Summer Energy Market and Electric Reliability Assessment

2024

A Staff Report to the Commission

FEDERAL ENERGY REGULATORY COMMISSION
Office of Energy Policy and Innovation
Office of Electric Reliability

PREFACE

The 2024 Summer Energy Market and Electric Reliability Assessment (Summer Assessment) provides staff's outlook for energy markets and electric reliability focusing on the upcoming period from June to September 2024. The report contains four main sections. The first section summarizes the findings of the Summer Assessment. The second section details the weather outlook for summer 2024. The third section discusses energy market fundamentals, primarily electric market and natural gas supply and demand expectations, including expected North American Electric Reliability Corporation (NERC) regional resource adequacy estimates. The fourth section highlights unique issues nationwide, specifically addressing the potential implications on United States (U.S.) energy markets of drought, hydroelectric power availability, wildfires, and reliability risks. The 2024 Summer Assessment is a joint report from the Commission's Office of Energy Policy and Innovation's Division of Energy Market Assessments and the Office of Electric Reliability's Division of Engineering and Logistics.

KEY FINDINGS

Weather Outlook: This coming summer, temperatures are expected to increase above normal, resulting in increased electricity demand for cooling. The U.S. National Oceanic and Atmospheric Administration (NOAA) forecasts a 60-70% likelihood of above-normal temperatures for the months of June, July, and August in the eastern and western United States, and increased chances of above-normal temperatures for the months of July, August, and September especially in the Northwest and Southwest regions. Other weather phenomena affecting electricity demand, including La Niña-Southern Oscillation, and seasonal storms along the Gulf Coast and the Eastern Seaboard, may also affect overall energy markets and grid reliability.[1]

Energy Market Fundamentals and Electric Reliability: Average wholesale electricity prices for summer 2024 in most areas of the country are expected to be close to, or slightly lower than, average wholesale electricity prices in summer 2023 because of modest declines in generation fuel costs. Total net summer generating capacity is projected to grow in summer 2024 compared to last summer by 3.4%, to 1,207 gigawatts (GW), with most additions coming from solar and wind resources and most retirements from coal resources. On the demand side, the U.S. Energy Information Administration (EIA) projects that total load will increase by 4.4% (39.75 terawatt hours) relative to summer 2023 for the continental United States, with new data centers being a significant contributor to this growth.[2] As for infrastructure, nearly 2,000 miles of Bulk Power System (BPS) transmission lines are either expected to be completed by the end of summer 2024 or already entered service this year, with the largest number of projects in the Electric Reliability Council of Texas (ERCOT), Midcontinent Independent System Operator (MISO) and PJM Interconnection LLC (PJM).[3] Based on data submitted by the regions, NERC anticipates all regions will have adequate resources available to meet the expected operating reserve requirement under a normal demand scenario but that the ERCOT and MISO regions, and the ISO-New England (ISO-NE), WECC-CA/MX and WECC-SW subregions, could face a resource shortfall under an extreme demand scenario and may need to rely on operating mitigations.[4]

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1 NOAA, *El Niño & La Niña* (*El Niño-Southern Oscillation*), https://www.climate.gov/enso.

2 Summer is defined as June, July, August, September. EIA, *Short Term Energy Outlook* (Mar. 12, 2024).

3 NOAA, *El Niño & La Niña* (*El Niño-Southern Oscillation*), https://www.climate.gov/enso.

4 The Northeast Power Coordinating Council-New England (NPCC-NE) and the Western Electric Coordinating Council (WECC) subregions of California/Mexico (CA/MX), and WECC-Southwest (SW) are further described in Footnotes 51 and 53.

Natural Gas Fundamentals: Summer 2024 average natural gas futures prices at Henry Hub, the national benchmark, and many major hubs as of May 1, 2024, were lower than the average final ("settled") futures prices for summer 2023. However, futures prices at Transco-Z6 in New York City and Mid-Atlantic Eastern Gas-South near Pittsburgh were higher than the average prices for each location last summer as regional natural gas demand growth in these regions is expected to outpace stable natural gas production in the Northeast. As of May 1, 2024, the Henry Hub futures contract price for summer 2024 averaged $2.25 per million British thermal units (MMBtu), down 9% from last summer's settled prices. In the West, natural gas prices are expected to decline by more than 30% from last summer's prices, although they are projected to remain the highest of any region in the country during summer 2024. Prices are projected to average $3.62/MMBtu at SoCal-Citygate, the main southern California trading hub, and $3.12/MMBtu at PG&E Citygate, the hub east of San Francisco Bay. At the Waha hub in the Permian Basin, futures prices averaged $1.08/MMBtu, down 47% from last summer's settled futures price of $2.04/MMBtu. According to EIA, lower prices for the coming summer are expected because the United States enters the season with relatively high levels of natural gas in inventory, 23% more than last year, following reduced natural gas consumption in the residential and commercial sectors last winter (November 2023-March 2024). Summer natural gas production is forecast to average 102.3 billion cubic feet per day (Bcfd), a slight decline of 1.6% relative to last summer and 5.8% above summer 2024 natural gas demand.

Summer natural gas demand is forecast to average 96.7 Bcfd, 1.7% above summer 2023 levels, continuing a trend of growth in recent years. Natural gas consumption for electricity generation, also known as power burn, is expected to remain steady, making up around 45% of total natural gas demand this summer. The share of U.S. electricity generated from natural gas power plants is also forecast to average close to 45%, down about 1% from last summer. Natural gas exports, including liquified natural gas (LNG) and pipeline net exports, are expected to increase 11% from last summer, contributing the most to year-over-year summer demand growth and making up 14% of total demand this summer. Residential/commercial usage is expected to grow 7.8% from last summer, making up 9.5% of total demand this summer. Industrial/other sector demand is forecast to be 1.6% lower than last summer, notwithstanding expected low natural gas prices, to make up about 30% of total demand this summer.

Notable Issues: Notably, anticipated summer heat, natural gas supplies, and hydrologic conditions could affect electric reliability and energy market outcomes this summer. According to NOAA, there is a one-in-three chance that 2024 will exceed 2023's heat record, and a 99% chance that 2024 will rank among the five warmest years on record.[5]

Drought and hydrological conditions also help determine the mix of U.S. electricity generation. The North American Drought Monitor, a joint effort between U.S., Canadian, and Mexican government agencies, states that roughly 39% of the United States is currently affected by drought or abnormally dry conditions, potentially affecting hydropower output in summer 2024.[6] Lower levels of snowpack in the West may also reduce hydropower output compared to summer 2023 and may increase the reliance on natural gas for power burn in the West to meet air conditioning or

5 NOAA National Centers for Environmental Information, *Monthly Global Climate Report for March 2024* (April 2024, accessed May 7, 2024), https://www.ncei.noaa.gov/access/monitoring/monthly-report/global/202403.

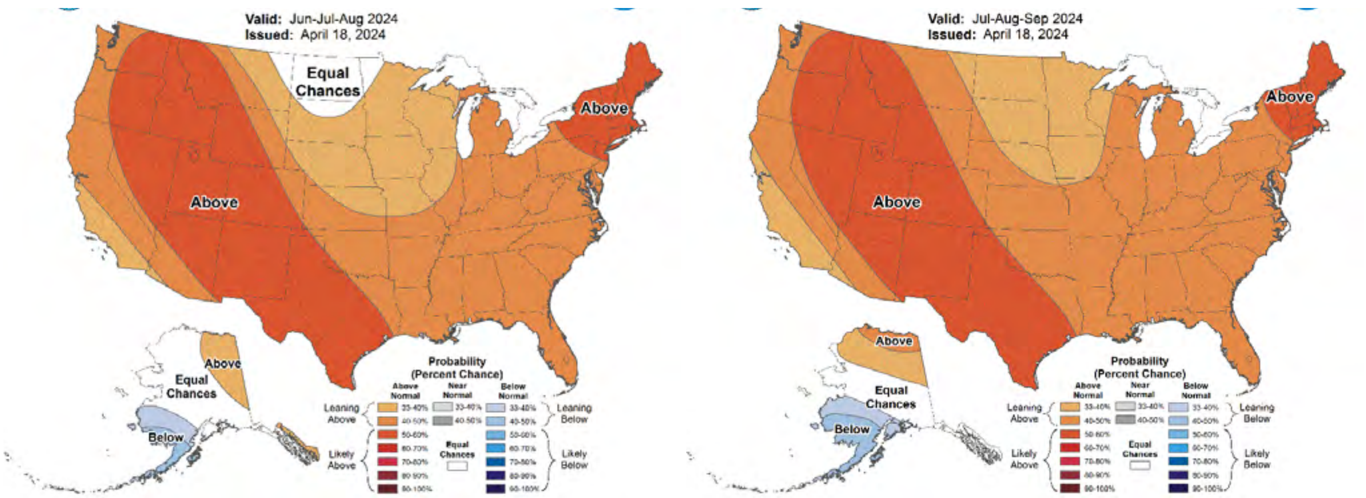
6 Major US participants in the NADM program include NOAA's National Centers for Environmental Information, NOAA's Climate Prediction Center, the US Department of Agriculture, and the National Drought Mitigation Center. Major participants in Canada and Mexico include Agriculture and Agrifood Canada, the Meteorological Service of Canada, and the National Meteorological Service of Mexico (SMN - Servicio Meteorologico Nacional).

“cooling” electric loads.[7] Supply chain trends also pose a risk this summer as availability of equipment and materials continue to be disrupted by both economic and geopolitical events. Additionally, data centers have rapidly increased electricity demand this summer throughout many areas of the country.

WEATHER OUTLOOK

Weather is a fundamental determinant of the demand for energy. Summer loads usually stress the electric infrastructure.[8] Warmer temperatures in the summer typically increase the demand for electricity for cooling and natural gas for power burn to help meet that demand. Weather can also impact the supply of energy. Weather events, such as hurricanes making landfall along the Gulf Coast, can impact the production of crude oil and natural gas or damage electrical infrastructure.

Figure 1: NOAA Seasonal Temperature Outlook



Source: NWS 3 Month Outlook, March 21April 18, 2024, Issue Date.

As with the past two years, NOAA forecasts that temperatures this summer will be above normal for most of the United States compared to NOAA’s 1991-2020 U.S. Climate Normals, a collection of thirty years of historical data that reflect typical conditions.[9] As shown in **Figure 1**, for June, July, and August, NOAA projects that above-normal temperatures are more than 50% likely to occur throughout the continental United States, with only North Dakota and portions

7 NIDIS, *Drought Status Update*, (April 3, 2024), https://www.drought.gov/drought-status-updates/snow-drought-current-conditions-and-impacts-west-2024-04-03,EIA, *Hydropower Explained* (Mar. 29, 2024), https://www.eia.gov/energyexplained/hydropower/where-hydropower-is-generated.php.

8 NOAA National Centers for Environmental Information, *Monthly National Climate Report for July 2023* (July 2023, accessed May 7, 2024) https://www.ncei.noaa.gov/access/monitoring/monthly-report/national/202307. Note that power system equipment is unable to cool down in the overnight hours due to warmer nighttime temperatures, creating additional strain on equipment during multi-day events.
Above-average seasonal temperatures can contribute to high peak demand, as well as an increase in some generation and equipment forced outages, straining capacity and infrastructure. *NERC, 2024 Summer Reliability Assessment* (May 15, 2024). https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2024.pdf.

9 NOAA, *U.S. Climate Normals*, https://www.ncei.noaa.gov/products/land-based-station/us-climate-normals.

South Dakota, Montana, and Minnesota expected to have an equal chance of above- or below-normal temperatures. Chances of above-normal temperatures are highest, at 60-70%, along the Mountain West, Desert Southwest, and Northeast. For July, August, and September, chances of above-normal temperatures increase throughout the West, especially in the Northwest, Southwest, and the East Coast.

High temperatures that are widespread can intensify stressed conditions on the electric grid by creating high electricity demand across a wide geographic area and reducing the availability of imported electricity from neighboring systems because they are also experiencing high demand.[10]

La Niña-Southern Oscillation

Following record-breaking warm weather and El Niño during summer 2023, the National Weather Service currently forecasts 69% odds for a La Niña condition to emerge for summer 2024.[11] The La Niña-Southern Oscillation (ENSO) is an oscillating warming and cooling climate pattern that can impact global weather conditions, wind patterns, and directly affect rainfall distribution in the tropics and strongly influence weather across the United States and other parts of the world.[12]

In North America, La Niña weather conditions typically drive weather patterns with large portions of the central United States more likely to experience increased storms, and decreased precipitation in the southern United States. La Nina conditions also affect ocean wind patterns, reducing wind shear that limits hurricane formation, thereby creating more favorable conditions for hurricane formation, with potential elevated risk for the coastal United States.

Storm/Hurricanes Forecast

Hurricane weather conditions bear watching because they can threaten offshore oil and natural gas production, electric transmission networks, and grid infrastructure along the Gulf and Atlantic Coasts. The Atlantic hurricane season runs from June 1 through November 30, typically peaking in late summer or early fall. The 2023 hurricane season was the fourth-most active on record, producing 20 named storms, of which seven became hurricanes and three intensified into major hurricanes.[13] On average, an Atlantic hurricane season has 14 named storms, seven hurricanes, and three major hurricanes.[14]

While NOAA will release the 2024 Atlantic hurricane outlook on May 23 for this season, Colorado State University issued an early-season warning of a potentially active hurricane season for 2024 given continued record-warm

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10 Unprecedented periods of extreme temperatures, referred to as "heat domes," occur when strong, high-pressure atmospheric conditions trap sweltering heat over large areas. The daily average and maximum temperatures under a heat dome are typically significantly above normal. Severe Weather Europe, *A Historic, Record-Shattering Heatwave is Forecast for the Midwest This Week*, (Oct 1. 2023) https://www.severe-weather.eu/global-weather/historic-heatwave-heat-dome-forecast-midwest-united-states-october-fall-season-2023-mk/ On August 24, temperatures in Chicago soared to 100°F—the first 100°F temperature since July 6, 2012—with a 120°F heat index, the highest ever recorded at Chicago's official climate observation site. NOAA National Centers for Environmental Information, *Monthly National Climate Report for August 2023* (Aug. 2023, accessed May, 2023) https://www.ncei.noaa.gov/access/monitoring/monthly-report/national/202308.

11 NOAA, *El Niño/Southern Oscillation Diagnostic Discussion* (May 9, 2024), https://www.cpc.ncep.noaa.gov/products/analysis_monitoring/enso_advisory/ensodisc.shtml.

12 NOAA, *What is El Niño-Southern Oscillation (ENSO)?*, https://www.weather.gov/mhx/ensowhat (accessed Apr. 1, 2024).

13 NOAA, *2023 Atlantic Hurricane Season Ranks 4th for Most-Named Storms in a Year* (Nov. 28, 2023), https://www.noaa.gov/news-release/2023-atlantic-hurricane-season-ranks-4th-for-most-named-storms-in-year.

14 Colorado State University, *Extended Range Forecast Of Atlantic Seasonal Hurricane Activity And Landfall Strike Probability For 2024* (April 4, 2024), https://tropical.colostate.edu/Forecast/2024-04.pdf.

ocean temperatures and a shift to a La Niña weather pattern more favorable to hurricane storm development.[15] This forecast notes that hurricane activity this summer could extend outside the typical hurricane season, extending from late spring into late summer and fall. Colorado State University states that an "extremely active" hurricane season is expected with a well above-average probability for major hurricanes making landfall along the continental United States coastline and in the Caribbean, with forecast activity near what was seen during 2020.[16] Colorado State University forecasts 23 named storms, 11 hurricanes and five major hurricanes for the 2024 season, nearly double the annual average, with a 62 percent chance of at least one major hurricane making landfall on the U.S. coastline. While early forecasts have higher uncertainty, the greatest risk for enhanced storm development is expected during late summer following the full expected transition to a La Niña weather pattern due to the combination of continued high temperatures across the Atlantic Basin and reduced wind shear. Reduced wind shear allows storms to form and remain organized while high water temperatures provide energy for storm growth.

ENERGY MARKET FUNDAMENTALS AND ELECTRIC RELIABILITY

This section of the report summarizes electricity and natural gas market fundamentals expected for summer 2024, including regional reserve margins, probabilistic assessments and electric generation capacity additions and retirements, as well as natural gas prices, production, and demand.

Electricity Market Fundamentals and Electric Reliability

On balance, much of the nation is forecast to see electricity prices this summer that are similar to, or slightly lower than, those seen in summer 2023, although higher natural gas prices in northeastern markets contribute to higher forecasted electricity prices in that region. Other supply and demand factors include capacity additions, primarily from wind, solar, and battery storage, which should increase aggregate capacity supply, although this expansion is partially offset by retirements of primarily coal capacity in many regions. Electricity demand is expected to grow in line with recent summers — at 4.4% (39.75 TWh) — due to warm weather, economic growth and building of new data centers.

ELECTRICITY PRICES

EIA forecasts that average wholesale electricity prices for 2024 in most areas of the country will be close to, or slightly lower than, summer 2023 because of stable or modest declines in generation fuel costs. ISO-New England (ISO-NE) is anticipated to have higher electricity prices this summer. Additionally, periods of higher-than-expected energy demand due to warmer summer weather or electricity market supply constraints could lead to temporary spikes in wholesale prices.

15 Tom Bayles Michael Braun, *Forecaster Says 2024 Hurricane Season Could be 'Blockbuster.' Others say its too Early to Tell*, WUSF: The World (Feb. 22, 2024). https://www.wusf.org/weather/2024-02-22/2024-hurricane-season-blockbuster-accuweather-el-nino-la-nina-megan-borowski-fpren. Accuweather and TSR have released special out-of-season forecasts due to ocean temperatures.

16 Colorado State University, *Extended Range Forecast Of Atlantic Seasonal Hurricane Activity And Landfall Strike Probability For 2024* (Apr. 4, 2024), https://tropical.colostate.edu/Forecast/2024-04.pdf.

Figure 2: Wholesale Electricity Prices in RTOs/ISOs, Summers 2023, 2024

Source: U.S. Energy Information Administration, *Short-Term Energy Outlook*, January March 2024.

EIA expects wholesale prices to range between $34 per megawatt-hour (MWh) and $49/MWh at major hubs this summer, as shown in **Figure 2**. The EIA forecasts U.S. electricity prices this summer to be similar to 2023 prices in SPP, MISO, PJM, and NYISO. Average prices in CAISO are expected to fall from $57/MWh last summer to $34/MWh (down 40%) this summer. The wholesale markets in the Northeast are expected to have the highest wholesale prices in the nation followed by the Pacific Northwest. EIA forecasts New England wholesale prices to increase in summer 2024, averaging $49/MWh (up 18%).[17]

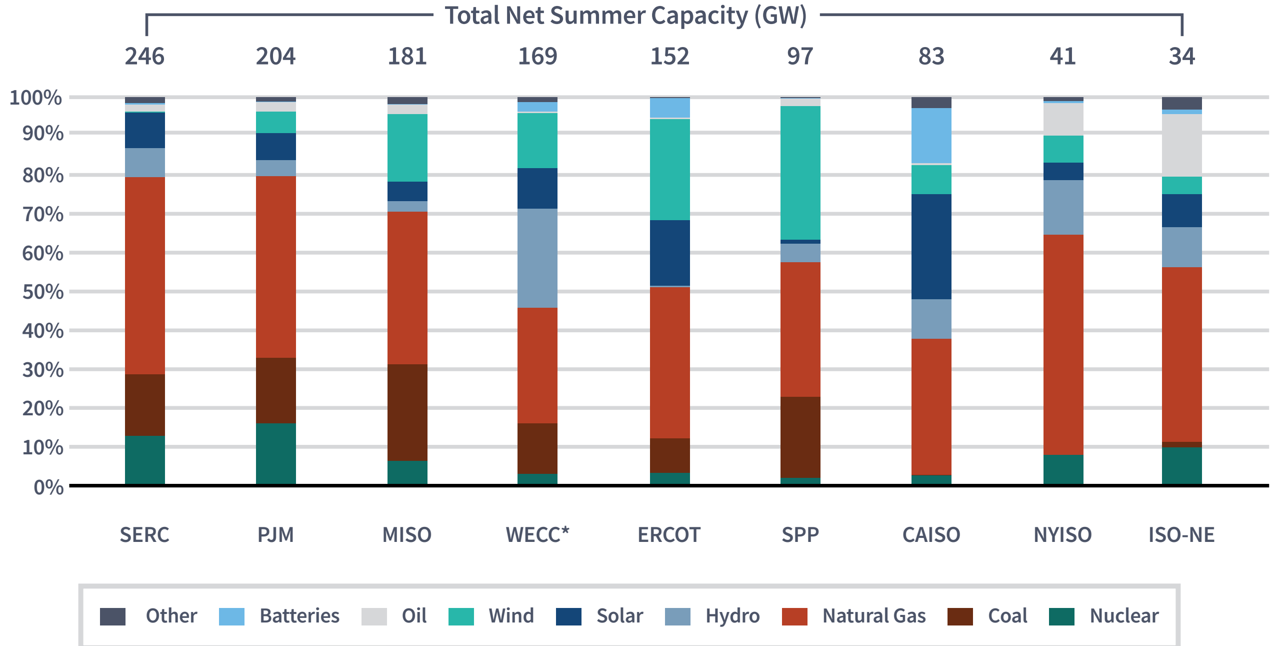
In the Western Interconnection, EIA forecasts that average wholesale electricity prices for summer 2024 will decline from 2023. The Pacific Northwest, the Southwest, and CAISO are all expected to experience declines in price. The region in the country with the largest expected decline is ERCOT, where prices are forecast to drop 79% compared to last summer, from $169/MWh to $35/MWh, primarily due to lower projected natural gas prices.

Electricity prices in U.S. wholesale markets are determined by numerous factors, with natural gas prices the most important one. Natural gas is the predominant generation fuel in all competitive power markets, and natural gas power plants commonly set the wholesale price as the marginal resource.[18] Other factors that can impact electricity price include electricity demand and the prevalence of variable energy resources (see the *Electricity Capacity and Generation* section below). The anticipated impact of natural gas prices this summer is covered in greater detail in the *Natural Gas Prices* section.

17 This section uses EIA forecast prices based on the following locations: CAISO SP 15 zone, SPP ISO South hub, MISO Illinois hub, PJM Western hub, NYISO Hudson Vally zone, ISO-NE Internal hub, and ERCOT North hub.

18 For more information on price formation in RTO/ISO markets, see the *Wholesale Electricity Markets* chapter in FERC's *Energy Primer: A Handbook for Energy Market Basics* (December 2023), https://www.ferc.gov/media/energy-primer-handbook-energy-market-basics.

Figure 3: Total Net Summer Capacity and Percentage Share by Resource Type across the U.S. Expected in September 2024



Source: U.S. EIA Form-860M, March 2024 Release. Data exclude Alaska and Hawaii. WECC* refers to WECC without CAISO.

