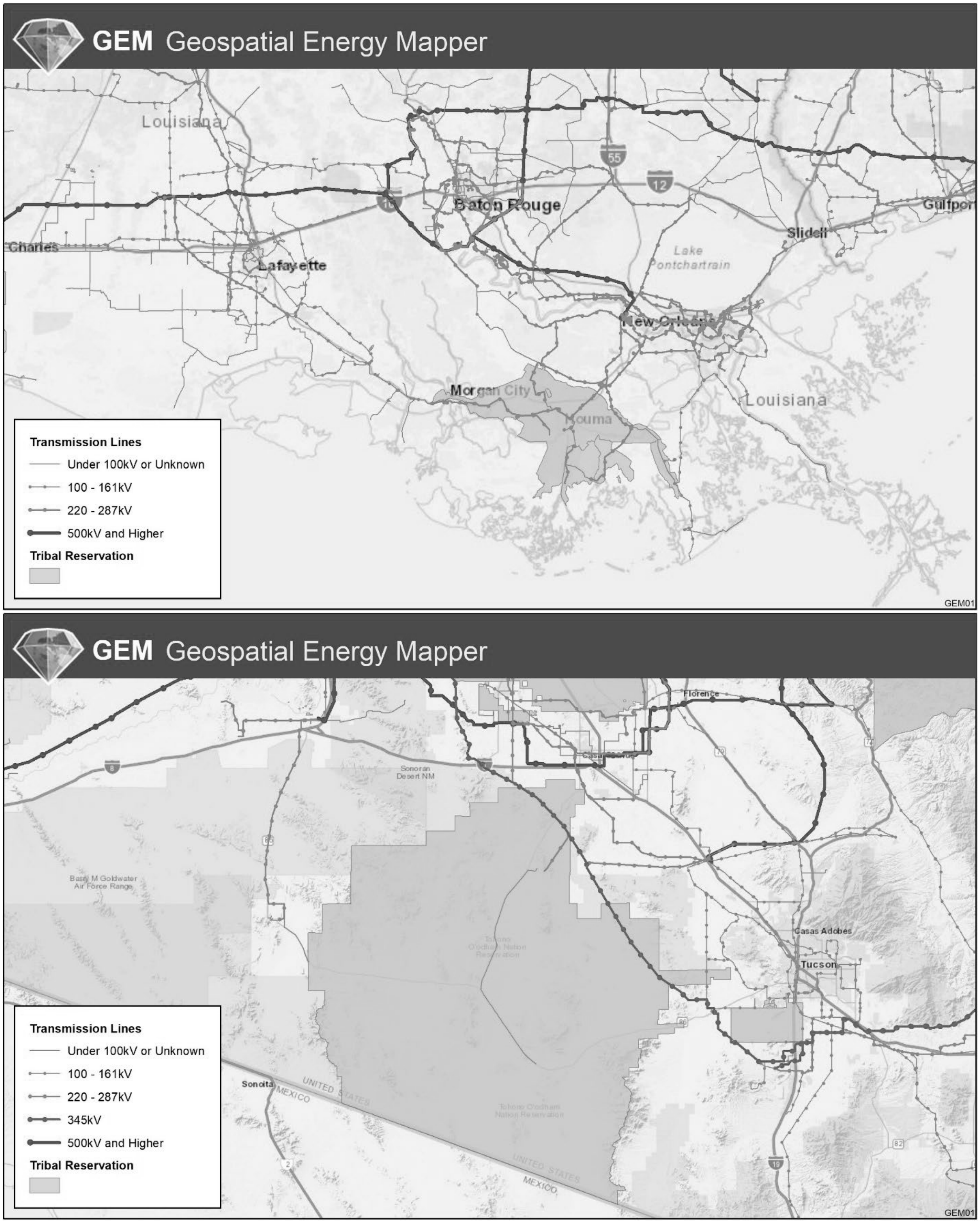
compared to other replacement sources of energy (Milbrandt, Heimiller, and Schwabe 2018). Future improvements to economic potential assessments on tribal lands include incorporating both in-region and out-of-region transmission costs and other policy drivers such as energy independence, reliability, 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.

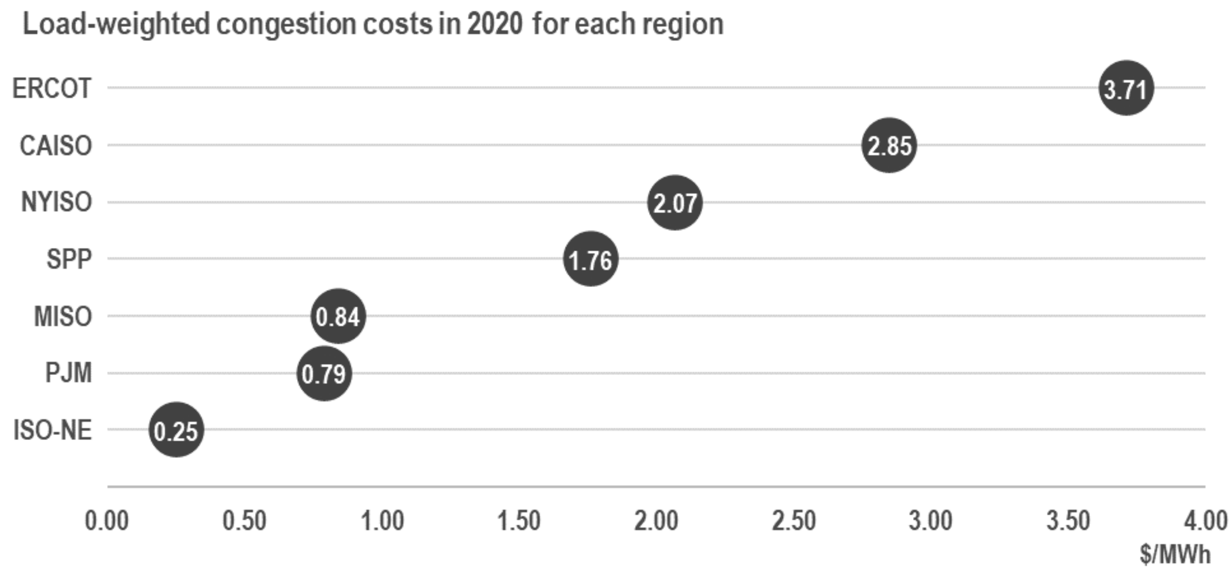
FERC (2020) similarly indicates that transmission investments can improve the competition of lowest-cost resources in wholesale markets by reducing congestion, noting that transmission investments have been rising for the past 20 years. In unconstrained cases, where the transmission system is modeled 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.

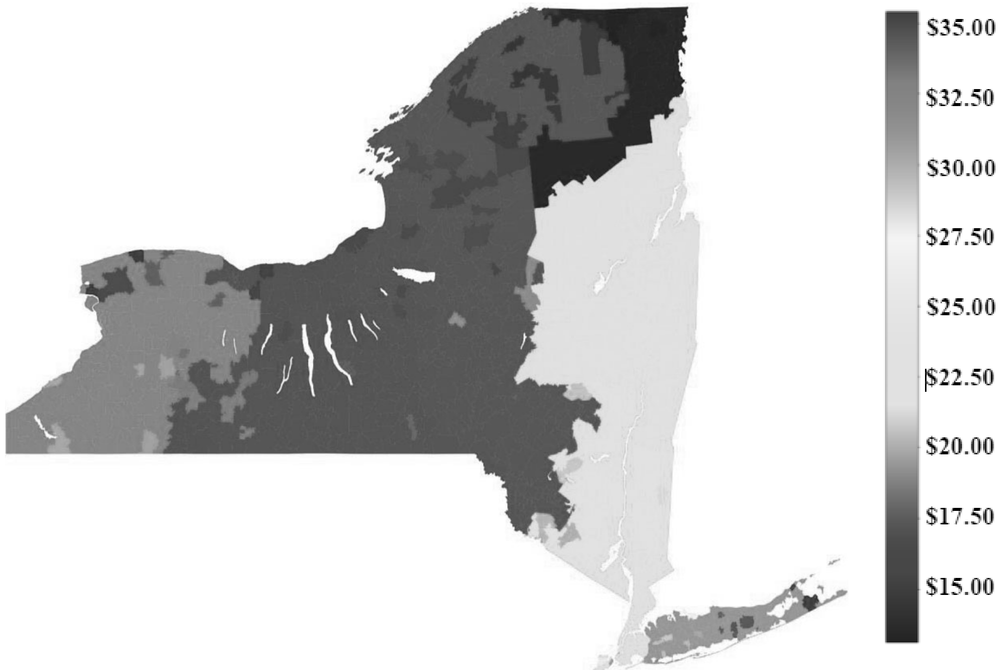
Additionally, ISO-NE (2020) notes that transmission enables low-cost resources to produce more energy, lowering wholesale electricity prices for several subareas. However, the report also mentions that increased congestion occurs on the SEMA/Rhode Island transmission interface from oversupply of wind 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.

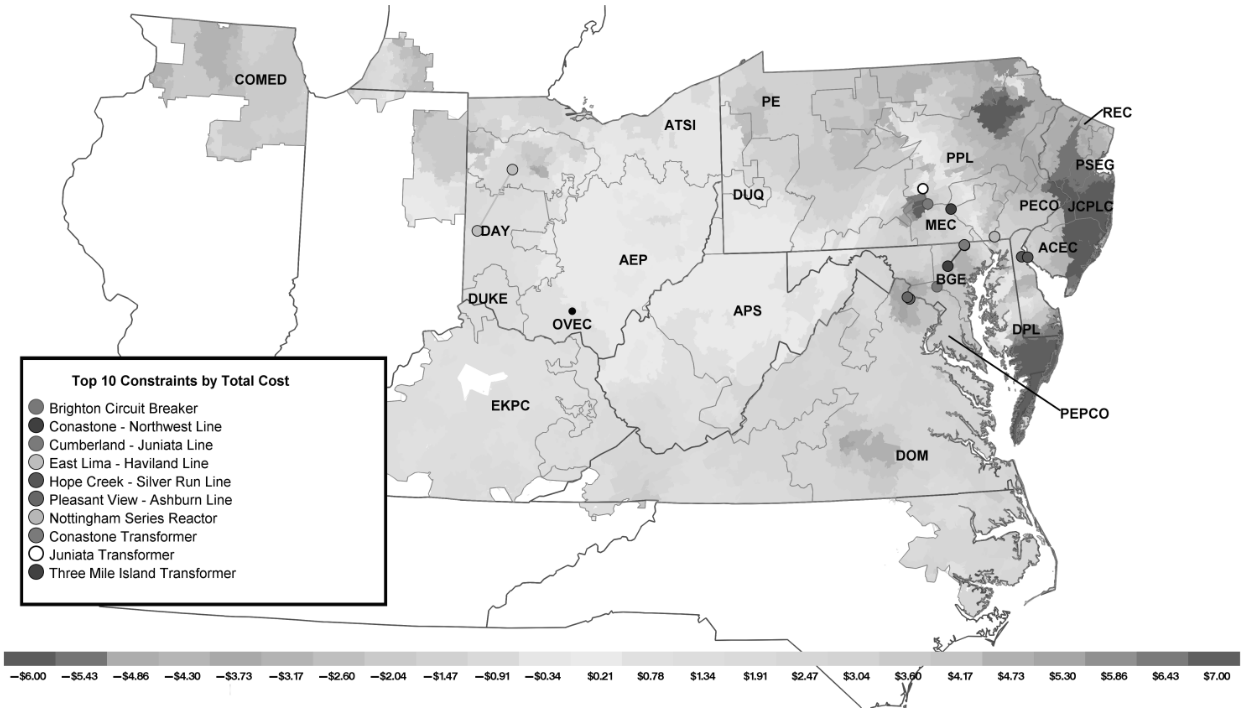
V.d.3. Mid-Atlantic

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.

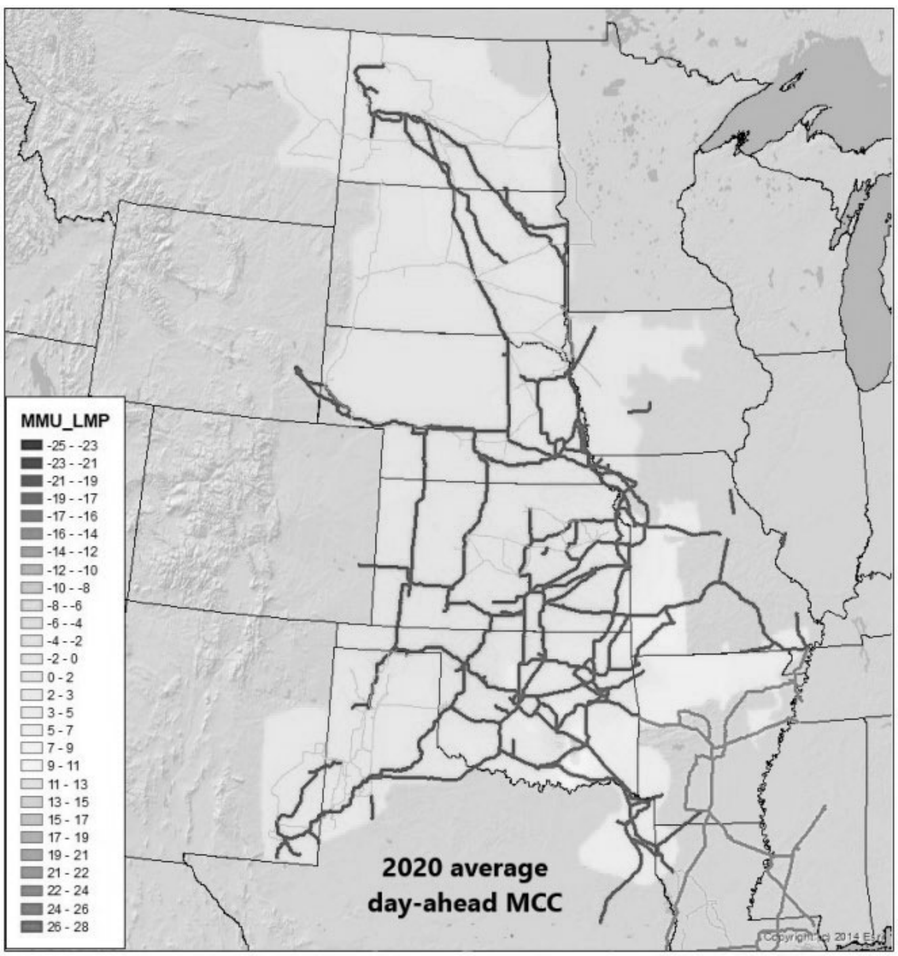
In addition, Potomac Economics (2021b) describes the negative impact of TLR on the MISO market. TLR is used as a congestion management method. TLRs called by the Independent Electricity System Operator of Ontario resulted in curtailments of large amounts of power from PJM to MISO, creating price spikes 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.

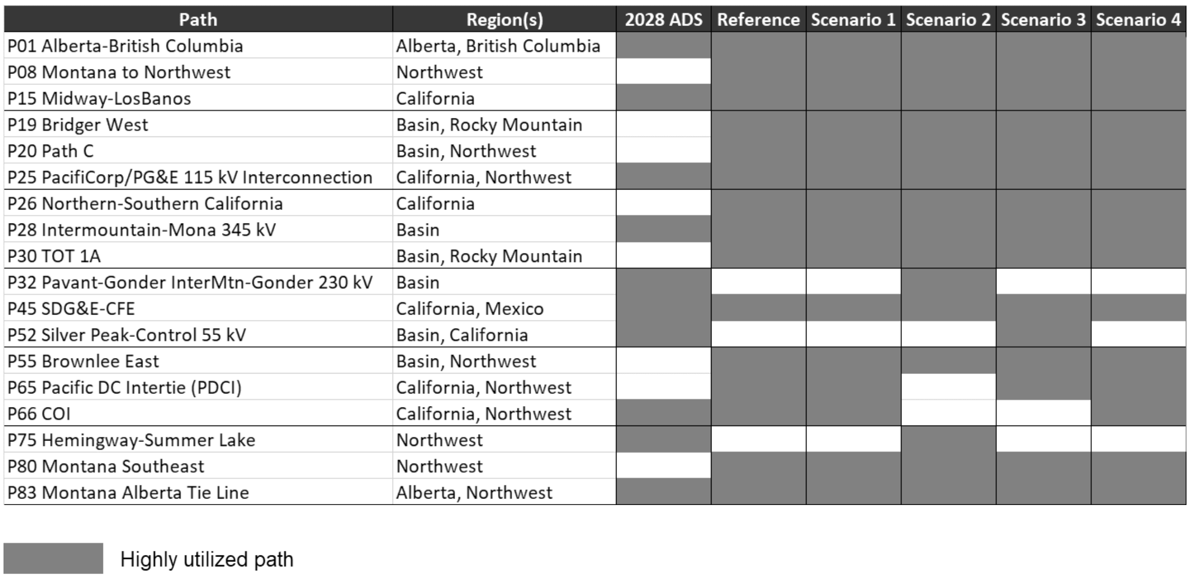


Figure V-8. Summary of WECC 2038 Scenario Reliability Assessment.

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.

> ## 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.

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.

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	<u>Scope</u> 2022–2050 <u>Resolution</u> CEM: 2-yr PCM: hourly	<u>Scope</u> Contiguous U.S. <u>Resolution</u> 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	<u>Scope</u> 2020–2050 <u>Resolution</u> CEM: 2-yr PCM: hourly RA: hourly	<u>Scope</u> Contiguous U.S. <u>Resolution</u> 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	<u>Scope</u> 2020–2050 <u>Resolution</u> CEM: 5-yr	<u>Scope</u> Contiguous U.S. <u>Resolution</u> State (transmissio n 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	<u>Scope</u> 2020–2050 <u>Resolution</u> CEM: 2-yr	<u>Scope</u> Contiguous U.S. <u>Resolution</u> 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.

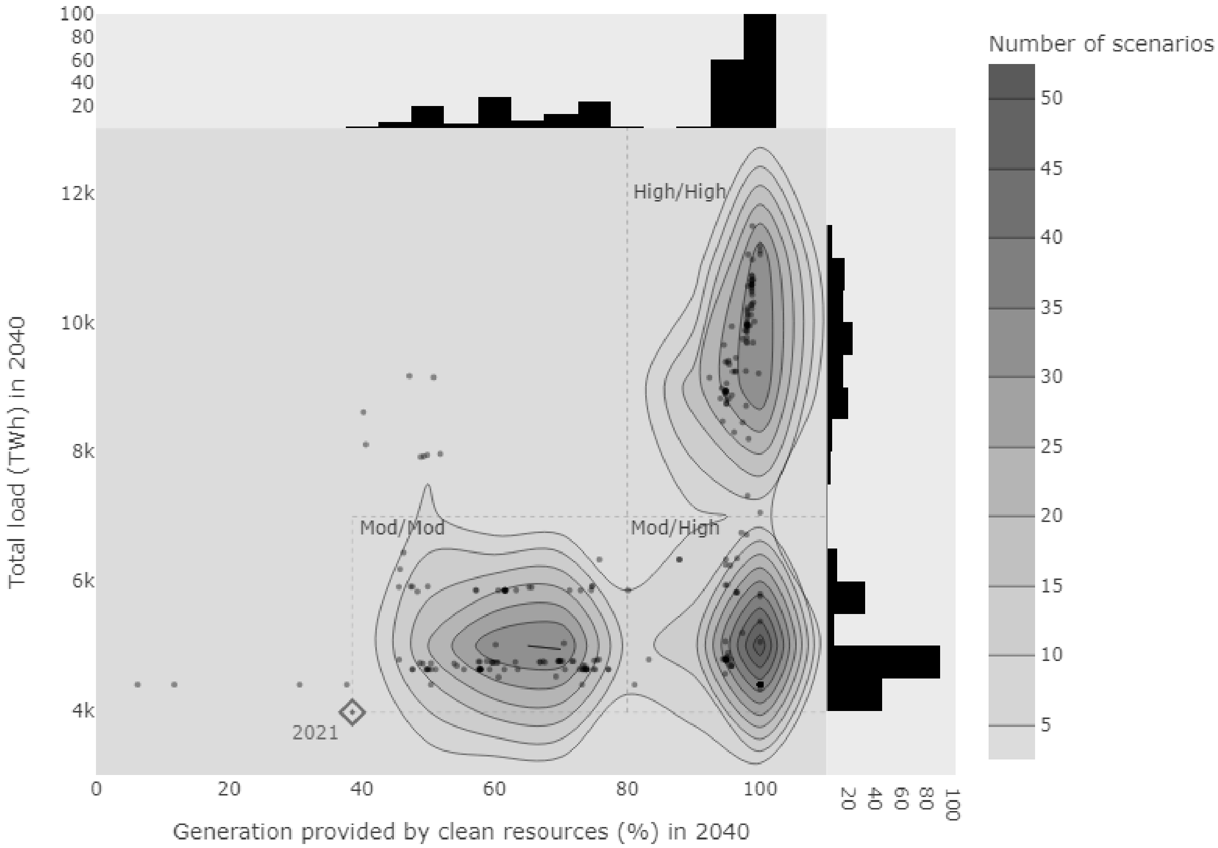
VI.a.2. Treatment of non-wire alternative transmission solutions

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.

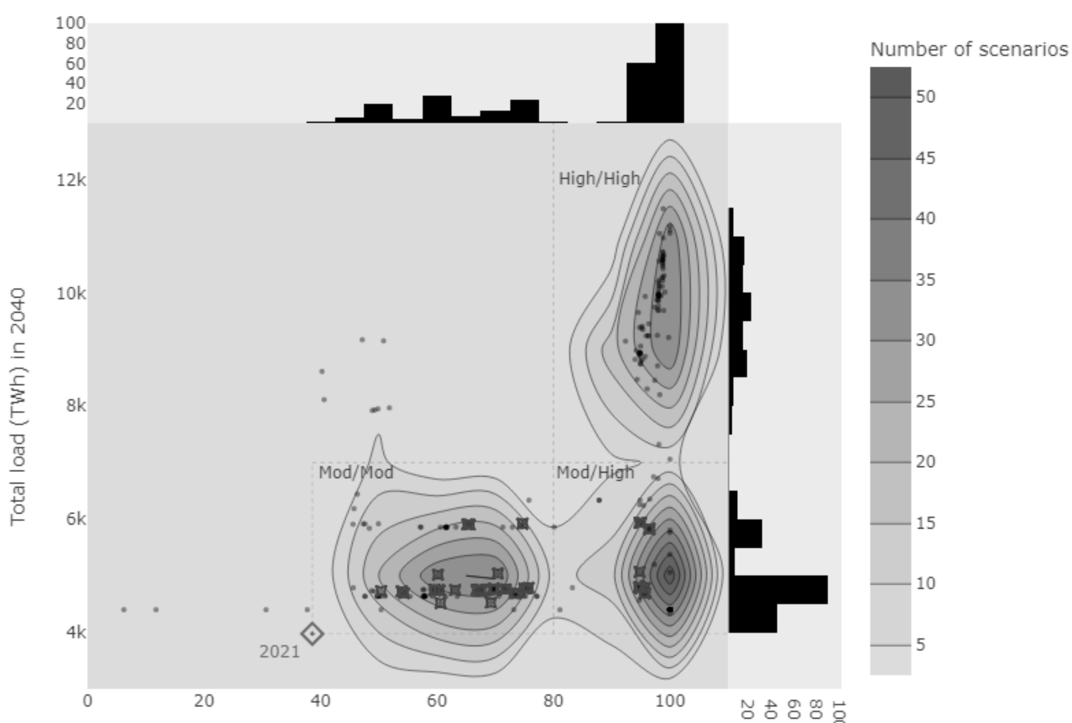
Energy storage resources enable a more efficient use of the grid. All studies except Larson, et al. (2021) co-optimized future capacity expansion of diurnal, stand-alone storage[52] among their respective suites of generation resources. The location of any new storage facilities chosen by the models 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).

