BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-29:
FERC Staff Winter Reliability Assessment

Winter Energy Market and Electric Reliability Assessment

2025-2026

A Staff Report to the Commission

November 20, 2025

FEDERAL ENERGY REGULATORY COMMISSION

Office of Technical Reporting and Economics

Office of Electric Reliability

Preface

Slide 1

The 2025-2026 Winter Energy Market and Electric Reliability Assessment (Winter Assessment) provides Commission staff's outlook for this winter – December 2025 to February 2026. It focuses on energy markets and electric reliability. The report contains four main sections. The first summarizes the findings of the Winter Assessment. The second details the weather outlook for the upcoming winter. The third discusses notable considerations for the upcoming winter. The last section discusses energy market fundamentals, primarily natural gas and electricity supply and demand expectations.

The 2025-2026 Winter Assessment is a joint product from the Commission's Office of Technical Reporting and Economics and the Office of Electric Reliability.

Winter Outlook

Slide 2

Winter Outlook

- Slightly warmer conditions expected in the southern and eastern U.S.
- Natural gas prices 26% higher compared to previous winter despite increased production.
- Electricity demand growth supported by generation and transmission additions.
- Resources and operating reserves adequate in all NERC assessment areas for normal winter conditions.
  - Possible reliability challenges in ERCOT, NPCC-NE, SERC-Central, SERC-East, WECC-Basin, and WECC-NW in extreme winter conditions

Winter Outlook In Summary

This winter, slightly warmer temperatures are expected compared to last winter, potentially contributing to lower domestic natural gas and electricity demand. A prolonged cold weather event could still affect prices and availability of natural gas and electricity. Drought and elevated wildfire risk conditions are forecast to continue in multiple regions and could affect grid operating conditions and reliability.

Notwithstanding the forecasted slightly warmer temperatures, natural gas prices are expected to rise slightly compared to last winter. As of November 4, futures prices for the Henry Hub national benchmark averaged $4.39/Million British thermal units (MMBtu), 26% higher than winter 2024-2025 settled prices. Total U.S. natural gas demand is forecasted to exceed production this winter, as in previous winters, with the difference met by storage inventory withdrawals. While warmer weather could cause residential and commercial demand to decline, net exports are expected to continue their long-term growth trend. Natural gas storage inventories began the withdrawal season above the five-year average but marginally below the starting level of last winter, which was the highest since 2016. Overall natural gas storage inventories are forecasted to remain relatively robust throughout the winter.

Electricity markets will see generators add 56.1 GW of net winter capacity nationwide, compared to last winter, with 64.7 GW of new additions offset by 8.6 GW of retirements. Solar and batteries comprise 80% of new capacity additions, while coal and natural gas will account for 88% of retired capacity. Winter electricity consumption is projected to be 2.7% above the five-year average, with total monthly consumption expected to peak in January at 352 TWh. If realized, the projected consumption for this winter (1,035 TWh) will represent the second-highest level of the past five years, second only to last winter's record of 1,041 TWh.

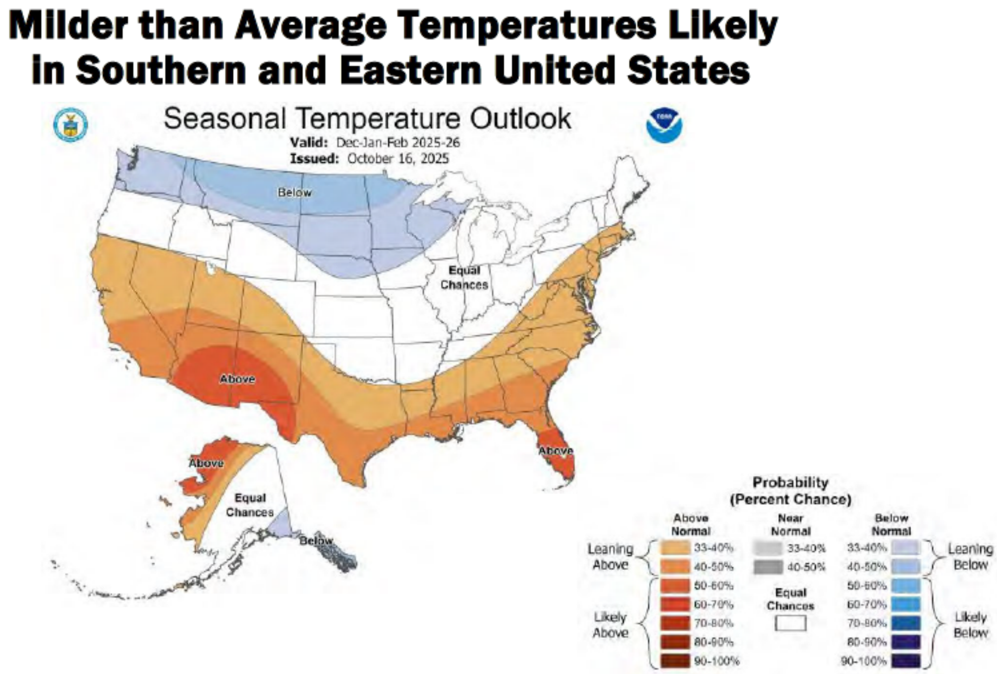
To support the grid, 3,132 new electric transmission projects totaling 19,008 miles of line will be available this winter. Of this total, 14,736 miles were placed in service between March and November 2025, with another 4,272 miles expected to be completed between December 2025 and February 2026. The primary drivers for these projects nationwide are storm and fire hardening (7,101 line-miles) and system reliability (4,238 line-miles), which together account for nearly 60% of all projected mileage. Other significant drivers include load growth (2,785 line-miles), asset renewal (2,738 line-miles), and generation interconnection (903 line-miles).

While the costs to produce electricity have remained relatively stable, in recent winters uplift payments have increased significantly during extreme weather or as a result of proactive operator actions taken to maintain reliability and continue to serve load.

Looking at the broader picture, all North American Electric Reliability Corp. (NERC) assessment areas are expected to have adequate generating resources to meet expected winter demand and operating reserve requirements under normal operating conditions. Under extreme weather conditions, the Electric Reliability Council of Texas (ERCOT), Northeast Power Coordinating Council-New England (NPCC-NE), SERC Reliability Corp.-Central (SERC-Central), SERC-East, Western Electricity Coordinating Council-Basin (WECC-Basin), and WECC-Northwest (WECC-NW) face a higher likelihood of tight generation availability, which may require operational mitigations to prevent potential reliability issues. However, NERC and the assessment areas have initiated various activities, such as readiness surveys of generators and facility inspections, to prepare for winter and increase the likelihood of their continued operation in the event of severe winter weather.

Weather

Slide 3



Weather Outlook

For the upcoming winter, the National Oceanic and Atmospheric Administration (NOAA) is predicting a weak La Niña phenomenon. La Niña refers to the large-scale, ocean-atmosphere climate phenomenon characterized by periodic cooling in sea-surface temperatures across the central and east-central equatorial Pacific. Based on the prediction, NOAA expects mildly wetter-than-average conditions in the northern Mountain West and Ohio River Valley regions and mildly drier-than-average conditions in the southern United States. As shown by the blue colors in the map on **Slide 3**, NOAA expects mildly colder-than-average temperatures in the Pacific Northwest and northern Midwest. The orange colors indicate mildly warmer-than-average temperatures along the East Coast, extending down through the South and West into the Desert Southwest and into California. The rest of the continental United States – shown in white – has equal chances of above or below average temperatures this winter. For its part, the U.S. Energy Information Administration (EIA) expects the population-weighted number of nationwide Heating Degree Days[1] in December, January, and February to decrease by 8% relative to last winter. This decrease reflects a slightly warmer winter nationwide.

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[1] Heating Degree Days are a measure of how cold a location is on a given day or during a period of days. A Heating Degree Day compares the mean (the average of the high and low)

It is important to note that NOAA's long-range predictions are dynamic and may change as more data becomes available. Furthermore, extreme winter storms, such as polar vortexes, are difficult to predict far in advance and are typically forecasted much closer to the event dates.

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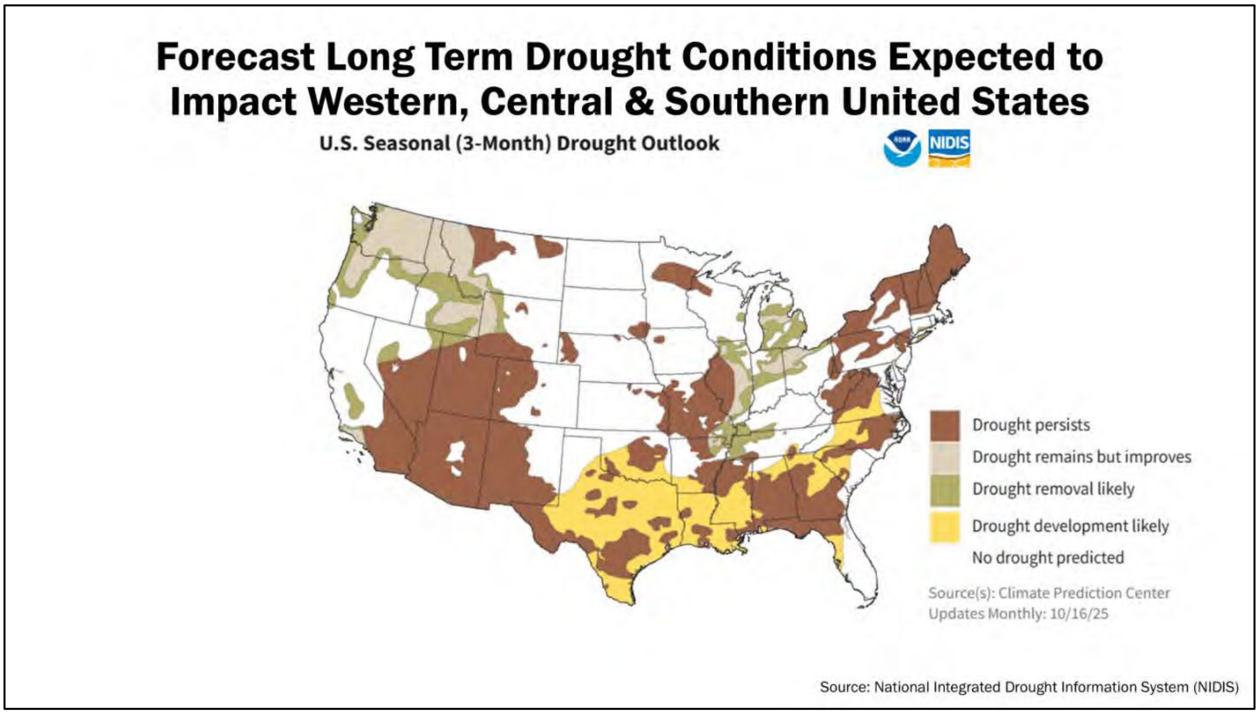
outdoor temperatures recorded for a location to a standard temperature, 65° Fahrenheit (F) in the United States. The colder the temperature, the higher the number of heating degree days. Natural gas is sometimes traded in a "Winter Strip" between November and March, which may have a different HDD forecast trend due to the two additional months.

Slide 4



Weather – Drought Condition Impacts

Drought conditions, illustrated by the dark brown areas in the map on **Slide 4**, persist across much of the western and central United States and are expected to continue into winter. If below-average snowfall, runoff, or conditions similar to this past spring occur this winter, significant impacts to water supplies in multiple basins are possible. Based on the La Niña forecast and current conditions, drought persistence is likely in the Southwest. This puts water basins in the southwestern United States at an especially high risk of water shortage impacts in early to mid-2026. In the South-Central and eastern regions of the United States, drought development, shown in yellow, is expected. Finally, minimal drought improvement, shown in tan and green, in the Pacific Northwest is also forecast for this winter.[2]

This winter, these dry conditions in the West are expected to reduce output from a significant portion of hydroelectric resources in WECC, including those in the Colorado River and Yakima Basins. Output in the Pacific Northwest will also continue to be limited. In early fall, reservoir levels throughout the western United States dropped sharply because withdrawals occurred at a greatly accelerated rate. For example, withdrawals in Utah were at twice the

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[2] NOAA, National Integrated Drought Information System, *The Western Drought Issue* (Sept. 3, 2025), https://www.drought.gov/news/western-drought-issue-2025-09-03.

typical rate and high withdrawals ended the water year[3] several weeks early in multiple irrigation districts in Washington state. If key headwaters do not receive above-average precipitation, it will not be possible to restore water supplies in the Pacific Northwest, Colorado and Great Basins to previous historical levels. The Colorado River Basin lost about 27.8 million acre-feet of groundwater between 2002-2024, roughly equal to the storage capacity of Lake Mead. As a result, water levels in Lake Powell are expected to fall into a lower balancing tier this winter, requiring reductions in output at the Glen Canyon Dam. Forecasts indicate that water levels could fall low enough to stop hydropower generation at the reservoir within the next year.[4] Impacts are also expected at downstream facilities, including at Hoover Dam, which is forecast to be in a Level 1[5] shortage condition this winter and fall to a Level 2[6] shortage by early spring 2026. This puts water basins in the southwestern United States at an especially high risk of water shortage impacts in early to mid-2026.

Also notable this winter, drought conditions are expected to continue in the central and southern United States. In the Mississippi River Basin, drought and extremely dry conditions have rapidly expanded due to above-average temperatures and low rainfall. As the region is entering what is typically a drier period, without significant and widespread rainfall, drought is expected to persist and expand across a significant portion of the Mississippi River Basin through December 31, 2025. For example, the Ohio River typically contributes 50% of the Mississippi River's flow. Recently, the Ohio River contribution fell to 8%.[7] These low water levels have impacted small hydroelectric facilities and restricted navigation, which could affect fuel transportation for some coal generators. Further downstream, low water levels on the Mississippi River may lead to the risk of saltwater intrusion and high-water temperatures, which could pose operational risks to thermal generators that use once-through-cooling

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[3] A water year is defined as October 1 to September 30 for surface water reports and water allocation planning.

[4] Bureau of Reclamation, *24-Month Study Inflow Scenarios* (Aug. 15, 2025), https://www.usbr.gov/uc/water/crsp/studies/images/PowellElevations.pdf.

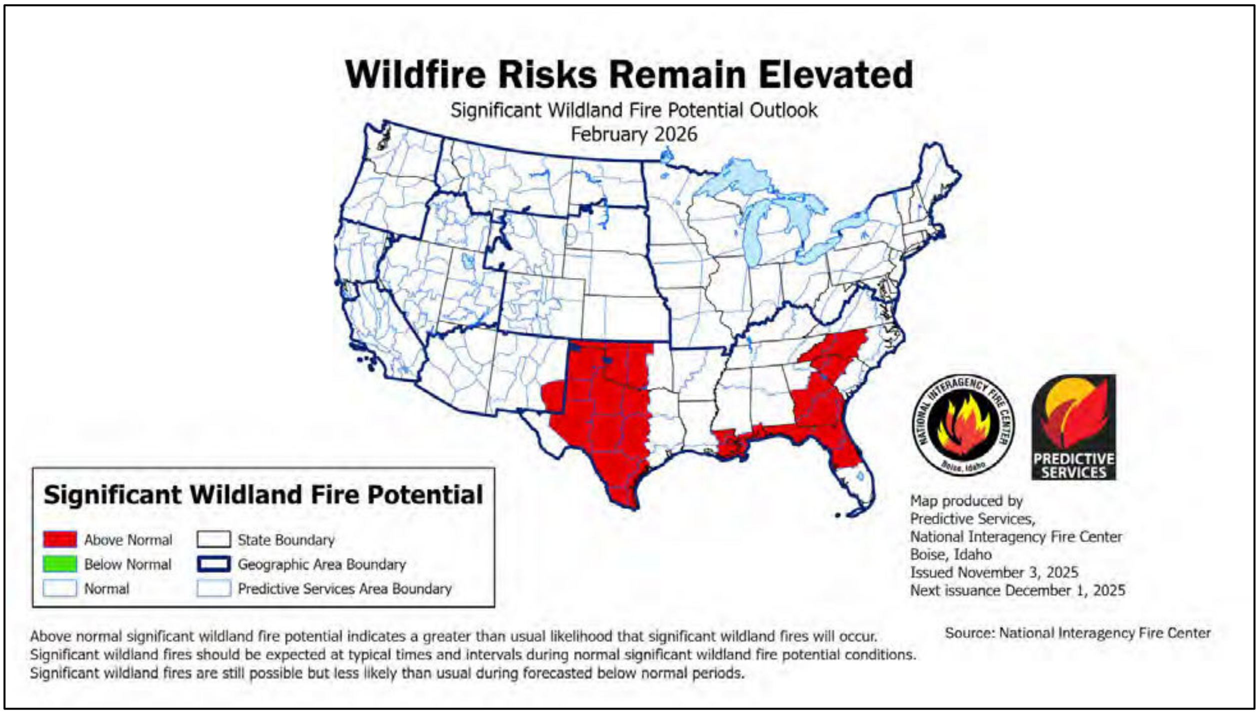
[5] A Level 1 Shortage Condition is triggered when Lake Meade's elevation falls below 1,075 ft. under the *2007 Interim Guidelines and the Lower Basin Drought Contingency Plan* and reduces total deliveries to 7.167 million-acre-feet.

[6] A Level 2 Shortage Condition is triggered when Lake Meade's elevation falls below 1,050 ft under the *2007 Interim Guidelines and the Lower Basin Drought Contingency Plan* and reduces total deliveries to 7.083 million-acre-feet.

[7] NOAA, National Integrated Drought Information System, *Drought and Water Update for the Mississippi River Basin* (Sept. 18, 2025), https://www.drought.gov/drought-status-updates/drought-and-water-update-mississippi-river-basin-2025-09-18.

equipment. While temperature and water level impacts are possible all along the river, salinity impacts are most likely for generators located in high-demand areas at the mouth of the river in southern Louisiana.

Slide 5



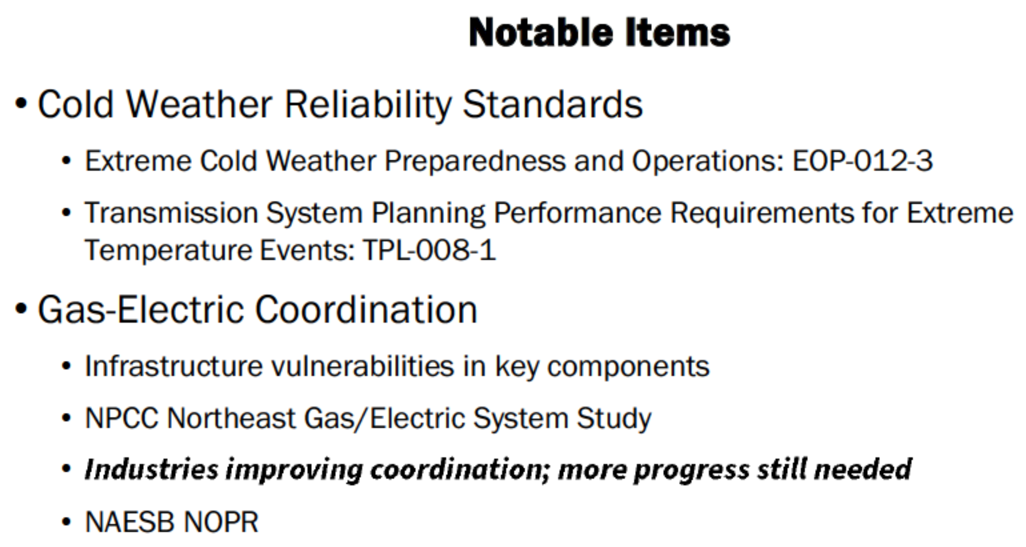
Weather – Wildfire Risk

Due to persistent high temperatures and a lack of rainfall in the western, central and southern United States, the risk of wildfires remains elevated in several states. Specifically, as indicated by the red areas on the map on **Slide 5**, risks remain elevated throughout Texas as well as in the Southeast from Louisiana to Florida and up through the Carolinas. These regions all experienced persistent drought, high temperatures, and dry conditions from late summer into fall. They experienced similar circumstances at the start of last winter.

This elevated wildfire risk can translate to significant infrastructure and operational risks for utilities. During dry conditions, utilities may temporarily turn off power to specific areas through a practice known as a public safety power shutoff. This is done to reduce the risk of electrical infrastructure starting a fire or to protect equipment from damage by nearby fires. While shutoffs have been used primarily in western states, they are now increasingly used in other regions to mitigate wildfire risk, including the central United States (South Dakota and Minnesota) and eastern states such as New Jersey. Wildfires can also cause significant electric transmission disruptions, potentially leading to extended outages due to damage to grid equipment or supporting infrastructure.

Notable Items

Slide 6



Cold Weather Reliability Standards

As winter 2025-2026 approaches, NERC Reliability Standards for generator winterization plans are becoming enforceable, and new additional requirements will require generator owners and operators to implement plans to remain operational in extreme cold temperatures. This is a shift from the now-retired Reliability Standard EOP-012-2 (Extreme Cold Weather Preparedness and Operations),[8] which mandated that generator owners and operators develop and implement extreme cold weather preparedness plans by winter 2025-2026. Its successor, Reliability Standard EOP-012-3,[9] additionally requires existing generators to begin implementing their plans to operate at their calculated unit's Extreme Cold Weather

[8] The purpose of this Reliability Standard was to address the effects of operating in extreme cold weather by ensuring each Generator Owner has developed and implemented plan(s) to mitigate the reliability impacts of extreme cold weather on its applicable generating units. *Order Approving Extreme Cold Weather Reliability Standard EOP-012-2 and Directing Modification*, 187 FERC ¶ 61,204 (2024).

[9] *Order Approving Extreme Cold Weather Reliability Standard EOP-012-3 and Directing Data Collection*, 192 FERC ¶ 61,229, at PP 34-37 (2025).

Temperature by October 1, 2025.[10] The Commission directed NERC to collect and submit generator owners' cold weather temperature reports detailing readiness for extreme conditions every May 15 beginning in 2025.[11]

Separately, Reliability Standard TPL-008-1 (Transmission System Planning Performance Requirements for Extreme Temperature Events) was approved earlier this year, with a phased implementation to begin in April 2026. Under this requirement, Planning Coordinators, in conjunction with their Transmission Planners, must conduct an extreme temperature assessment at least once every five years. These assessments evaluate future Bulk Electric System performance during extreme heat and extreme cold benchmark temperature events. The assessments required by this standard address a known reliability issue in which extreme temperatures cause operational failures by identifying vulnerabilities before those operational failures occur.[12]

Together, these standards will begin to help grid planners and operators anticipate and withstand any severe weather disruptions during winter 2025-2026.

Gas-Electric Coordination

Gas-electric coordination remains a critical focus for ensuring reliability across the electric grid, particularly during extreme cold weather events that could occur between December 2025 and February 2026. However, electric utilities, regional transmission organizations (RTOs), independent system operators (ISOs), and NERC have also taken actions to prepare for potential natural gas scarcity conditions based on lessons learned from past winter storms.

Cold weather vulnerabilities of natural gas infrastructure further compound risks to electric reliability. Cold weather-sensitive components such as electric-powered compressor stations and unprotected wellheads remain susceptible to freezing, and electrical or mechanical failures

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[10] Extreme Cold Weather Temperature refers to the lowest 0.2 percentile of the hourly temperatures measured in December, January, and February from 1/1/2000 through the date the temperature is calculated; NERC, Questions and Answers: Cold Weather Generator Data Request (Accessed Oct. 10, 2025), https://www.nerc.com/pa/comp/ColdWeatherGenDataDL/NERC_Cold_Weather_1600_DR_FAQ.pdf#:~:text=Extreme%20Cold%20Weather%20Temperature%20-%20The%20temperature,through%20the%20date%20the%20temperature%20is%20calculated.

[11] NERC, Questions and Answers: Cold Weather Generator Data Request (Accessed Oct. 10, 2025), https://www.nerc.com/pa/comp/ColdWeatherGenDataDL/NERC_Cold_Weather_1600_DR_FAQ.pdf#:~:text=Extreme%20Cold%20Weather%20Temperature%20-%20The%20temperature,through%20the%20date%20the%20temperature%20is%20calculated.

[12] *North American Electric Reliability Corporation*, 190 FERC ¶ 61,099, at PP 4-8 (2025).

at these points can disrupt natural gas deliveries to generating units during critical periods. While vulnerabilities at the production, gathering, and processing stages fall outside the Commission's jurisdiction, these vulnerabilities underscore the need for continued improvements in equipment winterization efforts and operational coordination.[13]

A study conducted by the NPCC, released on January 21, 2025, evaluated gas supply and pipeline constraints across New York and New England under extreme winter conditions. The study concluded that natural gas infrastructure in these regions is fully, or nearly fully utilized, during modeled cold weather events and found that any gas-side contingency, such as a pipeline disruption or a prolonged cold snap that affects gas production, could significantly stress the electric and natural gas systems and threaten electric grid reliability.[14]

On a positive note, the natural gas and electric industries have improved their coordination. For example, the performance of the Virginia-Carolinas Reliability Coordinator (VACAR) South region during the January 2025 Arctic cold wave illustrated notable gas-electric coordination.[15] According to a joint FERC-NERC report, improved performance in regions, including VACAR South, were made possible by enhanced coordination between pipeline operators and electric grid and generator operators, including proactive issuance of Operational Flow Orders[16] and real-time situational awareness calls.[17] Additionally, the same report highlights how natural gas infrastructure, including wellheads, compressor stations, and local distribution systems experienced minimal disruptions despite record-breaking demand of over 150 billion cubic feet per day (Bcfd). This marked improvement over previous winter storms was attributed to widespread winterization efforts and planned use of natural gas

[13] FERC, NERC, and its Regional Entities (a joint staff report), *January 2025 Events: A System Performance Review* (April 17, 2025), https://www.ferc.gov/media/report-january-2025-arctic-events-system-performance-review-ferc-nerc-and-its-regional.

[14] NPCC, *NPCC Northeast Gas/Electric System Study* (Jan. 3, 2025), https://www.npcc.org/news/npcc-northeast-gas-electric-system-study.

[15] VACAR is a division within the SERC Reliability Corporation that includes systems located in Virginia, North Carolina and South Carolina. VACAR South are the VACAR companies that are not located in the PJM BA area.

[16] An Operational Flow Order is a directive issued by a natural gas pipeline operator to maintain the operational integrity of the pipeline system during periods of imbalance. It typically occurs when forecasted pipeline inventory, either too high or too low, threatens system reliability.

[17] FERC, NERC, and its Regional Entities (a joint staff report), *January 2025 Arctic Events: A System Performance Review,* at 12 (April 17, 2025), https://www.ferc.gov/media/report-january-2025-arctic-events-system-performance-review-ferc-nerc-and-its-regional.

storage assets. The Mountain Valley Pipeline, which was placed into service in 2024, also played a pivotal role in maintaining electric reliability in VACAR South by sustaining stable pipeline pressure during peak demand. Additionally, some dual-fuel generators switched to alternate fuels to maintain gas system balance, while battery storage was used to alleviate stress on both the electric grid and pipelines during critical hours. Collectively, these actions demonstrate how targeted collaboration, infrastructure hardening, and flexible energy resources are beginning to close long-standing coordination gaps between the gas and electric sectors.[18]

To further strengthen gas-electric coordination, the North American Energy Standards Board (NAESB) Wholesale Gas Quadrant (WGQ) recently updated business practice standards collaboratively developed by NAESB's gas, electric, and retail working groups.[19] The Commission issued a proposed rule on October 16, 2025, that proposes to incorporate by reference into the Commission's regulations certain modifications and one new standard to Version 4.0 of the NAESB WGQ standards. These proposed modifications aim to improve transparency and situational awareness across the gas-electric interface by requiring interstate natural gas pipelines to publicly post scheduled quantity information for power plants directly connected to the pipeline grid, including their location, affiliated RTO/ISO, and total scheduled volumes.[20]

In summary, while infrastructure vulnerabilities continue to challenge gas-electric coordination, enhanced collaboration between the gas and electric industries along with improved winterization efforts have begun to close critical reliability gaps. As the natural gas

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[18] *Id.* at 2.

[19] The NAESB Wholesale Gas Quadrant Business Practice Standards Version 4.0 Revised were jointly developed on a consensus basis by NAESB's Wholesale Gas Quadrant, Wholesale Electric Quadrant, and the Retail Market Quadrant. The Wholesale Gas Quadrant includes the following five co-equal segments: Producers; Pipelines; Local Distribution Companies; End-users; and Services. The NAESB Wholesale Electric Quadrant includes the following seven co-equal segments: Transmission; Generation; Marketers/Brokers; Distribution/Load-Serving Entities; End Users; Independent Grid Operators/Planners; and Technology and Services providers. The NAESB Retail Market Quadrant includes: Retail Electric Service Providers/Suppliers; Retail Electric Utilities; Retail Electric End Users/Public Agencies; and Retail Gas Market Interests. For more information on the NAESB Quadrant Segments and Subsegments see: https://www.naesb.org/pdf/quadrant_description.pdf.

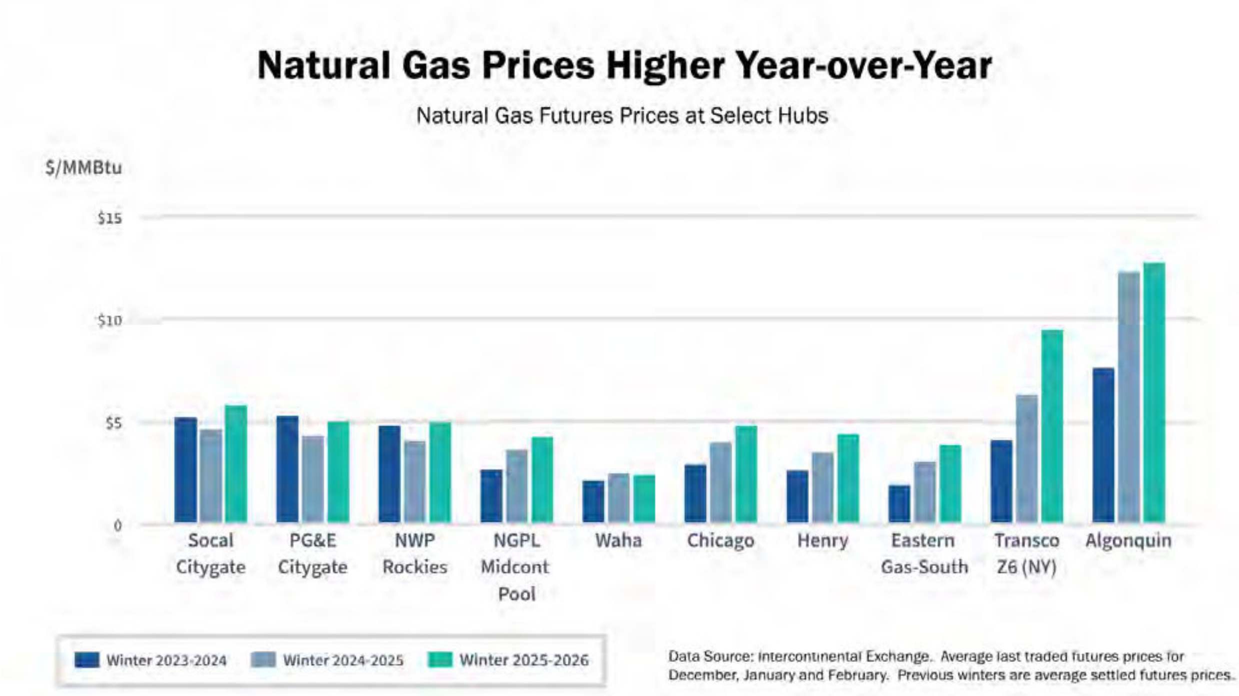
[20] *Standards for Business Practices of Interstate Natural Gas Pipelines*, Notice of Proposed Rulemaking, Docket No. RM96-1-044, (issued Oct 16, 2025).

and electric systems become more interdependent, sustained coordination between the two sectors will remain essential to safeguarding electric grid reliability.[21]

[21] For more on gas-electric coordination, see Chapter 3: Gas-Electric Interdependency, in FERC's *Energy Primer, a Handbook for Energy Market Basics,* http://www.ferc.gov/sites/default/files/2024-01/24_Energy-Markets-Primer_0117_DIGITAL_0.pdf.

Natural Gas Fundamentals

Slide 7



Natural Gas Prices

Natural gas futures provide expectations for natural gas prices at key hubs for the upcoming winter, as illustrated by the chart on **Slide 7**. The chart displays futures prices for three consecutive winters, with the light green bars representing futures prices for the upcoming winter (2025-2026) and the gray bars showing prices from last winter (2024-2025). In particular, natural gas futures in New England, New York, and California for winter 2025-2026 are currently trading higher than at other major hubs, and elevated natural gas demand is expected to drive prices higher on average across much of the United States. Heading into winter 2025-2026, higher natural gas futures prices at most major trading hubs across the United States are partly driven by rising futures prices at the Henry Hub national benchmark hub. **Slide 7** includes the Henry Hub, located in Louisiana, and nine other major supply and demand hubs in the Lower 48 States. As of November 4, Henry Hub futures averaged $4.39/MMBtu for this winter, up 26% from last winter's settled average of $3.49/MMBtu.[22]

[22] Natural gas futures prices are price quotations of contracts for the exchange of natural gas, as either a physical or financial settlement, at a specified time in the future. Winter futures prices in this section are the average quotes of the last traded futures contracts, as of November 4, 2025, for the winter months of December 2025, January 2026, and February

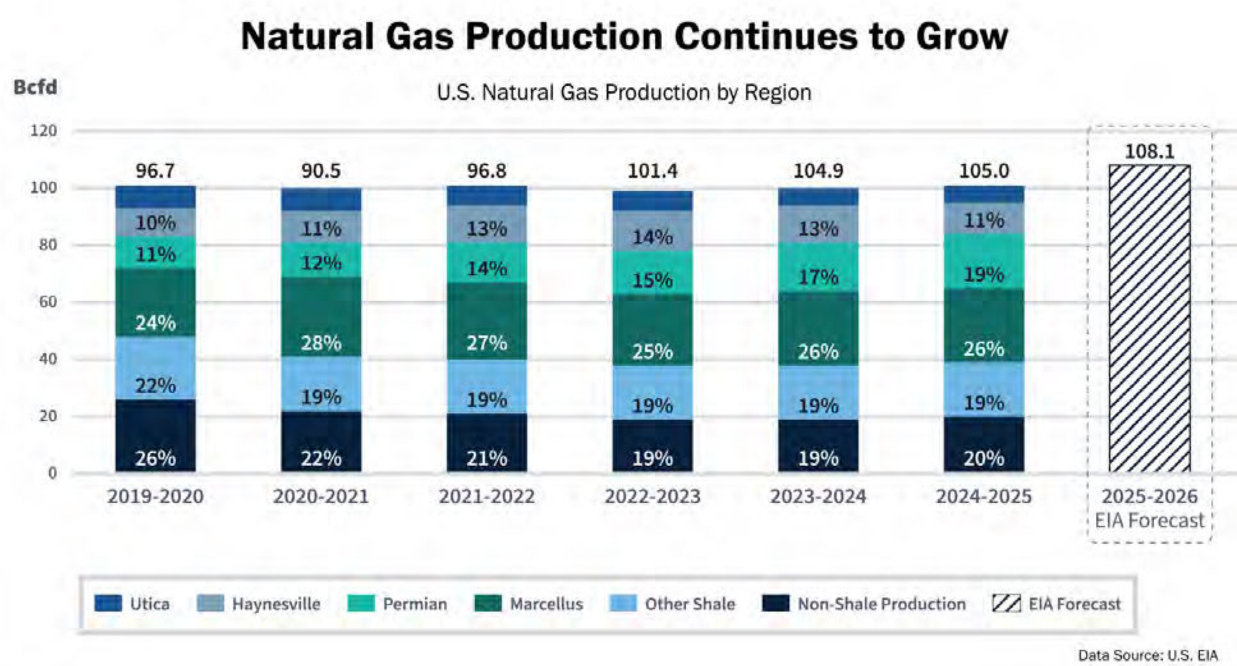
Rising demand for natural gas in the South-Central region, including from liquefied natural gas (LNG) export facilities, is contributing to higher commodity prices at Henry Hub, which operates as a benchmark for regional hub pricing.[23]

Consistent with previous winters, natural gas futures in New England, New York, and California for winter 2025-2026 are currently trading higher than at other major hubs. As shown in **Slide 7**, the Algonquin Citygates hub near Boston could see the highest prices in the country, averaging $12.76/MMBtu, a slight increase of $0.47/MMBtu from last winter's average. New England relies on imported LNG in the winter to help meet peak natural gas demand, and the region continues to compete for LNG volumes with Europe and Asia. Additionally, storage inventories in the East are currently 3% below last year's level and slightly below the five-year average. New York's Transco Zone 6 futures prices averaged $9.48/MMBtu, above last winter's average of $6.30/MMBtu, as that hub may face supply constraints this winter. California natural gas futures prices averaged $5.80/MMBtu at the SoCal-Citygate hub in southern California and $5.01/MMBtu at the PG&E-Citygate in northern California, both above last winter's levels by an average of $0.94/MMBtu. Infrastructure constraints continue to keep California natural gas prices among the highest in the country, but high regional natural gas storage inventories should help moderate price volatility this winter.

2026 as retrieved from InterContinental Exchange, Inc. Previous winter averages are the final settled futures prices for each month as retrieved from InterContinental Exchange, Inc.

[23] 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 United States. Regional basis prices reflect, among other things, the distance from producing basins, availability of natural gas transportation, and local weather expectations for the coming winter.

Slide 8



Natural Gas Production

Domestic natural gas production indicates the market's ability to meet U.S. demand this winter. As of October 7, 2025, EIA forecasted winter 2025-2026 dry natural gas production to average 108.1 Bcfd.[24] This represents a 2.9% increase from the winter 2024-2025 average of 105.0 Bcfd and is 7.7% higher than the five-year average. As illustrated on **Slide 8,** this reflects a fifth year of consecutive growth in production since winter 2020-2021, when the COVID-19 pandemic reduced natural gas production and demand. The different colored segments within each bar break down the total production by region, illustrating how various shale plays contribute to the overall volume.

Although overall natural gas production is projected to increase this winter, lower oil prices will suppress a subset of the production known as "associated gas," which is gas produced

[24] "Natural gas production" refers to dry production, or gross withdrawals less gas used for repressuring, quantities vented and flared, and nonhydrocarbon gases removed in treating or processing operations. The term includes all quantities of gas used in field and processing plant operations.

through drilling activity in oil-rich basins.[25] Lower crude oil prices typically dampen drilling activity in such basins and—because their output is linked—reduce production of both oil and gas.[26] As of August 2025, there were 538 oil and natural gas rigs in operation, about 7% below the same time last year.

Over the past five winters, total U.S. dry gas production increased by at least 14.5 Bcfd in aggregate although occasional freeze-offs (freezing of oil and gas wells and pipes) reduced gas output during winter events, particularly Winter Storm Uri (2021), Winter Storm Elliott (2022), Winter Storm Heather/Gerri (2024), and the winter storms of January 2025. To prevent potential loss of production, the upstream natural gas sector has ramped up winter preparedness and equipment winterization efforts.[27] While winter storms are not directly comparable, operators reported fewer issues in winter 2024-2025, when Northeast natural gas production dropped only approximately 2 Bcfd, compared to 11 Bcfd that came off-line during Winter Storm Elliott two years earlier.[28] During the January 21-22, 2025 winter storm, the U.S. natural gas system mitigated reduced production from freeze-offs and unplanned outages and supported a record-setting peak domestic demand of 150 Bcfd without requiring load shedding by electric utilities.[29]

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[25] EIA, *Short-Term Energy Outlook*, at 9 (Sept. 9, 2025), http://www.eia.gov/outlooks/steo/archives/sep25.pdf.

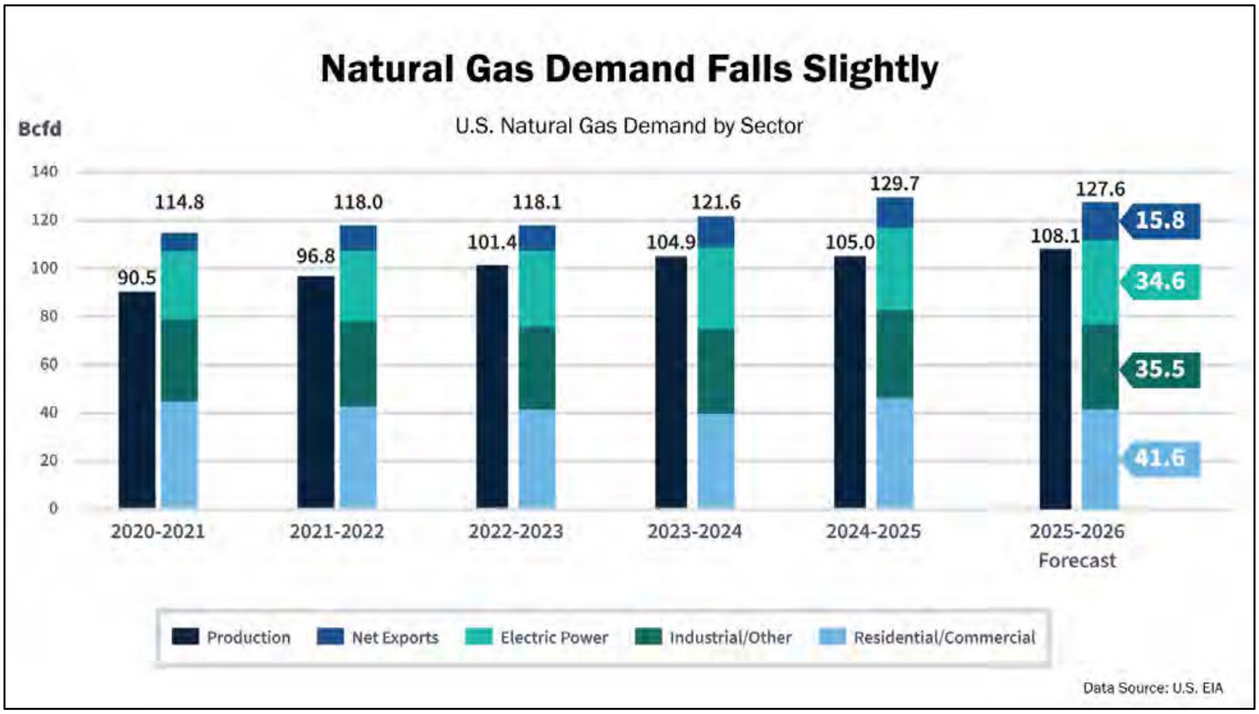
[26] Crude oil prices for West Texas Intermediate at the Cushing Interchange in Oklahoma, the U.S. crude oil benchmark, are expected to average $48.33 per barrel, 32.7% lower than the five-year average and 33.3% lower than the average winter 2024-2025 price of $72.46 per barrel. *See* EIA, *Short-Term Energy Outlook* (Sept. 9, 2025), https://www.eia.gov/outlooks/steo/data/browser/.

[27] American Gas Association, *Special Edition: Natural Gas Market Indicators – January 9, 2025* (Jan. 9, 2025), https://www.aga.org/research-policy/resource-library/special-edition-natural-gas-market-indicators-january-9-2025/.

[28] PJM Operating Committee, *Cold Weather Operations January 18–23, 2025,* at 22 (Feb. 6, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/committees/oc/2025/20250306/20250306-item-15---january-2025-cold-weather-update.pdf.

[29] FERC, NERC and its Regional Entities (a joint staff report), *January 2025 Arctic Events: A System Performance Review,* at 1 (April 17, 2025). https://www.ferc.gov/media/report-january-2025-arctic-events-system-performance-review-ferc-nerc-and-its-regional.

Slide 9



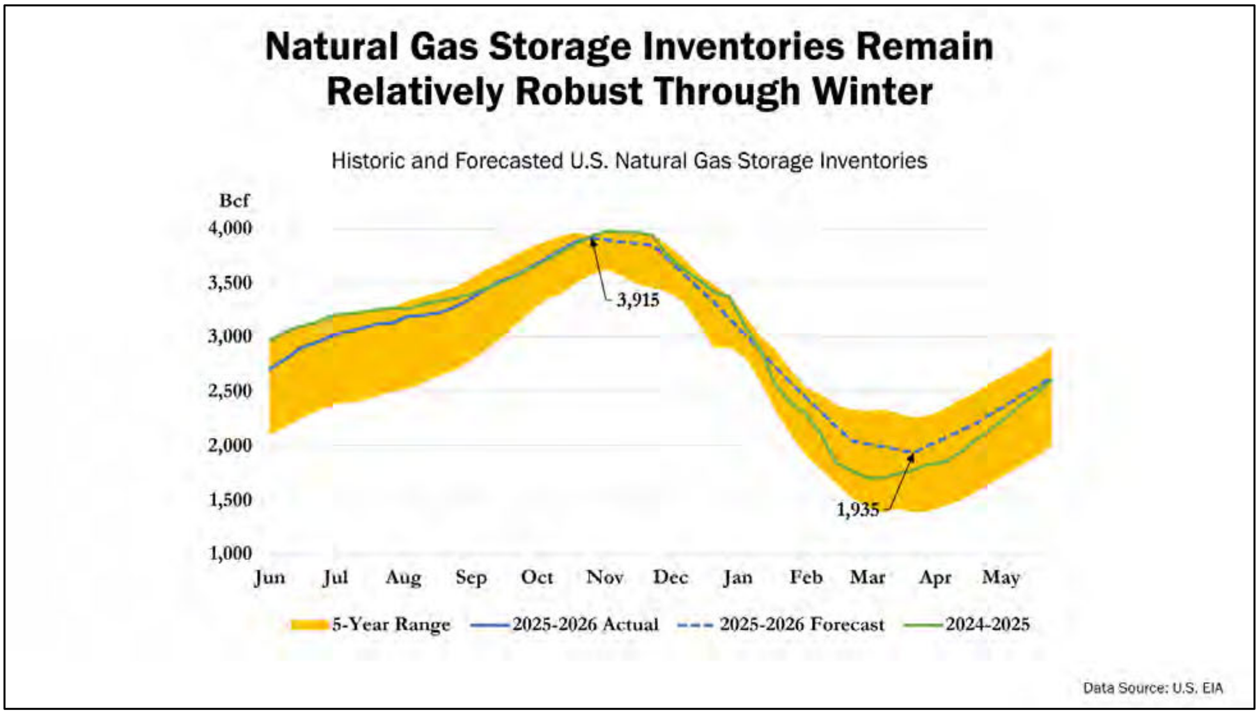
Natural Gas Demand

Total U.S. natural gas demand, represented by a core set of demand drivers, indicates the market need for natural gas this winter, as shown in the chart on **Slide 9**. Natural gas demand is forecasted to average 127.6 Bcfd in winter 2025-2026, 1.6% lower than the 129.7 Bcfd in winter 2024-2025. As the chart illustrates, total U.S. demand, represented by the height of the stacked bars, has grown over the last several years. Forecasted demand for winter 2025-2026 remains higher than the previous five-winter average by 5.6%. The different colored segments of each bar break down total demand into its components: residential, commercial, and industrial demand; natural gas consumed for electricity generation (power burn); and net exports. Total U.S. domestic natural gas consumption, which excludes net exports, is expected to average 111.7 Bcfd in winter 2025-2026, a decrease of 4.6% from winter 2024-2025 levels and a 2.1% increase from the previous five-winter average. Exports are discussed in greater detail in the *Natural Gas Exports and Imports* section below.