ELECTRICITY CAPACITY AND GENERATION

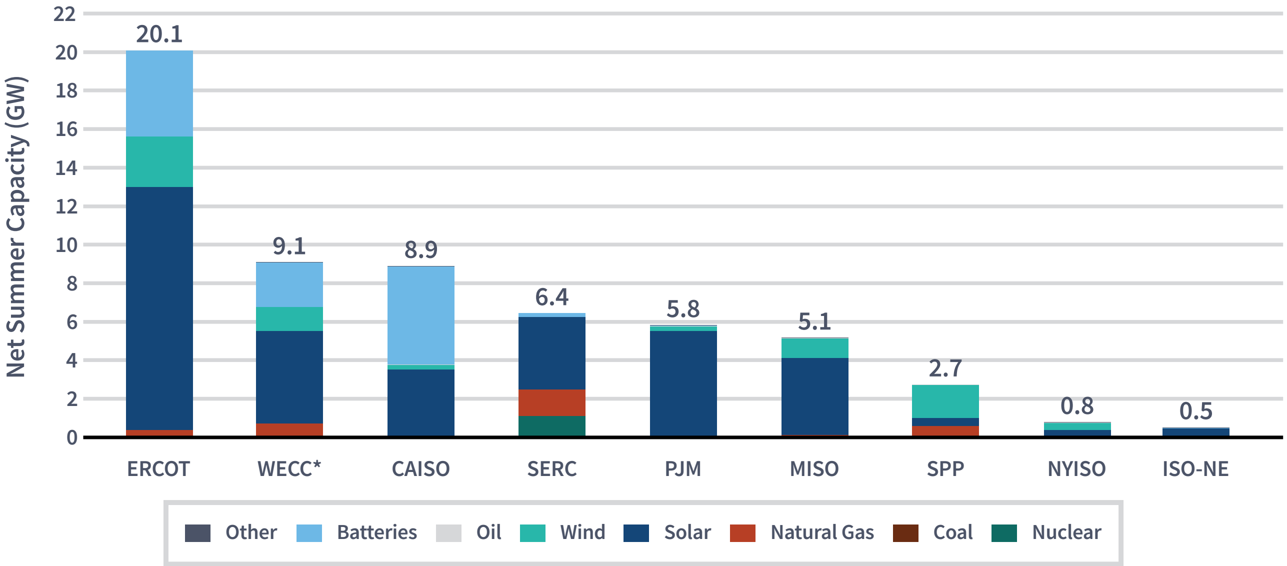
Nationwide summer capacity additions and retirements (measured along with the existing fleet as net summer capacity in GW) are expected to follow recent trends in which most capacity additions have come from solar and wind resources and most retirements from coal resources.[19] Total net summer capacity is expected to increase from 1,167 GW last summer to 1,207 GW across the RTOs/ISOs and other regions in the United States by September 2024.[20] **Figure 3** provides a snapshot of the percentage of net summer electric generation capacity reflecting the expected additions and retirements from the end of last summer through summer 2024.[21]

19 In this section, capacity refers to the maximum output, commonly expressed in MW, that generating equipment can supply to system load, as demonstrated by a multi-hour test, at the time of peak summer demand (period of June 1 through September 30). For wind and solar, which are not suitable for such test procedures, EIA allows respondents to report technically reasonable values for their generators. Some respondents will derate the net summer values from nameplate capacity. EIA checks for internal and historical consistency of these reported capacity values. The Form EIA-860M data is as of release date March 2024. **Figure 3** captures data on Operating and Standby resources entering operation and expected capacity retirements during the months of October 2023 through September 2024. **Figure 3** captures Operating and Standby resources that came online through February 2024. It also captures expected capacity retirements and planned capacity additions from March 2024 through September 2024.

20 Net Summer Capacity is the maximum output, commonly expressed in MW, that a generating facility can supply to the system, as demonstrated by a multi-hour test, during the time of summer peak demand (period of June 1 through September 30.)

21 "End of last summer through the summer 2024" refers to the period covering October 2023 through September 2024.

Figure 4: Planned and Actual Capacity Additions by Resource Type across the United States from October 2023 through September 2024



NOTE: Expected and actual additions and retirements from October 2023 through September 2024. Data exclude Alaska and Hawaii. WECC* refers to WECC without CAISO.

Source: U.S. EIA-Form 860M, March 2024 Release.

Some RTOs/ISOs expect notable changes in the mix of resource types through summer 2024. **Figure 4** includes new capacity by resource type in RTOs/ISOs and other regions in the United States, as expected by September 2024. Natural gas is projected to represent 42% of the nation's capacity mix, followed by coal at 14%, wind at 13%, solar at 10%, and hydroelectric power at 8%. Across the United States, most additions expected through summer 2024 will come from solar, battery storage, wind, and natural gas-fired resources, as shown in **Figure 4**.[22]

Changes also are underway in the composition of the nation's fleet of natural gas power plants. Roughly 79% of the natural gas capacity to be added in 2024 is from simple-cycle, natural gas turbines, which ramp quickly and are frequently dispatched when electricity demand reaches its peak and varies the most. 2024 will be the first year since 2001 that combined-cycle capacity will not be the predominant natural gas-fired generation technology for additions.[23]

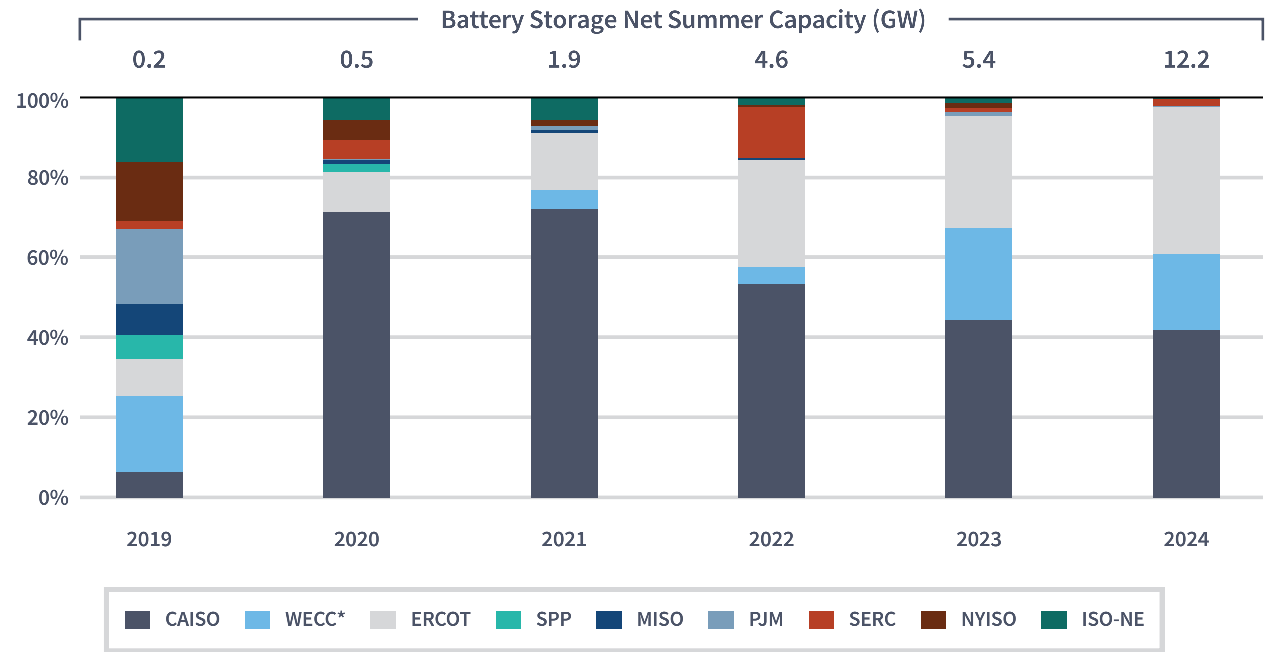
Also notable is anticipated battery storage capacity growth, which is expected to make batteries the second-largest category of capacity additions this summer, surpassing natural gas and wind capacity additions, and trailing only solar expansion. Battery storage capacity additions are anticipated to increase from 5.4 GW in summer 2023 to 12.2 GW through summer 2024. As **Figure 5** shows, the largest battery capacity addition among the RTOs/ISOs and non-

22 The Form EIA-860M data are as of release date March 2024. **Figure 4** captures data on Operating and Standby resources that entered operation from October 2023 through February 2024, and expected capacity additions from March 2024 through September 2024.

23 EIA, *Solar and battery storage to make up 81% of new U.S. electric-generating capacity in 2024*, Today in Energy (February 15, 2024), https://www.eia.gov/todayinenergy/detail.php?id=61424.

RTO/ISO regions is expected to occur in CAISO. According to EIA estimates, the projected battery storage additions by RTO/ISO are as follows: CAISO (5,100 MW), ERCOT (4,500 MW), PJM (51 MW), ISO-NE (33 MW), and NYISO (20 MW). SPP and MISO do not expect to add battery storage capacity through summer 2024.

Figure 5: Battery Storage Capacity Additions across the United States



NOTE: Expected and actual battery storage additions from October 2023 through September 2024. Data exclude Alaska and Hawaii.

Source: U.S. EIA-Form 860M, March 2024 Release.

As for individual projects, nationwide the largest resource additions expected through summer 2024 include the Nova Power Bank (620 MW) battery facility in Menifee, California; High Banks Wind, LLC, an onshore wind facility (604 MW) in SPP; and the Fox Squirrel Solar plant (577 MW) in PJM. In the non-RTO/ISO regions, the largest anticipated capacity addition is Unit 4 (1,114 MW) at the Vogtle nuclear plant in Georgia, which began commercial operation on April 29, 2024.[24] As of January 2024, the Edwards & Sanborn Solar plus Energy Storage project was fully online in California.[25] This is the largest solar-storage project in the United States and is capable of generating 875 MW of solar energy and storing 3,287 MWh of energy in its batteries, with a total interconnection capacity of 1,300 MW.[26]

24 EIA, *Plant Vogtle Unit 4 begins commercial operation*, Today In Energy (May 1, 2024), https://www.eia.gov/todayinenergy/detail.php?id=61963

25 Energy Storage News, *California Solar-plus-storage Project with World's Largest BESS Fully Online*, (Jan. 24, 2024) https://www.energy-storage.news/edwards-sanborn-california-solar-storage-project-world-largest-bess-battery-system-fully-online/; *Also See* Edwards Air Force Base, press release, *Largest Private-Public Collaboration in Department of Defense History Reflects Commitment to Clean Energy* (Feb. 6, 2023), https://www.edwards.af.mil/News/Article/3289170/largest-private-public-collaboration-in-department-of-defense-history-reflects/.

26 M.A. Mortenson Co., press release, *Mortenson Announces Completion of Edwards and Sanborn Solar + Storage Project*, (Jan. 19, 2024), https://www.mortenson.com/newsroom/edwards-sanborn-solar-storage-completion.

Two large offshore wind plants—the 800 MW Vineyard Wind 1 off the coast of Massachusetts and the 130 MW South Fork Wind off the coast of New York—began delivering power to the grid in 2024.[27] Phase 1 of Vineyard Wind began operation in February, and the project is currently being expanded. South Fork Wind came online at full capacity in March 2024, although it was initially scheduled to come online last year.[28]

Meanwhile, in California, state officials are taking steps to keep online units 1 and 2 at the Diablo Canyon nuclear plant, which have a total capacity of 2,240 MW and provide 9% of California's power generation. Previously, the units were scheduled to retire in 2024 and 2025, respectively. However, plant owner Pacific Gas & Electric (PG&E) filed a license renewal application with the U.S. Nuclear Regulatory Commission (NRC) on Nov. 7, 2023, as required by a California state law enacted in September 2022.[29] NRC accepted the application for a full review, which allows the two units to operate beyond the expiration of the current operating licenses while the review is underway.[30] In January 2024, DOE signed a $1.1 billion credit award and payment agreement with PG&E to support continued operation of the reactors.[31]

Coal-fired generation makes up the largest share of capacity retirements by resource types across the United States, as shown in **Figure 6**, with a forecast 3.3 GW of net summer capacity that has retired or is expected to retire through September 2024.

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27 As of February 22, 2024, the Vineyard Wind 1 project successfully installed its ninth turbine and was in the process of installing the 10th, with preparations underway to transport the 11th turbine to the offshore project site. Building on the 68 MW currently in operation, additional power will be delivered to the grid sequentially, with each turbine starting production once it completes the commissioning process. Commonwealth of Massachusetts, press release, *Massachusetts Governor Maura Healey, Vineyard Wind, America's First Large-Scale Offshore Wind Farm, Delivers Full Power from 5 Turbines to the New England Grid* (Feb. 22, 2024).

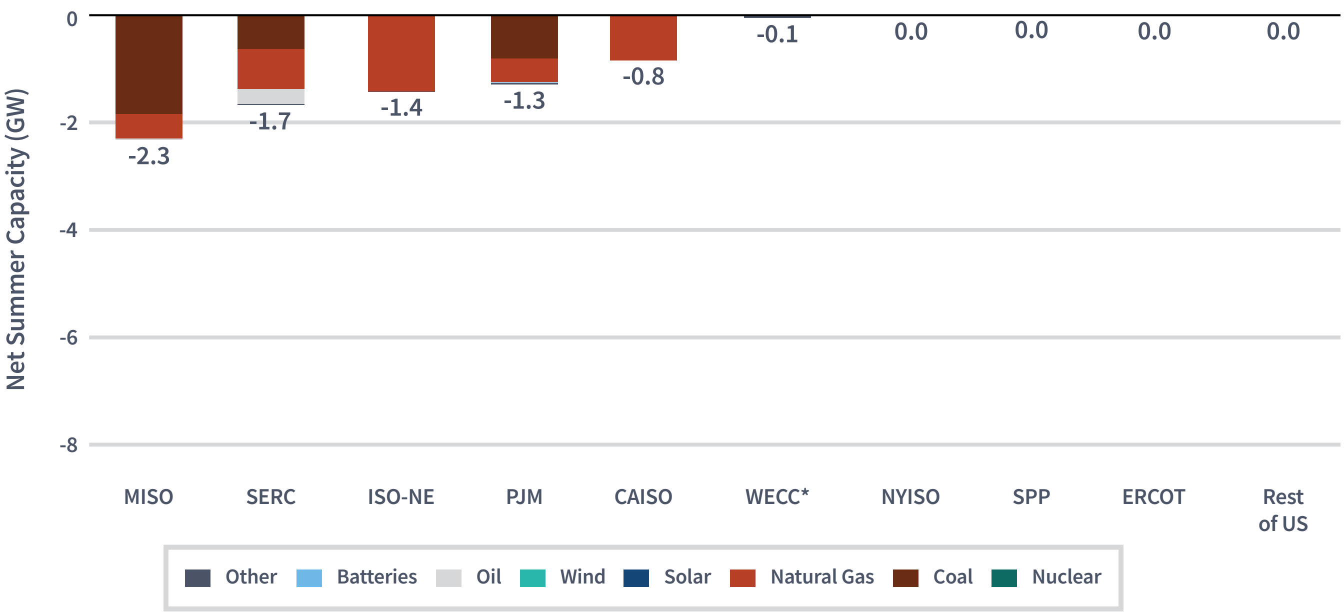
28 All 12 offshore wind turbines constructed and the wind farm successfully delivering power on March 14, 2024. Ørsted, press release, *South Fork Wind Powers Up New Era for American Clean Energy* (March 14, 2024).

29 California Senate Bill No. 846, Diablo Canyon Powerplant: Extension of Operations (Sept. 2, 2022) https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=202120220SB846 (SB846).

30 Federal Register - Nuclear Regulatory Commission, *Pacific Gas and Electric Company; Diablo Canyon Nuclear Power Plant, Units 1 and 2*, (Nov. 20, 2023); Nuclear Newswire, *Diablo Canyon license renewal slated for NRC review* (Dec. 23, 2023), https://www.ans.org/news/article-5649/diablo-canyon-license-renewal-slated-for-nrc-review/.

31 The award is part of the Civil Nuclear Credit Program, a $6 billion initiative created through the Bipartisan Infrastructure Law of 2021. It is designed to avoid the closure of financially vulnerable nuclear plants and is administered by the DOE Grid Deployment Office. DOE, press release, *Biden-Harris Administration Finalizes Award of $1.1 Billion in Credits to Pacific Gas and Electric's Diablo Canyon Power Plant* (Jan. 17, 2024), https://www.energy.gov/gdo/articles/biden-harris-administration-finalizes-award-11-billion-credits-pacific-gas-and; S&P Global IQ, *DOE, PG&E Utility Sign Deal to Extend Life of Diablo Canyon Nuclear Plant*, (Jan. 19, 2024), https://www.capitaliq.spglobal.com/apisv3/spg-webplatform-core/news/article?id=80096305.

Figure 6: Net Summer Capacity Retirements by Resource Type across the United States from October 2023 through September 2024



NOTE: Expected and Actual Additions and Retirements from October 2023 through September 2024. Data exclude Alaska and Hawaii. WECC* refers to WECC without CAISO.

Source: U.S. EIA- Form 860M, March 2024 Release.

More than 450 MW of U.S. petroleum-fired generation capacity is scheduled to retire in 2024, 95% of which is from TVA's Allen power plant, which is shutting down 20 combustion turbine units totaling 427 MW.[32]

The changes in the resource mix resulting from the increase in renewables and retirement of fossil fuel capacity described here is accounted for in NERC's assessments discussed in greater detail in the *Electricity Demand* section below.[33]

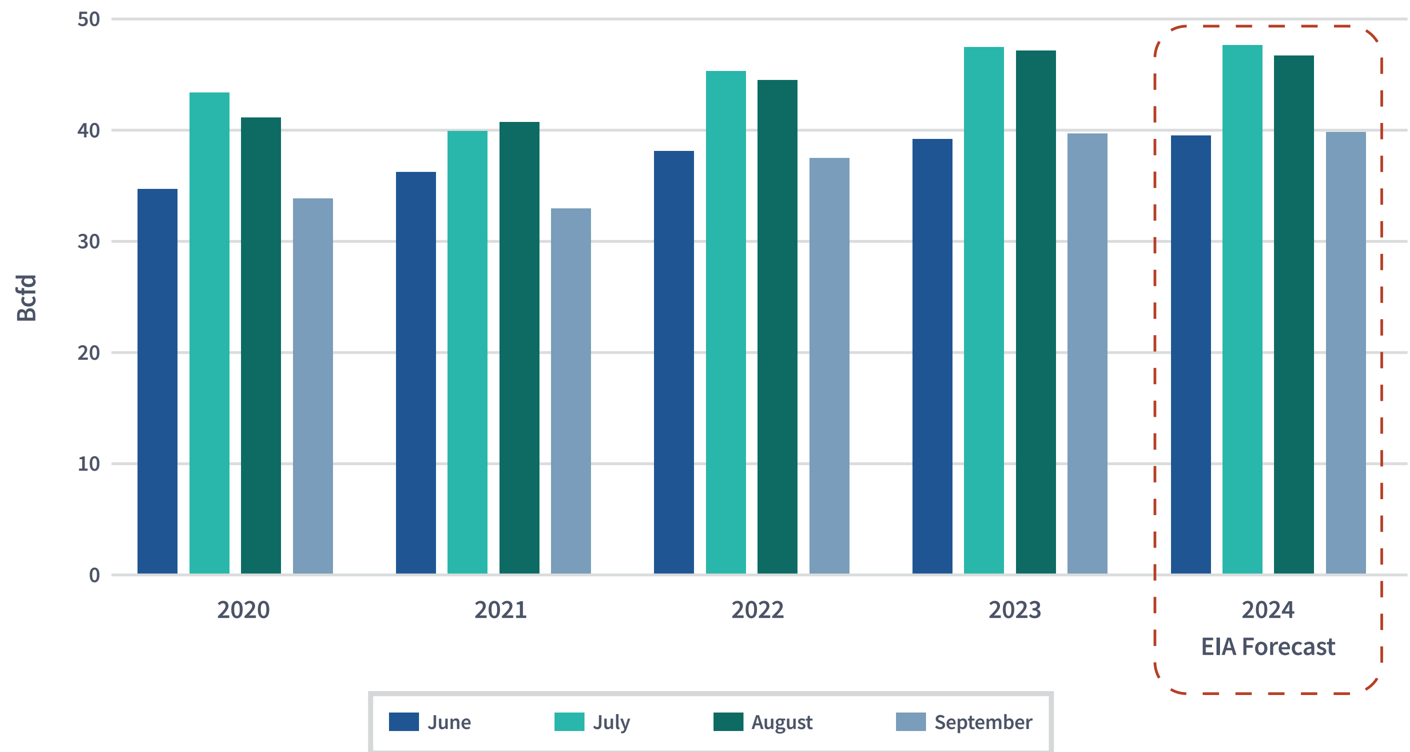
FUELS USED FOR ELECTRIC GENERATION

Natural gas used to generate electricity – or power burn – is expected to average 43.5 Bcfd in summer 2024, equal to power burn in summer 2023 but up 9.5% compared to the five-year average. Consistent with past summers, and as seen in **Figure 7**, power burn is forecast to peak during the typically hottest months of July and August at 47 Bcfd. June and September will see less demand for electricity and an average power burn of 39.7 Bcfd. Power burn is influenced by overall electricity consumption, which is driven in summer by high demand for space cooling and the share of electricity generation that natural gas power plants are called upon to provide (see additional details in the *Natural Gas Demand* section).

32 EIA, *Retirements of U.S. Electric Generating Capacity to Slow in 2024*, (Feb. 20, 2024), https://www.eia.gov/todayinenergy/detail.php?id=61425#:~:text=The%20largest%20coal%20retirements%20in,Generating%20Station%20retired%20last%20year.

33 NERC, *2024 Summer Reliability Assessment* (May 15, 2024). https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2024.pdf.

Figure 7: Power Burn by Summer Month



Source: EIA

Coal stockpiles at power plants at the beginning of 2024 were higher than the previous five-year average, and are expected to increase prior to summer 2024. According to EIA's Electric Monthly Update, total U.S. coal stockpiles at power plants totaled 127.1 million short tons (MMst) in February 2024. EIA forecasts that coal stocks at power plants will total 140.2 MMst in May 2024, a 10% increase from February 2024, after which they will decline as coal units produce electricity to meet summer air conditioning loads. According to EIA, U.S. coal production in summer 2024 is expected to average 43.8 MMst per month, a 9% decline from summer 2023, in part because of a decline in coal demand with the continued retirement of coal-fired generating plants.

Coal-related rail service issues have generally improved since the 2020-2022 pandemic years when delays occurred. However, some delays and scheduling issues persist. Overall, rail utility coal traffic declined by 0.5% in 2023.[34] The March 2024 Francis Scott Key Bridge collapse in Baltimore, Maryland and potential coal shipment delays are

34 Jim Blaze, *Mixed Outlook for North American Rail Freight in 2024*, Railway Age (Jan. 26, 2024), https://www.railwayage.com/freight/mixed-outlook-for-north-american-rail-freight-in-2024/.

not expected to impact U.S. electric resources this summer.[35] Coal power plants nearby may experience delays or disruptions to re-supply coal stocks via water (barges) if there is protracted disruption to shipping in nearby waterways to clean up the bridge collapse.[36] The bridge collapse temporarily halted coal deliveries by barge to the Brandon Shores and Wagner coal plants, totaling 1,865 MW, which are located directly adjacent to the bridge.[37] Baltimore is the second-largest exporting hub for coal in the United States, primarily exporting coal from the northern Appalachia coal fields in western Pennsylvania and northern West Virginia, accounting for 28% of total coal exports in 2023.[38] Because Baltimore is an export route for U.S. coal producers, with two large coal terminals, the bridge collapse temporarily affected water passage for those coal exports.[39]

Oil-fired generation makes up a small portion of the overall electric generating capacity in the United States but plays an important reliability role during critical periods and peak-demand periods in some regions.[40] In areas that face natural gas pipeline or electricity transmission constraints, oil-fired generation can serve as a backstop to other fuel sources. Additionally, many smaller (for example, 250 kilowatts [kW] to 600 kW) generators that provide station power at generating plants for auxiliary loads use distillate oil for operation.[41] Furthermore, some blackstart generators, including those with dual-fuel capability, use distillate oil as backup fuel.

EIA forecasts distillate fuel inventory to average 120.2 million barrels (MMb) in summer 2024, 3% higher than the summer 2023 average; and expects residual fuel inventory to be 28.2 MMb in summer 2024, 0.5% higher than the average in summer 2023. The average West Texas Intermediate spot price for summer 2024 is expected to be $85.50 per barrel compared to $79.29 per barrel in summer 2023. Higher forecasted fuel oil inventory levels suggest easier availability for oil-fired generators to rebuild their on-site storage, but actual fuel procurement by generators varies and could be affected by market conditions.

