Winter Energy Market and Reliability Assessment

2022-2023

A Staff Report to the Commission

October 20, 2022

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FEDERAL ENERGY REGULATORY COMMISSION

Office of Energy Policy and Innovation

Office of Electric Reliability

Preface

The 2022-2023 Winter Energy Market and Reliability Assessment (Winter Assessment) provides staff's outlook for energy markets and electric reliability, focusing on the period of December 2022 through February 2023 (winter 2022-2023). The report is divided into three main sections. The first section summarizes weather forecasts for the upcoming winter. The second section summarizes natural gas and electricity market and electric reliability fundamentals expected for the winter. The last section discusses notable considerations for the upcoming winter, including coal supply issues, natural gas dependence in New England, natural gas pipeline outages in the West, and winter preparedness progress.

The Winter Assessment is a joint report from the Office of Energy Policy and Innovation's Division of Energy Market Assessments and the Office of Electric Reliability's Division of Engineering and Logistics.

This report uses preliminary data from the North American Electric Reliability Corporation's (NERC) 2022-2023 Winter Reliability Assessment and the NERC Long Term Reliability Assessment. The final versions of NERC's Long Term Reliability Assessment and Winter Reliability Assessment are scheduled for publication in late 2022.

Key Findings

This section details staff's key findings in this report; other sections of this report contain details and background information supporting staff's findings.

Weather: Higher than average temperatures are expected for the coming winter in many regions of the country, which should translate into reduced natural gas and electric demand. The U.S. National Oceanic and Atmospheric Administration (NOAA) forecasts for December 2022 through February 2023 suggest a 50% to 80% likelihood of higher-than-average temperatures in Southern California, the Desert Southwest, Texas, and the Eastern Seaboard, with lower-than-average temperatures expected for the Northwest and the West North Central regions. Forecasts of above-average temperatures imply lower-than-average electric and natural gas demand, although a prolonged cold weather event nevertheless could cause disruptions and price impacts, even within the context of a warmer winter.

Natural Gas Markets: Natural gas prices for the upcoming winter are expected to remain higher than recent years at major trading hubs across the U.S. Even though natural gas production growth will likely outpace domestic natural gas demand growth in winter 2022-2023, forecasts anticipate that continued growth in net exports, including from liquified natural gas (LNG) export facilities, will place additional pressure on natural gas prices this winter. Specifically, the Henry Hub natural gas futures contract price is averaging \$6.82 per million British Thermal Units (MMBtu) for winter 2022-2023, up 30% from last winter's settled price, discussed in more detail below. Dry natural gas production[1] is forecast to increase over the winter period by 3.2% above winter 2021-2022 levels, to 99.1 billion cubic feet per day (Bcfd). The expected increase in

[1] Dry natural gas production is the natural gas which is available for consumption after processing out petroleum liquids.

production is due to high natural gas and crude oil prices leading to a rising number of natural gas-directed rigs and greater natural gas produced in association with oil from oil wells. Winter 2022-2023 demand for natural gas is expected to increase 2.4% over winter 2021-2022 levels to 121.2 Bcfd, driven primarily by growth in demand for natural gas exports. The anticipated greater volume of natural gas exports primarily results from the increase in LNG liquefaction capacity over the last year, as well as increased pipeline exports to Mexico. Natural gas storage withdrawals for the 2022-2023 withdrawal season,[2] which is expected to take place from November to March, are forecast to total 2.0 trillion cubic feet (Tcf),[3] 11.1% or 250 Bcf less than the 2021-2022 withdrawal season.[4] The reduced withdrawals will partially offset the anticipated gains in production and contribute to continuing supply-demand tightness.

Electricity Markets and Transmission: Wholesale electricity markets are expected to see a continuation of the generation capacity addition and retirement pattern seen in the past years through winter 2022-2023. Again this year, most additions will come from solar and wind, while most retirements will come from coal. In total, the U.S. will add 43 gigawatts (GW) of net winter capacity[5] between March 2022 and February 2023, mostly from solar and wind generation. Over that timeframe, 15 GW of net winter capacity are expected to retire, mostly coming from coal-fired generation. Generally, non-intermittent thermal resources possess higher accreditation values than renewable resources based on historical availability data. Moreover, nearly 6,700 line-miles of new transmission lines and transmission upgrades are expected to have come online through the upcoming winter since the previous one across the country, mostly in the Midcontinent Independent System Operator, Inc. (MISO), PJM Interconnection, L.L.C. (PJM), and Southeast regions. Some generator capacity additions scheduled to come online this winter could change or be subject to delays, and market factors may affect the ability of resources to operate at their net winter capacity. Regions are also reporting that some generation and transmission projects are impacted by component unavailability, shipping delays, and labor shortages.

Notable Issues: A few notable supply issues are expected this winter. Several regions may experience coal supply and transportation constraints because of ongoing rail service issues. Additionally, natural gas supply is expected to remain constrained in New England this winter, leading to higher natural gas and electricity

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[2] The withdrawal season for natural gas is defined as the period of time from the highest storage level of the season to the lowest storage level of the season. The withdrawal season typically begins in October/November and ends in March/April depending on market factors.

[3] 2,012 Bcf rounds to 2.0 Tcf.

[4] EIA, *Short-Term Energy Outlook* (September 7, 2022), https://www.eia.gov/outlooks/steo/.

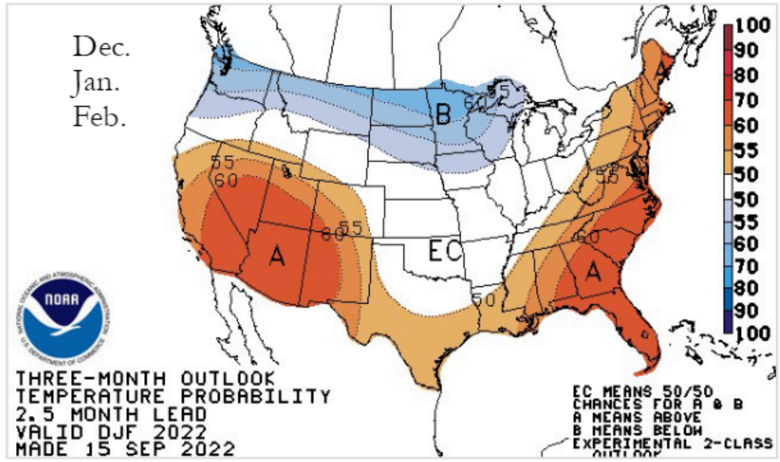
[5] The generation capacity that has been added since last winter or will be added this winter has a total net winter capacity that is 2.5% lower than its total nameplate capacity. By contrast, the generation capacity that has retired since last winter or will retire this winter has a 5.7% lower net winter capacity than its nameplate capacity. In this report, net winter capacity refers to the maximum output, commonly expressed in megawatts (MW), that generating equipment can supply to system load, as demonstrated by a multi-hour test, at the time of peak winter demand (period of December 1 through February 28). This output reflects a reduction in capacity due to electricity use for station service or auxiliaries. EIA, *Glossary* (accessed August 19, 2022), https://www.eia.gov/tools/glossary/index.php.

prices. Natural gas pipelines in California may also face constraints this winter due to ongoing pipeline outages. Finally, regions have taken steps to implement the FERC and NERC recommendations for winter preparedness following Winter Storm Uri in February 2021.

Weather Outlook

NOAA forecasts a mild winter for most of the U.S. relative to NOAA's 1991-2020 U.S. Climate Normals. As shown in **Figure 1**, the three-month NOAA outlook for December 2022, January 2023, and February 2023 forecasts the Northwest and West North Central regions to have higher probabilities of below-average temperatures; the upper South and Central regions to have an equal chance of above-normal or below-normal temperatures; and the West, Southwest, Southeast, and Northeast regions to have higher probabilities of above-normal temperatures.

Figure 1: Winter 2022-2023 Temperature Forecast



Source: National Oceanic and Atmospheric Administration

NOAA also predicts a third consecutive La Niña winter, with a 91% chance of La Niña from September-November and an 80% chance through November-January.[6] La Niña is the cool phase of the El Niño-Southern Oscillation climate pattern. La Niña affects global atmospheric circulation patterns, which tends to increase Atlantic hurricane season activity, bring drier conditions in the southern U.S., and bring wetter conditions in the northern U.S.

Although forecasts of above-average temperatures imply lower-than-average demand for electricity and natural gas across the winter season, severe cold weather events may still occur and affect energy supply and demand in particular regions of the country during the events. Winter energy demand is significantly impacted by low temperatures, which increase demand for natural gas and electricity for heating. Additionally, below-freezing temperatures can stress critical infrastructure for the production and delivery of energy. Prolonged periods of severe cold, as seen in the February 2021 Winter Storm Uri, can cause severe disruptions, even during a warmer-than-average winter overall.[7]

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[6] Climate Prediction Center/NCEP/NWS, *El Niño/Southern Oscillation (ENSO) Diagnostic Discussion* (October 13, 2022), https://www.cpc.ncep.noaa.gov/products/analysis_monitoring/enso_advisory/ensodisc.shtml

[7] FERC, *The February 2021 Cold Weather Outages in Texas and the South Central United States | FERC, NERC and Regional Entity Staff Report* (November 16, 2021). https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and

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Energy Market and Electric Reliability Fundamentals

In this section of the report, staff summarizes natural gas and electricity market and electric reliability fundamentals expected for winter 2022-2023, including natural gas prices, natural gas production, natural gas demand, natural gas storage inventories, electric resources, electric demand response, electric transmission, and electric reserve margin analyses.

Futures prices indicate higher natural gas prices for winter 2022-2023 as compared to last winter at major trading hubs across the U.S. Even though total natural gas demand is expected to increase at a slower pace than natural gas production growth this winter, the continued growth in net exports and reduced natural gas storage inventories are expected to place additional upward pressure on natural gas prices this winter.

Futures prices reflect higher natural gas prices, which are expected to translate into higher electricity prices through increased electricity production costs. Natural gas is the marginal fuel in many of the Regional Transmission Organization and Independent System Operator (RTO/ISO) electricity markets, and accordingly increased natural gas prices are correlated with increased electricity prices, as higher natural gas prices can increase overall electric energy prices when natural gas-fired generation sets the marginal electric energy clearing price. This relationship typically holds until electricity prices are high enough that alternatives or substitutes become economic.

According to U.S. Energy Information Administration's (EIA) forecasts, solar and wind generation will account for the majority of new electric capacity additions. Regions experiencing more changes in their resource mix are using additional planning tools, such as probability-based resource adequacy risk assessments, to help identify and plan for potential periods of increased risk. In addition, some regions anticipate additional transmission lines and transmission upgrades to be in service this winter.

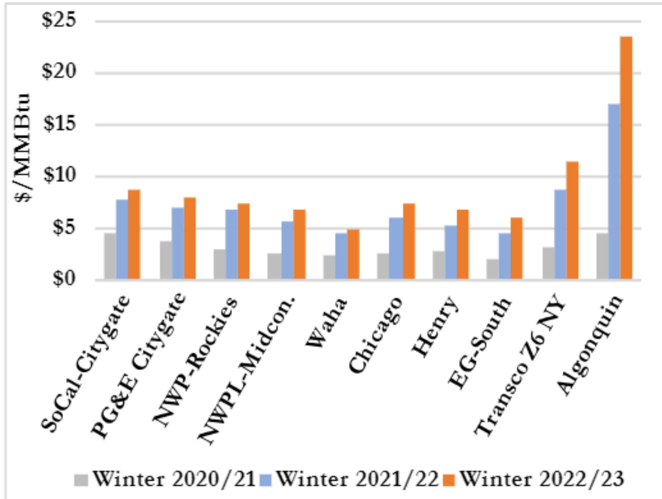
Natural Gas Fundamentals

Domestic and international factors, discussed in detail below, are expected to drive U.S. natural gas prices higher throughout winter 2022-2023. Domestically, EIA forecasts predict that natural gas production will increase 3.2% above winter 2021-2022 levels, from 96.0 Bcfd in winter 2021-2022 to 99.1 Bcfd in winter 2022-2023. Forecasts also indicate that total natural gas demand will increase slightly by 2.4% over winter 2021-2022 levels, from 118.4 Bcfd in winter 2021-2022 to 121.2 Bcfd in winter 2022-2023. However, EIA predicts natural gas exports will increase at a much higher pace than domestic natural gas demand in winter 2022-2023, primarily due to an increase in LNG liquefaction capacity. Net natural gas exports, including LNG and via pipeline, are forecast to increase by 24.3%, from an average of 10.8 Bcfd in winter 2021-2022 to an average of 13.4 Bcfd in winter 2022-2023. Natural gas storage withdrawals for the 2022-2023 withdrawal season are expected to fall 11.1% below the 2021-2022 withdrawal season levels, from 2,262 Bcf in winter 2021-2022 to 2,012 Bcf throughout winter 2022-2023.

Natural Gas Prices

As of October 12, 2022, futures prices for natural gas in winter 2022-2023[8] exceed the final settled futures prices for the last two winters across a sample of ten major natural gas trading hubs, comprising the national benchmark Henry Hub in Louisiana and nine other major supply and demand hubs in the Lower 48 States, as highlighted in **Figure 2**. As of October 12, 2022, trading for the Henry Hub futures contract price for winter 2022-2023, the base component of winter futures prices for all trading locations,[9] averaged $6.82/MMBtu, up 30% from last winter's settled price, an increase of $1.57/MMBtu from the settled average from winter 2021-2022.

Figure 2: Average U.S. Natural Gas Futures Prices Across Sampled Hubs, November to February



Source: InterContinental Exchange, Inc.
Note: Winter 2022/23 futures prices are as of September 14, 2022. Prior winters are settled prices.

According to EIA, multiple factors have contributed to higher Henry Hub spot prices over the course of the year: rising domestic natural gas consumption; relatively minor natural gas production growth; lower than average natural gas storage inventories; and continued growth in LNG exports.[10] Natural gas spot and futures prices have experienced volatility since an unplanned outage at Freeport LNG began in June 2022.

Traditionally, domestic fundamentals drive U.S. natural gas prices; this winter, international markets will likely also affect U.S. natural gas markets and prices, as they did at times last winter. Over the last decade, the expansion of LNG export capability has integrated formerly disparate North American regional natural gas

[8] Natural gas futures prices are price quotations of futures contracts for the exchange of natural gas, as either a physical or financial settlement, at a specified time in the future. Winter futures prices in this section are the average quotes of the last traded futures contracts, as of October 12, 2022, for the winter months of December 2022, January 2023, and February 2023 as retrieved from InterContinental Exchange, Inc. Previous winter averages are final prices for each month as retrieved from InterContinental Exchange, Inc.

[9] Regional natural gas prices are calculated by adding the Henry Hub winter futures price to the winter basis futures prices at major trading hubs in the U.S. Regional basis prices reflect, among other things, the distance from producing basins, availability of natural gas transportation, and local weather expectations for the coming winter.

[10] EIA, *EIA Expects U.S. Natural Gas Prices to Remain High Through 2022* (June 9, 2022), https://www.eia.gov/todayinenergy/detail.php?id=52698.

markets into the global market.[11] The U.S. participates in the global market by supplying feedgas at LNG export terminals and importing LNG in New England. Continuing a trend observed last winter, forecasts predict U.S. LNG export demand will remain high due to significant international demand and corresponding strong expected profits from exports to both Asian and European markets, as discussed below. Though existing export facilities' capacities limit possible U.S. LNG exports, existing export facilities' capacities have grown 1.9 Bcfd since winter 2021-2022 to 13.8 Bcfd. The Russian invasion of Ukraine prompted European markets to significantly increase their purchases of LNG from the constrained global supply chain, resulting in record high global LNG prices in Summer 2022. Despite declining in early fall after reaching peak levels in late August, global LNG prices remain at high levels relative to the recent past. Global LNG prices can impact domestic natural gas prices, given a tight balance between domestic natural gas production and demand.[12] U.S. domestic natural gas prices are unlikely to rise high enough to match or exceed global LNG prices this winter, with Henry Hub winter 2022-2023 futures at $6.82/MMBtu compared to Asian and European LNG price markers at around $30/MMBtu for December 2022 (as of October 12, 2022).[13]

In New England, high global LNG prices are contributing to higher winter natural gas futures prices, as the New England regional natural gas market relies on imported LNG in the winter to meet natural gas demand and must compete for LNG volumes with Europe and Asia.[14] The Algonquin Citygates futures price reflects higher peak natural gas prices in New England for winter 2022-2023 compared to last winter. For the second winter in a row, the Algonquin Citygates hub, located outside of Boston, has the largest expected year-over-year futures price increase of $6.49/MMBtu, with futures prices rising from $4.52/MMBtu for winter 2020-2021 and $17.08/MMBtu for winter 2021-2022, to $23.57/MMBtu for winter 2022-2023. While Algonquin Citygates prices are discounted to Henry Hub prices most of the year, prices at Algonquin Citygates typically increase above Henry Hub prices in January and February due to the winter-peaking New England region's limited natural gas pipeline capacity.[15] In past winters with lower global LNG prices and demand, LNG

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[11] International Energy Agency, *LNG Market Trends and Their Implications* (June 2019), https://www.iea.org/reports/lng-market-trends-and-their-implications.