The light blue segment of the bar represents the residential and commercial sector, which is forecasted to comprise a 32.6% share of total U.S. domestic demand mostly for winter space heating. EIA forecasts the residential and commercial sector to consume 41.6 Bcfd, a decrease of 10.2% from the notably high demand seen during winter 2024-2025 due to the January 2025 winter events. Lower residential and commercial demand usually reflects a warmer winter, resulting in lower demand for natural gas used for space heating. The light green portion of the bar represents power burn, which comprises 27.2% of domestic demand and is expected to remain relatively flat compared to last winter, averaging 34.6 Bcfd in winter

2025-2026. Natural gas-fired generation is forecasted to provide 38.6% of total U.S. electricity generation output in winter 2025-2026, nearly the same as the 38.3% share in winter 2024-2025, but slightly higher than the previous five-winter average of 37.6%.

Slide 10



Natural Gas Storage Inventories

Natural gas storage inventories help to balance natural gas supply and demand and thus are fundamental to winter natural gas price formation. The chart on **Slide 10** illustrates the current storage forecast in the context of recent history. Traders and wholesale consumers watch storage inventories for signs of a supply and demand imbalance.[30] The solid and dashed blue lines on the chart tracks inventory levels for the current winter (2025-2026). The U.S. natural gas storage withdrawal season began in early November with 3,915 Bcf in working gas inventories. At the end of the withdrawal season on April 1, 2026, EIA currently forecasts 1,935 Bcf remaining in storage, as shown in **Slide 10**. The starting inventory level was above the five-year average of 3,811 Bcf but lower than the previous season (2024-2025) when the starting inventory level was the highest since 2016. The ending inventory level is expected to be slightly higher than the five-year average level and much above the previous withdrawal season's level (1,698 Bcf on March 6, 2025). EIA expects total withdrawals of approximately 1,980 Bcf throughout the 2025-2026 withdrawal season, 13% less than 2024-2025 winter withdrawals but 2.3% more than the previous five-winter average. As such, overall natural gas storage inventories are forecasted to remain relatively robust through winter.

Regionally, natural gas storage inventories in the East and Midwest are expected to start the winter withdrawal season approximately 3% below last year's level but just 1% below the five-

[30] U.S. natural gas storage inventory data listed in this section is for the Lower 48 states.

year average. The lower-than-average storage inventories in the East and Midwest are expected to be offset by storage levels higher than the previous five-winter average in the Mountain, Pacific, and South-Central regions.[31]

Generators fueled by petroleum and liquid fuels, such as distillate or residual fuel, provide a small portion of the overall electric generation capacity in the United States but play an important reliability role during critical periods in the Northeast.[32] As of October 31, 2025, distillate fuel oil inventories, which include heating oil, were at 111.6 million barrels for the United States,[33] 8.8% below the five-year average.

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[31] For more on storage and its role in U.S. energy markets, see the Natural Gas Storage section (page 25) in FERC's *Energy Primer: A Handbook on Energy Market Basics,* http://www.ferc.gov/sites/default/files/2024-01/24_Energy-Markets-Primer_0117_DIGITAL_0.pdf.

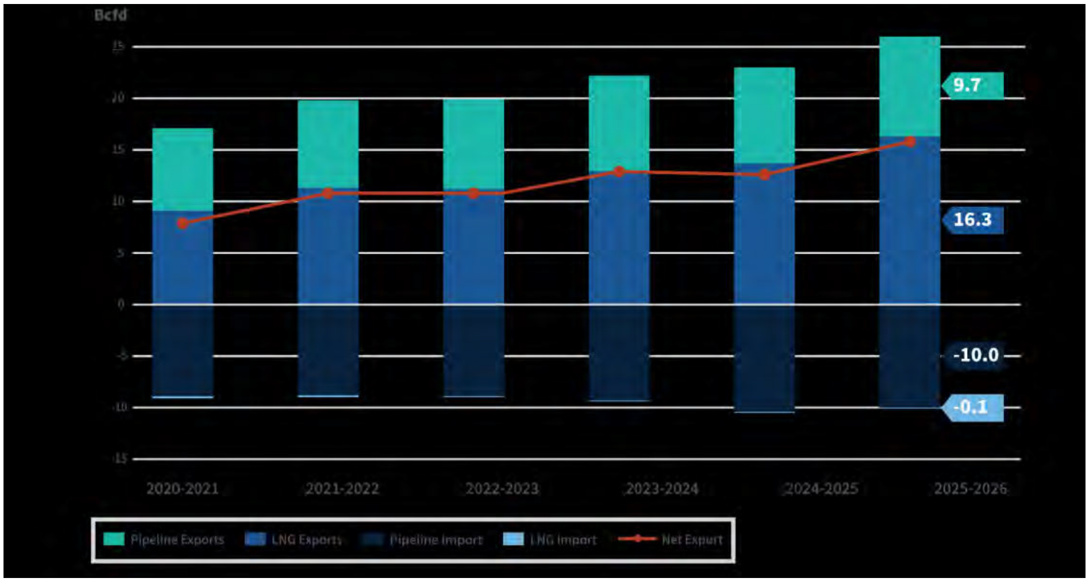
[32] For more on oil and its role in U.S. electricity generation, please see Chapter 4: U.S. Crude Oil and Petroleum Product Markets in FERC's *Energy Primer: A Handbook for Energy Market Basics*, http://www.ferc.gov/sites/default/files/2024-01/24_Energy-Markets-Primer_0117_DIGITAL_0.pdf.

[33] EIA, Weekly U.S. Ending Stocks of Distillate Fuel Oil (Oct. 31, 2025), https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=WDISTUS1&f=W.

Slide 11

Natural Gas Exports Continue to Outpace Imports

U.S. Natural Gas Imports (negative values) and Exports (positive values)



Natural Gas Exports and Imports

Natural gas exports represent the fastest growing demand segment in the U.S. market and are expected to outpace natural gas imports this winter. The chart on **Slide 11** illustrates this trend, breaking down the volumes of U.S. natural gas LNG and pipeline imports and exports. The stacked bars are segmented to show the volume of LNG exports (in blue), pipeline exports (in light green), and pipeline imports (in black). Net natural gas exports are expected to increase this winter from last winter, primarily due to increased LNG export capacity from Calcasieu Pass LNG, Corpus Christi LNG Stage 3, and Plaquemines LNG, along with an expected increase in natural gas pipeline exports to Mexico. As seen in **Slide 11**, EIA forecasts U.S. gross LNG exports to average 16.3 Bcfd in winter 2025-2026, up 18.7% from winter 2024-2025. The United States remains the world's largest LNG exporter, with FERC-authorized liquefaction capacity in the Lower 48 United States expected to increase to 20.1 Bcfd by the end of the winter.[34]

While LNG imports play a minor (and declining) role in the U.S. gas balance, they are still important in pipeline-constrained New England. Additionally, some U.S. LNG export facility operators such as Cove Point in Maryland have allowed for the delivery of re-gasified LNG stored on site to provide additional supplies to market areas near export facilities during peak

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[34] FERC, *North American LNG Export Terminals – Existing, Approved not Yet Built, and Proposed* (Oct. 14, 2025), https://www.ferc.gov/media/us-lng-export-terminals-existing-approved-not-yet-built-and-proposed.

winter demand days.[35] Altogether, the United States is expected to be a significant net exporter of natural gas this winter, with natural gas exports, including LNG and via pipeline, expected to exceed natural gas imports by an average of 15.8 Bcfd, compared to 12.6 Bcfd in winter 2024-2025.[36] This growth in net exports is represented by the blue line on the chart. Gross pipeline exports, including flows to both Canada and Mexico, are forecast to be 9.7 Bcfd, which is 0.3 Bcfd above average exports in winter 2024-2025. In total, the United States is a net gas importer from Canada and a net exporter to Mexico (via pipeline and trucks; the latter on a very small scale).

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[35] Cove Point's LTD-3 service allows shippers to liquefy domestic natural gas, inject LNG into storage, and then withdraw that stored LNG at any time. *See* Cove Point LNG, LP, FERC Gas Tariff, Tariff Record No. 1., Third Revised Volume No. 1., http://www.ferc.gov/sites/default/files/2020-05/066131_000110__contents.pdf.

[36] For more on LNG markets, see the Liquefied Natural Gas section (page 14) of FERC's *Energy Primer: A Handbook for Energy Market Basics,* http://www.ferc.gov/sites/default/files/2024-01/24_Energy-Markets-Primer_0117_DIGITAL_0.pdf.

Slide 12

Natural Gas Infrastructure Additions

- LNG Export Capacity Grows to 20.1 Bcfd
  - Two new projects in-service since start of last winter
- Pipeline Projects Added 2.2 Bcfd in Capacity in 2025
  - Additional capacity to support LNG export facilities
  - Increased takeaway capacity in the Southwest and Texas
- Natural Gas Storage Capacity Grows by 6.5 Bcf
  - New working gas capacity added in December 2024

Natural Gas Infrastructure

Natural gas infrastructure additions measure the growth in capacity used to process, transport, and store natural gas as it moves from initial production (or import) to ultimate delivery (including export). Natural gas infrastructure additions since last winter included expansions to export capacity, pipeline capacity, and storage capacity. New LNG export facilities and expansions are expected to bring peak LNG capacity to 20.1 Bcfd by the end of the winter. Pipeline projects placed in-service since last winter added 2.2 Bcfd of new transportation capacity, and an expansion project added 6.5 Bcf in new underground natural gas storage capacity.[37]

The United States was the world's largest LNG exporter in 2024, and U.S. natural gas exports are expected to increase again this winter, supported by two major projects completed since last winter.[38] Plaquemines LNG Phase 1 began operating in Louisiana in late 2024 and Corpus Christi LNG Stage 3 in Texas began in March of 2025, while Plaquemines LNG Phase 2 is

[37] This calculation is based on EIA's pipeline project database cross-referenced with FERC certificate filings and in-service announcements. EIA, Natural Gas Pipeline Projects (July 2025), https://www.eia.gov/naturalgas/pipelines/EIA-NaturalGasPipelineProjects_Jul2025.xlsx.

[38] EIA, *The United States remained the world's largest liquefied natural gas exporter in 2024* (March 27, 2025), https://www.eia.gov /todayinenergy/detail.php?id=64844.

expected to ship its first cargo in the fourth quarter of 2025. Including the new additions, by the end of the winter FERC-authorized U.S. LNG liquefaction capacity will be 20.1 Bcfd.[39]

Since November 2024, several interstate natural gas pipelines have increased pipeline capacity. Most notably, the Evangeline Pass Expansion Project Phase 2 entered service and increased the pipeline's total capacity to 2.2 Bcfd to deliver feedgas to Venture Global's Plaquemines LNG liquefaction and export facility. Several smaller pipeline expansion projects now in service are also expected to support production growth and demand, including the 0.19 Bcfd Texas to Louisiana Energy Pathway project which increases capacity between Haynesville production and Gulf Coast markets, and the 0.18 Bcfd East Lateral Xpress, which will supply the Plaquemine's LNG terminal.

Adding to natural gas storage capacity, the Tres Palacios Cavern 4 Storage Expansion project entered service in December 2024. Located in Texas, Tres Palacios Cavern 4 adds 6.5 Bcf of working gas capacity to the facility's existing 34.9 Bcf.[40] As a salt dome site, Tres Palacios can inject or withdraw gas quickly, supporting variable loads from a variety of users including LNG terminals.

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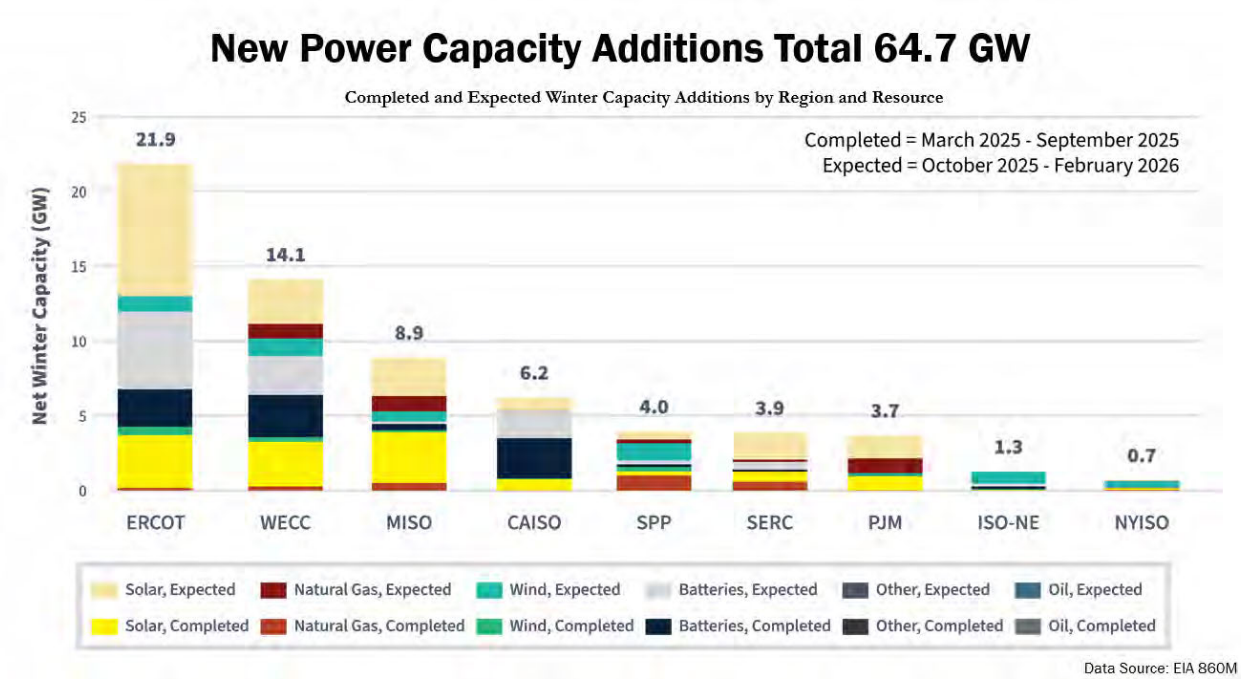
[39] EIA, U.S. Liquefaction Capacity (Sept. 17, 2025), https://www.eia.gov/naturalgas/data.php#imports; FERC, *North American LNG Export Terminals – Existing, Approved not Yet Built, and Proposed* (Sept. 18, 2025), https://www.ferc.gov/media/us-lng-export-terminals-existing-approved-not-yet-built-and-proposed.

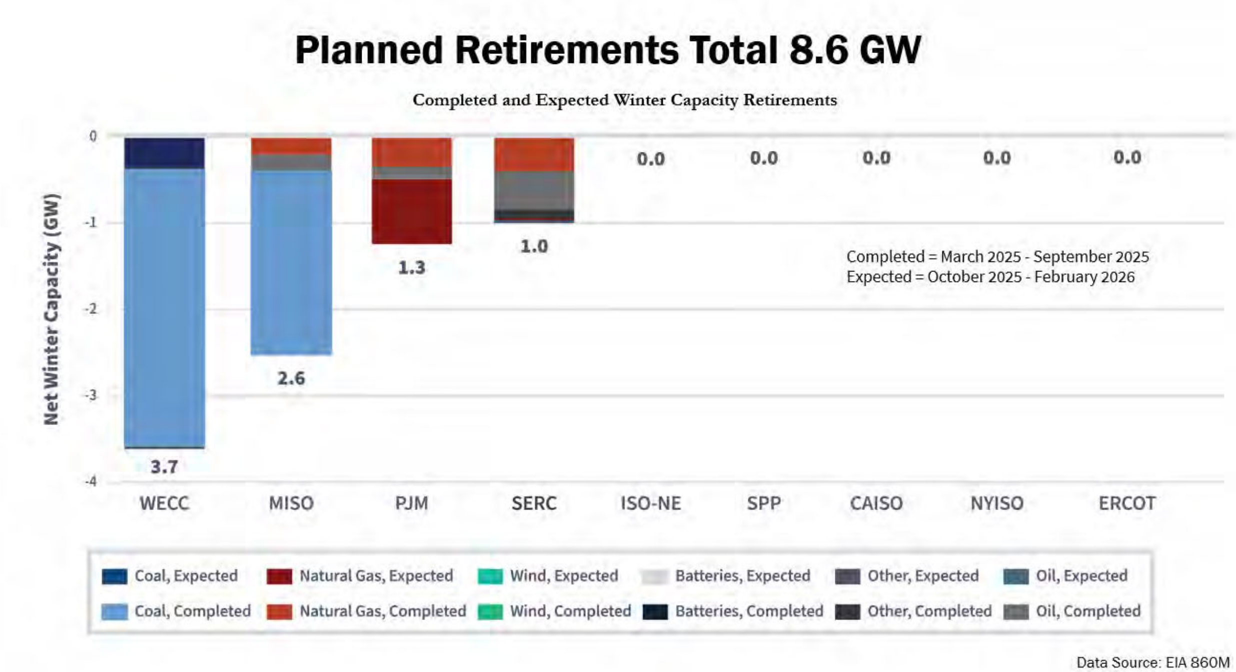
[40] Jodi Shafto, *Enbridge Ready to Bring on Fourth Cavern at Texas Natural Gas Storage Facility,* Natural Gas Intelligence (Nov. 22, 2024), https://naturalgasintel.com/news/enbridge-ready-to-bring-on-fourth-cavern-at-texas-natural-gas-storage-facility/.

Electricity Market Fundamentals and Electric Reliability

Slide 13



Slide 14



Electricity Generation Additions, Retirements, and Outages

Compared to last winter, the EIA projects the electricity sector will have 56.1 GW of additional net generation capacity this winter.[41] This net increase reflects 64.7 GW of new capacity additions offset by 8.6 GW of retirements. Of these capacity changes, 25.7 GW of additions and 2.4 GW of retirements were already completed between March and November 2025, while 39.0 GW of additions and 6.2 GW of retirements are expected to occur between December 2025 and February 2026. Given their operating characteristics, new capacity from solar, wind, or storage facilities does not replace the retired thermal capacity from coal, natural gas, or oil units on a one-for-one basis.

Capacity Additions

The chart on **Slide 13** breaks down the 64.7 GW of new winter capacity additions by region and resource type. Each vertical bar represents the total new capacity for a specific region, while the segments within each bar show the mix of different resources being added. In total, solar accounts for 50% (32 GW) of new capacity additions and batteries represent 30% (20 GW), with wind accounting for 11% (6.8 GW) and natural gas (6 GW) comprising the remainder. Solar represents the largest share of new capacity additions in PJM (68%) and MISO (67%). New battery capacity additions have continued to grow steadily from 695 MW in 2021 to a projected 11.5 GW in 2025. As the chart shows, western and central regions drive nearly 80% of overall capacity additions: ERCOT (21.8 GW), WECC (14.1 GW), the Midcontinent Independent System Operator (MISO) (8.9 GW), and the California Independent System Operator (CAISO) (6.2 GW).

Capacity Retirements

Capacity retirements are projected to total 8.6 GW, with coal-fired steam units representing 5.8 GW (67%) and natural gas units 1.8 GW (21%). The chart on **Slide 14** breaks down these figures by region and shows the specific fuel types being retired in each area. The majority of planned coal retirements are in WECC (3.2 GW) and MISO (2.1 GW), while the largest volume of planned natural gas retirements is in PJM (0.8 GW). The largest individual coal plant retirements include the Intermountain Power Project (1.8 GW) in Utah, J.H. Campbell Generating Complex (1.3 GW) in Michigan, and TransAlta's Centralia Generation Station (0.7 GW) in Washington. Notably, the J.H. Campbell plant's retirement is subject to a U.S. Department of Energy (DOE) emergency order extending its operation until February 17,

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[41] Net capacity additions and retirements data from EIA Form 860M show new generating capacity that entered service and existing capacity that retired during March 2025 through February 2026. The net increase represents total additions minus total retirements across all fuel types and technologies. *See* EIA (September 9, 2025) Form EIA-860M, https://www.eia.gov /electricity /data/eia860/

2026, to ensure grid reliability.[42] Similarly, the 397 MW oil-fired Wagner Unit 4 has been extended beyond its environmental run-hour limitations by a DOE emergency order until December 31, 2025, to help meet anticipated electricity demand in PJM.[43] In addition, DOE has ordered Units 3 and 4 of the Eddystone Generating Station to remain available through November 26, 2025, to minimize the risk of generation shortfalls in PJM.[44] Another notable coal retirement is the Merrimack Station in New Hampshire (460 MW). That plant ceased commercial operations in early October 2025, earlier than its previously planned 2028 retirement.[45]

Pace of Winter Capacity Changes

The pace of winter capacity additions has recovered after slowing in 2022. Capacity additions fell from 37.4 GW in 2022 to 32.7 GW in 2023, a 13% decline. Since then, the pace of capacity additions has rebounded strongly, reaching 42.6 GW in 2024 and 52.6 GW in 2025. Projected additions for 2026 are 64.7 GW, which would represent the largest annual capacity addition in over a decade. Conversely, the pace of generation retirements has slowed significantly following a surge in coal plant closures. Annual retirements peaked at 17.8 GW in 2023, then declined to 15.7 GW in 2024 and 8.6 GW in 2025—a 51% reduction from the 2023 peak. Retirements are projected to remain at similar levels in 2026 at 8.7 GW, consistent with this return to more moderate retirement rates.

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[42] Additional DOE orders could potentially delay other planned retirements this winter. U.S. Department of Energy, Order No. 202-25-9, Federal Power Act Section 202(c): Midcontinent Independent System Operator (Nov. 18, 2025), https://www.energy.gov/sites/default /files/2025-11/Order%20No%20202-25-9.pdf. *See* also U.S. Department of Energy, Order No. 202-25-7, Federal Power Act Section 202(c): Midcontinent Independent System Operator (Aug. 20, 2025), https://www.energy.gov/ceser/federal-power-act-section-202c-midcontinent-independent-system-operator-miso-0.

[43] *See* U.S. Department of Energy, Order No. 202-25-6A, Federal Power Act Section 202(c): PJM Interconnection (PJM) (Oct. 24, 2025), https://www.energy.gov/ceser/federal-power-act-section-202c-pjm-interconnection-0

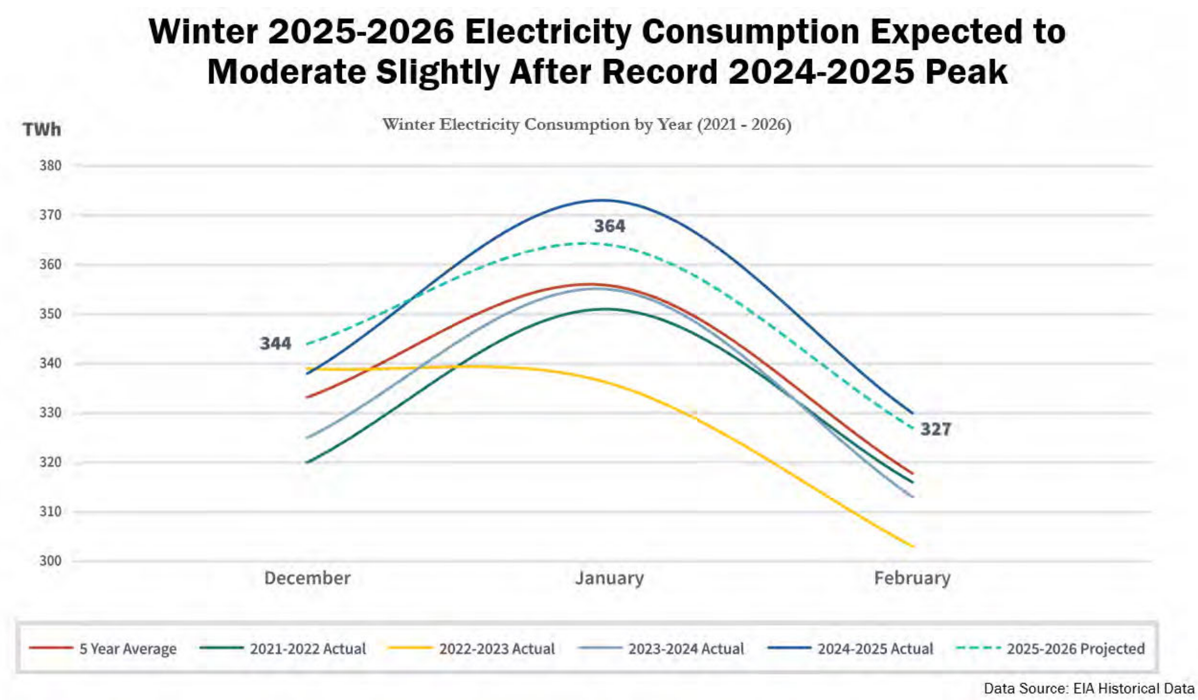
[44] *See* U.S. Department of Energy, Order No. 202-25-8 Federal Power Act Section 202(c): PJM Interconnection (PJM) (August 28, 2025), https://www.energy.gov/ceser/federal-power-act-section-202c-pjm-interconnection-pjm.

[45] Retirement data is based on EIA-860M reported retirement dates. Some units, such as J.H. Campbell, continue operating under DOE emergency orders (202(c)) beyond their reported retirement dates, while others, such as the Merrimack Station, retired earlier than planned. Actual operational status may differ from reported retirement timing.

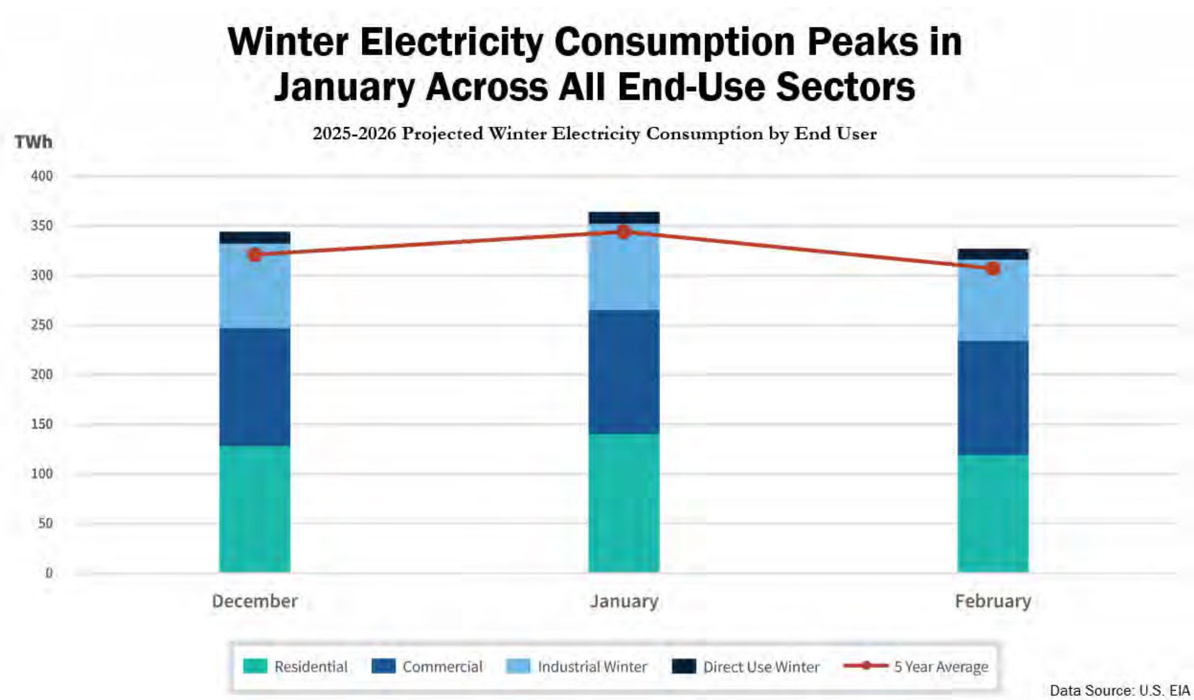
Planned Generation Outages

Oconee Nuclear Station Unit 3 (859 MW) in South Carolina is scheduled for a 28-day maintenance outage starting November 1, 2025. While the unit is scheduled to return to service before December 2025, any delays could reduce available capacity in the SERC region, emphasizing the importance of proactive grid management strategies for the winter season.

Slide 15



Slide 16



Electricity Consumption

EIA projects total winter electricity consumption to reach 1,035 TWh, or 2.7% above the five-year average of 1,007 TWh.[46] The chart on **Slide 15** provides historical context for this forecast, plotting projected consumption for winter 2025-2026 (the dashed green line) against the previous four winters. Among the last five winters, winter 2024-2025 represents the record peak at 1,041 TWh (3% above the five-year average), while winter 2025-2026 projections show more modest growth at 1,035 TWh, which would represent the second-highest consumption level of the five winters analyzed.

The breakdown of this electricity consumption by end-use sector for winter 2025-2026 is shown on **Slide 16**. The residential sector is projected to have the highest consumption at 387 TWh, followed by the commercial sector at 359 TWh and the industrial sector at 254 TWh. The stacked bars on the chart illustrate this monthly breakdown and show that consumption across all sectors is expected to peak in January, reaching a high of 352 TWh. The commercial sector is projected to see the strongest growth at 5% above its five-year average. Direct Use represents approximately 3% of total electricity consumption (or 35 TWh) and is expected to remain stable.[47]

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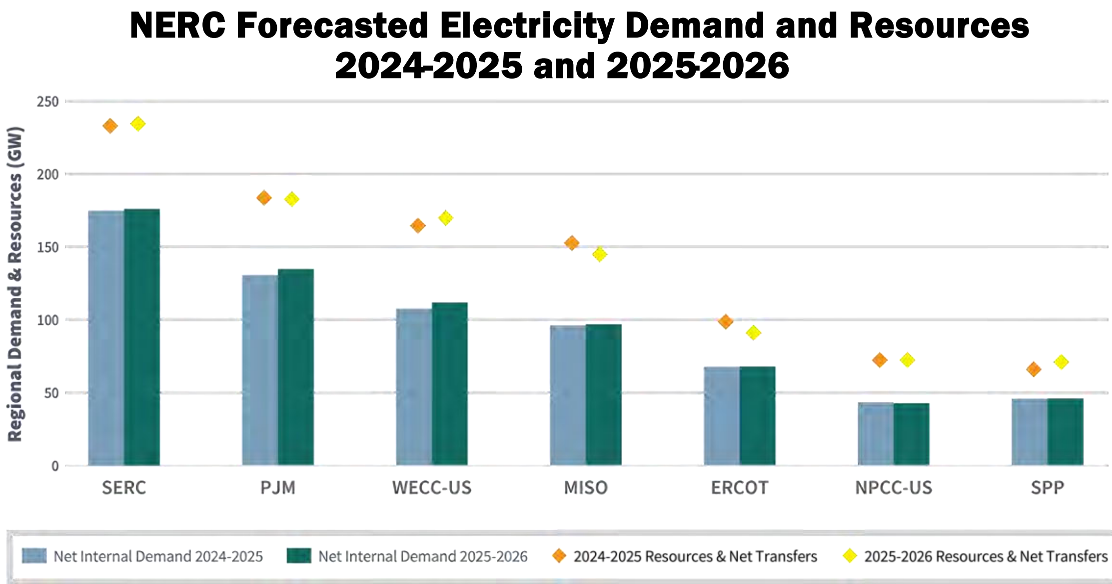
[46] EIA's *Short-Term Energy Outlook* (STEO) provides data and forecasts for U.S. electricity consumption retail sales to customers, broken down by residential, commercial, and industrial sectors. EIA, *STEO*, at Table 7A (Sept. 2025), https://www.eia.gov /outlooks/steo/archives/sep25.pdf.

[47] According to EIA, Direct Use represents "commercial and industrial facility use of onsite net electricity generation; and electrical sales or transfers to adjacent or colocated facilities for which revenue information is not available." See EIA, *STEO*, at Table 7A (Sept. 2025), https://www.eia.gov/outlooks/steo/archives/sep25.pdf.

Slide 17



NERC, 2025-2026 Winter Reliability Assessment
Net Internal Demand equals Total Internal Demand less Dispatchable, Controllable Capacity Demand Response used to reduce load.

NERC Forecasted Electricity Demand and Resources

According to NERC, electricity demand is expected to be higher this winter compared to last winter. NERC forecasts net internal demand[48] for electricity to increase by approximately 1.6%, or 11 GW, from 666 GW in winter 2024-2025 to 677 GW in winter 2025-2026. Actual electricity demand will depend on a number of factors, including the number, duration, and characteristics of extreme winter events.

Slide 17 shows the net internal demand as solid bars and the available resources and net transfer values (a combination of internal resources and additional external resources available to the region) as diamonds.[49] Despite the increased demand projected for Winter

[48] Forecasted Net Internal Demand: Total of all end-use customer demand and electric system losses within specified metered boundaries, reduced by the projected impacts of Controllable and Dispatchable Demand Response programs.

[49] "Resources and Net Transfers" refers to the addition of "Existing-Certain Capacity" and "Net Firm Capacity Transfers." Existing-Certain Capacity includes capacity to serve load during period of peak demand from commercially operable generating units with firm transmission or other qualifying provisions specified in the market construct. Net firm capacity transfers refers to the imports minus exports of firm contracts. NERC*, 2024 Long Term Reliability Assessment* (December 2024, updated July 15, 2025), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%2

2025-2026, all 15 U.S. NERC assessment areas are anticipated to have sufficient available generation resources and net transfers to meet their expected loads under normal winter conditions.[50] According to data from NERC,[51] planning reserve margins[52] exceed the reference reserve level margins[53] for the 15 NERC assessment areas. Even with expected ample planning reserve margins, regions can face tighter-than-expected supply if operating conditions deviate significantly from those expected for this winter. Planning reserve margins are a metric, but do not guarantee reliable operations at all times. For instance, they do not necessarily account for all extreme winter conditions that can lead to fuel unavailability for generators, derates of electric generators, unexpected generator outages, transmission outages, reduced power transfers from adjacent areas, delays in energy

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0Term%20Reliability%20Assessment_2024.pdf; *see also* Net Internal Demand equals Total Internal Demand less Dispatchable, Controllable Capacity Demand Response used to reduce load. NERC, *2025-2026 Winter Reliability Assessment,* (Nov. 18, 2025), http://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf.

[50] The 15 U.S. assessment areas, also shown in **Slide 20**, are the NPCC-New England and NPCC-New York subregions of NPCC-US; PJM Interconnection L.L.C. (PJM); the SERC-Central, SERC-East, SERC-Southeast, and SERC Florida Peninsula subregions of SERC-US; MISO; SPP; the Texas Reliability Entity-Electric Reliability Council of Texas (TRE/ERCOT); and the WECC-NW (Northwest), WECC-SW, WECC-Rocky Mountain, WECC-Basin and WECC-CAMX subregions of WECC-US. NERC, *2024 Long-Term Reliability Assessment* (Dec. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

[51] NERC *2025-2026 Winter Reliability Assessment* (Nov. 18, 2025), http://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf.

[52] The planning reserve margin is the primary metric used to measure resource adequacy defined as the difference in resources (anticipated or prospective) and net internal demand divided by net internal demand, shown as a percentile. NERC, *2024 Long Term Reliability Assessment, at 138* (Dec. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

[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 (accessed Oct. 22, 2025), https://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx.

resources coming online, and other factors that system operators must manage to maintain electric supply and reliability. In extreme scenarios, ERCOT, NPCC-NE, SERC-Central, SERC-East, WECC-Basin, and WECC-NW face a higher likelihood of challenges, which may require operational mitigations to avoid facing potential reliability issues. More comprehensive reliability assessments for these assessment areas are presented in the *Regional Highlights* section of this assessment.

To serve demand in winter 2025-2026, NERC forecasts a national decrease of 0.48%, or approximately 4.6 GW[54], in total electric generation capacity and net energy transfers from approximately 971.5 GW in winter 2024-2025 to approximately 966.8 GW in winter 2025-2026,[55] illustrated as diamonds in **Slide 17**.[56]

A forecast of the United States' electricity demand shows a significant upward trajectory.[57] This demand increase is driven by a combination of industrial sector recovery, electrification, and new demand from data centers and manufacturing. Currently, the size and speed with which data centers and crypto mining facilities can be constructed and connected to the grid presents unique challenges for demand forecasting and planning.[58] Data center demand alone

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[54] To determine these figures, using data provided in the "Demand and Resources Table of the NERC 2025-2026 Winter Reliability Assessment for each United States' assessment area, the Existing-certain capacity is summed across NERC assessment areas and the net firm capacity transfers projections are summed across all assessment areas, and compared to the same assessment area projections provided in the "2024-2025 WRA columns." The Existing-certain capacity and net firm transfers were described in FN 47 above Note that NERC's projected 4.6 GW decrease in generation capacity differs from EIA's anticipated 56.1 GW net increase in generation capacity because EIA estimates expected retirements and planned capacity through February 2025 based on data submitted to the annual EIA-860 and includes operating, out of service or on standby generators, as well as planned and not yet in operation generators. The EIA data is not directly comparable to the NERC data.

[55] NERC, *2025-2026 Winter Reliability Assessment* (Nov. 18, 2025), http://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf.

[56] *Id.*

[57] *Grid Strategies LLC, Strategic Industries Surging: Driving US Power Demand, (Dec. 2024), https://gridstrategiesllc.com/wp-content/uploads/National-Load-Growth-Report-2024.pdf.*

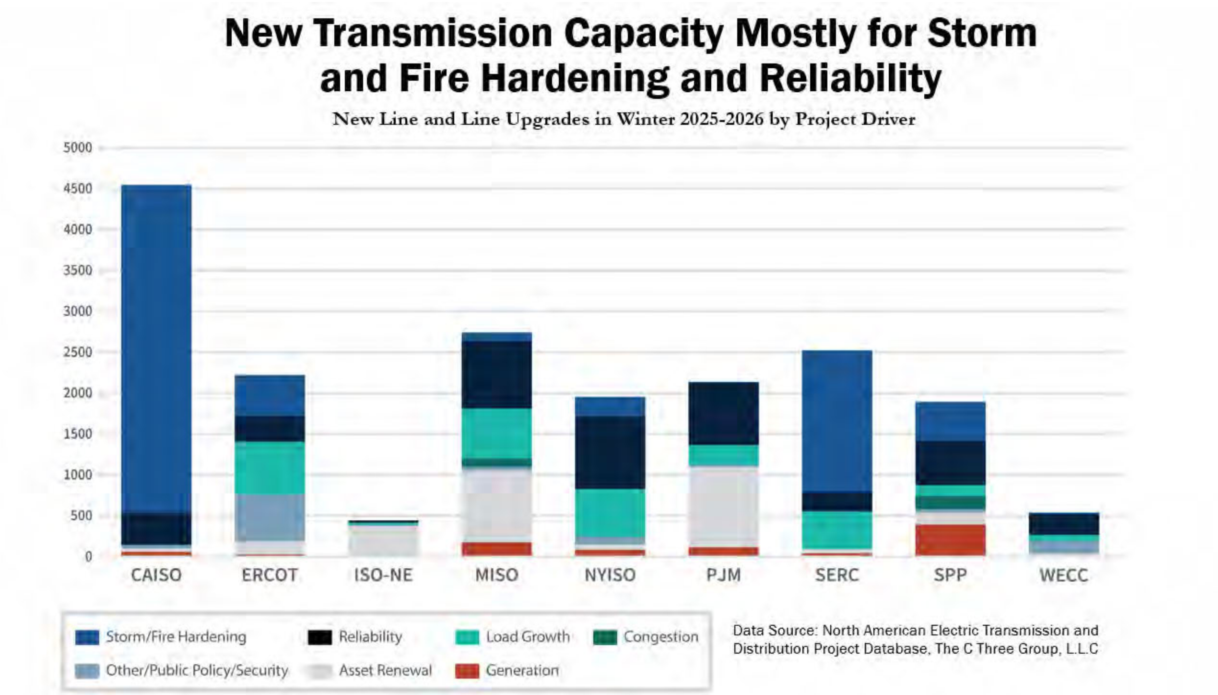
[58] NERC, *2024 Long-Term Reliability Assessment* at 8 (Dec. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

is projected to consume over 5% of the total U.S. power demand for 2025, up from 4.4% in 2024.[59]

This increase in demand, in combination with the decrease in supply, is pressuring utilities to accelerate infrastructure upgrades and energy resource deployment, and to reconsider scheduled resource retirements to maintain grid reliability, such as those described further in the *Electricity Generation Additions, Retirements, and Outages* section above.

[59] Lawrence Berkeley National Laboratory, *2024 United States Data Center Energy Usage Report* at 52 (Dec. 2024), https://escholarship.org/uc/lbnl.

Slide 18



Electricity Transmission Projects

There are 3,132 new transmission projects supporting grid reliability this winter, including 1,551 substation-only projects, 1,070 transmission line projects, and 511 combined projects. These projects total 19,008 line-miles, with 14,736 miles already completed and placed in service between March and November 2025, and 4,272 miles expected to enter service between December 2025 and February 2026.[60] The chart on **Slide 18** breaks down these new line and line upgrades by region and project driver. Nationwide, the primary drivers for these projects are storm and fire hardening (7,101 line-miles) and system reliability (4,238 line-miles), which together account for nearly 60% of all projected mileage.

By project count, ERCOT (771), MISO (655), and PJM (610) are the most active regions for transmission development. As the chart illustrates, the top drivers vary by region: ERCOT is primarily focused on storm and fire hardening (23% of its line-miles) and load growth (29%), MISO is driven by a combination of asset renewal/aging infrastructure (32%) and system reliability (30%), PJM's development is concentrated on asset renewal/aging infrastructure

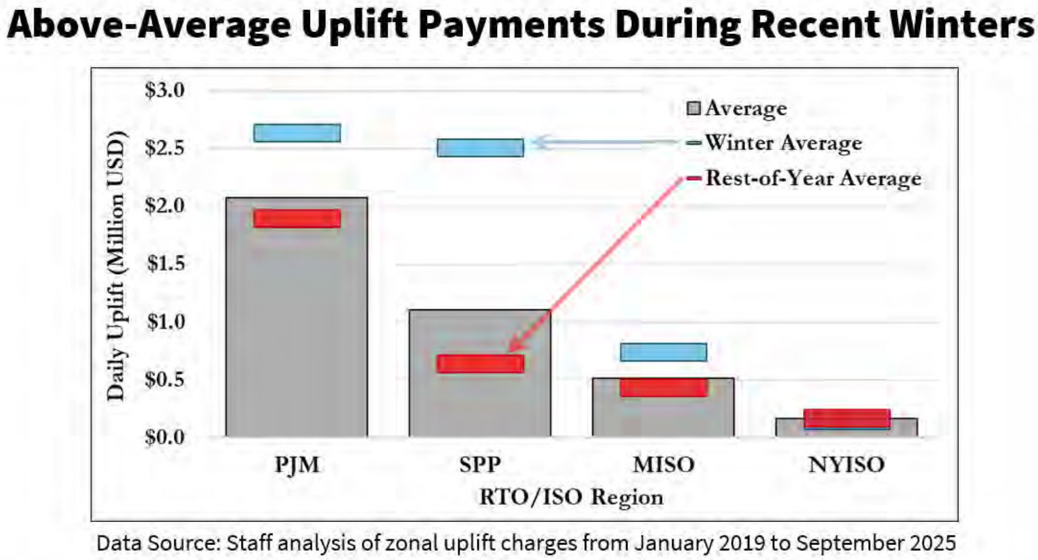
[60] Data on transmission line-miles is from The C Three Group's (Yes Energy) Electric Transmission and Distribution database. The projects listed in this report are limited to those placed into service between March 2025 and February 2026 that have one of the following statuses: conceptual, early development, advanced development, under construction, partial operations, or operating. Project terminology and the level of detail can vary significantly by region, which may result in incomplete data.

(46%) and system reliability (36%), and over 97% of CAISO's new mileage is for storm and fire hardening. Notably, all projects specifically developed for congestion relief are located in SPP and MISO, totaling 260 line-miles.

Most projects involve lines below 230 kV, accounting for 16,732 line-miles or 88% of total line-miles. For lines of 230 kV or higher, there are 2,277 line-miles or 12% of total mileage. The highest voltage lines of 500 kV or more account for 358 line-miles, primarily in CAISO (256 line-miles), WECC (91 line-miles), and MISO (7 line-miles).

Substation-only projects represent nearly half of all transmission infrastructure work this winter, with ERCOT (404 substations), MISO (320), and PJM (294) leading in substation development.