35 A 95,000-ton freighter lost control and struck one of the Francis Scott Key Bridge's main support structures, causing a large part of the bridge to collapse into the Patapsco River in Maryland on March 26, 2024, also disrupting the access to ports in Baltimore, which is the lead export hub for coal. S&P Global, *Baltimore Bridge Collapse Disrupts US Coal Export Hub* (Mar. 26, 2024) https://www.capitaliq.spglobal.com/apisv3/spg-webplatform-core/news/article?KeyProductLinkType=2&id=80992782; The Port of Baltimore processes 28% of US coal exports. S&P Global, *Domestic coal market sees no immediate impact from Port of Baltimore closure* (Mar. 28, 2024) https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/electric-power/032824-domestic-coal-market-sees-no-immediate-impact-from-port-of-baltimore-closure.

36 US Army Corps of Engineers, Baltimore District, anticipate fully re-opening the channel by the end of May. SeatradeMaritime, *Baltimore Key Bridge controlled demolition*, (May 14, 2024) https://www.seatrade-maritime.com/casualty/baltimore-key-bridge-controlled-demolition

37 Energy Ventures Analysis, *Baltimore Bridge Collapse Halts All Exports from the U.S. Second-Largest Coal Port* (Mar. 28, 2024) https://www.evainc.com/energy-blog/bridge-collapse-halts-all-exports-from-the-second-largest-port/.

38 EIA, W*hat are the Energy Impacts from the Port of Baltimore Closure?* Today in Energy (Mar. 28, 2024), https://www.eia.gov/todayinenergy/detail.php?id=61663.

39 The US Coast Guard is allowing nighttime passage through the Fort McHenry Limited Access Channel, and coal is being loaded onto ships from the CSX Curtis Bay Pier as of May 15, with CONSOL's Marine Terminal to begin loading on May 18. McCloskey, *Baltimore coal shipments resuming ahead of schedule*, (May 15, 2024) https://www.morningstar.com/news/dow-jones/2024051511216/baltimore-coal-shipments-resume-ahead-of-schedule-opis; S&P Global, *Baltimore Bridge Collapse Disrupts US Coal Export Hub* (Mar. 26, 2024) https://www.capitaliq.spglobal.com/apisv3/spg-webplatform-core/news/article?KeyProductLinkType=2&id=80992782.

40 *See, for example*, NYSRC, *Reliability Rules & Compliance Manual* (Jun. 10, 2022), https://www.nysrc.org/wp-content/uploads/2023/07/RRC-Manual-V46-final.pdf; *See also*, Utility Dive, *NYISO to keep 4 NYC peakers running past planned 2025 retirement to maintain reliability*, (November 21, 2023); According to EIA Electric Power Monthly, generation by petroleum liquids provided 3.8 TWh of electricity in June, July, August, and September of 2023, representing approximately 0.24% of total utility scale generation for the time period.

41 Auxiliary load refers to electrical power consumed by any auxiliary equipment necessary to operate the facility. This includes equipment such as pumps, blowers, fuel preparation machinery, exciters, etc.

Planned nuclear plant outages for refueling and maintenance in 2024, some of which have already occurred, will take around 63 GW at 59 units offline, 8.2% higher than the 58 GW that refueled in 2023 at 55 units.[42] Fewer reactors will refuel in the first half of 2024 compared with 2023, while more will refuel in the second half of 2024 than in 2023.[43] In 2023, nuclear plants experienced longer duration planned maintenance outages, and summer period unplanned outages increased.[44] Refueling outage averages in 2023 were once again affected by a handful of disproportionally long outages, with plants offline longer than anticipated.[45] In June 2023, some reactors were still offline at the end of the traditional spring refueling and maintenance season.[46]

ELECTRICITY DEMAND

The EIA estimates that electricity sales to ultimate customers, i.e. electricity consumption, will be 1,487 terawatt hours (TWh) this summer.[47] These sales are forecast to be 39.75 TWh, or 2.7%, higher in summer 2024 than last summer for the continental United States. Moreover, total electricity consumption is expected to be 62.1 TWh (4.4%) higher this summer than the average over the past five summers. The expected larger electricity consumption this summer results from forecasted warm weather and strong economic growth. Another significant source of electricity consumption growth is the construction of new data centers in many regions of the country, an issue that is discussed in its own section later in the report.

According to EIA projections, nearly all regions in the United States are expected to have higher electricity consumption this summer than last, with the exception of the West South Central region, where consumption is expected to decline by 4.05 TWh.[48] This region, which includes Texas, Oklahoma, Arkansas, and Louisiana, has seen very high electricity consumption in previous years. In 2022, the region had a 19.11 TWh increase in electricity consumption relative to the previous summer and in 2023 it saw a 14.47 TWh increase.[49]

According to data from NERC, the planning reserve margins exceed the reference (target) reserve level margins for all

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42 William Freebairn, *More US Nuclear Capacity to Shut for Refueling in 2024 Than Last Year*, Platts Megawatt Daily (Feb. 28, 2024). https://spglobal.com/#platts/insightsArticle?articleID=1a25f9c2-69eb-4ae4-82c2-1cd5e80c7136.

43 William Freebairn, *More US Nuclear Capacity to Shut for Refueling in 2024 Than Last Year*, Platts Megawatt Daily (Feb. 28, 2024). https://spglobal.com/#platts/insightsArticle?articleID=1a25f9c2-69eb-4ae4-82c2-1cd5e80c7136.

44 EIA, *U.S. summer nuclear outages rose in 2023, returning to 2021 levels* (October 17, 2023) https://www.eia.gov/todayinenergy/detail.php?id=60682.

45 Xcel Energy's Prairie Island Unit 2 in Minnesota entered an outage in October 2023 and returned to service in March 2024. Entergy's River Bend in Louisiana had 2023's second-longest outage, with a 127-day shutdown from February to June, and Entergy's Waterford-3 in Louisiana experienced 114-day outage. Millstone Nuclear Plant's Unit 2 in Connecticut saw a planned 30-day refueling outage extended to 86 days after discovery of equipment problems. The Columbia Generating Station in Richland, Washington, began a 44-day outage in early May 2023. William Freebairn, *More US Nuclear Capacity to Shut for Refueling in 2024 Than Last Year*, Platts Megawatt Daily (February 28, 2024).; Star Tribune. *Xcel's Prairie Island nuclear plant returns after lengthy outage drew questions*, (March 18, 2024) https://www.startribune.com/xcel-energy-prairie-island-nuclear-power-plant-puc-utility-commerce/600352107/; EIA, *U.S. summer nuclear outages rose in 2023, returning to 2021 levels*, Today in Energy (October 17, 2023), https://www.eia.gov/todayinenergy/detail.php?id=60682.

46 EIA, *U.S. summer nuclear outages rose in 2023, returning to 2021 levels* (October 17, 2023) https://www.eia.gov/todayinenergy/detail.php?id=60682.

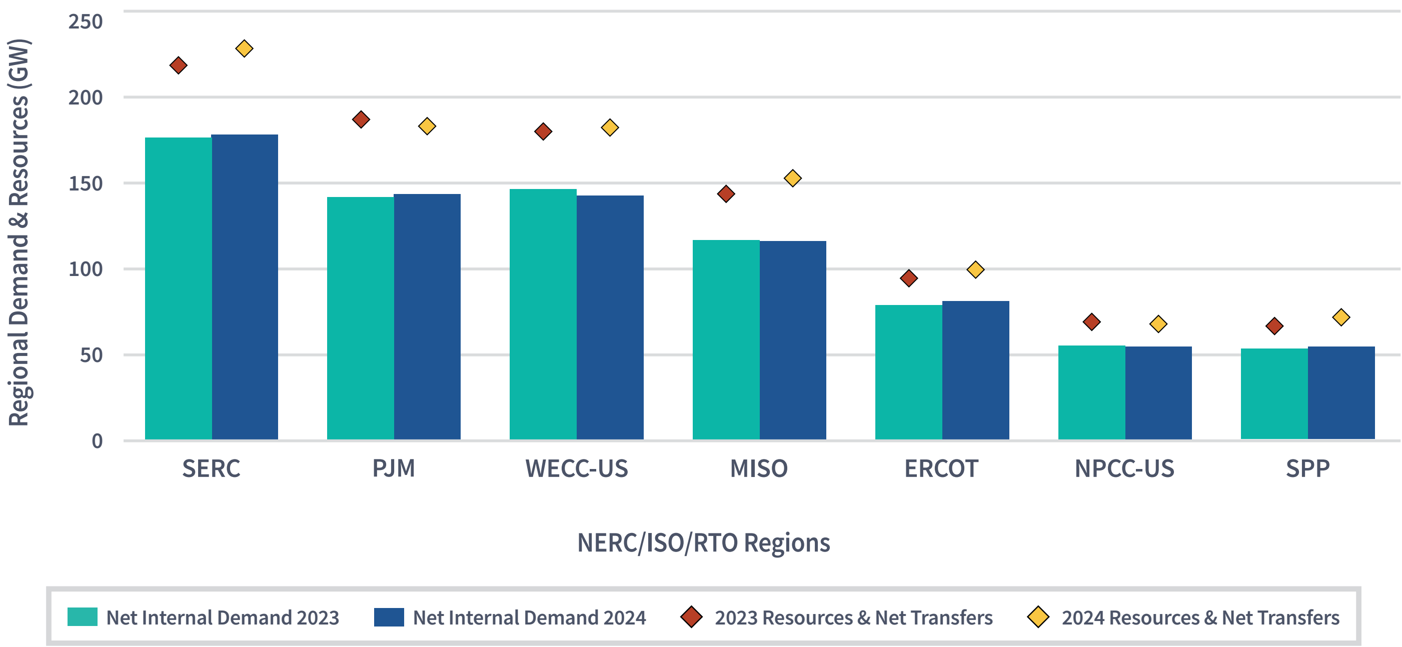
47 Summer is defined as June, July, August, September. EIA, *Short Term Energy Outlook* (Apr. 12, 2024) EIA defines sales to ultimate customers as: Electricity sales that are consumed by the customer and not available for resale. Includes electric sales to end users by third-party owners of behind-the-meter solar photovoltaic systems. https://www.eia.gov/tools/glossary/.

48 *Id.*

49 *Id.*

13 NERC assessment areas.[50] Overall, there appear to be sufficient resources to meet expected U.S. electric demand under normal summer conditions. Despite the expected strong reserve margins, NERC assessment areas can still face tighter-than-expected supply if operating conditions deviate significantly from those anticipated for this summer. Reserve margins do not account for extreme summer conditions that can lead to unexpected generator outages, transmission outages, derates of intermittent resources, reduced power transfers between adjacent areas, and delays in energy resources coming online that could affect a region's ability to serve customer load and maintain adequate operating reserves. Therefore, although all regions are expected to maintain adequate reserve margins through summer 2024, reserve margins do not guarantee reliable operations. A variety of factors affect reliable operations and are managed by system operators to help maintain electric supply and ensure reliability. A more comprehensive review of the ERCOT region and the ISO-NE, WECC-CA/MX and WECC-SW subregions is presented in the *Probabilistic Assessments and Regional Profiles* section below. [51]

Figure 8: NERC 2023 and 2024 Demand and Resources



Source: North American Electric Reliability Corporation

50 Data in this section is calculated with preliminary data provided by the NERC regions for the *2024 Summer Reliability Assessment*, released May 15, 2024. For a more detailed analysis that includes probabilistic scenario conditions, refer to the *Probabilistic Assessment and Regional Profiles* section of this report. The planning reserve margin is designed to measure the amount of generation capacity available to meet expected demand in a planning horizon. NERC, *Reliability Indicators, Metric 1-Reserve Margin*. https://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx.; Also known as a target reserve margin, the reference reserve level margin is provided by the region/subregion based on load, generation, and transmission characteristics as well as regulatory requirements. If not provided, NERC assigns a 15 percent reserve margin. NERC, *Reliability Indicators, Metric 1-Reserve Margin*. https://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx.

51 The 13 assessment areas are the Northeast Power Coordinating Council (NPCC) which includes the ISO-New England and New York ISO subregions; PJM; the Southeastern Reliability Corporation (SERC) and subregions SERC-Central, SERC-East, SERC-Southeast, SERC-Florida Peninsula; the Midcontinent ISO (MISO); the Southwest Power Pool (SPP); the Texas Reliability Entity-Electric Reliability Council of Texas (TRE-ERCOT); and the Western Electric Coordinating Council (WECC) and subregions WECC-NW (WECC-Northwest), and WECC-SW (WECC-Southwest), WECC-CA/MX (California-Mexico), as shown in **Figure 11**. NERC, Long-Term Reliability Assessment (December 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf.

Figure 8 shows the net internal demand as solid bars and the available resources and net transfer values, a combination of internal resources and net import capability from external resources available to the region, as diamonds. These illustrate both summer 2023 and summer 2024 values for comparison.[52] In **Figure 8**, the Northeast Power Coordinating Council (NPCC) subregions, New England (ISO-NE), and New York (NYISO) are combined into NPCC-US; the Southeast Reliability Corporation (SERC) subregions of SERC-East, SERC-Central, SERC-Southeast and SERC-Florida are combined as SERC; and the WECC-CA/MX, WECC-SW and WECC-NW subregions are combined as WECC-US.[53] This figure shows that all regions have sufficient available resources and net import capability necessary to meet their respective loads, which is consistent with observations about reserve margins discussed earlier in this section.

Focusing on just the summer months of June through September, in its Summer Reliability Assessment, NERC forecasts net internal electric demand to increase by approximately 0.41%, or 3.2 GW, from 768.7 GW in summer 2023 to 771.9 GW in summer 2024. Projected growth in net demand is concentrated in the PJM, SPP, and ERCOT regions, along with the SERC-Florida and WECC-SW subregions. However, NERC forecasts slight net demand reductions for the NYISO, WECC-CA/MX, and WECC-NW subregions. NERC forecasts that net demand will remain similar to summer 2023 levels in the MISO region along with the ISO-NE, SERC-East, SERC-Central and SERC-Southeast subregions, with less than a 1% change.[54] To serve that demand, NERC forecasts a national increase of 1.8%, or 17.5 GW, in total system resources from 958.5 GW in summer 2023 to 976 GW in summer 2024, as shown as diamond shapes in **Figure 8**.[55] For each region, increases were driven by increases in system resources and increases in net transfer availability in the following amounts: in the SPP (7.8%), ERCOT (5.2%) and MISO(1.9%) regions, along with the SERC-Southeast (6.8%), SERC-Central (4.7%), SERC-East (1.6%), WECC-SW (3.1%), and WECC-CA/MX (2.6%) subregions. However, generator capacity additions scheduled to come online for the summer could change or undergo delays, which may affect the ability of resources to operate at their expected summer capacity. Regions are reporting that some generation and transmission projects are being impacted by factors including product unavailability, shipping delays, and tight labor markets. Supply chain impacts on critical material are noted later in the *Equipment and Materials* section of this report.

In its assessments, NERC adjusts resources' capacity values to reflect their expected ability to serve load. In making these adjustments, NERC first reduces projected resource capacity (nameplate capacity) used in the NERC

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52 Net Internal Demand equals Total Internal Demand less Dispatchable, Controllable Capacity Demand Response used to reduce load. NERC, *2024 Summer Reliability Assessment* (May 15, 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2024.pdf.
Resources and Net Transfers refers to the addition of "Existing-Certain Capacity" and "Net Firm Capacity Transfers."
Existing-Certain Capacity includes commercially operable generating units 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. Net Firm Capacity Transfers refers to the imports minus exports of firm contracts.

53 SERC-East includes North Carolina and South Carolina. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC-Florida Peninsula includes the state of Florida. Sub-regions are also shown geographically in **Figure 11** of this report. NERC, *Long Term Reliability Assessment*, (Dec. 13, 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf ; WECC-CA/MX (California/Mexico) includes parts of California, Nevada, and Baja California, Mexico. WECC-SW (Southwest) includes Arizona, New Mexico, and part of California and Texas. WECC-NW (Northwest) includes Colorado, Idaho, Montana, Oregon, Utah, Washington, Wyoming and parts of California, Nebraska, Nevada, and South Dakota. Sub-regions are also shown geographically in Figure 11 of this report. NERC, *Long Term Reliability Assessment*, (Dec. 13, 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf .

54 NERC, *2024 Summer Reliability Assessment* (May 15, 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2024.pdf.

55 NERC, *2024 Summer Reliability Assessment* (May 15, 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2024.pdf.

Assessments to reflect known operating limitations (e.g., fuel availability, transmission limitations, environmental limitations), then compares the resulting values to the reference margin levels, which represents the level of risk based on a probabilistic loss-of-load analysis.[56] Consequently, the on-peak resource capacity that NERC uses reflects the expected output at the hour of peak demand. Because the electrical output of variable energy resources, such as wind and solar, depends on weather conditions, and hydroelectric capacity depends on reservoir levels, the estimated on-peak capacity contributions of these resources are less than nameplate capacity. Generally, the Eastern Interconnection expects 17% of nameplate wind capacity, 59% of nameplate solar capacity, and 76% of nameplate hydro capacity to be available to meet the peak demand hour. The Western Interconnection expects 15% of nameplate wind capacity, 51% of nameplate solar capacity, and 56% of nameplate hydro capacity to be available during the peak demand hour. ERCOT expects 23% of nameplate wind capacity, 73% of nameplate solar capacity, and 78% of nameplate hydro capacity to be available during the peak demand hour.[57]

In capacity planning, resources are categorized as either anticipated or prospective.[58] Anticipated resources include capacity designated Existing-Certain, Tier 1 capacity additions, and net firm capacity transfers.[59] Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during peak periods during a given season. Prospective resources, which include both planned and existing resources, are those that could be available but that do not meet the criteria to be counted as anticipated resources. Prospective resources include all anticipated resources, plus capacity designated Existing-Other.[60]

While NERC anticipates resources should be adequate to meet capacity needs this summer, energy emergency risks remain in several regions, especially as the generation resource mix evolves. As stated in prior summer reports, some risks are driven by a decrease in available generation due to resource retirements and an increase in variable energy resources, especially during off-peak or net-peak hours with high penetrations of renewables. As the sun sets and solar output declines, solar generation must be replaced by other resources, which can create challenging conditions for system operators as the demand increases, particularly in the West and ERCOT, which have a large share of solar generation. Similarly, regions such as SPP, MISO and ERCOT, with high penetrations of wind resources, can be at risk given wind variability. Additionally, the risk greatly increases when high demand in multiple regions, such as during widespread heat events, reduces the availability of imported electricity from neighboring systems. Also, any potential delays in commissioning of Tier 1 resources or transmission projects under development and expected to be operating could create potential local or regional reliability risks this summer.

56 Projected resource capacity used in the NERC Assessments is provided by the region/subregion based on load, generation, and transmission characteristics as well as regulatory requirements. NERC. *Reliability Indicators, Metric 1-Reserve Margin*, https://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx.

57 NERC, *2024 Summer Reliability Assessment* (May 15, 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2024.pdf.

58 Existing-Other capacity includes 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 an existing-certain resource. NERC, *Long Term Reliability Assessment* (Dec. 13, 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf.

59 The definition of Existing-Certain is provided in footnote 56 above. Tier 1 additions include capacity that is either under construction or has received approved planning requirements. Net firm transfers (imports minus exports) include transfers with firm contracts. NERC, *Long Term Reliability Assessment* (Dec. 13, 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf.

60 Existing-Other capacity includes commercially operable generators or portions of generators 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. NERC, *Long Term Reliability Assessment* (Dec. 13 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf.

DEMAND RESPONSE

Demand response is the voluntary reduction in consumption of electricity by customers from their expected consumption levels, in response to either reliability or price signals.[61] In critical periods, demand response can prevent an electricity shortfall by reducing electricity demand.[62] Formal demand response programs involving commercial and industrial customers that have agreements with load serving entities to curtail load during critical periods have grown in many regions. Some utilities have also implemented residential programs that provide the ability to dispatch enrolled demand response resources to reduce load, which supports operating reliability and energy adequacy needs when effectively implemented and monitored.[63] Demand response programs typically use monetary incentives to encourage consumers to change their usage patterns. RTOs/ISOs employ these programs to balance supply and demand, particularly during system emergencies, which can maintain reliability and lower wholesale market electricity costs.

Table 1: Demand Response Resources by RTO/ISO in 2022

RTO/ISO	Demand Response Resources (MW)	Percent of Available Peak Demand Resources
MISO	12,390	10.2%
PJM	10,595	7.3%
CAISO	3,956	7.6%
ERCOT	3,562	4.4%
NYISO	1,483	4.9%
ISO-NE	573	2.3%
SPP	362	0.7%
TOTAL	**32,921**	**n/a**

Source: FERC, 2023 Assessment of Demand Response and Advanced Metering

Based on data reported by RTOs/ISOs where demand response can register as a capacity resource, approximately 24 GW of demand response capacity is expected to be available this summer.[64] PJM reported 7,991 MW of demand response capacity from all programs for Delivery Year 2024/2025.[65] NYISO anticipates demand response capacity from approximately 1,281 MW of Special Case Resources for summer 2024.[66] MISO procured 8,660 MW of demand resources in the Planning Resource Auction for summer 2024.[67] ISO-NE anticipates 3,891 MW of demand resources for the 2024/2025 Capacity Commitment Period.[68] However, actual performance of demand response can be below the total demand response capacity dispatched by an RTO/ISO.[69]

61 FERC, *Energy Primer: A Handbook of Energy Market Basics*, pp. 41-44 (December 2023), https://www.ferc.gov/media/energy-primer-handbook-energy-market-basics.

62 For more information on demand response, see the *Demand Response* section on p. 41 in FERC's *Energy Primer: A Handbook for Energy Market Basics* (December 2023), https://www.ferc.gov/media/energy-primer-handbook-energy-market-basics.

63 NERC, *2024 Summer Reliability Assessment* (May 15, 2024). https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2024.pdf.

64 This figure only includes resources which participate as a capacity resource, other demand response resources may be available but not participating as a capacity resource.

65 Monitoring Analytics, IMM Analysis of the 2024/2025 RPM Base Residual Auction (October 30, 2023) https://www.monitoringanalytics.com/reports/Reports/2023/IMM_Analysis_of_the_20242025_RPM_Base_Residual_Auction_20231030.pdf.

66 NYISO, *2023 Load & Capacity Data 75* (April 2023), https://www.nyiso.com/documents/20142/2226333/2024-Gold-Book-Public.pdf/170c7717-1e3e-e2fc-0afb-44b75d337ec6.

67 MISO, *Planning Resource Auction Results for Planning Year 2024-25* (April 2024), https://cdn.misoenergy.org/2024%20PRA%20Results%20Posting%2020240425632665.pdf.

68 ISO-NE, *Fifteenth Forward Capacity Auction (FCA 15) for Capacity Commitment Period 2024-2025: Summary of Results* (March 2021), https://www.iso-ne.com/static-assets/documents/2021/03/a8_fca15_auction_results.pdf.

69 California ISO, *Demand response issues and performance 2023* (March 6, 2024), https://www.caiso.com/Documents/Demand-Response-Report-2023-Mar-6-2024.pdf.