[12] Natural Gas Intelligence, *Record LNG Imports Weighing on European Natural Gas Prices – LNG Recap* (September 19, 2022), https://www.naturalgasintel.com/record-lng-imports-weighing-on-european-natural-gas-prices-lng-recap/.

[13] S&P Global Commodity Insights, *Global Scramble for LNG Tankers Likely to Boost Gas Prices Further* (September 9, 2022), https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/shipping/090722-global-scramble-for-lng-tankers-likely-to-boost-gas-prices-further; S&P Global Commodity Insights, *Platts LNG Daily* (October 10, 2022).

[14] S&P Global Commodity Insights, *New England Winter Natural Gas Prices Top $40 as Global LNG Market Tightens* (July 22, 2022), https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/natural-gas/072222-new-england-winter-natural-gas-prices-top-40-as-global-lng-market-tightens.

[15] EIA, *Natural Gas Weekly Update* (January 20, 2022), https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2022/01_20/.

imports into New England provided additional supply during times of higher demand.[16] However, with European LNG prices currently trading above $30/MMBtu for winter 2022-2023 (as of October 12, 2022), New England natural gas futures prices have risen alongside European LNG prices.[17]

Winter futures prices at all major demand hubs currently reflect large year-over-year increases. For example, winter 2022-2023 futures prices at the Chicago Citygate hub have increased $1.25/MMBtu over last winter, and winter 2022-2023 futures prices at the PG&E Citygate hub have risen by $0.95/MMBtu and futures prices at the SoCal Citygate hub in California have risen by $0.88/MMBtu. At Transco Zone 6 NY, a major hub outside New York City that relies on some of the same pipelines that serve New England, futures prices rose to $11.49/MMBtu, an increase of $2.83/MMBtu over winter 2021-2022.

Similarly, futures prices at supply hubs also reflect year-over-year increases for winter 2022-2023. For example, at the Permian Basin's Waha trading hub, located in West Texas, futures prices have climbed to $4.96/MMBtu (compared to $4.56/MMBtu last winter), falling below Appalachia's Eastern Gas-South hub, located in western Pennsylvania at the center of the Marcellus Shale, where prices rose to $6.04/MMBtu. ($4.53/MMBtu last winter). NWP-Rockies, a major hub in the Rocky Mountains, similarly has seen futures prices rise to $7.46/MMBtu, up $0.67/MMBtu from last winter.

Natural Gas Production

EIA forecasts that winter 2022-2023 dry natural gas production will increase 3.2% above winter 2021-2022 levels to 99.1 Bcfd as shown in **Table 1**. This forecasted production increase likely ties to high crude oil and natural gas prices. Except for winter 2020-2021, natural gas production has increased year-over-year every winter since 2017-2018. Lower winter 2020-2021 natural gas production resulted from impacts of the COVID-19 pandemic. However, by winter 2021-2022, natural gas production returned to an average of 96 Bcfd.[18]

Table 1: Average Winter Natural Gas Production

Year	Average Winter Production (Bcfd)
2017-2018	79.8
2018-2019	89.5
2019-2020	95.9
2020-2021	90.6
2021-2022	96.0
2022-2023*	99.1

*Source: EIA; * Forecast*

Shale gas production was almost 80% of total natural gas production in the U.S. in winter 2021-2022. Marcellus, Permian,

[16] EIA, *Liquefied Natural Gas Imports Limited Price Spikes in New England This Winter* (May 13, 2019), https://www.eia.gov/todayinenergy/detail.php?id=39432.

[17] S&P Global Commodity Insights, *New England Winter Natural Gas Prices Top $40 as Global LNG Market Tightens* (July 22, 2022), https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/natural-gas/072222-new-england-winter-natural-gas-prices-top-40-as-global-lng-market-tightens.

[18] EIA, *Short-Term Energy Outlook, Table 5a. Natural Gas Supply, Consumption, and Inventories* (October 12, 2022), https://www.eia.gov/outlooks/steo/.

and Haynesville Basin[19] natural gas production represent the largest shares of shale natural gas production. During winter 2021-2022, the Marcellus Basin represented 33% of shale gas production, with the Permian Basin responsible for 18% of shale gas production, and the Haynesville Basin accounting for 16% of shale gas production.[20]

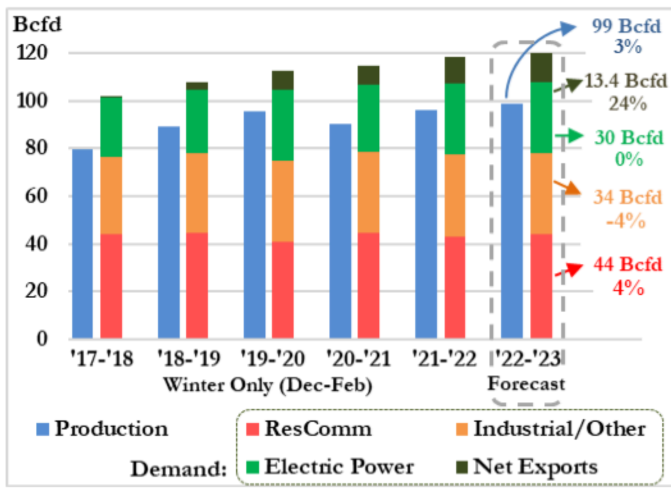
Natural gas production in the Haynesville Basin grew from 9.9 Bcfd in winter 2020-2021 to 12.6 Bcfd in winter 2021-2022, a 26.9% increase. For comparison, natural gas production grew by 0.8% in the Marcellus Basin and by 20.8% in the Permian Basin during the same period.

Since production changes typically lag in response to changes in prices by a few months, the increase in average year-to-date crude oil prices compared to winter 2021-2022 levels has increased drilling in the oil-rich Permian Basin, which could continue to increase crude oil production and associated natural gas production in winter 2022-2023. EIA forecasts crude oil prices to remain high this winter, further increasing production of associated natural gas.

Natural Gas Demand

EIA forecasts overall natural gas demand to increase to 121.2 Bcfd for winter 2022-2023, a 2.4% increase from winter 2021-2022.[21] Even though natural gas production growth will likely outpace domestic natural gas demand growth in winter 2022-2023, forecasts anticipate the continued growth in net exports will place additional pressure on natural gas prices this winter. As discussed in more detail below, forecasts indicate net exports will increase 24%, to nearly 13.4 Bcfd in winter 2022-2023. Increased global demand for natural gas, largely due to the factors described above and increased demand during colder months, drives the increase in winter LNG exports.

Figure 3: Natural Gas Demand and Production



Source: ELA

Furthermore, EIA forecasts demand for natural gas in the residential and commercial sector, which is the largest sector of natural gas demand in the winter, to

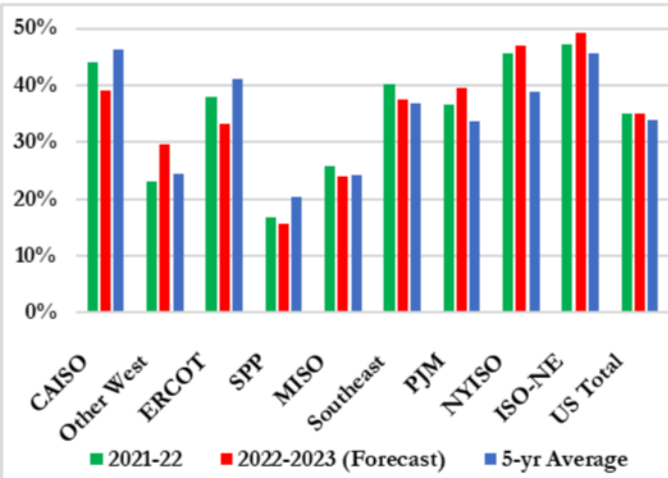
[19] The Marcellus Formation is located in the Eastern United States including Pennsylvania and West Virginia. The Permian Basin is located in the Southwest and includes parts of Western Texas and Eastern New Mexico. The Haynesville Basin is also partially located in Texas on the Eastern part of the state and includes parts of Western Louisiana.

[20] EIA, *Dry Shale Gas Production Estimates by Play* (September 29, 2022), https://www.eia.gov/naturalgas/weekly/img/shale_gas_202208.xlsx.

[21] EIA, *Short-Term Energy Outlook, Table 5a. Natural Gas Supply, Consumption, and Inventories* (October 12, 2022), https://www.eia.gov/outlooks/steo/.

average 44.3 Bcfd, a 3.5% increase from winter 2021-2022, as forecasts depict both commercial and residential natural gas demand to rise slightly. Forecasts indicate the combination of industrial and other demand will average 33.8 Bcfd, a 3.6% decline from winter 2021-2022.

Figure 4: Percent of Natural Gas Generation by Region



Source: EIA

As seen in **Figure 3**, natural gas consumption by the electric power sector for the generation of electricity, also known as power burn, is forecast to average 29.8 Bcfd (about a quarter of the total natural gas demand expected this winter), similar to levels observed in winter 2021-2022. Forecasts indicate the percentage of electricity generated from natural gas in the U.S. will be flat from last winter to winter 2022-2023. The percentage of electricity generated from natural gas in the U.S. is expected to be slightly less than in winter 2020-2021 and 4.3% less than in winter 2019-2020.

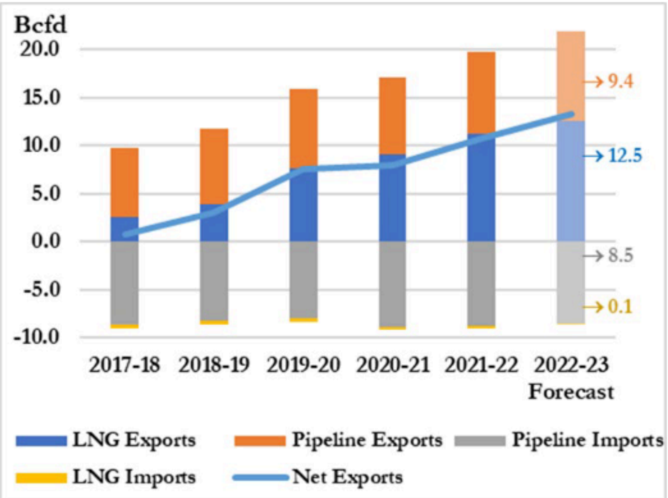
As shown in **Figure 4**, the California Independent System Operator (CAISO), Electric Reliability Council of Texas, Inc. (ERCOT), Southwest Power Pool (SPP), MISO, and the Southeast are projected to experience a decline in the percentage of electricity generated from natural gas since winter 2021-2022. This forecasted decline may lead to the percentage of electricity generated from natural gas being below the respective five-year averages for CAISO, ERCOT, SPP, and MISO.[22] Forecasts indicate that the percentage of electricity generated by natural gas in winter 2022-2023 compared to winter 2021-2022 will increase by 3 percentage points in PJM, by 1.3 percentage points in New York Independent System Operator, Inc. (NYISO), by 2.1 percentage points in ISO-New England (ISO-NE), and by 6.4 percentage points in Western regions outside of CAISO (Other West), with all four regions expected to generate electricity from natural gas above their respective five-year averages. NYISO's share of generation output from natural gas is expected to rise to 47%. ISO-NE's share of generation output from natural gas is expected to increase to 49% this winter. Finally, PJM's share of generation output from natural gas is expected to increase to 40%.

[22] EIA, *Short-Term Energy Outlook, Table 7d. Regional Electricity Generation, Electric Power Sector* (October 12, 2022), https://www.eia.gov/outlooks/steo/.

Natural Gas Exports and Imports

Additional LNG liquefaction capacity to serve growing international LNG demand will enable natural gas exports to increase in winter 2022-2023. EIA forecasts gross LNG exports to average 12.5 Bcfd in winter 2022-2023, up from 11.3 Bcfd in winter 2021-2022, a 10.9% increase.[23] Cheniere Energy's Sabine Pass, located in Texas, and Venture Global LNG's Calcasieu Pass, located in Louisiana, have added liquefaction capacity since last winter, increasing U.S. liquefaction capacity by 1.9 Bcfd to 13.8 Bcfd by October 2022. Specifically, the 0.8 Bcfd Sabine Pass Train 6 began service in February 2022. Venture Global LNG also received Commission approval for commercial service of a portion of its Calcasieu Pass terminal, adding 1.1 Bcfd to total U.S. liquefaction capacity.[24] In addition, Calcasieu Pass is expected to bring its second leg online in Fall 2022 adding an additional 0.6 Bcfd to total U.S. liquefaction capacity.[25] The 2 Bcfd Freeport LNG facility, located in Texas, went offline on June 8, 2022, and has not yet resumed operations.[26]

Figure 5: Winter Exports and Imports of Natural Gas in the U.S.



Source: EIA

The increased U.S. liquefaction capacity should help to supply tight international LNG markets in winter 2022-2023. Historically, U.S. LNG cargoes have primarily served Asian markets.[27] However, high European natural gas prices have incentivized more LNG exports to Europe in 2022, and LNG exports to Europe began

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[23] EIA, *Short-Term Energy Outlook, Table 5a. Natural Gas Supply, Consumption, and Inventories* (October 12, 2022), https://www.eia.gov/outlooks/steo/.

[24] FERC, *North American LNG Export Terminals – Existing, approved not Yet Built, and Proposed* (October 11, 2022), https://www.ferc.gov/natural-gas/lng.

[25] EIA, *U.S. Liquefaction Capacity* (August 22, 2022), https://www.eia.gov/naturalgas/importsexports/liquefactioncapacity/U.S.liquefactioncapacity.xlsx.

[26] Freeport LNG, *Freeport LNG Provides Update on Restart Timeline for its Liquefaction Facility* (August 23, 2022), http://freeportlng.newsrouter.com/news_release.asp?intRelease_ID=9749&intAcc_ID=77.

[27] EIA, *U.S. Natural Gas Exports and Re-Exports by Country* (September 30, 2022), https://www.eia.gov/dnav/ng/ng_move_expc_s1_m.htm.

outpacing exports to Asia in November 2021.[28] Continued increased international demand should incentivize U.S. LNG exports and LNG export terminal utilization throughout the winter.

As shown in **Figure 5**, in addition to LNG exports, forecasts depict gross pipeline exports increasing by 1 Bcfd, or 11.7%, from winter 2021-2022 and averaging 9.4 Bcfd this winter. For context, gross pipeline exports averaged 5.5 Bcfd to Mexico and 2.9 Bcfd to Canada in winter 2021-2022.[29] Mexico has expanded its natural gas pipeline infrastructure over the past several years, thus increasing Mexico's capacity to import natural gas from the U.S.[30] In contrast, EIA expects gross pipeline imports, primarily from Canada,[31] to average 8.5 Bcfd in winter 2022-2023, a 0.4 Bcfd or 4.2% year-over-year decrease. LNG imports by the U.S. are expected to average 0.11 Bcfd in winter 2022-2023 compared to 0.14 Bcfd in winter 2021-2022. Virtually all LNG imports by the U.S. are imported into New England. Altogether, forecasts indicate the U.S. will be a net exporter of natural gas this winter, with net natural gas exports, including LNG and via pipeline, averaging 13.4 Bcfd in winter 2022-2023 compared to 10.8 Bcfd in winter 2021-2022, a 24.3% increase.[32]

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[28] EIA, *U.S. Natural Gas Exports and Re-Exports by Country* (September 30, 2022), https://www.eia.gov/dnav/ng/ng_move_expc_s1_m.htm; and EIA, *Europe Imported Record Amounts of Liquefied Natural Gas In 2022* (June 14, 2022), https://www.eia.gov/todayinenergy/detail.php?id=52758.

[29] EIA, *U.S. Natural Gas Exports and Re-Exports by Country* (September 30, 2022), https://www.eia.gov/dnav/ng/ng_move_expc_s1_m.htm.

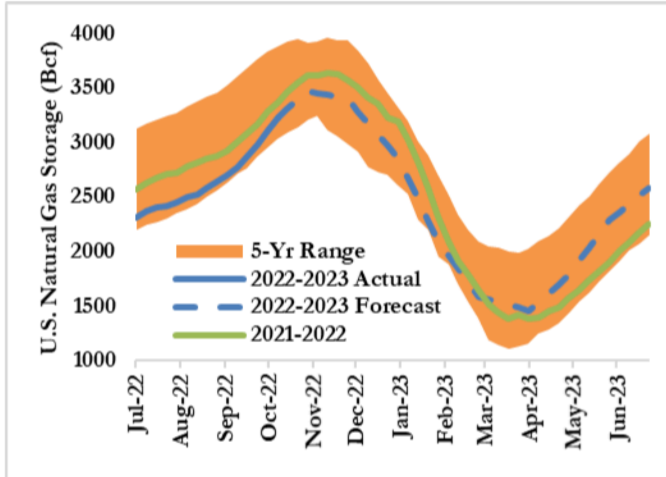
[30] EIA, *U.S. Natural Gas Exports to Mexico Are Increasing at the West Texas Border* (August 18, 2022), https://www.eia.gov/todayinenergy/detail.php?id=53499.