Slide 19



Electric Market Uplift Payments

Uplift payments in organized markets reflect the portion of the cost of reliably serving load that is not included in market prices. They compensate generators that are dispatched to operate but whose market revenues fail to cover their production costs. The costs of uplift payments are typically allocated among grid customers. For this coming winter, forecasted natural gas prices and electricity demand suggest that the cost of producing electricity will not be appreciably higher than that of recent winters.[61] But, unpredictable periods of extreme winter weather could still drive up both wholesale electricity prices and uplift payments for some days.

The chart on **Slide 19** illustrates this historical trend, visualizing how average daily uplift payments during the winter are typically higher than the average for the rest of the year across several grid regions.[62] Historical data shows that daily uplift payments have been higher on

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[61] EIA, *Short-Term Energy Outlook* (Oct. 7, 2025), showing that the wholesale electricity outlook for the coming winter has average wholesale electricity prices that are close to historical winter averages, except January where prices are expected to increase slightly. https://www.eia.gov/outlooks/steo/archives/oct25.pdf.

[62] Assessment in this report of zonal uplift payments are based on publicly available data obtained from datasets and market reports published by the ISO/RTOs from Jan. 1, 2019, to Aug. 31, 2025, for NYISO, MISO, and SPP and July 1, 2019, to Aug. 31, 2025, for PJM.

average during recent winters in several regions, driven by two key factors: extreme weather events and specific operator actions.[63]

- **Extreme Weather:** During an eight-day period of Winter Storm Uri in February 2021, total uplift payments exceeded $1.13 Billion in SPP and $160 million in MISO. The daily payments in SPP during the storm averaged over $140 million—more than 100 times the region's typical daily average since 2019.
- **Operator Actions:** Proactive operator decisions can also drive uplift. In January 2025, PJM's commitment of specific resources in advance of cold weather resulted in nearly $340 million in uplift payments across five days.[64] Such actions ensured system reliability,[65] but at the expected cost of atypically high uplift payments.[66]

This coming winter, system operators may similarly pre-position resources in advance of expected cold weather. This could reduce reliability risks but also increase uplift payments in RTOs/ISOs.

For example, for PJM see PJM, Data Miner 2: Daily Uplift Charges by Zone (last accessed Oct. 6, 2025), https://dataminer2.pjm.com/feed/uplift_charges_by_zone; for NYISO see Open Access Same-Time Information System: Pricing Data (last accessed Oct. 6, 2025), https://mis.nyiso.com/public/; for MISO see MISO, Market Reports (last accessed Oct. 6, 2025) https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/; and for SPP, see SPP, Make Whole Payment Report (last accessed Oct. 6, 2025), https://portal.spp.org/pages/make-whole-payment-report.

[63] Like daily uplift payments, daily wholesale electricity costs based on RTO/ISO LMPs are also higher in the winter on average, compared to the rest-of-the-year.

[64] Monitoring Analytics (PJM Independent Market Monitor), *2025 Quarterly State of the Market Report for PJM: January through June* at 284, 302-304 (Aug. 14, 2025), http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2025/2025q2-som-pjm-sec4.pdf.

[65] PJM Operating Committee, *Cold Weather Operations: January 18–23, 2025* at 3 (Feb. 6, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/committees/mrc/2025/20250319/20250319-item-08---1-january-2025-cold-weather-update---presentation.pdf.

[66] PJM Members Committee, *Markets Report* at 27 (Feb. 18, 2025) (showing uplift as a percent of energy costs equal to almost 8% in January 2025 and below 2% for all preceding months), http://www.pjm.com/-/media/DotCom/committees-groups/committees/mc/2025/20250218-web/item-05a---1---market-operations-report.pdf.

Slide 20

Regional Highlights and Probabilistic Assessment

Source: NERC

NERC Regional Probabilistic Assessments

In this section, staff relies on NERC's probabilistic risk analyses[67] to assess resource adequacy. Regions can face energy shortfalls despite having planned reserve margins that exceed the reference margin levels.[68]

NERC's analysis shows that all assessment areas, as shown in **Slide 20**, anticipate adequate supplies and reserve margins under normal conditions, but ERCOT, NPCC-NE, SERC-East, SERC-Central, WECC-Basin, and WECC-NW may face a higher likelihood of tight supply and reliability issues during extreme conditions.[69] For all assessment areas, above-normal

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[67] A probabilistic risk analysis assesses the potential variations in resources and load that can occur under changing conditions or during certain scenarios and incorporates operator actions that could help to mitigate any shortfalls in operating reserves.

[68] NERC, *2025-2026 Winter Reliability Assessment* (Nov. 18, 2025), http://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf.

[69] All Regional Entities and assessment areas provide a probability-based resource adequacy risk assessment for the winter season. NPCC-US consists of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont, and New York; PJM consists of all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the

winter peak load and resource outages could result in the need to employ operational mitigations. In the event of challenging operating conditions, system operators take actions known as operational mitigations 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, allowing system operators to call on a variety of additional resources that are only available during scarcity conditions such as activating emergency demand response measures and increasing generation imports from neighboring regions.

Additionally, NERC assessment areas coordinate extensively ahead of anticipated extreme weather to try to prevent supply shortages. For example, ERCOT performs day-ahead and near-term studies to evaluate generation capacity at high risk due to extreme weather conditions to assess potential load shed scenarios. As part of ERCOT's protocols with SPP and MISO, ERCOT coordinates with the two RTO neighbors if look-ahead study results indicate that emergency conditions may arise.[70] NPCC-NE continues to closely monitor regional energy adequacy, particularly during extended cold snaps where constrained natural gas pipelines contribute to rapid depletion of stored fuel supplies.[71] Both SERC-Central and

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District of Columbia; SERC encompasses all or parts of North Carolina, South Carolina, Tennessee, Georgia, Alabama, Mississippi, Missouri, Kentucky, Florida, Arkansas, Illinois, Iowa, Louisiana, Oklahoma, Virginia, and Texas; MISO encompasses all or parts of 15 U.S. states including Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, North Dakota, South Dakota, Texas, and Wisconsin, and the Canadian province of Manitoba; SPP encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming; ERCOT is located entirely in the state of Texas; and WECC's footprint extends from Canada to Mexico and includes the provinces of Alberta and British Columbia; the northern portion of Baja California, Mexico; Arizona, California, Colorado, Idaho, Nevada, New Mexico, Oregon, Utah, Washington, Wyoming; and portions of Montana, Nebraska, South Dakota and Texas. *See* NERC, *Long Term Reliability Assessment* (December 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

[70] ERCOT, ERCOT-SPP Coordination Plan (Accessed Oct. 7, 2025), https://www.ercot.com/files/docs/2020/05/29/ERCOT-SPP-Coordination-Plan.pdf; ERCOT, ERCOT-MISO Coordination Plan (Accessed Oct. 7, 2025), https://www.ercot.com/files/docs/2019/03/27/ERCOT-MISO_Coordination_Plan.pdf.

[71] *NERC, 2025-2026 Winter Reliability Assessment* (Nov. 18, 2025), http://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf.

SERC-East report that fuel supplies and transportation remain stable, supported by firm natural gas contracts, storage resources, and reliable pipeline capacity. Coal and oil inventories are projected to remain adequate to meet winter demand.[72] WECC operators monitor grid market conditions in real time, with forecasts extending from the next day to seven days ahead for prescheduled trading.[73]

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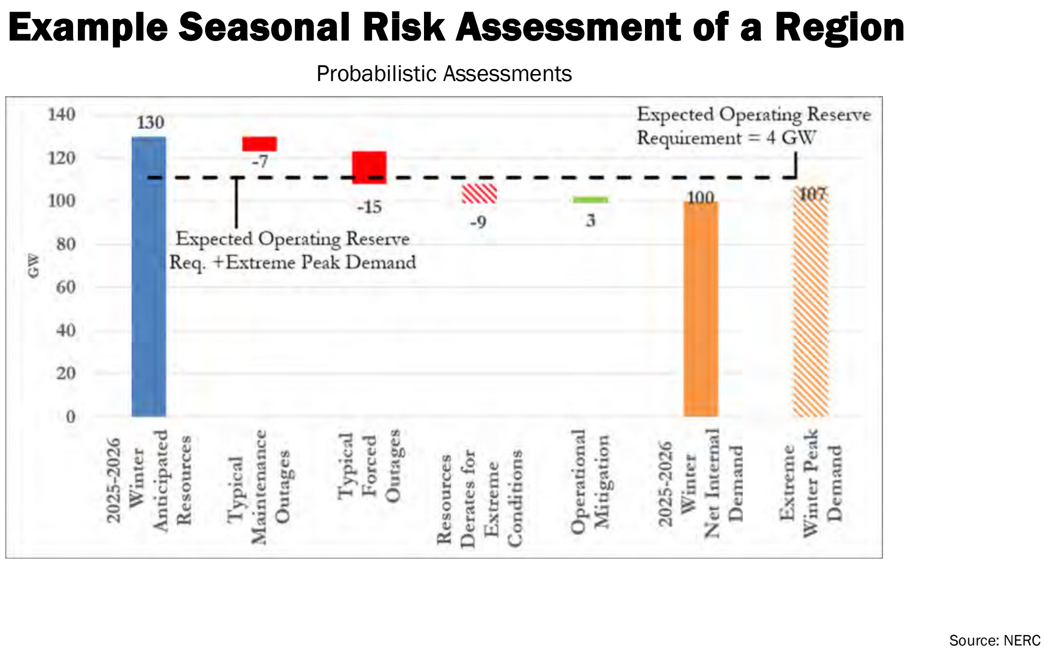
72 *Id.*

73 *Id.*

Slide 21



Regional Highlights

NERC conducts probabilistic assessments of each assessment area that evaluates the risk of resource adequacy shortfalls for the winter. This winter risk period scenario compares chosen extreme scenarios determined by the NERC assessment areas. In this section, FERC staff highlights the following assessment areas: ERCOT, NPCC-NE, WECC-Basin, and WECC-NW. However, NERC's *2025-2026 Winter Reliability Assessment* also highlighted SERC-East and SERC Central.

NERC's *2025-2026 Winter Reliability Assessment* uses "waterfall" charts to provide a helpful visual of its probabilistic assessments for each region. The chart in **Slide 21** is an example seasonal risk assessment for a hypothetical region. The left blue column on the chart shows anticipated resources and the two orange columns on the right show the normal peak (50/50) and the extreme winter peak (90/10) demand scenarios.[74] The middle red bars show the factors that can reduce resource availability, including maintenance outages and forced outages, not already accounted for in anticipated resources. The middle green bar depicts potential additions in resource availability from operational mitigation actions, if any, that are available during scarcity conditions but have not been accounted for in the reserve margins.

[74] A 50/50 peak load forecast is based on a 50% chance that the actual system peak load will exceed the forecasted value. A 90/10 peak load forecast is based on a 10% chance that the actual system peak load will exceed the forecasted value.

The dotted, horizontal line represents the expected operating reserve requirement plus the extreme peak demand, or the amount of power that a region would need to produce to avoid a shortfall.

The seasonal risk assessment scenarios are determined by the assessment areas to provide insight into unanticipated events during normal and/or extreme winter conditions. However, they do not account for all the unique energy adequacy risks associated with a specific area. The scenarios generally assess the greatest risk hour(s) for Expected Unserved Energy, along with the varying demand and available resource profiles. The methods, scenarios considered, and assumptions differ by assessment area and may not be comparable.

ERCOT. Winter peak demand in ERCOT's Texas footprint typically occurs before sunrise and after sunset when solar generation is unavailable.[75] ERCOT anticipates having sufficient operating reserves during the winter peak load hour (the hour ending at 8:00 a.m.) under expected normal system conditions. However, under extreme scenarios, the region faces increased risk of reserve shortages during both the peak-load hour and high net load hours. During these hours, the system relies heavily on wind generation and dispatchable resources.

Generally, risk in ERCOT continues to rise primarily due to factors such as robust load growth, slower evening load declines—which are largely attributed to continuous data center operations—and limited additions of new dispatchable capacity to meet elevated morning and evening net loads.[76] This risk is heightened by potential forced outages of thermal resources and reduced output from intermittent resources. The load growth in West Texas combined with scenarios for "no solar" and low wind conditions can cause transmission lines into this area to become heavily loaded. As one way to address this risk, ERCOT improved dynamic line ratings that allow for greater transfers at colder temperatures and periods of low solar irradiance.[77] The rapid increase in installed battery storage in ERCOT will also help address this risk. However, maintaining an adequate state of charge during prolonged high-load events, such as a widespread, multi-day event like Winter Storm Uri, remains a significant challenge.[78]

[75] NERC, *2025-2026 Winter Reliability Assessment* at 31 (Nov. 18, 2025), http://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf.

[76] NERC, *2025-2026 Winter Reliability Assessment* (Nov. 18, 2025), http://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf.

[77] *Id.*

[78] *Id. at 6*.

NPCC-NE. Under normal winter conditions, NPCC-NE has adequate resources to meet demand. However, a persistent concern in the region is whether sufficient energy will be available during an extended cold spell given the current resource mix, fuel delivery infrastructure, and expected fuel arrangements. Without significant efforts to replenish stored fuels such as fuel oil and LNG, energy adequacy could be challenged.[79]

In NPCC-NE, winter energy concerns are highest in scenarios when stored fuels are rapidly depleted; during these periods timely replenishment is critical to minimizing the potential for energy shortfalls. ISO-NE's 21-day energy forecast is intended to identify these types of scenarios. To support situational awareness and fuel procurement decisions, ISO-NE publishes a rolling 21-day energy assessment at least weekly with more frequent updates as needed.[80] This assessment provides early indications of potential fuel scarcity conditions for market participants.[81] ISO-NE has also expanded an existing winter readiness survey of generators to include more detailed questions, capturing additional data on potential temperature-related limitations.[82] ISO-NE will also continue to use its Probabilistic Energy Adequacy Tool to assess energy shortfall risks ahead of the 2025–2026 winter season.[83]

NPCC-NE shows little change to the anticipated reserve margin for this winter from the previous year, and a lower peak demand forecast and additional resources from demand

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[79] *Id at 22.*

[80] ISO-NE, 21-Day Energy Assessment Forecast and Report (accessed Sept. 23, 2025), https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/21-Day-Energy-Assessment-Forecast-and-Report-Results.

[81] *Id.*

[82] ISO-NE, OP-21, Operational Surveys, Energy Forecasting & Reporting, and Actions During an Energy Emergency (Accessed Oct. 7, 2025), https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op21/op21_rto_final.pdf.

[83] Probabilistic Energy Adequacy Tool is a tool that ISO-NE use for risk analysis under extreme weather events. It is essential for evaluating the region's risk of energy shortfall — the electricity supply falling below consumer demand — giving the region's stakeholders advance warning and the opportunity to take steps to avert it; ISO New England, Update on Energy Adequacy Tool, Energy Shortfall Threshold, and Perspectives on Retail Demand Response, (May 21, 2024), https://www.iso-ne.com/static-assets/documents/100011/necpuc_sgeorge_may_2024_final.pdf; ISO New England, ISO Newswire: ISO-NE's study of energy shortfall risks produces innovative tool for assessing energy adequacy (Dec. 11, 2023), https://isonewswire.com/2023/12/11/iso-nes-study-of-energy-shortfall-risks-produces-innovative-tool-for-assessing-energy-adequacy/.

response and firm imports should offset recent generator retirements.[84] NPCC-NE imports power from Canada and neighboring RTOs/ISOs and periodically assesses its reliance on power transfers from neighboring Reliability Coordinator areas through market mechanisms and reliability studies. External resources may participate in the Forward Capacity Market, securing Capacity Supply Obligations to supply energy to New England when needed, integrating them into the region's capacity mix. An annual tie benefits study conducted by ISO-NE estimates reliable import capacity during stressed system conditions.[85]

WECC. WECC warns of potential reserve margin shortfalls in the WECC-Basin and WECC-NW assessment areas during the 2025–2026 winter season during the extreme condition scenario.

WECC-Basin. WECC-Basin encompasses all of Utah, the western part of Wyoming, and the southern and eastern part of Idaho. Under an extreme combination of derates and outages, WECC-Basin could be short one GW of internal supply and imports needed to serve load, and it expects an increased reliance on transfers. Net internal demand is expected to increase 1% since last winter, with total internal demand up 1.8%. This is offset by a doubling of controllable and dispatchable demand response. However, Tier 1 resources, which are capacity that is under construction or that has received approved planning requirements, have declined and do not appear to be offset by increases in existing-certain generation resource capacity.[86] Meanwhile, nameplate wind has increased by almost 18% and solar by almost 30%, and hydro is also up over 7% in total installed capacity since last winter, but derates need to

[84] NERC, *2025-2026 Winter Reliability Assessment* at 5 (Nov. 18, 2025), http://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf.

[85] The study analysis accounts for expected emergency assistance, system reliability practices and the Total Transfer Capability of external interfaces. *See* ISO-NE*, Benefits Values for Reconfiguration Auctions to be Conducted in 2025,* https://www.iso-ne.com/static-assets/documents/100015/a03_review_of_2025_2026_ara_3_tie_benefits_study_results.pdf ; ISO New England, Tie Benefits Methodology: Evaluation Review of Probabilistic Analysis, Tie Benefits Methodologies of ISO-NE and Other ISO/RTOs, and Tie Benefits Evaluation Scope of Work (Oct. 19, 2023), http://www.iso-ne.com/static-assets/documents/100004/a05_tie_benefits_methodology_evaluation.pdf.

[86] Existing-certain 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: (1) unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; (2) unit must be classified as a designated network resource; and/or, (3) where energy-only markets exist, unit must be a designated market resource eligible to bid into the market.

be factored into the performance calculations. Overall, WECC-Basin expects to be reliant on imports to maintain resource adequacy.[87]

WECC-NW. WECC-NW encompasses all of Montana, Washington, and Oregon, and the northern parts of both Idaho and California. WECC-NW has historically been a mixed-season peaking region and shows operating reserve margins expected to be met before needing imports for all winter scenarios. This winter, projected total and net internal demand are up 9.3%, with the primary drivers being data centers, residential electrification, transportation electrification, and semiconductor manufacturing. Large coal unit retirements and conventional hydro unit retirements contribute to the reduction in existing certain capacity by 10.5%; however, planned Tier 1 resources (capacity that is under construction or has received approved planning requirements) have soared over 580%, from 463 MW to over 3 GW. An increase in nameplate capacity for both wind and solar in WECC-NW has also led to a moderate increase in solar availability during the peak hour.

To assess long-term vulnerabilities for all of WECC, WECC conducted two studies evaluating the impact of extreme cold weather events on electric system reliability 10 and 20 years into the future.[88] Both studies highlight the risks[89] associated with heavy reliance on natural gas during severe winter conditions. According to WECC, currently there are no reported or planned pipeline disruptions or outages that would directly threaten natural gas delivery in winter 2025-2026. But lessons from Winter Storm Elliott underscore how freeze-offs, scheduling mismatches, and pipeline constraints have previously contributed to generation

[87] NERC, *2025-2026 Winter Reliability Assessment* at 33 (Nov. 18, 2025), http://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf.

[88] WECC, *Year 10 Extreme Cold Weather Event* (Nov. 2023), https://www.wecc.org/sites/default/files/documents/meeting/2024/Year-10%20Extreme%20Cold%20Weather%20Event%20Report%202023.pdf; WECC, *Year 20 Extreme Cold Weather Event*, (April 2024), https://www.wecc.org/sites/default/files/documents/meeting/2024/Year%2020%20Cold%20Weather%20Event%20Study.pdf.

[89] The studies shows that the western grid depends heavily on natural gas-fired generation to meet demand during extreme cold events. According to the studies, during cold snaps natural gas supply and pressure can drop due to heating demand and infrastructure freezing. Also, the reports note that if gas supply is constrained or derated (by 15–35%), large amounts of unserved energy could occur.

shortfalls and power outages. Since then, improvements such as revised gas pipeline logic[90] and expedited emergency protocols have strengthened system resilience.[91]

The Western Interconnection remains a focal point for proposed pipeline expansions aimed at easing regional supply constraints.[92] While these projects could eventually stabilize fuel prices and support growing demand, most remain in early development stages and will not be in place for winter 2025-2026.[93]

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[90] Gas pipeline logic refers to the system of rules, controls and decision-making processes that govern the operation, monitoring, and optimization of natural gas transmission through pipelines.

[91] WECC Assurance Program provides WECC and its stakeholders with tools to help manage specific risks related to extreme weather and recommendations for improvements to policies, processes and procedures for reviewing system performance during extreme weather events; WECC, WECC Assurance Program explainer (May 15, 2025); https://www.wecc.org/sites/default/files/documents/initiative/2025/Assurance%20Program%205.15.2025.pdf.

[92] S&P Capital IQ Pro, Natural Gas Development Projects (Accessed Oct. 2, 2025), https://www.capitaliq.spglobal.com/web/client?auth=inherit#industry/GasProjects.

[93] These projects include the Desert Southwest Pipeline Expansion (Transwestern Pipeline Company, owned by Energy Transfer): This project involves constructing 516 miles of 42-inch pipeline and nine compressor stations to transport up to 1.5 Bcfd of natural gas from the Permian Basin (Texas/New Mexico) to markets in Arizona and the Southwest. It was announced in August 2025, with a binding open season launched in September 2025. The construction is pending regulatory approvals and final investment decisions. Energy Transfer LP, *Energy Transfer Announces Natural Gas Pipeline Project to Serve Growing Southwestern U.S. Markets*, press release, (August 6, 2025), https://ir.energytransfer.com/news-releases/news-release-details/energy-transfer-announces-natural-gas-pipeline-project-serve; Also included is the Helena-to-Three Forks Pipeline Project (NorthWestern Energy), a proposed natural gas pipeline in Montana, spanning from Helena south to the Three Forks area. It aims to enhance service reliability, add system redundancy by linking existing infrastructure, and support regional energy needs. Construction is expected to begin in 2027. NorthWestern Energy Group, Inc., Helena to Three Forks Natural Gas Transmission Pipeline Project 2024, (Accessed Oct. 7, 2025), https://northwesternenergy.com/about-us/our-projects/helena-to-three-forks-pipeline-project#.

Slide 22

2025-2026 Winter Energy Market and Electric Reliability Assessment

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This concludes the 2025-2026 Winter Energy Market and Electric Reliability Assessment. For questions regarding this report please contact market.assessments@ferc.gov.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-30:
Winter Storm Elliott System Operations Inquiry

Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott

FERC, NERC and Regional Entity Staff Report
October 2023

Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott

FERC, NERC and Regional Entity Staff Report
October 2023

FEDERAL ENERGY REGULATORY COMMISSION

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Regional Entities:
Midwest Reliability Organization, Northeast Power Coordinating Council, ReliabilityFirst Corporation, SERC Corporation, Texas Reliability Entity and Western Electricity Coordinating Council

Table of Contents

I. EXECUTIVE SUMMARY

This report describes how the extreme cold weather event occurring between December 21 and 26, 2022 (Winter Storm Elliott) impacted the reliability of the Bulk Electric System ("BES" or colloquially known as the grid) and the supporting natural gas infrastructure in the U.S. Eastern Interconnection[1] ("the Event").[2] During the Event, 1,702 individual BES[3] generating units in the Eastern Interconnection experienced 3,565 unplanned outages, derates, or failures to start.[4] Each individual unit could, and often did, have multiple outages from the same or different causes. At the worst point of the Event, there were 90,500 MW of coincident unplanned generating unit outages, derates and failures to start (meaning they all occurred at the same time). Including generation that was already out of service,[5] a total of over 127,000 MW of generation was unavailable, representing 18 percent of the U.S. portion of the anticipated resources in the Eastern Interconnection.

The Event was the **fifth** in the past **11** years in which

1 There are four nterconnect ons n North Amer ca, w th three of those nterconnect ons encompass ng the ower 48 states: the Eastern nterconnect on; the ERCOT nterconnect on; and the Western nterconnect on. NERC nterconnect ons, ava ab e at https://www.nerc.com/AboutNERC/keyp ayers/Pub sh ng mages/NERC%20 nterconnect ons.pdf. *See also*, FERC Re ab ty Pr mer, 11 (2020), https://www.ferc.gov/med a/2135.

2 Th s s a staff report, and does not speak for the Comm ss on, NERC or any of the Reg onal Ent t es. ***See*** Press Release, FERC, NERC to Open Jo nt nqu ry nto W nter Storm Ell ott (December 28, 2022) for a descr pt on of the nqu ry's commencement. *See* Append x A for l st of the W nter Storm Ell ott nqu ry jo nt team members (the "Team"). The Team of over 50 subject matter experts from the Comm ss on, NERC and all of ts Reg onal Ent t es: M dwest Rel ab l ty Organ zat on (MRO), Northeast Power Coord nat ng Counc l (NPCC), Rel ab l tyF rst Corporat on (RF), SERC Corporat on (SERC), Texas Rel ab l ty Ent ty (TRE) and the Western Electr c ty Coord nat ng Counc l (WECC); as well as the Nat onal Ocean c and Atmospher c Adm n strat on (NOAA), was formed shortly after the Event determ ne the causes of the Event and make recommendat ons to prevent recurrence of the effects that the extreme cold weather caused for the gr d. Append x B ncludes a l st of acronyms Used n the Report. The Report s wr tten for a reader who s already fam l ar w th pr nc ples of energy markets, electr c transm ss on operat ons, generat ng un t operat ons, and natural gas product on, process ng, and transportat on. For readers who are not as fam l ar, the staff Pr mers on Electr c and Natural Gas Markets deta l the essent al pr nc ples related to energy markets, electr c transm ss on operat ons, generat ng un t operat ons, and natural gas product on, process ng, and transportat on, *see* FERC Energy Pr mer (https://www.ferc.gov/med a/energy pr mer handbook energy market bas cs) and FERC Rel ab l ty Pr mer (https://www.ferc.gov/s tes/default/files/2020 04/rel ab l ty pr mer 1.pdf).

3 The Comm ss on's jur sd ct on extends to the Bulk Power System, defined by Sect on 215(a) (1) of the Federal Power Act as "fac l t es and control systems necessary for operat ng an nterconnected electr c energy transm ss on network (or any port on thereof), and electr c energy from generat ng fac l t es needed to ma nta n transm ss on system rel ab l ty." The mandatory Rel ab l ty Standards apply to owners and operators of the Bulk Electr c System (BES). n Order No. 773, the Comm ss on approved a defin t on of BES that generally covers all elements operated at 100 kV or h gher, w th a l st of spec fic nclus ons and exclus ons. Rev s ons to Electr c Rel ab l ty Organ zat on Defin t on of Bulk Electr c System and Rules of Procedure, Order No. 773, 141 FERC ¶ 61,236 (2012); order on reh'g, Order No. 773 A, 143 FERC ¶ 61,053 (2013), order on reh'g and clar ficat on, 144 FERC ¶ 61,174 (2013). Th s report w ll use BES because ts pr mary aud ence s most fam l ar w th that term. There were some non BES generat ng un ts (.e., that d d not meet the BES defin t on n the NERC Glossary of Terms) that exper enced outages, derates, or fa lures to start w th n the Eastern nterconnect on but the Team d d not request data from them and they are not ncluded n ts analys s. By defin t on these un ts would be less than 20 MW nd v dually or 75 MW n the aggregate w th a common po nt of connect on (e.g. a w nd or solar fac l ty). https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary of Terms.pdf .

4 The Team obta ned generat ng un t data d rectly from the Generator Owners and/or Operators (GOs/GOPs).

5 Those un ts that were already out of serv ce ncluded generat ng un ts undergo ng planned ma ntenance outages and those un ts that ncurred forced outages before the Event, that had not yet returned to serv ce dur ng the worst po nt of the Event.

unplanned cold weather-related generation outages jeopardized grid reliability.[6] Several Balancing Authorities (BAs) (grid operators that balance demand and electric energy) in the southeast U.S. needed to shed firm load during the Event to maintain system reliability, which in total (at different points in time) exceeded 5,400 MW. This was the largest controlled firm load shed recorded in the history of the Eastern Interconnection. Just one year before, in 2021, the Winter Storm Uri event in Texas and the South Central U.S. saw the largest controlled firm load shed event in U.S. history, with over 20,000 MW of firm load shed (20,000 MW in ERCOT alone). In that event, more than 4.5 million people lost power in Texas, and some went without power for as long as four days, while exposed to below freezing temperatures for as long as six days. Estimates of those who died during that event, primarily from causes connected to the power outages including hypothermia, carbon monoxide poisoning, and medical conditions exacerbated by freezing conditions, range from over 200 to over 800.[7] The Federal Reserve Bank of Dallas estimated the direct and indirect losses to the Texas economy from that event to be between $80 and $130 billion.[8]

The quantity of firm load shed during Winter Storm Elliott was not as large as in the Winter Storm Uri event, but it is especially disconcerting that it happened in the Eastern Interconnection which normally has ample generation and transmission ties to other grid operators that allow them to import and export power. And yet, for reasons described more fully in Section IV of the Report, electric grid operators were faced with a generation capacity shortage that resulted in 5,400 MW of firm load shed.

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6 n February 2011, an arct c cold front mpacted the southwest U.S. and resulted n 29,700 MW of generat on outages, natural gas fac l ty outages, and emergency power gr d cond t ons w th need for firm customer load shed. Report on Outages and Curta lments Dur ng the Southwest Cold Weather Event of February 1 5, 2011: Causes and Recommendat ons (Aug. 2011), Report on outages and curta lments dur ng the Southwest cold weather event (ferc.gov) ("2011 Report"). n January 2014, a polar vortex affected Texas, central and eastern U.S., tr gger ng 19,500 MW of generat on outages, and natural gas ava lab l ty ssues result ng n emergency cond t ons nclud ng voluntary load management. NERC "Polar Vortex Rev ew" (Sept. 2014), https://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Rev ew/Polar Vortex Rev ew 29 Sept 2014 F nal.pdf ("Polar Vortex Rev ew"). n January 2018, an arct c h gh pressure system and below average temperatures n the South Central U.S. resulted n 15,800 MW of generat on outages and the need for voluntary load management emergency measures. South Central Un ted States Cold Weather Bulk Electr c Systems Event of January 17, 2018 (July 2019), https://www.ferc.gov/s tes/default/files/2020 07/SouthCentralUn tedStatesColdWeatherBulkElectr cSystemEventofJanuary17 2018.pdf ("2018 Report"). F nally, n February 2021, extreme cold weather and freez ng prec p tat on n Texas and the South Central U.S. resulted n generat ng outages of over 60,000 MW and over 20,000 MW of firm load shed. The February 2021 Cold Weather Outages n Texas and the South Central Un ted States FERC, NERC and Reg onal Ent ty Staff Report (Nov. 2021), The February 2021 Cold Weather Outages n Texas and the South Central Un ted States FERC, NERC and Reg onal Ent ty Staff Report Federal Energy Regulatory Comm ss on ("2021 Report").

7 Recent "excess death" analyses of deaths n Texas dur ng the 2021 event range as h gh as 800. Amber Weber & Mose Buchele , *Texas has an official death count from the 2021 blackout. The true toll may never be known.*, Texas Standard (Aug. 15, 2022),Texas has an off c al death count from the 2021 blackout. The true toll may never be known. Texas Standard.

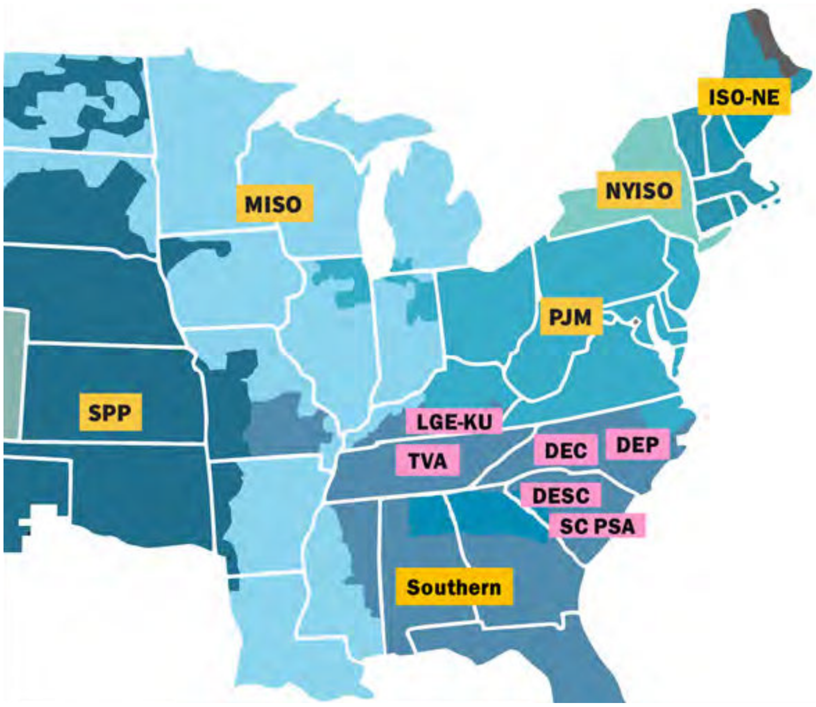
8 Garrett Gold ng et al., *Cost of Texas' 2021 Deep Freeze Justifies Weatherization*, Dallas Fed. Econom cs (Apr. 15, 2021), https://www.dallasfed.org/research/econom cs/2021/0415.

A. Synopsis of Event

The storm that came to be known as Winter Storm Elliott, variously characterized as a bomb cyclone and an extra-tropical cyclone,[9] moved from the upper Plains states eastward. By Wednesday, December 21, 2022, it reached the central U.S., eventually blanketing most of the eastern United States on December 23 and 24, and did not subside until December 26. In an unacceptably familiar pattern, the cold temperatures ushered in electric generation outages that coincided with winter peak electricity demands (i.e., winter peak loads), and resulted in many BAs declaring energy emergencies. The amount of generation that failed during the Event was unprecedented—90,500 MW in coincident unplanned outages.[10] The coincident incremental[11] unplanned generation outages *alone* represented 13 percent of the U.S. portion of the winter 2022-2023 anticipated generation resources in the Eastern Interconnection.[12]

Figure 1, below, shows the entities in the U.S. Eastern Interconnection most affected by Winter Storm Elliott, referred to as the "Event Area." The entities represented by a pink box shed firm load at some point during the Event, including Tennessee Valley Authority (TVA), Louisiana Gas and Electric Company/Kentucky Utilities (LG&E/KU),

Figure 1: Bulk Electric System Map of Entities in the U.S. Eastern Interconnection Affected by the Extreme Cold Weather



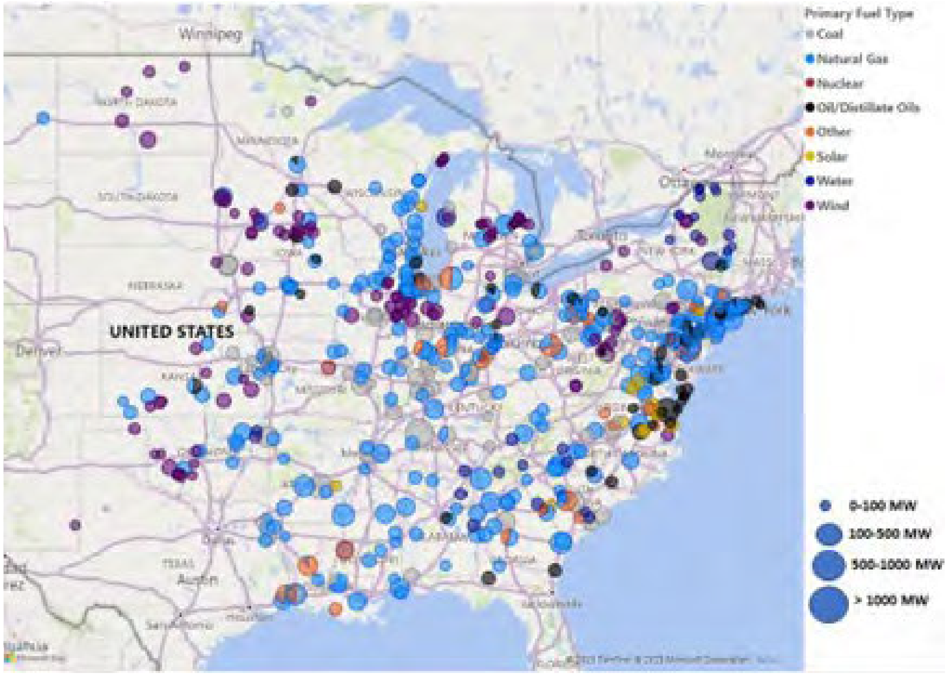
9 Both are terms that denote a storm assoc ated w th a rap d drop n pressure the more rap d the drop n pressure, the more ntense the storm. Pandora Dewan, *Bomb Cyclone Photos: What to Expect From Freezing Weather Forecast*., Newsweek (Dec. 20, 2022), https://www.newsweek.com/bomb cyclone photos freez ng weather forecast 1768515#:~:text Ell ott%20 s%20expected%20to%20arr ve%20 n%20the%20Pac fic,the%20M dwest%20and%20parts%20of%20the%20East%20Coast.

10 The 2021 W nter Storm Ur event had 65,622 MW co nc dent ncrementa unp anned generat ng un t outages, the most that occurred before the Event.

11 " ncremental" generat ng un t outages, derates, and fa lures to start refers to those wh ch occurred dur ng the Event (December 21 26, 2022), as compared to those wh ch occurred before the Event.

12 Based on data from the NERC 2022 2023 W nter Rel ab l ty Assessment. The 18 percent of Eastern nterconnect on resources reference earl er s for unplanned outages that occurred dur ng the Event at the moment when the most generat on was offl ne dur ng the Event ("the worst po nt"), plus unplanned and planned outages that were already n effect at the beg nn ng of the Event. NERC, *2022 2023 Winter Reliability Assessment* (Nov. 2022), https://www.nerc.com/pa/RAPA/ra/Rel ab l ty%20Assessments%20DL/NERC WRA 2022.pdf.

Figure 2: Location and Fuel Type of Unplanned Generation Outages and Derates During the Event (Bubble Size by MW for each Outage), as of December 24, 2022



Duke Energy Progress (DEP) and Duke Energy Carolinas (DEC), Dominion Energy SC (DESC), and South Carolina Public Service Authority (Santee Cooper). Other entities issued Energy Emergency Alerts (EEAs),[13] but did not need to shed firm load, including PJM Interconnection, LLC (PJM), Southern Company (Southern), Midcontinent Independent System Operator (MISO), Southwest Power Pool (SPP), and ISO New England (ISO-NE). All of the affected entities experienced significant unplanned generating unit outages, derates, or failures to start within their footprints. See Figure 2, above, shows the approximate locations of the generating unit outages during the Event and their fuel type.

The 2021 Report attributed the unplanned generating outages to generating units unprepared for the cold weather and natural gas fuel supply issues:

> A confluence of two causes, both triggered by cold weather, led to the [Uri] Event, part of a recurring pattern for the last ten years. First, generating units unprepared for cold weather failed in large numbers. Second, in the wake of massive natural gas production declines, and to a lesser extent, declines in natural gas processing, the natural gas fuel supply struggled to meet both residential heating load and generating unit demand for natural gas, exacerbated by the increasing reliance by generating units on natural gas. Natural gas pipeline capacity is for the most part designed, certificated and constructed to accommodate firm transportation commitments, while many natural gas-fired generating units rely on non-firm commodity and/or pipeline transportation contracts.[14]

13 New York ndependent System Operator (NY SO) d d not declare an EEA dur ng the Event.

14 2021 Report at 11 12.

The Event shows that, while some changes were implemented in response to previous cold weather events, generators and natural gas supply and infrastructure remain vulnerable to extreme cold weather.

Similar to other cold weather events,[15] the cold weather was forecast well in advance. Beginning with forecast colder weather mid-December, and with widespread warnings by December 20, grid operators knew that frigid weather was coming. Many issued cold weather preparation notices to their Generation and Transmission Owners and Operators. Temperatures were lower than normal during the Event, although not quite as far off normal lows as during the 2021 event. Winter Storm Elliott's departures from normal minimum lows were largely from 15 to 30 degrees lower than normal, though a small area was even lower. In Winter Storm Uri, departures from normal minimum lows ranged from 40 to 50 degrees lower than normal low temperatures. However, Winter Storm Elliott generally had higher winds than Uri, with gusts up to 60 miles per hour, which increased convective cooling. Rapid temperature drops to subfreezing levels across the eastern half of the U.S. occurred. For example, temperatures in Charleston, West Virginia dropped 42 degrees in six hours, and TVA reported a drop of 46 degrees in five hours. Some areas experienced blizzard conditions. Geographically, Winter Storm Elliott was a very large storm. At approximately 2,000 miles wide, its extreme cold and high winds covered the eastern two-thirds of the lower 48 U.S.

Winter Storm Elliott caused unplanned outages of natural gas wellheads due to wellhead freeze-offs and other frozen equipment. Weather-related poor road conditions prevented necessary maintenance.[16] This led to significant natural gas production decreases, which also occurred during the 2011 and 2021 events.[17] During the Event, "[d]ry natural gas production in the Lower 48 states dropped to a low of 82.5 Bcf on December 24, a 16 percent decrease (16.1 Bcf/d) from December 21...."[18] Gas production experienced the greatest declines in the Marcellus and Utica Shale formations, where it dropped by 23 to 54 percent during the Event.[19] Figure 3, below, shows the areas where production decreases occurred.

The affected grid operators, beginning with SPP and then MISO, saw rising load and increasing generating unit outages during the Event, which in many cases led to a reduction in their energy reserves. Neither SPP nor MISO needed to shed firm load throughout their footprints,[21] but, to combat the rising loads and generation outages, SPP twice curtailed non-firm exports on December 23 because its reserves were low. MISO and SPP closely coordinated on the Regional Directional Transfer Limit between MISO South and the rest of MISO (see Figures 41 and 42), twice lowering the limit at SPP's request.[22]

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15 *See* F gure 4 below, for a s de by s de compar son of the past five extreme cold weather events n 11 years. For add t onal nformat on on extreme cold weather cond t ons dur ng the events, *see* the 2021 Report, Append x B: Compar son of S m lar Severe Weather Events, at 245.

16 The Team also obta ned natural gas product on and process ng data d rectly from owners of these fac l t es, unless otherw se stated. However, because these ent t es are not subject to the Comm ss on's jur sd ct on, the Team d d not rece ve all data requested.

17 The teams observed decreases n natural gas product on n the 2011 and 2021 cold weather events. The teams study ng the 2014 Polar Vortex and January 2018 events d d not quant fy natural gas product on losses or nvest gate any causes for such losses.

18 James Easton and Max Ober, *U.S. natural gas consumption reached record daily high in late December 2022*, Today n Energy (Jan. 31, 2023), https://www.e a.gov/today nenergy/deta l.php? d 55359.

19 Source: S&P Global Commod ty ns ghts, ©2023 by S&P Global nc.

20 Source: E A: Maps: O l and Gas Explorat on, Resources, and Product on Energy nformat on Adm n strat on (e a.gov), adapted from "Lower 48 Shale Plays."

21 SPP had a local zed voltage ssue caused by a comb nat on of unplanned generat ng un t outages and transm ss on outages. Local transm ss on system operators n t ated a br ef] firm load shed of 29 MW to allev ate ssue. *See section* .B.3.a), Thursday, December 22: Effects of Ell ott beg n to mpact U.S. port on of Eastern nterconnect on BES, for add t onal d scuss on.

22 Unplanned generat on outages and underest mated loads n M SO's "South" reg on led t to ncrease ts north to south power transfer to supply more power to that port on of ts system. M SO agreed to l m t ts north to south transfer by half of ts contractual l m t (1,500 MW)..

On December 23, MISO declared EEA 1 and 2,[23] due to congestion on its transmission system and diminished generation deliverability and used 3,000 MW of Load Modifying Resources.[24] MISO also had several local transmission emergencies but did not need to shed any firm load.

Figure 3: Areas of Shale Natural Gas Production Where Extreme Cold Weather Occurred[25]

TVA experienced rapidly-increasing generating unit outages in the early morning hours of December 23. By 6 a.m. Eastern Standard Time,[26] TVA had lost over 5,000 MW of generation and declared EEA 1 and EEA 2. By 6:12 a.m., TVA declared EEA 3, which indicated that firm load shed was imminent, and secured emergency power from Duke, Southern, PJM, and MISO, but this solution was short-lived. As TVA continued to experience significant unplanned generation outages and increasing electricity demands, PJM needed to reduce the emergency power it was supplying to TVA, due to a transmission operating limit in PJM.[27] By 10:31 a.m., now faced with well over

23 *See* Rel ab l ty Standard EOP 011 2 Emergency Preparedness and Operat ons, “Attachment 1 EOP 011 2 Energy Emergency Alerts” for the levels of alerts and energy emergenc es, at https://www.nerc.com/pa/Stand/Rel ab l ty%20Standards/EOP 011 2.pdf. EEA levels nd cate to ne ghbor ng Balanc ng Author t es that a Balanc ng Author ty s exper enc ng an energy emergency and the level of sever ty. The Rel ab l ty Coord nator s respons ble for declar ng EEAs for ts Balanc ng Author t es w th n ts footpr nt per EOP 011 2, Requ rement R6, and as deta led n Attachment 1.

24 Load Mod fy ng Resources, or LMRs, are demand resources or beh nd the meter generat on.

25 Source: E A: Maps: O l and Gas Explorat on, Resources, and Product on Energy nformat on Adm n strat on (e a.gov), adapted from “Lower 48 Shale Plays.”

26 All t mes stated w th n the Report, unless otherw se spec fied, are Eastern Standard T me (EST). f the ent ty s located n the Central T me Zone, all t mes were converted to EST.

27 PJM operators curta led the emergency power schedule to TVA due to a System Operat ng L m t (SOL). The transm ss on fac l ty at ssue was exceed ng ts emergency l m t n real t me. *See also* s debar on N 1 at 60.