Demand response in CAISO consists of utility demand response resources, which account for about 80% of demand response capacity used to meet resource adequacy requirements, and supply plan demand resources, which account for 20% of demand response capacity.[70] In summer 2023, about 85% of CAISO demand response capacity was available for dispatch in peak net load hours on days where the CAISO issued system warnings or Restricted Maintenance Operations.[71]

ELECTRICITY INFRASTRUCTURE

The electric transmission system delivers electricity to load centers where it is needed, supports new generation additions, allows for the redispatch of generation and allows for interregional flows - all essential services for reliable and efficient operation of the grid.[72] However, summer conditions—and demand that peaks in summer for many RTOs/ISOs—can challenge grid operators to provide those services. For example, extreme heat and dry weather raise the risk of wildfires, and severe storms such as hurricanes can damage electric transmission. Additionally, transmission congestion or unplanned transmission line outages can limit the ability of system operators to import power, or a given region may be unable to import power from a neighboring region if both are simultaneously facing short supply.

Extreme heat in summer 2023, particularly in June, provided challenges for transmission operators in several regions of the country. Texas and the Southwest were the hardest hit with near-record temperatures above 100 degrees Fahrenheit for a large portion of the month.[73] In preparation for this summer, RTOs/ISOs plan to address these reliability concerns with upgrades to transmission lines and equipment.

In 2024, nearly 2,000 miles of new BPS transmission lines entered service or were on schedule for completion by the end of the summer. The largest category of the new transmission (over 700-line miles) is at the 138 kV voltage level (see **Figure 9**). ERCOT, MISO and PJM will complete the largest amount of these new transmission projects by this summer.[74] According to the RTO/ISO planners and involved utilities, the new transmission projects in service for summer 2024 are designed to replace aging infrastructure, increase reliability and address load growth.

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70 Utility demand response programs are operated and scheduled by utilities. Supply plan (third party) demand response are developed, bid and scheduled by non-utility (or third party) providers under contract to supply resource adequacy capacity for utilities. CAISO, *Demand Response Issues and Performance 2023* (March 6, 2024), https://www.caiso.com/Documents/Demand-Response-Report-2023-Mar-6-2024.pdf.

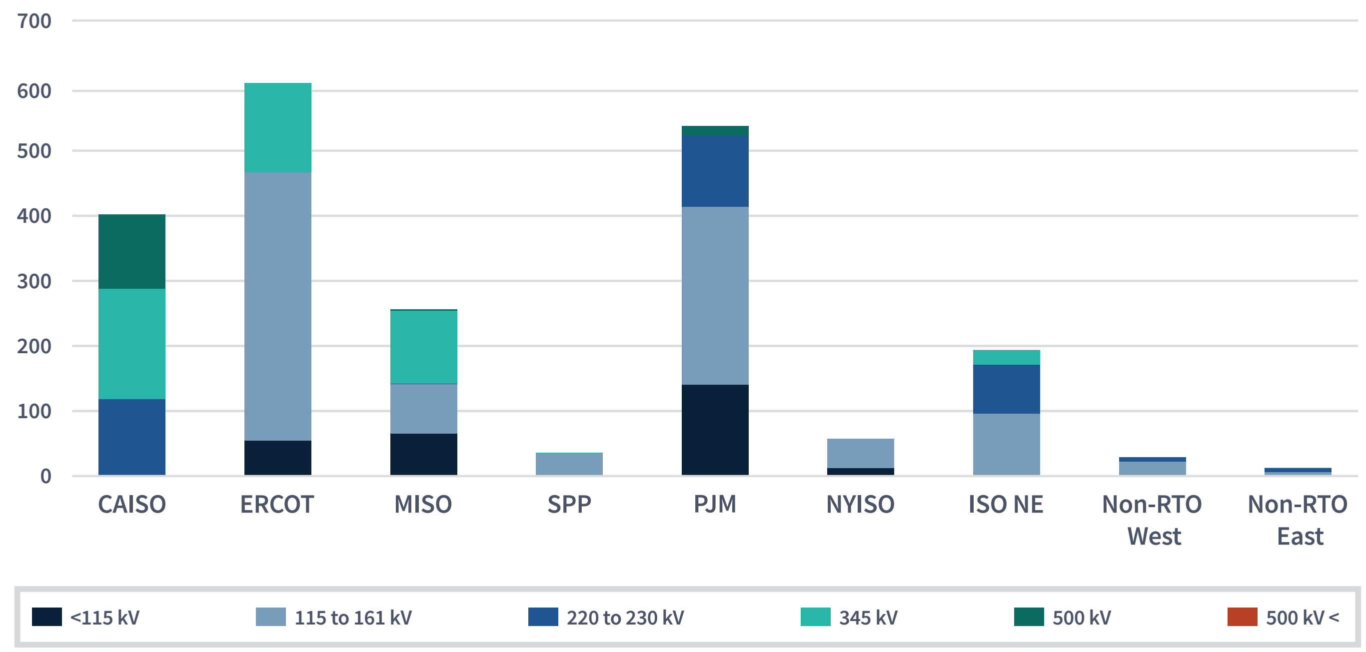
71 This capacity is used to meet resource adequacy requirements and thus has different requirements. In July 2023, the California Public Utilities Commission clarified that the ISO should be able to dispatch reliability demand response in the real-time upon the declaration of an EEA Watch or higher, a change from previous summers when the ISO had to be in EEA 2 or higher. CAISO, *Demand Response Issues and Performance 2023* (Mar. 6, 2024), https://www.caiso.com/Documents/Demand-Response-Report-2023-Mar-6-2024.pdf.

72 For more on the U.S. electric transmission system, please see the *Transmission* section on p. 52 in FERC's *Energy Primer: A Handbook for Energy Market Basics* (December 2023), https://www.ferc.gov/media/energy-primer-handbook-energy-market-basics.

73 For more on the U.S. electric transmission system, please see the *Transmission* section on p. 52 in FERC's *Energy Primer: A Handbook for Energy Market Basics* (December 2023), https://www.ferc.gov/media/energy-primer-handbook-energy-market-basics.

74 Estimates are based on the North American Electric Transmission Project Database by The C Three Group, L.L.C. "Line-related transmission projects" are transmission projects involving a transmission line including a new transmission line, a line upgrade, a line rebuild, or a line reconductor and have an operating status set as operating, partially operating, or under construction. Only projects with an in-service or completion date by the end of September 2024 are included in the staff analysis.

Figure 9: New Transmission Line Miles by Voltage Level



Source: Staff analysis of C Three Group LLC Electric Transmission and Distribution Database

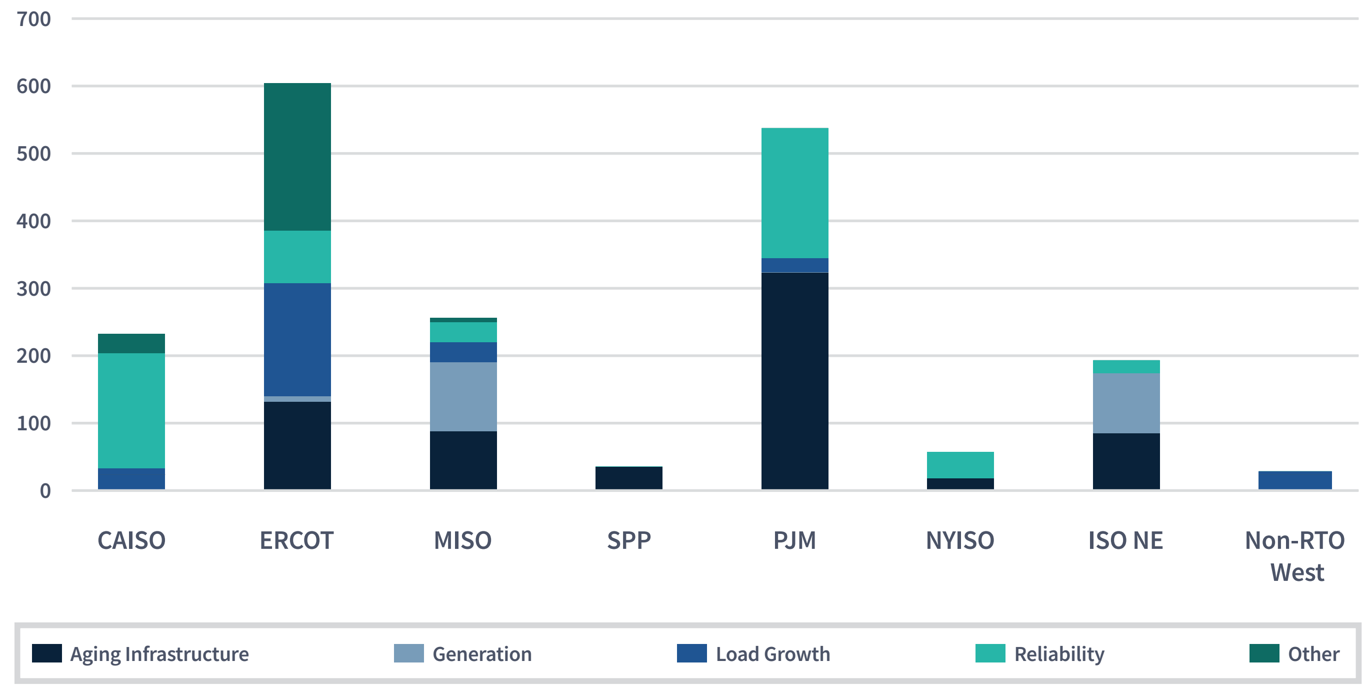
While many of the BPS transmission projects planned for 2024 are at the 138 kV voltage level, in ERCOT many new transmission lines planned for early 2024 are at the 345 kV level. These new 345 kV transmission projects include American Electric Power Texas' planned upgrade to the 78-mile North Edinburg-Tiempo line in southern Texas; the 68.8-mile Lobo-Fowlerton Second Circuit upgrade, also in southern Texas, planned by Electric Transmission Texas; and the South Texas Electric Cooperative's planned 59-mile upgrade to the Scheenman Draw-Big Hill Second Circuit line in South-Central Texas. These projects and several others reached completion in early 2024, while several others are slated for completion later in summer 2024. The largest of these projects include the 345 kV, 63.4-mile Lobo-San Miguel Second Circuit, which South Texas Electric Cooperative plans to complete by July.[75]

In PJM, the largest transmission project, a rebuild of the 79-mile, 230 kV Lanexa-Northern Neck line in Virginia by Appalachian Power, was completed in March of 2024. Five of the 10 longest lines set to be completed in PJM for this summer are at the 138 kV level. In line with the overall BPS trends, Dominion Virginia Power in PJM also rebuilt the 138 kV Joshua Falls-Riverville-Gladstone Project in eastern Virginia. In MISO, the largest transmission projects were already finished by the end of 2023. Many of the projects slated for 2024 are much shorter in length and capacity. However, the Cardinal-Hickory Creek Line is scheduled to provide a new 345-kV, 102-mile transmission connection between Iowa and Wisconsin by this June.[76]

75 North American Electric Transmission Project Database from The C3 LLC Group Data.

76 *Id.*

Figure 10: New Transmission Line Miles by Project Drivers



Source: Staff analysis of C Three Group LLC Electric Transmission and Distribution Database

In CAISO, new transmission projects were driven mostly by reliability needs, and a majority of these new projects involved upgrades to higher voltage lines and equipment. In December 2023, Southern California Edison completed the Eldorado-Lugo-Mohave Project, connecting substations spanning 232 total line miles from California to Nevada.[77] In similar fashion, DCR Transmission LLC will complete the Ten West Link spanning 114-line miles between substations from California to Arizona by May 2024.[78] Both large, 500 kV transmission upgrades target reliability needs in their respective interstate regions.

In ISO-NE, the 75-mile, 220 kV transmission line connecting the Vineyard Wind 1 Unit in Massachusetts will provide 85% of the line miles in ISO-NE ahead of the summer.[79] In NYISO also, most new transmission upgrades planned for the first half of 2024 are designed to address reliability needs. The largest among them, Central Hudson Gas and Electric's Ellenville Area upgrade, involves 34.2 line-miles of upgrades to existing lines and transformer units north of New York City and is slated for completion by June.[80] Ahead of the summer, SPP expects to complete the smallest number of new projects among RTOs/ISOs, most of them in Oklahoma at the 138 kV level. AEP Transmission plans to complete the Duncan Rush Springs Transmission Improvements Project, connecting 25 miles of substations in East Texas, by July, and to complete a rebuild of the 10-mile, Knox-Lee-Cherokee Connection-Tatum-Rockhill Line by June.[81]

77 *Id.*
78 *Id.*
79 *Id.*
80 *Id.*
81 *Id.*

During periods of stress such as extreme heat events, RTOs/ISOs can reduce system stress by transporting energy from areas with excess generation capacity to strained areas in need of electricity. Many RTO/ISOs have recently highlighted various zones in their transmission plans subject to congestion, along with interregional projects that could alleviate the congestion and thereby facilitate electricity transfers during times of stress. None of these identified projects are yet under construction and would not be in operation before this summer. Most of these identified interregional transmission projects would not come online until after 2026 at the earliest and are planned for the western regions.

REGIONAL HIGHLIGHTS AND NERC PROBABILISTIC ASSESSMENTS

This section details probabilistic analyses NERC conducted, based on data submitted by the Regions, that demonstrate possible reliability concerns for this summer. NERC uses resource projections for June to September 2024 in its analysis of summer reserve margins; all other analyses by FERC staff in this report use EIA data and forecasts covering the period since last summer, from October 2023 to September 2024.

In this Summer Assessment, staff relies on NERC's probabilistic risk analyses to assess resource adequacy. In the past, the FERC summer assessments relied on NERC's reserve margin analysis to determine resource adequacy levels. However, regions can face energy shortfalls despite having planning reserve margins that exceed the reference margin levels. Reserve margin analyses, even in well-supplied regions, may not address external factors that can create shortages, which include scheduled generator maintenance, forced outages, and conditions that affect generation resource performance or availability, such as constraints on fuel supplies. By contrast, probabilistic risk analyses can more fully assess the potential variations in resources and load that can occur under changing conditions or during certain scenarios, and also incorporate operator actions that could help to mitigate any shortfalls in operating reserves.[82] Thus, to provide a better picture of resource adequacy, NERC performs probabilistic risk analyses based on Regional data to assess the availability and sufficiency of resources to meet demand under normal operating conditions and under multiple risk scenarios for a range of conditions.

NERC's probabilistic risk analysis for each of these assessment areas as shown in **Figure 11** provides insight into how events during normal and/or extreme summer conditions may affect the total resource mix available to meet demand. In particular, NERC's analyses show that these regions/sub-regions anticipate adequate supplies and reserve margins under normal conditions but face a higher likelihood of tight supply and reliability issues during extreme conditions. In challenging operating conditions, system operators may take actions to address potential supply shortages, such as calling on demand response, canceling or postponing non-critical generation or transmission maintenance, and calling on voluntary conservation measures.[83] If system conditions deteriorate sufficiently, reliability coordinators may declare an Energy Emergency Alert (EEA), allowing system operators to call on a variety of additional resources that are only available during scarcity conditions such as activating emergency

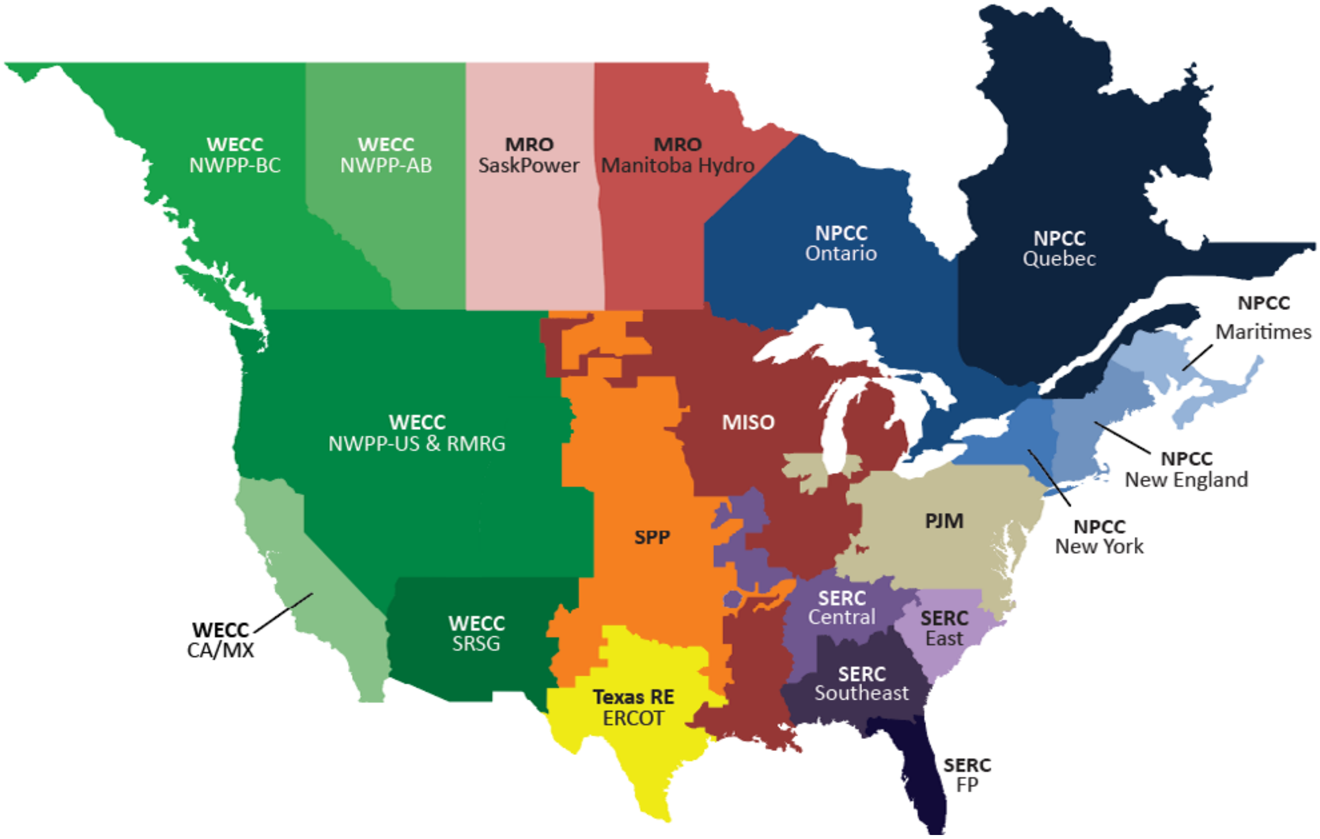
82 Operating Reserves are capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserves. NERC, *Glossary of Terms Used in NERC Reliability Standards* (Mar. 2024), https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

83 A system operator is an individual at a Control Center of a Balancing Authority, Transmission Operator, or Reliability Coordinator who operates or directs the operation of the Bulk Electric System (BES) in real time. NERC, *Glossary of Terms Used in NERC Reliability Standards* (March 2024), https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

demand response measures and increasing generation imports from neighboring regions.[84] These resources can help mitigate capacity shortages.

The seasonal risk assessment does not account for all the reliability risks associated with a specific area (e.g., expected unserved energy). Long-duration heat waves and disruptions to primary and backup fuel supply chains are not explicitly considered in the seasonal risk scenarios. The methods, scenarios considered, and assumptions differ by assessment area, and may not be comparable.

Figure 11: Map of NERC Sub-regions



Source: North American Electric Reliability Corporation

Since last summer, NERC notes that some regions have increased generation supply due to new resource additions and delayed generator retirements; new firm transfer agreements that increase reserves by tapping into neighboring resources; improved hydroelectric generation forecasts for California and a large part of the western U.S., as a result

84 EEAs are a series of emergency procedures that may be used when operating reserves drop below specified levels. These procedures are designed to protect the reliability of the electricity system as a whole and prevent an uncontrolled system-wide outage. Other examples of operational mitigations include, implementing a voltage reduction to reduce load, requesting generators and demand response, requesting voluntary load curtailment by large industrial and commercial customers, and allowing for depletion of operating reserves before shedding load. Load shedding is only used as an emergency, last resort measure.

of recent precipitation and snowpack; and increasing demand response and demand-side management programs.[85] However, in WECC and ERCOT, the timing of resources coming online and the potential for project delays could impact the availability of resources for this summer. These topics are further profiled throughout this report in greater detail.

Compared to prior summers, NERC reports fewer assessment areas at risk of electricity supply shortages. Several areas, including SERC-Central, SPP, and WECC-NW have moved from elevated risk last summer to normal risk this summer.[86] Some other assessment areas continue to face risks of electricity supply shortfalls during periods of more extreme summer conditions. These areas include MISO, ISO-NE, ERCOT, WECC-SW, and WECC-CA/MX.[87] These scenarios include extreme demand, historic high outage rates, as well as low wind or solar energy conditions.

The charts below represent NERC's probabilistic risk analyses for each assessment area and represent the summer risk period scenario chosen by each assessment area. This summer risk period scenario compares resources against levels of forecasted supply and demand, including required reserve levels, under chosen extreme scenarios, and includes the normal peak net internal demand (50/50) scenario and the extreme summer peak demand (90/10) scenario.[88] The left blue column shows anticipated resources and the two orange columns at the right show the normal peak (50/50) and the extreme summer peak (90/10) demand scenarios. The middle red or green bars show the factors that can affect resource availability, including maintenance outages and forced outages not already accounted for in anticipated resources, shown in red, and additions that represent the resources from operational mitigation tools, if any, shown in green, that are available during scarcity conditions but have not been accounted for in the reserve margins. The dotted line represents the expected operating reserve requirement plus the extreme peak demand that an area would need to meet in order not to present as a shortfall.

ISO-NE is retiring two gas-fired units at Mystic Generating Station in May 2024 (1,413 MW nameplate capacity). This retirement results in greater likelihood that ISO-NE will need to resort to operating procedures for obtaining resources or non-firm supplies from neighboring areas during periods of above-normal peak demand or low-resource conditions. Expected ISO-NE resources do not meet operating reserve requirements under normal peak-demand and outage scenarios. Operating mitigations (i.e., demand response and transfers) are likely to be needed to meet peak demand. More severe conditions (e.g., above-normal summer peak load and outage conditions) could result in an EEA. See **Figure 12**.

In ERCOT, rising demand is challenging resource adequacy. ERCOT is experiencing substantial growth in both load and renewable resources resulting in a risk of insufficient energy supply in the summer evening hours when solar generation ramps down as the sun sets.[89] During such grid conditions, operators may need to limit power transfers from South Texas into the San Antonio region. This may occur when high demand is coupled with low wind and solar output in specific areas, straining the transmission system and requiring South Texas generation curtailments and

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85 NERC notes that new resources, including 25 GW of nameplate solar capacity have been added to the BPS since last summer. NERC, 2024 Summer Reliability Assessment (May 15, 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2024.pdf.