[31] EIA, *U.S. Natural Gas Imports by Country* (September 30, 2022), https://www.eia.gov/dnav/ng/ng_move_impc_s1_m.htm.

[32] EIA, *Short-Term Energy Outlook, Table 5a. Natural Gas Supply, Consumption, and Inventories* (October 12, 2022), https://www.eia.gov/outlooks/steo/.

Natural Gas Storage Inventories

Figure 6: Total U.S. Storage Inventories



Source: EIA

EIA forecasts U.S. natural gas storage inventories to begin winter 2022-2023 below winter 2021-2022 inventory levels and the five-year average. Forecasts anticipate natural gas storage levels will peak at 3,472 Bcf during the 2022-2023 withdrawal season, which is expected to span from November 2022 to March 2023. Despite a 10.3% year-over-year increase in injections in 2022, natural gas storage levels are expected to be 5.5% below the five-year average in November, for the start of this year's withdrawal season, and 4.7% below levels at the start of the 2021-2022 withdrawal season, due to an overall downward trend in storage levels. Natural gas storage withdrawals are expected to decrease this winter, leading to higher natural gas storage inventories to begin the 2023 injection season. EIA expects withdrawals of approximately 2,012 Bcf throughout winter 2022-2023, 7.4% less than the five-year average and 11.1% less than winter 2021-2022 withdrawals. With lower withdrawals expected during winter 2022-2023, in part due to an expected mild winter, total natural gas storage levels are expected be 2.8% lower than the five-year average at the start of the 2023 injection season, and 5.6% higher than that of winter 2021-2022 at 1,460 Bcf.[33]

Propane, an alternate winter heating fuel, will begin winter 2022-2023 with stock levels at 83.15 million barrels. EIA forecasts that propane stock levels will rise 9% above last winter yet remain 2% below the five-year average. The U.S. will likely experience decreased domestic consumption of propane this winter, while propane production and net exports will increase. Winter 2022-2023 propane consumption is expected to measure 1.24 million barrels per day, 2.3% lower than winter 2021-2022 levels and 1.3% above the five-year average. Domestic consumption of propane has decreased in the U.S. petrochemical sector, while residential, commercial, industrial, agricultural, vehicle, and other demand has remained relatively flat for the past five years.[34] Forecasts indicate propane production, which includes production from both natural gas processing plants as well as net production from refineries and petroleum storage terminal blending facilities,[35] will

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[33] EIA, *Short-Term Energy Outlook, Table 4b. U.S. Hydrocarbon Gas Liquids (HGL) and Petroleum Refinery Balances* (October 12, 2022), https://www.eia.gov/outlooks/steo/; and EIA, *Weekly Natural Gas Storage Report* (October 13, 2022), https://ir.eia.gov/ngs/ngs.html.

[34] RBN Energy, *People Get Ready – Will the Propane Market Be Ready for Winter?* (July 24, 2022), https://rbnenergy.com/people-get-ready-will-the-propane-market-be-prepared-for-winter.

[35] The EIA defines refinery and blender net production as "…liquefied refinery gases, and finished petroleum products produced at a refinery or petroleum storage terminal blending facility. Net production equals gross production minus gross inputs." EIA, *Glossary*, https://www.eia.gov/tools/glossary/.

increase to 2.25 million barrels per day, up 9.9% this winter compared to winter 2021-2022, and 21% over the five-year winter average. Lastly, forecasts depict net exports of propane and propylene averaging 1.42 million barrels per day this winter, up 23.1% from winter 2021-2022, and 43.5% higher than the five-year winter average.[36] For context, Asian countries accounted for 53% of U.S. propane exports and European countries accounted for 17% of U.S. propane exports during the first seven months of 2022.[37]

Infrastructure Additions

According to EIA, 22 interstate natural gas pipeline projects have already or are expected to enter service in 2022.[38] These projects include greenfield pipelines to serve new customers, pipe replacement, and compressor upgrades to increase capacity on existing pipelines. In total, the projects will add 11.5 Bcfd in additional capacity. Located across the country, the projects include six projects in the Northeast region and nine projects in the Southeast and South Central regions. Of the new interstate projects, six projects will serve LNG export facilities and three projects will serve natural gas local distribution companies (LDCs).

Electricity Market and Reliability Fundamentals

This section summarizes the fundamental factors expected to impact electricity markets and reliability in winter 2022-2023. These factors include changes that affect supply, such as infrastructure and fuel that may affect the production and transmission of electricity; demand response; and expected reserve margins. This section addresses generation and transmission additions that have gone into service or are expected between March 2022 and February 2023, which will likely support system reliability this winter. Moreover, this section details relevant demand response program changes in effect by this winter across the RTOs/ISOs. Electric markets across the country will have demand response capabilities to help reduce electric demand and maintain reliability during peak winter conditions.

This section also presents preliminary reliability analyses performed by NERC using probabilistic analyses of potential reliability issues for this winter. In these preliminary reliability analyses, NERC uses resource projections for December 2022 through February 2023 in its studies of winter planning reserve margins. NERC generally expects that capacity will meet planning reserve margins in each NERC region. However, recognizing that reserve margins are estimated based only on generally expected conditions, NERC uses probabilistic analyses to estimate the effects of conditions that differ from those expected. In the event of

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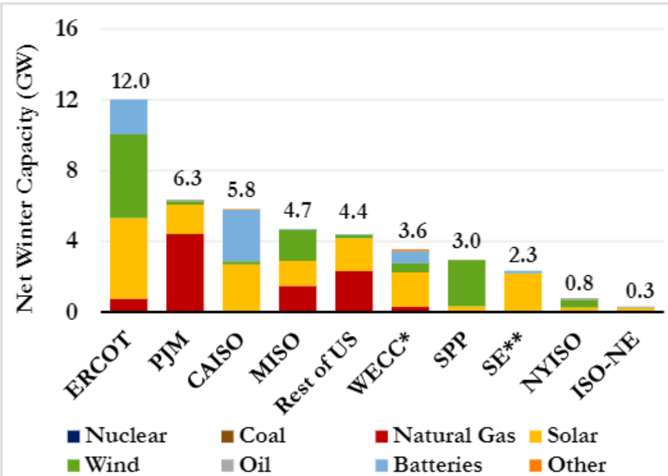
[36] EIA, *Short-Term Energy Outlook, Table 4b. U.S. Hydrocarbon Gas Liquids (HGL) and Petroleum Refinery Balances* (October 12, 2022), https://www.eia.gov/outlooks/steo/. EIA forecasts do not provide separate data for net exports of propane and propylene; therefore, they are combined here.

[37] EIA, *Propane Exports by Destination* (September 30, 2022), https://www.eia.gov/dnav/pet/PET_MOVE_EXPC_A_EPLLPA_EEX_MBBLPD_M.htm.

[38] Commission-approved projects with target completion dates in 2022, excluding projects that have not been approved, and approved projects that have been cancelled or are on hold. Data retrieved from EIA, *Natural Gas Pipeline Project Tracker* (July 29, 2022), https://www.eia.gov/naturalgas/pipelines/EIA-NaturalGasPipelineProjects.xlsx.

challenging operating conditions, system operators[39] 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. If system conditions deteriorate sufficiently, reliability coordinators may declare an Energy Emergency Alert (EEA),[40] allowing system operators to call on a variety of additional resources that are only available during scarcity conditions, defined by the operating reserves available, such as activating emergency demand response measures, and increasing generation imports from neighboring regions. These resources can help mitigate capacity shortages, should they occur.

Figure 7: Planned and Actual Capacity Additions



Source: Form EIA-860M, September 2022 Release. Note: Expected and Actual Additions and Retirements from March 2022 through February 2023. Data exclude Alaska and Hawaii. WECC refers to WECC without CAISO. SE** refers to the balancing authorities that make up the Southeast Market and excludes Florida.*

Available Electric Resources

The U.S. is expected to add 43 GW of net winter capacity[41] from March 2022 through February 2023, with 15 GW of net winter capacity retiring over that period, according to EIA forecasts.[42] The total net winter capacity additions are 2.5% lower than their nameplate capacity values and the total net winter capacity retirements are 5.7% lower than their

[39] 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. https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

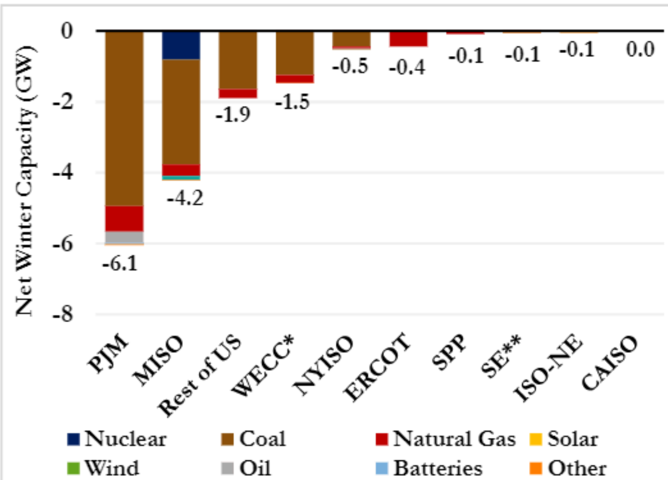
[40] Each region has a series of emergency procedures known as Energy Emergency Alerts (EEAs) that may be used when operating reserves drop below specified levels. These procedures are designed to protect the reliability of the electric system as a whole and prevent an uncontrolled system-wide outage.

[41] In this report, net winter capacity refers to the maximum output, commonly expressed in MWs, that generating equipment can supply to system load, as demonstrated by a multi-hour test, at the time of peak winter demand (period of December 1 through February 28). This output reflects a reduction in capacity due to electricity use for station service or auxiliaries. EIA, *Glossary* (accessed August 19, 2022), https://www.eia.gov/tools/glossary/index.php. Net winter capacity does not imply a differencing of capacity additions and retirements. According to EIA, net winter capacity is typically determined by a performance test and indicates the maximum electricity load a generator can support at the point of interconnection with the electricity transmission and distribution system during the winter season. For more information, please EIA FAQs (accessed October 14, 2022), https://www.eia.gov/tools/faqs/faq.php?id=101&t=3.

[42] **Figure 7** and **Figure 8** represent data on Operating and Standby resources entering operation and expected capacity retirements during the months of March 2022 through February 2023.

nameplate capacity values, for the same period. This section uses EIA data and examines changes in electric resources, and the resulting changes in the capacity mix. and later discusses the planning reserve margins that result from available capacity across the NERC regions for winter 2022-2023, using preliminary NERC data. Capacity additions and retirements discussed in this section occur between March 2022 and February 2023, and reflect net winter capacity, unless otherwise noted.

Figure 8: Planned and Actual Capacity Retirements



Source: Form EIA-860M, September 2022 Release. Note: Expected and Actual Additions and Retirements from March 2022 through February 2023. Data exclude Alaska and Hawaii. WECC refers to WECC without CAISO. SE** refers to the balancing authorities that make up the Southeast Market and excludes Florida.*

All regions of the US are expected to have more capacity in winter 2022-2023 than they did the prior year. **Figure 7** and **Figure 8** show expected net winter capacity changes across the regions, with notable resource changes detailed below. The values in **Figure 7** and **Figure 8** indicate installed capacity, not accredited capacity[43] or energy production. Across all regions, 64% of forecasted capacity additions come from solar and wind, 22% from natural gas, and 14% from battery storage. The increase in solar installations comes amid concerns over shipment disruptions,[44] with 20% of planned solar capacity delayed during the first half of 2022.[45] Resource retirements consist mainly of coal-fired generation capacity.

ERCOT is expected to add 12 GW, comprised of over 9 GW of solar and wind capacity and over 1.9 GW of battery storage additions. ERCOT is also expected to retire almost 500 MW of natural gas-fired generation.[46] Among the largest resource additions expected are three 500 MW solar projects, five wind projects totaling over 1,700 MW, and three battery storage projects totaling 400 MW. Natural gas-fired generation represents 743 MW of net winter

[43] Accredited capacity is installed capacity that has been reduced to reflect expected operation or availability of a resource.

[44] The Wall Street Journal, *U.S. Solar Shipments Are Hit by Import Ban on China's Xinjiang Region* (August 9, 2022), https://www.wsj.com/articles/u-s-solar-shipments-are-hit-by-import-ban-on-chinas-xinjiang-region-11660037401.

[45] EIA, *Utility-Scale Solar Projects Report Delays* (August 11, 2022), https://www.eia.gov/todayinenergy/detail.php?id=53400.

[46] EIA, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M)* (September 2022), https://www.eia.gov/electricity/data/eia860m/.

capacity additions. With respect to retirements, notably, the 448 MW Decker Creek natural gas plant retired in ERCOT in March 2022.

CAISO expects 5.8 GW to come online, including solar (2.6 GW) and battery storage capacity (2.9 GW). This battery storage capacity represents over half the nation's battery storage capacity additions, as CAISO seeks to integrate battery storage with growing levels of wind and solar generation. One notable addition is the 457 MW Palen Solar Project, which came online in June 2022 and combines solar generation with 50 MW of battery storage capacity.[47] No capacity retirements are forecast in CAISO this winter.

PJM expects to add 6.4 GW of net winter capacity, mainly from natural gas and solar additions, and generation retirements of 6 GW. One notable addition expected this November is the Guernsey Power Station, a 1,250 MW combined cycle natural gas plant in Ohio. Nearly all of the 6 GW of capacity retirements will come from coal. The largest retirement was the 1,333 MW W. H. Zimmer coal plant in Ohio, which retired in May 2022.

MISO expects to add roughly 4.7 GW from wind, solar, and natural gas-fired generation and to retire 4.2 GW from nuclear and coal. Among the capacity retirements is the 816 MW Palisades nuclear facility in Michigan, although the Michigan Governor has announced support for reopening the facility.[48] Solar, wind, and natural gas-fired generation are each expected to make up roughly a third of the new capacity additions.

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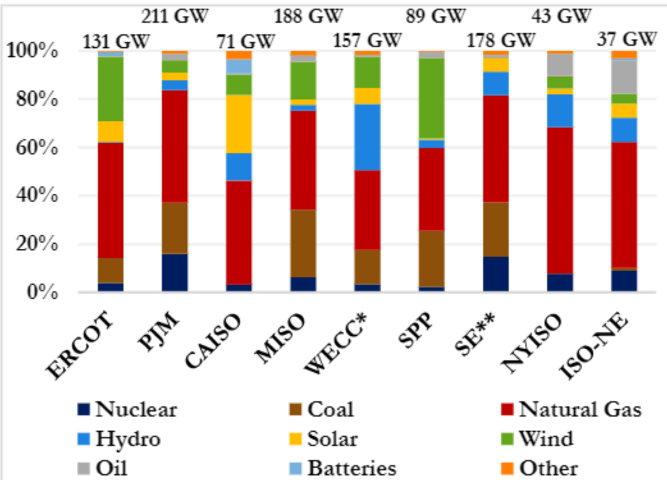
[47] S&P Global, *EDF's 457-MW Calif. Solar-plus-storage Project Becomes Fully Operational* (August 11, 2022), https://www.capitaliq.spglobal.com/web/client?overridecdc=1&auth=inherit#news/article?Id=71669326&KeyProductLinkType=2.

[48] S&P Global, *Mich. Governor throws weight behind effort to reopen Palisades nuclear plant* (September 12, 2022), https://www.capitaliq.spglobal.com/web/client?auth=inherit#news/article?id=72082349&KeyProductLinkType=6.

SPP is expected to add 2.6 GW of wind capacity, representing 89% of the total capacity planned or installed (all resources included) in SPP from March 2022 through February 2023. SPP also expects less than 100 MW of retirements, from natural gas-fired generation. Most notably, the wind additions include the 999 MW Traverse Wind Project that came online in April 2022 in Oklahoma.[49] Solar generation represents nearly all the remaining forecasted capacity additions in SPP.

Figure 9: Expected Net Winter Capacity Mix by Region



Source: Form EIA-860M, September 2022 Release. Note: Expected Net Winter Capacity through October 2022. WECC refers to WECC without CAISO. SE** refers to the balancing authorities that make up the Southeast Market and excludes Florida.*

NYISO is expected to add roughly 800 MW of net winter capacity, mostly from solar and wind resources, and ISO-NE is expected to add roughly 300 MW of net winter capacity, mostly from solar resources. In NYISO, nearly 450 MW of coal retirements are anticipated, and no significant retirements are anticipated in ISO-NE.