6,000 MW of unplanned generating unit outages since midnight, continually rising system load, and depleted generation reserves, TVA ordered firm load shed of over 1,500 MW, which represented five percent of its peak system load.[28]

LG&E/KU also experienced significant unplanned generation derates during winter peak load conditions on the evening of December 23. To offset the generation derates, LG&E/KU was able to import 400 MW from PJM. At 4:29 p.m., PJM BA curtailed the 400 MW import due to experiencing rapidly increasing levels of unplanned generation outages coincident with increasing system load in its own footprint. In response, LG&E/KU requested emergency energy from the TVA Contingency Reserve Sharing Group, which TVA was able to supply. With its system load increasing, LG&E/KU entered into EEA 3 at 4:45 p.m. Following TVA's return at 5:18 p.m. to EEA 3, by 6:00 p.m. it also could no longer spare its 400 MW emergency power to LG&E/KU. With the loss of the import power to offset the unplanned generation derates, LG&E/KU began over 300 MW firm load shed at 5:58 p.m. This was the first time LG&E/KU had ever ordered firm load shed in response to an energy emergency (EEA) event.

Through the morning of December 24, PJM was providing emergency energy to neighboring Balancing Authorities, but as unplanned outages multiplied and its load increased, it needed to curtail those emergency energy export schedules and declared EEA 1 and EEA 2. PJM benefitted from a Simultaneous Activation of Ten-Minute Reserve (SAR) agreement with the Northeast Power Coordinating Council Balancing Authorities, which allowed PJM to call on reserves of up to 1,500 MW during the Event. PJM requested assistance under the SAR agreement five times between December 23 and 24. Although PJM said it was "close" to needing to shed firm load, it did not.[29]

Southern, like PJM, at first was able to provide emergency energy to other Balancing Authorities. By 6:25 a.m. on December 24, it declared EEA 2, having declared EEA 1 in the early morning hours. Southern obtained emergency energy from Florida Power and Light. The emergency energy import assisted Southern in meeting its all-time December record peak load early that morning and enabled it to provide emergency energy to DESC. DEC, DEP, DESC and Santee Cooper, Balancing Authorities in the Carolinas which form the Carolinas Reserve Sharing Group,[30] experienced escalating unplanned generating unit outages in the face of early morning peak load conditions. Combined with their inability to obtain import power from surrounding Balancing Authorities experiencing the same conditions, at worst points the four Balancing Authorities had to shed a combined total of over 2,000 MW firm load.

28 Th s was the first of two nstances dur ng W nter Storm Ell ott where TVA needed to shed firm load. The other nstance was dur ng the early morn ng hours of December 24. From 6:12 a.m. on December 23 to m dday December 24, TVA was at EEA 3, other than for a br ef per od the afternoon of December 23, when t was at EEA 2. Early the morn ng of December 24, TVA first ordered firm load shed of five percent of ts peak system load, followed by an add t onal five percent reduct on of firm load (n total, 10 percent of ts peak system load wh ch was **over 3,000 MW**). Dur ng those hours, most of TVA's ne ghbor ng BAs were faced w th h gh electr c ty demands and escalat ng unplanned generat ng un t outages of the r own and as a result, could not prov de emergency power to TVA.

29 Although PJM was at an ncreased r sk of load shedd ng approach ng the morn ng peak on December 24, PJM st ll had opt ons before shedd ng firm load, f t had lost another large generat ng un t or f NY SO had to cut ts mports. PJM could have n t ated a Voltage Reduct on Act on, wh ch could have prov ded approx mately 1,700 MW of rel ef. f necessary, PJM could have followed the Voltage Reduct on w th a Manual Load Dump Warn ng (prov d ng Transm ss on Operators w th the r load allocat ons). F rm load shed would occur, f necessary, v a Manual Load Dump Act on, followed by ssuance of EEA 3. PJM Report at 63.

30 *See*, CRSG, Dom n on Energy South Carol na, nc. OATT & SA, § SA No. 239, CRSG Operat ng Manual (0.0.0), https://etar ff.ferc.gov/Tar ffSect onDeta ls.aspx?t d 6293&s d 312207.

B. Recurrence of Cold Weather Events with Unplanned Generating Unit Outages and Implications

The 2021 Report noted, "the [2021 Winter Storm Uri event] was the fourth cold-weather-related event in the last ten years to jeopardize BES reliability," and that "in each of the four BES events, planned and unplanned generating unit outages caused energy emergencies and in 2011, 2014 and 2021 they triggered the need for firm load shed."[31] Each event's report made recommendations to reduce the likelihood of similar consequences in the future.

In several of the previous events, there have been close calls, meaning, that if conditions worsened, it could have resulted in widespread firm load shed or outages. During Uri, for example, ERCOT came within four minutes of a potential complete blackout of the ERCOT Interconnection if the interconnection frequency had not recovered. During the January 2018 cold weather event, had the worst contingency generating unit forced outage occurred in MISO South, its electric grid operators would have needed to rely on post-contingency manual firm load shed to maintain voltages within limits, while faced with potential additional firm load shedding to maintain system balance and restore reserves. The Event, too, had its share of close calls. The natural gas provider for Manhattan, The Bronx, and portions of Queens and Westchester County, Consolidated Edison (Con Edison), faced reliability-threatening low pressures at its citygate[32] on all the interstate natural gas pipelines that it relies upon. Con Edison maintained its natural gas local distribution system pressure by using its own liquified natural gas (LNG) facility, among other measures. Had Con Edison not activated its LNG facility and taken its other emergency measures, or had the cold weather lasted longer, it could have faced large scale outages. System outages for a local natural gas distribution company generally take longer to restore than firm load shed, or even cascading outages, on the electric grid. Once electricity is restored to a circuit, all of the homes[33] can return to their normal functioning—lights turn back on, heating or air conditioning systems return to normal function, etc. By contrast, for the natural gas local distribution system to return system outages to normal operation, workers must go house-to-house and individually light every pilot light. Con Edison estimated it would have taken months to restore service, even with mutual assistance from other utilities, had it experienced a complete loss of its system.

In addition to the close call with Con Edison, the Eastern Interconnection's normally robust electric grid one-minute average frequency dropped to 59.936 Hz, slightly below its low frequency trigger limit of 59.95 Hz.[34] The frequency began declining on the morning of December 24 at 3:25 a.m. and over the next hour steadily decreased

31 2021 Report at 9.

32 C tygate a po nt or measur ng stat on at wh ch a d str but ng gas ut l ty rece ves gas from a natural gas p pel ne company or transm ss on system. *See* E A Defin t ons, Sources and Explanatory Notes, at https://www.e a.gov/dnav/ng/TblDefs/ng_pr_sum_tbldef2.asp.

33 For those that do not have secondary outage causes.

34 Frequency as a measure of the rel ab l ty status of a power system prov des a key nd cator of the overall ntegr ty of operat ons. 60.000 Hz s the nom nal frequency for the Eastern nterconnect on, and ma nta n ng t requ res generat ng un ts to automat cally respond to dev at ons, BAs to perform moment to moment balanc ng of the system's aggregate generat on output to ts load and ma nta n suff c ent respons ve reserves ava lable to w thstand the sudden tr pp ng of the largest generator on the system. The Low Frequency Tr gger L m t s approx mately 59.95 Hz for the Eastern nterconnect on and s used by BAs to calculate the r requ red response to frequency dev at ons that are below 60 Hz. *See* NERC Rel ab l ty Standard BAL 001 2 Real Power Balanc ng Control Performance, Attachment 2. RSCompleteSet.pdf (nerc.com)

from 60.00 Hz, reaching its lowest point by 4:25 a.m. At that time, the composite ACE[35] for the Core Event Area[36] was -2,754 MW, and PJM BA's portion of the composite ACE was -2,162 MW (due in part to PJM experiencing an additional 1,400 MW in unplanned generation outages from 4:20 a.m. to 4:25 a.m.). Although the Eastern Interconnection frequency recovered to its normal range[37] as PJM and several other Balancing Authorities concurrently initiated more severe emergency energy actions (including firm load shed for some Balancing Authorities), total unplanned generation outages continued to increase over and above generation that was already out of service, reaching a combined total of over 127,000 MW by 10:00 a.m. This left 18 percent of the winter 2022-2023 anticipated generation resources in the U.S. portion of the Eastern Interconnection offline during winter peak conditions.[38] Including this occasion, as well as the evening of December 23, there were four points during the Event at which the one-minute average frequency declined below 59.95 Hz, coinciding with lower online responsive reserves[39] within the Core Event Area due to generation outages. Ultimately on the morning of December 24, grid operators maintained frequency by reducing electricity demand, including by shedding over 5,400 MW of firm load, leaving hundreds of thousands of customers[40] without electricity to heat homes for several hours during the extreme cold weather conditions.

35 ACE stands for Area Control Error, wh ch s the m nute to m nute measure of how well the BA s perform ng ts balanc ng funct on; .e., balanc ng ts scheduled power outputs to meet actual nputs and outputs. f ACE s less than zero, then the BA needs to ncrease generat on supply/output n ts footpr nt to balance; or f add t onal generat on ncrease s not poss ble, the BA may need to curta l export power schedules, or worst case, reduce demand by shedd ng firm load.

36 The "Core Event Area" refers to the ocat on where concurrent EEA 2 and EEA 3 energy emergency measures were taken by e ectr c gr d ent t es the morn ng of December 24, 2022 (.e., concurrent EEA 2 oad management and EEA 3 firm oad shed measures) to ma nta n BES re ab ty. These gr d ent t es are NERC reg stered Ba anc ng Author t es. They are referred to as Core Ent t es or Core BAs n the Report, and are dep cted n F gure 9, be ow.

37 For the Eastern nterconnect on, the normal range s 59.95 60.05 Hz.

38 Th s exceeds NERC's 2022 2023 W nter Rel ab l ty Assessment "worst case" low generat on cond t on for the U.S. port on of the Eastern nterconnect on (worst case s calculated by comb n ng MW outage shortfall scenar os of: extreme low gen low w nd natural gas r sk scenar o) by 32,500 MW of add t onal generat on reduct ons.

39 Respons ve reserves are those onl ne reserves that are capable of respond ng and recover ng from frequency dev at ons.

40 On December 24, 2022, TVA ordered ts 153 oca power compan es (LPCs) serv ng 10 m on peop e n Tennessee and parts of s x surround ng states to nterrupt 10 percent of the r firm oad. Tennessee Va ey Author ty After Act on Report, at 20 21, ((https://www.tva.com/about tva/reports)), and https://www.tva.com/about tva#:~:text The%20Tennessee%20Va ey%20Author ty%20prov des, ndustr a %20customers%20and%20federa %20 nsta at ons. Duke Energy reported to the North Caro na Ut t es Comm ss on that on December 24, approx mate y 15 percent of customers overa rough y 500,000 n tota were mpacted by the company's rotat ng outages. (https://news.duke energy.com/re eases/duke energy updates north caro na ut t es comm ss on on w nter storm e ott emergency outage event#:~:text CHARLOTTE%2C%20N.C.%20%E2%80%93%20 Leaders%20from%20Duke,from%20occurr ng%20that%20way%20aga n.) Dur ng ro ng b ackouts firm oad shed] nst tuted by LG&E/KU, 54,637 customers were affected. *Kentucky Utilities Co. & Louisville Gas and Electric Co. Response* (Mar. 10, 2023), https://psc.ky.gov/pscecf/2022 00402/r ck. ovekamp%40 ge ku.com/03102023103319/02 AG DR1 LGE KU Responses.pdf.

Figure 4: Comparison of Events' Effects on Bulk Electric System Generation and Resulting Need for Load Shed

Event Date/ Duration:	SW U.S. Event/ Feb. 1-5, 2011	Polar Vortex/ Jan 6-8, 2014	2018 Event/ Jan 15-19, 2018	2021 Event/ Feb 8-20, 2021	2022 Event/ Dec 21-26, 2022
Deviation from Average Daily Temperature	17 to 36 deg. below average	20 to 30 deg. below average	12 to 28 deg. below average	40 to 50 deg. below average	20 to 30 deg. below average
Geographic Area of Event	Texas and Southwest U.S.	M dwest, South Central, and East Coast reg ons	South Central U.S.	Texas and South Central U.S.	Central, M dwest, and large parts of Southeast and Northeast U.S.
Event Area Sq. Miles (approx.)	656,300	1,923,000	418,000	869,600	1,517,000
Unavailable Generation Due to Cold Weather, at Worst Point (MW)	14,702	9,800	15,600	65,622	90,500
Causes of Unavailable Generation (in alphabetical order)	Freez ng ssues, Mechan cal/ Electr cal ssues, Natural Gas Fuel ssues	Freez ng ssues (cold weather), Natural Gas Fuel ssues	Freez ng ssues, Mechan cal/ Electr cal ssues, Natural Gas Fuel ssues	Freez ng ssues, Natural Gas Fuel ssues, Mechan cal/ Electr cal ssues	Freez ng ssues, Mechan cal/ Electr cal ssues, Natural Gas Fuel ssues
Energy Emergency Declared/ Highest Level	Yes/ EEA 3	Yes/ EEA 3	Yes/ EEA 2	Yes/ EEA 3	Yes/ EEA 3
Maximum Level of Firm Load Shed (MW)	5,411.6	300	0	23,418 (ERCOT 20,000, SPP 2,718, M SO South 700)	Over 5,400[41] Tota (TVA over 3,000, DEC 1,000, DEP 961, LG&E/ KU 317,[42] DESC 94.7,[43] Santee Cooper 86.4)
Overall Duration of Firm Load Shed	ERCOT: 7 hours, 24 m nutes	3 hours	N/A	ERCOT: over 70 hours, SPP: over 4 hours M SO South: over 2 hours	TVA: 7 hours, DEC: 3 hours, DEP: 2 hours, LG&E/KU: 4 hours, DESC and Santee Cooper: 9, and 17 m n., respect vely

41 Total of ent t es' max mum load shed ordered, wh ch occurred on December 23 and 24, 2022 at d fferent t mes. Sect on .B.3. of the report descr bes more deta ls on the magn tudes and t meframes of firm load shed for each ent ty.

42 317 MW was n t al level of firm load shed. Load shed levels were decreased over durat on.

43 94.7 MW was n t al magn tude of firm load shed. After 2 m nutes, load shed levels were decreased over durat on.

Figure 5: Similarities to Past Extreme Cold Weather Events

	2011 Event	2014 Event	2018 Event	2021 Event	2022 Event
S gn ficant levels of ncremental unplanned electr c generat ng un t losses w th top causes found to be mechan cal/electr cal, freez ng, and fuel ssues.	✓	✓	✓	✓	✓
S gn ficant natural gas product on decreases occurred, w th some areas of the country more severely affected.	✓			✓	✓
Short range forecasts of peak electr c ty demands were less than actual demands for BAs n event area.	✓		✓	✓	✓
S gn ficant natural gas LDC outages or near m ss.	✓				✓

As demonstrated by Figure 4, above, the Event was the fifth in the past 11 years in which unplanned cold-weather-related generation outages jeopardized grid reliability, and the fourth that triggered the need for firm load shed. Twice in 11 years the reliability of natural gas delivery to homes and businesses has been jeopardized. These recurring failures make clear that America's natural gas infrastructure and electric grid continue to be severely challenged during extreme cold weather events, repeatedly jeopardizing reliability during life-threatening conditions, even when technology exists to protect the vulnerable components.[44] Multiple extreme cold weather event reports, including the 2021 Report issued less than two years ago, have detailed the same three primary causes of the unplanned generating outages: Freezing Issues; Fuel Issues; and Mechanical/Electrical issues which are correlated with temperature, increasing in number as temperatures fall.[45]

Multiple extreme cold weather event reports made recommendations aimed at preventing recurrence of these events, and some progress has been made.[46] But some key drivers of these events remain unaddressed, especially the freezing of natural gas infrastructure. As noted in the NAESB Gas-Electric Harmonization Forum Report ("NAESB Report"):

> "In the last two decades, natural gas' fuel share for power generation has doubled: today it represents almost 40 percent of total resources. Both sectors of the American energy system have become highly interdependent economically and technically: natural gas represents the largest fuel resource for power generation, while power generation is the largest consumer of natural gas."[47]

44 *See* 2011 Report at 206 208 (recommendat ons on spec fic freeze protect on ma ntenance measures); note 119 (methods to protect natural gas nfrastructure), 2021 Report at 194 95 (Key Recommendat on 6) (same).

45 Append x E of the Report updates the progress on the recommendat ons from the 2021 Report.

46 Freez ng related generat ng un t outages are recogn zed as a s gn ficant dr ver of these events. As d scussed below, Rel ab l ty Standards requ r ng appropr ate generator w nter zat on are currently n development or soon to be n effect.

47 North Amer can Energy Standards Board Gas Electr c Harmon zat on Forum Report ("NAESB Report"), July 28, 2023, at 1. https://www.naesb.org/pdf4/geh_final_report_072823.pdf .

2014 Polar Vortex Event

On January 5 through 8, 2014, "the Midwest, South Central, and East Coast regions of North America experienced a weather condition known as a polar vortex, where extreme cold weather conditions occurred in lower latitudes than normal, resulting in temperatures 20 to 30 [degrees] below average. Some areas faced days that were 35 [degrees] or more below their average temperatures. These temperatures resulted in record high electrical demand for these areas on January 6 and again on January 7, 2014."[48] Demand for natural gas also increased, and significant amounts of natural gas-fired generating units were unavailable because they did not have natural gas.[49] "By properly and appropriately communicating through the NERC [EEA][50] process using interruptible load, demand-side management tools, and voltage reduction, only one BA was required to shed firm load. The amount shed was less than 300 MW, representing less than 0.1 percent of the total load for the Eastern and ERCOT Interconnections."[51] The "lower temperatures had a drastic impact on load, with many of the Reliability Coordinators [e.g., MISO, PJM, TVA, VACAR-South, and Southeastern RC] reporting record or near-record winter peak demands. PJM exceeded its historic winter peak on both January 7 and January 8, 2014, and MISO reported that [it] exceeded [its] historic winter peak for three straight days (January 6–8, 2014)."[52]

NERC staff reviewed and validated the Generating Availability Data Systems (GADS)[53] data covering the Polar Vortex event. Analysis of these data identified two principal causes of generating unit outages: curtailment or interruption of natural gas fuel supply and over 17,700 MW of lost generating capacity due to frozen equipment.[54] The majority of forced outages, 55 percent, were natural gas-fired generating units, although they only represented 40 percent of capacity in the Polar Vortex event area (Eastern and ERCOT Interconnections).[55] Although the Polar Vortex Review stated that "many generator outages" occurred as a result of entities exceeding the design basis of their plants, it did not quantify the percentage. The Review identified associations between temperature and increasing outages in most of the Regional Entity footprints.[56]

The Review's ten recommendations included the following: that the electric industry work with the gas industry "to allow generators to be able to secure firm supply and transportation at a reasonable rate;" to review and update generating units' weatherization plans; to implement periodic site reviews of generating units' winter preparedness; to reconsider forced outage rate assumptions in winter assessments, as well as assumptions about natural gas outage rates and heating oil replenishment; to limit planned outages during winter peak periods; to improve BAs' awareness of generating units' fuel status; to protect stored fuel against effects of cold weather; to review generating units' design basis and protect against outages that occur within design basis; and to prepare to apply for necessary environmental (or other) waivers during emergencies.

48 Polar Vortex Rev ew at .

49 d.

50 *See* note 21.

51 Polar Vortex Rev ew at .

52 Polar Vortex Rev ew at v .

53 Generat ng Ava lab l ty Data System (GADS) s a mandatory ndustry program for track ng nformat on about outages of BES generat ng un ts. Generat ng Ava lab l ty Data System (GADS) (nerc.com).

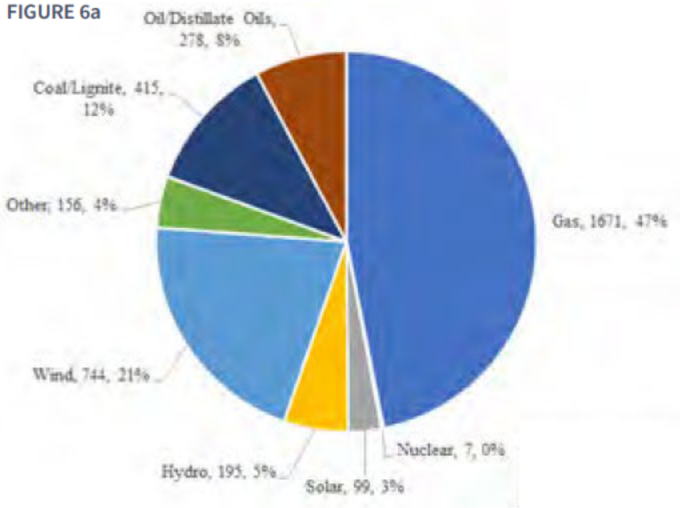
54 Polar Vortex Rev ew at 2.

55 Polar Vortex Rev ew at 13.

56 Polar Vortex Rev ew at 4 12.

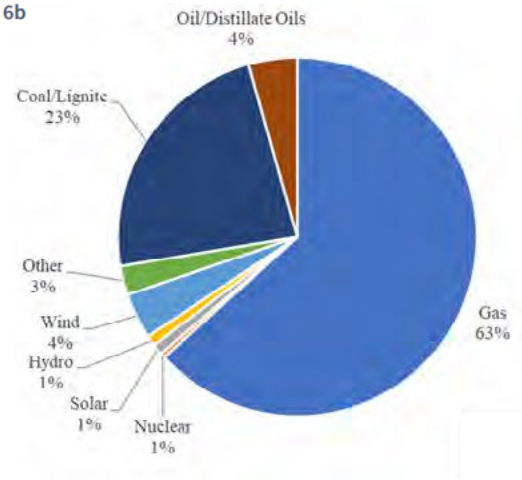
Figures 6a, 6b: Event Area Incremental Unplanned Generating Unit Outages, Derates and Failures to Start by Fuel Type: Percentages by Number of Outages, and Percentages by Unavailable MW[57]

FIGURE 6a



1,702 Generating Units   3,565 Outages/Derates

FIGURE 6b



1,702 Generating Units   3,565 Outages/Derates

57 Add t onal F gures of unplanned generat on outages by other fuel types can be found n Append x C: Add t onal Charts and F gures for Unplanned Generat on Outages Dur ng Event.

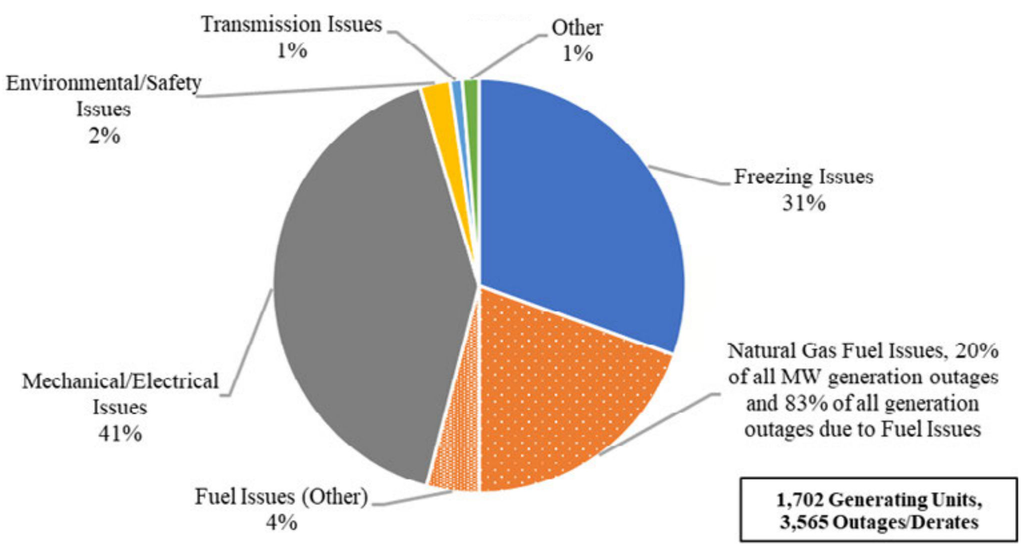
C. Key Findings and Causes

From December 21 to 26, 2022, in the Event Area, a total of 1,702 individual generating units—47 percent natural gas-fired, 21 percent wind, 12 percent coal, 3 percent solar, 0.4 percent nuclear, 17 percent other (oil, hydroelectric and biomass)—experienced 3,565 outages, derates, or failures to start (see Figures 6a & 6b, below).

Ninety-six percent of all outages, derates, and failures to start were attributed to three causes: Freezing Issues (31 percent), Fuel Issues (24 percent) and Mechanical/Electrical Issues (41 percent). Of those outages, derates, and failures to start, 55 percent were caused by either Freezing Issues or Fuel Issues, as shown in Figure 7 below. Natural Gas Fuel Issues[58] (a subset, but the majority, of Fuel Issues) were 20 percent of all causes, and issues with other fuels were four percent.

In addition to the outages, derates, and failures to start caused by Freezing Issues, those caused by Mechanical/Electrical Issues also indicated a clear pattern related to cold temperatures—as temperatures decreased, the number of generating units experiencing an outage, derate or failure to start due to Mechanical/Electrical Issues increased.

Figure 7: Incremental Unplanned Generating Unit MW Outages, Derates and Failures to Start, Total Event Area: by Cause



Prior to the Event, Generator Owners had ample reminders, guidance and opportunities to prepare for the extreme cold weather, and most did have plans in place. For example, FERC and NERC had provided

58 Natural Gas Fuel ssues nclude the comb ned effects of decreased natural gas product on; cold weather mpacts and mechan cal problems at product on, gather ng, process ng and p pel ne fac l t es result ng n gas qual ty ssues and low p pel ne pressure; supply and transportat on nterrupt ons; curta lments and fa lure to comply w th contractual obl gat ons. Add t onally, t ncludes sh ppers' nab l ty to procure natural gas due to t ght supply, proh b t ve, scarc ty nduced market pr ces, or m smatches between the t m ng of the natural gas and energy markets.

multiple prior recommendations and follow-up activities regarding steps for winter preparedness.[59] In addition, Generator Owners received annual reminders via Regional Entity workshops to prepare for winter (which provide detailed suggestions for how to protect generating units from freezing). Yet, despite these reminders, guidance, and their own preparation, over 75 percent of the generating unit failures caused by Freezing Issues[60] occurred at temperatures above the units' documented operating temperatures.[61] Over 150 blackstart-designated generating units,[62] totaling 19,000 MW, incurred outages during the Event, 119 of which were natural-gas-fueled generating units (accounting for just under 75 percent of all MW of blackstart-designated generation outages).

During the Event, natural gas production experienced its greatest decline since 2021's Winter Storm Uri, in which Texas production dropped by 70 percent. The Marcellus Shale[63] and Utica Shale[64] formations (combined, the Appalachia Region, which produced more natural gas than any other U.S. region in 2022) production dropped by 23 to 54 percent during the Event.[65] Wellhead freeze-offs, other natural gas supply chain equipment freezing and weather-related poor road conditions that prevented necessary maintenance were the top causes.

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59 For examples of other act v t es to publ c ze the need for, and how, generators can protect the r un ts from cold weather, *see* FERC, NERC and Reg onal Ent t es Techn cal Conference: mprov ng W nter read ness of Generat ng Un ts; NERC Alerts and Cold Weather Preparat ons for Extreme Weather Events; Cold Weather Preparat ons for Extreme Weather Events ; NERC annual web nars on preparat on for cold weather (https://www.nerc.com/pa/rrm/Pages/Web nars.aspx); NERC Compl ance Mon tor ng and Enforcement Program pract ce gu de (quest ons for BAs, RCs, and other ent t es for understand ng the r cold weather preparedness r sk m t gat on) https://www.nerc.com/pa/comp/gu dance/CMEPPract ceGu desDL/CMEP%20Pract ce%20Gu de%20 %20Cold%20Weather%20Preparedness.pdf.

60 ncludes unplanned outages, derates, and fa lures to start caused by Freez ng ssues. Th s analys s s l m ted to generat ng un ts that prov ded outage data, amb ent temperature data, and data concern ng that un ts' operat ng parameters. Not all GOs prov ded data for each of these data sources n a manner and format wh ch the Team was able to analyze.

61 GOs were g ven opt ons for document ng the r generat ng un ts' temperature l m ts n the r data responses: des gn temperature, h stor cal operat ng temperature, or current cold weather performance temperature determ ned by an eng neer ng analys s. Many GOs prov ded the Team w th more than one of these temperatures; f so, the Team used the h ghest of the temperatures to calculate the 75 percent figure. Us ng one of the lower temperatures prov ded for all GOs would have y elded a h gher figure. The Team w ll use the phrase "documented operat ng temperatures" to refer to these temperatures.

62 Blackstart ("blackstart") refers to restart ng the power gr d after a major port on of the electr cal network has been de energ zed, and generators that have blackstart capab l ty are those that can be started ndependently and w thout external power. *See* NERC Glossary of Terms for NERC defin t on of Blackstart Resource, and NERC Rel ab l ty Standard EOP 005 3 System Restorat on from Blackstart Resources.

63 The Marcellus Shale format on spreads across Pennsylvan a, New York, West V rg n a, Maryland, Tennessee, Kentucky, Oh o, and V rg n a.

64 The Ut ca Shale format on covers parts of Pennsylvan a, New York, West V rg n a, Maryland, Tennessee, Kentucky, Oh o, New York, and Canada.

65 " n 2022, the Appalach a reg on produced more natural gas than any other U.S. reg on, account ng for 29 percent] of U.S. gross natural gas w thdrawals." U.S. Energy nformat on Adm n strat on E A ndependent Stat st cs and Analys s

D. Recommendations

In response to the continued failures of generating units due to Freezing Issues, the Team[66] urges prompt development and implementation of the remaining revisions to the Reliability Standards recommended by Key Recommendation 1 from the 2021 Report to strengthen generators' ability to maintain extreme cold weather performance. Additionally, the Team suggests robust monitoring of the implementation of currently-effective and approved cold weather Reliability Standards to determine if reliability gaps exist. The Team includes several recommendations to prevent generating unit freeze issues, one targeted at those units that failed above their designated operating limits, and three applicable to all units. Another recommendation suggests that Generation Owners communicate changes in their operating limits to the BA in real time. The Team also recommends a technical review of the individual causes of cold-related mechanical/electrical generation outages to reduce the frequency of these outages and inform whether additional Standards are needed. Finally, the Team recommends another blackstart study, like the one currently being conducted for the ERCOT Interconnection in response to Recommendation 26 from the 2021 Report, but focusing on the Eastern and Western Interconnections.

In response to the natural gas production, processing and pipeline issues, the Team recommends that Congress and state legislatures (or state regulatory entities that have jurisdiction over natural gas infrastructure reliability) take action to establish reliability rules for natural gas infrastructure necessary to support the grid and natural gas LDCs in three areas: cold weather preparedness/freeze protection; regional natural gas situational awareness, coordination and information sharing (similar to the grid's Reliability Coordinators); and the designation of critical natural gas infrastructure (for prioritization during load shed).

The Team makes several recommendations concerning natural gas-electric coordination, including consideration of whether to require a one-time report to the Commission from FERC-jurisdictional natural gas entities describing how they are assessing and responding to their vulnerabilities to extreme cold weather; a NAESB effort to enhance situational awareness through communication during extreme cold weather events (both among natural gas infrastructure entities, and with grid entities); and a study to analyze whether additional natural gas infrastructure, including interstate pipelines and storage, is needed to support the reliability of the electric grid and meet the needs of natural gas LDCs.

Finally, the Team recommends several potential improvements for grid operations, including Balancing Authorities improving their short-term load forecasts for extreme cold weather periods by implementing and sharing effective practices with peers for continuous improvement; Balancing Authorities assessing whether new or modified processes such as multi-day risk assessment or reliability commitments are needed to mitigate the risk of capacity shortages or other reliability issues during extreme cold weather events; resource planners and entities serving load sponsoring joint-regional reliability assessments of electric grid conditions that could occur during extreme cold weather; and a study to examine potential Eastern Interconnection stability risks on December 23 and 24 during periods of decreased frequency and low responsive reserves.

66 *See* note 1 for defin t on of the Team.

II. EVENT OVERVIEW AND RELEVANT BACKGROUND INFORMATION

A. Event Overview: Both the Electric Grid and the Natural Gas Pipeline System Experienced a Supply Shortage Event, Leaving Some System Operators with No Choice but to Take the Extreme Step of Shedding or Curtailing Firm Customers in Order to Maintain System Reliability

Both the electric grid and the interstate natural gas pipeline system must account for situations where there is too little supply to maintain system reliability. Insufficient supply can create the risk of dangerously low voltage on the grid or pressure on the pipelines, respectively. This event was a supply shortage event for both the electric grid and the natural gas pipeline system.

During the Event, natural gas supply shortages began with freezing issues and weather-related access issues associated with production facilities and equipment, which rippled throughout the natural gas infrastructure system. Natural gas pipelines faced decreased supply flowing into the pipelines at the same time that shippers requested increased volumes of gas, with some shippers taking volumes of gas in excess of their entitlement. The reduced supply relative to higher volumes of delivered gas (a situation known as a draft condition) resulted in lower line pressures and reduced line pack. Pipeline system operators faced not only draft conditions but also freezing issues that affected important equipment like compressor stations. While they deployed line pack and storage, and dispatched personnel to respond to these conditions, most pipelines also needed to issue critical notices and Operational Flow Orders (OFOs), and some issued force majeures (which curtail even firm transportation).[67] Eventually pressures on some pipelines reached reliability-threatening levels. Con Edison, which provides local distribution of natural gas to over a million customers in Manhattan, The Bronx, and portions of Queens and Westchester County, New York, established an internal Gas System Emergency to preserve its system reliability due to rapidly decreasing pipeline pressures at its citygate that were not recovering. Had pipeline pressures not recovered, Con Edison could have faced an unprecedented loss of its entire system that, in this worst case scenario, would have taken months to restore, even with mutual assistance. WE Energies, a local gas distribution utility in Wisconsin, had to resort to consumer appeals to drop thermostats to 60 degrees on the night of December 23 when one of the interstate pipelines it relied upon experienced an unexpected compressor outage and curtailed natural gas flow to WE Energies by 30 percent.[68]

On the electric grid, natural gas production declines reduced the supply available for natural gas-fired generating units. Many natural gas-fired generating units either do not contract for firm gas supply or transportation, or contract for only a portion of the firm supply or transportation needed to meet their winter peak needs.[69] They are then unable to obtain natural gas when natural gas supply and available pipeline capacity become scarce-to-unobtainable in extreme cold weather. On top of the natural gas-related fuel outages, the grid experienced

67 *See* p. 76 for s debar on p pel ne commun cat ons for explanat ons of these terms.

68 Karl Ebert, "*On a bitter cold night, We Energies begged customers to turn down their thermostats. How close did the natural gas supply system come to failure?*" M lwaukee Journal Sent nel, (Jan. 20, 2023), https://www. sonl ne.com/story/money/bus ness/energy/2023/01/20/what caused we energ es natural gas cr s s on dec 23/69785899007/.

69 *See* F gure 85 for contractual arrangements held by some of the GOs/GOPs n the Event.

generating unit outages, derates and failures to start due to Freezing Issues and Mechanical/Electrical Issues that were closely correlated with falling temperatures. Total unplanned coincident generating unit outages, derates and failures to start during the Event exceeded 90,000 MW, the most ever observed compared to other extreme cold weather events that impacted the U.S.

While interstate pipeline and electric grid operators used every tool (e.g., EEA 1 or 2 for the grid, OFOs for pipelines) to avoid disruptions in service, some operators were forced to make difficult decisions such as curtailing firm natural gas customers or shedding firm electricity customers, to allow the system to recover from reliability-threatening conditions rather than deteriorate into an uncontrolled loss of an entire pipeline or the electric grid.

The coldest areas in Winter Storm Elliott did not deviate from normal lows as much as the coldest areas in 2021's Winter Storm Uri (comparing the NOAA-produced graphics of deviation from normal lows). In Uri, the coldest areas were between 40 and 50 degrees below the normal low, while in Elliott the coldest areas, on the peaks of the Appalachian Mountains, were between 30 and 35 degrees below the normal low. However, temperature alone is not the only factor in determining the extent to which extreme cold weather will wreak havoc on generating units and natural gas infrastructure. Wind and precipitation exacerbate the effects of temperature.[70] In the Event, TVA noted that rain followed by extreme cold weather and wind created an environment that was beyond the design basis of some TVA generating sites. Freezing rain can coat wind turbine blades, rendering them out of service until the icing is removed, while snow causes the largest performance drops at solar facilities.[71] Rain can also soak insulation, limiting or eliminating its ability to protect against cold. Another factor, which played a strong role in the Event, is how quickly the winter temperatures dropped. An extremely rapid drop (for example, temperatures in Charleston, West Virginia, ranged from 45 degrees at 2:43 a.m. to 3 degrees[72] at 8:43 a.m., a drop of 42 degrees in six hours), increases system load as it challenges the ability of home heating systems to maintain consistent temperatures.

The Event had the largest footprint of any examined in a joint FERC-NERC-Regional Entity inquiry. As shown in Figure 8, below, the extreme cold weather covered most of the eastern half of the lower 48 United States, except for some of Florida. The Team focused on affected entities that either shed firm load or lost larger percentages of their generating unit capacity. All were located within the Eastern Interconnection and had multiple tie lines to other entities within the Eastern Interconnection.

Entities that were more severely affected (Core Entities)[73] included PJM, (represented by the blue box below in Figure 9); TVA and LG&E/KU BAs, within TVA's Reliability Coordinator footprint (represented by red and white striped boxes); Southern (represented by an aqua box); and DEP, DEC/VACAR-South RC, DESC and Santee Cooper, represented by pink boxes). Within the Event Area, the Team also examined MISO, SPP, ISO New England and NYISO (collectively represented by gold boxes) to better understand how their generating unit outages and flows exchanged with Core Entities impacted Event outcomes.

70 The effects of a lower dry bulb temperature s equ valent to those of a h gher dry bulb temperature w th h gh w nds or assoc ated prec p tat on.

71 N cole D. Jackson & Thushara Gunda, Evaluat on of extreme weather mpacts on ut l ty scale photovolta c plant performance n the Un ted States, 302, Appl ed Energy, 1:7 (2021) Sand a Nat onal Labs.

72 The Report ncludes temperature references only n Fahrenhe t.

73 See note 35 for defin t on of Core Event Area, wh ch ncludes defin t on of Core Ent t es.

B. Background on Affected Systems and Entities

1. RELIABILITY ROLES

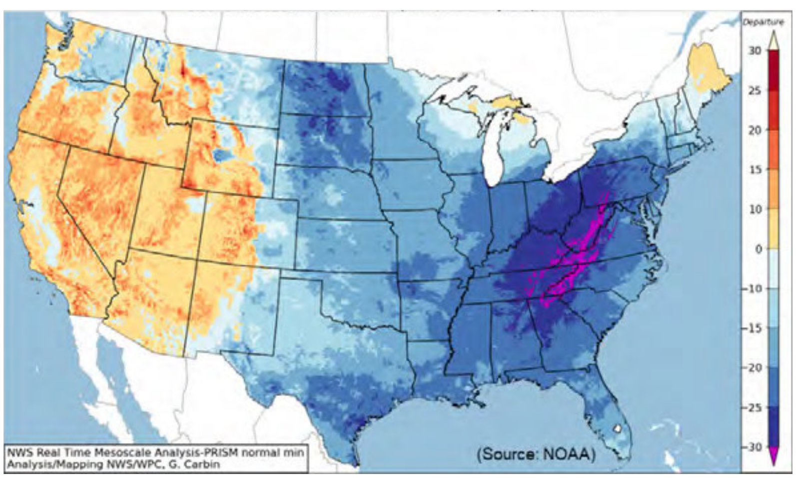
NERC categorizes the entities responsible for planning and operating the BES in a reliable manner into multiple categories of functional entity types. The NERC roles most relevant to the Event are Reliability Coordinators (RCs), Balancing Authorities (BAs), Generator Owners (GOs), Generator Operators (GOPs), Transmission Owners (TOs), Transmission Operators (TOPs), Planning Authority/Planning Coordinators (PA/PCs), and Transmission Planners (TPs). Several of the Core Entities (also referred to as "Core BAs"), especially PJM, TVA, Southern, DEC/VACAR-South RC, and DESC, served multiple reliability roles during the Event.

2. INTERCONNECTIONS BETWEEN AFFECTED ENTITIES AND OTHER PARTS OF THE ELECTRIC GRID

In North America, there are four separate power grids or "interconnections." The Eastern interconnection includes the eastern two-thirds of the continental United States and Canada from Saskatchewan east to the Maritime Provinces (see Figure 10, below), and is electrically independent from the other interconnections.

The Eastern Interconnection is the largest of the four interconnections, and by itself has been called the largest machine in the world.[74] The Eastern Interconnection is electrically connected to the Western, ERCOT and Quebec Interconnections by means of Direct Current (DC) asynchronous transmission tie lines.[75] Within each interconnection, power generally flows without barriers (subject to operational limits) from one utility's system to another across the entire grid via alternating current (AC) tie lines. A significant enough imbalance of generation and demand can cause instability of one utility's system to affect the stability of all utility systems operating in that interconnection.[76]

Figure 8: Extreme Cold Weather Conditions – December 24, 2022

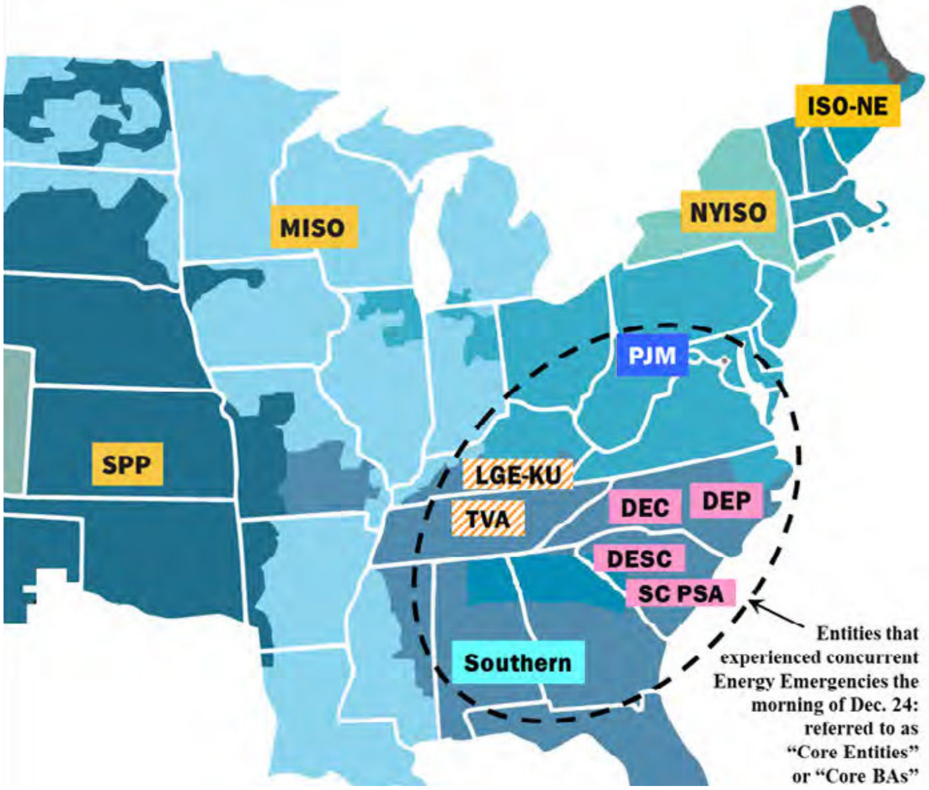


74 "Mult D mens onal ssues n nternat onal Electr c Power Gr d nterconnect ons," 15 (2006), https://www.un.org/esa/sustdev/publ cat ons/energy/ nterconnect ons.pdf.

75 For DC transm ss on l nes, the flow of power s controlled (.e., scheduled), rather than flow ng cont nuously as on synchronous t es.

76 *See* generally, U.S. Canada Power System Outage Task Force, F nal Report on the August 14, 2003 Blackout n the Un ted States and Canada: Causes and Recommendat ons, 5 10 (Apr l 2004), https://www.ferc.gov/s tes/default/files/2020 05/ch1 3 0.pdf.

Figure 9: Bulk Electric System Map of Affected Entities



3. DESCRIPTION OF U.S. BES ENTITIES IN THE EASTERN INTERCONNECTION AFFECTED BY WINTER STORM ELLIOTT

a. PJM and other RTOs/ISOs in the Eastern Interconnection[77]

PJM (Core Entity). PJM is a regional transmission organization (RTO) covering 13 states (Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia)[78] and Washington, DC for a total of 368,906 square miles.[79] PJM is NERC-registered as a BA, RC, PA/PC, and TOP, and in the latter capacity, operates 88,115 miles of transmission lines.[80] It monitors over 1,400 generating units. In 2022, PJM obtained energy from 40 percent gas generation, 20 percent coal, 32.3 percent nuclear, 1.9 percent hydroelectric, 3.7 percent wind, and 2.2 percent other (all calculated on a MWh basis). Its total installed capacity at the end of December 2022 was 183,385 MW.[81] PJM has historically been a summer-peaking region, and its all-time peak load was 165,563 MW during the summer of 2006. PJM operates an energy and ancillary services market that includes both day-ahead and real-time markets.

MISO. MISO is an RTO that operates the grid across 15 states and the Canadian province of Manitoba, and

77 Wh le both New York SO (NY SO) and SO NE ncurred s gn ficant d str but on power outages from W nter Storm Ell ott, both exper enced less severe BES mpacts dur ng the Event. These SOs are d scussed n Sect on of the Report.

78 https://www.p m.com/about p m/who we are.

79 https://www.p m.com/about p m, https://serv ces.p m.com/annualreport2022/.

80 https://learn.p m.com/ /med a/about p m/newsroom/fact sheets/p m at a glance.ashx.

81 http://www.mon tor nganalyt cs.com/reports/PJM State of the Market/2022/2022 som p m press br efing.pdf.

serves as a BA and RC, among other reliability roles.[82] MISO operates 75,000 miles of transmission lines, is a summer-peaking region, and experienced its highest peak load to date, 130,917 MW, on July 20, 2011. MISO's generating capacity is 198,933 MW, comprised of 42 percent natural gas-fired generation, 29 percent coal, 19 percent renewables and eight percent nuclear generation. Currently, MISO operates one of the largest energy and operating reserve markets, with annual gross transactions of $22 billion, as well as an ancillary services market, and includes both day-ahead and real-time markets.