86 *Id.*

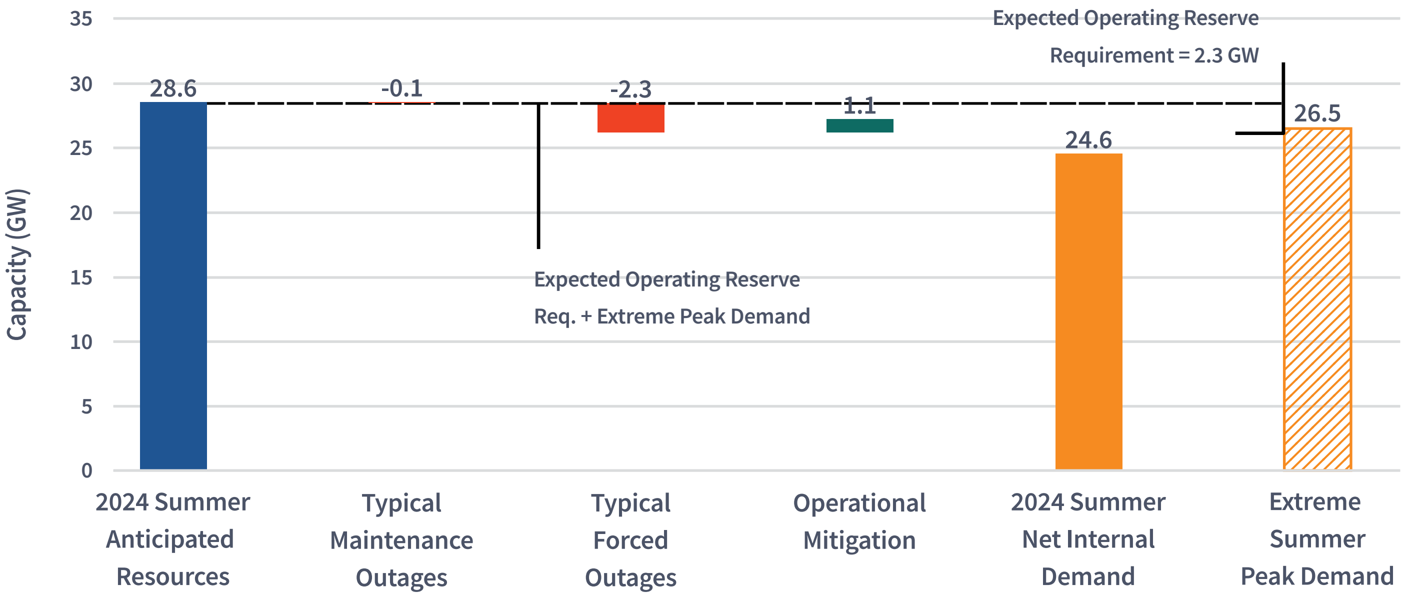
87 *Id.*

88 A 50/50 peak load forecast is based on a 50 percent chance that the actual system peak load will exceed the forecasted value. A 90/10 peak load forecast is based on a 10 percent chance that the actual system peak load will exceed the forecasted value.

89 ERCOT's Solar and battery energy storage installed capacity has grown by about 4,500 MW and 1,600 MW, respectively, since August 2023. NERC, *2024 Summer Reliability Assessment* (May 15, 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2024.pdf.

the potential for firm load shed to avoid cascading outages.[90] While resource additions in Texas, primarily solar, are outpacing demand increases, energy risks are growing during the hours when solar output is diminished. Further, strained transmission systems are struggling to connect new resources and deliver electricity supplies to growing load areas. As a result, there is risk of supply shortages as solar generation ramps down during early evening hours when system load is high and transmission constraints limit transfers.[91] See **Figure 13**.

Figure 12: NPCC-NE Risk Period Scenario



Source: North American Electric Reliability Corporation

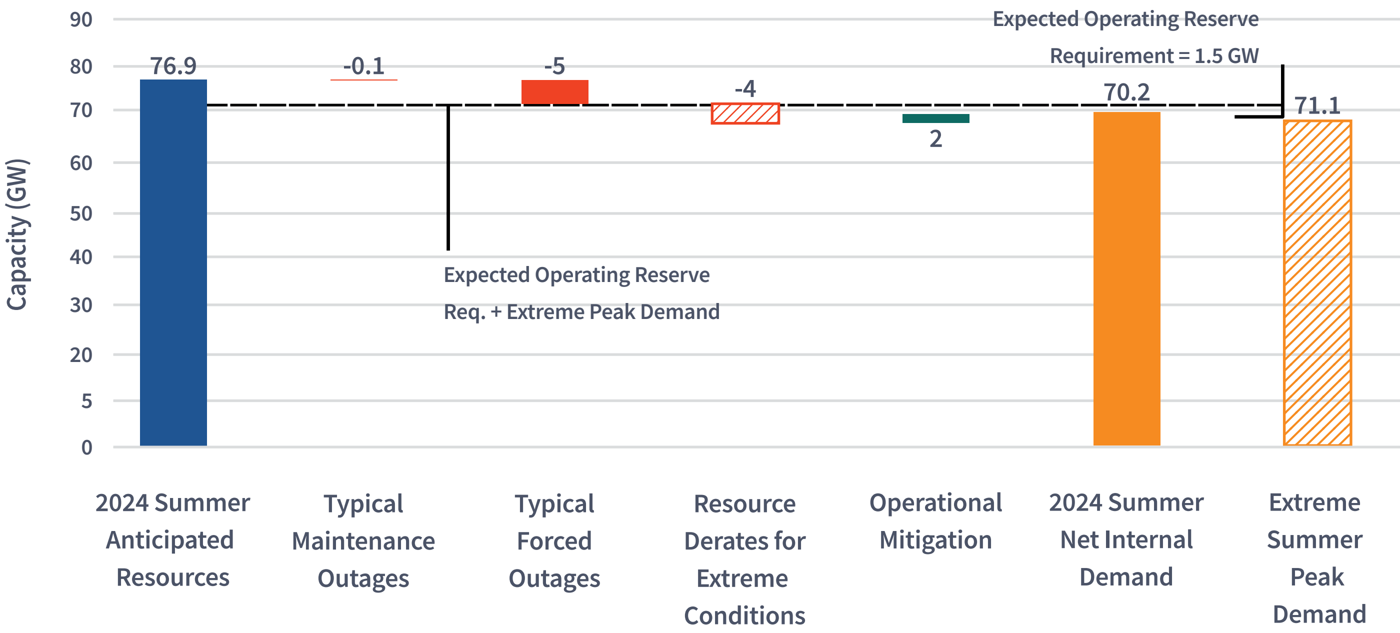
In the Western Interconnection, resource adequacy remains a critical risk and continues to challenge industry planners, operators, regulators, and partners. Resource adequacy risks over the medium and long term have increased significantly compared to last year's assessment. WECC has identified three items it identifies as risks meriting particular attention: increasing high variability, rate of demand growth and uncertainty of future load patterns, and the pace of new resource growth necessary to meet energy demand.[92]

90 Mitigation measures include the construction of the San Antonio South Reliability Project, which is anticipated to be completed by Summer 2027. NERC, *2024 Summer Reliability Assessment* (May 15, 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2024.pdf.

91 *Id.*

92 WECC, *Western Assessment of Resource Adequacy*, (Nov. 2023), https://www.wecc.org/Administrative/2023%20Western%20Assessment%20of%20Resource%20Adequacy.pdf.

Figure 13: ERCOT Risk Period Scenario

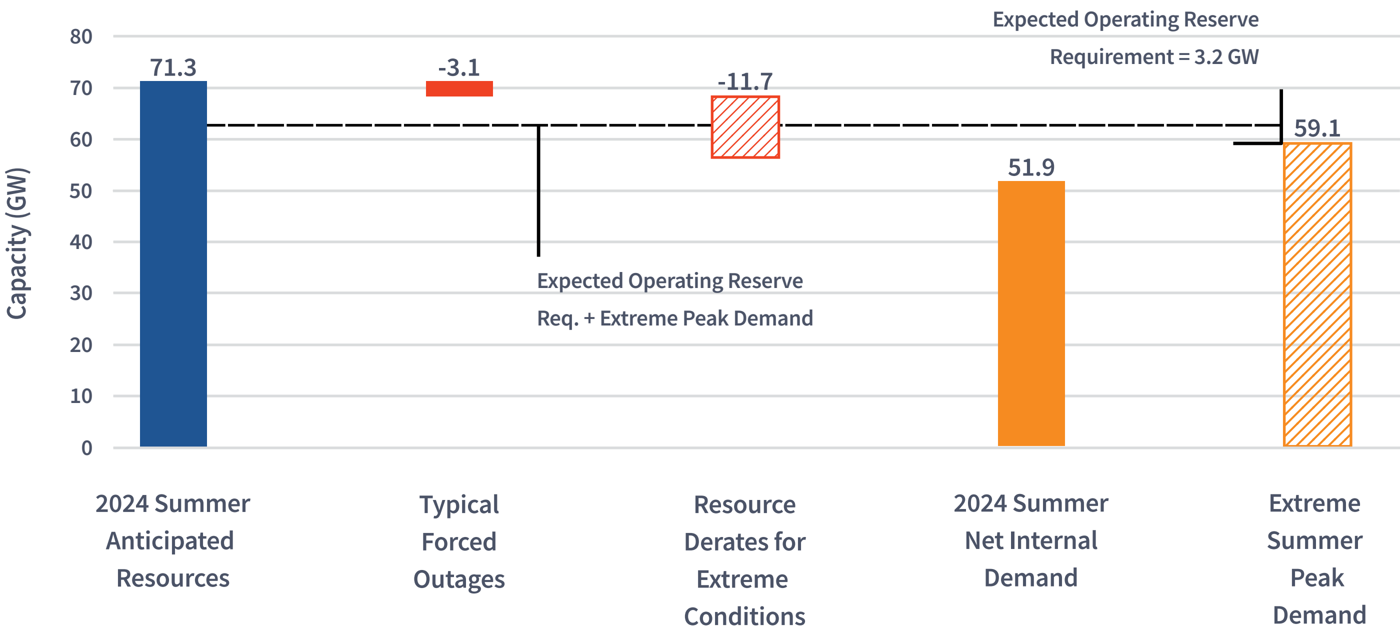


Source: North American Electric Reliability Corporation

In WECC-CA/MX, new solar and battery resources contribute to higher on-peak reserve margins, and drought conditions have alleviated due to winter precipitation and snowpack which makes more output from hydroelectric resources available to help balance variability in wind and solar output. Operational challenges for WECC-SW include drought, wildfires, and derates of gas facilities due to extreme heat, and supply chain issues potentially affecting thermal resource return-to-service dates and commercialization of new projects. Operational challenges for the WECC-NW include supply chain issues potentially resulting in project delays or cancellations, and unprecedented flow patterns associated with the expansion of inverter-based resources such as wind and solar power plants. The probabilistic analyses performed by WECC show that the risk of loss-of-load is similar to 2023, depending on whether anticipated new solar and battery resources are completed during the summer. According to these assessments, WECC is projected to meet the extreme (90/10) peak demand; however, WECC-CA/MX and WECC-SW may experience challenges during the peak demand hour (5pm) or later (up to 7pm) due to the variability of energy resource outputs and could require imports into the area to cover these risk periods. In WECC-CA/MX, the greatest risk is in the Baja (Mexico) part of the sub-region. See **Figure 14** and **Figure 15**. In WECC, resources are expected to 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.[93]

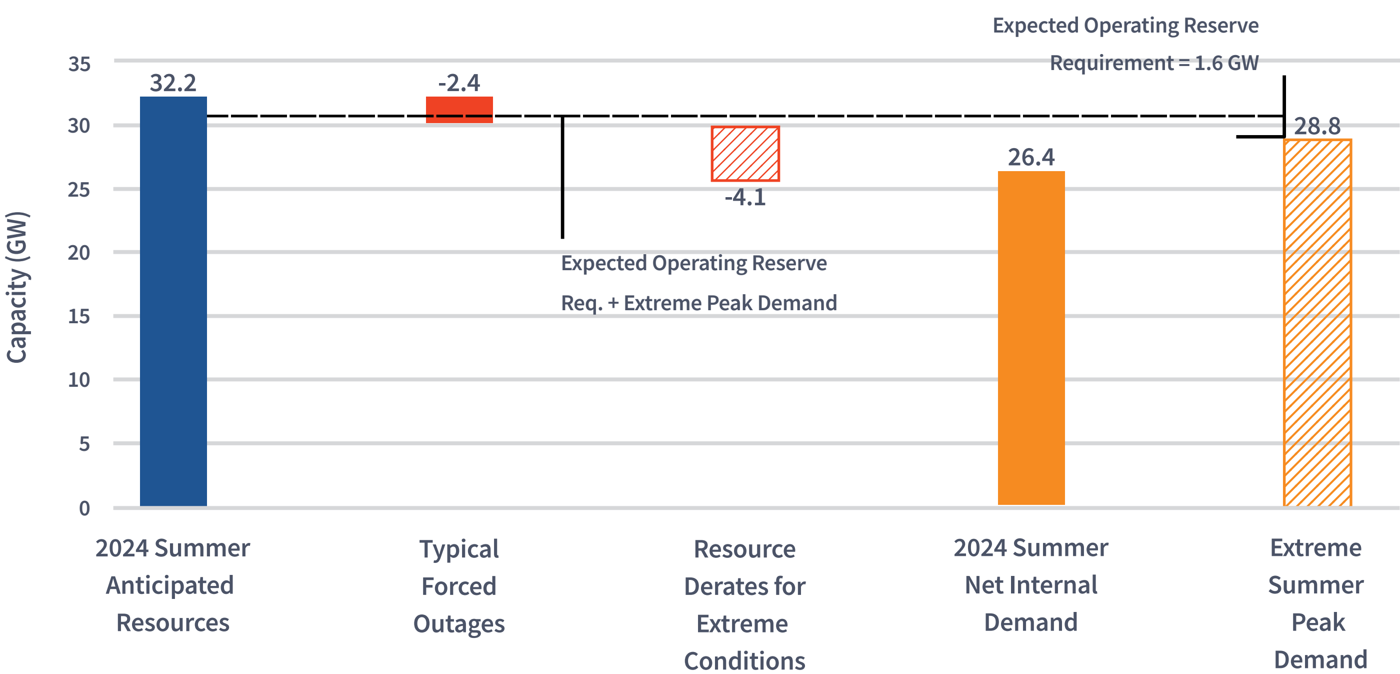
93 *Id.*

Figure 14: WECC-CA/MX Risk Period Scenario



Source: North American Electric Reliability Corporation

Figure 15: WECC-SW Risk Period Scenario



Source: North American Electric Reliability Corporation

While NERC reports that other assessment areas may not face energy shortfalls during summer 2024, there are still some challenges in those areas that are worth highlighting. In many assessment areas, due to the penetration of variable energy resources, the hour of highest risk is not the hour when demand peaks. For systems with significant penetration of solar resources, the highest risk hour tends to occur when the sun sets, and solar generation must be replaced by other resources. Similarly, periods of low wind, coupled with increased high load periods, or unanticipated generation outages, can create operational challenges.

For instance, MISO experienced peak electricity demand in August 2023 through that peak was less than its 90/10 summer peak forecast levels. Although MISO experienced lower forced outages of thermal generation than expected, the wind and solar resource outputs at the time of peak demand were also below expectations for summer on-peak contributions. MISO RC issued an EEA-2 on August 24 due to high forecasted loads and wind uncertainty.[94] MISO used operating procedures to ensure sufficient reserves were maintained during periods of high electricity demand and high forced generator outages, at times during the summer of 2023.[95] For summer 2024, according to NERC, MISO is expected to have sufficient resources, including firm imports, for normal summer peak demand. However, 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.[96] Wind generator performance 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 31,000 MW of installed wind capacity; however, the historically based, on-peak capacity contribution is 5,616 MW.[97]

The SPP region also experienced conditions similar to MISO, with SPP's summer electricity demand peaking during the same period in August 2023, and in this case exceeding 90/10 forecasts. SPP experienced above-normal levels of forced thermal generation outages; however, wind resource performance at the time of peak demand exceeded seasonal peak forecasts, helping to meet demand. However, during periods in June and July 2023, operators at SPP issued resource advisories during periods of forecasted high demand and when wind resource output was forecast to be low or was uncertain.[98] For summer 2024, SPP expects resources to be sufficient to meet operating reserve requirements under normal peak-demand and outage scenarios. For the summer of 2024, SPP risk is associated with low wind generation output levels or unanticipated generation outages in combination with high load periods.

According to NERC, all the other regions and subregions have sufficient operating reserves requirements under normal and extreme conditions. PJM experienced peak electricity demand in late July 2023, at a level between normal summer peak and the 90/10 forecast. Wind and solar resource outputs were below seasonal peak expectations, while low thermal generator outages were reported. For 2024 summer, PJM is again expecting a low risk of resources falling below required operating reserves. PJM forecasts a 29% installed reserve margin, (including expected, committed DR), well above the target of 17.7%. 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

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94 NERC, *2024 Summer Reliability Assessment* (May 15, 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2024.pdf; See also, MISO, *Overview of August 24th, 2023 Maximum Generation Event* (Oct. 3, 2023), https://cdn.misoenergy.org/20231003%20RSC%20Item%2005%20Overview%20of%20August%2024%20Max%20Gen%20Event630385.pdf.

95 NERC, *2024 Summer Reliability Assessment* (May 15, 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2024.pdf.

96 *Id.*

97 *Id.*

98 *Id.*

demand. However, rising demand, generator retirements, and slower-than-anticipated resource additions contribute to lower reserve margins in PJM, compared to last summer. PJM expects resources to meet operating reserve requirements under the assessed scenarios for normal and extreme conditions.[99]

NYISO's preliminary assessment results for 2024 indicate that expected resources will meet operating reserve requirements under the assessed scenario for normal summer peak load and outage conditions. Operating mitigations (i.e., demand response and transfers) may be needed to meet above-normal conditions, when New York could experience resource shortages during high demand conditions.[100] Notably, in 2023, peak electricity demand in NYISO occurred in early September 2023 and was below average summer peak forecasts.

According to NERC's assessment for the SERC Regional Entity, SERC-Central will have higher reserves compared to last summer due to increased firm imports and additions of gas and solar generation in summer 2024. There is a moderate risk of transmission impacts due to severe weather. Further, the age and condition of older coal- and gas-fired generators could result in forced outages and potential reliability challenges. SERC-Southeast will have higher reserves compared to last summer, due to a new 1,114 MW nuclear unit (Vogtle 4) and additional solar generation. However, with the increased penetration of variable energy resources, the curtailment of variable resources during light load conditions to support operations may become more prevalent. This, in combination with the retirement of resources, increases the operational challenges in managing the evening demand ramps in some areas of SERC Southeast. Overall, SERC-Central, SERC-East, SERC-Florida, and SERC-Southeast will meet operating reserve requirements under the normal and extreme assessed scenarios.[101]

Additionally, due to the interconnected design of the electric system, many regions rely on neighbors for support. During wide-area weather events, high demand can reduce the internal reserves in multiple locations, which can limit the ability of multiple regions to export power to neighboring regions. This has been notable during past extended extreme temperature events.[102] During 2023, the U.S. Southeast experienced peak demand above the 90/10 forecasts in mid- to late-August, but Balancing Authorities were able to maintain reserves during high demand periods due to high output from internal solar resources and imports from neighboring regions.[103]

Last summer, notable changes in expected transmission flow patterns included the inability of traditional Canadian exporters of hydro power to export to the United States due to drought conditions. This trend may continue this summer.[104] The MISO Independent Market Monitor notes that, last year, rather than importing power from Manitoba,

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99 *Id.*

100 *Id.*

101 *Id.*

102 CAISO, *Final Root Cause Analysis, Mid-August 2020 Extreme Heat Wave* (Jan 13, 2021), https://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf .

103 NERC, *2024 Summer Reliability Assessment* (May 15, 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2024.pdf.

104 Electricity transfers from Quebec to neighboring Maritimes and New England were curtailed or disrupted during periods in May and June 2023, when wildfires affected transmission facilities. Peak electricity demand in Ontario occurred in early September and exceeded 90/10 demand forecasts. Additional imports helped the area meet the extreme demand. NERC, *2024 Summer Reliability Assessment* (May 15, 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2024.pdf. The MISO IMM notes a decline of almost 50% in imports from Manitoba. Potomac Economics, *IMM Quarterly*.

the MISO region exported power to Manitoba, which led to different congestion patterns year-over-year.[105] With the continued Canadian drought (discussed more in the *Drought and Water Conditions* section of this report) this trend of reversed transmission flows may continue for summer 2024. Similarly, ISO-NE typically imports around 3,000 MW during summer peak load conditions, which may also be impacted, depending on Canadian drought conditions.[106] Extended heat waves also led to record-setting system electricity demand in the ERCOT system throughout the 2023 summer. For example, transmission system constraints on September 6, 2023, led to the curtailment of some supply from wind resources in the southern parts of the ERCOT system.[107] Similarly, the WECC-CA/MX assessment area issued public appeals to shift electricity use to off-peak hours during some high-demand periods in summer 2023.[108] The Mexico portion of the WECC-CA/MX assessment area faced reserve shortages during periods in July and August 2023 as a result of high demand, generator outages, and unavailability of imports.[109] This demonstrates the reliance on imports that may or may not be available during extreme conditions this summer.

Natural Gas Market Fundamentals

Natural gas prices across most of the United States for this summer are expected to be lower than in summer 2023, reflecting a further shift to a well-supplied market away from the tight supply-demand balance seen in summer 2022. In summer 2024, natural gas production is forecast to remain almost unchanged relative to last summer – with an expected slight decline of 1.6% – but still 5.8% above natural gas demand, which is anticipated to increase 1.7% relative to last summer. Consistent with previous summers, natural gas demand is expected to grow primarily due to increased feedgas demand for LNG exports. Natural gas storage inventories at the beginning of the injection season are relatively high, 23% above last summer's levels and 40% above five-year average levels.

NATURAL GAS PRICES

As of May 1, futures prices for natural gas for summer 2024 were below the final settled futures prices of the previous two summers at several major natural gas trading hubs.[110] The hubs comprise the national benchmark Henry Hub in Louisiana and nine other major supply and demand hubs in the Lower 48 States shown in **Figure 16.**[111] Prices at two major Northeast hubs, Transco-Z6 (NY) in New York City and Eastern Gas-South near Pittsburgh, were above the settled futures average price for each location for summer 2023, but well below the average for summer 2022, as regional natural gas demand growth is expected to outpace stable natural gas production in the Northeast. The Henry Hub futures contract price for summer 2024 averaged $2.25/MMBtu, down 9% from last summer's settled

105 Potomac Economics, *IMM Quarterly Report: Fall 2023* (Dec. 5, 2023) https://cdn.misoenergy.org/20231205%20Markets%20Committee%20of%20the%20BOD%20Item%2006%20IMM%20Quarterly%20Report631027.pdf; Potomac Economics, *IMM Quarterly Report: Winter 2024* (March 19, 2024) https://cdn.misoenergy.org/2024%20IMM%20Quarterly%20Report%20Winter632377.pdf.