Although wind, solar, and battery storage represent the bulk of capacity additions across the RTOs/ISOs through winter 2022-2023, natural gas, primarily from existing generating facilities, is expected to provide the largest share of net winter capacity available across the RTOs/ISOs, as shown in **Figure 9**. Natural gas-fired generation provides 43% of capacity across the regions, followed by coal at 18%, wind at 12%, hydropower at 9%, nuclear at 8%, and solar at 6%.[50] Regionally, for winter 2022-2023, natural gas-fired generation is forecast to provide between 30% to 60% of net winter capacity; over half of NYISO's capacity (60.5%) and of ISO-NE's capacity (52%); nearly half of the capacity in ERCOT (47.5%) and PJM (46.6%), over a third in the southeast (44.3%), CAISO (43.1%) and MISO (41%); as well as about a third of SPP's capacity (34.3%) and a third of the capacity of the non-CAISO Western Electricity Coordinating Council (WECC) (33.2%).

Coal-fired generation is forecast to provide 27.9% of MISO's capacity, 23.2% of SPP's capacity, 22.4% in the southeast, 21% in PJM, 14.2% in WECC, and 10.4% in ERCOT this winter.

Wind, solar, hydropower, and battery storage are expected to provide 27% of capacity nationwide this winter. CAISO has the largest share of solar (23.9%) and battery storage (5.9%) and SPP has the largest share of wind

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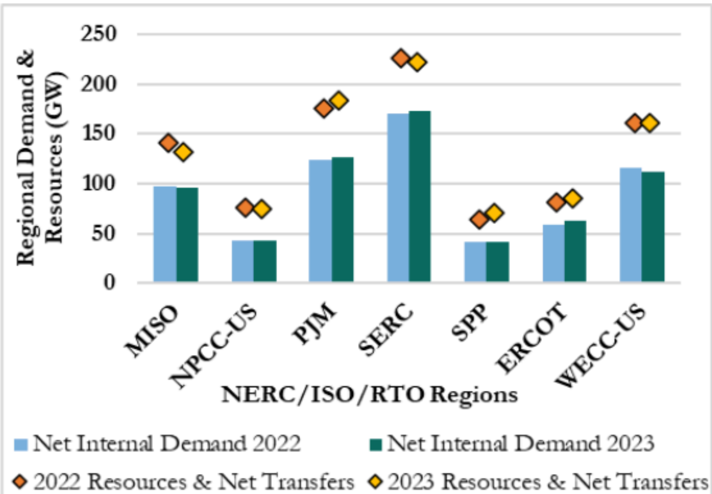
[49] EIA, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M)* (September 2022), https://www.eia.gov/electricity/data/eia860m/.

[50] Installed net winter capacity is assessed through October 2022 ahead of the peak winter period. Note that these estimates do not imply that generation output will match the net winter capacity of a resource type. **Figure 9** captures Operating and Standby resources expected to be available through October 2022. It also captures expected capacity retirements and planned capacity through October 2022.

(33.4%) as a percentage of its capacity mix. In ERCOT, solar and wind combine to represent 35.4% of the capacity mix. In WECC, hydropower provides 27.2% of the net winter capacity.

According to preliminary data from NERC,[51] the planning reserve margins[52] exceed the reference reserve level margins[53] for the 13 NERC assessment areas.[54] Overall, there appear to be sufficient resources to meet expected U.S. electric demand under normal winter conditions. Despite such strong expected reserve margins, electric regions can face tighter-than-expected supply conditions if operating conditions deviate significantly from those expected for this winter. Reserve margins do not necessarily account for extreme winter conditions that can lead to fuel unavailability for gas units, derates of intermittent resources, unexpected generating resource outages, transmission outages, reduced power transfers from adjacent areas, and delays in resources coming online that could affect a region's ability to serve customers and maintain adequate operating reserves. Therefore, although all regions are expected to maintain adequate reserve margins through the winter, reserve margins do not guarantee reliable operations, especially during the winter. A variety of factors affect reliable operations and are managed by system operators to help maintain electric supply and

Figure 10: NERC 2021-2022 and 2022-2023 Demand and Resources



Source: North American Electric Reliability Corporation

[51] Data in this section is calculated with preliminary data provided by the NERC regions for NERC's upcoming *2022 Long Term Reliability Assessment* and the *2022-2023 Winter Reliability Assessment*, which will both be released later this year. For a more detailed analysis that includes probabilistic scenario conditions, refer to the *Probabilistic Assessment and Regional Profiles* section of this report.

[52] 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.

[53] 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.

[54] The 13 assessment areas are NPCC-ISONE, NPCC-NYISO, PJM, SERC-Central, SERC-East, SERC-Southeast, SERC Florida Peninsula, MISO, SPP, ERCOT, WECC-NWPP (Northwest Power Pool), and WECC-SRSG (Southwest Reserve Sharing Group), WECC-CAMX (California-Mexico), and shown in **Figure 12**.

reliability. A more comprehensive review of ISO-NE, ERCOT, and MISO is presented in the *Probabilistic Assessments and Regional Profiles* section below.

Figure 10 shows the net internal demand[55] as solid bars and the available resources and net transfer values,[56] a combination of internal resources and additional external resources available to the region, as diamonds. These are shown for both the prior 2021-2022 winter and also this upcoming 2022-2023 winter for comparison. In **Figure 10**, staff aligned the assessment areas to present a more regional analysis. Specifically, the Northeast Power Coordinating Council (NPCC), New England (NPCC-NE), and New York (NPCC-NY) are combined into NPCC-US; the Southeast Reliability Council (SERC) subregions of SERC-East, SERC-Central, SERC-South East and SERC-Florida are combined as SERC;[57] and the WECC-CAMX, WECC-SRSG and WECC-NWPP subregions are combined as WECC-US.[58] This graphic shows that all regions have sufficient available resources and net transfers to meet their respective loads, which is consistent with observations about reserve margins discussed later in the *Probabilistic Assessments and Regional Profiles* section.

Looking at just the winter months of December through February, NERC forecasts net internal electric demand to increase by approximately 0.5% or 4 GW, from 652 GW in winter 2021-2022 to 656 GW in winter 2022-2023. Projected growth in net demand is concentrated in ERCOT, PJM, and SERC. However,

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[55] Net Internal Demand equals Total Internal Demand less Dispatchable, Controllable Capacity Demand Response used to reduce load. Preliminary NERC, *2022-2023 Winter Reliability Assessment* (release anticipated November 2022).

[56] 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 winter 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.

[57] 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 12**. NERC, *Long Term Reliability Assessment*, December 2021, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf.

[58] WECC-CAMX (California-Mexico) includes parts of California, Nevada, and Baja California, Mexico. WECC-SRSG (Southwest Reserve Sharing Group) includes Arizona, New Mexico, and part of California and Texas. WECC-NWPP (Northwest Power Pool) 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 12**. NERC, *Long Term Reliability Assessment*, December 2021, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf.

NERC forecasts slight net demand reductions for the MISO region, along with the NPCC-US and WECC-US combined subregions. NERC forecasts net demand in SPP will remain similar to winter 2021-2022 levels, with less than 0.5% change.[59]

To serve that demand, NERC forecasts a national increase of 0.7% or almost 6 GW in total system resources and net transfers from almost 926 GW in winter 2021-2022 to almost 932 GW in winter 2022-2023,[60] as shown as diamond shapes in **Figure 10**.[61] This national increase was driven by resource and net transfer increases in the PJM (4.6%), ERCOT (4.7%) and SPP (9.1%) regions. However, generator capacity additions scheduled to come online for the winter could change or be subject to delays and may affect the ability of resources to operate at their winter capacity. Regions are reporting that some generation and transmission projects are being impacted by product unavailability, shipping delays, and labor shortages.

NERC takes into account and adjusts capacity values to reflect the expected ability to serve load. Projected resource capacity used in the NERC Assessments may not reflect nameplate ratings, but is reduced by known operating limitations (e.g., fuel availability, transmission limitations, environmental limitations) and compared to the reference margin levels, which represents the level of risk based on a probabilistic loss of load analysis.[62] 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, on-peak capacity contributions are less than nameplate capacity. Each region provides a nameplate capacity, expected capacity, and the expected percent of nameplate capacity for wind, solar and hydropower resources.

When accounting for capacity planning, resources are categorized as anticipated or prospective. Anticipated resources include capacity designated Existing-Certain, Tier 1 capacity additions, and net firm capacity transfers.[63] Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during peak periods this season. Prospective resources are those that could be

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[59] Preliminary NERC, *2022-2023 Winter Reliability Assessment* (release anticipated November 2022).

[60] Preliminary NERC, *2022-2023 Winter Reliability Assessment* (release anticipated November 2022).

[61] Preliminary NERC, *2022-2023 Winter Reliability Assessment* (release anticipated November 2022).

[62] 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.

[63] 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*, December 2021, at 13. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf.

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.[64]

NERC notes that while anticipated resources should be adequate for capacity this winter, energy risks remain in several regions, especially as the resource mix continues to evolve. Regions such as SPP and ERCOT, with high penetrations of wind resources, can be at risk during low-wind events. Additionally, the availability of interregional imports greatly increases the risk when additional demand in multiple locations reduces the available resources for export to a neighboring region. Also, any potential delays in project completion for Tier 1 resources or transmission projects under development and expected to be operating, could create potential local or regional reliability risks this winter.

Demand Response

Demand response and energy conservation programs help RTOs/ISOs meet their supply and demand obligations by reducing electricity demand during peak periods. Broadly speaking, demand response comes in two forms: emergency demand response, where the RTO/ISO system operator calls on resources to reduce demand under extreme system conditions, and economic demand response, where resources offer into the energy or ancillary services markets to reduce demand at a given market price. Demand response program activations generally occur during pre-emergency or emergency conditions in the peak demand months, usually during the summertime, and less often in the winter. However, electricity demand may suddenly increase to unusually high levels (or generation may suddenly decline) during winter storm events, as occurred throughout much of the United States in February 2021 during Winter Storm Uri. Although MISO and ERCOT did activate demand response during Winter Storm Uri, none of the RTOs/ISOs activated emergency demand response during the most recent winter—more specifically, from December 2021 through February 2022.

RTOs/ISOs procure demand response capacity to have it available to use during peak demand periods, regardless of season. According to EIA data, in 2018 and 2019, of the approximately 30,000 MW of retail demand response capability, 15,000 MW came from the industrial sector.[65] Industrial customers operate year-round, unlike residential thermostat demand response programs, which are more prevalent in summer. Demand response resources bid into RTO/ISO energy and capacity markets, although the conditions under which they are dispatched differ from those of other categories of resources, such as generation, because they

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[64] 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 Existing-Certain. NERC., *Long Term Reliability Assessment*, December 2021, at 13. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf

[65] Federal Energy Regulatory Commission, *2020 Assessment of Demand Response and Advanced Metering,* (December 2020) at 19, https://cms.ferc.gov/sites/default/files/2020-12/2020%20Assessment%20of%20Demand%20Response%20and%20Advanced%20Metering_December%202020.pdf; Federal Energy Regulatory Commission, *2021 Assessment of Demand Response and Advanced Metering,* (Dec. 2021) at 19, https://www.ferc.gov/media/2021-assessment-demand-response-and-advanced-metering.

are generally used during emergencies or tight system conditions. PJM procured 7,555 MW of Load Management resources and 230 MW of Price Responsive Demand through the capacity market for Delivery Year 2022/2023.[66] In total, PJM reported 10,149 MW of demand response capability from all programs.[67] MISO procured 7,541 MW of load-modifying resources in the Planning Resource Auction for Planning Year 2022/2023.[68] NYISO anticipates demand response capability from approximately 693 MW of special case resources for winter 2022-2023.[69] ISO-NE reports monthly Active Demand Capacity Resource totals and reported 511 MW in December 2021 and 529 MW in January 2022.[70] In CAISO, demand response programs are operated by utilities and third-party providers. In December 2021, CAISO reported 1,173 MW of demand response available from utility operated programs and 139 MW from third-party providers for a total of 1,312 MW.[71] As of December 2021, SPP reported 176 MW from demand response resources.

Several RTOs/ISOs have studied or made changes to their demand response programs over the past several years that may become relevant this winter. For example, following Winter Storm Uri, SPP has undertaken an evaluation of demand response and behind-the-meter generation, focusing on communication processes and procedures, current effectiveness, and areas of potential improvement.[72] While SPP studied potential changes to its demand response programs heading into winter 2022-2023, SPP has not developed specific demand response tariff proposals ahead of the upcoming winter.

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[66] PJM, *2022 Demand Response Operations Markets Activity Report*, (September 2022) at 4, https://www2.pjm.com/-/media/markets-ops/dsr/2022-demand-response-activity-report.ashx.

[67] *Id.*

[68] MISO, *2022/2023 Planning Resource Auction Results*, (April 2022) at 22, https://cdn.misoenergy.org/2022%20PRA%20Results624053.pdf. For reference, MISO procured 7,152 MW of load-modifying resources in the auction for Planning Year 2021/2022.; and MISO, *2021/2022 Planning Resource Auction Results,* (April 2021) at 10, https://cdn.misoenergy.org/PY21-22%20Planning%20Resource%20Auction%20Results541166.pdf; and Potomac Economics, *2021 State of the Market Report for the MISO Electricity Markets*, (June 2022) at 100, https://www.potomaceconomics.com/wp-content/uploads/2022/06/2021-MISO-SOM_Report_Body_Final.pdf.

[69] NYISO, *2022 Load & Capacity Data,* (April 2022) at 73, https://www.nyiso.com/documents/20142/2226333/2022-Gold-Book-Final-Public.pdf.

[70] ISO-NE, *Demand Resources Working Group Monthly Statistics Report*, (December 2021) at 4, https://www.iso-ne.com/static-assets/documents/2021/12/dr_stats_december_2021.pptx; ISO-NE, *Demand Resources Working Group Monthly Statistics Report*, (Jan. 2022) at 4, https://www.iso-ne.com/static-assets/documents/2022/01/dr_stats_january_2022.pptx.

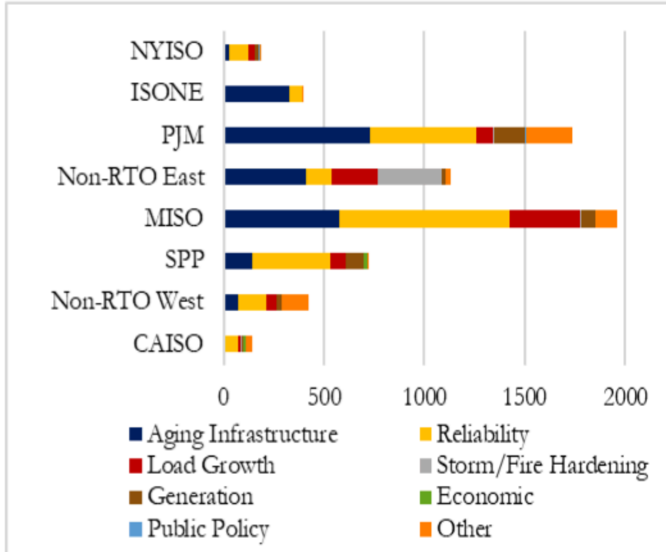
[71] CAISO, *2021 Annual Report on Market Issues and Performance*, (July 10, 2022) at 56, http://www.caiso.com/Documents/2021-Annual-Report-on-Market-Issues-Performance.pdf.

[72] Southwest Power Pool, *Winter Weather Event Tier 1 Initiatives: Progress Report – June 2022* (June 15, 2022), https://www.spp.org/Documents/67311/June%20Tracking%20Report.pdf.

Electric Transmission

New transmission lines and transmission upgrades will support operations this winter. As shown in **Figure 11**, between March 2022 and March 2023, approximately 826 line-related transmission projects, representing nearly 6,700 line-miles, are scheduled to enter service in the U.S. portions of the Eastern and Western interconnections.[73] PJM and MISO account for more than half of these line-related transmission projects. Most of the 826 projects are on transmission lines of lower voltage or shorter distance. Approximately 56 of these line-related transmission projects are additions or upgrades to significant transmission lines that are 230 kilovolt (kV) or higher voltage, and ten or more miles long.

Figure 11: Line Miles of Line-Related Transmission Projects Scheduled to Enter Service March 2022 – March 2023



Source: North American Electric Transmission and Distribution Project Database, The C Three Group, L.L.C.

Transmission changes can have a range of impacts on reliability and operations during the winter season. Typically, maintenance outages on transmission lines are scheduled for the fall and spring periods due to lower expected loads and more favorable weather conditions. However, the potential for supply chain or labor disruptions in supporting industries has complicated projects and could affect transmission maintenance and construction schedules this winter. Significant ongoing planned transmission outages in most regions are expected to be largely completed by the start of the winter season, although the duration of a few outages could extend into early winter and potentially longer if any delays occur. While no reliability impacts are expected from any of the current planned outages, several have risks of causing higher congestion and constraints in their respective regions.