SPP. SPP is an RTO and serves as a BA and RC, among other reliability roles. It operates a 552,885-square-mile area that includes all or portions of 14 states, including: Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas and Wyoming.[83] SPP operates 70,025 miles of transmission lines. It is a summer-peaking region and although it experienced its highest peak load of 56,184 MW on August 21, 2023, it experienced a new all-time winter peak load of 47,157 MW during Winter Storm Elliott. SPP's generating fleet is 38.5 percent (nameplate) natural gas, 29 percent wind, and 24.3 percent coal. However, coal accounts for the majority of the generated energy with 38.6 percent of the total, while wind and natural gas produce about 29.5 percent and 22.7 percent respectively.[84] SPP operates an energy and ancillary services market that includes both day-ahead and real-time markets.

b. Grid Operators in the Southeast U.S.

TVA (Core Entity). TVA is a federally-owned electric utility corporation, the largest public power provider in the U.S., and serves as a BA, RC, GO, GOP, TO and TOP, among others. TVA's service area covers most of Tennessee, portions of Alabama, Mississippi, and Kentucky, and small areas of Georgia, North Carolina and Virginia. TVA owns and operates approximately 16,200 miles of transmission lines and serves 12 million customers. TVA's generation fleet consists of 33 percent natural gas, 39 percent nuclear, 14 percent coal, 10 percent hydro, and four percent wind and solar. TVA is a dual (both summer and winter) peaking region and set a new record winter peak of 33,425 MW during the Event on December 23, 2022.

LG&E/KU (Core Entity). LG&E and KU are subsidiaries of PPL Corporation. They are regulated public utilities that serve more than 1 million electric customers combined. LG&E/KU operate their combined transmission systems as a joint BA Area, PC Area, and TOP Area. LG&E/KU are also registered as a GO, GOP, TSP, TP, and TO. TVA serves as LG&E/KU's RC. LG&E serves approximately 333,000 natural gas and 429,000 electric customers in Louisville and 16 surrounding counties.[85] KU serves approximately 566,000 electric customers in 77 Kentucky counties and five counties in Virginia operating as Old Dominion Power Company.[86] Together, the companies own approximately 5,400 miles of electric transmission lines.[87] Their combined generation fleet includes 37.5 percent natural gas, 59.6 percent coal, and 2.9 percent hydro and other. LG&E/KU is dual peaking, and its all-time winter peak BA load was 7,336 MW on January 6, 2014.

DEP and DEC (both Core Entities). DEP and DEC are subsidiaries of Duke Energy. DEP operates as a BA, GO, GOP, PA/PC, TO, and TOP. DEC is the agent for the VACAR-South RC, and operates as a BA, GO, GOP, PA/PC, TO, and TOP.[88] DEP has 16,390 megawatts of generation

82 M SO Corporate Fact Sheet, https://www.m soenergy.org/about/med a center/corporate fact sheet/.

83 SPP Fact Sheet https://www.spp.org/about us/fast facts/.

84 *Id.*

85 About LG&E and KU LG&E and KU (lge ku.com); https://lgeku.com/ nvestments#:~:text The%20same%20type%20of%20deta led,gas%20storage%20fields%20that%20enable .

86 https://lge ku.com/about.

87 https://lge ku.com/about.

88 https://www.nerc.com/comm/OC/Operat ng%20Rel ab l ty%20Subcomm ttee%20ORS%202013/ORS Presentat on Nov 6 7 2019.pdf pg 15

capacity within its footprint, 1.7 million residential, commercial and industrial electricity customers across a 29,000-square-mile service area in North Carolina and South Carolina, and operates 6,300 miles of transmission lines. Generation within its footprint includes 38.1 percent natural gas, 19.4 percent coal, 22.8 percent nuclear, 1.5 percent hydro and other. DEC has 25,848 megawatts of generation capacity within its footprint (34.2 percent natural gas, 23.7 percent coal, 28.5 percent nuclear, 13.2 percent hydro and other), 2.8 million residential, commercial and industrial electricity customers across a 24,000-square-mile service area in North Carolina and South Carolina,[89] and operates 13,000 miles of transmission lines. DEP's and DEC's record winter peak loads were 15,569 MW and 21,620 MW, respectively.

DESC (Core Entity). DESC (formerly known as South Carolina Electric & Gas Company) is a vertically integrated electric utility for the central, southern, and southwestern portions of South Carolina. DESC serves as a BA, GO, GOP, PA/PC, TO, and TOP. VACAR-South is its RC. DESC also purchases and distributes natural gas.[90] DESC's generating fleet is 40 percent natural gas,[91] 25 percent coal, 14 percent solar,[92] and 9 percent nuclear energy for a total net winter capacity of 6,821 MW. DESC is dual peaking, and its record winter peak load was 4,970 MW.

Santee Cooper (Core Entity). Santee Cooper (shown as "SC PSA" in Figures 1 and 9 above) is South Carolina's state-owned electric utility. It provides power to approximately two million people,[93] and operates as a BA, GO, GOP, PA/PC, TO, and TOP. VACAR-South is its RC. Santee Cooper sells electricity to Central Electric Power Cooperative, a wholesale power provider, which in turn provides power to South Carolina's 20 electric cooperatives.[94] It also provides power to the cities of Bamber and Georgetown, 27 large industrial customers including Joint Base Charleston, the Alabama Municipal Electric Authority, and the 10 member cities that form the Piedmont Municipal Power Agency.[95] Santee Cooper schedules power over 5,223 miles of transmission lines.[96] Its generation consists of 66.5 percent coal, 22.0 percent natural gas, 6.1 percent nuclear, 2.7 percent hydro, and 2.8 percent other. Santee Cooper is a winter-peaking region, and its highest winter peak demand was 5,342 MW in 2022.

Southern (Core Entity). Southern provides energy to nine million customers through its family of companies, including Alabama Power, Southern Power, Georgia Power, and Mississippi Power.[97] Southern also serves as a BA, PA/PC, and TOP, among others, and its RC is Southeastern RC.[98] Southern has electric operating companies in three states and natural gas distribution companies in four.[99] The Southern BA Area had 57,895 MW of projected generating capacity prior to Winter Storm Elliott and more than 27,000 miles of transmission lines.[100] The Southern BA Area generating fleet consisted of 53.5 percent natural gas, 20.3 percent coal, 11.5 percent nuclear, 8.7 percent hydro, 5.3 percent solar and wind, and 0.7 percent other. The Southern BA footprint is

89 https://p cd.duke energy.com/ /med a/pdfs/our company/duke energy fast facts.pdf?rev 77d14a34d96f449493f89595285d4d57.

90 https://www.dom n onenergy.com/pro ects and fac l t es/natural gas fac l t es/south carol na natural plants.

91 Th rty of the 40 percent of DESC's natural gas generat ng fleet s dual fuel.

92 Accord ng to DESC, "Most of the t me, DESC gets c ose to zero percent so ar at t me of morn ng w nter peak oads s nce they occur before the sun r ses."

93 https://www.santeecooper.com/about/.

94 https://www.fl psnack.com/santeecooper/fingert p facts 2022/full v ew.html.

95 https://www.fl psnack.com/santeecooper/fingert p facts 2022/full v ew.html.

96 https://www.fl psnack.com/santeecooper/fingert p facts 2022/full v ew.html.

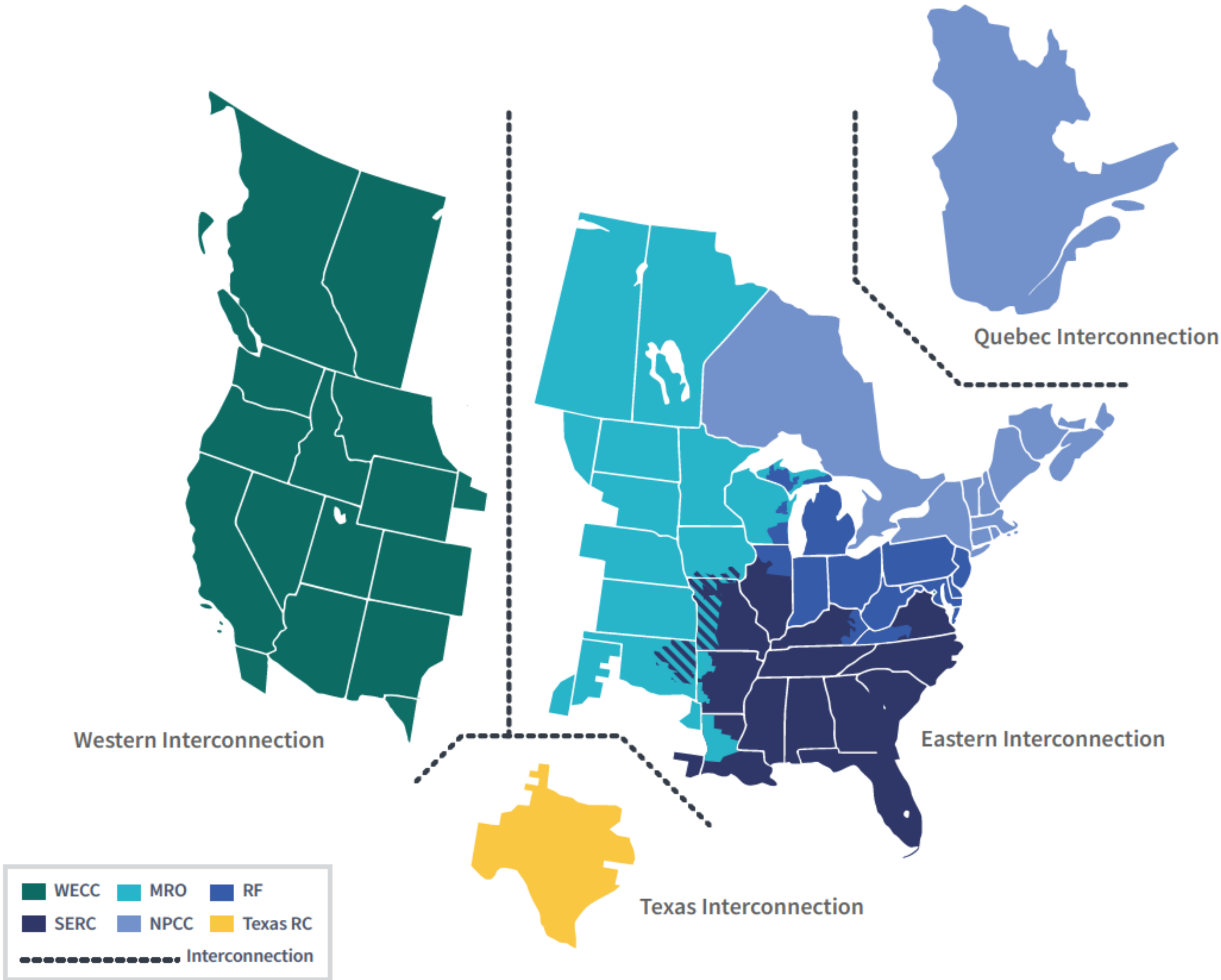
97 https://www.southerncompany.com/about/our compan es.html#:~:text We%20support%209%20m ll on%20customers,w reless%20commun cat ons%20across%20the%20country.

98 SERC recogn zes Southern Company Serv ces as the Rel ab l ty Coord nator for the Southeastern RC area.

99 https://www.southerncompany.com/about/our compan es.html#:~:text We%20support%209%20m ll on%20customers,w reless%20commun cat ons%20across%20the%20country.

100 https://www.southerncompany.com/about/our bus ness.html#:~:text Southern%20Company%20operat ons%20has%20respons b l ty,a%20safe%20and%20rel able%20gr d.

Figure 10: Electric Interconnections Map



generally dual peaking (summer and winter), with its all-time peak load being 48,008 MW.[101] Southern set a new December peak record during the Event of 45,153 MW on December 24.[102]

Figure 11, below, lists the capacity of BES generation resources for the Core Entities by fuel type, at the time of the Event. Natural gas-fueled generation comprised the largest percentage (41.90 percent) of generation across the core entities, followed by coal-fired generation at 24.19 percent. Renewable BES generation capacity was relatively low (1.94 percent solar and 1.12 percent wind, respectively) in the Core Event Area.

101 https://www.southerncompany.com/content/dam/southerncompany/susta nab l ty/pdfs/2022 Year n Rev ew.pdf.

102 https://www.southerncompany.com/content/dam/southerncompany/susta nab l ty/pdfs/2022 Year n Rev ew.pdf. For the Southern Company BA area, ts all t me w nter peak load was 45,887 MW.

Figure 11: Total Installed Net Capacity of BES Generation Resources Located within Core Entity Footprints During Event, and Resource Fuel Type Composition for Combined Core Entity Footprints

Core Entity Footprint	Capacity
	(MW)
DEC	25,848
DEP	16,390
DESC	6,821
LG&E/KU	7,973
PJM	186,270
Santee Cooper	5,237
Southern	57,895
TVA	36,456
TOTAL MW	**342,890**

Fuel Type	Combined Core Entity Footprints	
	(MW)	(Percent)
Coal	82,954	24.19%
Hydro*	34,455	10.05 %
Natural Gas	143,658	**41.90 %**
Nuclear	59,963	17.49 %
Solar	6,653	1.94 %
Wind	3,857	1.12 %
Other	11,350	3.31 %
TOTAL MW	**342,890**	**100%**

* ncludes Pumped Storage

c. Tie Lines Between Entities

The affected entities, each operating as BAs, have AC transmission tie lines which connect one BA to another, and enable power transfers to be routinely scheduled between them (resulting in power imports and exports) when generation reserves in the exporting BA and available transmission capacity are sufficient to accommodate the power transfers. All BAs in the Eastern Interconnection have multiple tie lines connecting them to neighboring BAs (BAs that are directly connected via tie lines are often referred to as "adjacent BAs").

In general, there is an extensive network of transmission tie lines between the Core BAs in the Eastern Interconnection, which under normal conditions allow for significant imports and exports among them. Figure 12, below shows the number of tie lines, by voltage level, between the Core BAs. ISO-NE, NYISO, MISO, and SPP also have tie lines with Canadian BES BAs (not shown on Figure 12).

Figure 12: Total Number of AC Transmission Tie lines, Number of Tie Lines between Adjacent Core BAs, and with other BAs Affected by Elliott, by Voltage Level

	DEC			DEP			DESC			LG&E/KU			PJM			Santee Cooper			Southern			TVA		
Totals:	29			41			31			85			201			35			55			61		
Voltage Level	DEC DESC	DEC PJM	DEC Santee Cooper	DEC Southern	DEP DEC	DEP PJM	DEP DESC	DEP Santee Cooper	DESC Santee Cooper	DESC Southern	LG&E/KU M SO	LG&E/KU PJM	PJM M SO	PJM NY SO	Santee Cooper Southern	Southern Flor da BAs	Southern M SO	TVA LG&E\KU	TVA M SO	TVA PJM	TVA Southern	TVA DEC	TVA DEP	TVA AEC
<100 kV											1	33	4	7		2	0	2	1	1				
100 to 150 kV	2	1			3	4	1	2	10	3	7	17	33	6		12	1		1	2	1			
150 to 300 kV	2		4		11	7	2	8	9	2	5	6		4	2	10	7	4	15	7	7	2	1	1
300 kV and Higher		1		1	1	1					7	2	51	11		2	1	1	7	3	4	1		
TOTAL	4	2	4	1	15	12	3	10	19	5	20	58	88	28	2	26	9	7	24	13	12	3	1	1

C. Background on Preparation for 2022-2023 Winter Peak Operations

1. SEASONAL PROJECTIONS AND ASSESSMENTS BY AFFECTED GRID ENTITIES

In general, BAs and RCs (which included both RTO and non-RTO entities) performed 2022-2023 winter season demand forecasts and projections of adequacy for both generation resources and transmission performance for their respective footprints.

a. Season Peak Load Forecasts

Figure 13, below, provides a summary of peak load forecasts that were made by the Core BAs in advance of the 2022-2023 winter season (typically developed by entities during the third calendar quarter in advance of the subsequent winter). Figure 13 compares the forecast peak loads against the actual peak loads that occurred within each Core BA footprint during the Event (as well as, where available, against the estimated peak if firm load shed or demand response had not reduced the actual peak load).

Figure 13: Winter 2022-2023 Season BA Peak Load Forecasts and Actual Hourly Winter Peak Loads for the Core Event Area (in MW)

		DEC	DEP	DESC	LG&E/KU	PJM	Santee Cooper	Southern	TVA
Previous All-Time Hourly Winter Peak		21,620	15,569	4,970	7,336	143,225	5,869*	45,887	33,352
Date of Occurrence		01/05/18	02/20/15	02/20/15	01/06/14	02/20/15	02/20/15	01/07/14	01/24/14
Winter 2022-2023 50/50 Forecast		20,246	14,454	4,169	6,453	132,980	5,481	41,300	30,295
Winter 2022-2023 90/10 Forecast		22,147	16,911	4,726	7,051	143,782	6,000	45,462	34,363
December 2022 Actual Hourly Peak		20,568	13,819	4,678	6,891	134,189	5,342	45,153	33,427
Date		12/24/22	12/24/22	12/24/22	12/23/22	12/23/22	12/24/24	12/24/22	12/23/22
December 2022 Estimated Peak without Load Management		21,800	14,800	N/A	6,986	134,951	5,900	46,000	35,000
Percent 2022 Actual Peak was Above Forecasts:	50/50	1.59%	4.39%	12.21%	6.79%	0.91%	2.54%	9.33%	10.34%
	90/10	7.13%	18.28%	1.02%	2.27%	6.67%	10.97%	0.68%	2.72%
Percent 2022 Estimated Peak was Above Forecasts:	50/50	7.68%	2.39%	N/A	8.26%	1.48%	7.64%	11.38%	15.53%
	90/10	1.57%	12.48%	N/A	0.92%	6.14%	1.67%	1.18%	1.85%

(a) DEC, DEP values l sted for 90/10 forecasts were projected super peak loads, ncluded Super Peak study as part of DEP and DEC w nter 2022 2023 season transm ss on capab l ty assessment. Super Peak values range from 9 (DEC) to 17 percent (DEP) to 17 percent (DEP) above 50/50 forecasts.

(b) DESC developed monthly 50/50 and extreme weather demand r sk peak values. Jan 2023 forecasts were 50/50, 4,902 MW; extreme, 5,459 MW.
(c) PJM: prev ous All T me Hourly W nter Peak value accounts for allocated 500 kV transm ss on losses. W nter 2022 2023 50/50 Forecast value represents the co nc dent peak 50/50 forecast and accounts for allocated 500 kV transm ss on losses (PJM uses the non co nc dent peak 50/50 forecast (136,867 MW for W nter 2022 2023, not l sted above) n ts Operat ons Assessment Task Force seasonal stud es). W nter 2022 2023 90/10 Forecastvalue accounts for allocated 500 kV transm ss on losses. 2022 Actual Hourly Peak and Est mated Hourly Peak w thout Load Management values account for allocated 500 kV transm ss on losses, and d ffer from peaks PJM reported elese where (135, 296) MW for actual and 136,010 MW for est mated peak w/o load management) due to a sl ght d fference n the way load s defined for the long term and short term forecast ng appl cat ons.
(d) *Santee Cooper 2015 / prev ous all t me w nter peak load ncluded load that s no longer served by Santee Cooper.
(e) Southern developed an extreme peak value based on stat st cal analys s.

Most of the BAs' actual winter peak loads during Winter Storm Elliott's extreme cold weather fell between their winter 2022-2023 50/50 and their 90/10 (or extreme forecast) winter season forecast peak loads.[103] A few BAs, such as TVA and Southern, would have exceeded both their 50/50 and 90/10 forecast peaks had they not implemented load management (Southern) or firm load reduction (TVA). Both BAs commented that winter peak load conditions do not exhibit a saturation point like summer peak air-conditioning-driven loads do, because electric heating (auxiliary backup heating for heat pumps, electric strip heating and electric space heaters) increases winter peak load in a non-linear manner as temperatures decrease.[104]

b. Capacity/Resource Reserves Projections

The Core BAs performed seasonal resource assessments in advance of the 2022/2023 winter to determine available generation reserves during winter peak conditions. The assessments included forecast peak loads, generation capacity, and projected reserves. Most of the Core BAs performed their respective winter season assessments assuming a 50/50 load forecast, although LG&E/KU's winter assessment assumed a 90/10 load forecast.[105] The paragraphs below summarize each BA's respective assessment.

Figure 14, below, depicts the winter 2022-2023 seasonal resource assessments for the Core BAs to meet their respective 50/50 and 90/10 forecast peak loads.

Figure 14: 2022-2023 Winter Season Resource Assessment Reserve Margins - Core BAs

		Without Demand Response		With Demand Response	
Balancing Authority	**NERC Region/Area**	50/50 Forecast W nter Peak Load (Percent)	90/10 Forecast W nter Peak Load (Percent)	50/50 Forecast W nter Peak Load (Percent)	90/10 Forecast W nter Peak Load (Percent)
DEC	SERC East	21.1	10.7	23.5	12.9
DEP	SERC East	9.0	6.8	10.6	5.5

103 A 50/50 peak load forecast s based on a 50 percent chance that the actual system peak load w ll exceed the forecast value, wh le a 90/10 peak load forecast s based on a 10 percent chance that the actual system peak load w ll exceed the forecast value.

104 *See* Recommendat on 16 and F gure 108 from the 2021 Report, wh ch shows how home heat ng demand due to electr c aux l ary heat ng ncreases from two to four t mes once temperatures drop below 14 degrees (as compared to the demand at 32 degrees).

105 For more about how BAs conduct these assessments, *see* page 30 of the 2021 Report.

Balancing Authority	NERC Region/Area	Without Demand Response		With Demand Response	
		50/50 Forecast W nter Peak Load (Percent)	90/10 Forecast W nter Peak Load (Percent)	50/50 Forecast W nter Peak Load (Percent)	90/10 Forecast W nter Peak Load (Percent)
DESC	SERC East	18.7	6.6	23.5	10.9
LG&E/KU	SERC Central	15.1	5.4	15.1	5.4
PJM	RF/PJM	14.9	9.4	20.5	14.7
Santee Cooper	SERC East	4.1	12.4	7.3	2.0
Southern	SERC Southeast	30.2	18.3	30.2	18.3
TVA	SERC Central	9.2	3.7	14.6	1.0

DESC. DESC performed a Winter 2022/2023 resource assessment assuming a 50/50 load forecast. Based on its winter assessment, DESC believed that it could meet its projected winter peak demand of 4,902 MW with available generation and imports (based on normal weather conditions). DESC's extreme winter forecast[106] was 5,459 MW, higher than its previous all-time winter peak demand record of 4,970 MW, set in 2015. To meet that extreme peak demand, DESC projected a seasonal resource capacity of 5,819 MW, once 1,147 MW of planned and forced outages were deducted from available resources. This resulted in estimated reserves of 917 MW assuming the 50/50 load forecast and 360 MW for an extreme weather demand risk scenario.

Duke/DEC and DEP. Based on its winter resource reserves projection, Duke believed that it could meet its projected winter peak demand of 20,246 MW for DEC and 14,454 MW for DEP, for a combined load of 34,700 MW, with available generation and imports (based on normal weather conditions). To meet the projected winter demand, DEC projected a resource capacity of 24,510 MW, once 1,338 MW of planned and forced outages were deducted from available resources. DEP projected a resource capacity of 15,754 MW, once 636 MW of planned and forced outages were deducted from available resources. Duke assumed a forced outage rate of 2.5 percent based on recent historical performance. Duke adjusts reserves by third party imports/exports, projected demand response and units in extended reserve shutdown. This resulted in estimated reserves of 2,246 MW for DEC and 1,648 MW for DEP for the 50/50 load forecast.[107]

Duke's extreme winter forecast was 22,147 MW for DEC and 16,911 MW for DEP (39,058 MW combined), which was higher than its previous all-time winter peak demand record of 21,620 MW, set on January 5, 2018 for DEC and 15,569 MW, set on February 20, 2015 for DEP. Duke performed this super peak study to determine potential transfer capability limitations. The DEC transmission system would be capable of serving load of 24,457 MW before seeing any significant issues. The DEP transmission system would be capable of serving load of 17,491 MW before seeing any significant issues.

Santee Cooper. Santee Cooper performed a Winter 2022/2023 resource assessment assuming a 50/50 load forecast. Santee Cooper's winter load forecast is prepared using 20 years of monthly peak demand and energy usage each year around April. This forecast is composed of several component forecasts, including forecasts for different customer classes. Based on its winter

106 DESC uses a stat st cal regress on techn que to quant fy an extreme w nter weather demand level, based on ts h stor cally coldest w nter days.

107 DEC and DEP also expla ned that there are no add t onal sub areas, reg ons, or load pockets w th n the DEC and DEP BA areas where reserves are mon tored to ensure suff c ent resource reserves and/or del verab l ty of reserves for the reg ons or sub areas.

assessment, Santee Cooper believed that it could meet its projected winter peak demand of 5,481 MW with available generation and imports (based on normal weather conditions).[108] Santee Cooper's extreme (i.e., 90/10) winter forecast was 6,000 MW, slightly higher than its previous all-time winter peak demand record of 5,869 MW, set on February 20, 2015.[109] To meet that extreme peak demand, Santee Cooper projected resource capacity of 5,237 MW and 626 MW of demand response. Without demand response, Santee Cooper projected a resource deficiency of up to 743 MW to meet its extreme load forecast of 6,000 MW. Santee Cooper relied on the Carolinas Reserve Sharing Group to recover from typical single-contingency outages of generating units and relied on import power purchases as needed for other scenarios such as multi-unit outage conditions.

LG&E/KU. LG&E/KU performed its Winter 2022/2023 resource assessment using the 90/10 load forecasts provided by the four load-serving entities in the LG&E/KU BA area: (1) LG&E/KU; (2) Owensboro Municipal Utilities; (3) Kentucky Municipal Power Agency; and (4) Kentucky Municipal Energy Agency. Although LG&E/KU used the 90/10 load forecast for their winter assessment, LG&E/KU also performed a 50/50 load forecast using the forecasts provided by the four load-serving entities (LSEs) in the BA area.[110] Based on the winter assessment, LG&E/KU believed that it could meet its projected winter peak demand of 6,453 MW with available generation and imports (based on normal weather conditions). LG&E/KU's extreme winter forecast demand was 7,051 MW. To meet that extreme peak demand, LG&E/KU projected resource capacity of 7,430 MW, assuming a 3.66 percent forced outage rate for coal units and 6.36 percent forced outage rate for natural gas units. LG&E/KU's assessment also considered multiple contingencies (e.g., analysis required in Reliability Standard TPL-001-5.1). This resulted in estimated reserves of 977 MW assuming the 50/50 load forecast and 379 MW for the 90/10 extreme load scenario.

TVA. TVA performed a Winter 2022/2023 resource assessment assuming a 50/50 load forecast. TVA uses 24 hourly regression models trained over the prior three years to estimate response of load to temperature (i.e., the corresponding MW increase from a one-degree increase or decrease of temperature). TVA's models use calendar factor variables (e.g., holidays, day of week, month, and year), seasonal weighted aggregate dry bulb temperatures based on the five largest cities in the TVA region,[111] and a 72-hour weighted average of the dry bulb temperature, where the more recent observations are more heavily weighted to estimate the impacts of thermal buildup. TVA uses these models to estimate load for its hourly temperature history (going back to 1960) as if the load had occurred with the current system size, in order to ensure a wide sample of load and temperature values. TVA uses the estimated loads to build a probability distribution to mitigate issues with a regression model. The models assume that the most extreme winter weather will occur in January and assume that the prior three years of hourly temperatures approximate current temperature response.

Based on its winter assessment, TVA believed that it could meet its projected winter peak demand of 30,295 MW with available generation and imports (based on normal weather conditions). TVA's extreme winter forecast was 34,363 MW, slightly higher than its previous all-time winter peak demand record of 33,352 MW, set on January 24, 2014. To meet that extreme peak demand, TVA projected resource capacity of 33,079 MW, once 577 MW of planned and 2,800 MW of unplanned outages were deducted from available resources. This resulted in estimated reserves of 2,784 MW for the 50/50 load forecast and 1,284 MW deficiency for the 90/10 extreme load scenario.

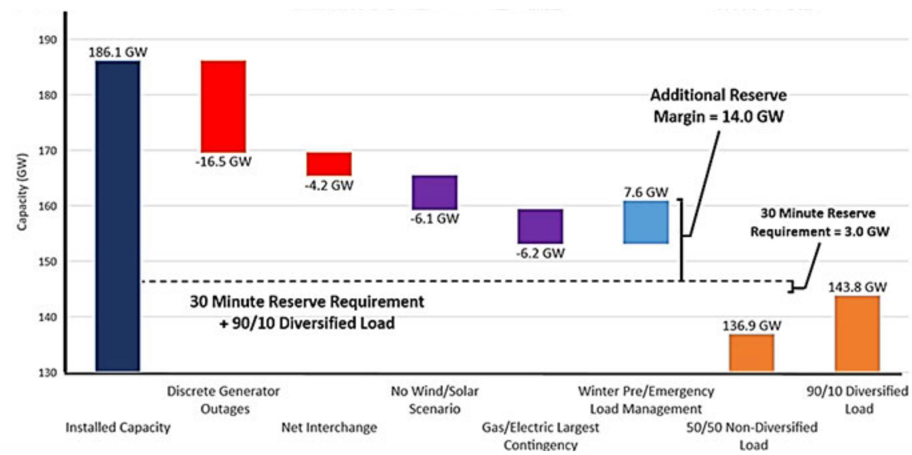
108 Based on ts 50/50 forecast reserve marg n w thout demand response, magn tude of mports to meet load and ma nta n operat ng reserves w thout deployment of demand response would have been n the range of 350 400 MW.

109 A port on of the load Santee Cooper was serv ng on February 20, 2015 s no longer served by Santee Cooper.

110 Accord ng to LG&E/KU, " t]he LG&E/KU] LSE forecasts the 50/50 w nter peak load us ng the average temperature on the peak day over the last 20 years. To assess generat on rel ab l ty and develop extreme weather load scenar os, the LG&E/KU] LSE develops hourly demand forecasts based on the actual weather n each year s nce 1973. Degree days are the pr mary var able used to develop these forecasts."

111 .e., Huntsv lle, Alabama; Memph s, Tennessee; Nashv lle, Tennessee; Chattanooga, Tennessee; and Knoxv lle, Tennessee.

Figure 15: PJM's Winter 2022-2023 Capacity Projections



However, TVA projected approximately 1,626 MW of load management available to respond to additional unplanned resource outages.

Southern. The Southern BA performed a winter 2022/2023 resource assessment assuming a 50/50 load forecast. Based on its winter assessment, the Southern BA believed that it could meet its projected winter peak demand of 41,300 MW with available generation and imports (based on normal weather conditions). The Southern BA's extreme winter forecast was 45,462 MW, slightly lower than its previous all-time winter peak demand record of 45,887 MW, which was set on January 7, 2014. To meet that extreme peak demand, Southern projected resource capacity of 53,759 MW, once 4,136 MW of planned and forced outages were deducted from available resources. This resulted in estimated reserves of 12,459 MW assuming the 50/50 load forecast and 8,297 MW for the 90/10 extreme load scenario. Southern BA also projected approximately 2,510 MW of load management available to respond to additional unplanned resource outages.

For assessing transmission system performance for the upcoming winter season, SERC (members include DESC, DEC, DEP, Santee Cooper, LG&E/KU, TVA, and Southern) conducted a 2022-2023 winter reliability study. The assessment studied an N-1 contingency analysis on the initial base case to determine whether there was adequate transmission for the upcoming winter season. SERC members also studied an "extreme weather" scenario under which a 12 GW power transfer was simulated from PJM to MISO South. A third study simulated what was termed as a "colder-than-normal" transfer case, which increased all generation in the SERC region that was online with available capacity and scaled the loads up in one subregion at a time, evaluating transmission adequacy given higher subregional demands that were 10 percent or higher above 50/50 forecasted levels. Overall, the above three studies did not show any transmission adequacy issues in the SERC subregions for the 2022-2023 winter season, and showed that potential thermal overloads identified in the studies could be mitigated with available operating guides or other mitigation strategies.

PJM. PJM performed a Winter 2022/2023 seasonal assessment assuming a 50/50 load forecast. PJM used power flow cases that simulated the expected system conditions for the 2022/2023 winter peak load period. For the PJM non-coincident load case, each transmission zone is set to its individual respective winter 50/50 peak load forecast value, without a reduction for load diversity and without considering any demand response resources that may be available. PJM also performed several sensitivity studies using the 50/50 non-coincident load case. Finally, PJM calculated projected reactive interface transfer limits[112] for various interfaces.

As shown in Figure 15,[113] based on its winter assessment, PJM believed that it could meet its projected 50/50 winter peak demand of 136,867 MW with available generation (based on normal weather conditions). PJM's extreme winter forecast was 143,782 MW, slightly higher than its previous all-time winter peak demand record of 143,225 MW, which was set on February 20, 2015. To meet that extreme peak demand, PJM projected resource capacity of 157,314 MW, once 16.5 GW of generator outages, 4.2 GW of exports, 6.2 GW for the loss of its largest contingency (gas/electric single point of failure) and 6.1 GW for a no wind/no solar scenario were deducted from available resources. This resulted in estimated reserves of 16,233 MW assuming the 50/50 load forecast and 9,318 MW for the 90/10 extreme load scenario. However, PJM projected approximately 7.6 GW of load management available to respond to additional unplanned resource outages.

2. GENERATOR OWNERS'/OPERATORS' AND NATURAL GAS FACILITIES' WINTER SEASON PREPAREDNESS

a. Generation Resources' Seasonal Preparations

GOs/GOPs indicated that over 90 percent of generators that experienced an outage, derate, or failure to start had a cold weather preparedness plan in effect during the Event, and the same percentage used a pre-winter generating unit maintenance checklist in the fall. See section III for additional information on GOs/GOPs' cold weather preparation.

b. Natural Gas Infrastructure/Facilities' Seasonal Preparations

Natural gas infrastructure facilities took a variety of actions to prepare for winter.[114] Production facilities inspected and made repairs as necessary to insure functionality of heat trace and other heating systems, if applicable. They ordered and stocked essential winter supplies such as cinders for roads (used to access wellheads during icy road conditions), and portable generators. Some buried flowlines[115] to protect them from freezing, and/or added burners to increase temperatures on gas processing units. Natural gas processing entities purchased supplies such as tarps, batteries, spare parts, and mobile heaters, and performed maintenance such as repairing insulation on pipes and checking mobile heaters to ensure they were in good working order.

Pipeline operators implemented their winter operations programs which included performing preventive maintenance on compressor stations and at receipt and delivery points, testing all emergency equipment, servicing backup power supply sources, and performing any necessary equipment overhauls, among other tasks.

112 nterface transfer l m ts are the MW flow l m tat on across a transm ss on nterface to protect the system from large voltage drops or collapse caused by any v able cont ngency.

113 Reproduced w th perm ss on of PJM and © PJM.

114 The Team nstructed all natural gas ent t es that t asked for data to prov de data for the follow ng states, f appl cable: New York, Delaware, Kentucky, Maryland, New Jersey, North Carol na, South Carol na, Oh o, Pennsylvan a, Tennessee, V rg n a, West V rg n a, D str ct of Columb a, Georg a, Alabama, M ss ss pp , Lou s ana, Arkansas, M ssour , owa, ll no s, M nnesota, W scons n, M ch gan, nd ana.

115 Flowl ne s the flow connect on from the wellhead to the separat on fac l ty, p pel ne or storage un t. *See* P p ng and p pel ne systems PetroW k (spe.org).

III. CHRONOLOGY OF EVENTS

A.Preparations in Advance of the Winter Storm

1. WEATHER FORECASTS PREDICTED SEVERE COLD FOR DECEMBER 23-24 AS EARLY AS DECEMBER 14

Similar to Winter Storm Uri, and past major winter storms, the storm that came to be called Winter Storm Elliott[116] was forecast many days in advance. On Wednesday, December 14, at 3 p.m., the National Weather Service issued its "US Hazards Outlook" covering the period that included December 22 to 25 and published its "8-14 Day Temperature Outlook" graphic, as shown in Figure 16, below, showing that large portions of the eastern U.S. were highly likely to experience below normal temperatures.[117]

In its outlook, the NWS predicted that "[a] negative Arctic Oscillation (AO) pattern forecast over North America later in December is expected to promote below normal temperatures" with "[h]igh risk of much below normal temperatures for much of the [contiguous U.S.] east of the Rockies excluding the Northeast, Thu[rsday through Sunday], Dec[ember] 22-25."[118]

SPP and MISO RCs. On the following day, December 15, SPP and MISO first identified the risk that the forecast extreme weather posed to their respective systems, with projected impacts beginning December 21-22.

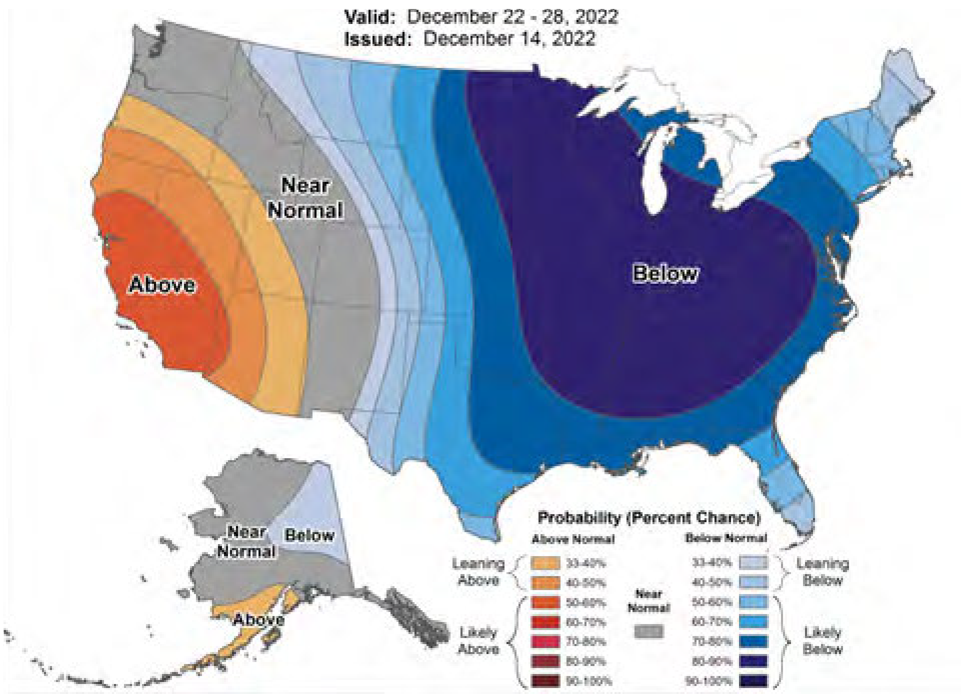
TVA, Southern, and VACAR-South RCs. On December 14, TVA recognized that a major arctic outbreak was likely for Christmas weekend (December 23 to 25), and on December 19, communicated that across its organization. On December 16, Southeastern RC recognized the threat posed by the forecast and discussed on Southeastern RC's daily RC calls from that day until December 25. It also began sharing forecast system conditions via Southeastern RC emails on December 16. Duke updated internal stakeholders on December 19 regarding its concern with the forecast winter conditions, which it expected to be a powerful cold front arriving on December 23, bringing falling temperatures and precipitation (mostly rain).

116 The Nat onal Weather Serv ce of the Nat onal Ocean c and Atmospher c Adm n strat on does not name w nter storms because, accord ng to ts then Deputy D rector of Publ c Affa rs, " w] nter storms are d verse w th cond t ons that evolve throughout the storm's l fe. That s why our (NWS) forecasts, watches and warn ngs focus on spec fic mpacts such as w nd cond t ons, snowfall, ce, temperature, v s b l ty, and other mpacts. W nter storm cond t ons can vary w dely and over a very large area, from commun ty to commun ty. t's cr t cal that people understand how a storm w ll mpact them, n the r area or where they are go ng." A pr vate company, The Weather Channel, began nam ng severe w nter storms n 2012 and those names have been recogn zed by some, but not all, med a sources. KSAT, for example, sa d that t would cont nue to follow the NWS and not recogn ze names for w nter storms. Sarah Sp vey, *Let's chat: Do winter storms really have names? The unofficial naming system has gained some popularity, but experts caution against the naming of winter storms.*,KSAT NEWS (Oct. 19, 2002) https://www.ksat.com/weather/2022/10/19/lets chat do w nter storms really have names/. n 2021 the Team d d not recogn ze the nam ng of W nter Storm Ur , but g ven the w despread use of the w nter storm names by med a d scuss ng both the 2021 and 2022 events, the Team used the names n the Report.

117 *See*, Mel ssa Ou, *National Weather Service Climate Prediction Center "U.S. Hazards Outlook"*,cpc.ncep.noaa.gov/products/arch ves/hazards/data/2022/KWNCPMDTHR.20221214, and "8 14 Day Temperature Outlook" graph c at 814temp.20221214.fcst.g f (3300×2550) (noaa.gov). *See* also examples of coverage n popular med a: Anna Sk nner, *Artic Blast to Bring Dangerous Below Zero Temperatures to These States*, Newsweek (Dec. 20, 2022), https://www.newsweek.com/arct c blast dangerous below zero temperatures these states 1768512; and Pandora Dewan, *Bomb Cyclone Photos: What to Expect From Freezing Weather Forecast*, Newsweek (Dec. 20, 2022), https://www.newsweek.com/bomb cyclone photos freez ng weather forecast 1768515#:~:text Ell ott%20 s%20expected%20to%20arr ve%20 n%20the%20Pac fic,the%20M dwest%20and%20parts%20of%20the%20East%20Coast.

118 Cont guous U.S. ncludes the 48 states south of Canada, nclud ng the D str ct of Columb a.

Figure 16: National Weather Service 8-14 Day Temperature Outlook – December 14, 2022



PJM. The storm was expected to move into PJM's footprint on December 23, bringing snowfall and high wind gusts combining to create blizzard conditions, and freezing rain in the central Appalachians with ice accumulation of 0.10 to 0.25 inches. On December19, PJM weather forecasting alerted PJM Dispatch via email of upcoming blizzard conditions and extreme cold.

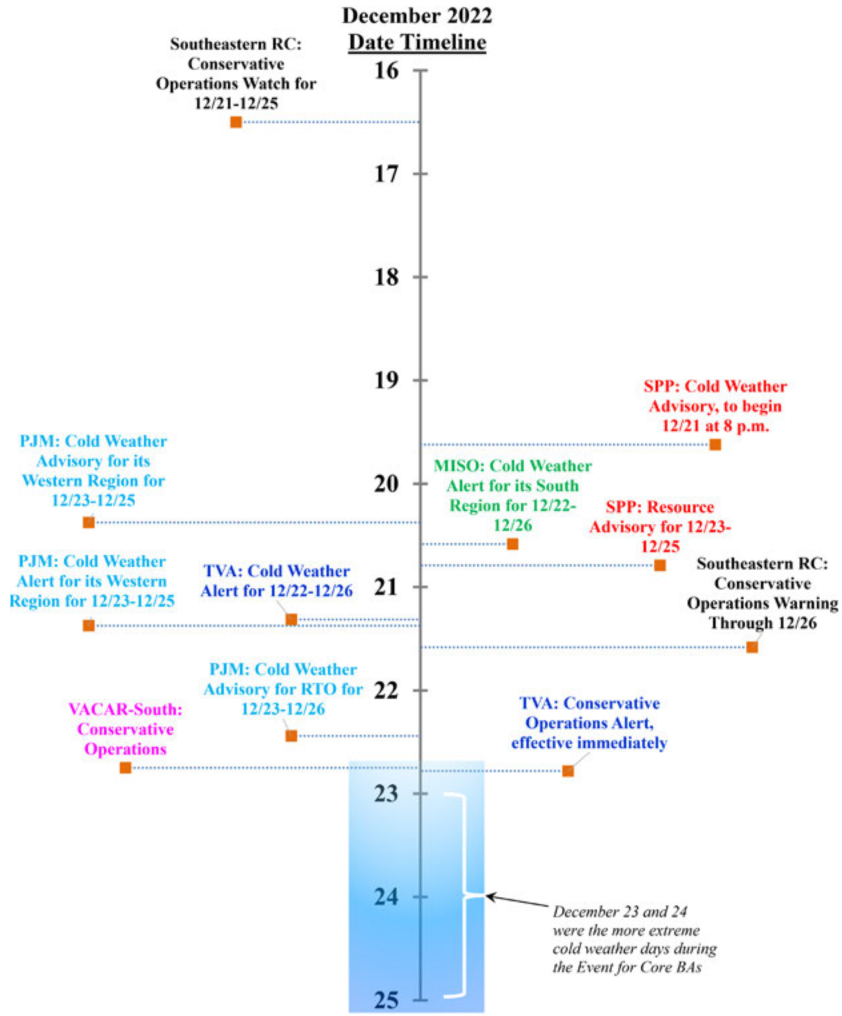
2. ALERTS ISSUED BY GRID ENTITIES AND EXPECTED PREPARATIONS FROM DECEMBER 16 THROUGH 22

All BAs and RCs have established emergency operating procedures (emergency procedures) as required by the Reliability Standards, particularly EOP-011-2, Emergency Preparedness and Operations.[119] Additionally, entities may have their own specific operating procedures that coordinate with or supplement the BA/RC emergency procedures. As part of their responsibilities under the emergency procedures, BAs and RCs issue cold weather advisories, alerts, and conservative operations notices, as necessary.[120] Each entity's emergency operating procedures document the actions that are required by the relevant TOs/TOPs and GOs/GOPs.