106 NERC, *2024 Summer Reliability Assessment* (May 15, 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2024.pdf.

107 NERC, *2024 Summer Reliability Assessment* (May 15, 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2024.pdf.

108 WECC-CA/MX subregion consists of the CAISO, Northern California, and CENACE (Mexico) balancing authorities.

109 NERC, *2024 Summer Reliability Assessment* (May 15, 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2024.pdf

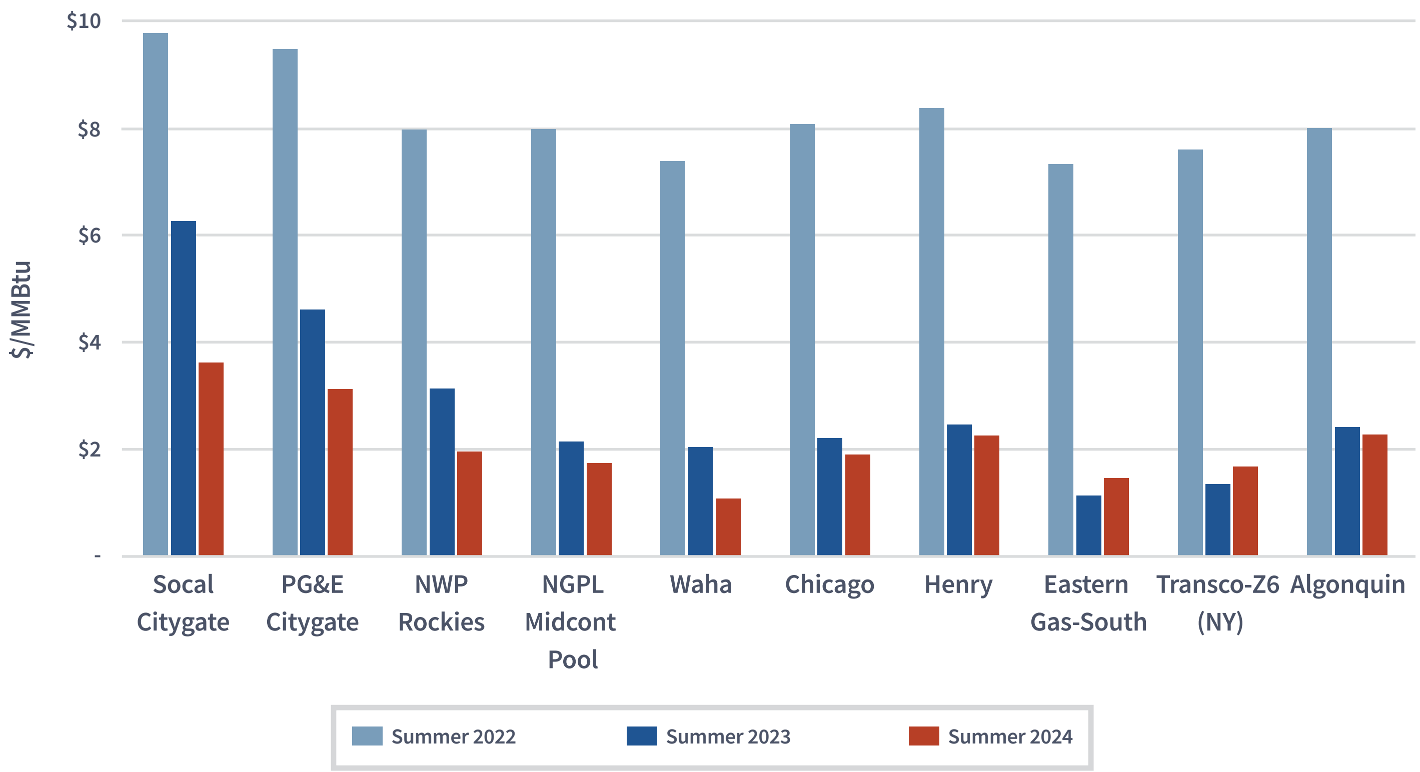
110 Natural gas futures prices are price quotations of contracts for the exchange of natural gas, as either a physical or financial settlement, at a specified time in the future. Summer futures prices discussed in this section are the average quotes of the last traded futures contracts, as of May 1, 2024, for the months of June 2024, July 2024, August 2024 and September 2024 as retrieved from InterContinental Exchange, Inc. Previous summer averages are the final settled futures prices for each month as retrieved from InterContinental Exchange, Inc.

111 For more information on U.S. natural gas markets and price formation, see the *Chapter 1: Wholesale Natural Gas Markets* in FERC's *Energy Primer: A Handbook for Energy Market Basics* (December 2023), https://www.ferc.gov/media/energy-primer-handbook-energy-market-basics.

price, a decrease of $0.21/MMBtu from the settled average from summer 2023.[112] Many factors affect traded natural gas prices, but low futures prices at the Henry Hub for this summer appear largely driven by the same factors that caused a dip in summer 2023: forecasts of greater availability of supply than the previous summer with a reduced need to inject natural gas into storage given above-average storage inventories.

Natural gas prices in the West are expected to decline the most from last summer's prices. The main southern California trading hub, the SoCal-Citygate, anticipated summer price average is $3.62/MMBtu – 42% lower than the summer 2023 price of $6.26/MMBtu, and 63% lower than the summer 2022 price of $9.77/MMBtu, which was the highest summer average seen at SoCal-Citygate in the previous five years. Lower futures prices relative to the last two summers can be attributed to California entering summer 2024 with high storage inventories, as discussed below in the *Natural Gas Storage* section. Despite the significant price declines over the past two years, SoCal-Citygate still has the highest futures price this summer relative to the other major regional hubs with PG&E Citygate not far below it at a $3.12/MMBtu average for summer 2024. As of May 1, 2024, there are planned outages on the Southern California Gas (SoCal Gas) and Pacific Gas and Electric (PG&E) mainline systems for the coming summer, which could lead to constrained regional import capacity and higher natural gas prices at the citygate hubs.[113] In the Permian Basin, the Waha hub futures price averaged $1.08/MMBtu, down 47% from last summer's settled futures price of $2.04/MMBtu.

Figure 16: Natural Gas Futures Prices at Major Trading Hubs



NOTE: Summer 2022 and summer 2023 averages are based on settled futures. Source: InterContinental Exchange

112 Regional natural gas prices are calculated by adding the Henry Hub summer futures price to the summer basis futures prices at major trading hubs in the United States. Regional basis prices reflect, among other things, the distance from producing basins, availability of natural gas transportation, and local weather expectations for the coming summer.

113 Southern California Gas Company, *System Maintenance Outlook for 2024* (Mar. 22, 2024). https://www.socalgas-envoy.com/ebb/attachments/1711142857895_Maintenance_Outlook_April_2024.pdf; Pacific Gas and Electric. CGT Prospective Maintenance (Mar. 19, 2024).

Futures prices at some Northeast hubs have increased over last summer despite lower Henry Hub prices. At Transco Z6 NY, as of May 1, futures prices this summer average $1.68/MMBtu compared to $1.35/MMBtu in 2023. In contrast, at the Algonquin Citygates hub, located outside of Boston, the average futures price as of May 1 was $2.27/MMBtu, a decrease compared to a settled average of $2.41/MMBtu in summer 2023. Demand for natural gas in the Northeast is heavily winter-peaking due to reliance on the fuel for residential and commercial space heating, although summer demand for electricity generation has increased over the last decade. Natural gas production and transportation from the nearby Appalachia region has typically been more than able to meet summer demand in the Northeast, generally resulting in slightly reduced prices in the summer as compared to the Texas and Louisiana Gulf Coasts (South Texas to Henry Hub), where natural gas demand is strong year-round for purposes of electricity generation, industrial processes, and LNG exports.

NATURAL GAS PRODUCTION

As of May 7, 2024, EIA forecasted summer 2024 U.S. dry natural gas production to average 102.3 Bcfd, a slight decline of 1.6% from the summer 2023 average of 103.9 and 5.8% above the previous five-year summer average of 96.7 Bcfd (see **Figure 17**).[114] Dry natural gas production has increased year-over-year every summer since 2019, except for summer 2020 due to the economic impacts of the COVID-19 pandemic. Production is expected to be slightly lower for summer 2024 than in summer 2023 because of curtailments announced by producers, due to low natural gas prices, along with a stable rig count.[115]

Despite relatively low prices, natural gas production in summer 2024 is expected to remain relatively stable year-over-year mainly due to associated natural gas production[116] from the oil-rich Permian basin located in Texas and New Mexico. EIA forecasts that most production growth in 2024 will come from the Permian Basin. Overall, most natural gas production in the United States comes from three regions: the Permian Basin, the Haynesville Basin, and Appalachia (the Marcellus and Utica shale basins). These shale formations accounted for nearly 60% of the total U.S. natural gas production during summer 2022 and summer 2023.[117]

NATURAL GAS DEMAND

In the United States, total natural gas demand, including residential/commercial, industrial, natural gas consumed for electricity (power burn), and net exports, is forecast to average 96.7 Bcfd in summer 2024, 1.7% more than summer 2023 levels and 11.8% more than the previous five-year summer average, as seen in **Figure 18**. Total U.S. domestic natural gas consumption, which excludes net exports, is expected to average 82.8 Bcfd in summer 2024, a 0.3% increase from summer 2023 levels and 6.6% above the previous five-year average. Consistent with previous summers, the increase in natural gas demand for summer 2024 is expected to primarily come from natural gas exports (including LNG and pipeline net exports), which are expected to average 14.0 Bcfd in summer 2024, up 10.8% from summer 2023 and 56.6% above the previous five-year average.

Domestically, the largest increase in natural gas demand in summer 2024 is expected to come from the residential/commercial sector, which is expected to average 9.2 Bcfd, a 7.8% increase from summer 2023 and 8.6% above the

114 Dry natural gas is consumer-grade natural gas that is almost entirely composed of methane, with little to no hydrocarbon liquids (such as propane and ethane) or impurities.

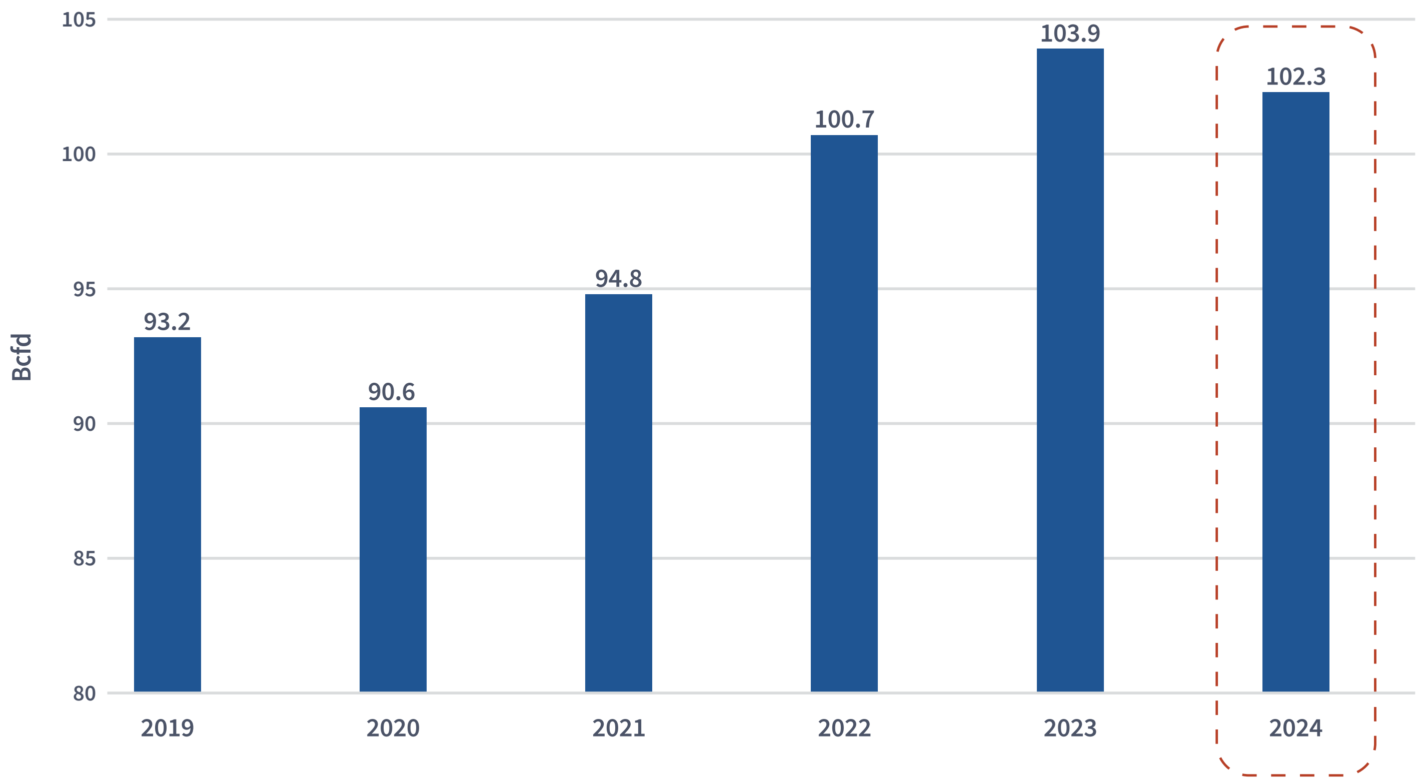
115 EIA, *Short-Term Energy Outlook* (Mar. 12, 2024) https://www.eia.gov/outlooks/steo/report/natgas.php.

116 Associated natural gas is natural gas produced as a byproduct of oil production.

117 For more on U.S shale gas development and its impact, see the *Natural Gas Supply* section at p. 6 in FERC's *Energy Primer: A Handbook for Energy Market Basics* (December 2023), https://www.ferc.gov/media/energy-primer-handbook-energy-market-basics.

previous five-year average. Natural gas demand growth in the industrial/other sector, which is primarily concentrated on the Gulf Coast due to expansions of petrochemical and other industrial facilities in the region, is forecast to average 30.1 Bcfd in summer 2024, down 1.6% from summer 2023 levels and 2.1% above the previous five-year average.

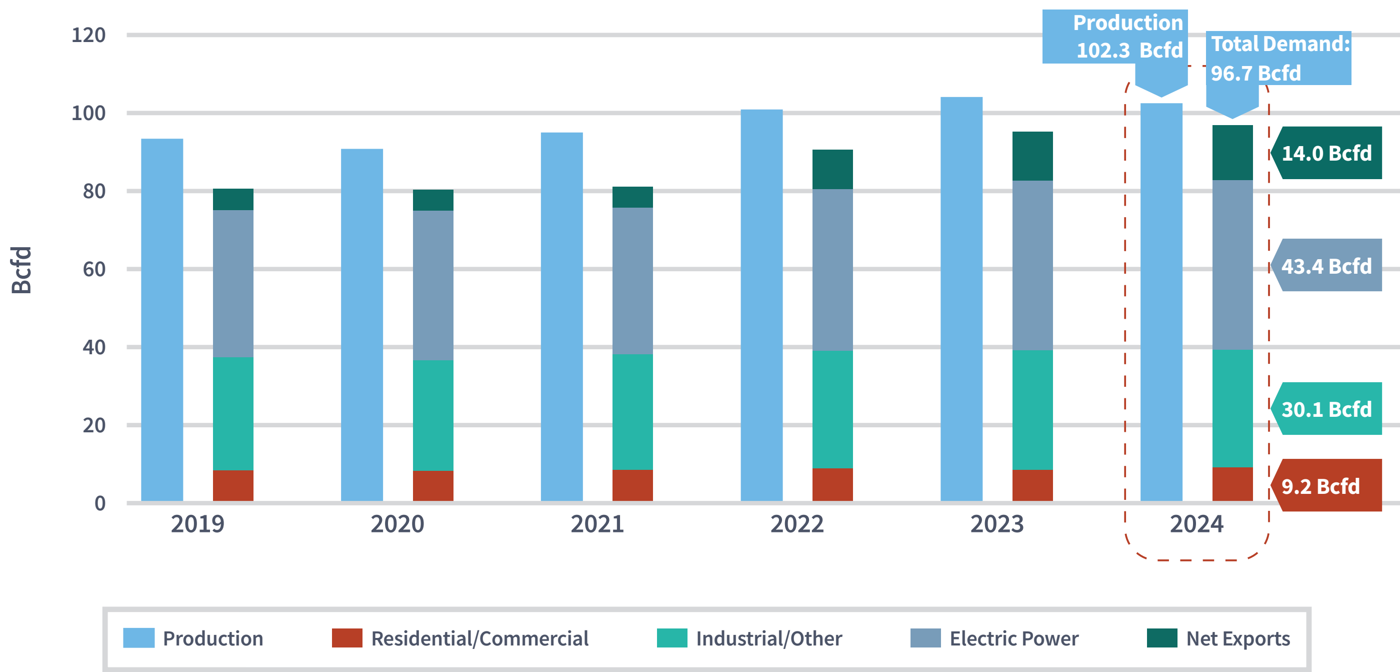
Figure 17: 2019-2024 Average Summer U.S. Dry Natural Gas Production



Source: EIA

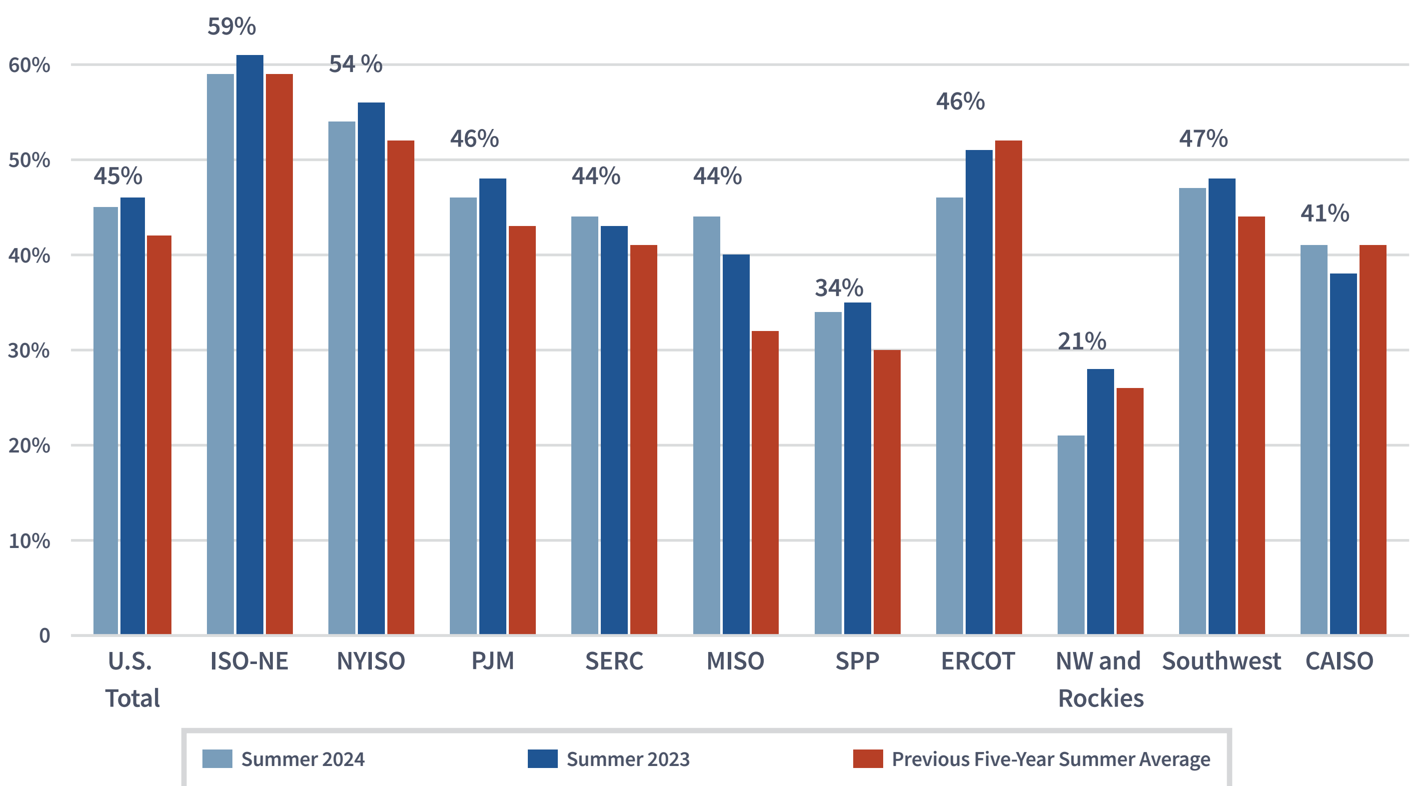
Power burn is expected to average 43.4 Bcfd in summer 2024, down 0.1% from summer 2023 and 9.6% above the five-year average. Consistent with past summers, power burn in 2024 is forecast to peak during the typically hottest months of July and August, at 47.2 Bcfd, while June and September will see less demand for electricity and an average power burn of 39.7 Bcfd. Demand for power burn is determined by overall electricity consumption, which is driven in summer by high demand for space cooling, and the share of electricity generation that natural gas power plants are called upon to provide. The share of U.S. electricity generated from natural gas power plants during summer 2024, is forecast to average 44.5%, down slightly from 45.7% in summer 2023, but still above the previous five-year average of 42.3%.

Figure 18: Summer Natural Gas Production & Demand



Source: EIA

Figure 19: Share of U.S. Electricity Generated from Natural Gas Generators in Summer by Region



Source: EIA

Regionally, the share of U.S. electricity generated from natural gas power plants in summer 2024 varies. Of the ten regions shown in **Figure 19**, ISO-NE, SPP, ERCOT, Northwest and Rockies, NYISO, PJM and the Southwest region expect to decrease their average shares of natural gas generation, while, SERC, CAISO, and MISO expect to increase their shares of natural gas generation. ISO-NE is expected to have the largest share of natural gas generation at 59%, while the hydropower-heavy Northwest and Rockies region is expected to have the smallest share at 21%. Notably, three regions are forecast to decrease their share of natural gas generation: SPP is forecast to decrease its share of natural gas generation from 35% in summer 2023 to 34% in summer 2024; ERCOT from 51% in summer 2023 to 46% in summer 2024; and the Northwest and Rockies region from 28% in 2023 to 21% in 2024. As each market has a different level of total electricity generation for the season, similar shares of natural gas-fired generation do not necessarily mean the same level of demand for power burn. Because PJM's total generation is much larger than ISO-NE's, for example, PJM is expected to burn more natural gas for power production even though gas generation is a smaller share of overall generation in PJM than in ISO-NE.

NATURAL GAS EXPORTS AND IMPORTS

The United States was the world's largest LNG exporter in 2023, and U.S. natural gas exports are expected to increase this summer.[118] As of May 7, 2024, the FERC-authorized export liquefaction capacity of the United States was 14.23 Bcfd across seven LNG export facilities. The anticipated level of LNG exports is due primarily to sustained demand for LNG cargos in the European market and elevated international LNG prices. Additionally, Venture Global commenced commercial operation on trains 10-18 at the Calcasieu Pass export facility in Louisiana in October of 2023, which brought an additional 0.79 bcf/d of LNG export capacity.[119] U.S. LNG cargos have helped supply Europe since the near-halt of Russian pipeline gas deliveries to Europe due to the Russia-Ukraine war, and EIA expects this trend to continue through 2024.[120] EIA forecasts gross LNG exports to average 11.6 Bcfd this summer (June, July, August, and September 2024), up from 11.29 Bcfd in summer 2023 (see **Figure 20**). Altogether, the United States is forecast to be a net exporter of natural gas this summer, with net natural gas exports, including LNG and via pipeline, averaging 14 Bcfd compared to 12.6 Bcfd in summer 2023. EIA expects gross pipeline imports, primarily from Canada, to average 7.2 Bcfd in summer 2024, a 9% decrease from summer 2023.

118 EIA, *The United States was the World's Largest Liquefied Natural Gas Exporter in 2023* (Apr. 1, 2024) https://www.eia.gov/todayinenergy/detail.php?id=61683.

119 FERC, North American LNG Export Terminals – Existing, Approved not Yet Built, and Proposed (Dec. 31, 2023), https://www.ferc.gov/media/us-lng-export-terminals-existing-approved-not-yet-built-and-proposed.

120 Russia's natural gas pipeline exports to Europe declined to almost 40-year lows between Jan. 1, 2016 and July 31, 2022 to 1.2 Bcfd in mid-July 2022. EIA, *Europe's LNG Import Capacity Set to Expand by One-third by end of 2024* (Nov. 29, 2022), https://www.eia.gov/todayinenergy/detail.php?id=54780.

Figure 20: U.S. Summer Natural Gas Exports and Imports

Source: EIA

In addition to LNG exports, gross pipeline exports are forecast to increase 0.35 Bcfd from summer 2023 and to average 9.57 Bcfd this summer.[121] For context, gross pipeline exports averaged 6.7 Bcfd to Mexico and 2.4 Bcfd to Canada in summer 2023.