Ongoing planned outages in the Midwest and Central United States are especially weather dependent, with the scale of impact varying based on wind generation levels and therefore most likely impacted by the expected La Niña conditions this winter. There may be unplanned outages caused by extreme weather in the Midwest and Central United States, which typically expect colder and wetter conditions during a La Niña winter and may be more at risk of icing, which can have a larger impact on transmission infrastructure.[74]

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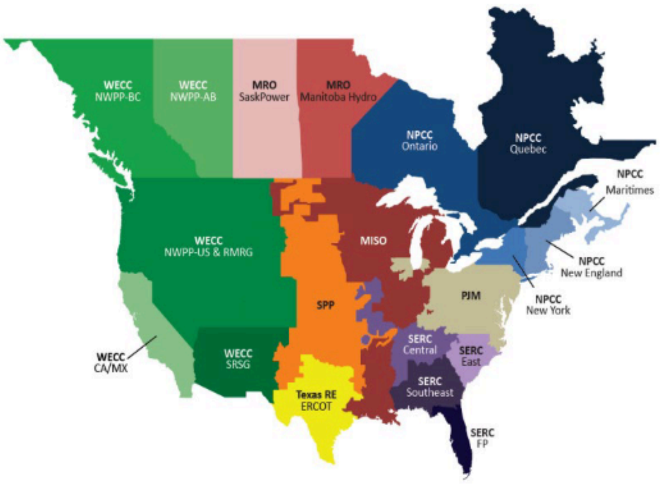
[73] Estimates are based on the North American Electric Transmission Project Database by The C Three Group, L.L.C. "Line-related transmission projects" are transmission projects involving a transmission line including a new transmission line or a line upgrade.

[74] See the *Weather Outlook* section above for more details.

Probabilistic Assessments and Regional Profiles

Figure 12: Map of NERC Sub-regions



Source: North American Electric Reliability Corporation

In prior years, this winter assessment has relied extensively on reserve margins analysis to determine resource adequacy levels. However, areas can face energy shortfalls despite having planning reserve margins that exceed reference margin levels. Insufficient resources during different demand levels could include generator scheduled maintenance, forced outages due to a range of factors, and conditions that affect generation resource performance or unit availability, including constrained fuel supplies. As a result, NERC and the Regional Entities, as shown in **Figure 12**, also use a probabilistic risk analysis to assess the availability and sufficiency of resources to meet demand under normal operating conditions as well as multiple risk scenarios with a range of conditions. Probabilistic risk analysis assesses the potential variations in resources and load which can occur under changing conditions or scenarios, as well as the potential effects that operating actions can have in mitigating shortfalls in operating reserves.[75]

This assessment spotlights three regions[76]—ISO-NE, ERCOT, and MISO—as shown in **Figure 13**, **Figure 14**, and **Figure 15** below. Each of the analyses for these regions provide valuable insight into how various unanticipated events that could occur during extreme winter conditions may affect the total resource mix available to meet demand.

The charts below are informally referred to as "waterfall charts" and step down to compare resources against levels of forecasted supply and demand, including required reserve levels, under chosen extreme scenarios, such as the normal peak net internal demand (50/50 scenario) and the extreme winter peak demand (90/10 scenario).[77]

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[75] 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*, https://www.nerc.com/files/glossary_of_terms.pdf.

[76] This section is based on preliminary data provided by the NERC Regional Entities for the NERC's upcoming *2022 Long Term Reliability Assessment* and the *2022-2023 Winter Reliability Assessment*, which will both be released later this year.

[77] A 50/50 scenario means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season. Similarly, a 90/10 scenario means that there is a 90% probability that actual demand will be higher, and 10% probability actual demand will be lower than the value provided for a given season.

As identified in past winter assessments, the seasonal risk assessment does not account for all the unique energy assurance risks associated with the area. Long-duration cold spells and disruptions to primary and back-up fuel supply chains are not explicitly considered in the regional seasonal risk scenarios and can cause unique risks to the area's operations. Note that methods, scenarios considered, and assumptions differ by assessment area and may not be comparable.

ISO-NE:

NERC's preliminary data indicate that ISO-NE expects to meet its regional resource adequacy requirements this winter period during normal conditions but may face challenges during an extreme winter event. Under extreme conditions, such as abnormally high loads during extreme cold weather, the region may have to rely on its external ties and operational actions during a capacity deficiency to operate reliably.[78] In addition, since ISO-NE's pipeline capacity to meet natural gas demand from both home heating and electric power generation during an extreme winter event is constrained, a standing concern is whether there will be sufficient energy available to satisfy electricity demand while maintaining operating reserves during an extended extreme winter event.

ISO-NE surveys fossil-fueled generators on a weekly basis to monitor[79] and confirm their current and expected fuel availability throughout the 2022-2023 Winter Operating Period. If conditions require more frequent updates, these surveys may be sent daily. Additionally, ISO-NE has proactively communicated with several generating stations with oil storage capability to determine the expected inventory prior to the start of winter. Based on this early outreach, ISO-NE expects a significant replenishment of oil stocks, but that replenishment is expected to occur closer to winter due to forward commodity pricing.[80]

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[78] Examples of these actions are (i) arranging to purchase available emergency capacity and energy from neighboring balancing authorities, (ii) implementing a voltage reduction to reduce load, (iii) requesting generators and demand response that do not have capacity obligation to provide energy or decrease demand for reliability purposes, (iv) requesting voluntary load curtailment by large industrial and commercial customers, and (v) allowing for depletion of operating reserves before shedding load. ISO New England *Operating Procedure No. 4 - Action During a Capacity Deficiency* - https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op4/op4_rto_final.pdf.

[79] Since December 2018, ISO-NE has implemented a 21-Day Energy Assessment Forecast, based on current system conditions, forecasted weather, load, generators' reports of stored-fuel inventories and emissions limitations, and status of fuel delivery systems. https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/21-Day-Energy-Assessment-Forecast-and-Report-Results.

[80] ISO-NE Winter Analysis Assessment and Recommendations at 9. https://www.iso-ne.com/static-assets/documents/2022/07/a09_mc_2022_07_12-14_winter_2022_2023_presentation.pptx.

Despite energy adequacy[81] concerns, as discussed below in the *Electricity Market Readiness in New England* section of this report, ISO-NE did not propose to implement a Winter Reliability Program or Inventoried Energy Program[82] for this winter.

This year, NERC also requested all the assessment regions to provide a progress summary for Recommendation 9 and Recommendation 10 of the inquiry into the February 2021 Cold Weather Outages in Texas and the South Central United States (Joint Inquiry Report).[83] Recommendation 9 has several suggestions including calling on Planning Coordinators to adjust the 50/50 forecasts to reflect actual historic peak loads that occurred during severe cold weather events in their footprints and reflect the potential for exponential load increase due to the resistive heating used in southern states.[84] The Joint Inquiry Report is further profiled in the *Winter Preparedness Progress* section below. Recommendation 10 guides Transmission Owners/Transmission Operators, in coordination with Distribution Providers and Reliability Coordinators to evaluate load shedding plans for opportunities to improve their capacity for rotating manual load shedding, especially when load shedding is required for extended periods during stressed system conditions.[85]

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[81] In January 2018, ISO New England published an operational analysis of fuel-security challenges to the continued reliability of New England's power system and opened a dialogue with stakeholders on the issue. The study illustrated the number and duration of energy shortfalls that could occur during the winter period in 2024/2025 if certain conditions developed, which would require implementation of emergency procedures to maintain reliability. This analysis provided a frame to study energy adequacy for an entire winter period based on several assumptions such as available stored fuel, daily load demand and gas pipeline capacity that would be available for gas units after account for firm demand for local gas distribution companies. Results from this study have pointed to energy adequacy concerns for an extreme winter condition. https://www.iso-ne.com/committees/key-projects/implemented/operational-fuel-security-analysis.

[82] ISO-NE, *Winter Energy-Security Initiatives Key Projects* (2022), https://www.iso-ne.com/committees/key-projects/implemented/winter-energy-security-initiatives.

[83] The Report made 28 recommendations — 9 of them "Key Recommendations" to prevent recurrence of problems, such as the ones experienced during Winter Storm Uri. For more information, please see *Winter Preparedness Progress: Joint Inquiry Report* section in this report. FERC, *The February 2021 Cold Weather Outages in Texas and the South Central United States | FERC, NERC and Regional Entity Staff Report* (November 16, 2021), https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and.

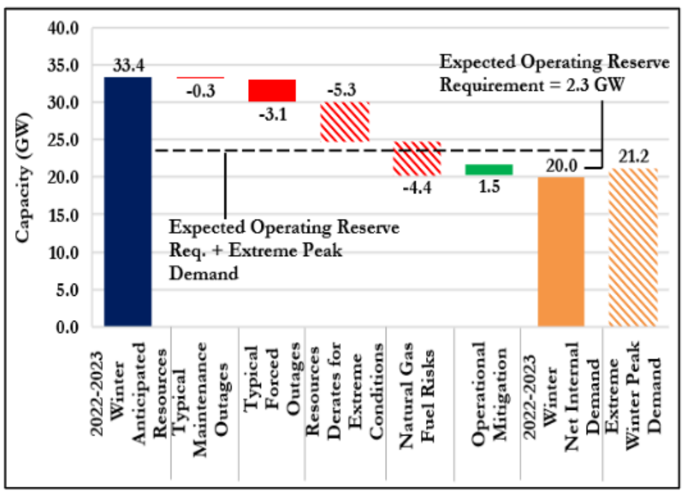
[84] FERC, *The February 2021 Cold Weather Outages in Texas and the South Central United States | FERC, NERC and Regional Entity Staff Report* (November 16, 2021), at 210. https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and.

[85] FERC, *The February 2021 Cold Weather Outages in Texas and the South Central United States | FERC, NERC and Regional Entity Staff Report* (November 16, 2021), at 213. https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and.

Regarding Recommendation 9, ISO-NE states that it has taken several measures to determine and improve the planning reserve margins during winter peak demand. Specifically, ISO-NE studies an "Above 90/10" winter case, which includes the current capacity in New England, the coldest recent weather (January 2018), gas at risk, and an added cold weather generation de-rate to account for outages occurring due to temperature. Finally, ISO-NE states that wind generation forecasts take into account cold weather cutouts for the turbines to have a more accurate and improved forecast capacity during peak winter demand days. Regarding recommendation 10, on October 12, 2022, ISO-NE conducted an exercise with its transmission owners to review emergency procedures for load shedding and coordination with transmission owners.[86]

Figure 13 below summarizes NERC's preliminary assessment for a normal winter and for an extreme winter for the ISO-NE region under certain scenarios. The left blue column shows anticipated resources, and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand (50/50 scenario) and the extreme summer peak demand (90/10 scenario).[87] Both scenarios are determined by the regional or sub-regional assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources, such as various factors affecting resources and demand that can combine to impact overall resource adequacy. Adjustments are applied cumulatively to anticipated capacity, such as reductions for typical generation outages (maintenance outages and forced outages not already accounted for in anticipated resources) shown in red, and additions that represent the quantified capacity from operational tools, if any, shown in green, that are available during scarcity conditions but have not been accounted for in the reserve margins. Note that methods and assumptions differ by assessment area and may not be comparable.

Figure 13: ISO-NE Risk Period Scenario



Source: North American Electric Reliability Corporation

Figure 13 shows anticipated resources of 33.4 GW, typical maintenance outages are 0.3 GW, and typical forced outages are 3.1 GW. This scenario leaves 30 GW to meet the expected 50/50 demand scenario forecast for a winter peak load of 20 GW. In this scenario, there are enough resources (30 GW) to meet load (20 GW) and also meet the operating reserve (2.3 GW) requirement, because net resources, after typical maintenance outages and forced outages, exceed load by 10 GW, and remain above the expected operating reserve margin

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[86] ISO New England Overview of Emergency Procedures and Communications Processes, slide 4 https://www.iso-ne.com/static-assets/documents/2022/05/webex_2022_pre_summer_OP4_briefing_may_19_final.pdf.

[87] A 50/50 scenario means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season. Similarly, a 90/10 scenario means that there is a 90% probability that actual demand will be higher, and a 10% probability actual demand will be lower than the value provided for a given season.

of 2.3 GW. For the extreme winter scenario, ISO-NE has the same 33.4 GW of resources available, but also removes an additional 5.3 GW of derated resources and 4.4 GW of generation is unavailable due to natural gas supply risks. These reductions (as shown in the red crosshatch bars) reduce the available resources to 20.3 GW to meet the 21.2 GW of extreme winter demand. In the extreme scenario, the system would need to use 1.5 GW from a set of operational mitigation actions,[88] as shown in green, to address the capacity deficiency. For this extreme scenario, the combined resources after deducting typical outages, additional derates, and natural gas risk, and including benefits obtained from operational mitigation actions equals roughly 21.7 GW, which is sufficient to meet an extreme winter peak load of 21.2 GW, although it may be insufficient to meet the required operating reserve.

ERCOT:

NERC's seasonal risk assessment preliminary data shows that ERCOT's expected resources meet operating reserve requirements under the normal peak-demand scenario. Above-normal winter peak load and outage conditions could result in the need to employ operating actions during a capacity deficiency (i.e., demand response, transfers, and short-term load interruption). EEAs[89] may be needed under extreme peak demand and outage scenarios studied.

When comparing winter 2022-2023 to winter 2021-2022, the ERCOT assessment area shows an increase in anticipated resources (1.7 GW), a decrease in typical maintenance outages (0.4 GW), an increase in typical forced outages (1.6 GW), an increase in resource derates for extreme conditions (16.6 GW), and an increase in the need for operational mitigations (0.6 GW). Additionally, the winter net internal demand (50/50 demand scenario forecast) increases by 3.6 GW and the extreme winter peak demand (90/10 demand scenario forecast) increases by 7.2 GW for winter 2022-2023. This represents a 6% increase for the normal 50/50 case and a 9.4% increase in the extreme 90/10 case compared to last year.

Regarding Recommendation 9 of the Joint Inquiry Report, ERCOT states that it always factors actual historic peak loads in its load forecasting, which includes severe cold weather events. The historical data set used in the ERCOT forecasts relies on data for the previous 15 years. The impact of Winter Storm Uri is also reflected in ERCOT's upcoming long-term load forecast, which is expected to be released in November 2022. In terms of resistive heating, ERCOT states that its service territory is approximately 50% electric heating, which is also reflected in its load forecasts.

Regarding Recommendation 10, ERCOT conducted two load shed exercises, in December of 2021 and in July of 2022, to review load shed procedures and provided training to ERCOT market participants. This training included the explanation of ERCOT's role during a load shed directive, specifically when load shed

[88] Operation actions/operator mitigation include the ability to import additional power from neighboring regions, request voluntary or mandatory conservation from customers to reduce load, manage load by reducing operating voltages, draw down operating reserves or shed load. However, load shedding is only used as an emergency, last resort measure, and it is each entity's overriding goal to avoid this scenario.

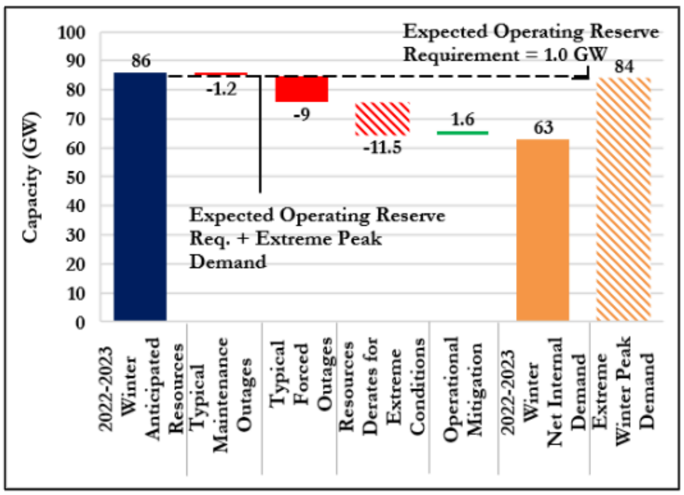
[89] Each region has a series of emergency procedures known as Energy Emergency Alerts (EEAs) that may be used when operating reserves drop below specified levels. These procedures are designed to protect the reliability of the electric system as a whole and prevent an uncontrolled system-wide outage.

is necessary and how directives are issued to Transmission Operators in ERCOT. ERCOT also conducted simulations of hypothetical events that would require load shed. Additionally, Transmission Operators in ERCOT presented their load shed practices and methods, which included how they responded to directives with ERCOT and their communications strategies with Distribution Service Providers.

Meanwhile, a U.S. Environmental Protection Agency (EPA) decision[90] is expected prior to winter that affects the J.K. Spruce unit 1 and unit 2 (coal units) owned by City Public Service Energy (CPS Energy) with a combined capacity of approximately 1,410 MW. These units are at risk of being shut down for part or all of this winter due to the EPA regulations for Coal Combustion Residuals. However, if ERCOT finds that the two units are required for maintaining reliability, then the EPA could authorize extended use of the units through this winter and allow ERCOT and CPS Energy to plan the outages to best minimize reliability issues during the outage period. The EPA's denial of the request would result in the plant shutdown prior to the end of winter. ERCOT is currently analyzing the impacts of a potential Spruce outage for the period January through August 2023.