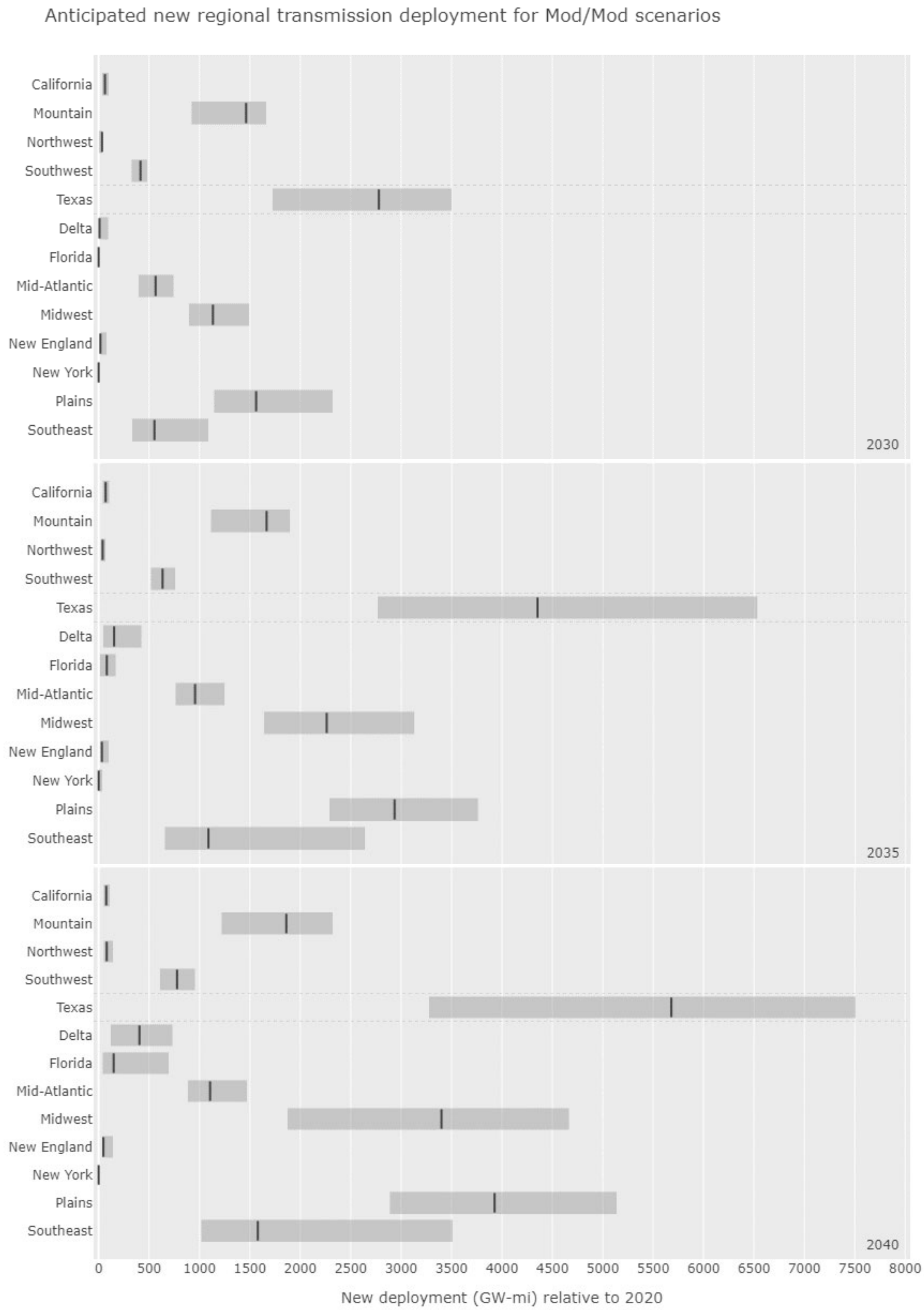
Figure VI-3 shows the transmission results for the Moderate/Moderate scenario group, which defines a power system without the IIJA and IRA enacted. Studies consistently find that the largest transmission expansion will take place in Texas to meet future power sector changes across all years. In 2035, 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.

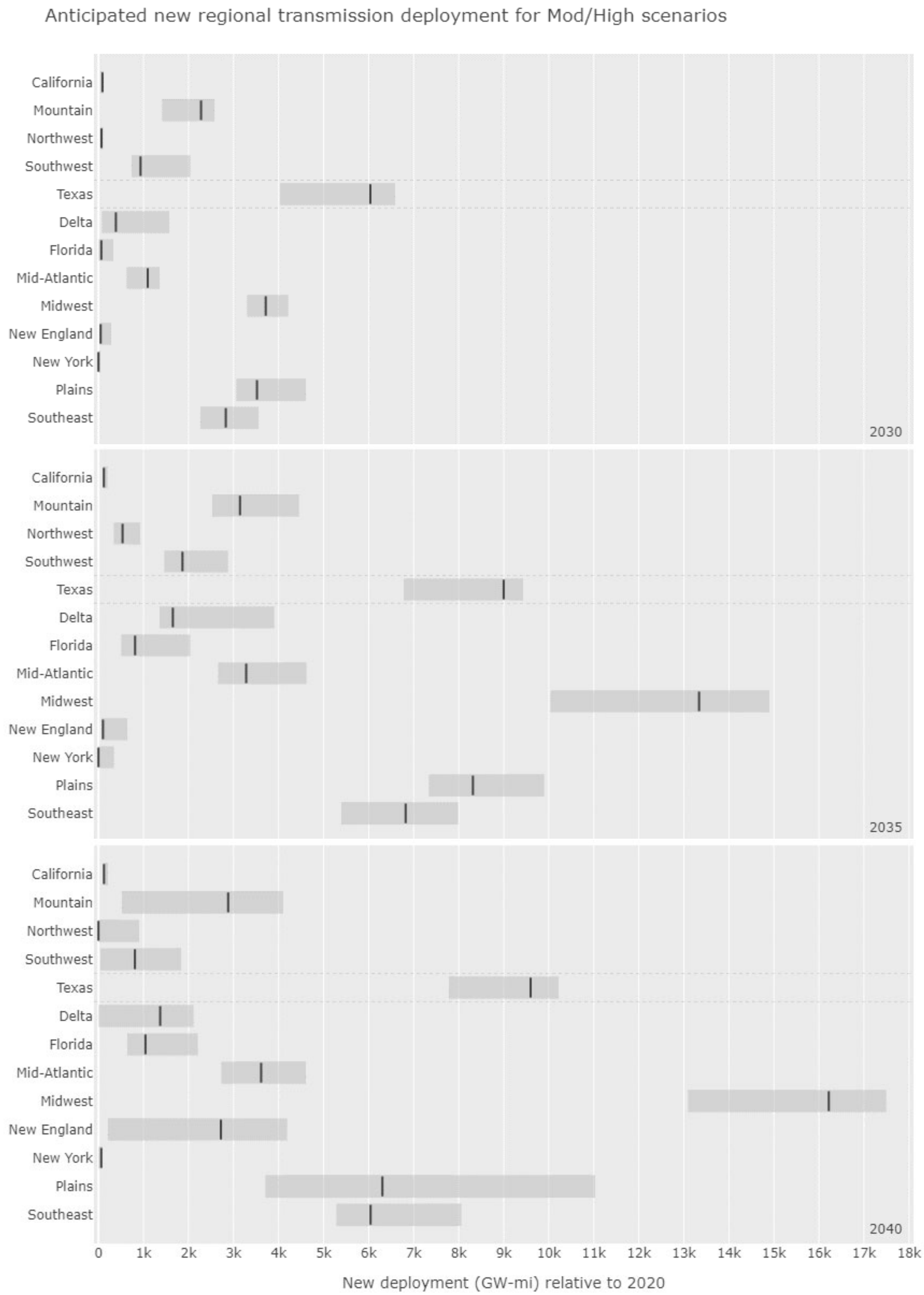
NERC collects data on 10-year projections of bulk power system as part of its annual Long-Term Reliability Assessment process (NERC 2021). These data include the near-term transmission development plans in each NERC assessment area. An initial comparison.[54] of these plans through 2030 against the Moderate/Moderate 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).



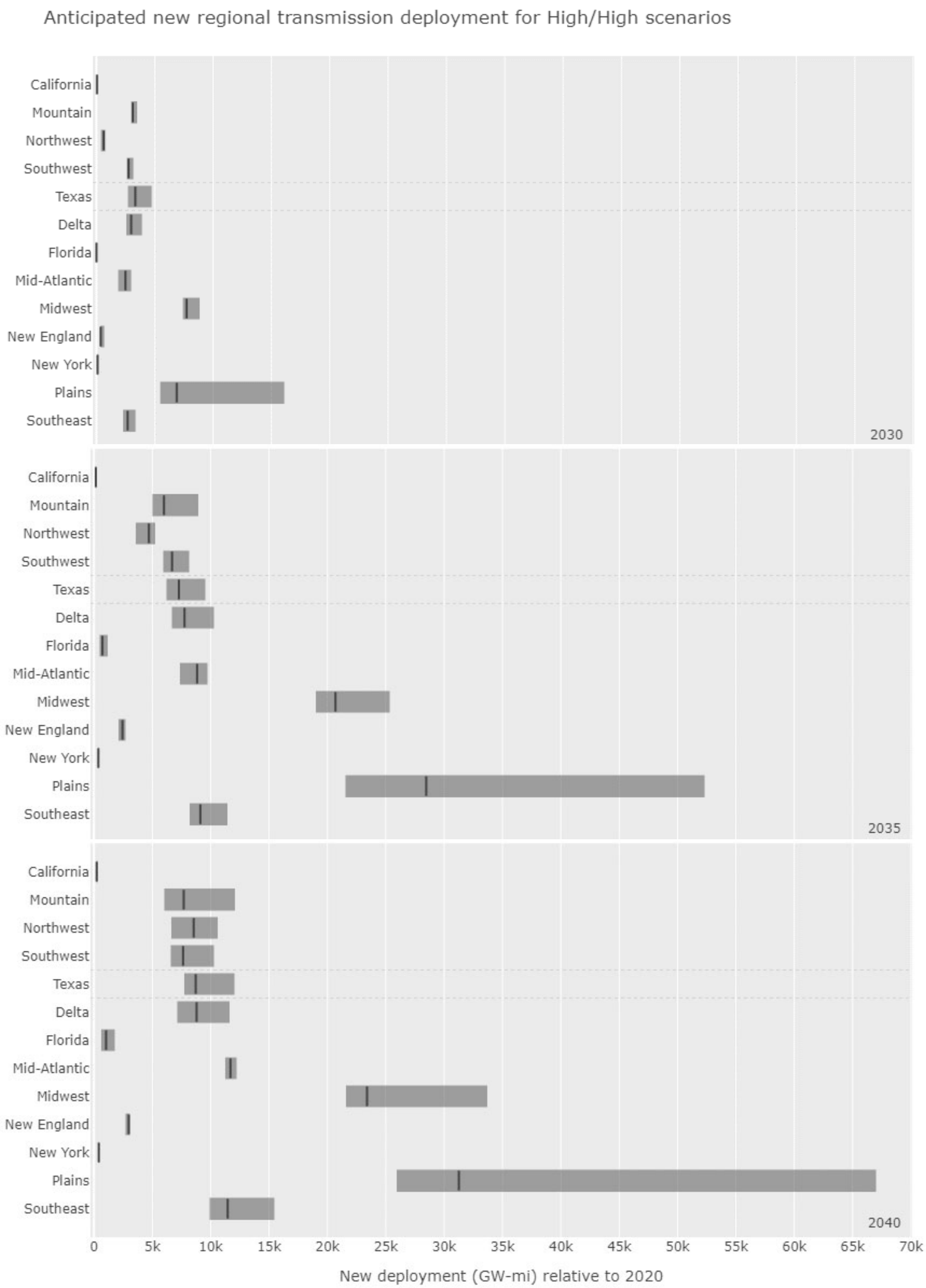
Note: New transmission relative to the 2020 system (from Denholm et al. 2022) of each study is shown for 2030 (top), 2035 (middle), and 2040 (bottom). Median and IQR for all scenarios in each region shown.

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



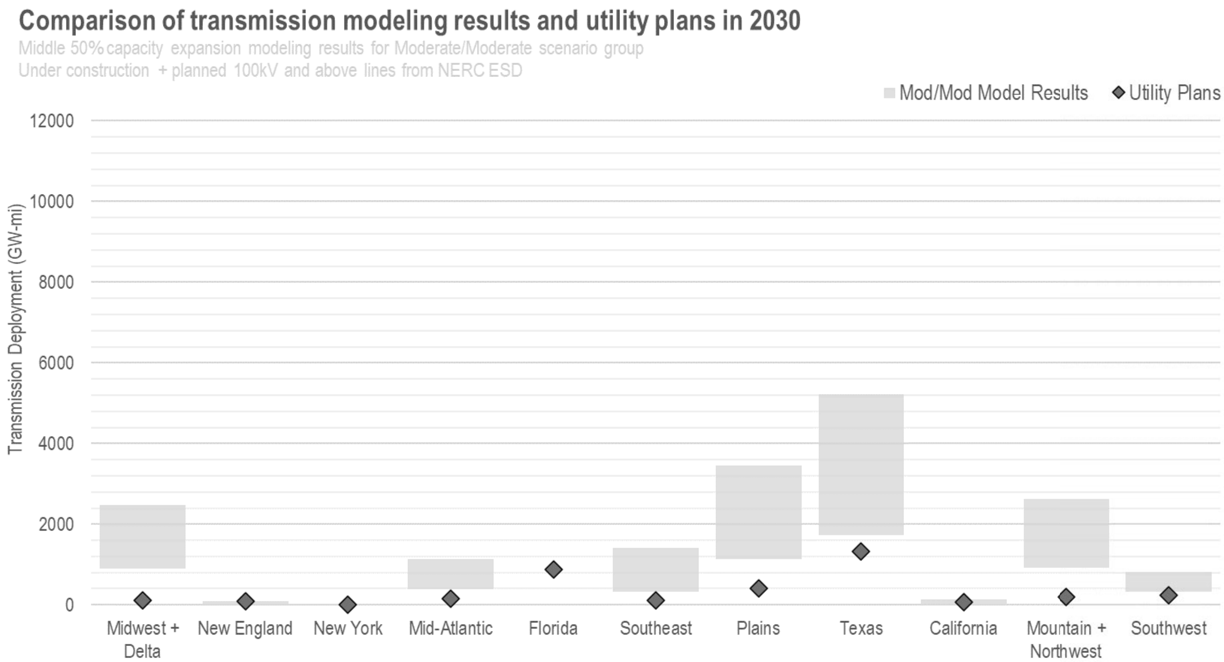
Note: New transmission relative to the 2020 system (from Denholm et al. 2022) of each study is shown for 2030 (top), 2035 (middle), and 2040 (bottom). Median and IQR for all scenarios in each region shown.

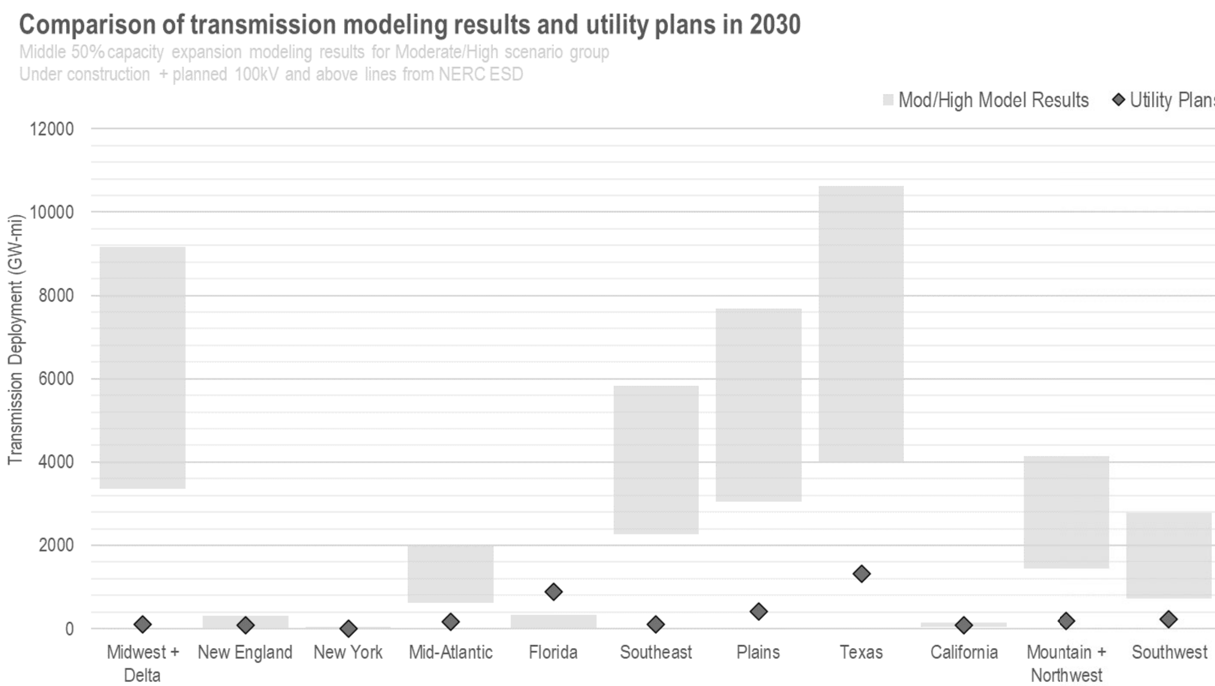
Figure VI-4. Regional transmission deployment for all scenarios in the Moderate/High scenario group.



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.

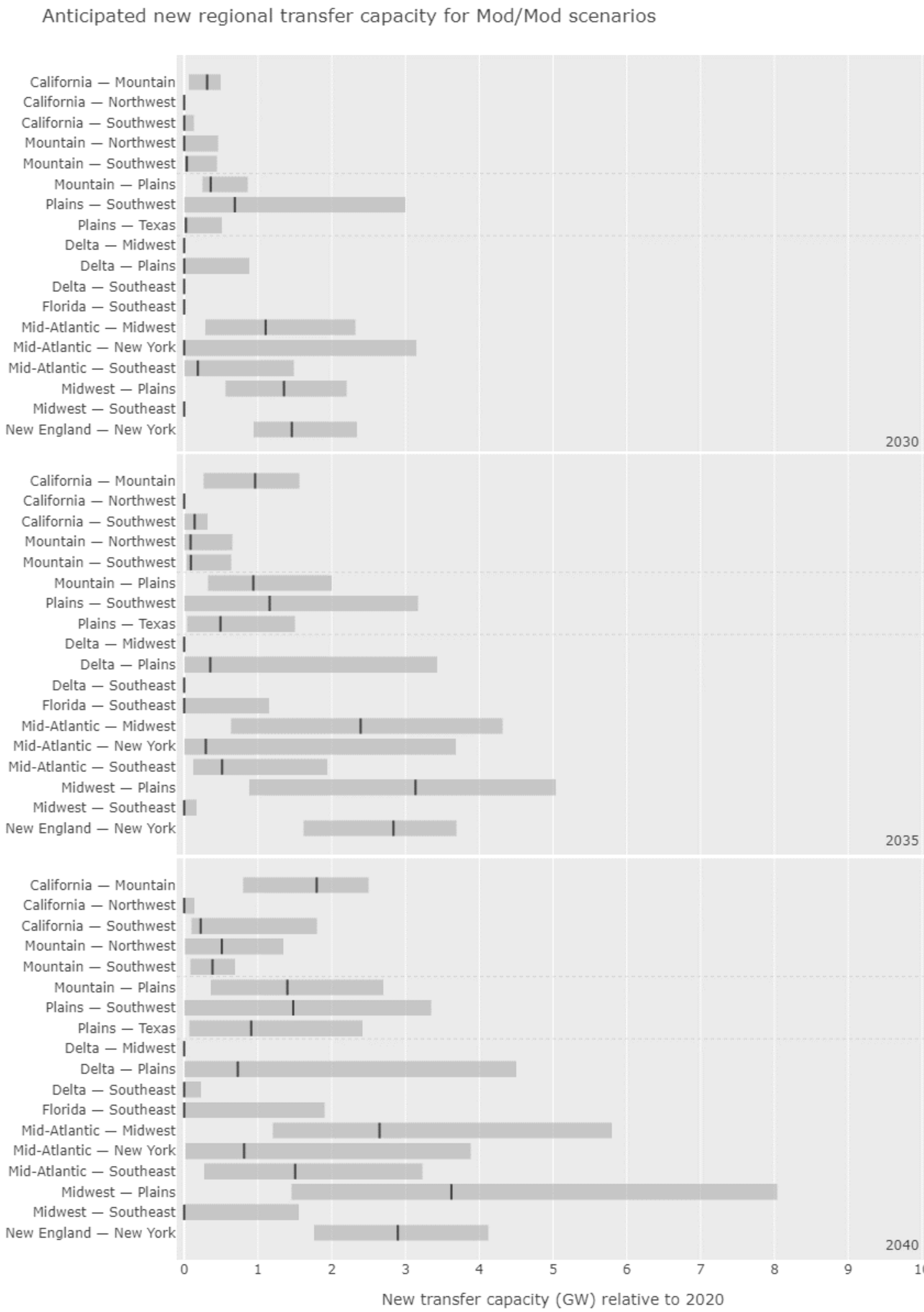
Figure VI-7 shows the regional transfers for the Moderate/Moderate scenarios in 2030, 2035, and 2040, which defines a power system without the IIJA and IRA enacted. These results are relatively low, indicating that local generation within a region can meet regional demand needs for modeled scenarios 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.

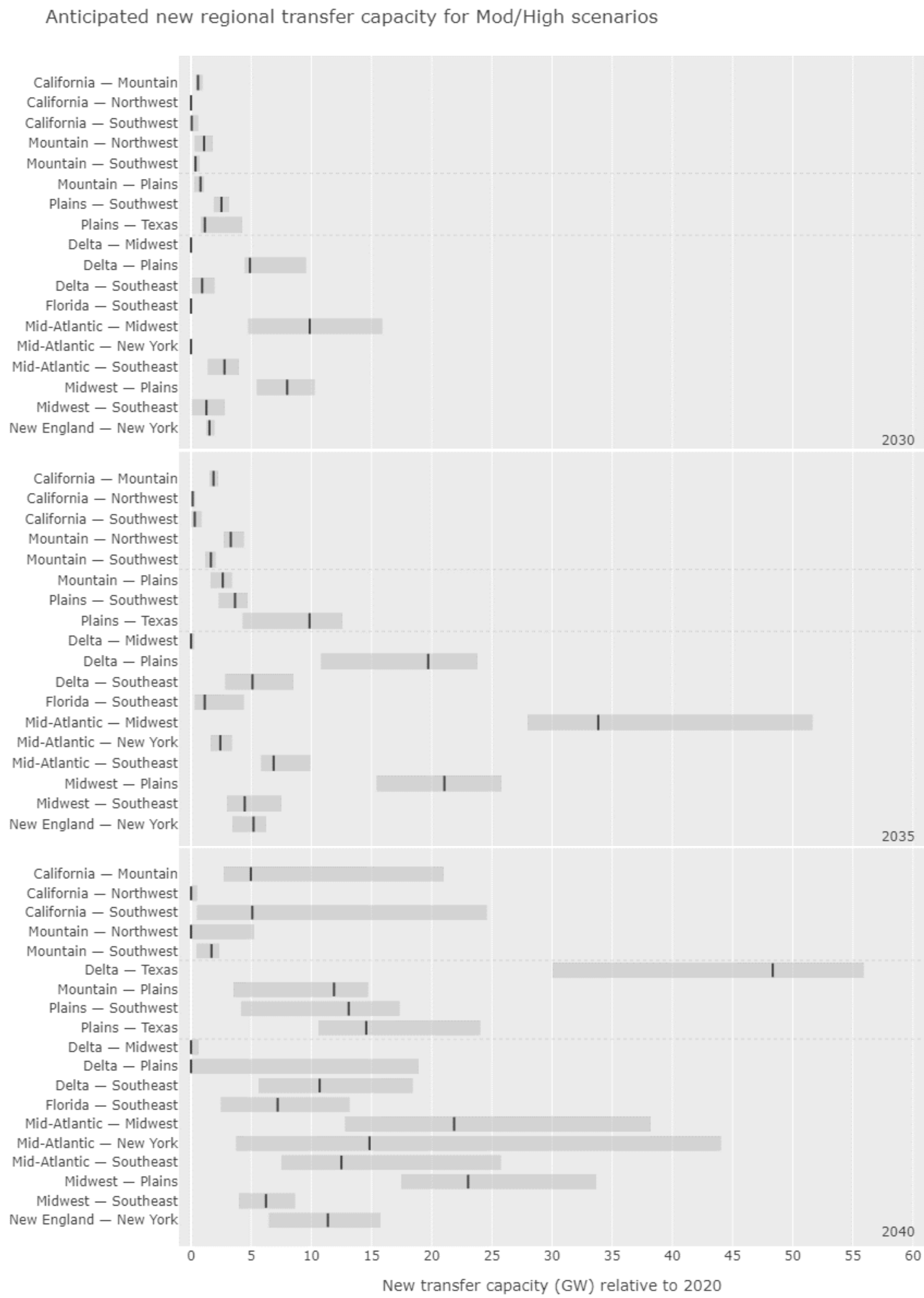
Figure VI-9 shows the regional transfers for the High/High scenarios in 2030, 2035, and 2040, which will not be realized without additional state and federal policies. Estimated transfer capacity between regions quadruples in the high load growth scenarios compared to the Moderate/High scenario group. 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.