NATURAL GAS STORAGE

Natural gas storage inventories help to balance natural gas demand and supply and are fundamental to price formation in natural gas markets.[122] The 2024 injection season began on March 29, when storage inventories from winter 2023-2024 ended with 2,259 Bcf, which is 23% (429 Bcf) more than the start of the 2023 injection season and 40% (648 Bcf) more than the five-year average of inventories at the start of the injection seasons.[123] Elevated natural gas storage levels at the start of this year's injection season resulted in part from the United States starting the past winter heating season with a

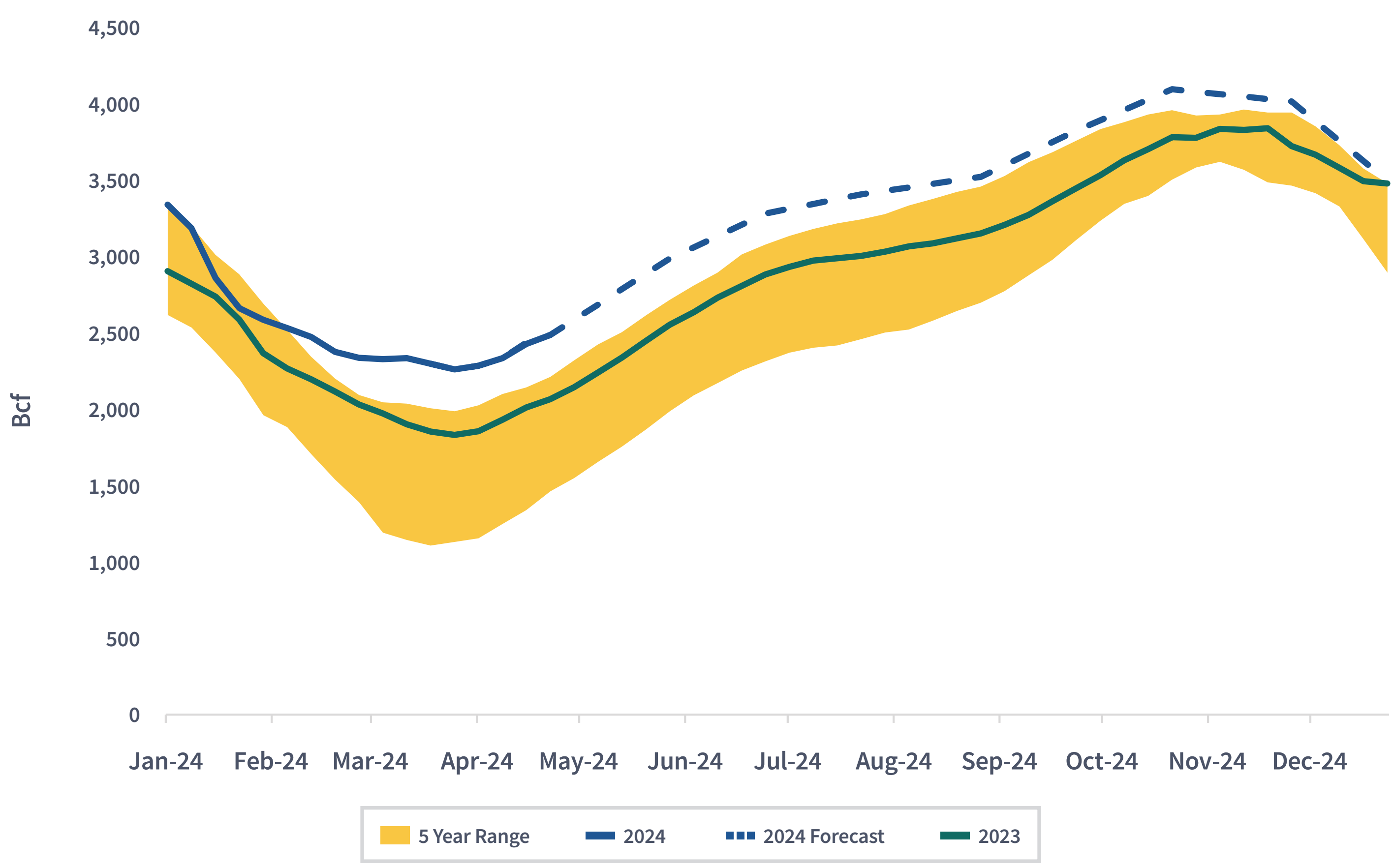
121 For more information on U.S. LNG markets, see the *Liquefied Natural Gas* section of the *Wholesale Natural Gas Markets chapter in FERC's Energy Primer: A Handbook for Energy Market Basics (December 2023),* https://www.ferc.gov/media/energy-primer-handbook-energy-market-basics.

122 For more information on U.S. natural gas storage markets, see the *Natural Gas Storage* section on p. 25 in FERC's *Energy Primer: A Handbook for Energy Market Basics* (December 2023), https://www.ferc.gov/media/energy-primer-handbook-energy-market-basics.

123 The natural gas storage injection season typically starts during the first week of April and ends the last week of October. In any given year, the start of the injection season is determined by the lowest natural gas storage level of the year and the winter withdrawal season by the highest natural gas storage level of the year.

5% surplus of natural gas inventories compared to the five-year average[124] along with a mild winter resulting in reduced residential and commercial consumption. The large storage inventory surplus is expected to contribute to low natural gas prices though the summer in most regions, especially in the West where natural gas prices are expected to decline the most of any region compared to summer 2023, as noted in the above pricing section. In Southern California specifically, SoCal Gas reported core storage inventories of about 72 Bcf at the end of the winter withdrawal season on April 4, 2024, which is 125% higher than at the same time last year.[125] In late summer 2023, the California Public Utilities Commission (CPUC) approved an increase in the allowed capacity that SoCal Gas can use at the Aliso Canyon storage facility, from 41.6 Bcf to 68.6 Bcf, which increased the total on-system storage maximum capacity to 120 Bcf.[126] The CPUC stated that the additional storage capacity in the SoCal Gas system would reduce scarcity in the market and reduce price volatility.[127]

Figure 21: U.S. Natural Gas Storage Inventories for the Lower 48 States



Source: EIA

124 EIA, *The United States Begins the Winter with the Most Natural Gas in Storage Since 2020* (Accessed Apr. 9, 2024), https://www.eia.gov/todayinenergy/detail.php?id=61044.

125 Southern California Gas Company, *Envoy system status dashboard*, https://www.socalgas-envoy.com/.

126 Energy Information Administration, *Southern California working natural gas storage increases with higher cap at Aliso Canyon*, Today in Energy (Sept. 27, 2023). https://www.eia.gov/todayinenergy/detail.php?id=60502.

127 California Public Utilities Commission, press release, *CPUC Takes Action to Enhance Energy Affordability For Ratepayers in Southern California* (August 31, 2023), https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-takes-action-to-enhance-energy-affordability-for-ratepayers-in-southern-california-2023.

According to EIA, natural gas storage inventories are forecast to grow 1,833 Bcf during the 2024 injection season and end the injection season (or start the 2024-2025 winter storage withdrawal season) at 4,092 Bcf, 7% (256 Bcf) above last year levels and 9% (329 Bcf) above the five-year average of inventories at the start of the winter storage withdrawal seasons.

NATURAL GAS INFRASTRUCTURE

Since September 2023, several interstate natural gas pipelines have increased transmission capacity, according to EIA's pipeline project database.[128] Most notably, in October 2023, Transcontinental Gas Pipe Line Company's Regional Energy Access Expansion Project, for natural gas flows from the Marcellus Shale production area to delivery points in Pennsylvania, New Jersey, and Maryland, placed 0.45 Bcfd of new capacity into service with plans to expand to 0.83 Bcfd. Another notable project newly in service since summer 2023 is Equitrans' Ohio Valley Connector Expansion, designed to deliver natural gas into eastern Ohio from the central Appalachian region, a 0.35 Bcfd capacity project placed into partial service in March 2024.[129] Additionally, Phase 1 of Venture Global's Gator Express pipeline project in Louisiana, delivering an additional 1.9 Bcfd of feedgas to the Plaquemine LNG terminal, began service in May 2024.

Other intrastate projects have increased the routes available to shippers by adding 3.95 Bcfd of capacity in Louisiana and Texas since last summer. Many of these additions increase takeaway capacity out of the Haynesville Basin in Louisiana and East Texas and the Permian Basin in West Texas to serve high-demand Gulf Coast markets.

As noted above, in October 2023, trains 10-18 of the Calcasieu Pass LNG facility in Louisiana began commercial service, adding an additional 0.79 Bcfd to the U.S. LNG export capacity.

NOTABLE ISSUES FOR SUMMER 2024

This section of the report highlights concerns unique to this upcoming summer such as natural gas supply issues in California, drought, hydropower availability and wildfire conditions. The section begins with a recap of summer 2023 to set the stage for possible issues this coming summer.

Recap of Notable Events from Summer 2023

Summer 2023 was challenging for the electric industry due to persistent extreme heat, significant drought, and storm damages impacting the bulk power system. North America had its warmest meteorological summer (June-August) on record in 2023, with much of the contiguous United States experiencing above-average temperatures.[130] Nearly all regions declared at least an EEA-1 during the summer of 2023, often attributed to intense heat and higher-than-

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128 EIA, *Natural Gas Pipeline Project Tracker*, https://www.eia.gov/naturalgas/pipelines/EIA-NaturalGasPipelineProjects.xlsx (Accessed April 2, 2023).

129 Tennessee Gas Pipeline, LLC, *Notification of Placing Project Facilities at Compressor Station 321 and Compressor Station 327 In-Service*. Docket CP20-493 (Nov. 6, 2023), https://elibrary.ferc.gov/eLibrary/docinfo?accession_number=20231106-5082; Gas Daily, *Tennessee Gas Gets OK to Partially Start Up East 300 Upgrade as Cold Weather Hits Northeast* (Nov. 1, 2023).

130 National Integrated Drought Information System, *Summer 2023 in Review: A Look Back at Drought Across the U.S. in 10 Maps*, (Sept. 21, 2023), https://www.drought.gov/news/summer-2023-review-look-back-drought-across-us-10-maps-2023-09-21.

anticipated demand.[131] During summer 2023, MISO North, MISO South, SPP, FRCC and ERCOT set all-time system peak demand records, all-time weekend peak records, or new monthly peak demand records.[132] ERCOT requested a DOE Federal Power Act section 202(c) emergency order authorizing specific electric generating units to operate at their maximum generation output levels due to ongoing extreme weather conditions and to preserve the reliability of the BPS in September 2023.[133]

In summer 2023, drought conditions expanded and intensified, largely influenced by lack of precipitation and extreme heat.[134] While the number and size of wildfires were relatively small in the western United States compared to recent summers, many U.S. towns and cities spent part of the summer shrouded in smoke moving in from a record-breaking Canadian wildfire season.[135] Severe storms and flooding in large portions of the country at several points during summer 2023 caused significant damage to homes and businesses and left hundreds of thousands without power.[136]

The summer 2023 heat persisted into September, which experienced record-breaking temperatures in portions of the United States.[137] ERCOT set a new September peak demand record, exceeding the 2022 September monthly record

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131 CAISO, press release, *Energy Emergency Alert (EEA) 1 declared and ended* (July 20, 2023), https://www.caiso.com/Documents/energy-emergency-alert-eea-1-declared-and-ended.pdf; ERCOT, press release, *ERCOT has initiated Energy Emergency Alert Level 2 (EEA2), Conservation is Critical* (September 6, 2023), https://www.ercot.com/news/release/2023-09-06-ercot-has-initiated; MISO, *Overview of August 24th, 2023 Maximum Generation Event* (October 3, 2023), https://cdn.misoenergy.org/20231003%20RSC%20Item%2005%20Overview%20of%20August%2024%20Max%20Gen%20Event630385.pdf; PJM Inside Lines, *PJM Issues Update on Grid Conditions* (July 27, 2023), https://insidelines.pjm.com/pjm-issues-update-on-grid-conditions/; ISO-NE Newswire, press release, *ISO-NE successfully manages through July 5 capacity deficiency* (July 6, 2023) https://isonewswire.com/2023/07/06/iso-ne-successfully-manages-through-july-5-capacity-deficiency/.

132 Potomac Economics, *IMM Quarterly Report: Summer 2023* (Sept. 18, 2023) https://www.potomaceconomics.com/wp-content/uploads/2023/09/IMM-Quarterly-Report_Summer-2023_Final.pdf ; SPP, *SPP Resource Adequacy Overview*, a presentation to the Kansas Special Committee on Energy and Utilities (Oct. 17, 2023), https://www.kslegislature.org/li/b2023_24/committees/ctte_spc_2023_special_committee_on_energy_and_ut_1/documents/testimony/20231017_08.pdf; S&P *Global, Heat Wave Pushes up Central US Power Prices; MISO Prepares for Peak Load Record* (Aug. 22, 2023), https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/electric-power/082223-heat-wave-pushes-up-central-us-power-prices-miso-prepares-for-peakload-record; Shauna Muckle, *Tampa Electric Sets Summer Power-use Record Two Days in a Row*, Tampa Bay Times (Aug. 11, 2023), https://www.tampabay.com/news/breaking-news/2023/08/11/tampa-electric-sets-summer-power-use-record-two-days-row/; Shira Moolten, *Peak Demand: South Florida Energy Use is Surging Under this Summer's Extreme Heat*, South Florida Sun Sentinel, (Aug. 11, 2023) https://www.sun-sentinel.com/2023/08/11/peak-demand-south-florida-energy-use-is-surging-under-this-summers-extreme-heat/; ERCOT, *2023 Peak Demand Records*, (Nov. 13, 2023) https://www.ercot.com/static-assets/data/news/Content/a-peak-demand/2023/all-time-records.htm.

133 Under the Federal Power Act (FPA) section 202(c), during the continuance of a war in which the United States is engaged or when an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy, or of facilities for the generation or transmission of electric energy, or of the fuel or water for generating facilities, or other causes, the Secretary of Energy may require by order temporary connections of facilities, and generation, delivery, interchange, or transmission of electricity as the Secretary determines will best meet the emergency and serve the public interest. 16 U.S.C. § 824a(c).

134 National Integrated Drought Information System, *Summer 2023 in Review: A Look Back at Drought Across the U.S. in 10 Maps,* (Sept. 21, 2023), https://www.drought.gov/news/summer-2023-review-look-back-drought-across-us-10-maps-2023-09-21.

135 American Public Power Association, *Canadian Wildfires Impact Solar Production in Eastern U.S., Grid Operators Report* (June 9, 2023) https://www.publicpower.org/periodical/article/canadian-wildfires-impact-solar-production-eastern-us-grid-operators-report. S&P Global, *US company observes solar power output declines in the Northeast due to Canadian wildfire smoke*, (June 12, 2023), https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/electric-power/061223-us-company-observes-solar-power-output-declines-in-the-northeast-due-to-canadian-wildfire-smoke.

136 NOAA National Centers for Environmental Information, *Monthly National Climate Report for June 2023*, https://www.ncei.noaa.gov/access/monitoring/monthly-report/national/202306; NOAA National Centers for Environmental Information, *Monthly National Climate Report for July 2023*, https://www.ncei.noaa.gov/access/monitoring/monthly-report/national/202307; NOAA National Centers for Environmental Information, *Monthly National Climate Report for August 2023*, https://www.ncei.noaa.gov/access/monitoring/monthly-report/national/202308.

137 NOAA National Centers for Environmental Information, *Monthly National Climate Report for September 2023*, https://www.ncei.noaa.gov/access/monitoring/monthly-report/national/202309.

by more than 10 GW.[138] Generally, September temperatures were also above average across much of the contiguous United States, with below-normal temperatures in southern parts of the West Coast and in parts of the Southeast.[139] September also saw persistent drought across parts of the Midwest, damaging hurricane activity in New England and the Carolinas, and heavy precipitation in the Pacific Northwest and New York City.[140]

NOAA projects a one-in-three chance that 2024 will be even hotter than 2023, which was already the world's hottest on record, and a 99% chance that 2024 will rank among the five warmest years on record.[141] Seasonal periods are also beginning to shift to a warmer May and October, increasing the need for energy for cooling earlier and later in the summer season. NERC notes that 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, regions are facing resource-constrained periods during the shoulder months as unseasonable temperatures coincide with generator unavailability. The potential for unusual heat patterns in the shoulder months informs the need for careful attention to long-term weather forecasts and more conservative outage coordination periods.[142]

Drought and Water Conditions

Drought conditions persist in much of the United States in 2024, potentially affecting hydropower availability in certain regions, including the Southwest and central and northern United States, which face elevated risks compared to summer 2023. Drought conditions currently affect 19% of the continental United States, with a total of 39% affected by both drought and abnormally dry conditions, potentially affecting hydropower production.[143] Over 71% of Canada is also experiencing abnormally dry or drought conditions and faces potential reoccurrence of wildfires this summer, which could affect Canadian hydropower production and U.S.-Canada energy transfers in both the Eastern and Western Interconnections. If wildfires persist, the smoke could affect output of solar resources.

As of April 1, 2024, states in the West reported a range of snowpack levels heading into the summer months with some regions reporting higher levels of snowpack while others remain at lower levels.

DROUGHT IN WEST, CENTRAL, AND MIDWEST UNITED STATES HYDROPOWER AVAILABILITY

Figure 22 shows the extent of drought conditions heading into summer 2024. NOAA's Climate Prediction Center projects that from April 1 to June 30, 2024, significant areas of the Desert Southwest, Pacific Northwest, and Midwest will continue to face drought conditions.[144] By contrast, California, parts of the Mountain West, and the East Coast are not expected to face drought conditions from April 1 through June 30, 2024. While Northwestern and North-Central

138 ERCOT, *2023 Peak Demand Records*, (Nov. 13, 2023) https://www.ercot.com/static-assets/data/news/Content/a-peak-demand/2023/all-time-records.htm.

139 NOAA National Centers, *U.S. Climate Summary for September 2023* (Oct. 11, 2023), https://www.climate.gov/news-features/understanding-climate/us-climate-summary-september-2023.

140 NOAA National Centers for Environmental Information, *Monthly National Climate Report for September 2023*, https://www.ncei.noaa.gov/access/monitoring/monthly-report/national/202309.

141 NOAA, *2023 Was the World's Warmest Year on Record, by far* (Jan. 12, 2024). https://www.noaa.gov/news/2023-was-worlds-warmest-year-on-record-by-far.

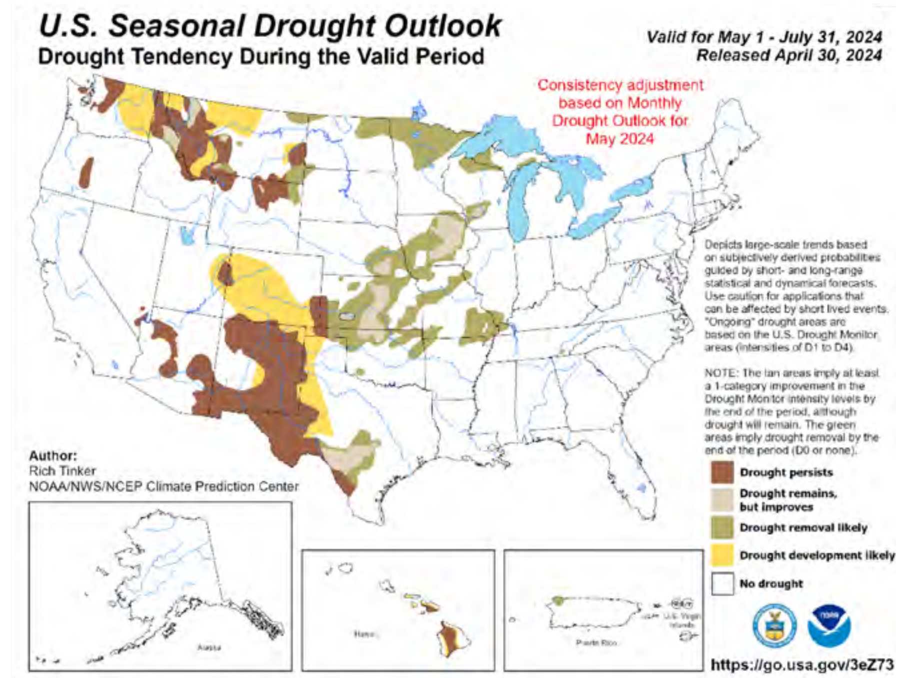
142 NERC, *Summer 2023 Reliability Assessment* (May 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2023.pdf.

143 NOAA, *North American Drought Monitor* (Feb. 29, 2024), https://www.ncei.noaa.gov/access/monitoring/nadm/maps.

144 NOAA Climate Prediction Center, *U.S. Seasonal Drought Outlook* (Apr. 3, 2024), https://www.cpc.ncep.noaa.gov/index.php.

U.S. snowpack is down, in California continued high levels of snowfall and rain in winter 2023-2024 contributed to precipitation levels at 107% of the NOAA climate normal and snowpack levels at 109% of the NOAA climate normal as of April 1, 2024.[145]

Figure 22: U.S. Drought Conditions March 2024



Source: U.S. Drought Monitor

Drought conditions remain present in several regions of the United States with impacts to some types of generation. In the central United States, drought conditions continue to affect the Midwest and Southern Plains, including the Missouri and Mississippi River basins. During fall 2023, shipments typically sent by barge on the Mississippi River and other nearby navigable waterways were diverted due to low water conditions, potentially affecting coal shipments to generators seeking to build stockpiles to meet winter requirements in some regions.[146] Continued drought conditions would affect smaller hydro resources along the affected rivers as well as thermal plants drawing cooling water from the rivers later in the summer as temperatures rise and water levels drop. If drought conditions continue for the Mississippi River through the summer, later in the summer or during early fall, salinity may also be an issue for power plants near the mouth of the river that draw cooling water from the river.[147] This saltwater intrusion occurred during summer 2023.[148]

145 California Data Exchange Center, *Snow Water Equivalents* (Apr. 3, 2024), https://cdec.water.ca.gov/snowapp/sweq.action. California Water Watch, *Track California Water Conditions* (Apr. 3, 2024), https://cwww.water.ca.gov/.

146 NOAA *Mississippi River Basin Forecasts* (Accessed October 2023), https://www.weather.gov/lmrfc/obsfcst_mississippi_riverwatch/.

147 NOAA, *Spring Outlook: Warmer for most of U.S., wetter in the Southeast,* (March 21, 2024), https://www.noaa.gov/news-release/spring-outlook-warmer-for-most-of-us-wetter-in-southeast.