Concerning a potential rail interruption, which is further discussed in the *Coal Industry Issues and Responses from the RTOs/ISOs* section of this report, ERCOT notes that most of the affected coal units in its region have 30-day coal inventories.

Figure 14: ERCOT Risk Period Scenario



Source: North American Electric Reliability Corporation

Figure 14 shows NERC's preliminary assessment for a normal winter and for an extreme winter for the ERCOT region. The anticipated resources total 86 GW, typical maintenance outages are 1.2 GW, and typical forced outages are 9 GW. This leaves 75.8 GW to meet expected winter peak load of 63 GW, which is for a 50/50 demand scenario forecast.

In this scenario, net resources, after typical maintenance outages and forced outages, exceed load by 12.8 GW, which is above the expected operating reserve margin of 1 GW. For extreme winter conditions, such as occurred during Winter Storm Uri, ERCOT indicates the need to allow for a resource derate of 11.5 GW.[91] This would reduce available resources to 64.3 GW for an extreme winter condition, which is below the extreme winter peak load

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[90] U.S. Environmental Protection Agency. Coal Combustion Residuals (CCR) Part A Implementation. Docket Number EPA-HQ-OLEM-2022-0333, https://www.regulations.gov/document/EPA-HQ-OLEM-2022-0333-0001.

[91] ERCOT's extreme winter assessment accounts for the risk of another weather event like Winter Storm Uri as well as the impacts of winter preparedness standards implemented by the Public Utility Commission of Texas and the Texas Railroad Commission. Preliminary NERC, *2022-2023 Winter Reliability Assessment* (release anticipated November 2022).

of 84 GW by about 19.7 GW. During extreme winter conditions, while ERCOT can gain 1.6 GW of benefit from operational mitigations, this still leaves a shortfall of up to 18.1 GW. These above-normal winter peak load and outage conditions could result in the need to employ EEAs and operational tools (i.e., demand response, transfers, and load shed), which may be needed under extreme peak demand and outage scenarios.

ERCOT also performs a winter probabilistic assessment annually.[92] The 2022-2023 assessment's preliminary finding indicates a low probability of a risk of declaring an EEA during the expected daily peak load hour. An EEA-1 declaration may occur when the capacity available for operating reserves falls to 2,300 MW. The model incorporates probabilistic representation of an extreme winter storm event (given a 1% probability of occurrence, comparable to Winter Storm Uri) as well as reduced thermal weather-related outages due to weatherization improvements.

MISO:

NERC's seasonal risk assessment analysis for MISO shows that MISO's expected resources meet operating reserve requirements under the normal peak-demand scenario. However, there is some risk under a high load, high outage scenario for an increased reliance on emergency-only Load Modifying Resources (LMRs) (Demand Response and Behind-the-Meter Generation), and non-firm system imports. Various measures have helped to maintain system reliability in past winter events, and the measures taken since Winter Storm Uri to better coordinate with neighbors and MISO members will help ensure reliability over the coming winter season.

When comparing winter 2021-2022 to winter 2022-2023 data, the MISO assessment area shows minimal change, based on preliminary NERC data. For example, there is a small increase in typical maintenance outages (0.9 GW) and typical forced outages (0.7 GW). The extreme low generation scenario decreased only by 0.6 GW and operational mitigation remained at the same level. Also, winter demand remained constant for the 50/50 forecast and increased by 1.3 GW for the 90/10 demand scenario forecast.

MISO does not expect any fuel supply, inventory, or transportation issues for the upcoming winter season. Unit winterization and fuel supply concerns continue to be discussed and surveyed annually, plus the North and Central regions are prepared for extended periods of extreme winter weather. Also, MISO stated that working with generation in the southern region is critical to ensuring unit readiness for the type of cold weather observed over the last several years.

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[92] This probabilistic assessment calculates the probability that "Capacity Available for Operating Reserves" (CAFOR) is at or below various risk thresholds for EEAs declarations, including controlled load shed. CAFOR serves as a forecasting proxy for real-time operating reserves. https://www.ercot.com/files/docs/2021/10/25/SAWG__Meeting_10-29-2021_Winter_2021-22_Probabilistic_SARA.pptx__*See also:* ERCOT Seasonal Assessment of Resource Adequacy (SARA) reports. https://www.ercot.com/gridinfo/resource.

Regarding Recommendation 9 of the Joint Inquiry Report, MISO has taken actions to address specifically Recommendation 9(d)[93] and states that it is proposing to change from a summer-only approach to a seasonal (summer and winter) capacity construct in the future. According to MISO, it will also update how units are accredited looking at overall seasonal availability in hours of peak need, not just the standard unforced capacity accreditation. Regarding Recommendation 10, MISO states that it is engaging with stakeholders at its Resource Adequacy Subcommittee (RASC) regarding LMR accreditation reforms, planned to go into effect for the 2024-2025 Planning Year at the earliest. The purpose is to enhance LMR availability and to give MISO operators greater visibility into available load reductions at any given time. MISO is currently conducting transfer studies between internal and external operating areas[94] during extreme winter conditions and the results will be available after November 1.[95] MISO also continues efforts to study its internal system and prepare for potential challenging operating conditions driven by extreme weather or resource challenges.

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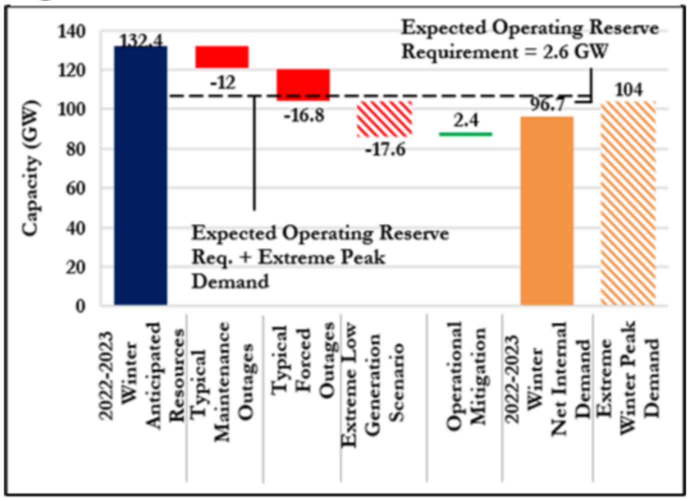
[93] Recommendation 9(d), the Joint Inquiry Report stated MISO should perform a winter peak analysis for each MISO sub-zone (focusing on MISO South) to improve its winter peak load forecast. MISO should use actual prior winter peak loads in the analysis, rather than summer peak load data modified by uncertainty factors, *The February 2021 Cold Weather Outages in Texas and the South Central United States | FERC, NERC and Regional Entity Staff Report* (November 16, 2021), at 211. https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and.

[94] MISO manages energy, reliability, and operating reserve markets that consist of 36 local Balancing Authorities and 394 market participants. Preliminary NERC, *2022-2023 Winter Reliability Assessment* (release anticipated November 2022).

[95] Transfer studies are part of MISO's Coordinated Seasonal Assessment. https://www-stg.misoenergy.org/planning/resource-adequacy/#nt=%2Fplanningdoctype%3ACoordinated%20Seasonal%20Assessment%2Fpubliccsatype%3AArchive&t=10&p=0&s=FileName&sd=desc.

Based on NERC's preliminary assessment for a normal winter and for an extreme winter for the MISO region, **Figure 15** shows NERC's preliminary assessment for a normal winter and for an extreme winter for the MISO region. The anticipated resources are 132.4 GW, typical maintenance outages are 12 GW, and typical forced outages are 16.8 GW. This leaves 103.6 GW to meet the expected 50/50 demand scenario forecast for a winter peak load of 96.7 GW. In this scenario, net resources, after typical maintenance outages and forced outages, exceed load by 6.9 GW, which is well above the expected operating reserve margin of 2.6 GW. For extreme winter conditions, NERC's assessment of MISO indicates a capacity derate of 17.6 GW. This would reduce available resources from 103.6 GW to 86 GW, which is lower than the 90/10 demand scenario forecast for an extreme winter peak load of 104 GW.

Figure 15: MISO Risk Period Scenario



Source: North American Electric Reliability Corporation

During extreme winter conditions, while MISO can gain 2.4 GW of benefit from operational mitigations,[96] this still leaves a potential shortfall of up to 15.6 GW. MISO states that for this gap, maintaining reliability would require triggering LMRs, non-firm transfers into the system, use of energy only interconnection service resources not receiving capacity credit, or internal transfers that exceed the Sub-Regional Import/Export Constraint between the MISO North/Central and South regions. According to MISO, the region also continues to coordinate extensively with neighboring Reliability Coordinators and Balancing Authorities to improve situational awareness and examine any needs for firm or non-firm transfers to address extreme system conditions.

Notable Issues for Winter 2022-2023

This section of the report highlights four issues with heightened potential to affect energy markets during winter 2022-2023: (1) coal supply issues, (2) natural gas dependence and winter electric reliability in New England, (3) natural gas pipeline outages and changes in Southern California and the Desert Southwest, and (4) overall winter preparedness based on the Joint Inquiry Report recommendations.

[96] Operation actions/operator mitigation include the ability to import additional power from neighboring regions, request voluntary or mandatory conservation from customers to reduce load, manage load by reducing operating voltages, draw down operating reseves or shed load. However, load shedding is only used as an emergency, last resort, measure and it is each entity's overriding goal to avoid this scenario.

Coal Industry Issues and Responses from the RTOs/ISOs

U.S. coal-fired power plants' ability to get coal this winter may be affected by ongoing coal production and shipment issues.[97] U.S. coal production decreased 24% in 2020 amid low coal demand and low natural gas prices during the pandemic. U.S. coal production increased by 8% in 2021 from 2020 levels, attributed to a rebound in domestic consumption and global exports.[98] As of September 17, 2022, U.S. year-to-date coal production is 3.9% higher than last year.[99] However, coal deliveries have been hampered by labor challenges, mine closures, and transportation limitations. An extended coal shortage for power generation could impact regions that continue to rely on coal-fired generation, such as the WECC region (excluding CAISO), SPP, MISO, PJM, ERCOT and the southeast region (SERC-E, SERC-SE, SERC-C, and SERC-FL).[100] Most of these regions forecast coal at over 20% of their net winter capacity, with the non-CAISO WECC, Florida, and ERCOT at lower levels of coal-fired capacity.[101]

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[97] S&P Global Financial Focus, *Global energy shortfalls stoke US coal further* (August 4, 2022), https://www.capitaliq.spglobal.com/web/client?auth=inherit#news/article?KeyProductLinkType=2&id=71510397; S&P Global Market Intelligence, *US coal sector's frustrations with western rail constraints growing* (July 29, 2022), https://www.capitaliq.spglobal.com/web/client?auth=inherit#news/article?id=71406381&KeyProductLinkType=6; S&P Global Market Intelligence, *Rail service 'meltdown' constraining US coal sector in hot market* (May 9, 2022), https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/rail-service-meltdown-constraining-us-coal-sector-in-hot-market-70189190.

[98] EIA, Coal, *Archive weekly and monthly coal production – revised and original estimates* (Accessed September 23, 2022), https://www.eia.gov/coal/production/weekly/includes/archive.php.

[99] EIA, Coal, *Weekly Coal Production* (September 17, 2022), https://www.eia.gov/coal/production/weekly/.

[100] 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 12**. NERC, *Long Term Reliability Assessment*, December 2021. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf.

[101] By October 2022, according to EIA data, WECC (excluding CAISO) is expected to have 14.2% of coal net winter capacity, SPP 23.2%, MISO 27.9%, PJM 21.0%, ERCOT 10.4%, Southeast region 22.4%, and Florida 7.2%.

Table 2: Average Number of Days of Burn for Coal by Region (Electric Power Sector)

Zone	Coal	July 2021 Days of Burn	July 2022 Days of Burn	Year over Year % Change
Northeast	Bituminous	328	365	11%
	Subbituminous			
South	Bituminous	64	56	-13%
	Subbituminous	45	38	-16%
Midwest	Bituminous	66	65	-2%
	Subbituminous	107	93	-13%
West	Bituminous	120	159	33%
	Subbituminous	80	70	-13%
U.S. Total	Bituminous	77	74	-4%
	Subbituminous	85	72	-15%

Source: EIA Electricity Monthly Update, Electric Power Sector Coal Stocks, with data for July 2022, Release Date September 23, 2022.

In response, MISO, SPP and PJM have been monitoring coal production and shipping issues since last year and implementing processes to adjust to the current environment. In MISO, which expects to have 27.9% of coal net winter capacity by October 2022, market participants will likely continue to adjust reference prices to allow fuel-constrained generators to run less often and maintain their existing stockpiles.[102] MISO will also continue to implement weekly fuel survey requirements—a measure introduced last winter to better understand fuel positions, in light of warnings issued about coal supply issues and forced outages during cold fronts.[103] Given power plant reports regarding coal delivery and low stockpile problems, SPP revised its Marketplace protocols to allow coal-fired generators to include opportunity costs in their energy bids to help manage coal stockpiles.[104] SPP expects 23.2% of coal winter net capacity. PJM expects to have 21.0% of coal winter net capacity and is likely to continue to relax its threshold to move a generator into the Maximum Emergency category from 32 hours of fuel supply to 240 hours. A generator moved into this category could be restricted from operating unless required to meet reliability needs. This began as a temporary measure last year and is in the process of becoming a permanent change in PJM's emergency operations manual, which does not require Commission approval.[105]

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[102] Potomac Economics, *2021 State of the Market Report for the MISO Electricity Markets* at 52 (June 2022), https://cdn.misoenergy.org/2021%20State%20of%20the%20Market%20Report625295.pdf.

[103] RTO Insider, MISO Opening Winter Fuel Surveys Next Month (September 1, 2022), https://www.rtoinsider.com/articles/30737-miso-opening-winter-fuel-surveys-next-month.

[104] SPP, *RR502 Opportunity Cost Revisions Addressing Coal Transportation Issues Recommendation Report* (July 29, 2022), https://www.spp.org/spp-documents-filings/?id=299889. The document, 01 – RR502 Recommendation Report.docx, can be found in the zipped file entitled *22-08-05 Special MOPC meeting RR502.*

[105] PJM, Issue Details, Max Emergency Changes for Resource Limitation Reporting, (accessed October 12, 2022), https://www.pjm.com/committees-and-groups/issue-tracking/issue-tracking-details.aspx?Issue=65273322-ad48-4a54-b630-a480c5695a14.

Coal stockpiles at power plants remain relatively low compared to historical levels[106] and some power plant operators report challenges in replenishing coal levels.[107] The average number of days of burn[108] held at electric power plants is a forward-looking estimate of coal supply given a power plant's current stockpile and past consumption patterns.[109] According to EIA's Electricity Monthly Update, U.S. total coal stockpiles at power plants (bituminous and subbituminous coal[110]) are 17% lower than last year, though that is not uniform across regions around the country. Similarly, days of burn from bituminous and subbituminous coal are stockpiled onsite at 4% and 15% lower levels than last year, respectively, as shown in **Table 2**.[111] Among bituminous coal units, largely located in the eastern U.S., the average number of days of burn dropped from 77 days in July 2021 to 74 days in July 2022.[112] Among subbituminous coal units, largely located in the western U.S., the average days of burn dropped from 85 days in July 2021 to 72 days in July 2022.[113]

In recent months, rail service issues have restricted coal shipments from the western U.S., where companies primarily mine coal used for power generation.[114] Most recently, on September 15, the White House secured

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[106] U.S. coal stockpiles remain at a relatively low historical level of 86 million tons as of July 2022. EIA, *Electric Power Sector Coal Stocks: May 2022* (September 26, 2022), https://www.eia.gov/electricity/monthly/update/coal-stocks.php.

[107] SPP, RR502 Opportunity Cost Revisions Addressing Coal Transportation Issues Recommendation Report (July 29, 2022), https://www.spp.org/spp-documents-filings/?id=299889. The document, 01 – RR502 Recommendation Report.docx, can be found in the zipped file entitled *22-08-05 Special MOPC meeting RR502*.

[108] Average Days of Burn is computed as follows: End of month stocks for the current (data) month, divided by the average burn per day. Average Burn per Day is the average of the three previous years' consumption as reported on Form EIA-923. EIA, *Electricity Monthly Update, Methodology and Documentation* (July 26, 2022), https://www.eia.gov/electricity/monthly/update/methodology.php.

[109] EIA, *Electricity Monthly Update* (July 23, 2022), https://www.eia.gov/electricity/monthly/update/coal-stocks.php.