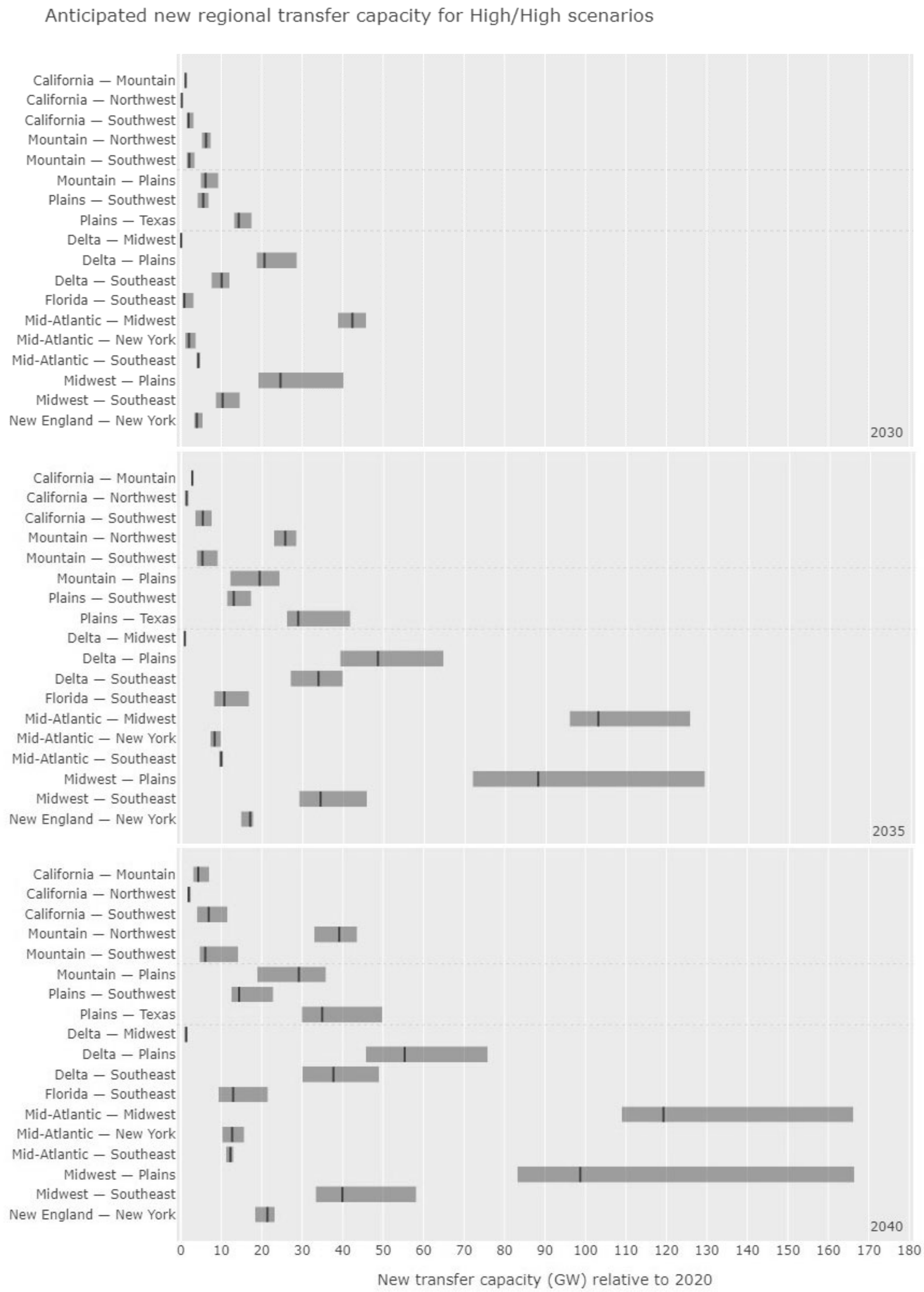
Note: New transmission relative to the 2020 system (from Denholm et al. 2022) of each study is shown for 2030 (top), 2035 (middle), and 2040 (bottom). Median and IQR for all scenarios in each region shown.

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.

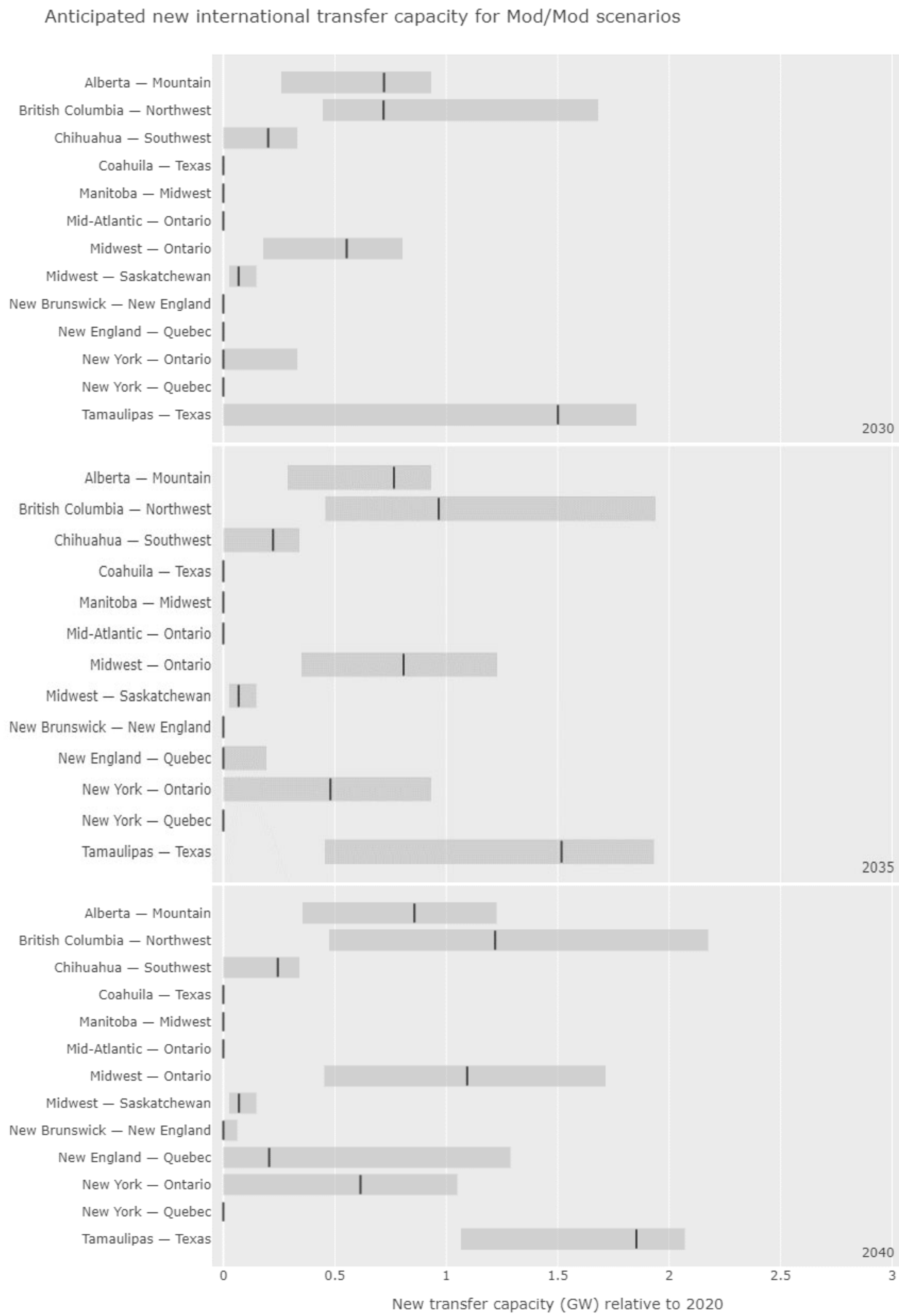
Appreciable international transfer capacities between Canada and New York and New England do not arise until 2040 in Brinkman et al. (2021). For comparison, an anticipated 1.8 to 4.1 GW of new transfer capacity (IQR) is modeled between New England and New York in 2040 in the analogous Moderate/Moderate 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 a more efficient transmission study process that ensure the Essential Reliability Services are included can help hasten connection of those resources to the grid.*	Modified sentence: "Many energy resources are currently within backlogged interconnection queues and a 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 need for the 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 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).”*	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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TRANSMISSION MAKES THE POWER SYSTEM RESILIENT TO EXTREME WEATHER

Grid Strategies LLC

ACORE
AMERICAN COUNCIL ON RENEWABLE ENERGY

PREPARED FOR ACORE, WITH SUPPORT FROM THE MACRO GRID INITIATIVE

AUTHOR
MICHAEL GOGGIN
Grid Strategies LLC

JULY 2021

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This February, millions of Americans experienced prolonged power outages when electricity demand exceeded supply as record cold gripped much of the Central U.S. Power outages are always life-threatening for those who rely on electric medical devices, but they can be dangerous for anyone during a period of extreme cold or heat. Tragically, it appears the February power outages contributed to hundreds of deaths in Texas alone.[1] Electricity is also increasingly the lifeblood of America's economy, and is essential for powering first responders and national security workers. The Congressional Research Service estimates that weather-related power outages cost Americans $25-70 billion annually.[2]

Investigations are underway to determine what caused February's outages. Regardless of which energy sources failed, strengthening transmission is an essential part of the solution for preventing future outages. Extreme weather events tend to be most severe in relatively small areas, so stronger transmission ties to neighboring regions can be a lifeline to keep homes warm and people safe. Transmission ties cancel out local fluctuations in the weather that affect electricity demand. This is primarily due to heating/cooling needs and supply, including changes in wind and solar output as well as failures of conventional power plants due to extreme weather.

Many severe weather events migrate from region to region, allowing one region to import during its time of need and then export to other regions once the storm moves on. Grid operators have confirmed that connecting large geographic areas via transmission saves billions of dollars per year by reducing the need for power plant capacity by reducing variability in electricity supply and demand.[3] A strongly integrated grid network also provides valuable resilience, so if some power lines or power plants are taken offline by any type of disaster, there are alternative sources of power available.

1 Peter Aldhous, Stephanie M. Lee, and Zahra Hirji, "The Texas Winter Storm and Power Outages Killed Hundreds More People Than the State Says," (May 26, 2021), available at: https://www.buzzfeednews.com/article/peteraldhous/texas-winter-storm-power-outage-death-toll.

2 Executive Office of the President, *Economic Benefits of Increasing Electric Grid Resilience to Weather Outages*, (August 2013), available at: https://www.energy.gov/sites/default/files/2013/08/f2/Grid%20Resiliency%20Report_FINAL.pdf.

3 For example, see PJM, "PJM Value Proposition," (2019) available at: https://www.pjm.com/about-pjm/-/media/about-pjm/pjm-value-proposition.ashx, MISO, "Value Proposition," (n.d.), available at: https://www.misoenergy.org/about/miso-strategy-and-value-proposition/miso-value-proposition/.

EXECUTIVE SUMMARY

Severe weather events are becoming more common and more extreme, with severe events challenging nearly every part of the U.S. power grid in the last decade alone.[4] This analysis reviews five recent severe weather events to determine the value additional transmission would have provided.

February 2021 Winter Storm Uri — Each additional 1 GigaWatt (GW) of transmission ties between the Texas power grid (ERCOT) 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, other parts of the Central U.S. also could have avoided power outages while saving consumers hundreds of millions of dollars. In particular, consumers in the Great Plains, served by the Southwest Power Pool (SPP), and those in the Gulf Coast states, served by the southern part of the Midcontinent Independent System Operator (MISO), **each could have saved in excess of $100 million** with an additional 1 GW of transmission ties to power systems to the east.

Texas heat wave in August 2019 — An extended heat wave in Texas led to high power prices across 12 days in August 2019. 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.

The "Bomb Cyclone" cold snap across the Northeast in December 2017-January 2018 — New England, New York, and the Mid-Atlantic region suffered cold weather for nearly three weeks, causing natural gas price spikes and nearly exhausting fuel oil supplies in New England. **Each of these regions could have saved $30-40 million** for each GW of stronger transmission ties among themselves or to other regions. 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.

4 See, e.g. NOAA National Centers for Environmental Information, "Billion-Dollar Weather and Climate Disasters: Overview," (2021), available at: https://www.ncdc.noaa.gov/billions/.

The January 2014 “polar vortex” event in the Northeast — New England, New York, and the Mid-Atlantic region suffered several days of extreme cold in early January 2014. The grid operator for the Mid-Atlantic region, PJM, resorted to voltage reductions to avoid the need for rolling outages. **Greater transmission ties within and among these regions could have saved consumers tens of millions of dollars and prevented reliability concerns.** Like the 2017/2018 Bomb Cyclone event, regions switched between importing and exporting as the most extreme cold migrated from region to region.

The “polar vortex” event in the Midwest in 2019 — While an additional 1 GW of transmission between MISO and PJM would have only saved a few million dollars during this short-lived cold snap, this event was notable for illustrating how transmission expansion benefits both interconnected regions. As the extreme cold moved eastward from MISO to PJM, so did the high power prices, and transmission flows switched from westward to eastward.

These results for these five events are summarized in the table below. For reference, long-distance transmission costs around $700 million per GW of transfer capacity, based on the average cost for the 18 above-ground shovel-ready projects identified in a recent report, though costs vary considerably based on the length of the line and other factors.[5] In the case of the February 2021 Texas outages, the value of power delivered to Texas could have fully covered the cost of new transmission to the Southeast, while for other lines and severe weather events the value could have defrayed a significant share of the cost of building transmission.

TABLE 1. *Value of 1 GW of additional transmission by region for each event*

Receiving region – delivering region	Savings per GW of additional transmission capacity (millions of $)
WINTER STORM URI, FEBRUARY 2021	
ERCOT – TVA	$993
SPP South – PJM	$129
SPP South – MISO IL	$122
SPP South – TVA	$120
SPP S – MISO S (Entergy Texas)	$110
MISO S-N (Entergy Texas - IL)	$85
MISO S (Entergy Texas) – TVA	$82
TEXAS HEAT WAVE, AUGUST 2019	
ERCOT – TVA	$75
NORTHEAST BOMB CYCLONE, DECEMBER 2017 – JANUARY 2018	
Eastern PJM (VA) – Western PJM (Northern IL)	$43
NYISO – PJM	$41
PJM – MISO	$38
NYISO – ISONE	$29
NORTHEAST POLAR VORTEX EVENT, JANUARY 2014	
PJM – MISO	$17
NYISO – PJM	$9
NYISO – MISO	$21
MIDWEST POLAR VORTEX EVENT, JANUARY 2019	
MISO – PJM	$2

For each event, the savings across the multiple potential new lines are not always additive, with the total savings tending to be somewhat lower than the sum of all lines' savings. This is because building the first line into a region will alleviate some of the congestion, reducing the value of additional lines into that region.

5 Michael Goggin, Rob Gramlich, and Michael Skelly, *Transmission Projects Ready to Go: Plugging Into America's Untapped Renewable Resources*, (April 2021), available at: https://cleanenergygrid.org/wp-content/uploads/2019/04/Transmission-Projects-Ready-to-Go-Final.pdf.

Across these events, transmission congestion tends to recur at certain notable points on the grid, confirming the need for expanded transmission in those areas. Expanding transmission between ERCOT and the Southeast, from SPP and MISO to power systems to the east like PJM and the Southeast, between western and eastern PJM, and among eastern PJM, New York, and New England appears to be particularly valuable for protecting against the impact of severe weather.

These events demonstrate that all generation sources are vulnerable to severe weather, making increased transmission to broaden the pool of available resources one of the best options for increasing resilience. ERCOT[6] and SPP[7] data for the February 2021 event show that coal, gas, diesel, wind, solar, nuclear, and hydropower plants were all taken offline by the record cold and ice; however, gas generators accounted for the majority of outages, with the cold causing generator equipment failures as well as fuel interruptions due to overwhelmed pipeline capacity and frozen gas wells.

Despite the large savings identified above, transmission's value for making the grid more resilient against severe weather and other unexpected threats is not typically accounted for in transmission planning and cost allocation analyses. Grid operator transmission planning processes typically assume normal electricity supply and demand patterns, and in most cases do not account for the value of transmission for increasing resilience. Transmission's hedging or insurance value from protecting consumers against the economic and reliability impacts of these rare events is also not typically accounted for.

As a result, pro-transmission policies need to be enacted to account for the resilience benefits of transmission. Just as President Eisenhower created the interstate highway system to protect national security and facilitate interregional trade, there is a clear national interest in ensuring that the backbone of the 21st century economy — the power grid — is strong and secure.

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6 ERCOT, "Hourly Resource Outage Capacity," (2021), available at: http://mis.ercot.com/misapp/GetReports.do?reportTypeId=13103&reportTitle=Hourly%20Resource%20Outage%20Capacity&showHTMLView=&mimicKey.

7 SPP, "Capacity of Generation on Outage," (2021), available at: https://marketplace.spp.org/pages/capacity-of-generation-on-outage#%2F2021%2F02.

Federal legislation and action by the Federal Energy Regulatory Commission (FERC) can enable the needed investment. A tax credit for building high-voltage transmission lines is now under consideration in Congress. FERC can require greater regional and interregional coordination in how transmission is planned and paid for, and could require minimum levels of interregional transmission to ensure grid reliability. Congress could also pass legislation directing FERC to make those changes.

A stronger grid will be valuable every day, not just during extreme weather events. Many of the new transmission lines that would have been highly valuable during these severe weather events are the same ones needed to deliver the Midwest's low-cost wind resources to electricity demand centers to the east. Power can flow in both directions on transmission, so both ends of the line benefit. Most of the time these lines will export wind generation from the Midwest, but during an emergency power can flow back into the Midwest.

Many recent studies show that interregional transmission lines like those discussed in this paper become increasingly essential as wind and solar penetrations increase in different parts of the country. Just as these lines aggregate diverse sources of electricity supply and demand to balance out localized disruptions during extreme weather, they provide a similar value by canceling out local fluctuations in wind or solar output.[8]

There have also been other extreme temperature and severe weather events in other regions over the last decade in which stronger transmission ties would have been similarly valuable.[9] However, those events occurred in regions without centralized power markets or in regions that were not adjacent to those with centralized power markets, making it more difficult to quantify the value of transmission due to the lack of transparent market price information. It is likely that these regions could have seen benefits from transmission expansion that are comparable to those quantified in this report.[10] The following section discusses in more detail the value additional transmission could have provided during the five recent severe weather events.

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8 For example, *see* Patrick Brown and Audun Botterud, "The Value of Interregional Coordination and Transmission in Decarbonizing the US Electricity System," (January 20, 2021), Joule, Volume 5, Issue 1, at 115-134, available at: https://www.sciencedirect.com/science/article/abs/pii/S2542435120305572?dgcid=author; Eric Larson et al., *Net-Zero America: Potential Pathways, Infrastructure, and Impacts*, (December 15, 2020), available at: https://environmenthalfcentury.princeton.edu/sites/g/files/torugf331/files/2020-12/Princeton_NZA_Interim_Report_15_Dec_2020_FINAL.pdf; Aaron Bloom et al., *The Value of Increased HVDC Capacity Between Eastern and Western U.S. Grids: The Interconnections Seam Study*, (October 2020), available at: https://www.nrel.gov/docs/fy21osti/76850.pdf; NREL, Renewable Electricity Futures Study," (2012), available at: https://www.nrel.gov/docs/fy13osti/52409-ES.pdf; Christopher Clack, Michael Goggin, Aditya Choukulkar, Brianna Cote, and Sarah McKee, *Consumer, Employment, and Environmental Benefits of Electricity Transmission Expansion in the Eastern U.S.*, (October 2020), available at: https://cleanenergygrid.org/wp-content/uploads/2020/10/Consumer-Employment-and-Environmental-Benefits-of-Transmission-Expansion-in-the-Eastern-U.S..pdf.

9 For example, many parts of the Western U.S. have experienced record heat or cold, or natural gas supply interruptions like the Aliso Canyon leak and British Columbia pipeline explosion, that resulted in power outages or extreme price spikes. See, e.g. outages and price spikes in the Southwest following extreme cold and gas supply interruptions, FERC and NERC Staff, *Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011: Causes and Recommendations*, (August 2011), available at: https://www.ferc.gov/sites/default/files/2020-04/08-16-11-report.pdf. Similarly, many utilities in the Southeast have been challenged by unusual cold snaps or extreme heat and drought. See, e.g. FERC and NERC Staff, *The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018*, (July 2019), available at: https://www.nerc.com/pa/rrm/ea/Documents/South_Central_Cold_Weather_Event_FERC-NERC-Report_20190718.pdf.

10 For example, in August 2020 California experienced power outages and high prices when a high level of generator outages coincided with record-breaking heat across many parts of the Western U.S. While this event was highly unusual in that the extreme heat affected much of the West at the same time, additional transmission capacity to other regions still could have helped alleviate the outages and price spikes. The California grid operator has calculated that congestion on transmission ties with other regions, mostly the Pacific Northwest, added around $45 million in consumer costs, while transmission congestion within California imposed an additional $37 million in costs.

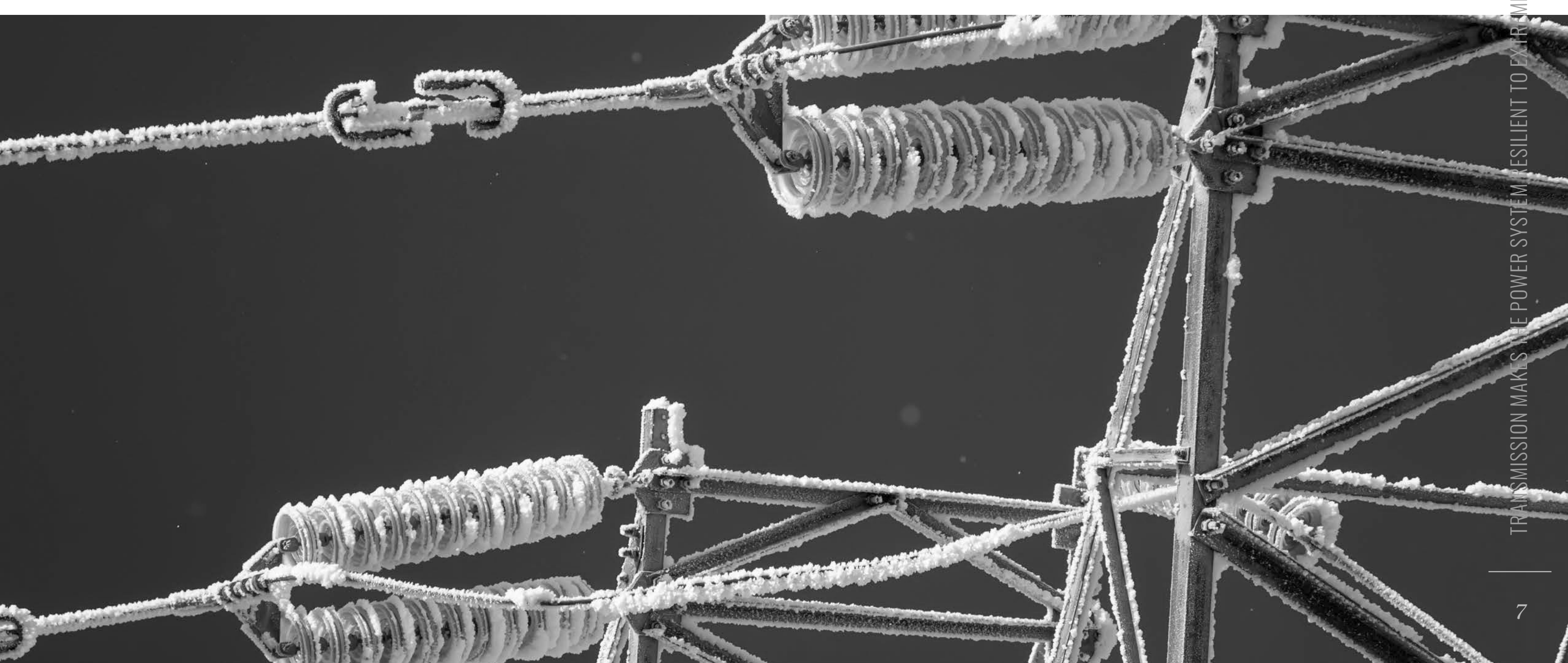
RESULTS: VALUE OF TRANSMISSION DURING RECENT SEVERE WEATHER EVENTS

These events demonstrate that all generation sources are vulnerable to severe weather, making increased transmission to broaden the pool of available resources one of the best options for increasing resilience. Almost all severe weather events are at their most extreme in a relatively narrow geographic area, so transmission allows surplus electricity supplies to be delivered from neighboring regions that are not experiencing extreme electricity demand or loss of generating supply.

Winter Storm Uri in February 2021

The value of transmission for resilience can be seen in the drastically different outcomes of MISO and SPP relative to ERCOT during the February 2021 cold snap event. SPP and MISO were able to weather the storm with much less severe power outages thanks to stronger transmission ties to neighboring regions that allowed them to import more than 15 times as much power as ERCOT.

While SPP and MISO also experienced extreme cold, they were able to avoid major power shortfalls by importing electricity from regions experiencing milder temperatures, mostly to the east. As shown in the bottom half of the Department of Energy chart below, at maximum MISO was importing nearly 9,000 megawatts (MW) from PJM, several thousand MW from the Tennessee Valley Authority (TVA), and around an additional 1,000 MW each from Southern Company, Louisville Gas and Electric, and Canada.[11] Total MISO imports were consistently over 13,000 MW during the most challenging period from midday February 15 to midday February 16.



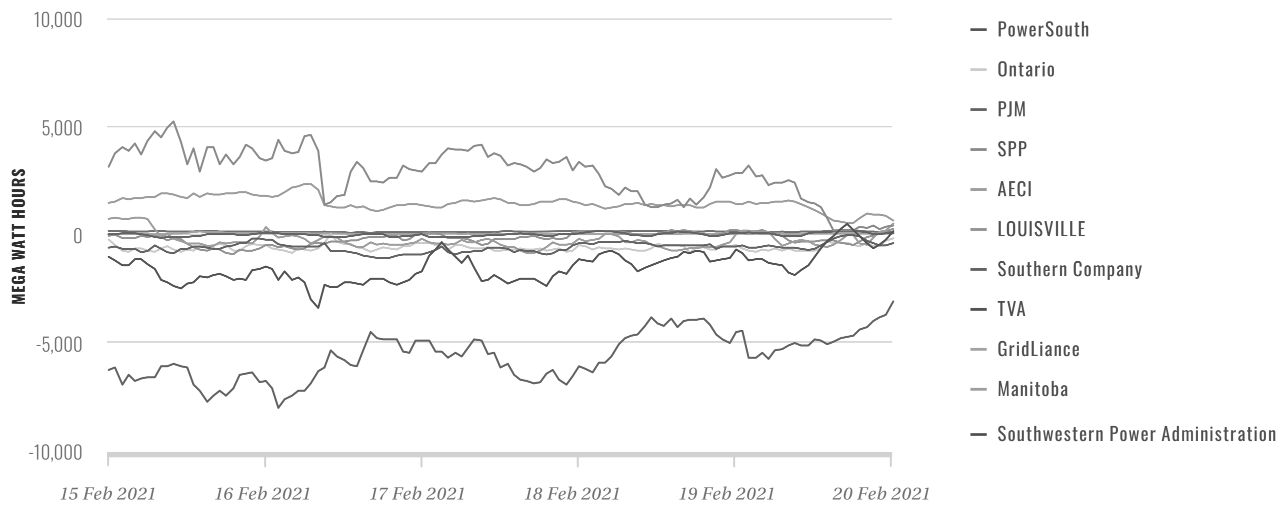


FIGURE 1. *Midcontinent Independent System Operator, Inc. (MISO) electricity interchange with neighboring balancing authorities 2/15/2021-2/19/2021, Eastern Time*

In turn, MISO was exporting to power systems to its west, delivering over 5,000 MW to SPP and nearly 2,500 MW to the Associated Electric Cooperative Incorporated, as shown in the top part of the chart. Thus around half the power MISO was importing was effectively flowing through MISO to reach power systems farther to the west.