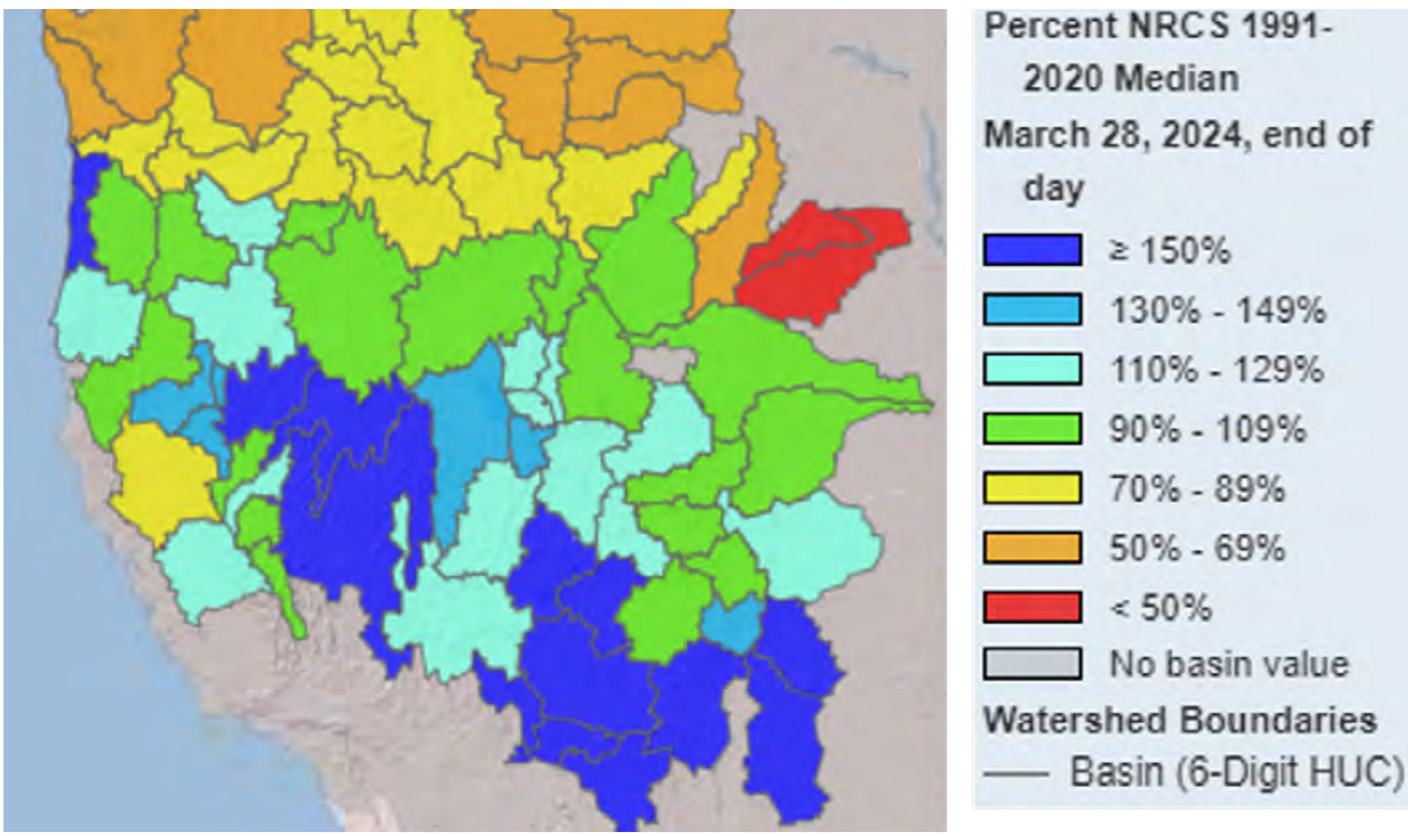
148 City of New Orleans, NOLA Ready, *Lower Mississippi Saltwater Intrusion*, (Oct 1, 2023) https://ready.nola.gov/incident/saltwater-intrusion/about-saltwater-intrusion/.

In the West, precipitation mostly accumulates in the fall and winter months in the form of snow at higher elevations and then melts in the spring and summer as temperatures gradually increase. As seen in **Figure 23**, the West, particularly the Northwest and Rockies, received lower levels of precipitation and snowpack during the recent fall and winter months than the historical median. With nearly 60% all U.S. conventional hydropower generation located in the West, lower generation from hydropower in summer 2024 may increase reliance on natural gas for power to meet electricity demand for air conditioning.[149]

Regionally, conditions vary with states in the Desert Southwest still maintaining snowpack levels above the historical median and states in the Pacific Northwest and Rockies with snowpack levels below the historical median. In California, snowpack levels were 111% of median; a major decrease from 299% of median a year ago.[150]

EIA forecasts hydropower generation during summer 2024 to be 6% less in the Northwest and Rockies and 8% less in the Desert Southwest as compared to the respective previous five-year averages. California is forecasted to increase hydropower generation in summer 2024 by 19% as compared to its previous five-year average, in part because the state has recovered from the extended drought conditions of recent years.

Figure 23: Western Snowpack Levels

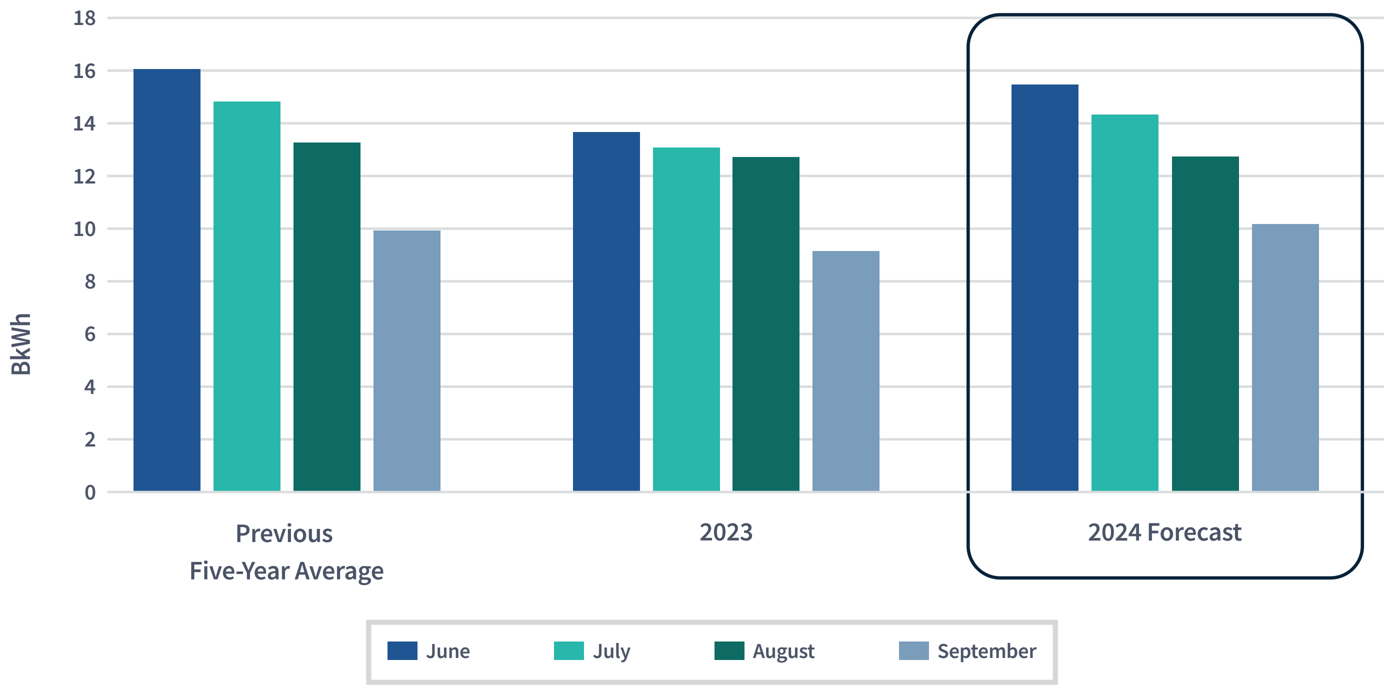


Source: USDA Natural Resource Conservation Service, U.S. Department of Agriculture, March 29, 2024

149 EIA, *Hydropower Explained* (accessed Mar. 29, 2024), https://www.eia.gov/energyexplained/hydropower/where-hydropower-is-generated.php.

150 Note: Median calculated from 1991-2020. California Department of Water Resources, Snow Water Equivalents (Mar. 29, 2024), https://wcc.sc.egov.usda.gov/reports/UpdateReport.html.

Figure 24: U.S. Western Hydropower Generation by Summer Month



Source: EIA STEO

In the West, hydrological conditions vary widely. The California-Nevada region benefited from multiple atmospheric river events, helping to alleviate precipitation deficits, with a single event bringing 20-40% of the water year precipitation to Southern California and improving snowpack and reducing the extent of snow drought conditions.[151] Reservoir storage levels for California and Nevada are expected to be near normal for summer 2024, but remain below normal for the lower Colorado River basin reservoirs, with a 100% forecast of continued shortage conditions for Lake Mead in summer 2024.[152]

Low reservoir levels in lakes Powell and Mead will continue to limit hydropower generation at Glen Canyon Dam (1,320 MW capacity) and Hoover Dam (2,090 MW capacity). The Pacific Northwest also continues to experience drought conditions in the eastern part of the region, which could affect the availability of hydropower, a key resource in the region. Finally, drought conditions persist in the Southwest, especially in New Mexico and Texas. Some regions with long-term or higher levels of drought are experiencing falling groundwater levels and reduced availability of cooling water access for some plants, especially later in the summer season.

151 Atmospheric rivers are relatively long, narrow regions in the atmosphere – like rivers in the sky – that transport most of the water vapor outside of the tropics. When the atmospheric rivers make landfall, they often release this water vapor in the form of rain or snow. See NOAA, *What Are Atmospheric Rivers?* (March 23, 2023), https://www.noaa.gov/stories/what-are-atmospheric-rivers,NIDIS, *California-Nevada Drought Status Update* (February 15, 2024), https://www.drought.gov/drought-status-updates/california-nevada-drought-status-update-2024-02-15.

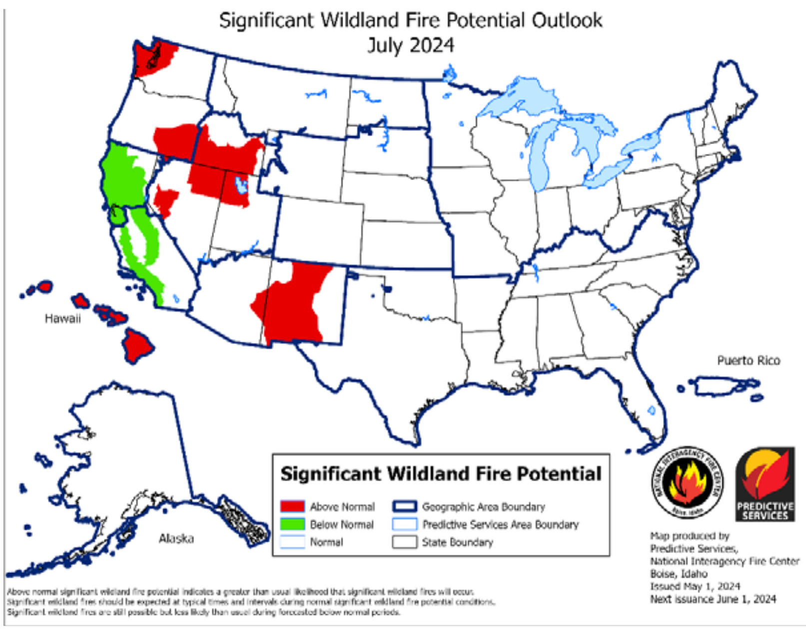
152 University of California, San Diego Scripps Institution of Oceanography, *Water Storage Tracking for Sierra Nevada and Upper Colorado River Basins*, https://cnap.ucsd.edu/storage_in_sierra_ucrb/ (Accessed April 7, 2024); Metropolitan Water District of Southern California, *Water Supply Conditions Report*, (Apr. 2, 2024) https://www.bewaterwise.com/water_supply_conditions/water_supply_conditions.pdf.

Hydropower availability throughout Canada has also been limited due to ongoing drought conditions, with the most significant impacts in Western Canada. This in turn has reversed typical transmission line flows changing net imports into U.S. regions into exports to Canada. For example, BC Hydro, typically a net exporter, became a net importer of power from U.S. states and Alberta during 2023, using imports to serve approximately 20 percent of its load.[153] Other utilities throughout Canada have been similarly affected, as discussed in the *Regional Highlights and NERC Probabilistic Assessment* section above.

WILDFIRE RISK ASSESSMENT

The combination of continued drought conditions and elevated temperatures forecast for summer 2024 increases risks of wildfires in several regions. A notable risk arising from wildfires include the possibility of preemptive transmission outages in high-risk areas outside of California, especially in the central United States, with Public Safety Power Shutoffs being used in Colorado, Kansas and Oklahoma in Spring 2024.[154] As shown in **Figure 25**, the National Interagency Fire Center (NIFC) forecasts a risk of elevated wildfire activity in parts of the western United States, with areas of concern in the Northwest, Desert Southwest and central Rocky Mountain regions. Year-to-date annual acres burned in the United States are well above the 10-year average, at 240% of normal, but with a below-average number of fires, at nearly 76 % of average.[155] Persistent extreme- to-exceptional drought in southern New Mexico and northwestern Montana as well as drought in Arizona and the Upper Midwest westward to the northern Rockies has also increased the risk of wildfires in those regions.

Figure 25: Wildland Fire Potential Outlook, July 2024



Source: National Interagency Coordination Center Outlook, April May 1, 2024

153 Simon Little and Richard Zussman, *Protracted Drought Leaves Hydro-power-dependent B.C. Importing Electricity*, Global News (Dec. 19, 2023) https://globalnews.ca/news/10180251/bc-hydro-drought-electricity-import/.

154 Xcel Energy, press release, *Xcel Energy to Proceed with Public Safety Power Shutoffs* (April 4, 2024, https://co.my.xcelenergy.com/s/about/newsroom/press-release/xcel-energy-to-proceed-with-public-safety-power-shutoffs-MCRIETLUTEYFEQRPVWYZKIGNMPDA.

155 National Significant Wildland Fire Potential Outlook (April 1, 2024), //www.nifc.gov/nicc-files/predictive/outlooks/monthly_seasonal_outlook.pdf.

In Canada, areas of Alberta, British Columbia, the Northwest Territories and other jurisdictions that were affected by fires in 2023 continue to present wildfire risks, with active wildfires already impacting Alberta and British Columbia this spring. If widespread fire conditions return to Canada this summer, the smoke is likely to affect solar output in the United States.[156]

Drought conditions that can contribute to wildfire risk persist throughout Canada, creating continued elevated wildfire risks into the summer. Monthly mean temperatures were 3-5 degrees C above normal for much of Canada in February, with the exception of British Columbia and southern Alberta.[157] While western Canada received additional precipitation in Spring 2024, with some areas even seeing above normal levels, this precipitation was insignificant in terms of drought relief.[158]

ELECTRIC RELIABILITY RISKS AND TRENDS

This section describes current electric reliability risks that have developed since summer 2023 and presents both topics of general awareness and specific examples that may impact reliability this summer.

Persistent supply chain disruptions could challenge schedules and costs for commissioning of new projects, as well as ongoing equipment maintenance and replacement. The underlying problems contributing to supply change risks include continued geopolitical unrest, climate change, and aluminum shortages, which have been exacerbated by the recent closure of several domestic manufacturing facilities. The limited number of spare transformers remains a reliability and security risk, although the federal government and industry continue to try to mitigate this risk.

Equipment and Materials

A well-managed supply chain for equipment and materials is necessary for the power system to be reliable and secure. Supply chain disruptions during summer 2024 could negatively affect the electric industry's work on construction, operations, reliability, and security.[159] Supply chain issues have made it more difficult for generators and transmission owners to schedule maintenance outages, to determine when new transmission resources will come online and when line upgrades can be completed, and to interconnect new resources.[160]

Supply chain disruption can also affect the timing of restoration or repair – a particular concern during stressed system conditions. For instance, utilities have reported that lead times for replacing BPS transformers have increased from 12 to 18 months to 18 to 36 months for a large utility and from 10 months to one to seven years for a smaller

156 American Public Power Association, *Canadian Wildfires Impact Solar Production in Eastern U.S., Grid Operators Report* (June 9, 2023) https://www.publicpower.org/periodical/article/canadian-wildfires-impact-solar-production-eastern-us-grid-operators-report. For example, a solar radiation sensor in Queens, New York, on a clear day normally measures around 1,000 watts/per meter squared, but on the afternoon of June 7, 2023, with wildfire smoke, the sensor read 44 watts/m2; S&P Global, *US company observes solar power output declines in the Northeast due to Canadian wildfire smoke*, (June 12, 2023), https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/electric-power/061223-us-company-observes-solar-power-output-declines-in-the-northeast-due-to-canadian-wildfire-smoke.

157 North American Drought Monitor-February 2024 Report, https://www.ncci.noaa.gov/access/monitoring/nadm/maps.

158 *Id.*

159 NERC, *2024 Summer Reliability Assessment* (May 15, 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2024.pdf.

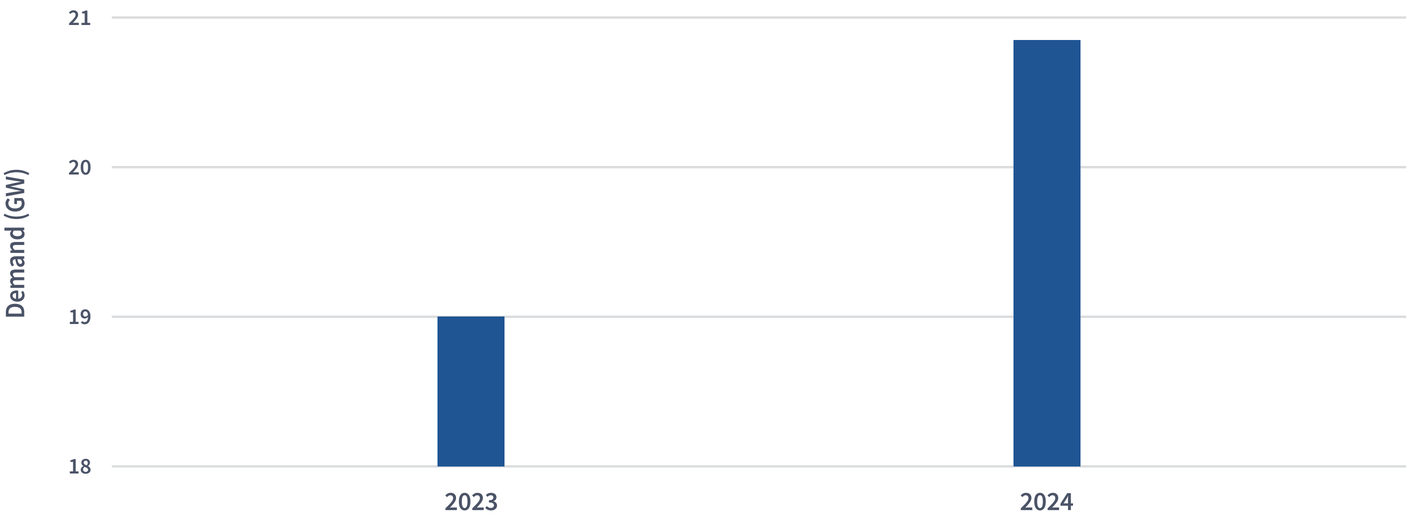
160 NERC, *2023 Long Term Reliability Assessment* (Dec. 13, 2023). https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf.

utility.[161] Utilities have implemented equipment-sharing efforts to speed event restoration, making coordination and inter-area planning efforts especially key this summer.[162] Further, to mitigate the limited supply of transformers, Siemens Energy plans to invest $150 million to build its first transformer production facility in Charlotte, NC, although the first transformers are not set to be manufactured until early 2026.[163]

Load Growth Due to Newly Constructed Data Centers

Data centers are key contributors to the recent growth in electricity demand due to digitalization and data-driven technologies.[164] The rapid growth of emerging technologies like Artificial Intelligence (AI) /Machine Learning (ML) has fueled growth in data centers over the past decade and continues to do so.[165] As shown in **Figure 26**, growth associated with data center power consumption from 2023 to 2024 is almost 2 GW.[166]

Figure 26: Estimated U.S. Data Center Power Consumption



Source: McKinsey & Company

161 U.S. Government Accountability Office, *Electricity Grid: DOE Could Better Support Industry Efforts to Ensure Adequate Transformer Reserves* (Aug. 2, 2023), GAO-23-106180, https://www.gao.gov/products/gao-23-106180.

162 EEI, *Spare Equipment and Grid Resilience* (Aug. 1, 2023), https://www.eei.org/-/media/Project/EEI/Documents/Issues-and-Policy/Reliability-and-Emergency-Response/Spare-Equipment-and-Grid-Resilience-Programs.pdf.

163 S&P Global, *Siemens Energy to Invest $150M in US Transformer Manufacturing Facility* (Feb. 14, 2024), https://www.capitaliq.spglobal.com/apisv3/spg-webplatform-core/news/article?id=80444566.

164 A data center is any facility that primarily contains electronic equipment used to process, store, and transmit digital information. Department of Energy, *Definition of Data Center*, https://www7.eere.energy.gov/femp/requirements/laws_and_requirements/definition_data_center.

165 NEWMARK, *2023 U.S. Data Center Market Overview & Market Cluster* (January 2024), https://www.nmrk.com/insights/market-report/2023-u-s-data-center-market-overview-market-clusters.

166 McKinsey & Company, *Investing in the Rising Data Center Economy*, (Jan. 17, 2023) https://www.mckinsey.com/industries/technology-media-and-telecommunications/our-insights/investing-in-the-rising-data-center-economy#/.

Currently, Northern Virginia, Dallas, Chicago, Phoenix, and Northern California remain the primary data center markets.[167] However, data center development is also expanding in over 20 metro areas nationwide. Nationwide, data center demand is expected to reach 35 GW by 2030, up from 17 GW in 2022, and has been one of the major drivers behind the sharp increase in electricity demand in 2023.[168]

CONCLUSION

Forecasted warmer-than-average temperatures across much of the United States in summer 2024 will increase electricity demand, on balance. However, electricity prices in much of the country are expected to be similar to, or slightly lower than, prices in 2023, partly because generation fuel costs are expected to be stable or to decline modestly. In particular, lower natural gas prices should bolster the availability of natural gas-fired resources absent any major supply disruptions from unscheduled outages or extreme weather events.

The natural gas market is expected to be well supplied with increased storage levels entering the injection season and production declining by 1.6% compared to summer 2023. Natural gas demand this summer is anticipated to increase 1.7% relative to last summer. Summer 2024 average natural gas futures prices at Henry Hub, the national benchmark, are 9% lower than last summer. LNG exports and residential/commercial use of natural gas are forecast to have the largest growth of the demand sectors compared to summer 2023.

Additionally, increased generating capacity from solar and battery storage resources should bolster available generation to meet demand and contribute to lower electricity prices this summer.

These market fundamentals could be affected by specific risks to reliability and market operations. Drought conditions across the West, Central, Midwest United States and Canada may strain power supplies reliant on water. Wildfire disruptions to the bulk electrical system and physical security concerns may further impact power generation.

Finally, while the March 2024 collapse of the Francis Scott Key bridge in Baltimore is not expected to significantly affect coal deliveries to U.S. generators, it may hinder U.S. coal exports as Baltimore is a typical export route for U.S. coal producers.

NERC forecasts that all regions will have sufficient generating resources to meet expected summer demand and operating reserve requirements under normal operating conditions. Some assessment areas continue to face risks

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167 The largest concentration of data centers in the world—known as Data Center Alley—is located in the Dominion Transmission Zone of PJM in Northern Virginia (NOVA). Data Center Frontier, *Northern Virginia Data Center Market* (May 30, 2022), https://www.datacenterfrontier.com/data-center-markets/whitepaper/11431609/digital-realty-northern-virginia-data-center-market; Data Center Frontier, *Rapidly Growing Chicago Data Center Market's Tier 1 Expansion Is Persistent and Ongoing* (Sept. 11, 2023), https://www.datacenterfrontier.com/site-selection/article/33011320/rapidly-growing-chicago-data-center-markets-tier-1-expansion-is-persistent-and-ongoing; Phoenix is the second-largest data center market, after Northern Virginia, with 748 MW of energy transactions requested in 2023. Dallas Innovates, *Big Demand Meets Tight Supply: JLL's 2023 North American Data Center Report*, (Feb. 29, 2024) https://dallasinnovates.com/big-demand-meets-tight-supply-jlls-2023-north-american-data-center-report; NEWMARK, 2023 *U.S. Data Center Market Overview & Market Cluster*, (January 2024), https://www.nmrk.com/insights/market-report/2023-u-s-data-center-market-overview-market-clusters.

168 NEWMARK, 2023 *U.S. Data Center Market Overview & Market Cluster*, (January 2024), https://www.nmrk.com/insights/market-report/2023-u-s-data-center-market-overview-market-clusters.

of electricity supply shortfalls during periods of more extreme summer conditions, and regions may need to rely on operating mitigations during challenging summer conditions. The risks of these conditions are more acute in the ERCOT region, the MISO region, the ISO-NE subregion, the WECC-CA/MX subregion, and the WECC-SW subregion.

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