119 RSCompleteSet.pdf (nerc.com)

120 For purposes of th s d scuss on, the Report uses the terms "adv sor es," "alerts," and "conservat ve operat ons not ces" to encompass the range of not ces that BAs and RCs ssue as part of the r respect ve emergency operat ng procedures, https://www.nerc.com/pa/Stand/Rel ab l ty Standards Complete Set/RSCompleteSet.pdf. Each BA and RC uses spec fic defined terms for the r not ces. *See, e.g.,* PJM Manual 13: Emergency Operat ons (Aug. 24, 2023), https://www.p m.com/ /med a/documents/manuals/m13.ashx (nclud ng PJM's defined terms for ts alerts and not ces).

Figure 17: RC Watches, Advisories, Alerts and Warnings Issued From Friday, December 16 Through Thursday, December 22, 2022



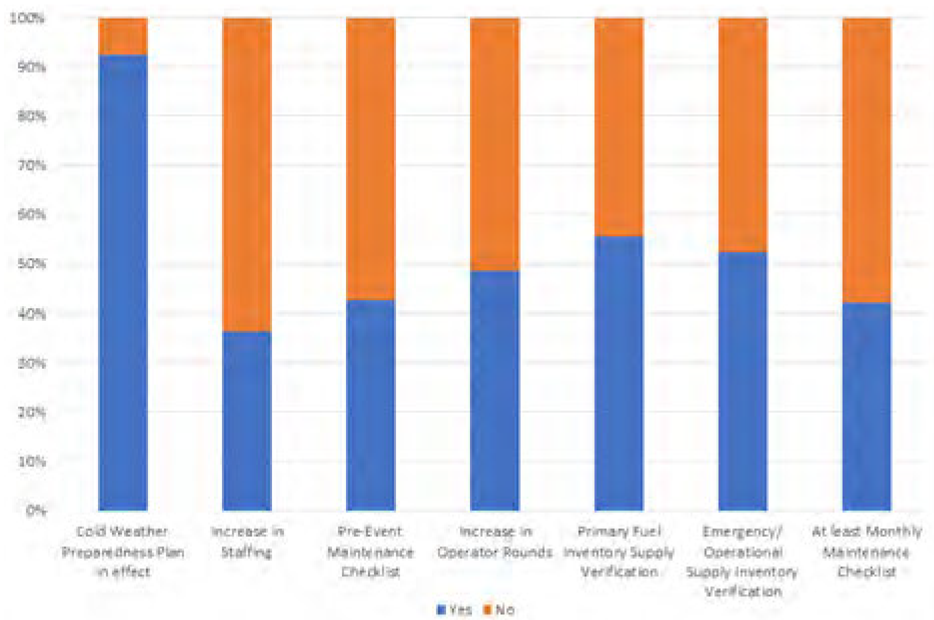
Before and during the Event, affected RCs issued cold weather advisories[121] and alerts,[122] as well as conservative operation declarations. Figure 17, above, summarizes the notices issued in advance of the more extreme cold weather days during the Event (including conservative operations declarations) from December 16 through December 22.

BAs issue the in-advance cold weather alerts and advisories to their stakeholders, including those BES

121 By way of example, PJM's cold weather adv sor es adv sed PJM members to prepare to (1) take freeze protect on measures; (2) rev ew weather forecasts, determ ne any forecast operat onal changes, and not fy PJM of any changes; and (3) update PJM w th operat on l m tat ons assoc ated w th cold weather preparedness (e.g., generator capab l ty and ava lab l ty, fuel supply and nventory concerns, fuel sw tch ng capab l t es, env ronmental constra nts, and generat ng un t m n mum temperatures).

122 Aga n, as an example, PJM's cold weather alerts stated that generat on d spatchers should: (1) rev ew fuel supply/del very schedules n ant c pat on of greater than normal operat on of un ts; (2) mon tor and report projected fuel l m tat ons to PJM d spatcher and update the un t Max Run field n PJM's Markets Gateway f less than 24 hours of run t me s rema n ng; and (3) contact PJM D spatch f t s ant c pated that spot market gas s unava lable, result ng n unava lab l ty of b d n generat on.

Figure 18: Cold Weather Event Preparation by GOs/GOPs with Outages/Derates/Failures to Start



GOs/GOPS within their footprints.[123] The GOs/GOPs are not required to respond to the alerts or verify that they completed their winter readiness steps (i.e., no confirmation to the BA that the generating unit is prepared for the forecast cold weather).

3. NEAR-TERM PREPARATIONS BY GENERATION OWNERS/OPERATORS

Under the currently effective Reliability Standards, GOs/GOPs are required to have cold weather preparedness plans that include inspection and maintenance of the generating unit's freeze protection measures.[124] A common method for implementing inspection and maintenance of freeze protection measures is the use of inspection and maintenance checklists. Over 40 percent of the GOs/GOPs that experienced an outage, derate or failure to start during the Event performed monthly inspections using their checklists, with a subset of those inspecting weekly.Approximately 40 percent of those that have a pre-winter checklist (used to prepare for the season) implement a "pre-event" checklist (which can be used to confirm that nothing has degraded, and that no new maintenance issues have arisen, since the pre-winter checklist was completed).[125] Sixty percent do not perform pre-event inspection or maintenance checklists, which suggests room for improvement. Figure 18, above, illustrates the responses provided by GOs/GOPs that had at least one generating unit that incurred an outage, derate, or failure to start during the Event, when asked whether they performed various near-term preparations. Other areas of cold weather preparedness that could benefit from improved effort include the actions that had 50 percent or less adoption rates in Figure 18, such as providing additional staffing (during an event), increasing operator rounds, verifying inventory of primary fuel and emergency supplies, and using a monthly maintenance checklist.

123 The Report d scusses not ces ssued after December 22 dur ng the Event n Sect on .B.3., below.

124 Rel ab l ty Standard EOP 011 2, Requ rement R7.2. RSCompleteSet.pdf (nerc.com).

125 For example, outages have resulted from nsulat on be ng moved away from p pes to perform work and not be ng properly replaced before the onset of freez ng temperatures.

4. NEAR-TERM PREPARATIONS BY NATURAL GAS INFRASTRUCTURE ENTITIES

As the storm approached, natural gas infrastructure facilities supplemented their seasonal prparations. Some entities took steps to determine that readiness had not declined since the pre-winter preparations, along with implementing short-term measures to be taken shortly before a major storm.

Production. Producers stationed additional field personnel and supplied them with resources to prevent and manage freeze offs by ensuring functionality of heat trace and other heating systems, by injecting methanol, and by increasing flow rates.[126] They pre-arranged for removal of snow and ice from roads to ensure safe access to sites and facilities, along with prepping the roads with cinders in advance of cold weather conditions. Producers also pre-staged materials such as water tanks and portable backup generation where they would most likely be needed. Some producers used tarps and deployed shelters (which could hold heaters, if necessary) to protect equipment prone to freezing. They lowered levels in or emptied water, condensate, and oil tank levels at facilities to which access was expected to become difficult. Most conservatively, two producers anticipated production declines and proactively reduced the amount of natural gas that they marketed in the short term.

Processing. Processing companies increased personnel on duty to respond to plant issues and equipment failures, ensured adequate supplies of methanol, stocked critical spare parts (tarps, batteries, etc.), performed any last-minute maintenance (e.g., repair insulation), and coordinated with producer customers and purchasers of the residue gas produced by the plant. Finally, to the extent that they relied upon some form of an alternative power source (e.g. on-site backup generators), they serviced the power source to ensure operation during the Event.

Pipelines. Pipelines in the path of Winter Storm Elliott began to monitor the weather forecast as the storm began to form, while also implementing cold weather plans and holding internal meetings.[127] These meetings focused on estimated load forecasts, storage strategies, maintenance activities, and line pack management strategies. Due to anticipated operational challenges, some pipelines staffed key compressor stations that ordinarily are not staffed but are essential during peak demand for system reliability. Some tested emergency equipment in advance of the Event.

All pipelines proactively managed and monitored line pack and system integrity. Some pipelines issued critical notices in advance of the storm, ranging from weather advisories to OFOs. Each pipeline increased line pack in anticipation of high demand, supply loss, and potential equipment problems. Most also prepared storage facilities to allow them to withdraw natural gas – including liquid natural gas – to meet customer requests and respond to anticipated increased demand.

5. SHORT-TERM LOAD FORECASTS BY GRID ENTITIES

Accurate short-term load forecasts (that is, the load forecasts BAs performed just days in advance or during the Event, with knowledge of the forecast extreme cold weather) assist with committing and scheduling resources. Many of the BAs normally aim to keep their load forecast error near or below three percent. For example, PJM's daily peak forecast error only exceeded its target load forecast error of up to three percent on a single day between December 1 and December 23, 2022.

126 The Gas Technology nst tute completed a report as part of the nqu ry nto the 2011 Southwest cold weather event, wh ch deta led techn ques for prevent ng freez ng of natural gas product on. L. Brun H lbert et al., *Natural Gas Production in Extreme Weather*, P pel ne & Gas Journal, (June 2021), https://www.pg onl ne.com/magaz ne/2021/ une 2021 vol 248 no 6/guest commentary/natural gas product on n extreme weather. Other methods ncluded water removal us ng glycol dehydrat on and heat ng methods such as catalyt c heaters, fuel l ne heaters and steam systems.

127 One p pel ne held a November 2022 meet ng w th ts customers regard ng cold weather preparedness. Although th s act on was an outl er, t was an effect ve pract ce and the Team encourages all p pel nes to cons der hold ng s m lar meet ngs n the future.

Although BAs projected higher electricity demands for the impending winter storm, most core BA significantly underestimated the peak loads in advance of December 23 and 24, the most extreme cold weather days of the Event. Figures 19 and 20 below, show the Core BAs' four-, three-, two- and day-ahead forecasts versus actual peak loads for December 23 and 24, respectively. Figure 21, below, shows their Mean Absolute Percentage Error (MAPE) across the four-, three-, two-, and day-ahead peak load forecasts for December 23 and 24.

Figure 19: BAs' Four-, Three-, Two-, and Day-Ahead Peak Load Forecasts vs. Actual[128] Peak Loads (Percent Difference) For December 23, 2022

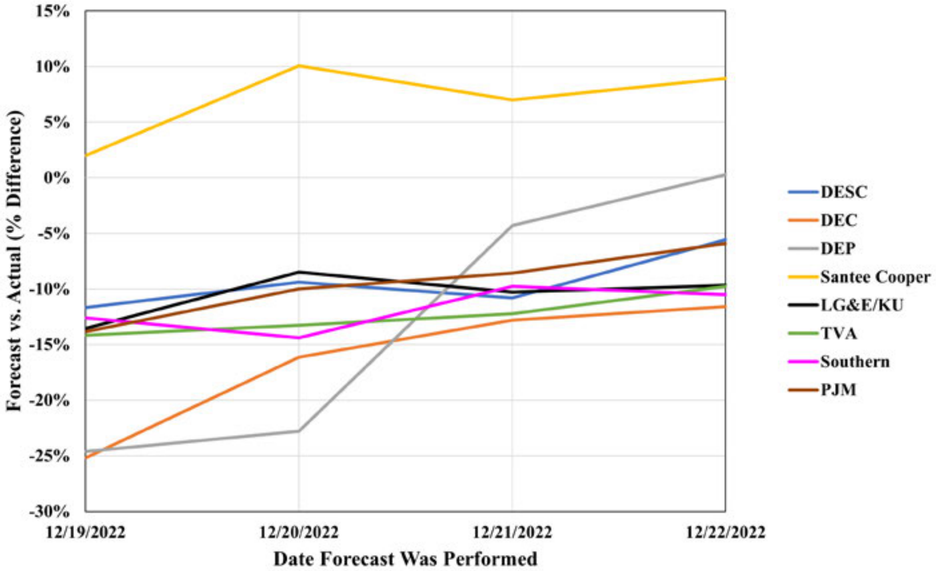
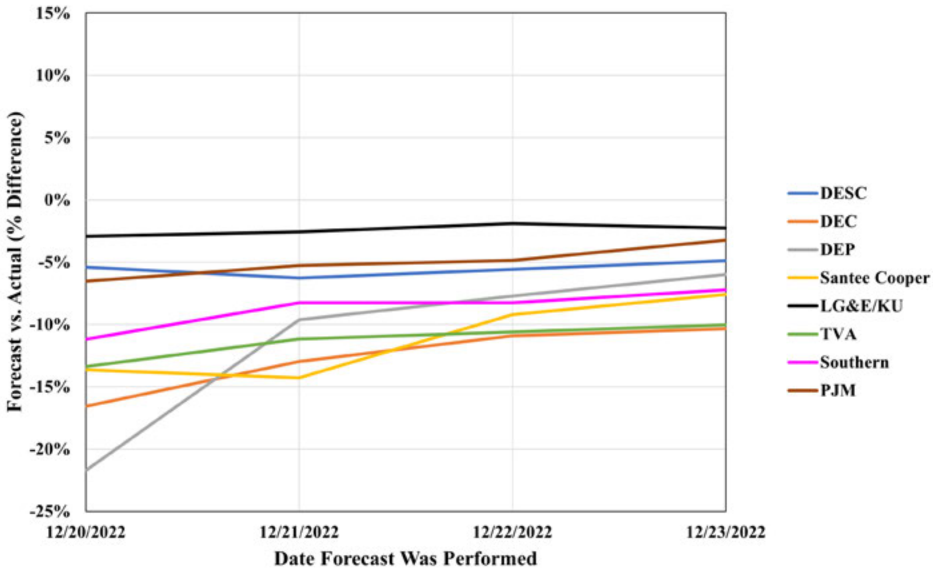
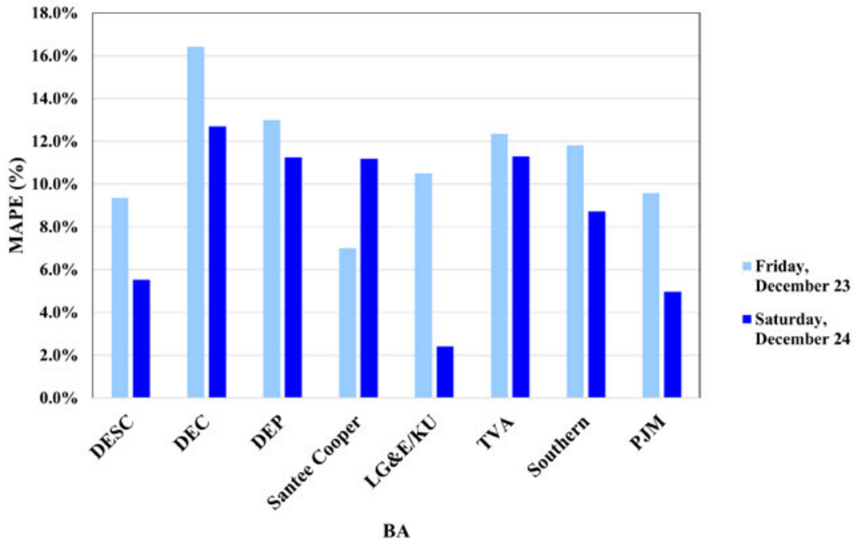


Figure 20: BAs' Four-, Three-, Two-, and Day-Ahead Peak Load Forecasts vs. Actual Peak Loads (Percent Difference) For December 24, 2022



128 For F gures 19, 20, and 21, for BAs that mplemented load management measures dur ng the r respect ve peak load t meframes, actual peak loads used for calculat ons are based on BAs' est mated peak loads w thout load management.

Figure 21: Mean Absolute Percentage Error (MAPE) For BAs' Four-, Three-, Two-, and Day-Ahead Peak Load Forecasts for December 23 and 24, 2022



All of the BAs use weather data as inputs into their short-term forecasts. Most use only three years of data to train their models, which can be problematic if the conditions experienced have no similar day within the past three years. Some BAs have their own meteorologists, while others use only external vendors for weather forecasts. Two BAs automatically add buffers (MW or percentage of load forecast) to account for potential load forecast error. Some have a single system-wide forecast, while others split their forecast to reflect differences in the makeup of their load (e.g., mountains vs. beaches).

Figure 22, below, summarizes how each BA approaches these short-term load forecasts.

Figure 22: Summary of BAs' Short-Term Load Forecast Processes

	Weather Forecast Data	Short-Term Load Forecast Model
DEC, DEP	nternal meteorology team produces forecast.	Uses models developed by three external vendors and projects load based on evaluat on of the r outcomes. Usually p cks h ghest for extreme cold weather day, or looks for h stor cal day to match. DEP prepares east and west (Ashev lle only) forecasts.
DESC	Obta ns weather data from th rd party vendors.	Based on weather forecast model and load model nputs, uses comb nat on of external vendors and one nternal model for develop ng load forecast. ncorporates solar nputs, and any manual adjustments deemed necessary to account for lack of s m lar days to produce a seven day hourly load forecast.
LG&E/KU	External weather nformat on prov ders, vendors.	Short term load forecast s an aggregate of the load forecasts prov ded by the LSEs n the LG&E/KU BA area. n week ahead/next day stud es use a five percent buffer.
PJM	Three external weather nformat on vendors, uses we ghted average based on recent performance.	nternal team manages su te of neural network and pattern match ng models w th final short term load forecast based on staff evaluat on. Benchmarks day ahead forecast aga nst actual for track ng of forecast error.

	Weather Forecast Data	Short-Term Load Forecast Model
Santee Cooper	External weather nformat on prov ders, vendors	Pr mary short term load forecast s prov ded by an external vendor and evaluated aga nst alternat ve forecast prov ded by another vendor. Uses 100 MW (approx mately 1.8 percent of w nter season peak) adder for load forecast error.
Southern	External weather nformat on prov ders, vendors	Next 10 days' hourly weather forecasts are prov ded by external vendors, w th mult ple c t es' peak load we ghted for nput to load forecast ng models, wh ch are neural network based. Southern has large number of models produc ng load forecasts, nclud ng a vendor suppl ed forecast that uses d str but on level metered load data as nputs, wh ch has proven to be the most accurate of the r vendors' forecasts over the past two years for the 1 5 day ahead load forecasts.
TVA	Two external weather nformat on vendors feed nto ts load forecast software.	nternal blend of three load forecast models from vendors, based on three year h story, nformed by weather data and weather forecast. f no s m lar event n the three year h story, look for s m lar events n more d stant past to adjust/extrapolate the load forecast.

6. GRID ENTITIES' OPERATIONAL PLANNING ACTIONS TO PREPARE FOR EVENT

Given the higher electricity demands forecast for the upcoming Winter Storm Elliott, BAs arranged for resources to meet those demands, including attempting to return resources to service that were offline before the storm (e.g., for periodic maintenance). Planned generator outages are typically scheduled months or even years in advance, to perform necessary maintenance, or in the case of nuclear power plants, refueling. BAs in organized markets can ask GOs/GOPs to reschedule their planned generation outages for system reliability, but they cannot require the GOs/GOPs to do so.

a. Generation Returned to Service Prior to Most Severe Event Conditions

Forced outages and derates for the Event Area remained relatively constant (41,607 MW on December 21 versus 42,856 MW on December 23) before the worst part of Winter Storm Elliott began to impact the Event Area.[129] Figure 23 shows the planned and unplanned generation outages and derates within the Event Area from the start of December 21 to the start of December 23.[130] Overall, some BAs had more success than others in returning to service generation that was on outage before the worst period of the Event. For example, Santee Cooper's system operations coordinated with a gas generator in the week preceding the storm to return the unit to service following an unplanned outage due to a pump failure. The pump was repaired on December 21, restoring 28 MW of generating capacity. LG&E/KU was able to return to service nearly all of its generation that was on planned outages before the Event. A total of 8,501 MW of planned outages were returned to service within the BA footprints listed in Figure 23 before the worst part of Winter Storm Elliott began to impact the Event Area. Beyond December 23, GOs continued efforts to return prior-outaged generation to service where feasible, which offset the total unavailable generation during the Event.

129 Forced outages often occur due to equ pment fa lure or freez ng and when and f a un t can be t mely returned to serv ce s unpred ctable.

130 The start of December 23 (w th the except on of the SPP, wh ch was mpacted w th ncreased unplanned generat on outages dur ng the Event beg nn ng December 22) was pr or to the most severe drops n temperature. Accord ngly, SPP s not ncluded n F gure 23 to prov de a more un form compar son.

Figure 23: Planned and Unplanned Generation Outages in BA Footprints, at the Start of December 21, and December 23, 2022 (Prior to the Most Severe Drops in Temperature)

	Planned at the start of :		Unplanned at the start of:		Total Unava lable, at the start of:		21st 23rd Decrease n Generat on Out of Serv ce
BA	Dec. 21 (MW)	Dec. 23 (MW)	Dec 21 (MW)	Dec. 23 (MW)	Dec. 21 (MW)	Dec. 23 (MW)	(MW)
DEC	391	391	1,662	1,820	2,053	2,211	158
DEP	983	1,811	507	841	1,490	2,652	1,152
DESC	7	7	350	133	357	140	217
LG&E/KU	704	10	138	631	842	641	201
MISO	12,610	11,178	20,824	20,004	33,434	31,182	2,252
NYISO	3,161	2,085	2,414	3,119	5,575	5,204	371
PJM	9,586	6,253	12,582	12,787	22,168	19,040	3,128
Santee Cooper	570	570	400	110	1,540	1,250	290
Southern	3,022	2,486	758	913	3,780	3,399	381
TVA	3,153	895	1,972	2,498	5,125	3,393	1,732
TOTAL	34,187	25,686	41,607	42,856	75,794	68,542	7,252

b.Generation Committed Early for Reliability

In general, all BAs within the Core Event Area thought in advance of the Event that they individually had sufficient resources to meet their respective forecast electricity demands expected during Winter Storm Elliott. The BAs did not discount the possibility of some level of unplanned generation outages as a result of the storm, but those with smaller reserve margins thought they could purchase (i.e., import) power from external sources, or rely on bringing online quick-start/short-lead-time generating units to meet their peak electricity demands. TVA committed all available generation seven days prior to the Event and told the GOP when they would need the generation to be online. Santee Cooper planned to staff two generating units for quick start-up that would otherwise have longer lead times. SPP made multiple long-lead-time generating unit commitments: (1) on December 21, for the next two days, (2) on December 22, for Christmas Eve, and (3) on December 23, for Christmas Day, to improve the likelihood of having the additional online capacity for those days, as well as committing short-lead-time natural gas-fired units so that they could procure sufficient natural gas before the holiday weekend.

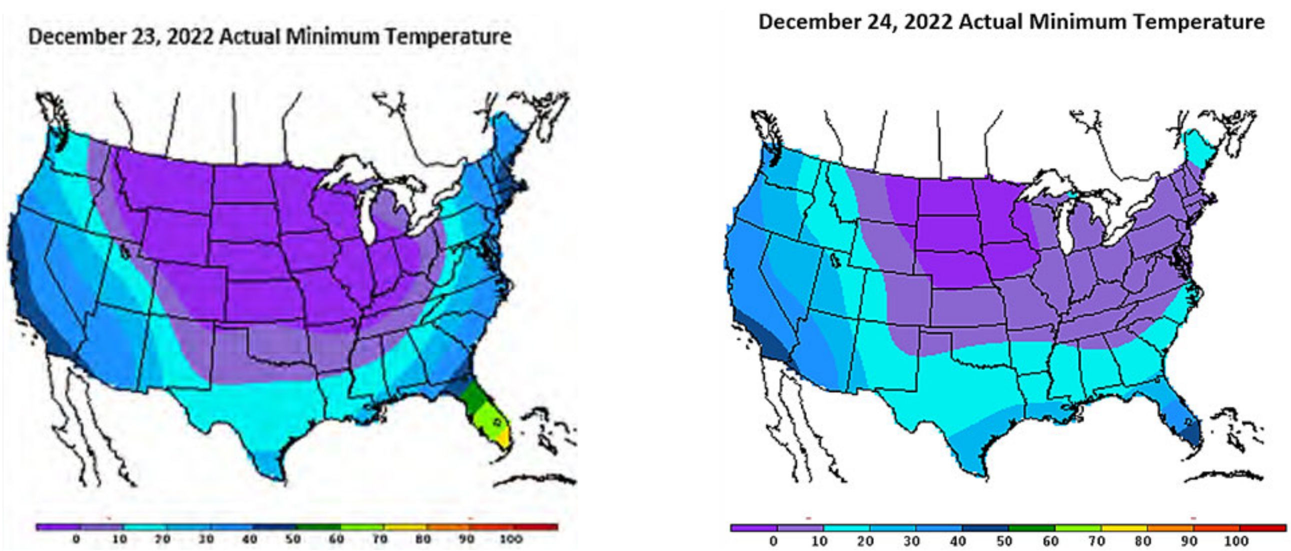
c. Transmission Facilities Returned to Service Before the Event

Some TOPs provided details on actions they took to return transmission facilities to service that had been on outage prior to the Event. TVA returned several transmission facilities to service before the Event, including one transmission line and two circuit breakers. Southern restored a transmission line that improved its ability to transfer power to and from Florida utilities, and additionally restored to service two other transmission lines, a circuit breaker, and two power transformers. PJM increased its transfer capability through coordination with its TOs which resulted in the return to service of two major transmission lines early on December 23. DEP and DEC indicated that they had no significant transmission outage plans or outages before or during the Event.

B. December 22 - 24: Extreme Cold Weather Conditions Lead to Widespread Generation Outages and Natural Gas Infrastructure Issues, Forcing Grid and Pipeline Operators to Make Difficult Decisions, Such as Shedding Firm Electric Load or Curtailing Firm Pipeline Customers

On December 22, the storm hit the Midwest, bringing snow, low temperatures and strong winds (with gusts up to 60 miles hour) and wind chill temperatures as low as -42 degrees. Although accumulation was minimal, the combination of snow and gusting winds caused blizzard conditions in some areas. The storm moved eastward and by December 23, Chattanooga, Tennessee had dropped from 49 degrees to 7 degrees. Similarly, Charleston, West Virginia dropped 42 degrees on December 23 (with wind gusts over 50 mph). The actual lows for December 23 for the Midwest and South Central U.S. were largely 20 degrees or below. From December 23 into 24 the extreme cold finally reached the east coast, and the actual lows for December 24, as shown on Figure 24, below, reflect that except for part of Florida, the lows were below 20 degrees. These temperatures were 15 to 30 degrees lower than normal low temperatures, with some elevated areas greater than 30 degrees lower (than normal low temperatures), as seen in Figure 25, further below.

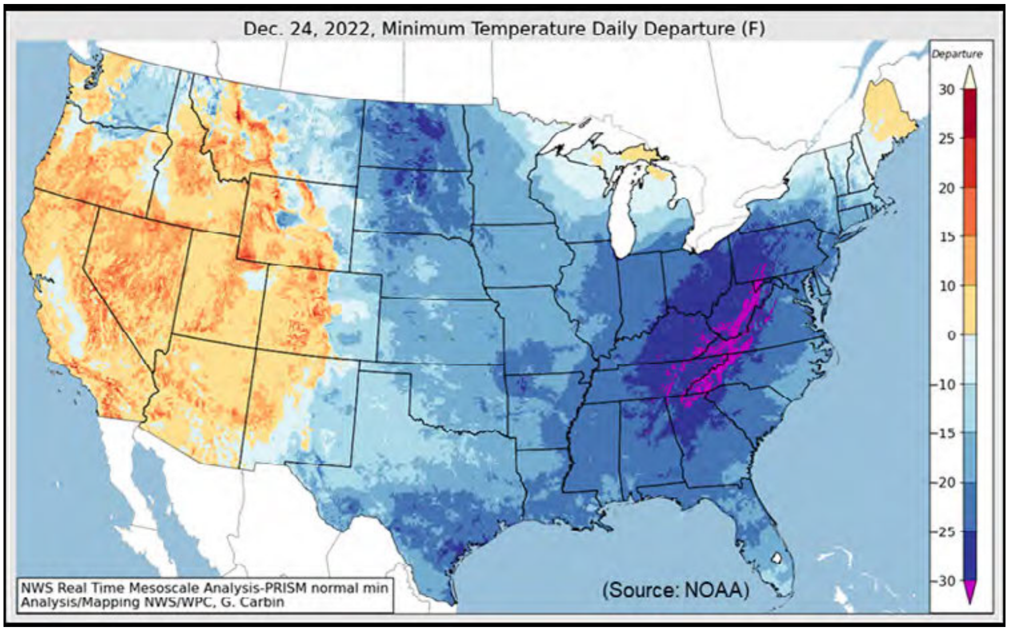
Figure 24: December 23 and 24, 2022 Actual Minimum Temperatures – Lower 48



1. UNPLANNED GENERATING UNIT OUTAGES RAPIDLY ESCALATE

All of the BAs went into the Event with some measure of generation unavailable, but during the afternoon and evening of December 22 unplanned generation outages began to rapidly escalate. In fact, of the more than 371,000 MW of generation that was lost due to forced outages, derates and failures to start during the entire Event—a period stretching from December 21 to December 26—more than 20 percent (74,000) of all generation losses would occur in the 12 hours between 6:00 a.m. and 6:00 p.m. on December 23.

Figure 25: Departures from Normal Minimum Low Temperatures, December 24, 2022



SPP (outages began afternoon of 12/22). SPP experienced "key generation losses in the eastern part of SPP's footprint"[131] beginning December 22 at around 3:40 p.m.[132] and continuing into the evening and early morning hours. By December 23 at 10 a.m., unplanned generation outages and derates in the SPP footprint escalated by 8,900 MW.

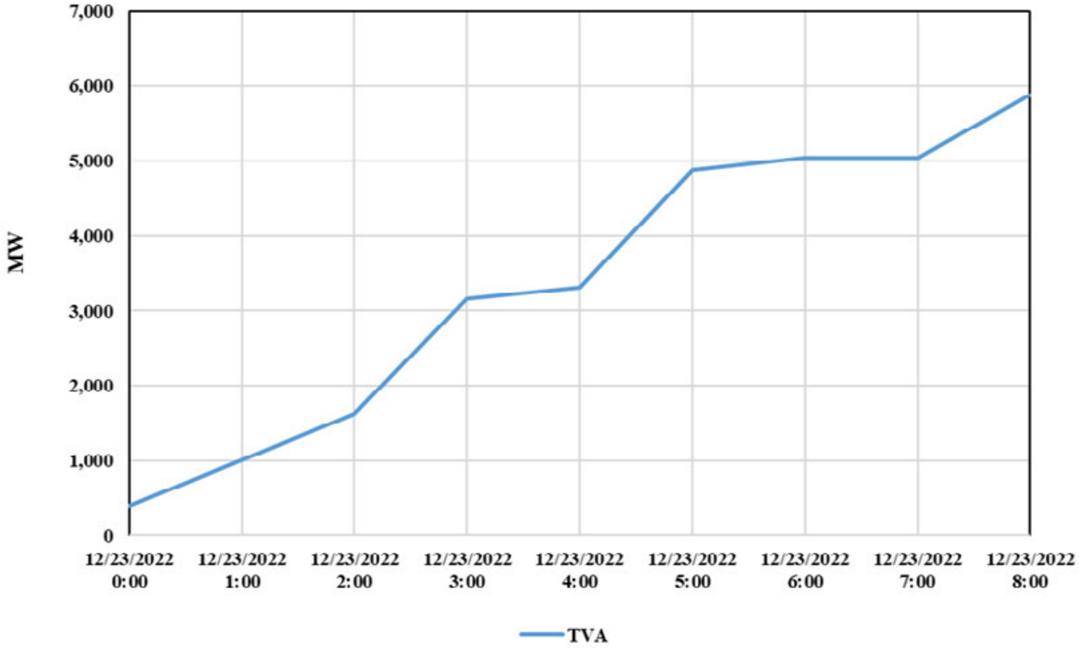
MISO (outages began early 12/23). In MISO, unplanned generation outages and derates began to escalate on December 23 and MISO BA operators were faced with over 6,000 MW of incremental unplanned generation outages; by 9:15 a.m., 2,000 MW of unit trips and failures to start in MISO South contributed to MISO BA operators implementing emergency measures.

TVA (outages began early 12/23). TVA unplanned generation outages began shortly before 1:00 a.m. on December 23. Outages and failures to start escalated sharply to a total of nearly 6,000 MW by 8 a.m. as shown in Figure 26, equivalent to nearly 20 percent of its peak load.

131 *See Review of SPP's Response to the Dec. 2022 Winter Storm* (Apr l 2023), at 10.

132 All t mes stated w th n the Report, unless otherw se spec fied, are n Eastern Standard T me, even f the ent ty s n the Central T me Zone (EST).

Figure 26: Incremental Unplanned Generation Outages in the TVA BA Footprint During Event, December 23, 12 a.m. to 8 a.m.

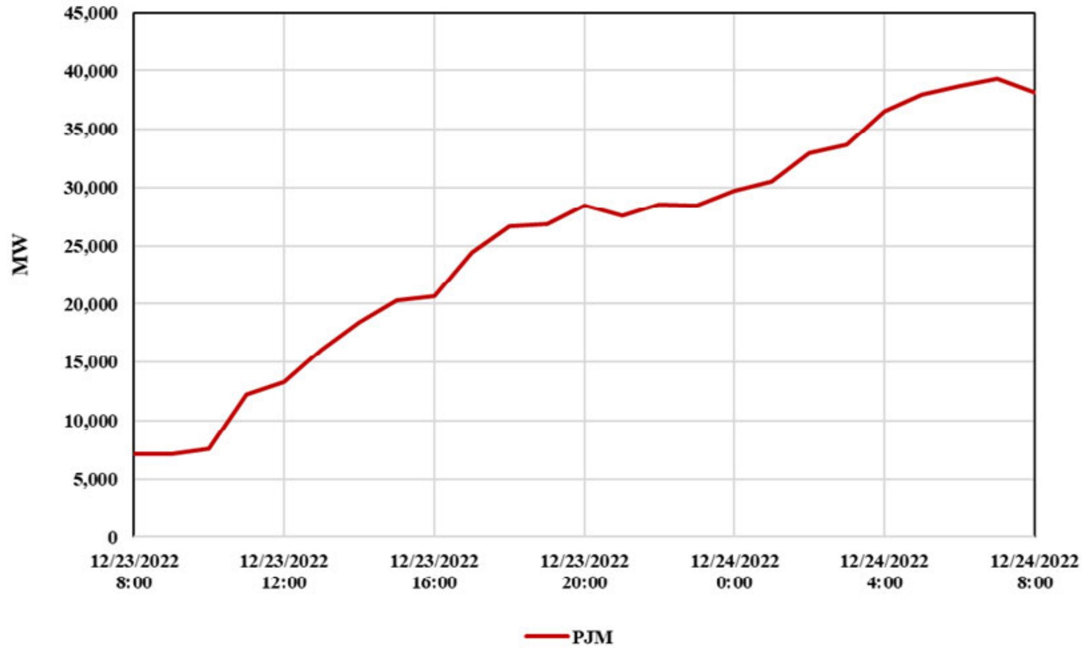


LG&E/KU (outages began early 12/23). Beginning at 1:28 a.m. on December 23, then throughout the morning and afternoon, generators experienced derates and outages due to cold weather and mechanical issues; at 1:08 p.m., significant power plant derates due to fuel issues (discussed further in subsection (a) below) led to an approximately 900 MW reduction, including one unit trip and six units that were derated to operate at minimum output for approximately 50 hours (until December 25, 4:00 p.m.); then from 3:39 p.m. to 6:44 p.m., an additional 500 MW of unplanned generation outages occurred.

PJM (outages began about 4 a.m. on 12/23). Unplanned outages and derates began to escalate shortly after 4 a.m. on December 23, then from about 8:00 a.m. to 5:00 p.m., rapidly escalated at a rate of over 2,200 MW per hour (for a total of approximately 20,000 MW); outages continued to escalate until December 24 at 8:00 a.m.[133] Over the 24-hour period, PJM sustained nearly 33,000 MW of unplanned generation outages and derates, as illustrated in Figure 27.

133 Th s outage data, l ke all other generat on outage data unless found on a graph c cred ted to an ent ty other than the Team, s based on the data the Team obta ned d rectly from the GOs/GOPs.

Figure 27: Incremental Unplanned Generation Outages in the PJM BA Footprint During Event, December 23, 8 a.m. to December 24, 8 a.m.



DEC and DEP (outages began late evening 12/23). In the DEC and DEP footprints, unplanned generation outages and derates began at about 11:30 p.m. on December 23, and by December 24 at 8 a.m., DEC and DEP had lost about 2,000 MW; outages continued into the early afternoon of December 24.

Southern (outages began midnight 12/23). From December 24, 12:00 a.m. to December 24, 2:00 a.m., Southern had approximately 500 MW of gas/oil generating unit capacity forced offline; then from 2:00 a.m. to 6:00 a.m., it had an additional 890 MW of gas/combined cycle generating capacity forced offline (1,390 MW total incremental unplanned outages from midnight to December 24, 6:00 a.m.).

DESC (outages began early 12/24). Six generating units, over 1,000 MW of generation total, sustained unplanned outages from December 24, 12:30 a.m. until about 9:10 a.m.

Santee Cooper (outages began early 12/24). Santee Cooper experienced over 500 MW of unplanned generation outages and derates beginning December 24 at 2:35 a.m. to 7:00 a.m. In addition, a boiler tube leak forced a 300 MW unit offline late December 23; it was unrelated to the weather but increased Santee Cooper's total unplanned generation outages to over 800 MW.

GOs reported to several BAs, including TVA and LG&E/KU, that many of the generating unit outages were due to Freezing Issues.

a. Rapid Emergence of Fuel Issues

Fuel Issues were a significant driver of the unplanned generation outages and derates early on December 23. Notably, within PJM, outages caused by Fuel Issues grew eight-fold between 6:00 a.m. and noon on December 23—and fifteen-fold between 6:00 a.m. and 6:00 p.m. that same day, outpacing the increase in outages due to Mechanical/Electrical Issues. By midnight on December 23, the total unplanned generation shortfall due to Fuel Issues exceeded the shortfall due to Freezing Issues, as seen in Figure 28, below.

Figure 28 Growth in Unplanned Generation Outages, Derates, and Failures to Start for Three Most Common Causes of Generation Outages in PJM, December 22 to 24

PJM	12/22/2022	12/23/2022				12/24/2022	
	Midnight	6:00am	Noon	6:00pm	Midnight	6:00am	Noon
Mechanical/Electrical Issues	5,746	6,448	7,497	10,927	12,458	16,909	16,130
Fuel Issues	576	597	5,062	9,014	11,133	13,283	12,709
Freezing Issues	1,966	2,625	5,436	10,770	10,379	12,979	12,928

Although the growth in Fuel-Issues-related generation loss was most acutely seen in PJM, virtually all of the BAs/RCs saw generation lost or derated due to Natural Gas Fuel Issues[134] on December 23 and 24. SPP, TVA, LG&E/KU, and VACAR-South RC all reported gaining awareness on December 23 or 24 that generating units were struggling to find adequate natural gas supply or that pipelines were struggling or unable to maintain adequate pressure at certain locations.

SPP. SPP began receiving system overrun limitation alerts for gas pipelines during the week of December 19. This was an early indication of potential fuel supply problems and SPP considered the alerts when evaluating forecasts of resource unavailability. Between December 22 and 25, SPP received communications from plant operators about fuel procurement issues through operator-to-operator communication and via plant operator outage entries made in SPP's generator outage management system.

MISO. Gas supply availability contributed to increased unplanned outages, particularly on the afternoon of December 23, that pushed MISO into emergency procedures. Generation in the MISO Region is connected to nearly three dozen interstate and intrastate pipelines, and the top five pipelines serve over 36 GW of gas generation in MISO. MISO became aware of gas availability issues when gas generators began communicating outages to MISO's generator outage management system, indicating an unavailable commitment status in their real-time offers, and/or phoning to inform the MISO Generation and Interchange operator of their expected outage submission due to gas unavailability. By the end of the day on December 23, MISO had experienced 23 GW of gas generation forced outages. Nearly 50 percent of gas generators reported outages to MISO that were due to Fuel Transportation/Supply Issues. Most of these were forced/emergency outages with little or no prior notice to MISO Operations. Such a significant volume of unplanned outages eroded MISO's reserve margin and contributed to MISO's declaration of emergency procedures on December 23. Increased fuel risk and associated uncertainty regarding gas generator availability on December 24 contributed to MISO operators committing additional generation.

TVA. GOs reported to TVA BA operators that some generating units were experiencing outages due to low natural gas fuel pressure. For example, on December 24, at 8:00 a.m., a 900 MW combustion turbine (CT) / combined cycle (CC) site was derated by 243 MW due to low natural gas delivery pressure issues. Further, on December 25, at 4:20 a.m., a 1,075 MW multi-CT/CC site was reduced by 978

134 As descr bed earl er n the Report, Natural Gas Fuel ssues nclude the comb ned effects of decreased natural gas product on; cold weather mpacts and mechan cal problems at product on, gather ng, process ng and p pel ne fac l t es result ng n gas qual ty ssues and low p pel ne pressure; supply and transportat on nterrupt ons; curta lments and fa lure to comply w th contractual obl gat ons. Add t onally, t ncludes sh ppers' nab l ty to procure natural gas due to t ght supply, proh b t ve, scarc ty nduced market pr ces, or m smatches between the t m ng of the natural gas and energy markets.

MW to minimum output (97 MW total), because of low gas delivery pressure issues.

LG&E/KU. On December 23, at 1:09 a.m., pipeline pressures for two natural gas-fired generating stations began to drop below the contract limits; and at 1:08 p.m., LG&E/KU experienced approximately 900 MW in generation losses (unit trip and six units derated) arising from low delivery pressures on a pipeline supplying these generating units.

DEC. On December 24, Transco pipeline notified DEC BA operators of low pressure issues and the potential timeline to recover pressure. The low pressure affected two natural gas-fired units, totaling 178 MW in unplanned generation derates.[135]

PJM. PJM had 186 generating units that failed to start. One-third of those were natural gas-fired CTs and CC units that reported to PJM that they did not have fuel or were fuel-limited.

135 Derates occurred after the DEC BA morn ng peak demand ended and d d not mpact DEC's ab l ty to meet ongo ng system demand, wh ch rema ned at lower levels throughout the rema nder of the hol day weekend.

Fuel Switching

As the 2021 Report noted, "[u]nits capable of fuel switching have both economic and reliability benefits: allowing operators to purchase the cheaper of two fuels and have an alternate source of fuel if one source is interrupted or curtailed." In the Event, about 259 generating units, representing 34,518 MW, were capable of a secondary fuel option. About 53 of those generating units, representing 15,405 MW, attempted to switch from their primary fuel to their secondary fuel. The majority, 88 percent, representing 12,567 MW, were initially successful in switching fuel types. Approximately twelve percent of the fuel-switching-capable units, representing 2,749 MW, either failed to switch or experienced outages related to their use of alternate fuels after switching, due to various mechanical problems. Causes for switching failures included low gas supply pressure, gas\fuel oil leak, fuel pump issues, fuel oil divider failure, feedwater pump breaker failure, isolator failure, combustor purge line failure, high exhaust spread temperature, and solenoid freezing.

Figure 29: Location of Fuel-Switching-Capable Units in the Event Area

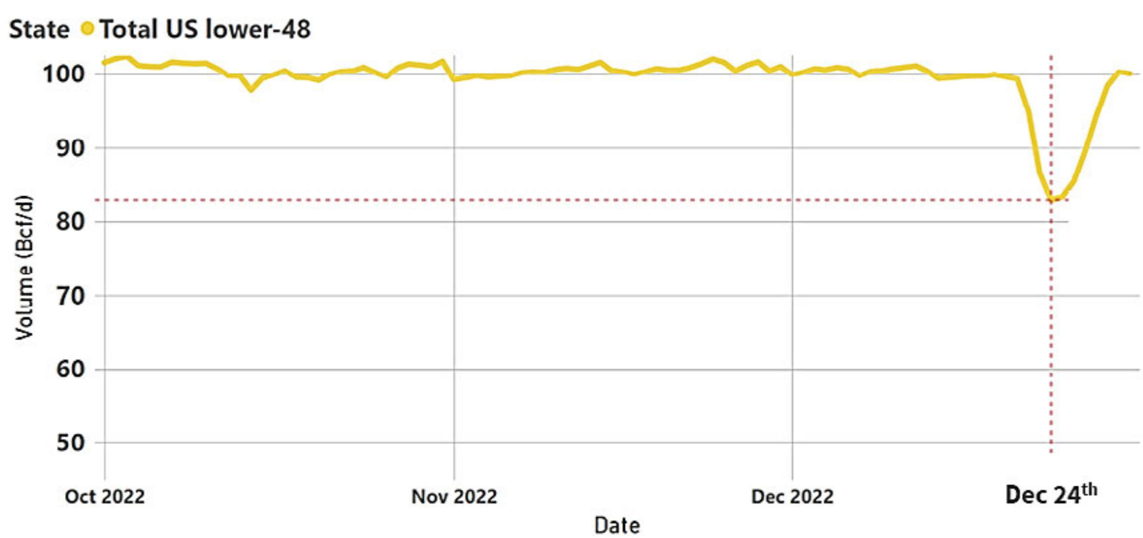
Of the generating units that successfully switched fuels, 73 percent, representing 11,767 MW, used gas as their primary fuel and oil\distillate oil as an alternate fuel. About 27 percent, representing 672 MW, used oil or distillate oil as their primary fuel and gas as an alternate fuel, and two units, representing 520 MW, used gas as their primary fuel and coal as an alternate fuel.

2. NATURAL GAS INFRASTRUCTURE OPERATING ISSUES RAPIDLY MOVE FROM PRODUCTION FACILITIES TO PIPELINES

a. Production declines begin

As Winter Storm Elliott moved across North America and temperatures decreased, dry natural gas[136] production in the lower 48 states declined. Production volumes on December 22 fell by 4,411 MMcf/day from the previous day and reached their largest daily decline between December 22 and December 23 – a difference of 8,368 MMcf/day. Dry natural gas production declined by 18 percent, falling to a low of 82.9 Bcf/day on December 24, 2022, as shown in Figure 30, below. Winter Storm Elliott primarily affected production in the Marcellus and Utica Shale formations. Together the Marcellus and Utica Shale formations create the Appalachian basin, which produced more gas in 2022 than any other area of the U.S., accounting for 29 percent of U.S. gross natural gas withdrawals (or 34.6 Bcf/d), according to EIA (see Figure 31, below). As shown in Figure 32 below, Marcellus Shale production volumes reached a low of 21,856 MMcf/d on December 24 (a 23 percent decrease compared to maximum production on December 19). Utica Shale production volumes reached a low of 3,017 MMcf/d on December 26 (a 54 percent decrease compared to maximum production on December 19).