In contrast to the 13,000 MW MISO was importing during the peak of last month's event, ERCOT was only able to import about 800 MW of power throughout the event, as shown below. ERCOT was initially able to import nearly 400 MW from Mexico, though those imports were cut early on February 15 when Mexico also experienced generator outages due to a loss of gas supply. Imports from SPP were also briefly cut at various points as SPP experienced its own shortages, particularly on February 16.

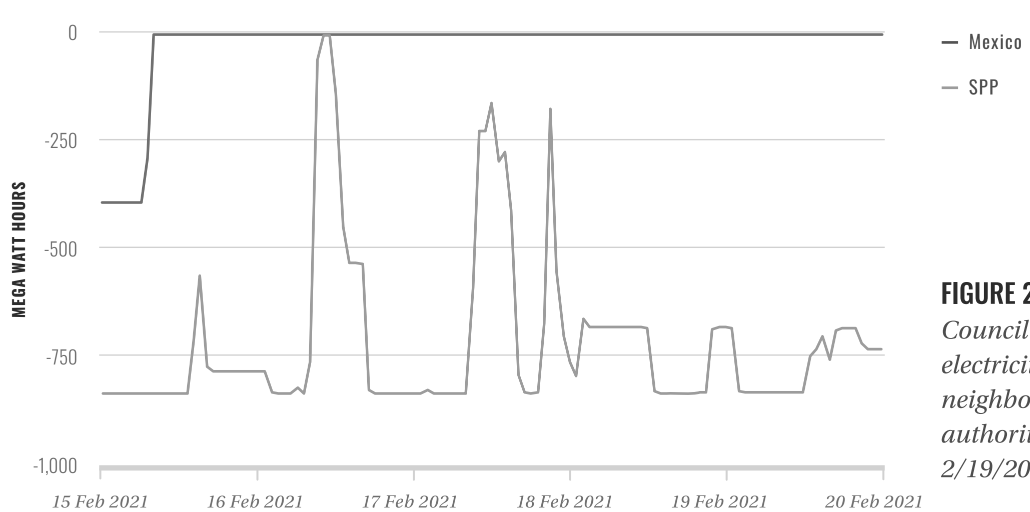


FIGURE 2. *Electric Reliability Council of Texas, Inc. (ERCOT) electricity interchange with neighboring balancing authorities 2/15/2021-2/19/2021, Eastern Time*

MISO and SPP also could have benefited from stronger transmission ties to neighboring regions, as well as stronger ties between northern and southern MISO. Power prices in SPP and southern MISO spiked during the event, reaching or exceeding the $1,000/MWh price cap in those markets as prices for natural gas spiked.[12] The need for more transmission capacity was also reflected in the strong west-to-east price gradient across MISO and PJM shown below, with prices in the hundreds of dollars per MWh in MISO versus around $50/MWh in eastern PJM on the morning of February 15.

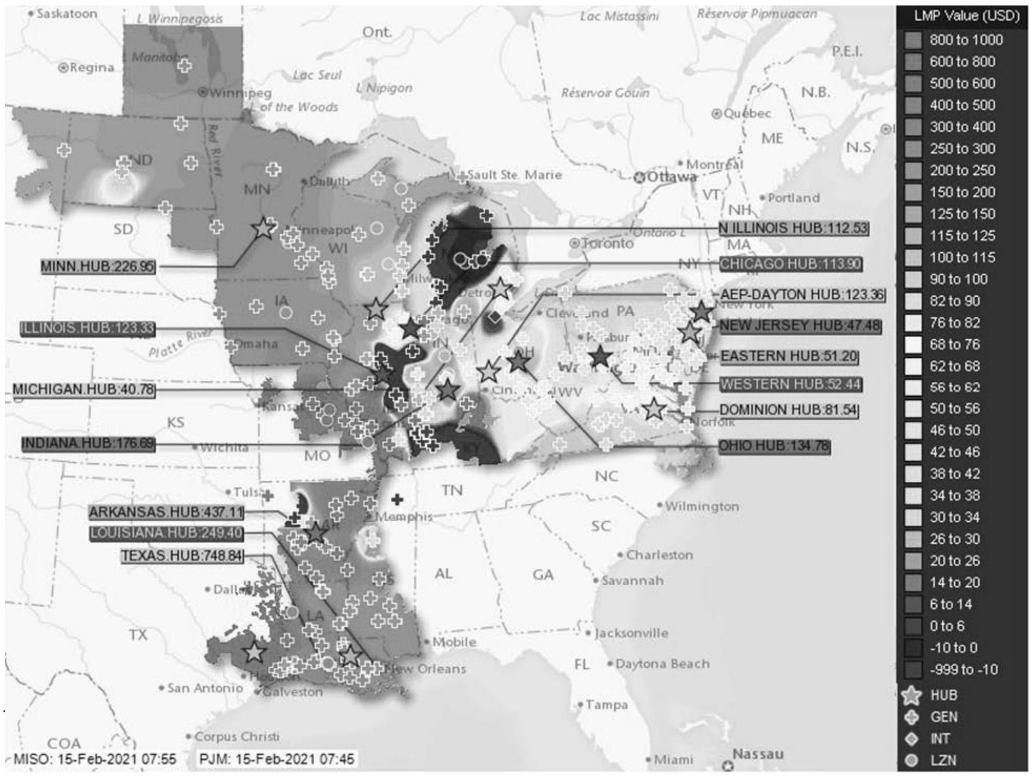


FIGURE 3. *Snapshot of power prices on the morning of February 15, 2021*

Transmission congestion costs at the seams between PJM, MISO, and SPP routinely approached $2,000/MWh throughout the event, reflecting the need for more transmission.[14] In many cases those costs flow to consumers who are forced to buy more expensive power because there was insufficient transmission capacity to deliver lower-cost imports. As is often the case, a large amount of transmission congestion at the MISO-PJM seam in Illinois and Indiana prevented more power from reaching SPP and MISO. Grid-enhancing technologies that allow more power to be transferred across transmission lines likely would have reduced the outages and price spikes in MISO and SPP.[15] Long-standing operational issues at the seams between the markets may have also contributed to the congestion and caused the localized pockets of very low

12 SPP, "Order 831 Verification Frequently Asked Questions," (April 1, 2021), available at: https://www.spp.org/documents/64402/spp%20mmu%20order%20831%20verifcation%20faq%20v4.pdf.

13 Screenshot taken February 15, 2021, from Joint and Common Market Contour Map, available at https://www.miso-pjm.com/markets/contour-map

14 MISO, "SRW Hourly Market-to-Market Settlements," (2021), available at: https://docs.misoenergy.org/marketreports/M2M_Settlement_srw_2021.csv.

15 T. Bruce Tsuchida, Stephanie Ross, and Adam Bigelow, *Unlocking the Queue With Grid-Enhancing Technologies,"* (February 1, 2021), available at: https://watt-transmission.org/wp-content/uploads/2021/02/Brattle__Unlocking-the-Queue-with-Grid-Enhancing-Technologies__Final-Report_Public-Version.pdf90.pdf.

prices along the seam shown in the map above.[16]

Throughout the event, transmission constraints within MISO were also limiting the transfer of power from areas with more abundant power to areas with higher prices. The quantity and price impact of binding transmission constraints within MISO were at least an order of magnitude higher than a typical winter day.[17] Price differences between northern MISO and southern MISO were also extreme throughout the event, routinely hitting $500/MWh.[18]

The following chart shows our analysis of the extreme price differences among these neighboring grid areas during Winter Storm Uri, illustrating the value of expanding transmission ties among these regions. Power prices in PJM, TVA, and MISO Illinois remained relatively low throughout the event, while prices in ERCOT were consistently high. Interestingly, power prices in SPP South and MISO South were minimally or even negatively correlated throughout much of the event, indicating that increased transmission capacity could have significantly benefited both regions. About two-thirds of our calculated $110 million in savings per GW of increased transmission between those regions would have accrued to SPP ($72 million), while one-third would have accrued to MISO ($38 million). As discussed below, it is common for transmission to benefit both ends of the transmission line over the course of many severe weather events, as the area of the most severe weather often migrates over time.

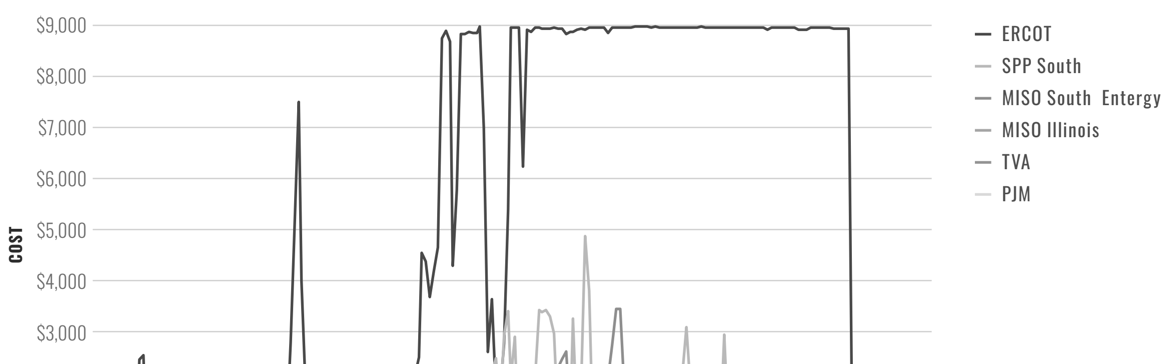


FIGURE 4. *Power prices by region during Winter Storm Uri*

16 David Patton and Mike Wander, “Identification of Seams Issues for OMS/SPP RSC,” (March 19, 2021), available at: https://www.spp.org/documents/59674/oms_rsc_seamsissuesmemo.pdf.

17 MISO, “Real-Time Binding Constraints,” (2021), available at: https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3AReal-Time%2FMarketReportName%3AReal-Time%20Binding%20Constraints%20(xls)&t=10&p=0&s=MarketReportPublished&sd=desc.

18 MISO, “Real-Time Binding Sub-Regional Power Balance Constraints,” (2021), available at: https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3AReal-Time%2FMarketReportName%3AReal-Time%20Binding%20Sub-Regional%20Power%20Balance%20Constraints%20(csv)&t=10&p=0&s=MarketReportPublished&sd=desc.

Additional Transmission Could Have Alleviated Price Spikes and Kept the Heat on During Uri

More transmission capacity from ERCOT, MISO, and SPP to power systems to the east, such as PJM and TVA, and between northern MISO and southern MISO, and could have greatly alleviated these price spikes. Using the methodology described in the Appendix, our analysis finds large consumer savings for each potential 1 GW addition of transmission capacity, with savings approaching $1 billion for 1 GW of additional ties between ERCOT and the Southeast, and over $100 million for most of the other lines.

TABLE 2. *Savings per additional GW of transmission, February 12-20, 2021*

Receiving region – delivering region	Savings per GW of additional transmission capacity (millions of $)
ERCOT – TVA	$993
SPP South – PJM	$129
SPP South – MISO IL	$122
SPP South – TVA	$120
SPP S – MISO S (Entergy Texas)	$110
MISO S-N (Entergy Texas - IL)	$85
MISO S (Entergy Texas) – TVA	$82

Because ERCOT, MISO, and SPP were all forced to resort to rolling power outages during this event, the value of transmission is not only measured in dollars. A stronger transmission network could have kept the heat and power on for millions of homes and businesses, avoiding devastating loss of life and property. ERCOT says that one MW powers 200 homes during times of peak usage, so each additional 1 GW of transmission could have kept the lights on for around 200,000 Texas homes. The total electricity shortfall in ERCOT was around 10-20 GW during February's event, so multiple high-capacity transmission lines could have greatly alleviated the pain inflicted by the outages. Because many of the gas generator failures in ERCOT were due to interdependencies between the electric system and the gas supply system, like the use of electricity to power pipeline compressors and wellhead equipment, it is possible that several high-capacity transmission lines could have entirely prevented the power outages. Transmission also helps to protect national security. During Winter Storm Uri, several military bases were forced to close due to a loss of power, or the loss of water service when water utilities lost power.[19]

Transmission projects have been proposed for many of the interregional paths identified in the table above. Pattern Energy has proposed the 2 GW Southern Cross transmission line between ERCOT and Southeastern power systems like TVA. FERC and Texas regulators have determined that this line would not interfere with ERCOT's independence from FERC regulation, so those

19 Rose L. Thayer, "Winter Weather Causes More Than a Dozen Military Bases to Close," (February 16, 2021), available at: https://www.stripes.com/news/us/winter-weather-causes-more-than-a-dozen-military-bases-to-close-1.662417.

concerns should not prevent the construction of this or other transmission between ERCOT and FERC-regulated power markets.[20] Our analysis showing nearly $1 billion in savings per GW of transmission indicates that, had Southern Cross been in service during Winter Storm Uri, it could have provided nearly $2 billion in value by delivering 2 GW from the Southeast to ERCOT for the duration of the event. This value greatly exceeds the $1.4 billion estimate cost for the transmission project in this single event, without even considering the additional billions of dollars in benefits it would provide over the many decades of the project's life.[21]

Other proposed lines would have benefited SPP and MISO. Grain Belt Express, originally developed by Clean Line and now owned by Invenergy, is proposed to run between SPP South and PJM. The Clean Line Plains and Eastern line, the Oklahoma portion of which is now owned by NextEra Energy, would have connected SPP South with the Southeast. MISO's transmission planning processes routinely examine stronger transmission ties between northern and southern MISO, and studies have shown significant value for transmission between SPP, MISO, and PJM. Unfortunately none of those lines have been built, primarily due to disagreements over who should pay for the transmission.

Those two lines could have provided hundreds of millions of dollars in benefits during Winter Storm Uri alone. While that is not enough to cover the full cost of those transmission lines, it adds to the savings they provide during normal operations. Across the half century or longer life of a typical transmission line, it is almost certain that the line will provide critical supplies of power during at least one severe weather event — particularly with the frequency and magnitude of severe weather increasing. Accounting for resilience benefits in transmission planning and cost allocation would significantly increase the calculated benefit-to-cost ratio of transmission, enabling more transmission projects to move forward.

The experience of MISO and SPP during February's Winter Storm Uri likely would have been even worse had they not made large internal investments in transmission over the last decade.

During a recent MISO Board meeting, MISO President Clair Moeller stated that the Multi-Value Project transmission lines that his organization has built over the last decade, at a cost of around $6.5 billion,[22] provided around $18 billion in benefits across three days of Winter Storm Uri.[23]

20 Pattern Energy, "Pattern's Southern Cross Transmission Project Receives Key FERC Approvals," (December 19, 2011), available at: https://www.prnewswire.com/news-releases/patterns-southern-cross-transmission-project-receives-key-ferc-approvals-135852828.html.

21 *Southern Cross Transmission LLC*, Direct Testimony of David Parquet on Behalf of Southern Cross Transmission LLC, (2017), Attachment A, 2017-UA-79, at 7, available at: https://www.psc.state.ms.us/InSiteConnect/InSiteView.aspx?model=INSITE_CONNECT&queue=CTS_ARCHIVEQ&docid=385777.

22 MISO, "Regionally Cost Allocated Project Reporting Analysis: 2011 MVP Portfolio Analysis Report," (January 2021), available at: https://cdn.misoenergy.org/MVP%20Dashboard%20Q4%202020117055.pdf.

23 This calculation is different from that presented in this paper, as it is based on the cost of the more extensive power outages that would have happened without recent transmission investments, at an assumed cost of around $20,000/MWh of unserved energy. In contrast, our analysis evaluates reductions in power prices with potential additional transmission.

Other severe weather events have also challenged the South Central region, though none was as severe as Winter Storm Uri. On February 2, 2011, ERCOT experienced rolling outages when cold weather similarly caused power plant outages and natural gas supply shortages. Millions of Texans experienced rolling outages that morning, and power prices hit the then-price cap of $3,000/MWh.[24] An extended heat wave in summer 2011 also challenged the power grid in ERCOT, causing high prices but no widespread outages. During another cold snap on January 6, 2014, ERCOT prices spiked to $5,000/MWh, and prices have gone even higher during other extreme temperature and severe weather events.

During other severe weather events, ERCOT could have delivered needed power to neighboring regions, reversing the flows that were seen in February 2021. MISO South, SPP South, and parts of the Southeast experienced extreme cold on January 17, 2018, causing over 14,000 MW of unexpected generation outages and bringing utilities to the brink of implementing rolling outages.[25] Stronger east-west transmission ties to ERCOT and power systems to the east, and transmission to northern SPP and MISO, could have alleviated the resulting price spikes and prevented reliability concerns.

August 2019 ERCOT heat wave

An extended heat wave in Texas led to high power prices across 12 days in August 2019. An additional 1 GW transmission tie to the Southeast could have saved Texas consumers nearly $75 million, per our calculations using the methodology described in the Appendix. As shown below, power prices in TVA and MISO South remained consistently low across the 12 days, while prices in ERCOT spiked most afternoons. Additional transmission ties to those regions, or to SPP or the Western Interconnect, could have prevented those price spikes.

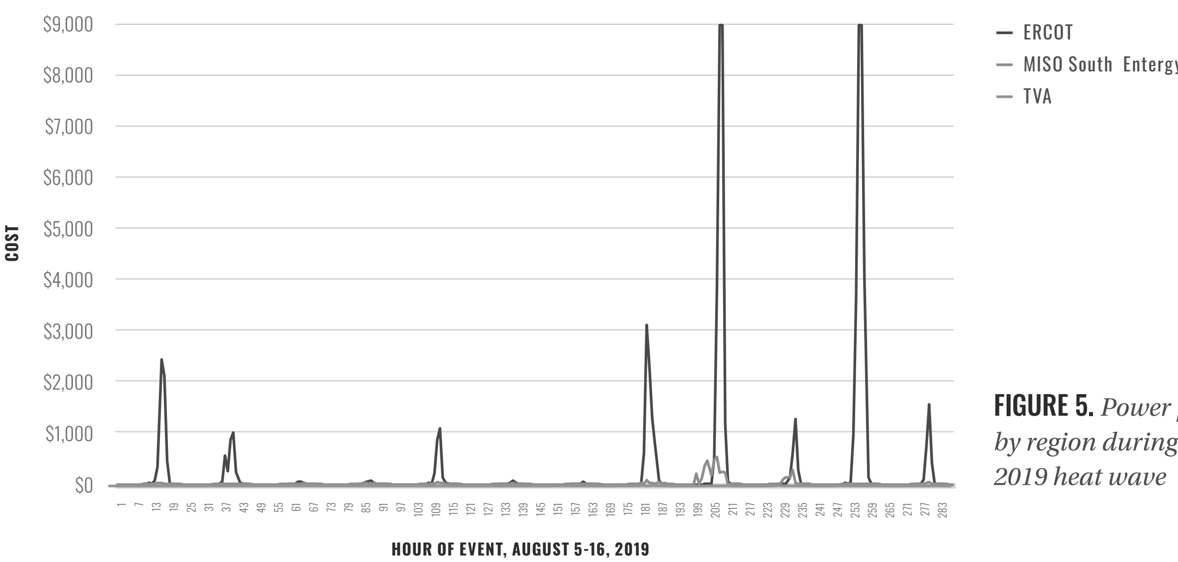


FIGURE 5. *Power prices by region during August 2019 heat wave*

24 Potomac Economics, LTD., *Investigation of the ERCOT Energy Emergency Alert Level 3 on February 2, 2011*, (April 21, 2011), available at: http://www.ercot.com/content/meetings/tac/keydocs/2011/0505/09._IMM_Report_Events_020211.pdf.

25 FERC and NERC Staff, *The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018*, (July 2019), available at: https://www.nerc.com/pa/rrm/ea/Documents/South_Central_Cold_Weather_Event_FERC-NERC-Report_20190718.pdf.

The "Bomb Cyclone" cold snap across the Northeast in December 2017-January 2018

New England (ISO-NE), New York (NYISO), and the Mid-Atlantic region (PJM) suffered cold weather for nearly three weeks, causing natural gas price spikes and nearly exhausting fuel oil supplies in New England. As summarized in the table below, each of these regions could have saved around $30-40 million for each GW of stronger transmission ties among themselves or to other regions. More specifically, PJM could have saved around $38 million from each GW of greater imports from MISO to its west. One GW of stronger transmission ties between eastern and western PJM also could have provided over $40 million in net benefits during this event.[26]

TABLE 3. *Savings per additional GW of transmission, December 26, 2017 – January 19, 2018*

Receiving region – delivering region	Savings per GW of additional transmission capacity (millions of $)
Eastern PJM (VA) – Western PJM (Northern IL)	$43
NYISO – PJM	$41
PJM – MISO	$38
NYISO – ISO-NE	$29

PJM, New York, and New England 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. The chart below shows how eastern PJM, New York, and New England experienced price spikes at different times during the event. New York prices were highly volatile given the relatively small size of its market and lack of transmission ties to neighboring regions. ComEd power prices, in western PJM, were consistently low throughout the event, even as power prices spiked in Virginia and other parts of eastern PJM. Largely as a result, PJM reported $900 million in internal PJM transmission congestion costs in the first half of 2018, up from $285 million in the first half of 2017.

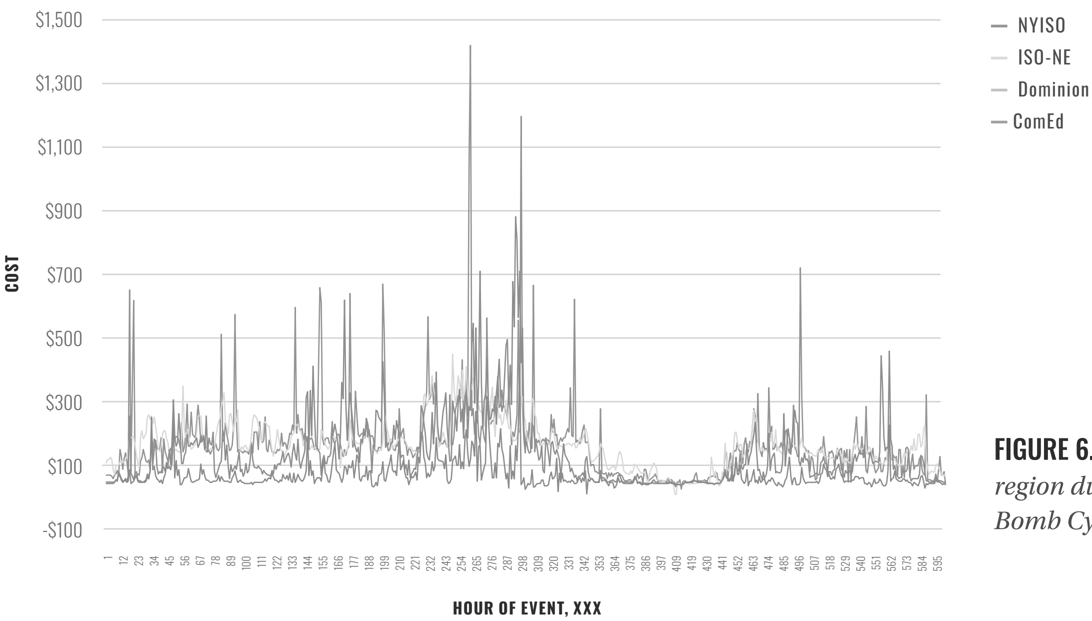


FIGURE 6. *Power prices by region during 2017-2018 Bomb Cyclone*

The January 2014 “polar vortex” event in the Northeast

The Central U.S., Northeast, and Mid-Atlantic regions suffered several days of extreme cold in early January 2014. PJM was forced to resort to system-wide voltage reductions to avoid the need for rolling outages. Greater transmission ties within and among these regions could have saved consumers tens of millions of dollars and prevented reliability concerns.

TABLE 4. *Savings per additional GW of transmission, January 5-10, 2014*

Receiving region – delivering region	Savings per GW of additional transmission capacity (millions of $)
PJM – MISO	$17
NYISO – PJM	$9
NYISO – MISO	$21

As shown below, prices were generally lower in MISO throughout the event, as the most extreme cold was located to the east in PJM and New York. Delivering power from MISO to PJM, or even to NYISO, would have greatly reduced consumer costs, as shown in the table above.