[110] Bituminous coal is a middle rank coal between subbituminous and anthracite. Bituminous coal usually has a high heating (Btu) value and is used in electricity generation and steel making in the U.S. Subbituminous coal has low-to-moderate heating values and is mainly used in electricity generation. USGS, *What are the types of coal?* (accessed August 12, 2022), https://www.usgs.gov/faqs/what-are-types-coal.

[111] EIA, *Electricity Monthly Update* (September 23, 2022), https://www.eia.gov/electricity/monthly/update/coal-stocks.php.

[112] *Id.*

[113] *Id.*

[114] S&P Global Market Intelligence, *Rail Service Meltdown Constraining US Coal Sector in Hot Market* (May 9, 2022), https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/rail-service-meltdown-constraining-us-coal-sector-in-hot-market-70189190; S&P Global Market Intelligence, *US Coal (continued ...)*

a tentative deal to avert a strike among workers in the U.S. railroad sector.[115] However, as of October 14, 2022, the agreement has not been ratified.[116] Only four out of the 12 railroad unions have approved their agreements.[117] All 12 unions must ratify their contracts to prevent a strike.[118] A potential strike could complicate coal deliveries.

Winter Readiness in New England

The New England region has historically experienced natural gas and electric reliability and market stresses during periods of severe or extended cold weather. New England's winter energy issues motivated the Commission-led forum held in Burlington, Vermont, on September 8, 2022, to discuss winter reliability and gas-electric coordination in New England ahead of this winter.[119]

The natural gas and electric stresses in New England arise from a variety of factors. New England relies on natural gas-fired generation that is served by finite natural gas pipeline capacity, which is frequently constrained during peak winter conditions. While some natural gas generation has secured firm fuel supply, many natural gas generators contract primarily for lower priority secondary and interruptible pipeline capacity, while LDCs contract for the majority of the firm natural gas pipeline capacity and associated no-notice pipeline service. During extreme conditions, LDCs' contracts entitle them to use most of the transportation capacity, leaving many generators with lower priority rights and limited natural gas deliveries.

Other issues contribute to the winter stresses on ISO-NE's electric grid. In the absence of new, diverse generation resources coming online, retirement of power plants that operate on fuels other than natural gas

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Sector's Frustrations With Western Rail Constraints Growing (July 29, 2022), https://www.capitaliq.spglobal.com/web/client?auth=inherit#news/article?id=71406381&KeyProductLinkType=6.

[115] President Biden signed an Executive Order establishing a Presidential Emergency Board, effective July 18, 2022, to help resolve an ongoing dispute between major freight rail carriers and their unions. https://www.whitehouse.gov/briefing-room/statements-releases/2022/07/15/president-biden-signs-executive-order-creating-a-presidential-emergency-board/.

[116] Reuters, *U.S. rail strike averted, but labor deal faces tough union votes* (September 15, 2022), https://www.reuters.com/world/us/us-reaches-tentative-agreement-with-rail-workers-strike-2022-09-15/; Reuters, *Factbox: Latest on ratification status of U.S. railroad unions to avert strike* (September 29, 2022), https://www.reuters.com/world/us/latest-ratification-status-us-railroad-unions-avert-strike-2022-09-29/.

[117] PBS News Hour, *Large rail union rejects contract deal with railroads, renewing strike possibility* (October 10, 2022), https://www.pbs.org/newshour/economy/large-rail-union-rejects-contract-deal-with-railroads-renewing-strike-possibility.

[118] *Id.*

[119] FERC. *Regional Energy Challenges on Deck Today at FERC's New England Winter Gas-Electric Forum* (September 8, 2022), https://www.ferc.gov/news-events/news/regional-energy-challenges-deck-today-fercs-new-england-winter-gas-electric-forum.

has increased ISO-NE's natural gas reliance. Further, limited fuel oil storage and environmental restrictions restrict operations of the region's oil-fired and dual-fuel power plants. Finally, developing new natural gas pipeline and electric transmission capacity in New England has been challenging, which has further limited import capability from other regions.

Natural Gas Dependence in New England

In October 2022, winter 2022-2023 natural gas futures prices at the Algonquin Citygate hub, outside Boston, traded at $23.57/MMBtu, as discussed above in the Natural Gas Prices section.[120] A variety of factors drove this price increase, including the New England region's limited natural gas pipeline import capacity and competition for global LNG cargoes in light of rising global LNG prices and demand.

Fuel availability for power generation is a primary concern when assessing winter readiness and electric reliability, particularly for generators using natural gas and liquid fuels (e.g., oil, diesel, liquid petroleum gas). Forecasts indicate natural gas will account for approximately 49% of the region's electric generation energy output this winter (see *Natural Gas Demand* above).[121] Severe winter weather conditions have historically placed ISO-NE at risk of generator fuel shortages during prolonged periods of extreme cold weather. This risk arose most recently in winter 2017-2018, when New England experienced a deep freeze, natural gas supplies became scarce, and the electric system experienced significant operational and market stress.

While New England depends on natural gas to fuel its winter electricity production, it has a limited number of pipelines and pipeline capacity into the region, no internal natural gas production, and only a small amount of local natural gas storage capacity.[122] Five major interstate natural gas pipelines serve the region: Algonquin Gas Transmission LLC, Tennessee Gas Pipeline Company, LLC, Iroquois Gas Transmission System, Maritimes & Northeast Pipeline LLC, and Portland Natural Gas Transmission System. Most of the year, the five pipelines have surplus pipeline capacity into New England that is available for purchase through secondary markets. However, during periods of severe cold weather, demand from the power sector coincides with peak heating demand from LDC customers. As a result, generators and other customers without firm pipeline service must compete for the significantly-reduced remaining pipeline capacity.[123] Such customers must either pay higher prices for temporary releases of capacity from firm pipeline capacity holders, if available, or purchase natural gas at a premium from marketers. New England's vulnerabilities intensify when natural gas-fired generators compete for pipeline capacity with the LDCs. The LDCs have long-term contracts for firm transportation service for delivery of natural gas, enabling them to supply natural gas to

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[120] Winter 2022-2023 Futures price as of October 12, 2022.

[121] EIA, *Short-Term Energy Outlook* (September 7, 2022), https://www.eia.gov/outlooks/steo/.

[122] EIA, *Natural Gas Weekly Update* (January 20, 2022), https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2022/01_20/.

[123] ISO New England, *Natural Gas Infrastructure Constraints* (accessed on August 11, 2022), https://www.iso-ne.com/about/what-we-do/in-depth/natural-gas-infrastructure-constraints.

local customers during such weather events.[124] By contrast, many natural gas-fired generators in the region historically have not contracted for long-term firm pipeline capacity, which limits their ability to secure and transport natural gas to their facilities during extreme cold weather events.

LNG import terminals can provide deliveries of LNG into New England during peak periods. However, the LNG import terminals have limited capacity and imported LNG is typically more expensive than pipeline natural gas deliveries.[125] Three active LNG import facilities can regasify LNG cargoes and deliver natural gas into the region's pipeline network: Everett LNG, Northeast Gateway, and Saint John LNG (formerly known as Canaport LNG). The combined regasification capacity of the three terminals is about 2.2 Bcfd but, as discussed above in the *Natural Gas Imports and Exports* section, EIA forecasts LNG imports this winter (which do not include natural gas delivered by pipe to New England from the Saint John LNG facility) will average 0.1 Bcfd, down from 0.12 Bcfd last winter. The Northeast Gateway facility, in particular, requires specialized Floating Storage and Regasification Units that are in shorter supply than regular LNG tankers, which can limit its use.

Natural gas from LNG facilities typically costs more than natural gas delivered into New England by pipeline, as LNG prices reflect international competition for LNG supplies. As noted above in the *Natural Gas Prices* and *Natural Gas Exports and Imports* sections, European LNG price markers for December 2022 are around $30/MMBtu throughout this winter (as of October 12, 2022). New England natural gas futures prices at the Algonquin Citygate hub for January and February 2023 rose above $23/MMBtu indicating a high degree of convergence between New England and international gas prices during the winter season due to pipeline limitations.[126]

Related to energy adequacy concerns, six Governors in the New England region sent a letter on July 27, 2022, to Department of Energy Secretary Jennifer Granholm with concerns that the increased prices in LNG and global petroleum could have significant implications for the region's electric and natural gas customers and raise reliability concerns if the region should suffer a severe winter. In response, Secretary Granholm convened a meeting with the New England governors, at which, among other things, she emphasized the need for the region to build adequate fuel inventories heading into the upcoming winter.[127]

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[124] ISO New England, *Operational Fuel-Security Analysis*, (January 17, 2018).

[125] EIA, *Liquefied Natural Gas Imports Limited Price Spikes in New England This Winter* (May 13, 2019), https://www.eia.gov/todayinenergy/detail.php?id=39432

[126] S&P Global Commodity Insights, *LNG Daily* (October 12, 2022).

[127] U.S. Department of Energy, *Readout of Energy Secretary Granholm's Meeting With New England Governors* (September 15, 2022), https://www.energy.gov/articles/readout-energy-secretary-granholms-meeting-new-england-governors

In an August 18, 2022 letter to the governors of the New England states, Secretary Granholm addressed a number of related issues, including noting that DOE is a consulting agency for Jones Act waiver requests *(continued ...)*

Electricity Market Readiness in New England

Recognizing the challenges of operating during New England's winter conditions, in July 2022, ISO-NE analyzed its operations for the coming winter[128] and determined that it should be able to operate reliably through a mild or moderate winter,[129] although load shedding remains a risk if the region experiences sustained cold weather and multi-day major resource outages (ISO-NE Winter Analysis). The ISO-NE Winter Analysis also considered whether ISO-NE needs changes to its market rules this winter to incent fuel procurement, as discussed below. The ISO-NE Winter Analysis included information from fuel surveys, discussions with resource owners, and replenishment strategies for facilities with stored fuel capabilities. It also modeled different scenarios to evaluate regional energy adequacy under various assumptions and operating conditions.

Among other things, the ISO-NE Winter Analysis evaluated two ISO-NE programs that incent fuel procurement—the Winter Reliability Program (WRP) and the Inventoried Energy Program (IEP).[130] The WRP compensates oil-fired generators for unused fuel at the end of winter. The IEP, approved by the Commission for winters 2023-2024 and 2024-2025, is under revision at ISO-NE to implement a federal appeals court decision, and compensates resources for up to three days of inventoried energy, which is energy stored on-site (oil in a tank) or offsite (an LNG contract) and which can be converted to electric energy at ISO-NE's direction, among other conditions. The region relies on its significant fuel-oil generating capability—approximately 12,700 MW of winter capacity—to help offset some of its risk from natural gas disruptions; sufficient oil inventories are essential for ensuring oil-fired generation is available when needed.

ISO-NE concluded that the WRP and IEP should not be implemented for winter 2022-2023, as the costs of the programs, estimated at $160 million, outweigh the minimal expected reliability benefits, even during extreme weather conditions. The determination was primarily based on the conclusion that current market fundamentals already incent generators to procure fuel for their facilities prior to the start of winter. In fact, according to ISO-NE, conversations with resource operators indicate that fuel oil inventories are being refilled

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related to energy and works closely with Department of Homeland Security to provide input into how energy supplies impact national defense interests.

[128] ISO-NE, *Winter 2022/23 Analysis* (July 2022) at 2, https://www.iso-ne.com/static-assets/documents/2022/07/a09_mc_2022_07_12-14_winter_2022_2023_presentation.pptx.

[129] ISO-NE defined a mild winter scenario as represented by the 2021/22 winter season and a moderate winter scenario as represented by the 2017/18 winter season. At 13, ISO-NE, *Winter 2022/23 Analysis* 13 (July 14, 2022), https://www.iso-ne.com/static-assets/documents/2022/07/a09_mc_2022_07_12-14_winter_2022_2023_presentation.pptx.

[130] Descriptions of these programs can be found here: https://www.iso-ne.com/committees/key-projects/implemented/winter-energy-security-initiatives.

without implementation of the WRP and IEP, and resource operators expect to continue their fuel oil procurement into winter.[131]

In assessing the need for the WRP and IEP this winter, ISO-NE considered other programs that enhance resource adequacy and situational awareness. First, ISO-NE delayed the retirement of the Mystic 8 and 9 natural gas-fired units through a cost-of-service agreement, which also preserved LNG import capacity and contracted volumes through the Everett LNG facility used to serve the Mystic units. Second, ISO-NE continues to refine a 21-day energy assessment process,[132] which improves ISO-NE's and resources' ability to prepare for extreme weather. Third, ISO-NE's Pay for Performance market rules provide incentives for resources that perform during capacity-scarcity conditions.[133] Finally, ISO-NE implemented the Energy Market Opportunity Cost project to enhance dispatch of oil-fired and dual-fuel generators with short-term supply limitations and to preserve fuel-constrained generating units until operating conditions warrant dispatching them.[134]

While fuel oil inventories are being filled without additional incentives and new programs have been put in place that promote reliability, New England nonetheless faces a risk that sustained cold weather could interrupt electric supply in the region. The Commission recognizes the risks to reliability and markets in New England and hosted the above-noted New England Winter Gas-Electric Forum to engage with the region about the challenges it faces in upcoming winters. The conference docket is open, and the Commission is still taking comments.[135]

Pipeline Outages and Changes in Southern California and the Desert Southwest

Southern California may find natural gas supplies reduced in winter 2022-2023. Similar to last winter, El Paso Natural Gas (El Paso), one of the two largest interstate natural gas pipelines between the Permian Basin and California, remains under a force majeure that has reduced pipeline capacity. The force majeure was put in place after an explosion occurred on Line 2000 near Coolidge, Arizona, roughly 60 miles southeast of Phoenix,

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[131] ISO-NE, "New England Winter Gas-Electric Forum," September 8, 2022, https://www.iso-ne.com/static-assets/documents/2022/09/ne_gas_electric_forum_presentations.pdf.

[132] Since December 2018, ISO-NE has implemented a 21-Day Energy Assessment Forecast, based on current system conditions, forecasted weather, load, generators' reports of stored-fuel inventories and emissions limitations, and status of fuel delivery systems. https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/21-Day-Energy-Assessment-Forecast-and-Report-Results.

[133] https://www.iso-ne.com/markets-operations/markets/forward-capacity-market/fcm-participation-guide/about-fcm-pay-for-performance-pfp-rules.

[134] https://www.iso-ne.com/participate/support/participant-readiness-outlook/emoc-project.

[135] FERC, *New England Winter Gas-Electric Forum* (Last Updated September 23, 2022), https://www.ferc.gov/news-events/events/new-england-winter-gas-electric-forum-09082022.

on August 15, 2021. El Paso has not provided an estimate for Line 2000's return to service, and the outage may last through winter 2022-2023.[136] The constraint continues to affect all customers downstream of the explosion, primarily in Arizona and Southern California.

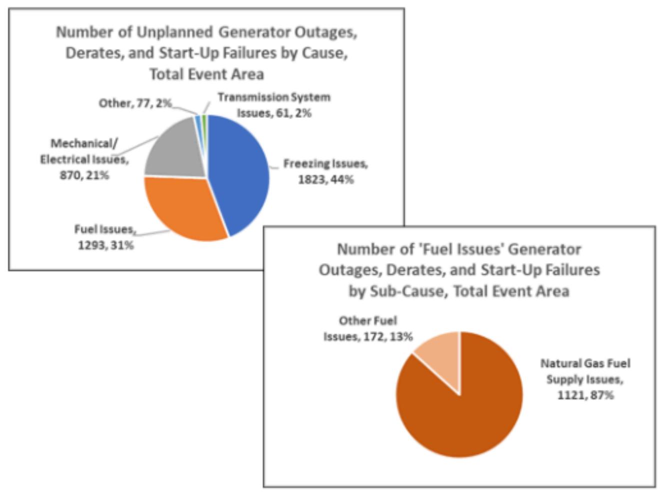
TC Energy's Baja Xpress Project, approved by the Commission in April, also has the potential to affect natural gas supply to California by shifting natural gas supply from California to Mexico.[137] The project, which interconnects with El Paso, will add approximately 0.5 Bcfd of natural gas delivery capacity to the Energía Costa Azul LNG export terminal project along Mexico's Pacific coast, with service anticipated to start in fall 2022.

Winter Preparedness Progress

Joint Inquiry Report

February 2021's Winter Storm Uri affected millions of electricity customers in ERCOT, SPP, and MISO, as extreme and prolonged winter weather drove up natural gas and electricity demand for heating and led to widespread outages of critical natural gas and electric infrastructure in Texas and the south central U.S. The Joint Inquiry report[138] concluded that the controlled firm load shed event that followed was the largest in U.S. history, with a total of more than 23 GW of load shed. At the time, it was the fourth event in 10 years[139] that jeopardized bulk power system reliability due to unplanned generating unit outages that escalated because of cold weather.