Figure 30: Daily Dry Natural Gas Production (October - December 2022)[137]



136 "Dry natura gas" s produced by natura gas process ng fac t es that remove other hydrocarbons to produce what s known as "p pe ne qua ty" dry natura gas that meets the heat ng content and other restr ct ons necessary for the safe operat on of p pe ne and d str but on company fac t es.

137 S&P Global Commod ty ns ghts, ©2023 by S&P Global nc.

Figure 31: Monthly U.S. natural gas gross withdrawals by region (January 2012 - December 2022)

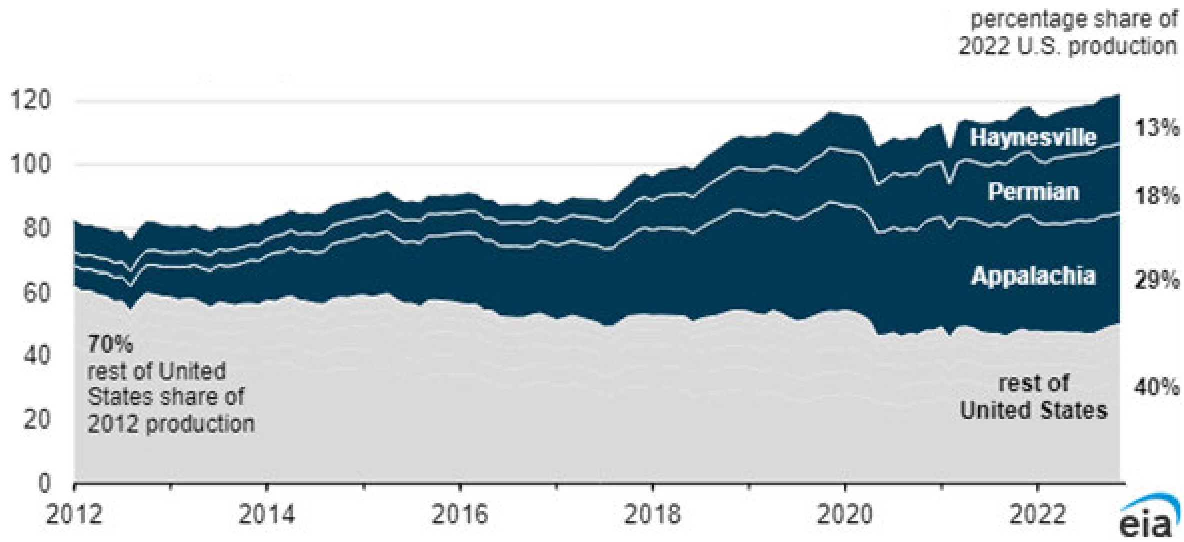
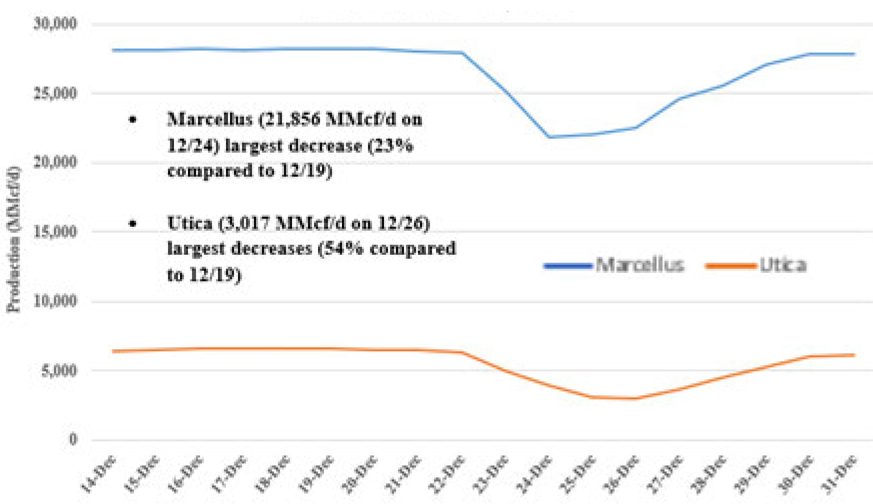


Figure 32: Natural Gas Production - Marcellus and Utica Shale Basins, December 14 – 31, 2022



(Data Source: IHS March 31, 2023)

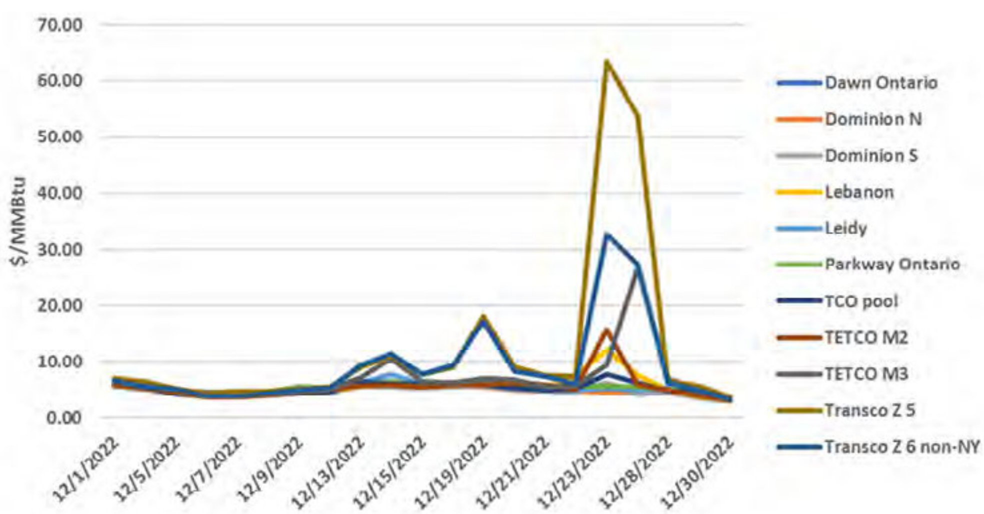
All but one natural gas producer identified freeze-offs as the primary cause of production declines, including frozen production equipment as well as wellhead freeze offs. Seven of the ten reporting producers identified downstream issues[138] as a significant driver of production declines. Downstream issues included outages in gathering systems, compressors, and processing plants, as well as one pipeline that could

138 Some producers also own and operate gather ng l nes/fac l t es, others del ver the r product on to gather ng systems owned by others. Thus the categor zat on of “downstream” may not be cons stent or l m ted to gather ng systems.

not take gas from certain producers,[139] which caused idling of producer equipment. The idling of producer equipment then exacerbated freezing of production equipment and caused further reductions in natural gas production. Poor road conditions, which prevented personnel and, in some cases, water hauling trucks, from reaching remote production sites were also identified as an issue, although not as commonly as during Winter Storm Uri.[140]

These natural gas losses from critical natural gas production areas, in conjunction with increased demand, caused prices to increase dramatically in natural gas markets. For example, natural gas prices for Transco Zone 5, which extends from the Georgia-South Carolina border to the Virginia-Maryland border, increased more than eight-fold for trading on December 23 as compared to December 21. See Figure 33, below. Higher price levels can have a cascading effect in the marketplace, as natural gas pipelines may calculate their OFO penalties by pricing the penalty as a multiple of the natural gas market price. As a result, a shipper that is out of balance on a pipeline may choose to pay higher market prices for natural gas to avoid paying penalties; this in turn produces higher penalties and adds to the incentive to buy ever more expensive natural gas.[141]

Figure 33: S&P Global Market Intelligence Day-Ahead Natural Gas Prices for Northeast Region – Non-NY/NE for December 2022[142]



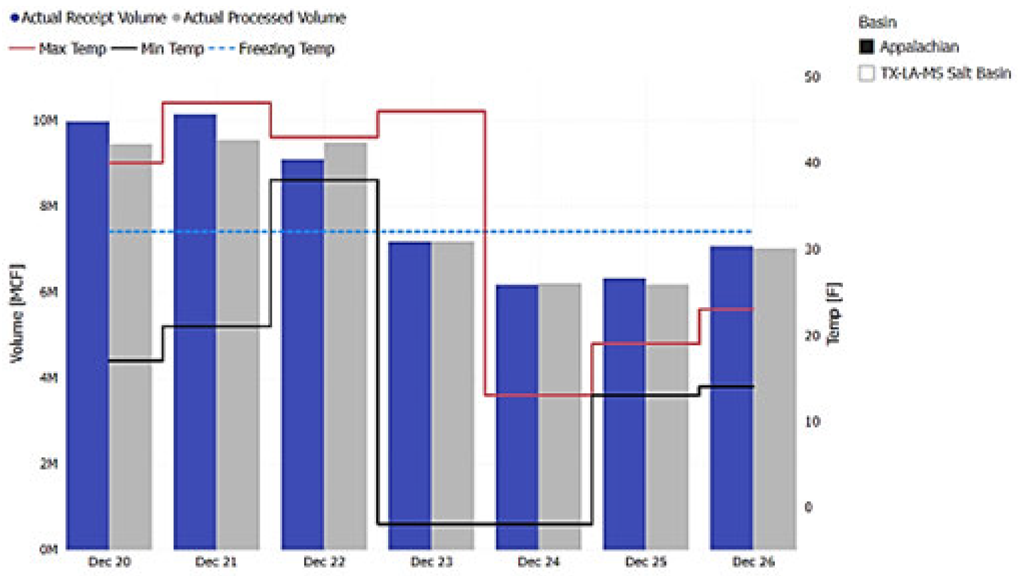
139 One p pel ne stated that lead ng up to and on the even ng of December 23, t started to pack ts l nes n preparat on for h gh demand on December 24. The h gh pressure temporar ly prevented producers from be ng able to move the r gas onto the p pel ne. The same p pel ne also had a lag n demand load the morn ng of December 24, caus ng pressures to rema n h gh, wh ch exposed producers further to freez ng vulnerab l t es as they could not move the r supply onto the p pel ne system at that t me.

140 *See* Analys s, sect on V.C.2., for more exam nat on of the causes of product on losses.

141 Natural gas traders have expla ned the exacerbat ng effect of potent al penalt es dur ng scarc ty events dur ng prev ous extreme cold weather events. The Team d d not nterv ew traders n the Event about th s ssue, although the same preex st ng cond t ons of scarc ty and cr t cal not ficat ons w th potent al for penalt es ex sted dur ng the Event as ex sted dur ng prev ous events.

142 Source: S&P Global Market ntell gence Cap tal Q Pro. © 2023 S&P Global Market ntell gence (and ts aff l ates, as appl cable) (nd v dually and collect vely, “S&P”). Reproduct on of any nformat on, data or mater al, nclud ng rat ngs (“Content”) n any form s proh b ted except w th the pr or wr tten perm ss on of S&P. S&P does not guarantee the accuracy, adequacy, completeness, t mel ness or ava lab l ty of any Content and s not respons ble for any errors or om ss ons (negl gent or otherw se), regardless of the cause, or for the results obta ned from the use of such Content. n no event shall S&P be l able for any damages, costs, expenses, legal fees, or losses (nclud ng lost ncome or lost profit and opportun ty costs) n connect on w th any use of the Content.

Figure 34: Natural Gas Processing Facilities - Receipt Volume (December 20 – 26, 2022)



b. Processing and Pipeline Operating Issues

The extreme low temperatures beginning December 22-23 caused natural gas demand to increase at the same time that the volume of gas received by processing facilities declined, as illustrated in Figure 34.

Some processing companies said that they did not receive the full contracted amount of gas supply from producers, though they reported that they generally processed the gas they received.

On December 23 and 24, the strained operating conditions due to gas supply shortages experienced across the pipeline network were further exacerbated by equipment issues faced on certain pipelines. Natural gas pipeline facilities experienced 19 equipment issues which directly affected shippers, such as GOs/GOPs and local gas distribution companies. The largest reported cause of pipeline equipment issues was weather/freezing issues, followed by mechanical issues. The cold temperatures caused valves and compressor units at varying locations along the pipeline system to freeze, reducing or preventing the flow of gas through these facilities (see Figure 35, below). These issues caused instances of reduced natural gas pressure and 14 declarations of force majeure on certain pipelines which directly affected shippers (see Figure 36, below). Pipeline operators issued force majeures (which curtailed firm and interruptible gas transportation) to inform shippers that an event outside of their ability to reasonably foresee would affect all or a portion of the gas scheduled to flow through a segment of the pipeline system. Two pipelines issued a total of seven force majeures which affected a total of 156 firm shippers due to freezing issues, mechanical issues and reduced supply at seven compressor stations.

Eight of the fifteen interstate pipelines surveyed by the Team reported a total of 53 instances of commercial power loss at their facilities, totaling 466.5 hours during the Event. The outages averaged approximately nine hours in duration, although some lasted longer than three days.[143]

143 *See* sect on V.C.4 for add t onal analys s.

Figure 35: Number of Pipeline-Reported Equipment Issues with Some Associated Flow Reduction

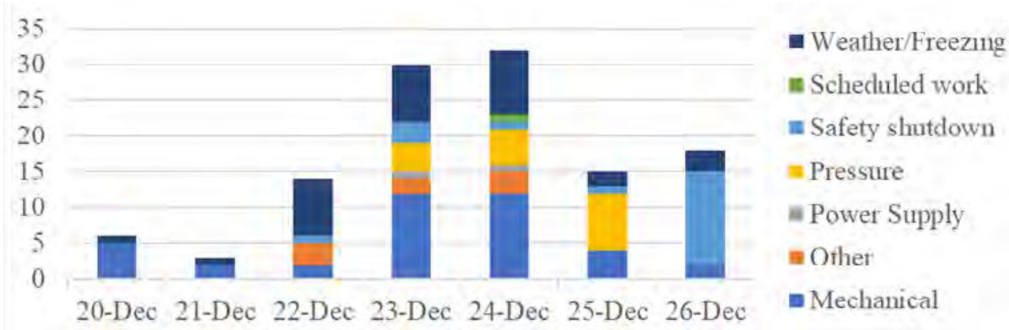
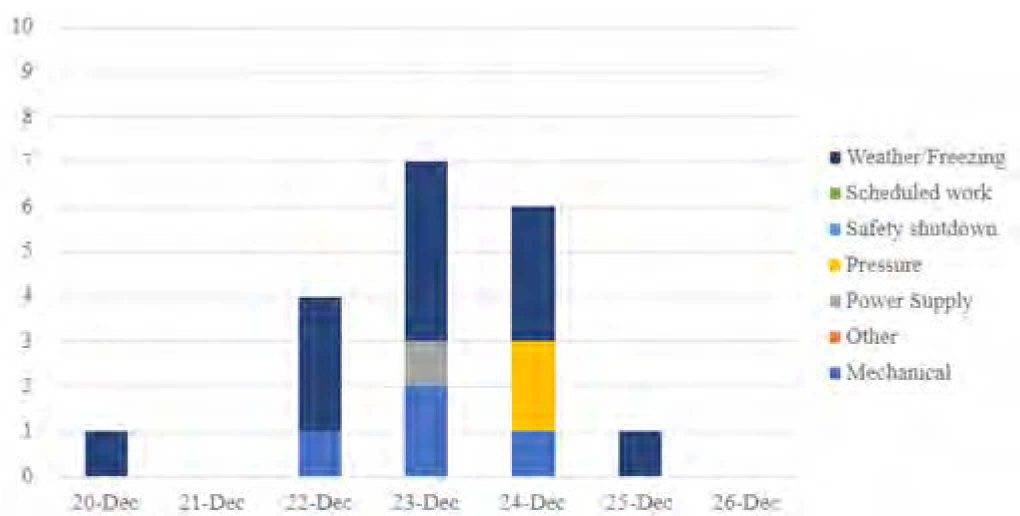


Figure 36: Number of Pipeline-Reported Equipment Issues Directly Affecting Shippers



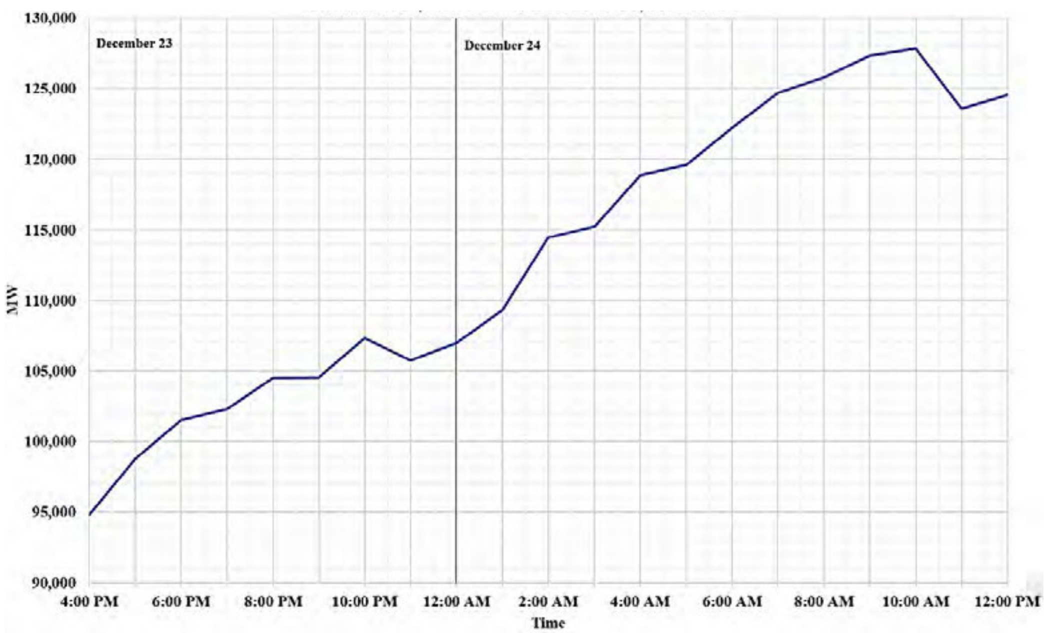
3. GRID OPERATORS' REAL-TIME ACTIONS AND COORDINATION DUE TO UNPLANNED GENERATION OUTAGES AND HIGH ELECTRICITY DEMANDS TO MAINTAIN BES RELIABILITY ACROSS A WIDE AREA

The breadth and scope of generation loss resulting from Winter Storm Elliott created unique and challenging conditions for grid operators. Figure 37, below, shows the total generation outages and derates impacting the Event Area during the most difficult period for the grid, the evening of December 23 and the morning of December 24. The graph includes both planned and unplanned generating unit outages; those existing at the beginning of the Event and those that occurred during the Event. Including generation that was already out of service,[144] a total of over 127,000 MW of generation was unavailable at the worst time, approximately 10 a.m. on December 24, which represented **18 percent** of the U.S. portion of the winter 2022-2023 anticipated resources in the Eastern Interconnection.[145]

144 Those un ts that were already out of serv ce ncluded generat ng un ts undergo ng planned ma ntenance outages and those un ts that ncurred forced outages before the Event, that had not yet returned to serv ce dur ng the worst po nt of the Event.

145 Based on data from NERC 2022 2023 W nter Rel ab l ty Assessment. *See* note 12. W thout the generat on that was already out of serv ce, the outages represented 13 percent of the U.S. port on of the w nter 2022 2023 ant c pated resources n the Eastern nterconnect on.

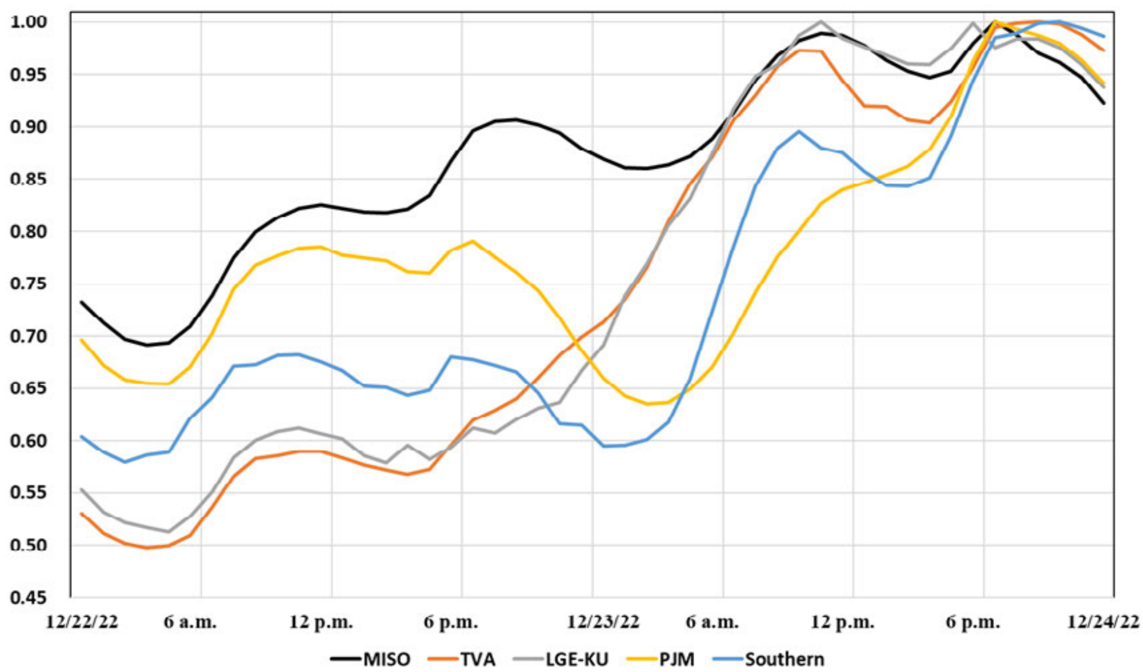
Figure 37: Total Estimated Unavailable Generation in U.S. Portion of Eastern Interconnection[146] – December 23, 4:00 p.m. to December 24, 12:00 p.m.



Due to the breadth and scope of generation loss during the Event, several BAs encountered the same set of circumstances during the day and into the evening on Friday, December 23: rapidly-increasing electricity demands due to the extreme cold weather and high levels of unplanned generation outages and derates. Figure 38, below, shows how dramatically BA electricity demands increased from Thursday morning, December 22, to Friday evening, December 23, and explains why BAs had little energy to share with other BAs experiencing EEAs. Other than Southern BA, which experienced its winter peak load the morning of December 24, the BAs shown *all* experienced their peak demands on the evening of December 23.

146 Total generat on shortfall s est mated, s nce t does not nclude potent al planned and unplanned generat on outages that may have ex sted for the Flor da pen nsula dur ng the t meframe, s nce analys s of that reg on was not ncluded n the targeted scope of the nqu ry.

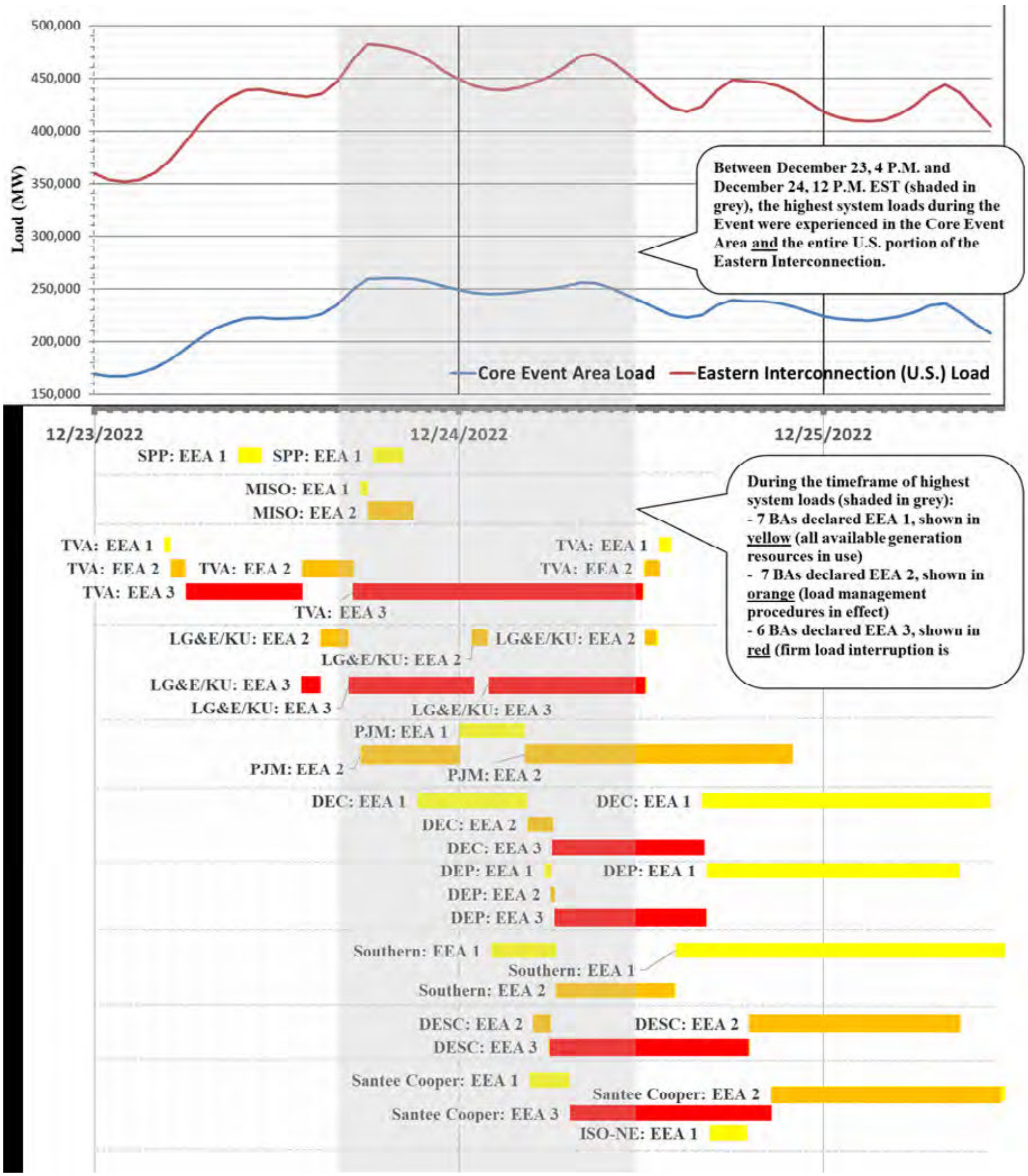
Figure 38: BA Normalized Hourly System Load Patterns for December 22-23, 2022 (Normalized to December 23 Peak Loads Experienced)[147]



As demand grew and supply shrank over December 23 and 24, electric grid entities took proactive measures to protect their footprints by declaring conservative operations actions. By the end of December 24, almost all the BAs impacted by Winter Storm Elliott were forced to implement EEA procedures. See Figure 39, below. The gray shaded area represents the timeframe of highest system loads in the Core BAs.

147 DEC, DEP, DESC and Santee Cooper BAs (not shown n the figure), wh ch are located further east, l kew se exper enced the r system peak loads on Saturday, December 24, and exper enced a s m lar pattern of ncreas ng load.

Figure 39: Core Event Area and Eastern Interconnection (U.S.) System Loads and Event Area Energy Emergencies Timeline – December 23 12:00 a.m. to December 25, 12:00 p.m.



The widespread and simultaneous energy emergency conditions greatly reduced the BAs' ability to obtain power from neighboring entities.

Note regarding "N-1"

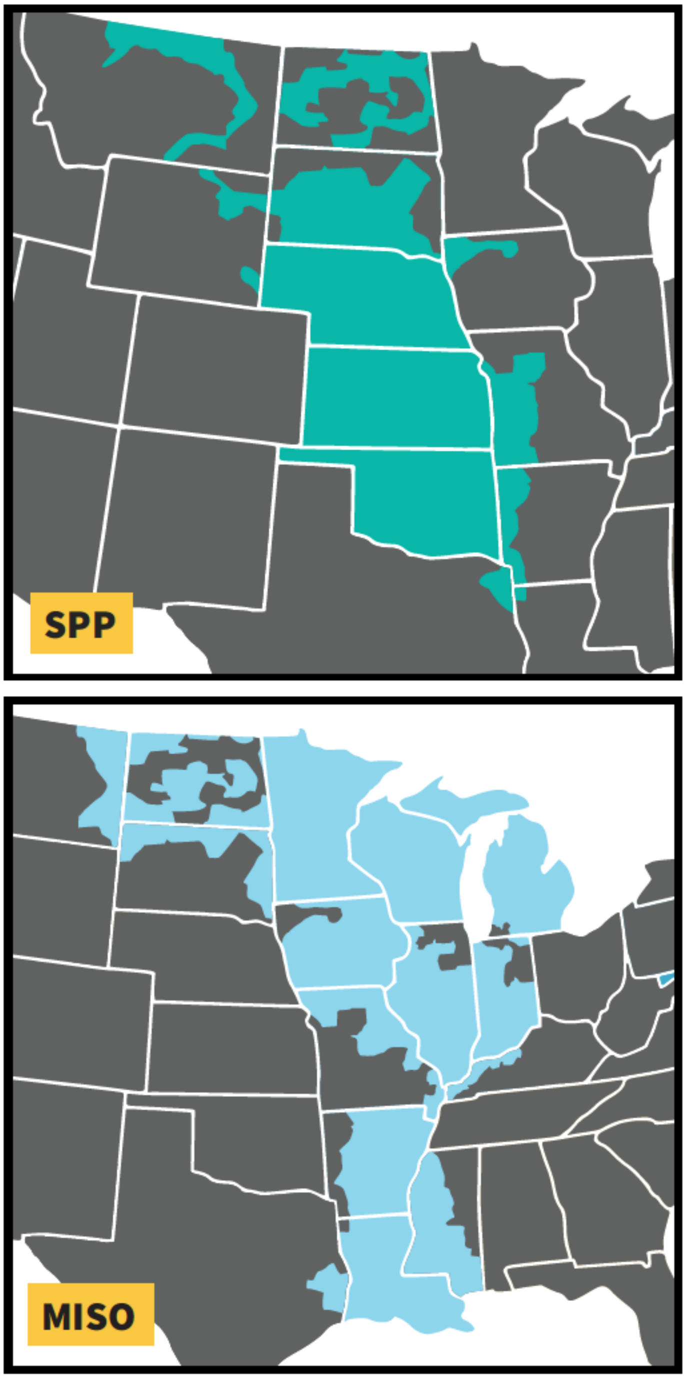
As described above in Section III, there were numerous coincident unplanned generator outages and derates. This meant the grid operators were operating a grid that was far from the N-1 planning c iteria (e.g., loss/outage of one generator) used to plan the transmission grid.[148] Instead they were experiencing an **N-"numerous"** condition[149] at any given time during the Event. The AC transmission system that comprises the BES relies heavily on online generation for reliable operation. Having sufficient online generators enables more effective congestion management, by facilitating AC power transfers while allowing transmission constraints to remain within system operating limits, as well as enabling system stability and the maintenance of normal thermal and voltage limits.

a. Thursday, December 22: Elliott begins to impact U.S. portion of Eastern Interconnection

- Winter Storm Elliott begins to impact westernmost part of U.S. Eastern Interconnection
- SPP and its TOPs first face operating challenges

SPP was the first BA in the U.S. portion of the Eastern Interconnection to experience Elliott's extreme cold and high winds, although its footprint did not incur more severe emergency conditions as others did in Elliott, or as SPP had experienced in Winter Storm Uri. SPP noted that the storm front moved more quickly than in 2021 and swept from northwest to southeast.[150]

Figure 40: SPP and MISO Footprints



148 For more nformat on on transm ss on system plann ng performance, *see* NERC Rel ab l ty Standards, Transm ss on Plann ng (TPL), TPL 001 5.1 Transm ss on System Plann ng Performance Requ rements. RSCompleteSet.pdf (nerc.com).

149 1,702 nd v dual generat ng un ts exper enced outages, derates, or fa lures to start for the ent re Event Area from December 21 to 26, 2022.

150 *See* SPP Report at 21.

SPP reported that it did not experience an increase in unplanned transmission outages. SPP largely escaped the heavy snow and freezing precipitation that most threatens transmission elements. However, its system operators were challenged with escalating unplanned generation outages and electricity demands on December 22, before grid operators to the east like PJM experienced the same conditions. In addition, a localized area on its transmission grid created operational challenges.

Between 1:00 and 7:00 p.m. on December 22, SPP experienced multiple unplanned generating unit outages totaling 1,400 MW in the eastern portion of SPP's footprint in a very short time frame between 1:00 p.m. and 7:00 p.m. As these unplanned generation outages were occurring, SPP was on its way to setting a record for winter seasonal electricity demand of 47,157 MW, which occurred at 6:27 p.m.[151] In addition, SPP's eastern area grid conditions were further strained by a planned transmission line outage near the 1,400 MW of generating unit losses. The transmission outage, which began in September 2022, was scheduled for completion in January 2023 (a planned upgrade to increase the transfer of energy from the central portions of the SPP system eastward into the area most impacted during the Event).[152] The combination of events contributed to increased transmission congestion and low voltages on the 345 kV and 161 kV networks in southwest Missouri. Local transmission operators in the SPP footprint implemented 29 MW of load shed at 10:00 p.m. on December 22 in the Branson, MO area to alleviate the low transmission voltages.[153] After hydroelectric generation in the area was restored to provide voltage support and voltages recovered, transmission operators were able to restore the load by 12:00 a.m. on December 23.

b. Morning of Friday, December 23: BES reliability conditions worsen overnight

- Extreme cold weather moves eastward
- MISO and TVA operators faced with rising unplanned generation outages coupled with high electricity demands
- Grid operator coordination to manage transmission constraints
- SPP's ability to maintain reserves challenged during early morning
- SPP and TVA declare energy emergencies
- TVA declares EEA 3, sheds firm load[154]

MISO. As the extreme cold weather moved eastward, throughout the early morning hours of December 23, and as unplanned generation outages and failures to start began in the MISO South region, MISO found that its real-time MISO South system load exceeded its forecast. Pursuant to its security constrained economic dispatch, MISO's north-to-south power transfer, known as its Regional Directional Transfer (RDT),[155] increased to supply more power to meet its southern load (see Figures 41 and 42, below).

151 All t mes stated w th n the Report, unless otherw se spec fied, are n Eastern Standard T me (EST). f the ent ty s located n the Central T me Zone, the t mes were converted to EST.

152 SPP Report at 28.

153 SPP performed a post event analys s and found that f dur ng Ell ott the planned transm ss on l ne outage (the l ne descr bed earl er that was outaged from September 2022 to January 2023) had been back n serv ce, along w th an add t onal newly constructed transm ss on l ne and a then unava lable capac tor bank, t would have reduced low voltage l m t exceedances to less than ten t mes as many (from 292 low voltage l m t nstances to only 25 low voltage l m t nstances).

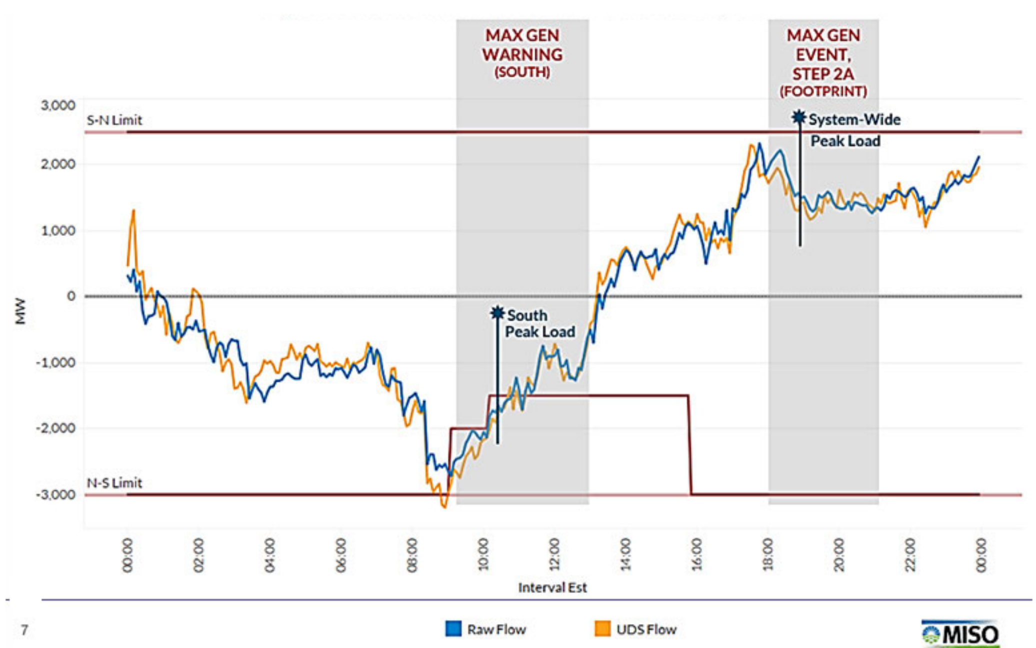
154 Red text references EEAs exper enced by BAs.

155 M SO l m ts the amount of power t transfers ntra market v a ts RDT, referred to as ts Reg onal D rect onal Transfer L m t (RDTL), under a jo nt coord nat on agreement w th SPP, AEC (Assoc ated Electr c Cooperat ve, nc.), TVA, LG&E/KU, Southern and PowerSouth, to 3,000 MW from north to south (1,000 MW firm and 2,000 MW non firm, as ava lable) and 2,500 MW from south to north (1,000 MW firm and 1,500 MW non firm, as ava lable). Wh le the total AC t e l ne capac ty, calculated by add ng the total capac ty of all t e l nes between the BAs at ssue, may nd cate a large transfer capac ty, the actual ab l ty to transfer power w ll be dependent on system cond t ons at the t me of transfer, nclud ng amb ent temperatures, generat on outages and d spatch, transm ss on outages and derates, all of wh ch dr ve actual power flows on transm ss on l nes and can l m t ava lable transfer capab l ty.

Figure 41: Illustration of MISO's Regional Directional Transfer

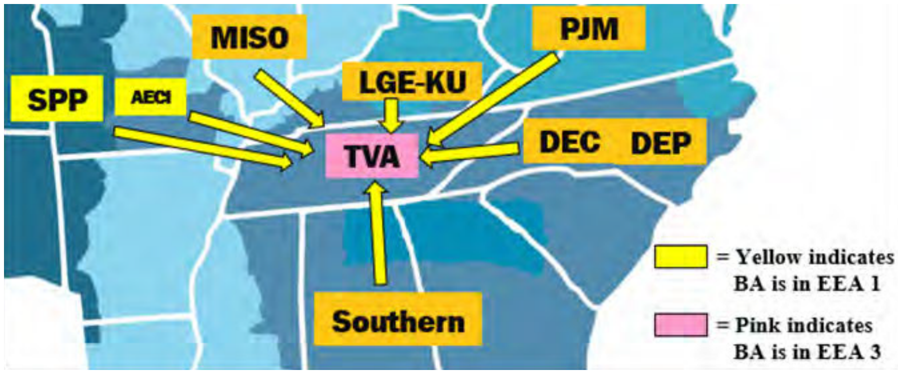
At 9:00 a.m., based on SPP's observed system conditions, SPP asked MISO to reduce its RDT limit (north-to-south power transfer) to 2,000 MW, and approximately an hour later, asked MISO to further reduce it to 1,500 MW. MISO complied with both requests, reducing the RDT, as shown in Figure 42, below. MISO and SPP coordinated to release the RDT reduction later that afternoon.

Figure 42: MISO Regional Directional Transfer (RDT) Flow,[156] December 23, 2022



156 Pos t ve flow s M SO South to North flow; negat ve flow s M SO North to South flow. mage used by perm ss on of M SO.

Figure 43: Status of TVA's Neighboring BAs for Potential of Scheduling Import Power, Morning of December 23



Throughout the morning of December 23, MISO's electricity demand continued to increase along with unplanned generation outages within its own footprint. At 9:15 a.m., MISO implemented a "Maximum Generation Warning" in MISO South.[157] MISO's entire BA footprint electricity demand also escalated throughout the morning of December 23, with morning and evening hour-average peak loads close in magnitude to one another. For the hour-ending 11:00 a.m., MISO's hourly load was 104,804 MW, 99 percent of what its evening peak hourly load would soon be. The combination of high system loads and higher-than-expected forced generation outages throughout the day eventually led MISO to declare an energy emergency at 5:30 p.m., as described further below.

SPP. SPP RC faced local transmission issues the morning of December 23. A combination of unplanned generating unit outages and transmission outages in the eastern SPP footprint contributed to depressed local voltage conditions in southwestern Missouri/northeastern Oklahoma.[158] In addition to these challenges, SPP BA faced operating reserve shortages to meet its early morning peak system load, which by hour-ending 10:00 a.m., had reached 96 percent of its previous-evening record-breaking winter peak load. From 9:27 a.m. to 11:00 a.m. on December 23, SPP declared EEA 1, and curtailed approximately 600 MW of non-firm exports due to its own operating reserve shortfalls, preventing SPP from being a source of power for neighboring BAs during that time. At 11:33 a.m., SPP declared a transmission operating emergency in response to abnormally large numbers of post-contingency system constraints that were breached due to system conditions. According to SPP, the purpose of its transmission operating emergency declaration was to ensure internal and neighboring entities were aware of the abnormal system conditions in its footprint. At 4:09 p.m., SPP terminated the transmission operating emergency. SPP did not need to implement pre-contingent load shed, but rather relied on post-contingent plans put in place by the TOPs within its footprint. At no time during the transmission operating emergency did SPP have an interconnection reliability operating limit (IROL) exceedance.

TVA. When TVA's available generation resources rapidly decreased the morning of December 23, TVA declared EEA 1 and 2 by 5:38 a.m., followed by EEA 3 at 6:12 a.m.

157 M SO's Max mum Generat on Warn ng declarat on, n add t on to call ng for all generat on resources to be comm tted to meet load, called for ts members to schedule n (to the M SO footpr nt) external resources, and to curta l non firm exports.

158 AEC , a transm ss on operator and BA located n M ssour and northeastern Oklahoma, contacted TVA (ts Rel ab l ty Coord nator) and other ne ghbor ng ent t es at approx mately 8:30 a.m. to request voltage support for ts southwestern M ssour /northeastern Oklahoma serv ce area, wh ch was affected by SPP's unplanned outages n the area. AEC declared a Transm ss on Emergency at 9:05 a.m., and prepared to shed load, but d d not need to shed load due to mproved cond t ons.

In addition to taking the emergency actions, TVA sought emergency energy from its neighboring BAs.

Initially, TVA received emergency energy imports from MISO, DEC, Southern, and PJM (depicted in Figure 43, above). These imports were sufficient to avert the need for TVA to order firm load shed for a time. By 9:38 a.m., PJM needed to curtail half (250 MW) of its emergency power delivery to TVA due to an SOL condition – a portion of PJM's emergency energy interchange schedule actual power flow caused a transmission facility within the PJM footprint to reach its emergency flow limit in real time.[159] Despite tightening conditions on the MISO system as the morning progressed, MISO maintained steadily increasing exports to TVA throughout the day. At 10:15 a.m., TVA was able to obtain 243 MW from its Reserve Sharing Group (from LG&E/KU), which offset a portion of the PJM reduction in emergency energy.[160] By 10:31 a.m., TVA operators ordered firm load shed of approximately five percent of its peak system load (estimated to provide over 1,500 MW in load reduction) in response to escalating unplanned generation outages (now at 6,500 MW, an increase of 2,000 MW since 5:00 a.m.) and rising electricity demand. At the same time, TVA's available emergency purchase power had decreased, and other neighboring BAs were unable to provide emergency energy.[161]

This was the first time in TVA's history that TVA ordered firm load shed. TVA would need to shed firm load a second time due to even worse conditions across the entire Event Area by early morning December 24. A little over two hours later, at 12:43 p.m., TVA was able to order restoration of firm load due to an increase in TVA's own available generation resources beginning early afternoon, and a limited increase in import power. These conditions enabled TVA to temporarily improve to EEA 2 for approximately three hours; it later returned to EEA 3 as the evening peak approached with energy supply conditions worsening.

c. Friday Evening, December 23: BES conditions continue to worsen

- Extreme cold weather now expands across LG&E/KU and PJM footprints
- Friday evening peak loads are highest for several BAs in Event Area
- Energy emergencies declared by SPP, TVA, MISO, LG&E/KU, and PJM
- MISO declares two local transmission emergencies, no load shed needed
- SPP returns back to EEA 1, challenges maintaining reserves
- TVA returns to EEA 3, continues load management measures and customer appeals for voluntary load reduction
- PJM and MISO declare EEA 2, implement load management measures
- LG&E/KU declares EEA 3, sheds firm load

During the day and into the evening hours on Friday, December 23, several BA footprints experienced the same challenging combination: rapidly increasing electricity demands due to the extreme cold weather (as illustrated in Figure 38, above), plus high levels of unplanned generation outages. For some BAs, the unplanned generation outages continued to increase at a rapid rate as illustrated earlier in Section III.

LG&E/KU. With LG&E/KU's system load already at 96 percent of its new all-time record winter peak load which occurred December 23, coupled with significant unplanned generation derates, by 1:36 p.m. on December 23, LG&E/KU declared EEA 3, but recovered to an EEA 2 by 2:52 p.m. At 4:29 p.m., PJM BA curtailed

159 H gh level of transm ss on fac l ty load ng or flow was further exacerbated by s gn ficant levels of unplanned generat on outages (an N "numerous" cond t on) comb ned w th ncreas ng electr c ty demands, n the reg on. PJM took appropr ate act ons to ma nta n the fac l ty load ng w th n ts l m t, ma nta n ng BES rel ab l ty.