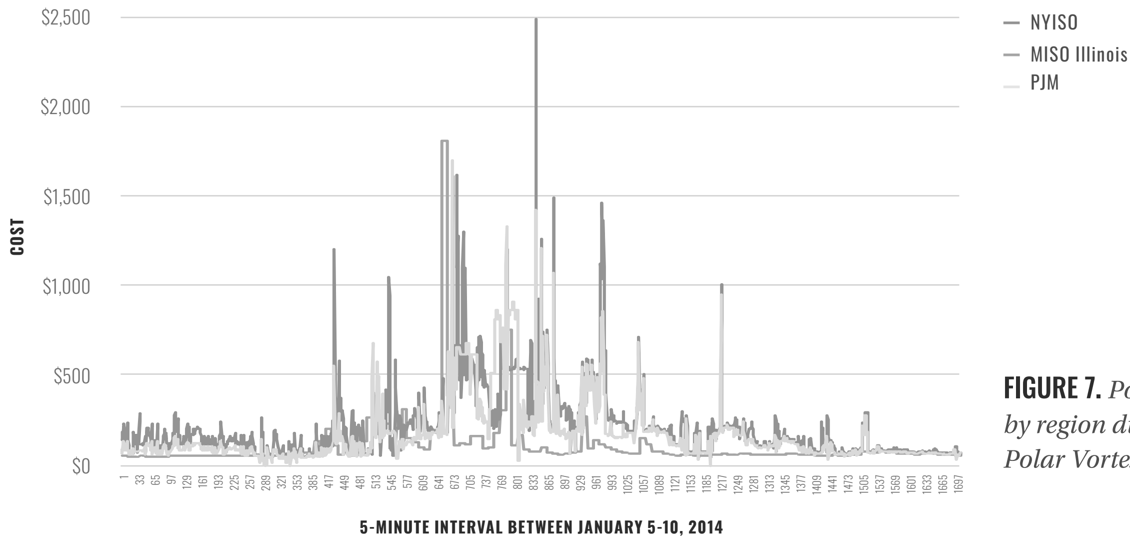


FIGURE 7. *Power prices by region during 2014 Polar Vortex*

Like in the 2017/2018 Bomb Cyclone event, regions switched between importing and exporting as the most extreme cold migrated from region to region. This trend was most apparent the morning of January 7, the day when most regions experienced the most extreme cold. As shown in the following chart that zooms in on that morning, each region moving west to east lagged the other by an hour or two in experiencing the highest prices.

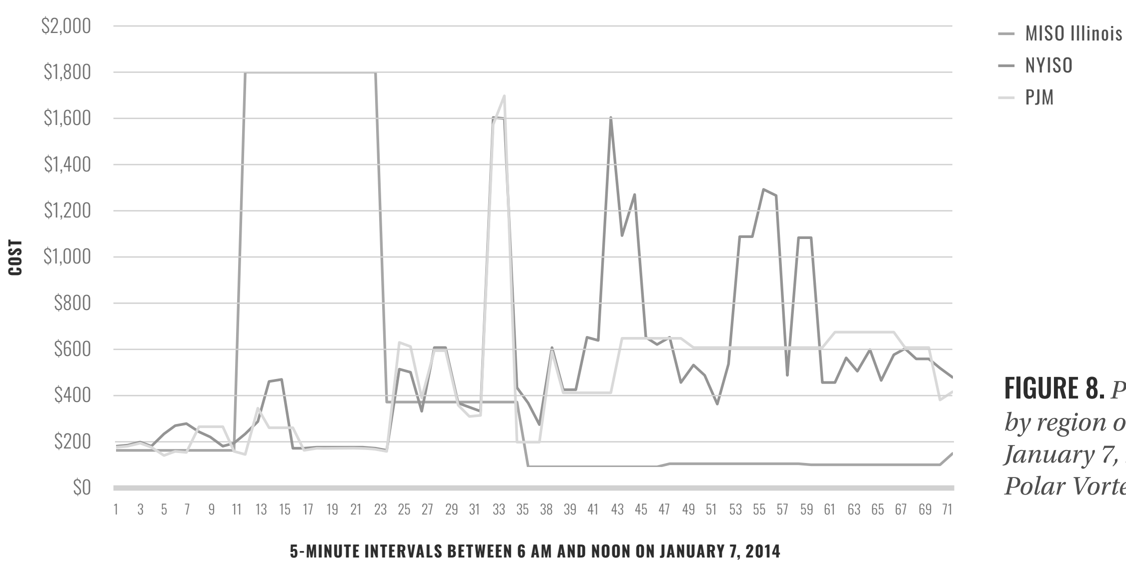


FIGURE 8. *Power prices by region on morning of January 7, 2014, during Polar Vortex*

The "polar vortex" event in the Midwest in 2019

While an additional 1 GW of transmission between MISO and PJM would have saved around $2.4 million dollars during this short-lived cold snap, this event was more notable for illustrating how transmission expansion benefits both interconnected regions. As the extreme cold moved eastward from MISO to PJM on January 30-February 1, 2019, so did the high power prices, and transmission flows switched from westward to eastward.

Early on January 30, MISO's wind output dropped off as temperatures fell below the low temperature limit for wind turbines, forcing them to shut down. Fortunately, wind output in PJM was nearly twice as high as average. This higher wind output helped PJM export in excess of 5,000 MW of power westward to the Midwest grid operator (MISO) during its time of peak demand, a reversal of the typical eastward flow of power. This shows the value of wind's geographic diversity paired with a well-connected grid, creating a more resilient overall system. Transmission also allowed MISO and PJM to take advantage of the diversity in their electricity demand patterns, in addition to the diversity in their wind output. PJM electricity demand was relatively low on the morning of January 30 when MISO experienced its peak demand, while MISO demand was lower by that evening when PJM experienced its peak demand for the day.

This lagged shift in need can be seen in the chart of power prices below. Because of the lack of correlation between PJM and MISO in both electricity supply and demand, the $2.4 million in benefits from an additional GW of transmission are evenly split between the regions.

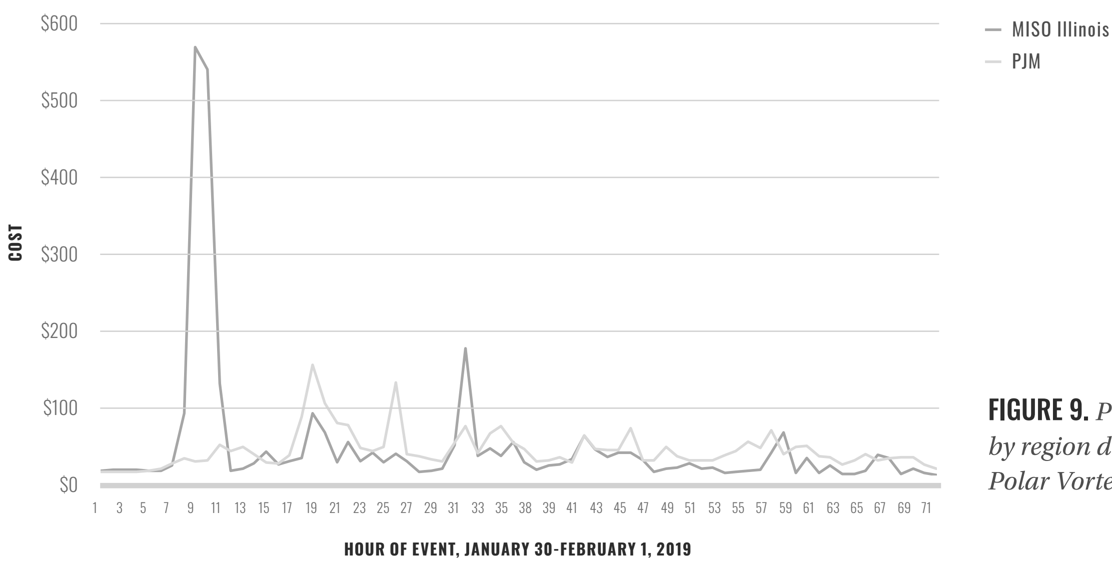


FIGURE 9. *Power prices by region during 2019 Polar Vortex*

This event also revealed other opportunities for expanding transmission to provide consumers with greater access to low-cost energy resources like wind. For example, when MISO and PJM experienced their highest electricity demand on the morning of January 31, SPP had more than 9,000 MW of wind output, keeping prices low. Similarly, electricity prices in MISO South region were consistently low throughout January 30 and 31 because that area was not as affected by the extreme cold. Stronger transmission ties within MISO and between MISO and SPP also could have benefited consumers by providing them with greater access to low-cost electricity generation.

PRO-TRANSMISSION POLICIES TO REALIZE THESE BENEFITS

Like other forms of infrastructure including roads and sewer systems, transmission is often described as a public good in that many of the benefits of transmission cannot be realized by the party making the investment. However, in many parts of the country, generation developers are required to pay for a large share of transmission upgrades. This is much like requiring a driver entering a congested highway to pay the full cost of adding another lane. Policy intervention is therefore needed to correct for the resulting underinvestment in transmission and other public goods. Grid Strategies has labeled the key areas of policy reform needed to enable greater transmission investment, the "three Ps:" planning, paying for, and permitting transmission. Potential policies to correct for the underinvestment in transmission include:

Transmission investment tax credit

A bill has been introduced by Senator Heinrich to create a tax credit to incentivize investments in high-voltage transmission lines.[27] The proposed tax credit is carefully targeted to incentivize high-voltage long-distance transmission projects that are difficult to build but provide large net benefits, but not the smaller local grid upgrades utilities are currently able to plan, pay for, and permit.

A transmission tax credit would provide large net benefits, many times greater than its cost. Many studies have documented the large net benefits of transmission,[28] though those benefits are not typically fully accounted for in transmission planning and cost allocation methodologies.[29] A transmission tax credit particularly benefits lower-income individuals, as electricity bills make up a disproportionate share of their total spending. A federal tax credit is analogous to how federal funds are used to build interstate highways — both account for how those infrastructure investments make the country more resilient against a range of threats and provide economic benefits across broad geographic areas.

27 A Bill to Amend the Internal Revenue Code of 1986 to Establish a Tax Credit for Installation of Regionally Significant Electric Power Transmission Lines, S.1016, 117th Congress, (March 25, 2021), available at: https://www.congress.gov/bill/117th-congress/senate-bill/1016/.

28 For example, see SPP, *The Value of Transmission*, (January 2016), available at: https://www.spp.org/documents/35297/the%20value%20of%20transmission%20report.pdf; MISO, *MTEP17 MVP Triennial Review*, (September 2017), available at: https://cdn.misoenergy.org/MTEP17%20MVP%20Triennial%20Review%20Report117065.pdf; PJM, *The Benefits of the PJM Transmission System*," (April 16, 2019), available at: https://pjm.com/-/media/library/reports-notices/special-reports/2019/the-benefits-of-the-pjm-transmission-system.ashx?la=en.

29 Judy Chang, Johannes Pfeifenberger, and Michael Hagerty, *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments*, (July 2013), at v, available at: https://cleanenergygrid.org/uploads/WIRES%20Brattle%20Rpt%20Benefits%20Transmission%20July%202013.pdf; Judy Chang, Johannes Pfeifenberger, Samuel Newell, Bruce Tsuchida, and Michael Hagerty, Recommendations for Enhancing ERCOT's Long-Term Transmission Planning Process, (October 2013), Appendix B, available at: http://files.brattle.com/files/6112_recommendations_for_enhancing_ercot%E2%80%99s_long-term_transmission_planning_process.pdf.

Anchor tenant

Legislation could be enacted to direct the federal government to directly invest in new transmission lines as an “anchor tenant” customer, and then re-sell that contracted transmission capacity to renewable developers and others seeking to use the transmission line. This would help provide the certainty needed to move transmission projects to construction and overcome what is called the “chicken-and-the-egg problem,” in which renewable developers and transmission developers are each waiting for the other to go first due to the mismatch in the length of time it takes each to complete construction. The Department of Energy can also use its existing loan-making authority to provide low-cost financing to build transmission.

FERC action

The Federal Energy Regulatory Commission (FERC) has authority over how transmission is planned and paid for. FERC can use that authority to break the transmission planning and cost allocation logjams that are preventing large regional and interregional lines from being built. Specific reforms include developing workable interregional transmission planning and cost allocation methodologies, accounting for transmission’s resilience benefits in planning and cost allocation, moving to proactive multi-value transmission planning, and moving away from requiring interconnecting generators to pay for most transmission upgrades. Legislation directing FERC to use these authorities could also be helpful.

FERC could also implement a reliability rule requiring a certain amount of interregional transmission. FERC oversees the North American Electric Reliability Corporation (NERC), which sets and enforces minimum standards for electric reliability. FERC or NERC could require minimum levels for interregional transmission interconnections, recognizing their value for ensuring grid reliability against a range of potential threats. NERC Standard TPL-001 already requires regions to implement solutions, including transmission additions, if their reliability planning studies indicate the system is not resilient against the loss of certain large transmission lines or power plants.[30]

FERC can also develop more workable compensation methods for grid-enhancing technologies that allow more power to be transferred across transmission lines, as this would help to alleviate the economic and reliability impacts of severe weather.

Streamlined permitting

While most authority for permitting transmission lines is held by states, federal agencies have authority over lines that cross federal lands. Steps can be taken to streamline and expedite permitting for transmission, which can currently take a decade or more.

30 NERC, *Standard TPL-001-4 – Transmission System Planning Performance Requirements*, (n.d.), available at: https://www.nerc.com/files/TPL-001-4.pdf.

TECHNICAL APPENDIX

Hourly real-time market prices were obtained from each of the RTOs (MISO,[31] PJM,[32] NYISO,[33] ISO-NE,[34] and ERCOT[35]) for the five severe weather events. Prices for the NYISO Capital zone were used to represent NYISO prices because of significant transmission congestion in the NYC-area zones of NYISO. MISO's Illinois hub was used to represent prices for MISO North, while the Caldwell pricing node in Entergy's Texas footprint was used to represent MISO South during the February 2021 Winter Storm Uri event. TVA-MISO interface prices, obtained from MISO's price dataset, were used to represent TVA prices during the February 2021 Winter Storm Uri and ERCOT 2019 heat wave events. Prices for the ComEd and Dominion zones were used to analyze the prices in western and eastern PJM during the Bomb Cyclone event. Otherwise, average LMPs across the entire RTO were used to represent prices in that RTO.

To calculate the net benefit of transmission reducing power prices by increasing supply on the receiving end of the line during these events, it is also necessary to account for the corresponding price increase caused by the increased demand on generators on the delivering end of the transmission line. The price increase on the delivering end is generally much smaller than the price decrease on the receiving end because the electricity supply curve slopes much more steeply upward when demand is high. For example, the relationship between MISO electricity prices and demand during the January 2014 Polar Vortex event is shown in the chart below. Prices remain relatively low until demand exceeds 90 GW, at which point prices ramp up dramatically as demand increases. As a result, delivering an additional GW from a region with low demand will not dramatically raise prices there, while prices will be dramatically reduced in the receiving region where demand is high.

31 MISO, "Historical Annual Real-Time LMPs," (n.d.), available at: https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3AHistorical%20LMP%2FMarketReportName%3AHistorical%20Annual%20Real-Time%20LMPs%20(zip)&t=10&p=0&s=MarketReportPublished&sd=desc.

32 PJM, "Settlements Verified Hourly LMPs," (n.d.), available at: https://dataminer2.pjm.com/feed/rt_da_monthly_lmps.

33 NYISO, "Real-Time Market LBMP – Zonal," (n.d.), available at: https://www.nyiso.com/custom-reports?report=rt_lbmp_zonal.

34 ISO New England, "Final Real-Time Hourly LMPs," (n.d.), available at: https://www.iso-ne.com/isoexpress/web/reports/pricing/-/tree/lmps-rt-hourly-final.

35 ERCOT, "Historical RTM Load Zone and Hub Prices," (n.d.), available at: http://mis.ercot.com/misapp/GetReports.do?reportTypeId=13061&reportTitle=Historical%20RTM%20Load%20Zone%20and%20Hub%20Prices&showHTMLView=&mimicKey.

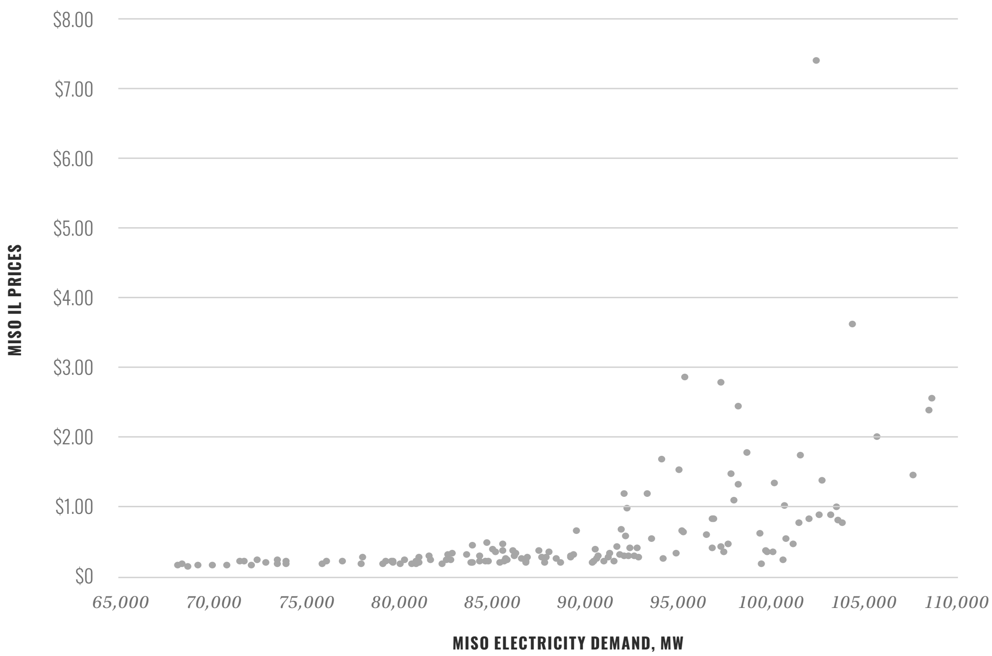


FIGURE 10. *Relationship between MISO demand and power prices during 2014 Polar Vortex*

Demand data for MISO,[36] TVA,[37] and other delivering regions were combined with the price data obtained earlier to create similar scatterplots for those delivering regions. Two linear best-fit slopes were added to each scatterplot, one on the flat part of the slope for periods of low demand, and one on the steep part of the slope for periods of high demand. For example, for the chart above, when MISO demand is greater than 90 GW, the linear best-fit slope indicates that an additional GW of demand increases prices by $15.30/MWh; however, when demand is less than 90 GW, each GW of demand increases prices by only $0.80/MWh. Those linear functions were then used to model the increase in prices in the delivering region, starting from actual demand and prices and then increasing demand by 1 GW to account for exports using the new transmission. This accounts for how increasing demand on the delivering end of the transmission slightly reduces the benefits of transmission.

36 MISO, "Historical Daily Forecast and Actual Load by Local Resource Zone," (n.d.), available at: https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3ASummary%2FMarketReportName%3AHistorical%20Daily%20Forecast%20and%20Actual%20Load%20by%20Local%20Resource%20Zone%20(xls)&t=10&p=0&s=MarketReportPublished&sd=desc.

37 EIA, "Demand for Tennessee Valley Authority (TVA), Hourly – UTC Time," (n.d.), available at: https://www.eia.gov/opendata/qb.php?category=3390009&sdid=EBA.TVA-ALL.D.H.

THE VALUE OF TRANSMISSION DURING WINTER STORM ELLIOTT

FEBRUARY 2023

ACORE
AMERICAN COUNCIL ON RENEWABLE ENERGY

FOR THE AMERICAN COUNCIL ON RENEWABLE ENERGY

GridStrategies

MICHAEL GOGGIN AND ZACHARY ZIMMERMAN
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As families gathered for the holidays at the end of last year, in many regions they were joined by an unwelcome guest: bitter cold. From December 22-26, 2022, Winter Storm Elliott brought near-record low temperatures and wind chills across much of the Central and Eastern U.S. In the power sector, record winter electricity demand coincided with the large-scale loss of fossil power plants due to equipment failures and interruptions to natural gas supplies. Parts of the Southeast experienced rolling blackouts as electricity demand exceeded supply, while power prices spiked in many regions.

Additional transmission capacity would have protected consumers from those blackouts and price spikes by bringing in power from other regions. The large differences in power prices across regions as Winter Storm Elliott moved west-to-east across the country, plus the economic cost of outages in parts of the Southeast, indicate the value a stronger power grid could have provided during the event. This report finds that in some areas modest investments in interregional transmission capacity would have yielded nearly $100 million in benefits during the 5-day event, while most areas could have saved tens of millions of dollars. The following map summarizes the benefits a hypothetical one gigawatt (GW) expansion of interregional transmission capacity could have provided in different areas.

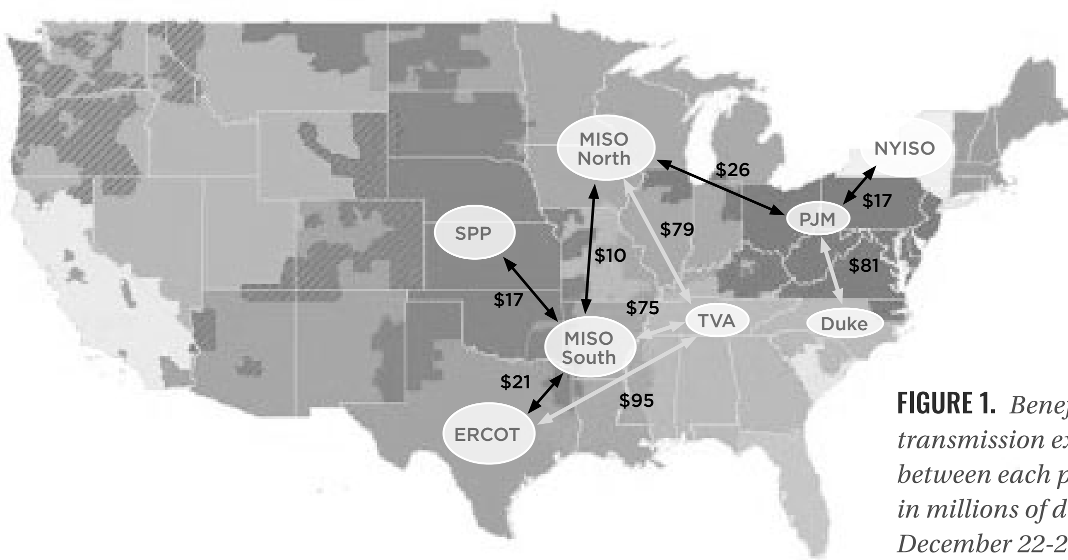


FIGURE 1. *Benefit of 1 GW transmission expansion between each pair of regions, in millions of dollars, December 22-26, 2022*

Additional transmission into the Duke/Progress utility area in the Carolinas and the Tennessee Valley Authority (TVA) would have provided the largest benefit by alleviating customers' rolling outages. The value of additional transmission into these regions was calculated by using power prices at TVA's interface with MISO as well as Duke's interface with PJM during hours without outages, and an assumed Value of Lost Load of $9,000/MWh during time periods with outages.[1] For all other regions in our analysis the value of transmission was calculated based entirely on the difference in hourly power prices, as these regions did not experience rolling outages.

1 https://pubs.naruc.org/pub/2AF1F2F3-155D-0A36-3107-99FCBC9A701C, at 3, footnote 7.

As shown in Figure 2 below, a one GW transmission line between the Electric Reliability Council of Texas (ERCOT) and TVA would have provided nearly $95 million in value, mostly to TVA customers. That adds to the nearly $1 billion in value that line, flowing in the other direction, would have provided Texans suffering through outages during Winter Storm Uri in February 2021.[2] Similarly, one GW of additional transmission capacity from PJM into the Duke/Progress operating areas in the Carolinas could have provided those customers with electricity valued at over $80 million by helping to keep the lights on, when combined with the expansion of PJM's ties to MISO and NYISO shown in Figure 1 above..