Figure 16: Cold Weather Outages



Source: FERC-NERC-Regional Entity Staff Report: The February 2021 Cold Weather Outages in Texas and the South Central United States

The Report made 28 recommendations—9 of them "Key Recommendations"—to prevent

[136] El Paso Natural Gas Company, LLC, *Informational Postings* (accessed October 3, 2022), https://pipeline2.kindermorgan.com/Notices/NoticeDetail.aspx?code=EPNG&notc_nbr=615714&date=8/22/2022&subject=&notc_type=-1&notc_sub_type=-1&notc_ind=C.

[137] *North Baja Pipeline, LLC*, 179 FERC ¶ 61,039 (2022).

[138] FERC, *The February 2021 Cold Weather Outages in Texas and the South Central United States | FERC, NERC and Regional Entity Staff Report* (November 16, 2021), https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and.

[139] See Report at 9, Footnote 5.

recurrence of problems, such as the ones experienced during Winter Storm Uri. FERC, NERC and Regional Entity staff from the report team formed a sub-team that has been tracking government and industry responses to the recommendations since the report's November 2021 issuance. Some of the more noteworthy developments are summarized below:

- Key Recommendation 1 included ten proposals for new mandatory Reliability Standards requirements for generator winter readiness—specifically to withstand extreme cold weather conditions, such as what was experienced during Uri, and for improved grid emergency operations. NERC commenced Standards development "Project. 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination" on November 22, 2021, soon after the report's issuance, to develop the Standards. NERC plans to file proposed new Standards responding to approximately half of Recommendation 1 with the Commission before this winter, with the remainder to be filed with the Commission by winter 2023-2024.[140]

- In response to Key Recommendation 3, the Commission and NERC held a joint technical conference on April 27-28, 2022, focused on improving generating unit cold weather reliability.[141]

- In response to Key Recommendation 7, which recommended a gas-electric forum to discuss ways to improve gas-electric coordination, the Commission convened a Commissioner-led forum on September 8, 2022, to discuss the electricity and natural gas challenges faced historically during New England winters and discussed the stakeholders' differing expectations of challenges for future winters, including what steps in understanding the challenges may be needed towards identifying solutions.[142]

- Also, in response to Key Recommendation 7, the North American Energy Standards Board has convened a Gas-Electric Harmonization Forum, working with Commission, NERC staff and NARUC. The forum kicked off on August 30, 2022, and held its first of four meetings planned for this fall on September 23, 2022, with aim to develop concrete actions and associated plans for implementing them.[143]

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[140] NERC, *Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination* (September 2022), https://www.nerc.com/pa/Stand/Pages/Project-2021-07-ExtremeColdWeather.aspx.

[141] FERC, *FERC, NERC and Regional Entities Technical Conference: Improving Winter-readiness of Generating Units* (Last Updated May 5, 2022), https://www.ferc.gov/news-events/events/ferc-nerc-and-regional-entities-technical-conference-improving-winter-readiness.

[142] FERC, *New England Winter Gas-Electric Forum* (Last Updated September 23, 2022), https://www.ferc.gov/news-events/events/new-england-winter-gas-electric-forum-09082022.

[143] FERC, *NAESB Gas-Electric Forum* (Last Updated September 20, 2022), https://www.ferc.gov/news-events/events/naesb-gas-electric-forum-september-23-2022-09232022.

- Seventeen recommendations have been incorporated into NERC committees' and task forces' work plans, and FERC, NERC and Regional Entity Staff are working with NARUC staff and committees on an additional eight recommendations that are within state jurisdiction.

Regional Activities

Along with the activities related to the Joint Inquiry team, all regions are taking additional actions based on state or enhanced internal RTO/ISO guidance. These activities are separate from the Inquiry Team recommendations. Overall, Regional Entities report further enhancements to internal winter preparedness programs in the areas of situational awareness tools, site specific generator preparedness plans, system reliability and resiliency, fuel supply, and communications. Each region also coordinates with other regions external to its own system to address potential electric deliverability issues associated with extreme weather events. Efforts are aimed at enhancing communications and operator preparedness through coordinated communications with neighboring Balancing Authorities or RTO/ISOs. Most regions report that Winter Readiness Workshops will be held prior to the season. NERC also hosted a Winter Prep for Severe Cold Weather Webinar[144] on September 1, 2022, to prepare for the upcoming winter weather. This webinar included lessons learned from recent severe cold weather events and effects on generation resources, the Generating Unit Winter Weather Readiness Reliability Guidelines, and 2022-2023 winter items of interest for generators.

ISO-NE: The *Winter Readiness in New England* section of this report profiles ISO-NE in greater detail.

NYISO: NYISO's annual fuel survey of generators to assess any potential winter shortfalls is scheduled to be completed in late October 2022. NYISO's 2022 Fuel and Energy Security project[145] will provide additional monitoring and analysis enhancements, including both fuel supplies and winterization actions generators are taking, such as dual-fuel operation, cold weather preventative maintenance, fuel procurement arrangements and fuel switching capabilities and coordination with transmission and maintenance outages to mitigate any reliability impacts during extreme cold weather periods. NYISO typically releases a Winter Operating Study and hosts a pre-Winter workshop annually in November.[146]

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[144] NERC, Winter Weather Prep Webinar. September 1, 2022, https://www.nerc.com/pa/RAPA/Lists/RAPA/DispForm.aspx?ID=465.

[145] NYISO is concerned that future changes to New York's fuel supply mix as well as the expected increases in winter peak loads due to electrification may challenge the ability to meet electric system demands under certain stressed system conditions, such as a prolonged cold weather event and/or natural gas supply/transportation disruptions. Depending on the results of the study, the NYISO would facilitate the subsequent development of recommendations for potential operational and/or capacity and energy market enhancements necessary to achieve desired improvements in grid resilience as related to fuel and energy security. NYISO *2021-2022 Fuel & Energy Security Update*, June 2022.

[146] NYISO Winter 2021-2022 Operating Study, https://www.nyiso.com/documents/20142/3691300/Winter2021-22-Operating-Study-Approved-OC_11-12-2021.pdf/711bcd39-c03a-3a98-8045-32b4ef2e4288.

PJM: PJM has also taken several winter preparedness actions, including distributing data requests to Generator Owners, to capture winter readiness activities and ambient temperature limitations. PJM also continues to monitor potential impacts of fuel and non-fuel consumables supply and delivery status on generation resources by issuing periodic data requests to all thermal generation resources. And finally, PJM has begun bi-directional seasonal transfer studies with adjacent Balancing Authorities. On October 7, 2022, PJM briefed its Operating Committee on Generation Resource Cold Weather Preparation.[147] This included a number of initiatives, including Pre-Winter Reactive Capability Verification; Cold Weather Checklist; Seasonal Fuel Inventory and Emissions Data Request; NERC Webinar and Additional Mechanisms for PJM Situational Awareness. PJM notes it is not hosting a Cold Weather Exercise this year, and generation resources are asked to self-schedule any testing required.

SERC: In the SERC region, entities may consider minimizing hourly natural gas flows at the plant to ensure pipeline pressure is available when needed during the peaks, and entities are also actively managing their coal inventory levels and supply chain to ensure fuel availability for the winter peak. SERC utilities are conserving coal for winter reliability and resiliency by minimizing coal burn and by limiting coal generation this fall. They are also actively working with their coal suppliers to restock inventory. Additionally, for oil generators, the SERC entities maintain adequate on-site inventory levels at each oil-fired plant and utilize their firm pipeline transportation and fuel oil capacity to meet their expected load demand. SERC is hosting its 2022 Extreme Weather Webinar[148] on October 20, 2022, and focuses on Generator Owners/Operators, Transmission Operators, Balancing Authorities, and Reliability Coordinators as well as Registered Entity staff that have weather related duties or a role that is impacted by extreme weather, including compliance, security, and recovery. The webinar objectives will discuss previous extreme weather events and lessons learned; the ongoing hurricane season; the available winter outlook; and cold weather preparations and useful material to aid entities.

MISO: Overall, MISO continues to monitor and prepare for potential localized reliability challenges driven by extreme weather conditions using multiple methods. First, MISO continues to survey and coordinate with its members on winter preparedness and fuel sufficiency via a Generation Winterization Survey[149] due by September 27, 2022. This survey combines prior generator and gas surveys into a single response and is designed to focus on quantitative and forward-looking questions. MISO is also currently conducting studies for its Coordinated Seasonal Assessments for Winter 2022-23, which includes transfer studies with neighboring Balancing Authorities.

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[147] https://www.pjm.com/-/media/committees-groups/committees/oc/2022/20221007/item-16---generation-resource-cold-weather-preparation.ashx.

[148] https://www.serc1.org/outreach/events-calendar/event-details?id=9a6ae1fb-c0ed-4700-8dc2-2ddc28c4724a.

[149] MISO Generator Winterization Survey August 23, 2022, https://cdn.misoenergy.org//2021%20MISO%20Generator%20Winter%20Survey%20Info585898.pdf.

In addition, MISO has a Winter Readiness Workshop[150] scheduled for October 20, 2022, to discuss its generation and transmission assessment for Winter 2022-23, review applicable operating procedures and communications processes during abnormal and emergency conditions, and to present other topics related to seasonal operations. The agenda will cover the following topics: Global Gas Markets, Preparedness/Readiness, Seasonal Assessment, Annual Generation Winterization Survey Results, Weekly Fuel Consumables Data Request, Reliability Imperative, Emergency Procedures, Coal Transport Update, and a Gas Pipeline Update. MISO also continues to coordinate extensively with neighboring Reliability Coordinators and Balancing Authorities to improve situational awareness and assess any needs for firm or non-firm transfers to address extreme system conditions. MISO recognizes the follow up actions to these items as important next steps in ensuring winter readiness.

SPP: SPP's independent board directed staff and stakeholders to conduct a comprehensive review of the organization's response to the February 2021 event. The review yielded seven key observations and 22 recommendations to help SPP learn, mitigate, and be better prepared for future extreme reliability threats. The comprehensive review evaluated hundreds of process changes, system enhancements, new and amended policies, assessments, and other solutions to address the event's root causes and enable SPP and its stakeholders to improve their response to future extreme system events. SPP's board approved 22 actions, policy changes and assessments to address issues related to fuel assurance, resource planning and availability, emergency response, communications, and other critical areas. SPP also created the Improved Resource Availability Task Force (IRATF), which took primary responsibility for addressing Tier 1 recommendations related to fuel assurance and resource planning and availability identified in the Comprehensive Review of SPP's Response to the February 2021 Winter Storm report.[151] SPP will host its annual Winter Preparedness Workshop,[152] scheduled for November 9, to help inform members of forecasted conditions of the upcoming season, field concerns and discuss mitigations from members, and review SPP's seasonal preparedness steps outlined in its operating procedures.

ERCOT: In addition to the items noted in the *Probabilistic Assessment and Regional Analysis* section of this report, ERCOT was directed by the Public Utility Commission of Texas (PUCT),[153] to address specific winter preparedness efforts. ERCOT conducted 324 weather preparedness inspections during 2021, covering 302 generation sites and 22 Transmission Service Providers. These inspections focused on whether each reporting

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[150] https://www.misoenergy.org/events/2022/winter-readiness-workshop---october-20-2022/.

[151] The Improved Resource Availability Task Force (IRATF) will take primary responsibility for addressing Tier 1 recommendations related to fuel assurance (FA) and resource planning and availability (RPA) identified in the Comprehensive Review of SPP's Response to the February 2021 Winter Storm report as approved by the July 26, 2021, SPP Board of Directors Meeting. https://www.spp.org/stakeholder-groups/organizational-groups/regional-state-committee/improved-resource-availability-task-force/.

[152] https://www.spp.org/events/calendar/2022-23-winter-preparedness-workshop-and-ecuf-meeting-2022-11-09/.

[153] Rule 25.55 (16 TAC § 25.55), finalized on October 19, 2021, which established a first phase of weather emergency preparedness standards for generation and transmission facilities.

entity performed the weatherization activities described in their Winter Weather Readiness Reports required by the PUCT. Also, ERCOT has been working with the PUCT on developing phase II of the preparedness standards, which address both winter and summer preparedness compliance.

Additionally, on August 30, 2022, the Railroad Commission of Texas (RRC), which regulates the Texas oil & gas industry, approved its Final Rule[154] on weather emergency preparedness standards for designated "critical gas facilities" in the State's new Electricity Supply Chain Map.[155] This rule became effective September 19, and applies to operators of gas supply chain facilities and gas pipeline facilities[156] included on the Map.[157] RRC inspectors will begin inspecting facilities to determine compliance beginning December 1, 2022, based on submitted compliance attestations. Inspections will focus on infrastructure that produces, stores, processes, or transports large volumes of natural gas, prioritized by facility size. Administrative violations could carry fines of up to $1 million.

While ERCOT does not expect emerging reliability issues for the upcoming winter associated with fuel supplies, through a request for proposals, it is seeking to procure 3,000-4,000 MW of Firm Fuel Supply Services at a cost not to exceed $54 million for an obligation period from November 15, 2022, through March 15, 2023.[158] On October 7, ERCOT reported the results of this request for proposals[159] and announced that it procured 2,940.5 MW from 19 generators to provide storage of backup fuel to ensure natural gas generators can operate for 48 hours even in the event of gas supply curtailments or other fuel supply interruptions. This service was developed consistent with directives from the Texas Legislature requiring ancillary or reliability services to address reliability during extreme cold weather conditions and the PUCT order for ERCOT to develop a firm-fuel product that provides additional grid reliability and resiliency during extreme cold weather

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[154] Railroad Commission of Texas memorandum, August 30, 2022, Relating to Weather Emergency /Preparedness Standards, https://www.rrc.texas.gov/media/c5hdc4ga/rule-3-66.pdf.

[155] Texas First-Ever Electricity Supply Chain Map, https://www.puc.texas.gov/agency/resources/pubs/news/2022/042922-Joint-RRC-PUC-Map-press-release.pdf.

[156] RRC has requested the rule to be modified to only cover gas wells producing over 250 Mcf/d, up from the original 15 Mcf/d limit established last year, and oil-directed leases producing more than 500 Mcf/d in gas, up from an original 50 Mcf/d limit. Published Texas Register September 16, 2022. / Comment period closed October 7, 2022 https://www.sos.state.tx.us/texreg/pdf/backview/0916/0916prop.pdf.

[157] RRC, Notice to Oil & Gas and Pipeline Operators: Weather Emergency Preparedness Standards, https://www.rrc.texas.gov/announcements/09192022-notice-to-oil-gas-and-pipeline-operators-weather-emergency-preparedness-standards/.

[158] ERCOT Firm Fuel Supply Service Program, June 30, 2022, Request for Proposal, https://www.ercot.com/files/docs/2022/10/07/Request_for_Proposal_posted%20to%20ERCOT.com.docx.

[159] All 19 Generation Resources were awarded at a clearing price of $6.19/MW/hr. ($18,000/MW) and the total cost of procurement was $52,857,722.28. https://www.ercot.com/services/programs/firmfuelsupply.

and compensates generation resources that meet a higher resiliency standard. ERCOT is also hosting two Winter Weather Preparedness Workshops on October 25, for generation resources and transmission providers.[160]

WECC: To enhance winter preparedness, WECC held a Winter Readiness[161] webinar on September 15, 2022, to coordinate with stakeholders. This event discussed WECC's 2022 Reliability Risk Priorities, Extreme Natural Events, and covered the following topics: Winter Weather Lessons Learned and Best Practices; Generator Owner, Generator Operator Communications and Changes to NERC's Winter Weather Readiness Guidelines; Feedback on Winter Storm Uri by Texas Reliability Entity, Inc; FERC and NERC Winter Weather Report and Recommendations; Winterization and Internal Controls—Enterprise Asset Management Software; ReliabilityFirst's Winterization Program: Site Visits, Best Practices, and Surveys; CAISO Cold and Extreme Weather Contingency Planning Task Force Update; NERC Cold Weather Preparation Resources; and WECC's Winter Preparation Checklist "More Than Flipping a Switch".

Conclusion

The operation of the electricity and natural gas systems this winter could be impacted by extreme weather and changing natural gas market fundamentals. Natural gas exports are forecast to continue growing, which will place upward pressure on natural gas demand this winter. However, growth in natural gas demand is not expected to outpace growth in production this winter.

Forecasts show electricity market operators will have sufficient capacity to maintain reliable operations this winter, under normal winter conditions. All regions anticipate adequate reserve margins, although extreme winter events may stress operations. Coal supply constraints may affect coal deliveries and coal stockpiles this winter across those regions that have relied on increased coal-fired dispatches during recent stress periods, including SPP, MISO, ERCOT, SERC and PJM. Finally, despite challenges associated with constrained natural gas import capacity, ISO-NE expects to maintain reliability this winter under mild and moderate winter conditions and has concluded it does not need a dedicated winter reliability program, unlike in past years.

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[160] ERCOT Winter Weatherization Workshop for Generation Resources; ERCOT Winter Weatherization Workshop for Transmission Service Providers, October 25, 2022, https://www.ercot.com/calendar.

[161] https://www.wecc.org/Lists/WECCMeetings/DispForm.aspx?ID=16531.