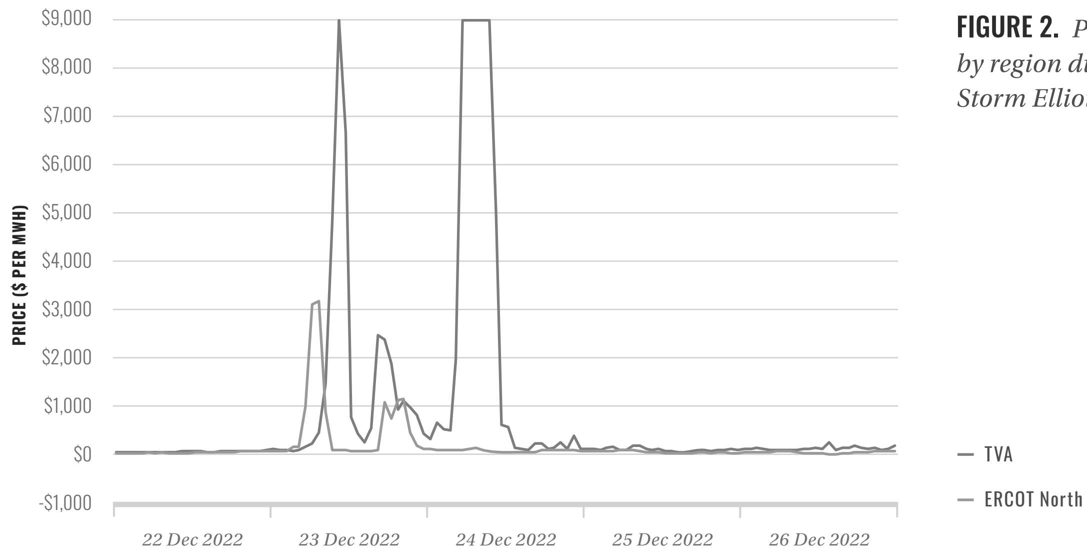
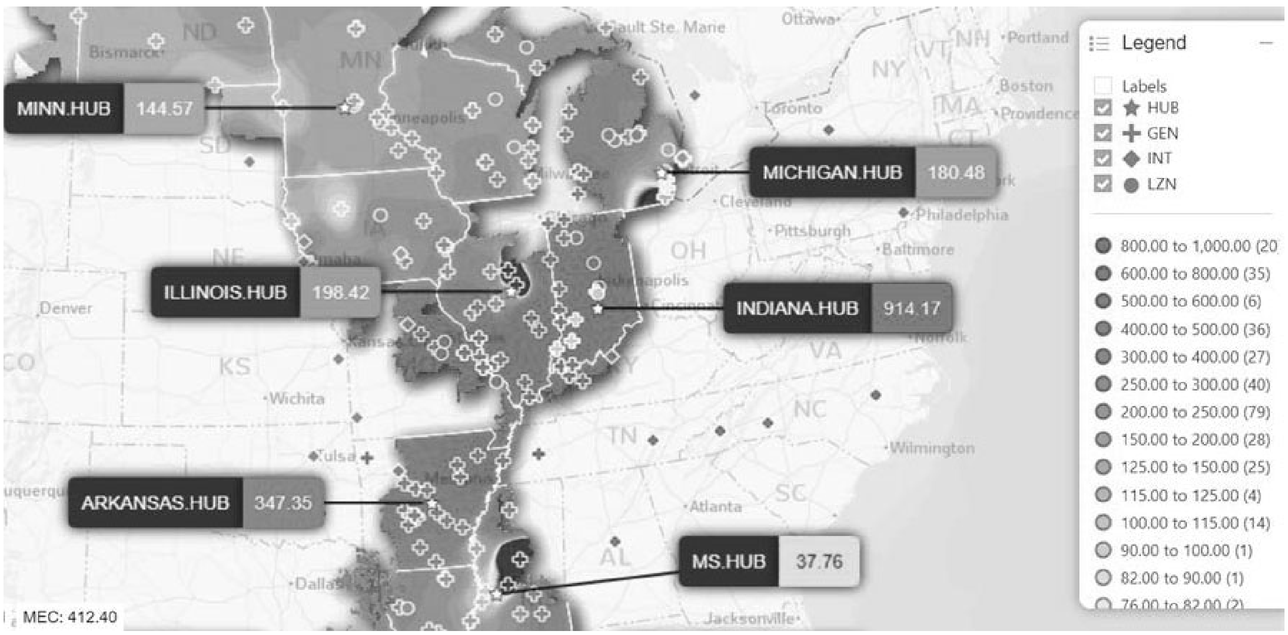


FIGURE 2. *Power prices by region during Winter Storm Elliott*

2 https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf

One GW lines from neighboring Louisiana or Illinois, parts of the Midcontinent Independent System Operator (MISO), into TVA could have provided around $75 million or $79 million in value, respectively. As an influx of polar air caused record low wind chills, it also drove up wind energy output across the MISO, Southwest Power Pool (SPP), ERCOT, and PJM grid operating areas, driving power prices down. Unfortunately, there was insufficient transmission to deliver that wind energy to areas that needed it. It appears that on Christmas Eve morning, wind plants in parts of western MISO were forced to curtail their output while the lights went out in neighboring TVA. At several points in time that morning power prices were slightly negative in western MISO, likely reflecting the curtailment of wind energy. The large west-to-east gradient in Locational Marginal Prices (LMPs) within MISO at one point on the morning of December 24 is shown below.

FIGURE 3. *MISO LMPs on December 24, 2022 at 8:00 am, Eastern Time*



Additional transmission within MISO and SPP would have enabled additional low-cost wind energy to reach customers who needed it, saving nearly $9 million within MISO and $6 million within SPP, and could have helped to alleviate outages in TVA. Congestion and seams issues between MISO and PJM, and between MISO and the Southeast, appear to have caused the localized pockets of negative prices seen in Mississippi, Illinois, and Michigan in the map above.

As shown in Figure 4 below, power prices across parts of MISO North were very low or even slightly negative the morning of December 24, reflecting seams congestion and possibly the curtailment of wind energy.

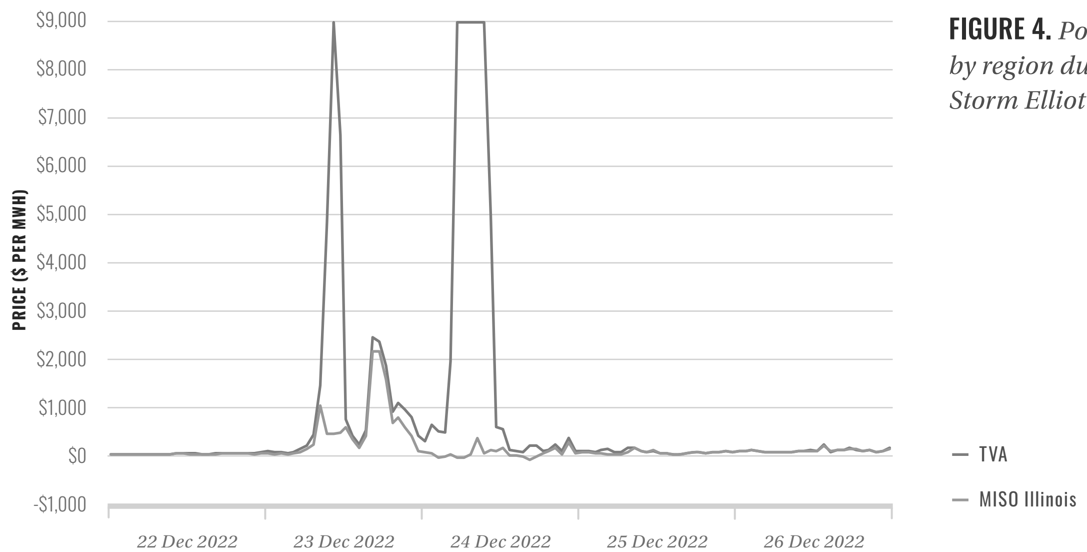


FIGURE 4. *Power prices by region during Winter Storm Elliott*

Over December 22-26, each GW of additional transmission capacity across the MISO-PJM seam in Illinois, between MISO's Illinois hub and the Commonwealth Edison zone in PJM, would have provided around $27 million in economic value. Both regions would have benefited significantly, reflecting that over the course of the event prices and power flows reversed as the extreme cold moved from west to east across the country. As shown below, power prices spiked in MISO on the morning of December 23, while it was not until that evening and the next morning that the extreme cold reached much of PJM.

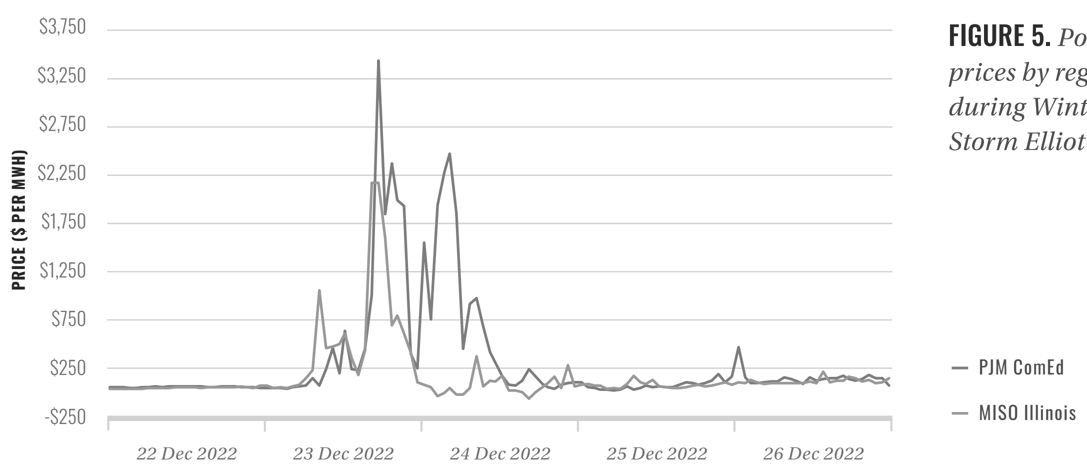
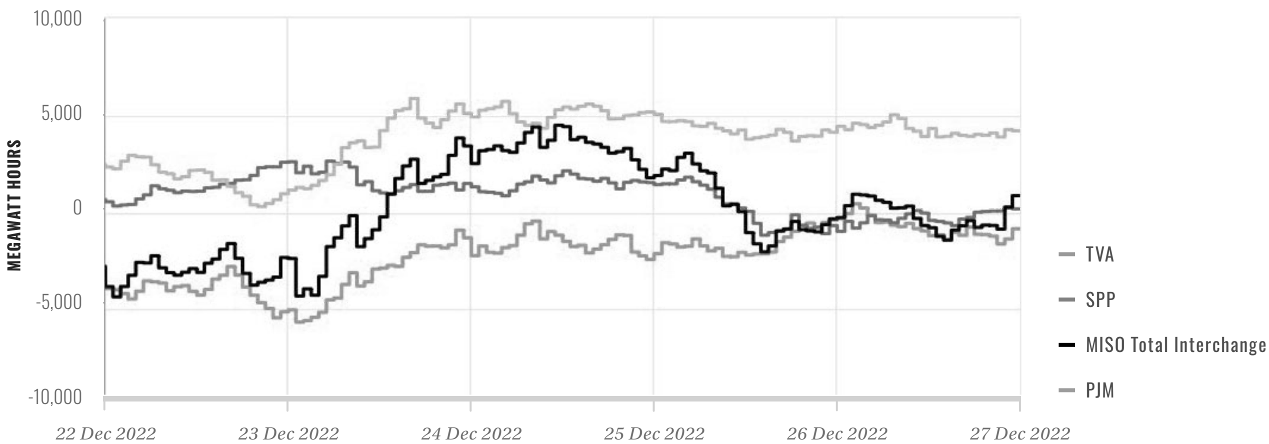


FIGURE 5. *Power prices by region during Winter Storm Elliott*

MISO swung from initially importing nearly 4,500 MW as it and SPP dealt with the worst of the extreme cold, to exporting nearly 4,500 MW later in the event after the extreme cold moved farther east, as shown below. Bidirectional flips in power flows and prices have occurred during past events as the area of most severe weather migrates over time.[3]

FIGURE 6. *MISO electricity interchange with neighboring balancing authorities 12/22/2022–12/26/2022, Eastern Time (positive = export, negative = import)*

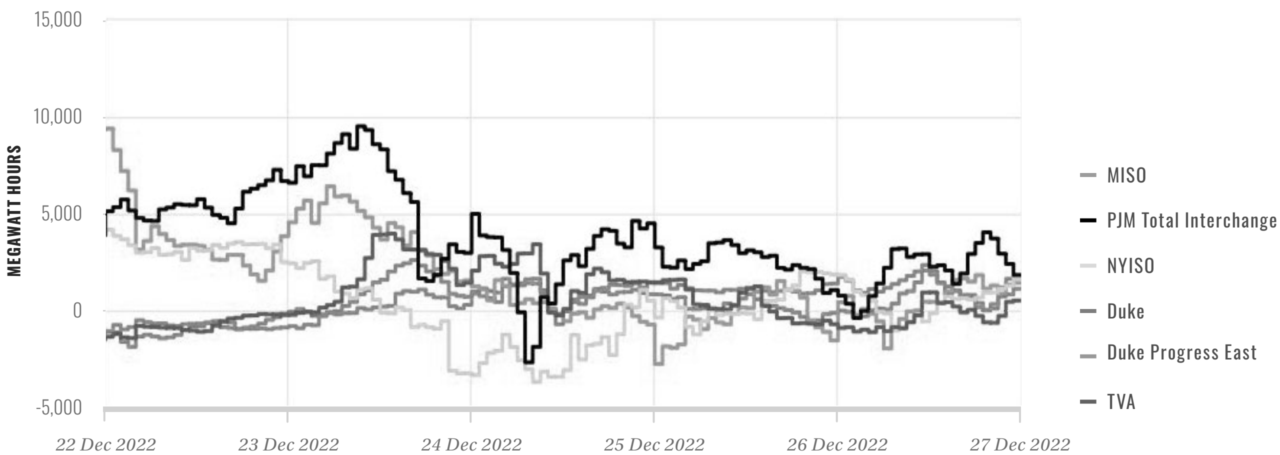


Similarly, a region that primarily exports power during one severe weather event is likely to benefit from imports during another event. While Winter Storm Elliott had the largest impact on the Southeast, Winter Storm Uri primarily affected the Central U.S. and had minimal impact on the Eastern U.S. As a result, expanded ties between Texas and the Southeast would have helped keep the heat on in Texas during Winter Storm Uri and in the Southeast during Winter Storm Elliott. Other studies have confirmed that expanded ties between ERCOT and the Southeast have large reliability value, due to diversity in weather patterns and generation resources and because the main Texas grid lacks strong transmission ties to other states.[4]

3 https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf.
4 https://www.esig.energy/wp-content/uploads/2022/07/EStvIG-Multi-Value-Transmission-Planning-report-2022a.pdf.

In less than 24 hours between December 23 and the morning of December 24, PJM also flipped from exporting nearly 10,000 MW to importing more than 2,500 MW, as shown in Figure 7. Much of that swing involved transactions with New York. While PJM power prices spiked during the evening of December 23 and the morning of December 24, prices in New York remained relatively low because the extreme cold had not yet reached the Northeast, so additional transmission capacity could have allowed additional electricity exports to PJM and other regions facing the brunt of the storm. Over the course of the 5-day event, additional transmission between PJM and NYISO would have saved nearly $17 million.

FIGURE 7. *PJM electricity interchange with neighboring balancing authorities 12/22/2022–12/26/2022, Eastern Time (positive = export, negative = import)*



One GW of additional transmission capacity within PJM, between Commonwealth Edison in Illinois and the Dominion zone in Virginia, also would have yielded nearly $27 million in savings during the event. Similarly, expanding ties between the Louisiana hub in MISO South and the Illinois hub in MISO North would have saved around $10 million, with those benefits fairly evenly split between those zones. As indicated in the chart below, this occurred because power prices peaked at alternating times between MISO South and North, reflecting the movement of the storm and the lack of strong transmission ties between those MISO subregions.

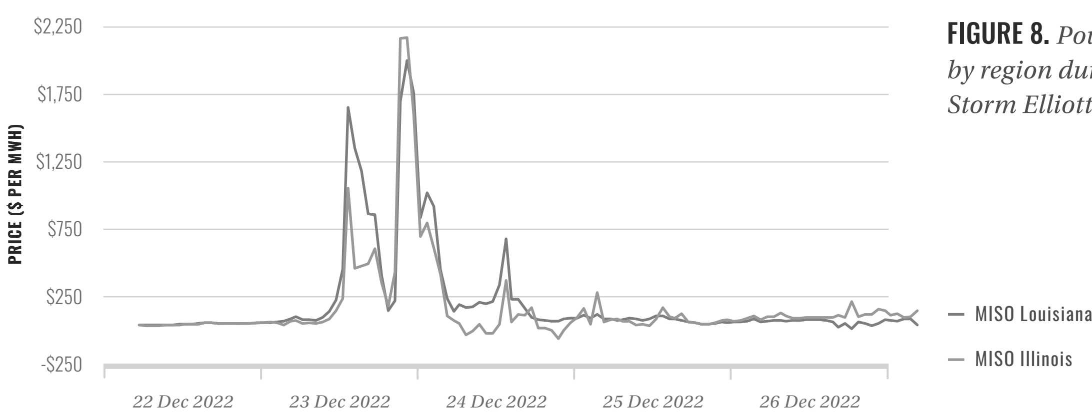


FIGURE 8. *Power prices by region during Winter Storm Elliott*

Additional transmission also would have helped to alleviate significant congestion among ERCOT, SPP, and MISO. An additional GW connection between ERCOT and the Louisiana hub in MISO South would have saved over $20 million over those five days, with the benefits nearly evenly split between ERCOT and MISO customers. As shown below, one GW of expanded transmission between SPP's South hub and the MISO Louisiana hub would have saved around $17 million.

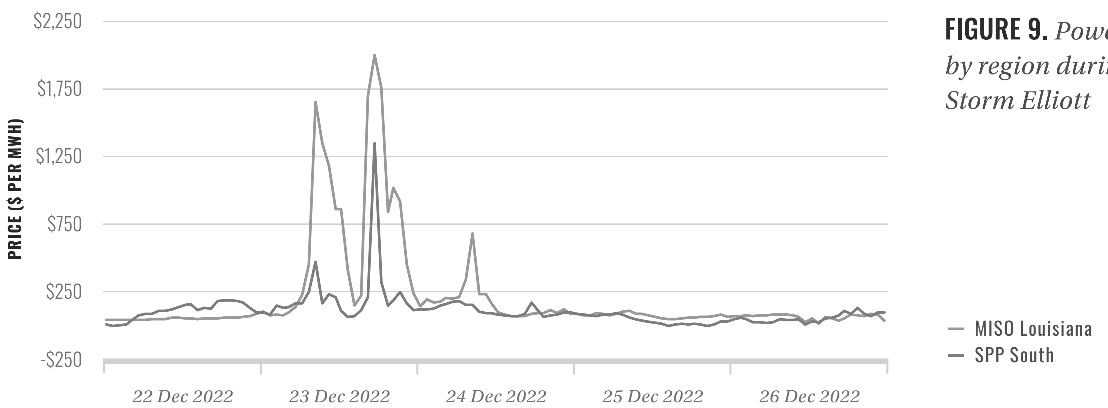


FIGURE 9. *Power prices by region during Winter Storm Elliott*

Table 1 summarizes the benefits of expanding transmission across the 12 regional and interregional interfaces discussed above.

TABLE 1. *Benefit of 1 GW transmission expansion between each pair of regions, December 22-26, 2022*

Region-to-region interface (primary exporting region listed first)	Benefit of 1 GW transmission expansion
ERCOT North-TVA	$95 million
PJM Dominion-Duke/Progress intertie	$81 million
MISO North-TVA	$79 million
MISO South-TVA	$75 million
PJM ComEd-PJM Dominion	$27 million
MISO North-PJM ComEd	$26 million
ERCOT North-MISO South	$21 million
SPP South-MISO South	$17 million
NYISO- PJM Dominion	$17 million
MISO North- MISO South	$10 million
Western MISO-MISO North	$9 million
Western SPP-SPP South	$6 million

Making the grid bigger than the weather

Transmission is becoming increasingly valuable as climate change causes more frequent and more severe extreme weather events. Changes in the generation mix are also making interregional transmission more valuable. A primary cause of the outages and price spikes during Elliott appears to have been the loss of gas generators due to a systemic failure of the natural gas system, as was also the case during Uri and other recent cold snaps, including the 2014 and 2019 Polar Vortex events, the 2018 Bomb cyclone and South Central U.S. cold snaps, and the 2011 Southwest outages. As the press reported after Elliott:

On Dec. 23, US natural gas production suffered its worst one-day decline in more than a decade, with roughly 10% of supplies wiped out because of wells freeze-offs. Output was as low as 84.2 billion cubic feet on Saturday, a 16% decline from typical levels, before a slow recovery started, according to BloombergNEF data based on pipeline schedules… Most of the output loss was seen in the Northeastern Appalachia basin, where supplies plunged to the lowest level since 2018. US natural gas futures posted gains on Tuesday as supplies remained severely constrained by freeze-offs. Supplies from Appalachia to the Tennessee Valley and the Midwest more than halved from typical levels, according to pipeline flow data compiled by BloombergNEF.[5]

Equipment failures across all types of power plants also played a significant role in electricity shortfalls during Elliott, as was the case in previous cold snaps. At one point on December 23,

5 Gerson Freitas, Jr. et al., *America's electrical grid barely escaped a calamity as massive storm exposes a vulnerable natural-gas infrastructure,* Fortune (Dec. 27, 2022, 2:36 PM EST), https://fortune.com/2022/12/27/america-electrical-grid-barely-escaped-a-calamity-as-massive-storm-exposes-a-vulnerable-natural-gas-infrastructure/.

2022, TVA lost more than 6,000 megawatts of power generation or nearly 20% of its load at the time, including three large coal units.[6] Preliminary data for MISO,[7] PJM,[8] and SPP[9] show all fuel types were taken offline, though gas makes up the largest share of lost capacity.

Investigations are underway to determine which generators failed during Winter Storm Elliott, and why. Regardless of which energy sources failed, strengthening transmission is an essential part of the solution for preventing future outages due to all types of severe weather, including extreme heat, cold, and drought. Extreme weather events tend to be most severe in relatively small areas, so stronger transmission ties to neighboring regions can be a lifeline to keep homes warm and people safe. Transmission ties cancel out local fluctuations in the weather that affect electricity demand, primarily due to heating and cooling needs, and supply, including changes in wind and solar output as well as failures of conventional power plants due to extreme weather. A few weeks before Winter Storm Elliott, nearly all panelists at a Federal Energy Regulatory Commission (FERC) workshop endorsed expanding interregional transmission as an insurance policy against severe weather events that affect all energy sources.[10]

Most transmission planning processes do not account for severe weather events in the net benefit calculations that determine whether grid investments move forward.[11] This is despite the fact that recent analysis by Lawrence Berkeley National Laboratory indicates that half of transmission's value accrues in only 5% of hours, typically when the power system is being stressed by extreme weather.[12] Policy changes are therefore needed to account for transmission's value as an insurance policy for grid resilience, such as through a minimum interregional transfer requirement as was discussed at FERC's December 2022 workshop.

Making the grid bigger than the weather will become even more important as wind and solar provide a larger share of our electricity.[13] Just as transmission helps cancel out the localized impact of severe weather events, it also captures geographic diversity in wind and solar output across larger regions. This reduces the variability of wind and solar output and ensures a higher level of dependable output during periods of peak need. Transmission also captures complementary output profiles between wind and solar resources in different regions on a daily and seasonal basis. For example, transmission will allow the Southeast to export solar power to the Midwest during the day and during summer months, and then import wind energy from the Midwest at night and during the winter.[14]

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6 Dave Flessner, *Chattanooga area hit with 1-minute power outages as cold weather forces rolling blackouts*, Chattanooga Times Free Pres (Dec. 24, 2022, 9:42 AM), https://www.timesfreepress.com/news/2022/dec/24/power-outages-tfp/.

7 https://cdn.misoenergy.org/20230117%20RSC%20Item%2005%20Winter%20Storm%20Elliott%20Preliminary%20Report627535.pdf.

8 https://pjm.com/-/media/committees-groups/committees/mic/2023/20230111/item-0x---winter-storm-elliott-overview.ashx.

9 SPP, "December 2022 Winter Storm Elliott."

10 https://www.ferc.gov/news-events/events/staff-led-workshop-establishing-interregional-transfer-capability-transmission

11 https://www.brattle.com/wp-content/uploads/2021/10/2021-10-12-Brattle-GridStrategies-Transmission-Planning-Report_v2.pdf, at 36, 82.

12 https://emp.lbl.gov/news/regional-and-interregional-transmission-have

13 https://www.ferc.gov/media/panel-3-christopher-clack-vibrant-clean-energy-llc.

14 https://cleanenergygrid.org/wp-content/uploads/2020/10/Consumer-Employment-and-Environmental-Benefits-of-Transmission-Expansion-in-the-Eastern-U.S..pdf.

Methodology

The transmission benefits in this report were primarily calculated by comparing Locational Marginal Prices (LMPs) within Regional Transmission Organizations (RTOs) and at interfaces with non-RTO areas in each hour during December 22-26, 2022.[15] The Cimarron River LMP node in western SPP and LMPs at the NSP/OTP interface in western MISO were used to represent prices in the wind-heavy western parts of those RTOs, while all other calculations were based on prices at the major RTO hubs and interfaces listed in Table 1 above. As noted above, a $9,000/MWh value was assumed for deliveries into TVA[16] and Duke/Progress[17] during their rolling outages.

The analysis conservatively used hourly average LMPs instead of prices at 5-minute intervals, as current practices for scheduling transactions between regions include market seam inefficiencies that limit the ability to use transfers to address short-term fluctuations in price. To test the impact of this assumption, the hourly results were compared against results using 5-minute prices for the SPP West-SPP South and NYISO-PJM ties, which indicated that using 5-minute prices would increase the calculated value of transmission by 5.4% in SPP and 4.1% for the NYISO-PJM tie.

This understatement of savings is about equal to the estimated overstatement of savings because this analysis did not account for increases in LMPs in exporting regions due to the 1 GW increase in demand that would be caused by the expansion of transmission ties. Our 2021 analysis found comparably modest increases in prices in exporting regions due to that effect, as the price increase on the delivering end of a line is generally much smaller than the price decrease on the receiving end because the electricity supply curve slopes much more steeply upward when demand is high.[18] Because those two factors roughly offset each other, they are not accounted for in this analysis.

15 MISO LMP and TVA interface price data obtained from https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3AHistorical%20LMP%2FMarketReportName%3AReal-Time%20Final%20Market%20LMPs%20(csv)&t=10&p=0&s=MarketReportPublished&sd=desc; PJM LMP, NYISO interface, and Progress/Duke interface price data at the Roxboro intertie obtained at https://dataminer2.pjm.com/feed/rt_hrl_lmps; SPP LMP data from https://marketplace.spp.org/pages/rtbm-lmp-by-location#%2F2022%2F12%2FBy_Day; and ERCOT North LMPs from https://www.ercot.com/misdownload/servlets/mirDownload?doclookupId=886632075.

16 https://www.wbir.com/article/news/local/tva-artic-blast-rolling-blackouts-east-tennessee/51-9fac437b-6cce-40eb-a0ce-650be785b1de indicates the TVA outages on December 23 extended from 9:31 AM to 11:43 AM, while on December 24 they extended from 4:51 AM to 10:31 AM.

17 https://ncpolicywatch.com/2023/01/04/several-crises-malfunctions-at-duke-energy-led-to-rolling-blackouts-on-christmas-eve-utility-officials-tell-state-regulators/ indicates Duke/Progress outages occurred from 6:14 AM to 4 PM on December 24.

18 https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf, at 20-21.

The Value of Increased HVDC Capacity Between Eastern and Western U.S. Grids: The Interconnections Seam Study

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***Abstract*—The Interconnections Seam Study examines the potential economic value of increasing electricity transfer between the Eastern and Western Interconnections using high-voltage direct-current (HVDC) transmission and cost-optimizing both generation and transmission resources across the United States, proposing, assessing, justifying, and illustrating a major infrastructure change involving two of the world's largest power grids. The study conducted a multi-model analysis that used co-optimized generation and transmission expansion planning and production cost modeling. Four transmission designs under eight scenarios were developed and studied to estimate costs and potential benefits. The results show benefit-to-cost ratios that reach as high as 2.5, indicating significant value to increasing the transmission capacity between the interconnections under the cases considered, realized through sharing generation resources and flexibility across regions.**

***Index Terms*—HVDC transmission, interregional transmission, power generation dispatch, power system economics, power system reliability, power system planning, resource adequacy, solar power generation, wind power generation.**

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I. Introduction

At THE western edge of the American prairie, just east of the Rocky Mountains, lies a collection of electrical transmission resources that tie together the otherwise segregated U.S. and Canadian Eastern and Western Interconnections (EI and WI). These seven back-to-back (B2B) high-voltage direct-current (HVDC) facilities enable 1320 megawatts (MW) of electricity to flow between the U.S. EI and WI. This transfer capability between the interconnections is very small compared to the networks they connect—the larger EI is home to 700000 MW of generating capacity, and the WI roughly 250000 MW. But as small as these B2B facilities may be, they are important: they are located strategically at the "seam" where the East meets the West—and with the U.S. resource portfolio in transition, the ability to share additional resources across the seam could be economically attractive under a variety of possible futures. At the same time, these facilities are aging, and thus their continued use will require additional investment for keeping them in service. These observations suggest that increasing cross-seam transmission capacity may represent a timely and impactful opportunity for utilities, developers, regulators, and policy makers to modernize and strengthen the U.S. electric grid.

Over the last 95 years, a number of entities have indicated interest in developing additional cross-seam transmission. The earliest [1], in 1923, was motivated by a desire to integrate the continent's hydro and coal resources. Subsequent studies [2]–[5] investigated joining the existing systems for economic and/or reliability benefits. An HVDC overlay of the U.S. western and Midwestern grids was proposed in [6]. Reference [7] argued for an integrated alternating-current/direct-current (AC/DC) approach and illustrated a national overlay design of predominantly 765 kV AC lines. More recent work [8]–[10] applied generation and transmission co-optimization on a set of geographically aggregated electric nodes across the United States to design a national transmission network that was shown to be economically attractive under various futures. A variety of challenges have prevented nationwide HVDC overlays from development so far. References [11], [12] describe transmission planning efforts around the world, including HVDC overlay designs.

Here we present the Interconnections Seam Study, a coordinated transmission planning analysis of the two major U.S. interconnections. The study co-optimizes capacity expansion and systems operations to quantify the potential value of increasing the transmission capacity between the EI and WI using HVDC technology to facilitate more economically efficient exchange of power and adequacy throughout the United States. The work described in this paper differs from previous efforts in three ways:

1) *Study objective*: The objective was to identify the value of increased cross-seam transmission capacity; as a result, several HVDC designs were studied—one of which, called the macrogrid, has features similar to those of previously developed overlays.
2) *Analysis fidelity*: The study uniquely captures capacity expansion and production cost at an unprecedented geographic scale and detail, all performed with consistent data inputs. The production cost modeling (PCM) deploys a novel geographic decomposition computational method to more precisely represent operational constraints, enable increased modeling resolution, and reduce solve time.
3) *HVDC and AC transmission*: In each cross-seam transmission design, HVDC capacity was co-optimized not only with generation investments but also with AC transmission investments; this process ensured that AC transmission investment needs were satisfied.

This paper makes two significant contributions to the literature. The first is that it describes a process for developing high-capacity interregional transmission designs using an expansion planning tool on an aggregated zonal model and translating those investment results to a large and granular nodal model. The second is that it describes and illustrates operational simulations of a US macrogrid on a large nodal model representing two asynchronous grids.

An earlier paper [13] described the cooptimized expansion planning (CEP) procedure and results of this study. This paper extends that work through the contributions described above. In addition, [13] reported results on a renewable penetration level that reached 50% by energy in 2038, conditions manifested by the modeling of an escalating price on carbon and without constraints imposing the renewable goals of individual state renewable portfolio standards (RPS). In contrast, this paper reports on a renewable penetration level that reaches 40% by energy in 2038, conditions manifested by the modeling of what we consider to be the “current policy” where there is no price on carbon, but meeting the renewable goals of individual state RPS is required. Finally, whereas [13] reports CEP results only, this paper focuses on PCM results together with the process necessary to obtain them.

II. Approach

To ensure the technical rigor of this study, a technical review committee (TRC) including more than 20 organizations met on six occasions to discuss the approach, methods, scenarios, data, assumptions, and results. The study provides initial valuations of increasing connection between the interconnections but should not be referenced as reporting final ready-to-build designs. It also does not take the place of regional planning studies, but can provide analysis of potential ways regions can benefit from interregional planning efforts. Similarly, the study does not obviate the need for state and federal siting review. The study did not consider the impact on wholesale rates set by the Federal Energy Regulatory Commission or North American Electric Reliability Corporation (NERC) reliability standards under Federal Power Act Sections 203, 205, and 206.

TABLE I
Description of the Scenarios*

Scenario	Key assumption differences
Base Case	AEO 2017 gas price, state RPS laws
Low Gas Price	AEO 2017 High Gas Resource (regionally and temporally varying around \$4/mmbtu)
High Gas Price	AEO 2017 Low Gas Resources gas prices (varying around \$6/mmbtu)
High AC Trx Cost (1.5x)	50% higher than base transmission cost. Base transmission cost from [17]
High AC Trx Cost (2x)	Double the base transmission cost
No retirements	Model does not retire any generating units beyond announced retirements
Low-cost renewables	ATB 2017 Low-Cost VG
High VG	Least-cost generation mix when using a carbon cost from \$3/tonne in 2024 to \$45/tonne in 2038**

*Acronyms used here include Energy Information Administration (EIA) Annual Energy Outlook (AEO); Renewable Portfolio Standard (RPS); Annual Technology Baseline (ATB) (atb.nrel.gov); Variable Generation (VG).
**: The study TRC recommended this approach (consistent with cost estimates in [18]) as a proxy for potential growth in wind and solar in light of uncertainty in traditional deployment forecasts [19].

The first step of the study was to conduct a detailed capacity expansion analysis for four future (through 2038) transmission designs and eight different generation scenarios developed using differing assumptions regarding transmission costs, renewable generation, wind and solar costs, gas prices, and retirements (see Table I). Each of the 32 simulated power systems (four transmission designs applied to eight scenarios) meet long-term simplified, single-year, consistent, resource adequacy requirements. In the base case, the systems are expanded cost-optimally based on state renewable portfolio standards existing in 2017 and business-as-usual assumptions for generation technology cost improvement. A detailed nodal transmission model was created to evaluate the ability of the power system to reliably schedule and dispatch generation to meet demand at all hours of the year for select scenarios.

Table II summarizes the four interregional transmission designs considered in the generation scenarios. In all designs, new AC transmission and generation are co-optimized to minimize system-wide costs in addition to the HVDC and B2B facility expansions allowed under each transmission design. For co-optimized generation and transmission expansion, Iowa State University’s co-optimized generation and transmission plan

TABLE II
SUMMARY OF TRANSMISSION DESIGNS

Design Name	Description
Design 1 (D1)	Existing B2B facilities are maintained at their 2017 capacity
Design 2a (D2a)	Existing B2B facilities are allowed to expand in the optimization
Design 2b (D2b)	Three HVDC transmission segments (along with the expansion of the B2Bs) are built between the EI and WI
Design 3 (D3)	A national-scale HVDC transmission network, or macrogrid, is built

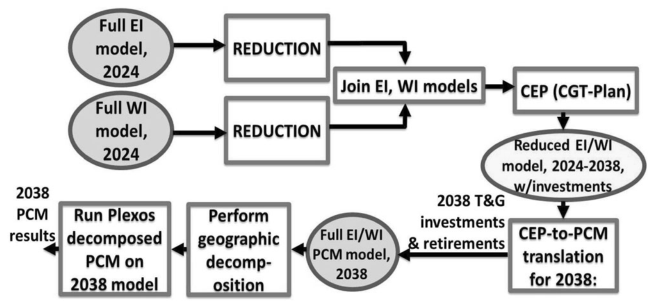

Fig. 1. Analysis process implemented in this study.

(CGT-Plan) model [15] was used. Energy Exemplar's PLEXOS was used for PCM.

The model development and the analysis process are illustrated in Fig. 1. It starts from full industry-scale 2024 EI and WI nodal models (25000 and 73000 buses, respectively), reduces and joins the models to obtain a single 169-bus zonal model, runs the CEP tool CGT-Plan to identify the 15-year generation and transmission investment plan, translates those investments back to the 98000-bus nodal model, and finally runs the PLEXOS PCM application to obtain sequential hour-by-hour operational results for the year 2038. The process of reducing, co-optimizing, translating, and simulating two asynchronous grids, both very large, as reported in this paper, is unique to the literature.

III. Input Data and Assumptions

A variety of input data and assumptions were used to build power system representation of the EI and WI. The near-term expected generation and transmission for the EI and WI was obtained from NERC regional entities. The Eastern Interconnection Reliability Assessment Group's (ERAG) Multiregional Modeling Working Group (MMWG) 2026 summer case and the Western Electricity Coordinating Council (WECC) Transmission Expansion Planning Policy Committee (TEPPC) 2024 common case were chosen as the starting point for creating an updated nodal representation of the 2024 EI and WI. These cases included announced and planned generation and transmission additions from 2016 to 2026, including both US, Canada, and cross-border. Additional information on the 2024 data can be found in [14]. Both capacity expansion and production cost modeling used consistent data for the transmission topology, existing and expanded generation fleet, thermal plant operating characteristics, load forecasts, and time-series data for wind and solar resources. Expansion was limited to the US so that study results depend only on US growth.

A. Capacity Expansion Modeling

The capacity expansion model, CGT-Plan, determines the location, size, and technology type for generation and transmission built in each scenario. It does this by minimizing generation and transmission investment costs, generation retirement costs and generation production cost over time from 2024-2038 using 169 buses reduced from the 98000 nodal 2024 U.S. EI and WI transmission networks. Production costs include, for new and existing resources, fixed and variable operating and maintenance costs, fuel cost and operational reserve cost (regulation up/down and contingency reserve). Constraints imposed include: power balance at each node; "DC" angle constraints across each existing line; upper and lower limits on generation dispatch and line flows; lower limits on available up/down regulation reserves and available contingency reserves; upper limits on up/down regulation (contingency) reserves by the unit's 1-minute (10-minute) ramp rate; capacity in excess of the NERC-recommended 115% of peak [15] (all units contributed to the planning reserve according to each units capacity value which, for wind and solar, varied locationally as described in [16] but were independent of renewable penetration); and the definition of the particular transmission design being studied. Operational reserves were imposed system-wide; a capacity constraint was imposed in each of four regions: West, Northwest, Midwest, and East. A full description of the model is available at [16].

CGT-Plan was run 32 times, for each of the four designs, D1, D2a, D2b, and D3 under the eight scenarios. CGT-Plan identified investments in two-year increments to minimize net present value of investments plus operational costs occurring during the 15-year decision horizon, plus operating costs occurring for another 20 years thereafter. Operations were simulated for every year using 19 conditions; wind and solar were dispatched using a P_{max} set by their capacity factor (for energy blocks) or capacity value (for peak blocks) and were redispatched down under congested conditions as necessary; flexibility requirements were modeled as a function of net-load variability. The 19 conditions included 15 "energy blocks" capturing five time periods in each of three seasons (summer, winter, and shoulder): 1–7 a.m., 8 a.m.–12 p.m., 1–4 p.m., 5–6 p.m., and 7 p.m.–12 a.m. The remaining four conditions were "peak net-load blocks" to capture one-hour annual peak conditions in each of four regions. The peak blocks were used to model the capacity constraint; because different regions peak at different times of the year, this enabled analysis of interregional reserve-sharing subject to transmission-related deliverability constraints [16].

Decision variables included investment in various generation and transmission technologies, as well as retirement of existing generation. Percentage of load served by VG ranged from approximately 30% to 40% in the base case and high VG case, respectively. All generation assets were based on commercially available technologies in 2017 and were modeled with appropriate maturation rates at all buses. The natural gas price assumption for the Base Case was adopted from the U.S. Energy Information Agency's (EIA) 2017 AEO [20]; the nominal price for electric generation ranged by region from \$4.2/million British thermal units (MBTU) to \$5.1/MBTU in 2024; these assumed prices are similar to those projected in the "low oil and gas supply curve" of the 2020 EIA AEO [21]. Battery energy storage was not an investment option. At each bus, the wind resources available for selection included three 100-meter wind technologies, each having different costs and the ability to be optimized for unique wind resource characteristics by geography. This included three different capacity factor categories that identified the investment potential at a particular range of capacity factor. Investments in solar photovoltaics (PV) were limited to utility scale and were split evenly between single-axis tracking and fixed-tilt. Distributed PV capacity projections for 2024 came from the 2016 NREL Standard Scenarios [22], and a 3% per year growth rate [23] was applied until 2038.

Investment options among transmission technologies included additional AC capacity on any existing branch at the voltage of that branch, at a cost per mile appropriate for that voltage and the geography of the region. Table I summarizes the additional HVDC investments that are allowed in D2a, D2b, and D3. In D2a and D2b, B2B facilities could expand independently of one another. In D2b, the three additional HVDC lines connecting the EI and WI are required to develop equal capacity. Similarly, in D3, all segments of the macrogrid are required to maintain equal capacity. Although the N-1 reliability criterion was not explicitly imposed, the "equal capacity" constraints for the HVDC lines in D2b and D3 were employed as proxies to avoid significant violation of this criterion. For example, three equal-capacity parallel HVDC bipole lines can be loaded to capacity and withstand a monopole loss of any one of them (considered to be an N-1 outage) if the remaining five poles can each provide an additional 20% capacity for a short time on their emergency overload ratings. Based on analysis of discount rates recommended by the White House Office of Management and Budget and other studies [22]–[24], a nominal discount rate of 7.7% and an inflation rate of 2% were chosen, resulting in a real discount rate of 5.7%. Demand growth was set within each region consistent with recent studies [25], [26]; technology costs and regional multipliers for all generation resources and AC and HVDC transmission were based on [17, [27]–[30]. All HVDC converters were assumed to be line communicated converters (LCC), and all HVDC lines were assumed to be point-to-point, enabling HVDC line protection to be provided on the AC side, consistent with macrogrid designs presented in [13], [31], [32]. Voltage source converters could also be considered, providing the opportunity to deploy a macrogrid design as a multiterminal network, or as a hybrid as in [33], reducing the number of converters but requiring deployment of DC breakers. This rich line of inquiry is a logical follow-on to this paper.

A capacity credit is given to each generator type; it is the percent of that unit's capacity that can be applied towards satisfying the annual peak [34], [35]. Other data and associated sources are identified in [13], [16]. After the translation (III.B) and PCM (III.C) were completed on the penultimate CGT-Plan runs, the CGT-Plan was re-run for analysis presented in the results section on costs and benefits (IV.C), this time allowing expansion of a comprehensive set of transmission interfaces, considering end-effects beyond 2038 in the optimization.

B. *Translation From Capacity Expansion to PCM*

CGT-Plan developed year-2038 aggregated zonal transmission and generation for the EI and WI. In order to study the year-2038 operation of these systems and determine operational savings (in perpetuity) due to the HVDC and B2B facilities, a nodal PCM of the 2038 system was created. This required a translation of the CGT-Plan zonal generation and transmission results to the nodal PCM network. This is a two-step process that begins with a 2024 nodal transmission model. Step 1 distributes generation investments and retirements identified by CGT-Plan operating on the 2024 nodal model, using the following criteria: (i) Individual generating units are retired in the 2024 model based on heat rate until the CGT-Plan retirement amounts are satisfied; (ii) CGT-Plan new thermal generators are added at locations in the 2024 model where thermal plants were retired; and (iii) wind and PV investments identified by CGT-Plan were added to the high-voltage node ($\geq$230 kV) in the PCM that is geographically closest to the wind and PV sites.

Step 1 resulted in a nodal model that contained 2038 load and generation for the PCM (from CGT-Plan) but did not update the transmission system. For step 2, a transmission expansion planning (TEP) optimization program was developed and applied it to the nodal PCM obtained from Step 1. This optimization is non-linear, given each transmission investment changes the circuit capacity and the circuit reactance. To address this, the TEP was developed as a sequence of linear programs (LPs), where each LP minimized the total transmission investment cost (subject to DC power flow equations), and only circuit capacity was treated as a decision variable, while circuit reactance was held constant. Following the LP solution, the reactance of each invested circuit was updated to reflect the change in capacity, after which the LP was rerun. The iterations were terminated when the circuit with the largest change in capacity relative to the previous iteration was within a specified tolerance. This two-step process results in a nodal version of the 2038 systems created by CGT-Plan, which is used in the PCM. The process is illustrated in Fig. 2.

C. *Production Cost Modeling*

The nodal PCM resulting from the capacity expansion scenarios was used to simulate a full year of continuous operation for 2038. The simulation has two phases, a day-ahead unit commitment, made up of 365 serial optimizations, and a real-time dispatch where 8760 serial optimizations are completed. Each day-ahead unit commitment optimization is a mixed integer linear program modeling 24 hourly decisions with additional 24-hours of look-ahead information. The look-ahead is used to improve decisions about operations of energy-limited resources and units with long minimum online/offline times. The real-time

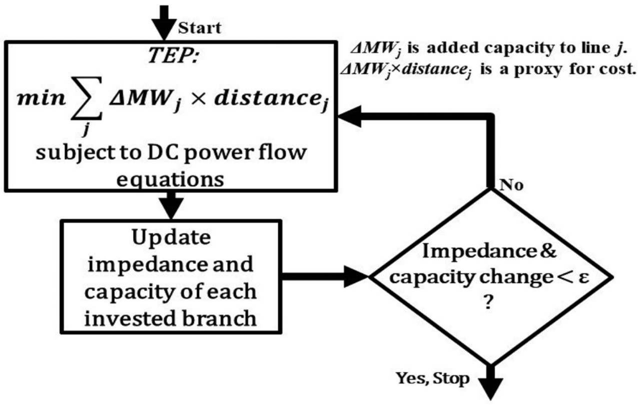

Fig. 2. Translating investments from reduced model to full.

dispatch is also a mixed integer linear program that only considers a single hourly decision at a time.

The detailed PCM formulation used within PLEXOS is not provided, which is standard, but rather point to Barrows *et al.* [36] which summarizes the system of equations that define the optimization problem for each phase of the PCM. The objective function minimizes the total cost to operate the system, while deciding which generating units to start or shut down and how much power online units should generate. Constraints to the objective functions include requiring total system generation meet total system load, the technical limitations of generators (such as ramp rates and minimum up/down times), temporal energy limits, nodal power balance, and linearized power flow equations, among others.

A new decomposition method described in [37] was adopted to complete the day-ahead unit commitment phase to improve representation of realistic operations for multiple regions, reducing solve times by three orders of magnitude. This method enables unit commitment and dispatch to be simulated independently for each region (independent system operator, ISO/regional transmission organization, RTO); application of this method here is to a model larger than any yet attempted.

The 2038 PCM includes approximately 13000 generating units, 98000 transmission nodes, and 96000 transmission lines and transformers. Wind data is from the Wind Integration National Dataset (WIND) Toolkit, and solar data is from the National Solar Radiation Database (NSRDB). Load data is from multiple sources, including the various RTOs, ISOs, and Federal Energy Regulatory Commission (FERC) [14]. Weather conditions for the years 2007–2013 were evaluated for use in the PCM. A geospatial analysis of wind and solar resource availability identified 2012 as the closest to average across the seven-year data set, so the 2012 data was used for wind, solar, and load to maintain correlations and time synchronicity between these data sets.

Thermal plant assumptions were adopted from [38] and enabled detailed modeling of every thermal generator. When possible, existing thermal plants that are still in operation in 2038 have unit-specific plant flexibility characteristics that were extracted by analyzing the Environmental Protection Agency's

TABLE III
SUMMARY OF CGT-PLAN BENEFIT/COST RESULTS FOR BASE SCENARIO

Cost Item, $B	D1	ΔD2a	ΔD2b	ΔD3
Transmission	40.03	2.57	6.76	8.19
Generation	555.23	3.6	10.44	4.17
Operational cost, $B	2376.50	-8.79	-21.70	-15.30
35-yr Net Cost	-	-2.62	-4.5	-2.94
35-yr B/C ratio	-	2.02	1.66	1.36

Note: D1 results are shown as absolute costs; D2a, D2b, and D3 results are shown relative to D1.

TABLE IV
35-YEAR NET COST SAVINGS FOR SENSITIVITIES ($B)

Sensitivity	ΔD2a	ΔD2b	ΔD3
Base Case	-2.62	-4.5	-2.94
Low Gas Price	-2.91	-4.15	-2.38
High Gas Price	-4.67	-9.51	-5.88
High AC Trx Cost (1.5x)	-2.23	-5.35	-4.56
High AC Trx Cost (2x)	-2.08	-5.46	-5.48
No retirements	-1.24	-1.58	-0.82
Low-cost renewables	-2.87	-4.78	-3.00
High VG	-18.35	-28.83	-23.04

Note: D2a, D2b, and D3 results are shown as savings relative to D1. Emission costs included in the High VG scenario are not included in Net Costs.

TABLE V
35-YEAR BENEFIT/COST RATIO FOR SENSITIVITIES

Sensitivity	ΔD2a	ΔD2b	ΔD3
Base Case	2.02	1.66	1.36
Low Gas Price	1.81	1.52	1.22
High Gas Price	1.76	1.84	1.46
High AC Trx Cost (1.5x)	1.87	1.45	1.29
High AC Trx Cost (2x)	2.26	1.52	1.37
No retirements	1.98	1.72	1.33
Low-cost renewables	2.53	1.77	1.56
High VG	2.09	2.89	1.80

Note: D2a, D2b, and D3 results are shown relative to D1. Emission costs included in the High VG scenario are not included in ratio.

Continuous Emissions Monitoring System. When unit-specific data was unavailable, generic assumptions were made based on the generator vintage and type.

Contingency and regulation reserves are held regionally, either by ISO/RTO boundary or by FERC Order 1000 planning region. The amount of regulation required is calculated using the method described in Ibanez *et al.* [39]. The method determines the amount of reserves required to cover the uncertainty and variability of the load, wind, and solar.

IV. RESULTS

A. Costs and Benefits

In this section, the results of the generation and transmission expansion through 2038 are described, for the four transmissions designs in the base case (Table III) and then the suite of eight scenarios (Tables IV and V). The capacity expansion model was used to assess the costs and benefits of each of the study scenarios and designs, using the investment costs and operating costs for

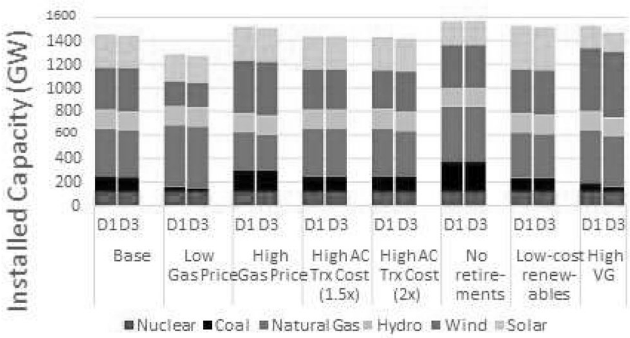

Fig. 3. Installed generation capacity by resource type in 2038. The installed capacity was determined using CGT-Plan.

the years 2024–2038, plus 20 years with no load or generation growth after 2038 in order to reduce the impacts of end effects. Because D1 was the only design that did not allow cross-seam transmission investment, it is reference for comparison for the other three designs; positive numbers indicate cost increases and negative indicates cost decreases. The investment and operational costs for each transmission design in the base case are presented in Table III, where the 35-year net cost change (total transmission and generation investment costs plus operational cost, relative to D1) is greatest for D2b and D3 in each scenario.

An important observation from Table III is that the benefit-to-cost (B/C) ratio, calculated as the change (relative to D1) in the generation investment and operational cost divided by the change in the transmission investment cost, is well above the industry threshold of 1.25 considered necessary to justify transmission investments [40]. Most of the benefit occurs as a result of reduction in generation operational costs enabled by increased transfer capability provided by transmission builds. The values shown may be considered as lower bounds on B/C ratios since they do not reflect externalities nor non-quantified benefits such as increased resiliency of the electric system to continue supplying low-cost energy during catastrophes such as large hurricanes and widespread wildfires. While including these details could increase overall costs of the scenarios, transmission would likely continue to have additional benefits.

Tables IV and V show the 35-year net cost savings and benefit to cost ratios for D2a, D2b and D3, relative to D1 for the various scenarios. The cost (net present value) of the D1 design under the base case conditions is $B29712. Though D2a consistently produces the highest B/C ratio among the three cases per sensitivity, D2b results in the greatest potential net cost savings.

The B/C ratio in almost every case (except D3 for the low gas price case) remains above the 1.25 threshold mentioned above. In most cases, it is significantly higher.

The 2038 installed generation capacity from CGT-Plan is presented in Fig. 3 for D1 and D3. Maps of the resulting AC and DC (post-translation) transmission additions are shown in Fig. 4. Fig. 3 reveals a slight decrease in installed capacity in all scenarios in designs D3, relative to D1 (D2a and D2b, not shown, are all between D1 and D3). The High VG scenario has the largest capacity reduction and the most transmission. Tables VI and VII identify the additional transmission capacity added in the Base and High VG scenarios. Each design requires significant AC transmission expansion, but this AC transmission expansion is less for the designs with high HVDC capacity (D2b and D3). Additional details on the CGT-Plan modeling are provided in [13], [16].

TABLE VI
TRANSMISSION INVESTMENT SUMMARY, BASE SCENARIO

Design→	D1	D2a	D2b	D3
HVDC-B2B (GW)	0	6.7	6.3	0
HVDC-Line (GW-miles)	0	0	14,487	29,062
AC Line (GW-miles)	18,409	19,357	17,778	16,076

Note: New transmission investments are identified, for B2B in terms of GW increased capacity between B2B terminals; and also, for lines, in terms of GW-miles, which is the GW capacity multiplied by the path distance.

TABLE VII
TRANSMISSION INVESTMENT SUMMARY, HIGH VG SCENARIO

Design→	D1	D2a	D2b	D3
HVDC-B2B (GW)	0	25.7	7.5	0
HVDC-Line (GW-miles)	0	0	31,335	63,156
AC Line (GW-miles)	52,737	60,141	50,964	43,190

B. System Operations

An hourly PCM is used to help evaluate the operability of a given scenario by simulating an entire year of hourly operations, as opposed to the time slices used for capacity expansion. The PCM simulated the operations of the 2038 power systems built by the penultimate (and largely similar to the final) version of CGT-Plan buildout. The base case is compared to the high VG scenario, as they showed the most operations, as opposed to the time slices used for capacity expansion. The PCM simulated the operations of the 2038 power systems built by the penultimate (and largely similar to the final) version of CGT-Plan buildout. We compare the base case to the high VG scenario, as they showed the most differences in B/C ratio, net cost savings, and overall generation buildout. In those simulations, all of the power systems met all load in all hours and met 99.69%–99.97% of all contingency and regulation reserve requirements. In both of the capacity scenarios, D1, the design with the least cross-seam transmission capacity, had the largest total reserve shortage. In the PCM modeling, nuclear generation did not change across the scenarios. Fossil fuels provided 36% of generation in the four Base designs and approximately 26% in the four High VG designs. Wind and solar increased from just under 30% in the Base designs to just under 40% in the High VG designs.

VG curtailment ranged from 11%–15% across all scenarios and designs. A review of curtailment outcomes indicates that congestion on AC transmission lines is a significant driver of curtailment. Other options, such as additional energy storage investment or additional demand response, may also become economically attractive at these curtailment levels, but they were not considered as an investment option. Additional analysis

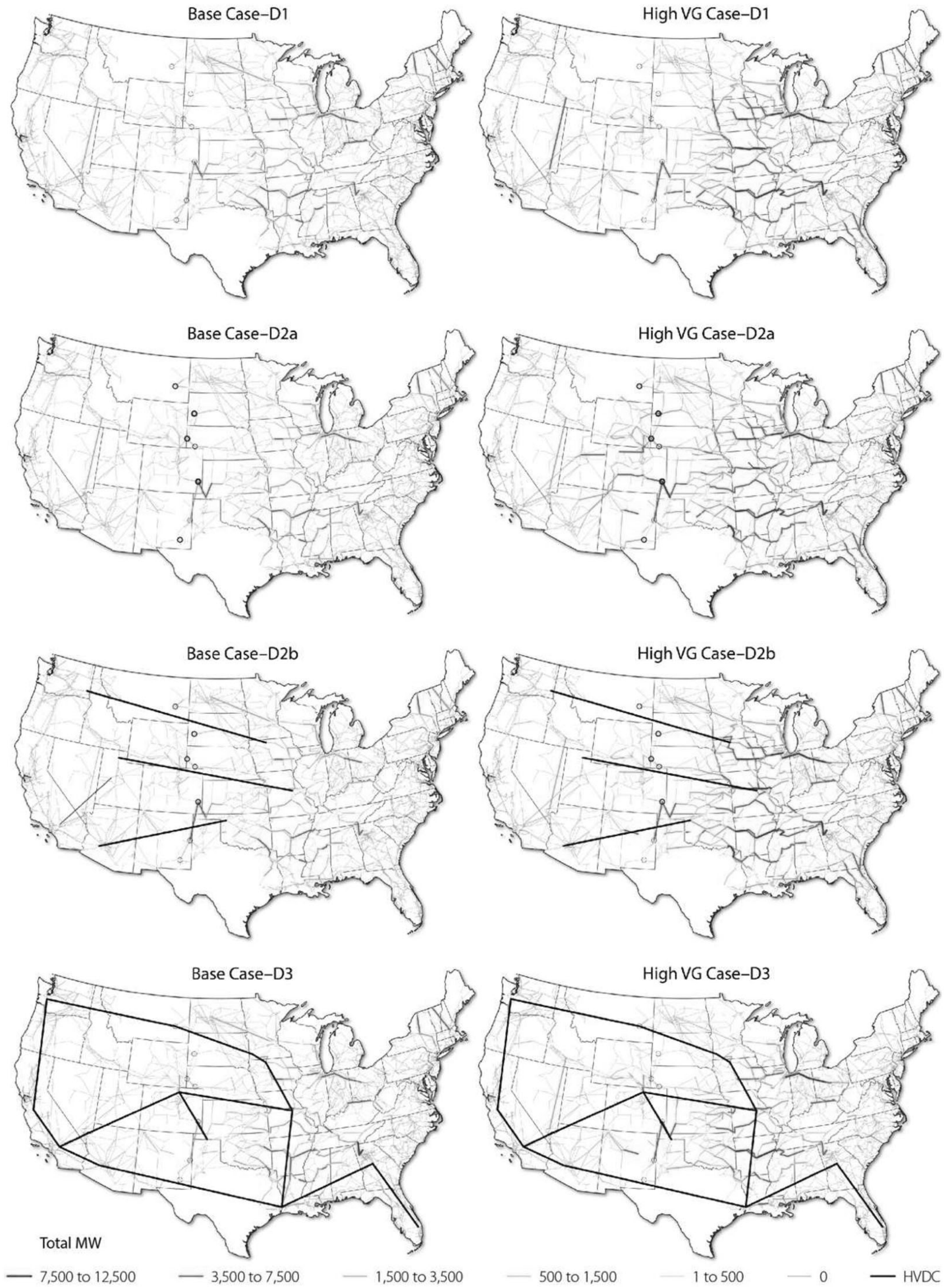

Fig. 4. Maps of the resulting AC and DC transmission additions between 2024 and 2038 from the TEP (i.e., post-translation and as modeled in the PCM). On the left are the four transmission designs in the base scenario. The results for the designs in the high VG scenario are on the right.

is necessary to understand the tradeoffs between curtailment, transmission, storage, and other options.

In addition to assessing overall system performance in 2038, the PCM was also used to conduct a detailed analysis of extreme time periods based on 2012 load and meteorology. Two such cases that reflect periods of high net-loads and ramping are presented, as well as the value of cross-seam transmission in potentially mitigating them. The first period is the three-day period in August around the coincident peak load across the EI and WI. The hourly cross-seam flow across the B2B and HVDC lines during this period is displayed in Fig. 5. There is a strong diurnal pattern in the aggregate power flow across the interconnections seam during this period in all transmission designs. In the afternoon, the load in the EI begins to peak. At the same time, solar PV generation is high in the WI, while the WI load is still relatively low. Cross-seam lines are nearly

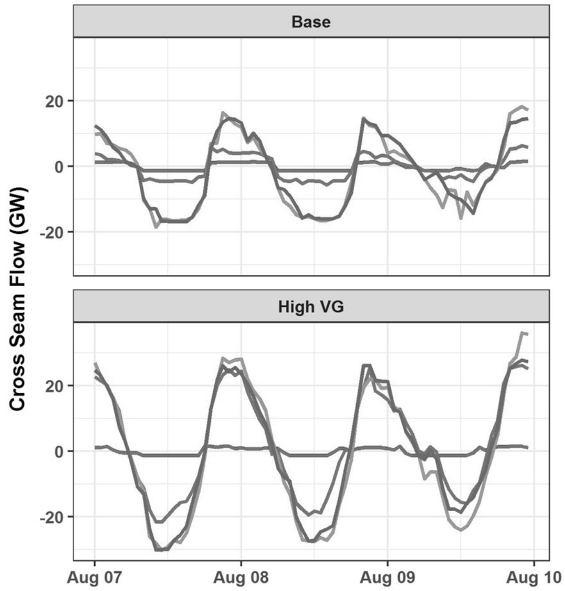

Fig. 5. Cross-seam transmission power flow (B2B and HVDC) during the coincident peak load period. A positive flow is a net export from the EI to the WI; a negative flow is a net import into the EI from the WI. Times are Eastern Standard Time.

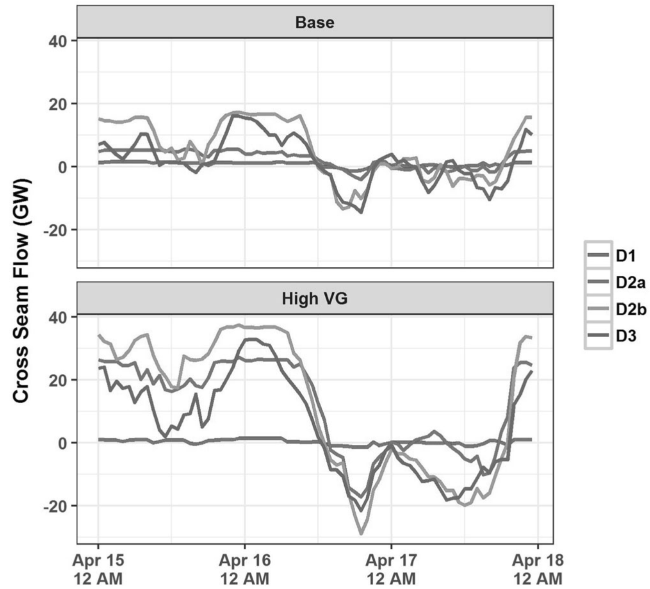

Fig. 6. Cross-seam transmission power flow (B2B and HVDC) during a large down-ramp in Midwest wind generation. A positive flow is a net export from the EI to the WI; a negative flow is a net import into the EI from the WI. Times are Eastern Standard Time.

fully loaded and are used to flow power from the WI to EI. As the sun begins to set on the West Coast, load decreases in the EI and wind in the Midwest increases its output. The flow on the cross-seam lines changes direction, delivering power from the EI to the WI. The lines export Midwestern wind power and power from thermal units that otherwise would have turned off after the EI peak load.

A three-day period in April was analyzed. On the first day of this period, April 15th, the VG instantaneous penetration hovers around 60% of total generation for all designs in both scenarios. VG curtailment is also significant throughout the day. However, in the late morning hours of the next day, April 16th, Southwest Power Pool (SPP) wind begins a steady ramp down, and a decrease in Midcontinent Independent System Operator (MISO) wind follows. Fig. 6 shows how cross-seam transmission helps respond to this event. On April 15th, the cross-seam HVDC is used to export wind from SPP and MISO to the WI. But as the wind power drops off on the morning of April 16th, the flow changes direction, and the WI begins exporting to the EI. Rather than requiring SPP and MISO to deal with the down-ramp in wind on their own, cross-seam transmission allows lower-cost resources in the WI to help balance the loss of the wind power on the other side of the seam.

V. Conclusion/Next Steps

This study demonstrates significant novelty in its multi-model approach. Combining CGT-Plan and PCM allowed for a thorough assessment and evaluation of the benefits and costs of four alternative cross-seam transmission designs in the United States and eight generation and transmission cost scenarios. The study also deploys novel modeling techniques to 1) characterize the value of capacity sharing, and 2) enable a nodal simulation of every generator and transmission line in the two largest North American Interconnections. This paper provides a macrogrid design methodology that is deployed on realistic, and very large models spanning the two major interconnections of the North American continent; it shows that macrogrid operation is operationally feasible and economically attractive. The paper contributes to the methodological features necessary to pursue scientific inquiry regarding macrogrid design, and it unearths knowledge and understanding about macrogrid deployment that contributes to the scientific knowledge base.

The study shows with increased intercontinental transmission that the system was able to balance generation and load with less total system installed capacity across each of the generation scenarios, due to load and generation diversity, and increased operating flexibility. The results show a robust benefit-to-cost ratio ranging from 1.2 to 2.5 over different HVDC designs and different conditions, indicating significant value to increasing the transmission capacity between the interconnections and sharing generation resources for all the cost futures studied. Production cost modeling identified that new lines would likely have high utilization during challenging operational periods throughout the year.

While fundamental elements of transmission and generation were represented throughout the study, additional modeling and analysis is required to further examine the alternative grid designs and evaluate the technical and economic benefits. For example, there may be value to studying a distributed PV annual growth rate beyond the 3% assumed here, though even an aggressive 7% assumption (the highest rate assumed in [41]) would only reduce total generation growth of other forms from 600 GW to 515 GW and would be unlikely to reduce benefits from sharing reserves and peaking capacity. Contingency analysis, particularly for new HVDC designs D2a, D2b, and D3, is an essential step in going forward. Industry review and input will remain vital to further evaluation of potential transmission expansion across the interconnections, as studies often present the most optimal solution given the model inputs. Additionally, this study does not address market adoption feasibility as well as other technical details needed to develop a more thorough understanding of system reliability implications (e.g., dynamic power flow, voltage stability, more complete contingency analysis). Full exploration of the potential benefits and costs of cross-seam transmission to the continent will require additional multi-model analysis.

This study provides a platform for conducting additional research at a large geographic scale, and recent efforts indicate such research is ongoing [13], [31]–[33], [42]. Potential reliability and resilience benefits of transmission could be explored through AC power flow studies with steady-state and stability modeling; consideration of system resilience and security requirements related to weather and extreme conditions; and incorporation of natural gas delivery infrastructure and gas-electric operational coordination. Additional analyses could estimate additional system- and local-level costs and benefits (e.g., economic and environmental impacts).

Acknowledgment

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Expensive energy may have killed more Europeans than covid-19 last winter

Our modelling estimates that high energy prices claimed 68,000 lives

After russia invaded Ukraine in February 2022, Vladimir Putin weaponised his country's energy supplies: cutting gas exports to Europe and causing prices to surge. Although wholesale costs have now fallen across the continent, the prices of domestic electricity and gas, compared with two years earlier, were up by an eye-watering 69% and 145% last winter.

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Our modelling estimates that high energy prices claimed 68,000 lives

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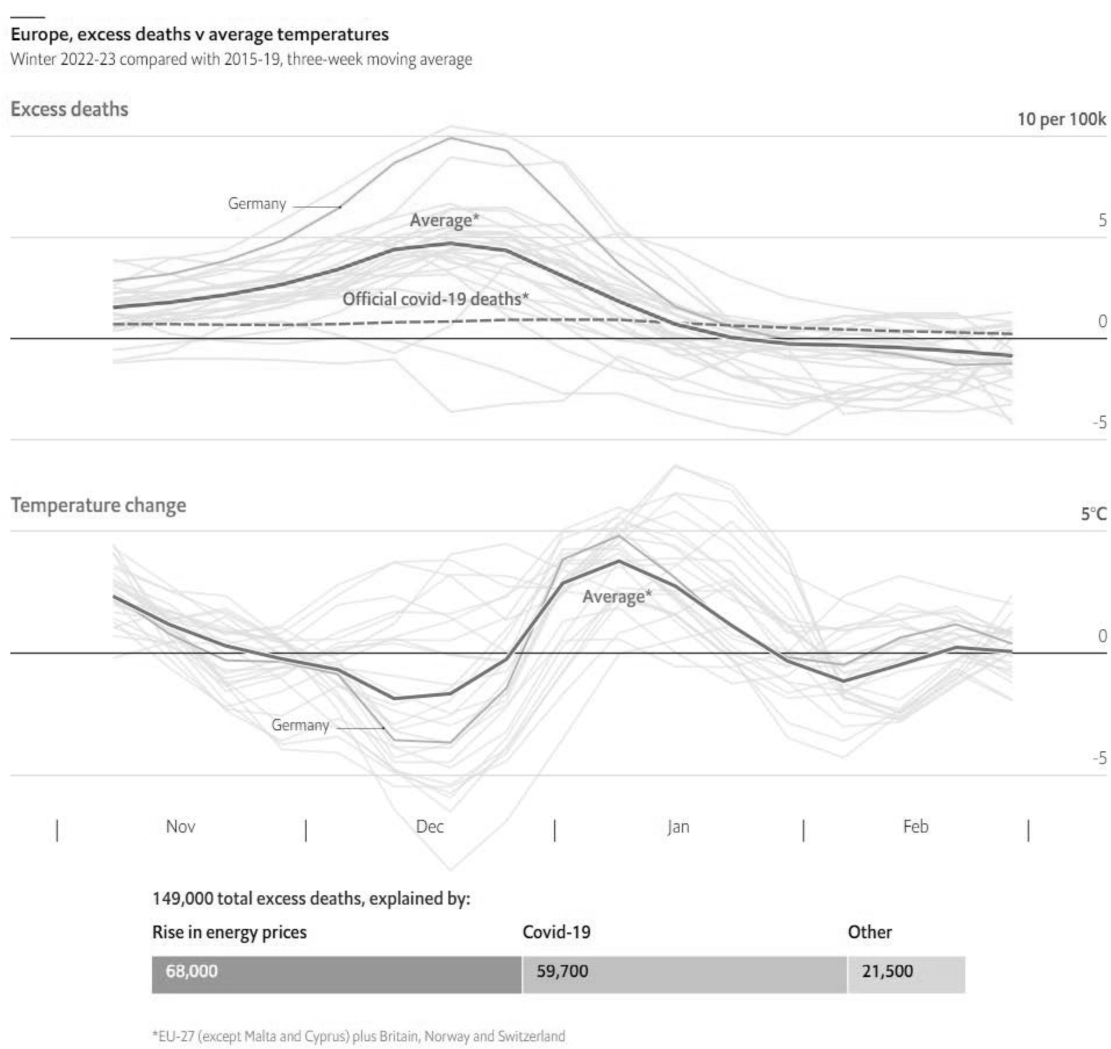

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High energy prices can cost lives. They discourage people from heating their homes properly, and living in cold conditions raises the risk of cardiac and respiratory problems. In November *The Economist* predicted that expensive power might result in between 22,000 and 138,000 deaths during a mild winter. Unfortunately, we appear to have been correct.

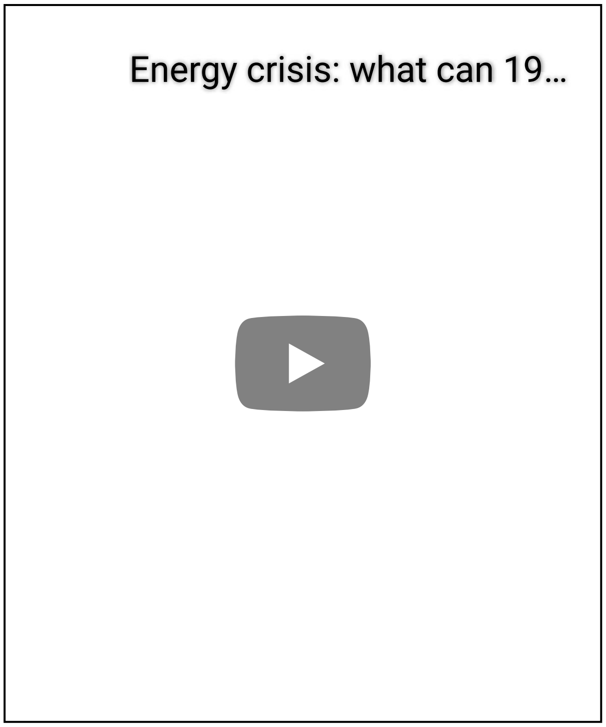
To assess how deaths last winter compare to previous ones we have used a common measure of mortality: excess deaths. Comparing actual deaths with the number we might expect given mortality in the same weeks of 2015-19, we found that deaths across Europe were higher than expected. Across 28 European countries we investigated, there were 149,000 excess deaths between November 2022 and February 2023, equivalent to a 7.8% increase.

Several factors might explain this rise. Among those that died last winter, nearly 60,000 were recorded as covid-19 deaths. The disease probably contributed—directly or indirectly—to more, but it is unlikely that it can account for all of last winter's surge. Between March 2020 and September 2022 the official covid death count was 79% of total excess deaths among our 28 countries. Last winter it was 40%.

The weather has also affected the number of deaths. A cold snap in December was accompanied by a rise in mortality. A drop of 1°C (1.8°F) in the average temperature over a three-week period is associated with a 2.2% rise in total deaths. However, last winter was milder than the average of 2015-19, so the cold alone cannot be responsible for the additional deaths.

It appears that high energy prices might have had an effect. Looking across countries reveals that those with the highest excess deaths typically experienced the biggest increases in fuel costs. To disentangle energy costs from covid and temperature changes we have built a statistical model. Our model also accounts for a country's demographics, the number of covid deaths prior to last winter and historic underreporting of those deaths.

We estimate that a price rise of around €0.10 per kWh—about 30% of last winter's average electricity price—was related to an increase in a country's weekly mortality of around 2.2%. If electricity last winter had cost the same as it did in 2020, our model would have expected 68,000 fewer deaths across Europe, a decline of 3.6%.



Deaths in Europe might have been higher had governments not intervened in energy markets (although lower prices bid up demand, causing problems elsewhere in the world). Using data from VaasaETT, a consultancy, we have estimated how many excess deaths would have occurred had bills not been reduced by price caps or lower sales taxes. Across 23 countries our model finds that these subsidies saved 26,600 lives. As wholesale energy prices fall and temperatures rise, the immediate threat may be over, but it is clear Mr Putin's energy weapon was deadly.■

Chart sources: The Economist's excess-deaths tracker; Copernicus; HEPI

October 21, 2022

RECEIVED
By The Federal Energy Regulatory Commission Office of External Affairs at 10:15 am, Oct 24, 2022

The Honorable Richard Glick
Chairman
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

The Honorable Allison Clements
Commissioner
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

The Honorable James Danly
Commissioner
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

The Honorable Mark Christie
Commissioner
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

The Honorable Willie Phillips
Commissioner
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Dear Chairman Glick and Commissioners Danly, Clements, Christie, and Phillips,

We write to express our support for the Gas Transmission Northwest (GTN) Xpress project, docket number CP22-2. The GTN Xpress project will greatly expand the Pacific Northwest's regional transportation capacity of low-cost natural gas and must be completed without delay.

The GTN Xpress project will help meet growing demand for natural gas from residential, commercial, and industrial consumers in Idaho and in the rest of the Pacific Northwest by adding 150,000 dekatherms per day (Dth/d) of natural gas to the current GTN system. The project developer seeks to modify three existing compressor facilities at various points along the pipeline. These facility modifications will provide the needed energy transportation service with minimal, if any, impacts on landowners or the environment.

The Intermountain Gas Company (Intermountain), which serves more than 400,000 customers in 74 communities in Idaho, has executed a binding precedent agreement with the project sponsor to use over half of the project's new capacity for the next 30 years. The new capacity will help meet the natural gas needs of Intermountain's customer base, which is expected to grow by 2.8-

percent every year. The remaining percentage of the new project capacity has also been claimed by two other shippers with 30-year precedent agreements, clearly indicating region-wide public need.

We are aware of arguments that FERC should base its infrastructure determinations off of arbitrary "clean energy standards" adopted by Idaho's neighboring states. However, this would directly conflict with FERC's other recent proceedings. The commission concluded earlier this year that "claims that a project is not needed because of [state] legislation related to reducing GHG emissions are not sufficient to undermine [a] finding that [the applicant] has demonstrated a need for the project through a precedent agreement for 100% of the project."

It is clear FERC must implement the Natural Gas Act (NGA) as Congress intended, which, as the Supreme Court has held, is to "encourage the orderly development of plentiful supplies of ... natural gas at reasonable prices." FERC does not have the authority to abandon the NGA's mandate based on individual state policy goals. Attempts to use the NGA to impose individual state policy preferences on other states would be misguided and clearly conflict with observable, real-life need for additional pipeline capacity.

Given these legal considerations, the demonstration of clear market signals, and the need for low-cost, reliable energy, FERC must move quickly in the approval process for the GTN Xpress Project. GTN Xpress currently serves as a critical component of the Pacific Northwest's energy infrastructure, and this expansion presents a great opportunity to ensure continued service for years to come.

Sincerely,

James E. Risch
U.S. Senator

Brad Little
Governor of Idaho

Mike Crapo
U.S. Senator

M.C.
Mike Simpson
Member of Congress

Russ Fulcher
Member of Congress