160 Aga n at 11:50 a.m., LG&/KU cont nued ts ass stance to TVA by extend ng prov s on of 243 MW Reserve Shar ng to TVA.

161 As of 9:42 a.m., AEC BA was also at EEA 1. SPP, though not a ne ghbor ng BA to TVA but a potent al source of power v a wheel ng through AEC or M SO, was also n an EEA 1 dur ng th s per od.

the 400 MW import power due to experiencing rapidly increasing levels of unplanned generation outages coincident with increasing system load in its own footprint. With import power curtailment, at 4:29 p.m., LG&E/KU requested emergency energy from its contingency reserve sharing group. TVA, although in EEA 2 at the time, supplied LG&E/KU with 400 MW of emergency energy. At 4:45 p.m., LG&E/KU re-entered EEA 3. However, following TVA's return at 5:18 p.m. to an EEA 3 condition, at 6 p.m. it could no longer spare the 400 MW of emergency power to LG&E/KU. With the loss of its import power schedules to offset the generation derates, and its increasing system load conditions, LG&E/KU began over 300 MW firm load shed at 5:58 p.m. Over the next several hours, LG&E/KU was able to incrementally restore firm load that was shed as system loads decreased after its evening peak, and by 10:11 p.m., restored all firm load.

PJM. As the severe cold weather moved into the PJM area, loss of generation resources and load increases both exceeded their forecast amounts. As these factors increased throughout the Event, PJM needed to take emergency actions to mitigate the impact to its system. Earlier in the Event, before Winter Storm Elliott reached its footprint, PJM exported energy to neighboring BAs to its west that were short on capacity. However, as the storm moved in and the generation losses and loading increased on the PJM system, by 5:30 p.m. on December 23, PJM itself needed to declare EEA 2, invoking load management measures (e.g., demand response). PJM also reduced its energy exports, no longer able to be a source of power for BAs in need due to its own operating reserve shortfalls. According to PJM operators, PJM had barely avoided load shedding on December 23.[162]

Figures 44 and 45,[163] below, show how PJM's reserves declined throughout the day on December 23, driven heavily by unplanned generation forced outages in its footprint.

162 Aff dav t of Paul McGlynn n Essent al Power OPP, LLC et al. v. PJM nterconnect on, LLC, Docket No. EL23 53 000, 23 54 000, 23 55 000 (hereafter "McGlynn Aff dav t"), at ¶¶ 10, 34, 36 40, 48 51, 59.

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Figure 44: PJM Unplanned Generation Outages and Reserves, December 21-26, 2022

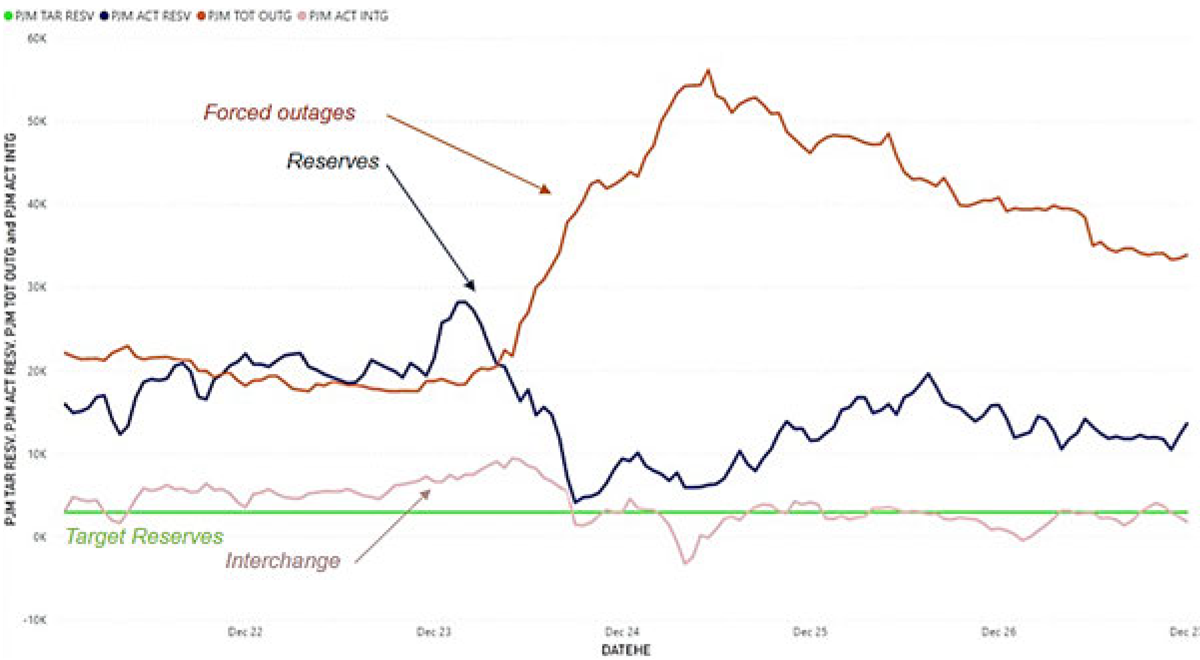


Figure 45: PJM BA Synchronized Reserves, December 23, 2:00 p.m. – December 24, 12:00 a.m.

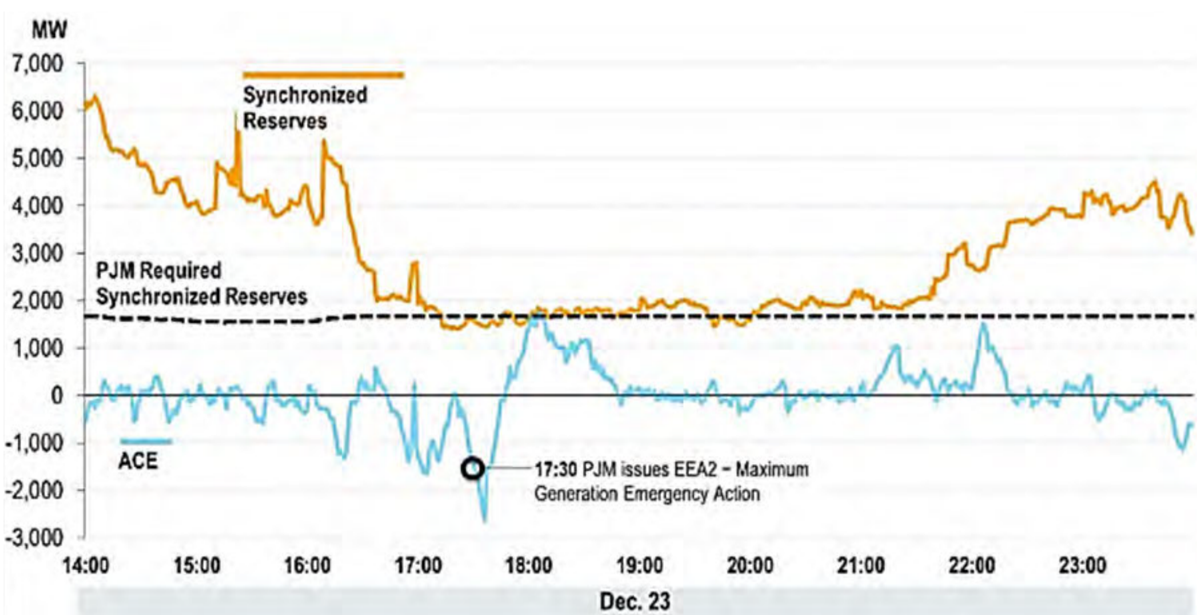
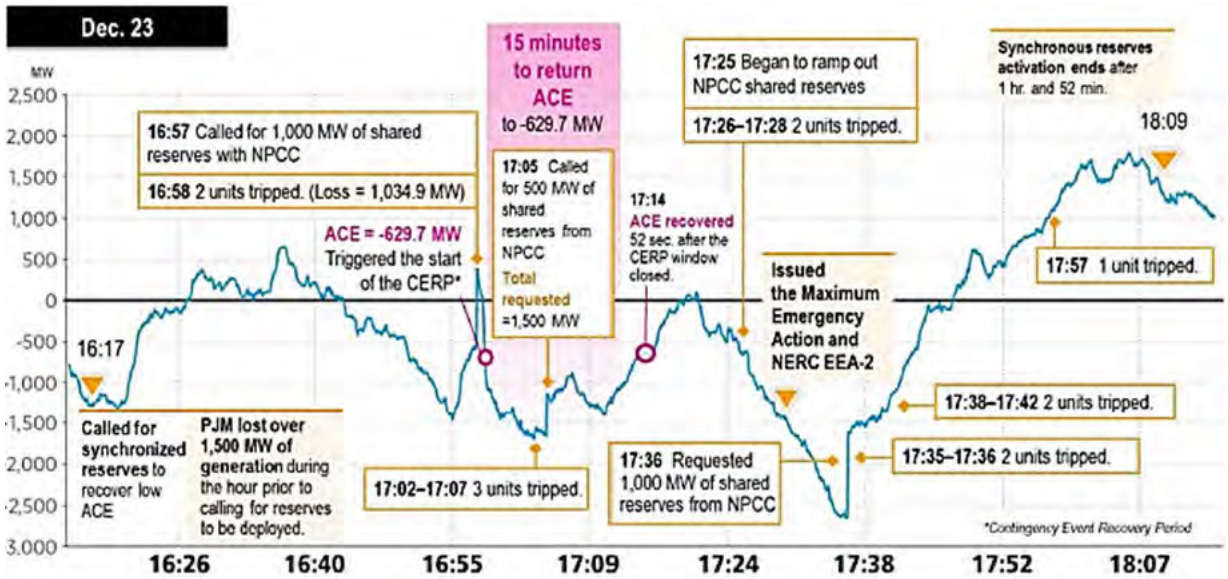


Figure 46: PJM BA Area Control Error (ACE) and Actions Timeline, December 23, 4:15 p.m. – December 24, 6:15 p.m.



As shown in Figure 46[164] above, PJM was able to benefit from a Simultaneous Activation of Ten-Minute Reserve (SAR) agreement with the Northeast Power Coordinating Council (NPCC). The SAR Agreement allowed PJM to call on reserves of up to 1,500 MW during the Event. PJM requested SAR assistance five times between December 23 and 24, all of which were due to stressed system conditions. PJM remained in EEA 2 until midnight December 23, narrowly avoiding the need that evening to declare EEA 3 and shed firm load. By midnight, conditions improved enough for PJM to downgrade to EEA 1, but that was short-lived, as described further below.

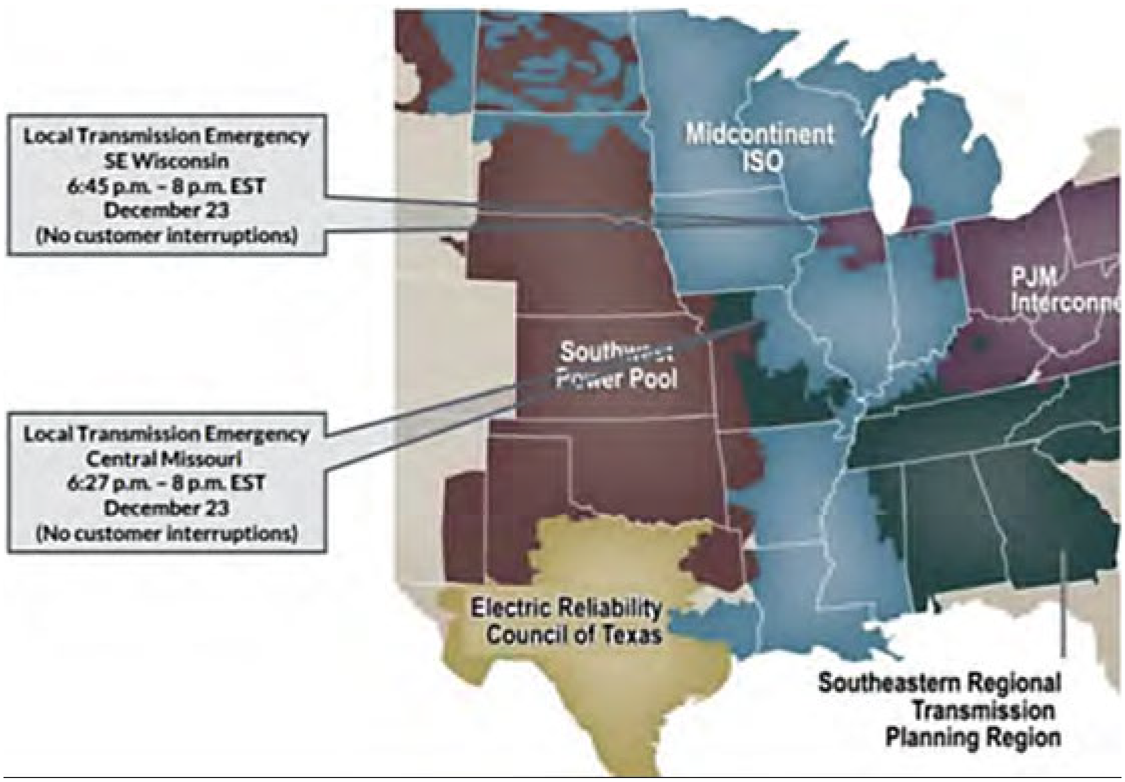
MISO. System electricity demand levels remained elevated throughout the day on December 23. This was not only true for its south region, which, as described above, contributed to MISO invoking a maximum generation warning, but also for its entire footprint. Following MISO's morning peak load on December 23, demand levels remained at or above 95 percent of the Winter Storm Elliott peak demand that MISO would experience that evening. Those high loads, coupled with unplanned generation outages increasing throughout the afternoon, led MISO to declare EEA 1 at 5:30 p.m. and EEA 2 at 6:00 p.m., when load and generation losses did not improve. Similar to PJM, when MISO declared EEA 2, it implemented its demand response, which reduced the electricity demand in its footprint. MISO remained in EEA 2 until 9:00 p.m., when its electricity demand lessened.

During the evening of December 23, MISO RC operators declared two local transmission emergencies to help manage congestion on its system. As shown in Figure 47, below, on December 23, in southeastern Wisconsin, MISO established a post-contingent mitigation plan to avoid significant redispatch of generation within that local area. Also on December 23, in eastern Missouri, MISO declared a local transmission emergency, which provided access to additional hydroelectric generation that was only available during emergency conditions.

164 Th s mage s reproduced w th the perm ss on of PJM © PJM.

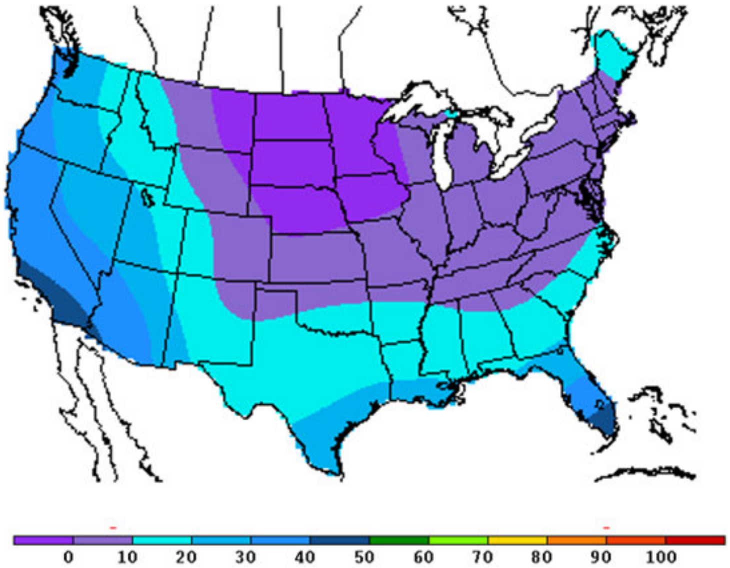
Finally, MISO declared a Transmission Loading Relief (TLR) 5[165] to manage transfers for a post-contingent constraint in southeastern Michigan, which was in effect from December 24 at 2:00 a.m. until 12:00 p.m. on December 26.

Figure 47: MISO Local Transmission Emergencies, Evening of December 23, 2022



165 Transm ss on Load ng Re ef (TLR) 5 s the h ghest eve of Transm ss on Load ng Re ef that can be dec ared by a Transm ss on Prov der. f system cond t ons warrant, a TLR 5 can enab e the Transm ss on Prov der to curta a firm transm ss on reservat on(s) to decrease the mpact on an over oaded transm ss on fac ty. f a Transm ss on Prov der curta s a F rm Transm ss on Reservat on, t must curta ts own firm oad on an equa bas s.

Figure 48: December 24, 2022 Actual Minimum Temperatures – Lower 48



SPP. Just as in the morning, SPP BA was still facing operating reserve shortages to meet its December 23 evening peak system load, which by hour-ending 7:00 p.m., was already over 90 percent of December 22's evening record peak load and rising. The evening of December 23, SPP declared its second EEA 1 from 6:20 p.m. to 9:20 p.m. and curtailed approximately 1,100 MW of non-firm exports, which prevented SPP from being a source of power for BAs in need due to its own reserve shortfalls.

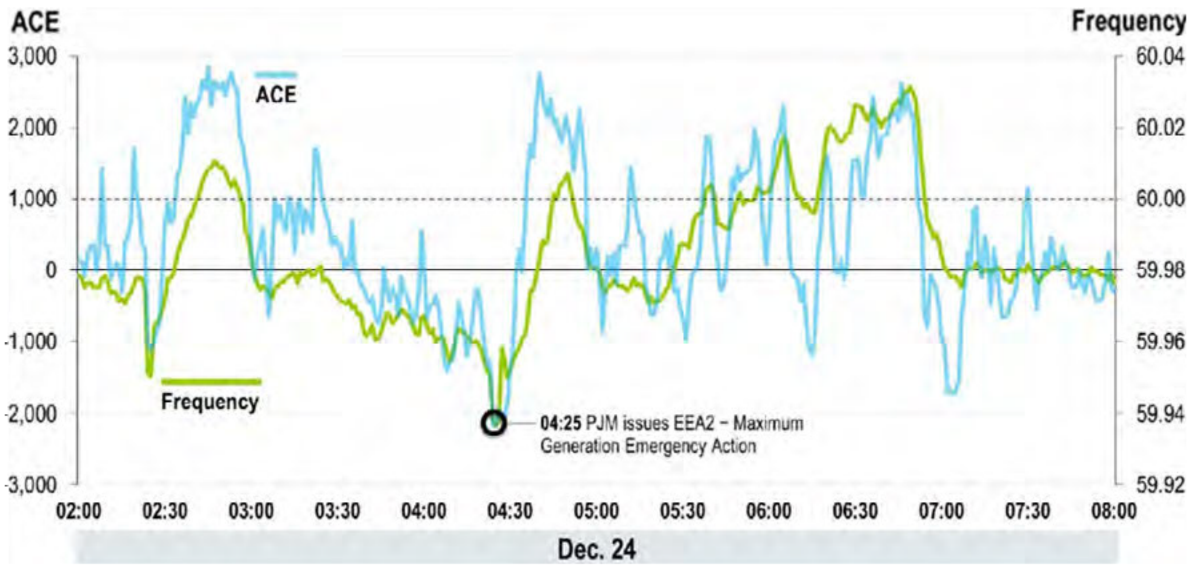
TVA. At 5:18 p.m., TVA returned to EEA 3 because neighboring entities such as Southern were dealing with their own energy emergencies by reducing their energy exports to TVA, and TVA's electricity demand was trending toward what would become its all-time record winter peak load later that evening. TVA, now at risk of shedding firm load, recalled the 400 MW contingency reserves that it was providing LG&E/KU at 6:00 p.m. This action, combined with later receiving emergency energy imports through their evening peak hours from DEC and Southern enabled TVA to avoid shedding firm load that evening. TVA would not be able to avoid load shed by the next morning. Figure 39, above, includes a timeline illustrating the Energy Emergencies declared by BAs on December 23.

d. Saturday Morning, December 24: Many simultaneous BES Energy Emergency conditions

- Extreme cold weather expands across southeastern U.S.
- Responsive reserves decline across the Core Event Area
- Simultaneous energy emergencies exist in TVA, LG&E/KU, PJM, DEC, DEP, DESC, Southern, and Santee Cooper
- PJM returns back to EEA 2, implements load management measures, and makes customer appeals for voluntary load reduction
- TVA, DEC, DEP, DESC, Santee Cooper BAs declare EEA 3, shed firm load
- Southern declares EEA 2, obtains emergency energy from Florida, implements load management measures to lower system load, did not need to shed firm load
- NYISO and ISO-NE impacts

Extreme cold weather continues – generation reserves continue to diminish. In the overnight hours heading into the morning of December 24, the extreme cold weather conditions accompanying Winter Storm Elliott eventually blanketed the southeastern U.S. all the way to the Atlantic Ocean, Figure 48, above).

Figure 49: PJM BA Frequency Plot and ACE Conditions, December 24, 2:00 a.m. – 8:00 a.m.



The pattern of unplanned generation outages and high electricity demands seen in the BA footprints described above continued overnight and into the morning of December 24 for BA footprints located in the easternmost region of the U.S. Forced outages and derates of generating units continued to diminish BA reserves during the early morning hours of December 24.

PJM. PJM began December 24 in EEA 1. As the PJM BA continued to experience significant unplanned generation outages and derates through the early morning hours as referenced in Figure 27, above, at 4:00 a.m. on December 24, PJM issued a call for voluntary conservation to last until 10:00 a.m. on December 25. PJM estimated that responses to its call for conservation helped to reduce load beginning at about 7:15 a.m.

At 4:20 a.m., PJM BA needed to return to EEA 2. At 4:23 a.m., PJM BA had a low ACE event,[166] and called for over 1,000 MW of synchronized (responsive) reserves from its reserve-assigned generation. Only 169 MW of synchronized generation reserves responded (a 16.8 percent response rate).[167]

As shown in Figure 49,[168] above, at 4:25 a.m., PJM BA issued EEA 2, and called for Maximum Generation Emergency Action. PJM also used load management measures during its EEA 2, to take effect at 6:00 a.m. At 6:17 a.m., PJM BA asked Market Participants to submit bids to sell emergency energy in case PJM needed to purchase or import emergency energy, but other actions that PJM took averted the need for the PJM BA to purchase emergency energy. At 6:30 a.m., PJM BA received reports that generators were having to limit their output due to federal government environmental restrictions. PJM petitioned the Department of Energy (DOE), and DOE later granted permission,[169] to lift emissions-related restrictions until noon, Monday December 26.

166 A low ACE event s the Low Balanc ng Author ty ACE L m t (MW), calculated based on the Low Frequency Tr gger L m t of approx mately 59.95 Hz for the Eastern nterconnect on. *See* F gure 49, above, and NERC Rel ab l ty Standard BAL 001 2 Real Power Balanc ng Control Performance, Attachment 2. RSCompleteSet.pdf (nerc.com).

167 PJM has normally seen performance over the past three years n the 50 70 percent response range when call ng for synchron zed reserves.

168 Reproduced w th perm ss on of PJM and copyr ghted by PJM.

169 PJM secured the order from the DOE under sect on 202(c) of the Federal Power Act (16 U.S.C. § 824a(c)). PJM rece ved the DOE order at 5:45 p.m. on December 24 and mmed ately mplemented t.

At 7:15 a.m., PJM BA issued a Voltage Reduction Warning and Reduction of Non-Critical Plant Load, indicating that a voltage reduction[170] may be required during a future critical period. At 7:30 a.m., PJM BA conducted an SOS Transmission conference call on which PJM BA advised TOs to prepare for a Voltage Reduction Action (i.e., order to perform voltage reduction) and to be sure to have their load shed plans in place. By 8:00 a.m., over 24 percent of the PJM generation fleet (approximately 46,000 MW) was experiencing a forced outage, which was higher than the 22 percent forced outage level that PJM experienced during the Polar Vortex in 2014.[171] In total, PJM BA faced approximately 57,000 MW of generator unavailability for the morning peak on December 24 (including planned outages and forced outages that began before the Event). The other load management measures improved system conditions enough over the next few hours that PJM did not need to order voltage reduction or firm load shed on the morning of December 24.[172] At first PJM estimated that its load management efforts reduced load by 7,400 MW, but it later realized that it only received approximately 3,500 MW.[173] Still, PJM was able to restore exports to support its neighbors by 10 a.m. At 10:00 p.m., PJM BA terminated its EEA.

TVA. As shown in Figure 39, above, TVA remained at EEA 3 since the evening of December 23. At 5:51 a.m. on December 24, with its system load still near where it had peaked the evening before, unplanned generation outages still occurring, and its import power curtailed, the TVA BA area again ordered firm load shed of approximately five percent of its peak system load/1,500 MW. At 6:12 a.m., TVA suffered an additional curtailment of import power and ordered an additional five percent firm load shed (10 percent total, estimated by TVA to be a 3,200 MW reduction).[174] TVA later incurred an additional unit trip of nearly 300 MW and was unable to reduce back to five percent of its peak system load until 10:27 a.m. Finally, at 11:30 a.m. TVA BA released its order for the remaining five percent load shed. As system load began to decrease and some generating capacity returned to service, TVA lowered from EEA 3 to EEA 2 at 12:08 p.m., dropping to EEA 1 at 1:07 p.m. and terminating its EEA at 1:45 p.m.

DEC. Already in EEA 1 at the start of December 24, as unplanned generation outages increased and PJM BA curtailed export schedules to DEC, DEC declared EEA 2 at 4:30 a.m., and EEA 3 at 6:10 a.m. By 6:27 a.m., DEC ordered 400 MW of firm load shed, later increasing it to 1,000 MW at 7:10 a.m. Later that morning, as system load dropped and a generation plant returned to service, DEC ordered the restoration of firm load at 10:00 a.m. DEC manually restored the last load shed circuits at 3:45 p.m.

DEP. Experiencing conditions similar to DEC, DEP declared EEA 1 December 24 at 5:37 a.m. DEP escalated to EEA 2 at 6:06 a.m. when its purchased power was curtailed, and to EEA 3 at 6:18 a.m. after an additional generation outage. With system load increasing, DEP ordered 600 MW of firm load shed at 6:25 a.m., but increased it to 800 MW at 7:10 a.m., up to a maximum of 961 MW by 7:56 a.m. By 8:14 a.m. DEP began restoring a portion of its firm load,

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170 Based on transm ss on equ pment wh ch ex sts n certa n locat ons of the BES, electr c gr d operators can control the transm ss on equ pment to reduce voltage levels to lower the BA system load (wh le ma nta n ng BES rel ab l ty) as an emergency load management measure, n advance of and to reduce the need for firm load shed. *See* PJM Manual 13: Emergency Operat ons.

171 McGlynn Aff dav t, at ¶ 13.

172 At 6:15 p.m. on December 24, PJM ended the Voltage Reduct on Warn ng and Reduct on of Non Cr t cal Plant Load, and the Voltage Reduct on Alert at 6:34 p.m.

173 PJM Report at 42 (for December 23 (1,100) and 24 (2,400).

174 n add t on to PJM, other BAs ne ghbor ng TVA had concerns of meet ng the r own load/reserve requ rements the morn ng of December 24 based on h gh electr c ty demands and unplanned generat on outages, derates, and fa lures to start exper enced thus far dur ng W nter Storm Ell ott. For example, w th the SPP BA exper enc ng challenges to ma nta n ng adequate operat ng reserves tw ce on December 23 dur ng morn ng and even ng peak t meframes, to l m t further ncrease of the export of the SPP BA, the SPP transm ss on serv ce prov der (TSP) reduced the r total power] transfer capab l ty (TTC) of the SPP export nterface from December 23, 10:00 p.m., through December 25, 1:00 p.m. SPP BA commun cated th s act on w th M SO, TVA and Southern and not fied them to contact SPP f they needed ass stance and SPP would evaluate ts ab l ty to help. These calls were on the morn ng of the 24th. (*See* SPP Report at 9).

restoring all by 8:43 a.m. DEP improved to EEA 1 at 4:20 p.m.

DESC. With increasing generation outage levels, on December 24, at 4:56 a.m., DESC declared EEA 2 and initiated load management procedures, followed by voltage reductions to reduce system load. By 5:53 a.m., DESC declared EEA 3. At 8:00 a.m., DESC ordered approximately 95 MW firm load shed. DESC was able to purchase 100 MW of import power from Southern, and by 8:09 a.m., restored its firm load. DESC continued to implement load management, customer appeals for conservation, and voltage reduction to lower its system load, and at 7:10 p.m., dropped to EEA 2. DESC remained at this level overnight until 9:00 a.m. on December 25 when it exited its energy emergency.

Santee Cooper. Santee Cooper began experiencing unplanned generation outages related to Winter Storm Elliott during the early morning hours of December 24. At 5:34 a.m., Santee Cooper declared EEA 1, and by 7:18 a.m. was at EEA 3 and ordered 86 MW firm load shed. At 7:33 a.m., Santee Cooper ordered all firm load shed restored.

Southern, NYISO, and ISO-NE. On December 24, due to the unplanned generation outages and increasing loads, Southern BA declared an EEA 1 at 2:00 a.m. The Southern BA requested implementation of voltage reduction programs to help reduce load on its system. Faced with additional unplanned generation outages, at 6:25 a.m., the Southern BA declared an EEA 2 due to declining operating reserves and expected load increase, and requested emergency energy from its neighbors. At 7:00 a.m., Florida Power and Light provided 1,000 MW of emergency energy to the Southern BA Area. As it began to receive emergency energy from Florida Power, the Southern BA was able to provide 100 MW of emergency energy assistance to DESC. By midday, Southern BA load began to decrease, and Southern BA was able to increase this assistance to DESC to 400 MW at 1:00 pm, and by 2:15 p.m., downgraded to an EEA 1. As the need for emergency energy decreased due to improved system conditions in the DESC BA area, Southern BA decreased its emergency energy to 200 MW and finally to 0 MW at 10:00 p.m.

With the winter storm making its way to New York and New England, the governor of New York on Thursday December 22, declared a state of emergency for the entirety of New York, and on the same day, the National Weather Service Buffalo upgraded the winter storm watch to a blizzard warning, and warned of possible blizzard conditions in Buffalo to begin Friday afternoon December 23, and to last approximately 30 hours, with peak wind speeds that could reach approximately 70 mph, with one to three feet of snow.[175] Although there were over 100,000 power outages in the NYISO footprint, as well as tens of thousands of customers without power in the ISO-NE footprint across Maine, Vermont, and New Hampshire, they were mostly due to the winter storm's impact on the electric distribution systems. While there were unplanned BES generation outages in the NYISO footprint during the Event, NYISO did not need to enter into an energy emergency and was able to assist neighboring BAs during the Event, such as PJM, with reserves as described earlier in Section III.

ISO-NE needed to invoke EEA 1 the evening of December 24. ISO-NE incurred over 2,000 MW of unplanned generation outages and derates in its footprint on December 24, and also experienced over 1,000 MW reduction of import power from Hydro Quebec due to the winter storm's impact on Hydro Quebec's system. Those conditions, coupled with high electricity demands, led ISO-NE to declare EEA 1 from 4:30 p.m. to 7:00 p.m., which was then cancelled as conditions improved in its BA.

e. Operating Conditions Improve - Evening of December 24 –December 25

- Core Event Area operating conditions improve
- Energy Emergencies end

175 NEW YORK STATE PREPAREDNESS AND RESPONSE EFFORTS Bl zzard of 2022 After Act on Rev ew (August 2023) at 15, https://www.dhses.ny.gov/system/files/documents/2023/08/nys aar on buffalo bl zzard response.pdf.

As Christmas Eve and Christmas Day unfolded, Event Area electricity demands decreased (as seen on the graph in Figure 39, above). Also, on December 25, extreme cold weather ushered in by Elliott began to subside in some of the BA footprints. Some generating units also returned to service and increased BA reserve levels. However, also as shown in the Figure 39 timeline, above, multiple BAs were experiencing Energy Emergencies which extended into midday, December 25, although none needed to shed firm load on Christmas Day:

- DEC BA, returned to EEA 1, December 24, at 4:00 p.m., EEA 1 cancelled on December 25, at 11:00 a.m.
- DEP BA, EEA 1 cancelled on December 25, at 9:00 a.m.
- DESC BA, cancelled EEA 2 on December 25, at 9:00 am.
- Santee Cooper BA, EEA 2 until December 25, 5:04 a.m., EEA 1 cancelled December 25, at 9:00 a.m.
- Southern BA, EEA 1 cancelled December 25, 12:00 noon.
- PJM BA, EEA 1 cancelled December 24, at 10:00 p.m.

4. NATURAL GAS PIPELINE OPERATORS' REAL-TIME ACTIONS

a. Pipeline Operator Actions Due to Natural Gas Supply Shortfalls and Equipment/Facility Outages

1. Gas Pipeline Scheduling

The natural gas scheduling system is based on the Gas Day which is standard nationwide, beginning at 9:00 a.m. CCT[176] and ending at 9:00 a.m. CCT the following day. All nominations for transportation service are for a daily quantity to be transported over that 24-hour period. The rate at which a shipper may use its contracted quantity, also known as a flow rate, on a given pipeline is determined by the individual pipeline's tariff and the flexibility of that pipeline to permit non-ratable flows (that is, delivery in a single hour of more than 1/24 of the daily nominated quantity). Except for special services, pipeline services are generally based on the assumption of uniform hourly flows over the Gas Day.

At a designated time each day, a shipper "nominates" a quantity of natural gas that it wishes to have transported by the pipeline under a transportation contract between receipt and delivery locations on the pipeline. The nomination goes through a confirmation and scheduling process to ensure that the nomination matches the amount of gas that the pipeline will receive from or deliver to the designated locations, and that there is enough available capacity for the nomination to flow. Before a pipeline schedules a shipper's nominated quantity of natural gas for transportation, the pipeline confirms the shipper's nomination with upstream and downstream parties to make sure the shipper has contracted for sufficient gas with an upstream supplier to fulfill its nomination, and to ensure the downstream entity, such as an LDC, has sufficient capacity to accept the gas. If demand for service along a specific path exceeds the pipeline's capacity (i.e., if a pipeline has capacity constraint), priority rules are used to schedule higher priority nominations while lower priority nominations are reduced or rejected. After all gas has been scheduled, nominations are confirmed back to the shippers and the pipeline is obligated to deliver the confirmed nominated quantity of gas.

2. Gas Pipeline Operations Under Normal Conditions

Natural gas pipelines (and LDCs) have operations centers or control rooms that are staffed 24 hours a day, every day of the year. Pipeline personnel known as controllers monitor the pipeline systems for, among other things, operational status, natural gas flow rates, and readings of the natural gas pressure within the pipeline and temperatures. Controllers are the first to notice and respond to abnormalities such as pressure changes or compressor failures and notify and to communicate with field personnel who respond to these conditions.

Each pipeline must maintain a minimum pressure for gas to flow and must stay below the maximum allowable

176 Central Clock T me, wh ch s Central Standard T me except dur ng Dayl ght Sav ngs T me, when t s one hour n advance of Central Standard T me.

operating pressure at which it can safely operate (MAOP). Like electric grid operators, pipeline operators use Supervisory Control and Data Acquisition (SCADA);[177] pipelines use it primarily to monitor the flow of gas on the system.

Line pack is the volume of gas maintained or held within a pipeline system. The more gas that is "packed" into the pipeline, the higher the pressure. System operators continually manage the amount of gas in their pipelines to ensure that customer demands can be met while staying within safe and reliable pressure ranges, which vary from pipeline to pipeline. Pipelines rely on line pack to match the time-varying demands of their customers (shippers) and the supply of natural gas that generally is injected into the pipeline at a consistent rate through the day (production gas). Under normal operating conditions, line pack on a pipeline goes through a 24-hour cycle. During the morning peak, when some shippers, such as electric generating units, withdraw gas at a non-ratable flow rate, the line pack decreases. Later in the day, when shippers either pause or decrease the rate of gas withdrawal, pipelines pack the lines to replenish the gas taken off the system. As long as a customer's gas usage does not threaten the pipeline system's integrity, pipeline operators may provide customers with the flexibility of non-ratable flows or deviation from their scheduled quantity. Additionally, pipelines generally offer balancing services and bill their shippers monthly to allow for daily fluctuations. This allows shippers up to 30 days to balance the amount of gas that shippers delivered into the pipeline with the quantity of gas that was taken off the pipeline. Lastly, during normal operating conditions, if the pipeline is not constrained and is able to meet all of its firm contractual nominations, any excess capacity can be used for interruptible transportation service.

Ahead of weather events or at other times that stress the system, a pipeline system operator will store gas in its transmission system during the hours of low demand (packing) leading up to the event, and then use that gas during the hours of high demand, reducing the amount of gas in the system (drafting). During periods of high demand, natural gas supplies flowing ratably[178] into a pipeline over the 24-hour gas-day period may not be sufficient to satisfy the increased demand from shippers in the same overlapping period leading to the draft condition. A draft condition occurs when supply is less than demand. This may occur on an hourly or daily basis. A draft condition leads to lower line pressure and/or reduced line pack, to which operators respond with a variety of approaches, such as reduced system tolerances and the use of natural gas imbalance management techniques designed to maintain system integrity and provide reliable service to all shippers.

During constraint periods, a pipeline may more strictly enforce ratable flows and reduce system imbalances by requiring shippers to match their supply of gas delivered into the pipeline with the amount taken out. If a shipper's supply of natural gas into the pipeline is less than its nominated amount, a pipeline may reduce the shipper's confirmed nomination to match the amount of natural gas actually delivered into the pipeline system.[179] Pipelines may also use the types of notices described below in the sidebar on pipeline communications to keep the system balanced and within operating pressure range.[180] By using notices to reduce the amount of gas customers may take off the pipeline or the rate at which the gas is being taken off, pipelines can keep pressure up. During the Event, one pipeline restored its line pack by reversing flow in a segment of its system, but not all pipelines have that ability. Pipelines may also reduce or curtail certain

177 A Superv sory Control and Data Acqu s t on (SCADA) system operates v a coded s gnals sent over commun cat on channels to remote stat ons to mon tor and prov de control of remote equ pment.

178 Mean ng at a constant rate; rece pt operators flow on a steady rate bas s as ment oned above. Steady state flow refers to the cond t on where the flu d propert es at a po nt n the system do not change over t me.

179 Changes n gas del ver es do not occur nstantly. Operat onal Balanc ng Agreements (OBA) contractually spec fy how gas mbalances between flows and scheduled amounts are to be managed. nterstate p pel nes are obl gated by FERC regulat ons to have OBAs at nterconnects w th other nterstate p pel nes and w th ntrastate p pel nes. These agreements enable counterpart es to make operat onal changes and rev se nom nat ons.

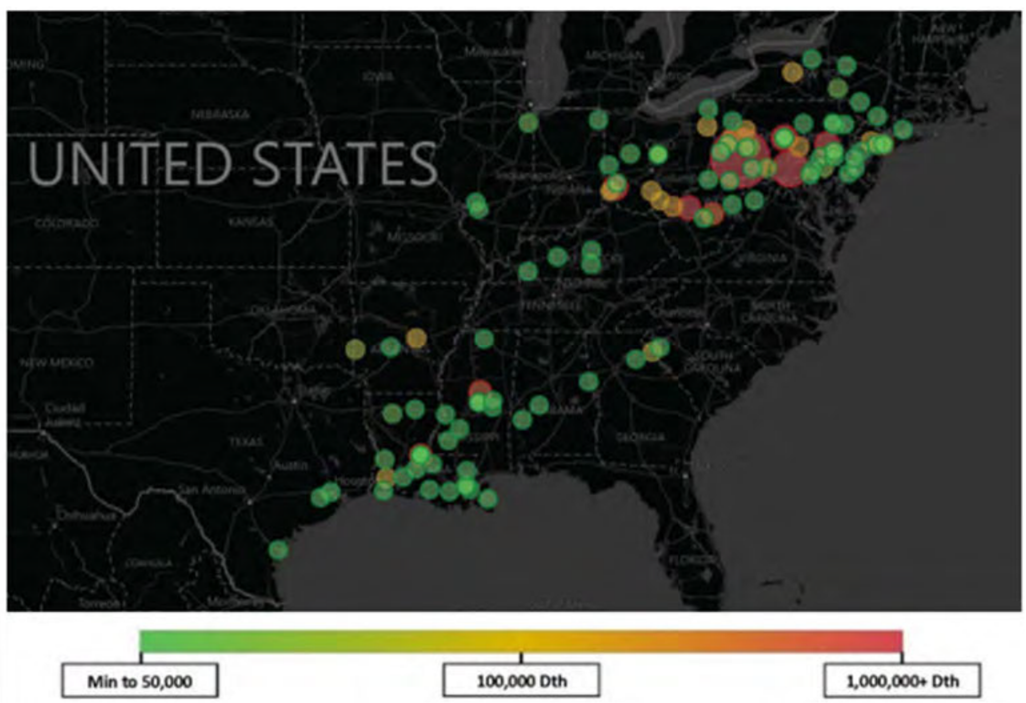
180 *See* s debar on p pel ne commun cat ons at 76, below.

transportation services based on their priority level (e.g., interruptible transportation) if their capacity cannot meet all of the demand.

Pipelines can turn some facilities on and off, whether by remote operation via SCADA or manually using field personnel, to alleviate pressure concerns that could affect the reliability of their system. However, this option is rarely exercised. In 2011, New Mexico Gas Company curtailed pipelines to several rural communities when it received reports of no gas or low gas pressure in the Albuquerque area, indicating that its system was near collapse.[181] These curtailments allowed pressure to recover in the remainder of its system. The option to turn off facilities feeding shippers at designated delivery points that are supplying less gas than they are withdrawing is rarely, if ever, exercised. If enough customers take more gas than they are entitled to, this can negatively affect pipeline pressures for customers located farther down the pipeline.

Interstate pipelines use storage to support system operations (e.g., to provide system balancing or support no-notice transportation services), to provide contract storage services, or a combination of both. Interstate pipeline companies, intrastate pipeline companies, LDCs and independent storage service providers may own and operate underground or above-ground storage facilities. However, the owners/operators of storage are not necessarily the owners of the natural gas held in storage.

Figure 50: Magnitude of Supply Shortages by Receipt Point Locations for Gas Days December 20-26, 2022



Most of the working gas held in storage belongs to shippers, LDCs, or end users who own the gas. Some interstate pipelines reserve varying amounts (from three percent to 22 percent) of their natural gas storage capacity to support their system operations. During extreme cold weather events withdrawals from customers with rights to storage such as LDCs (for natural gas-fired home heating, among other uses) increases. In Winter Storm Uri, the South Central Region (including Texas) saw record storage withdrawals of 156 Bcf for the week ending February 19,

181 2011 Report at 127 130.

2021, which were instrumental in preventing more adverse outcomes on both the natural gas infrastructure system and the grid.

Each of these tools is important in maintaining the reliability of the pipeline system, allowing operators to ensure the proper amount of gas flows through the system. Force majeure can be issued when emergency conditions, such as freezing of equipment, threaten operations. OFOs are important because they notify shippers to stay within their nominated and confirmed quantities of gas or risk penalties.

3. Gas Pipeline Real-Time Operations During Winter Storm Elliott

Once Winter Storm Elliott struck, many pipelines began to experience decreased natural gas supply at numerous receipt points, which are the points where pipelines receive gas into their system. Figure 50, shows the magnitude of supply shortages during the relevant period by receipt point locations. Ten out of the 15 surveyed pipelines reported supply loss or underperformance, defined as the actual physical receipts being less than the shipper's confirmed nomination. The magnitude of supply loss is represented on Figure 50 by the green to red color gradient, with red indicating a higher volume of supply loss. Figure 50 clearly shows significant supply reductions at receipt points located in the Marcellus and Utica Shale formations. Pipelines also indicated that although they can track the volume of supply underperforming at receipt points on their respective systems, they were not always privy to the upstream issues causing the supply loss.

Pipeline Communications

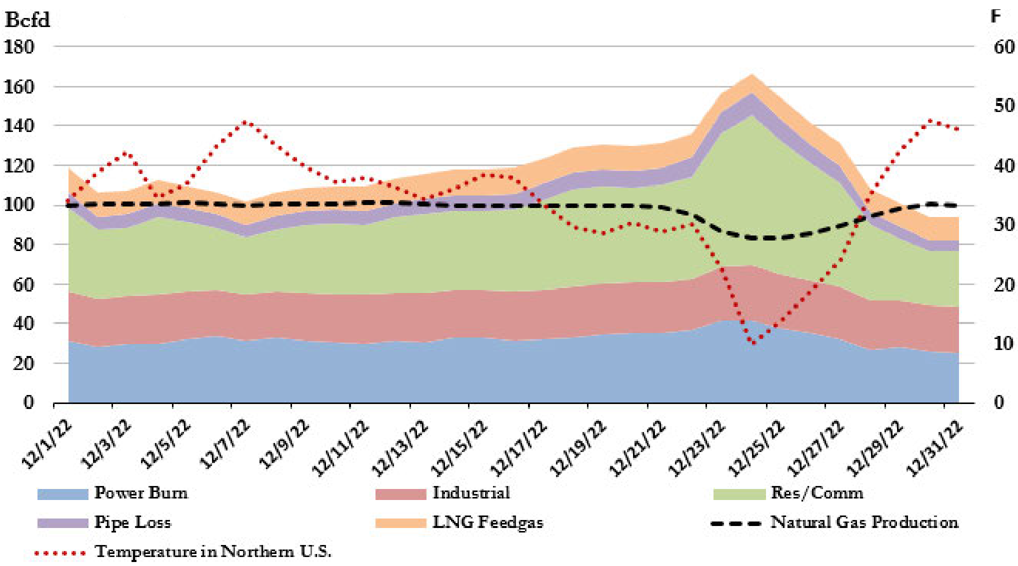
Interstate pipelines issue a variety of communications and directives to shippers and, pursuant to FERC regulations (18 CFR §284.12 (2022)), post critical notices to describe strained operating conditions, to issue operational flow orders and, when applicable, to make force majeure announcements. Most intrastate pipelines provide similar information and instructions to shippers, either by posting or direct communications.

Critical notices describe situations when the integrity of the pipeline system is threatened. A critical notice will specify the reasons for and conditions making issuance necessary, and also state any actions required of shippers. Operational integrity may be determined by use of criteria such as the weather forecast for the market area and field area; system conditions consisting of line pack, overall projected pressures at monitored locations, and storage field conditions; facility status (defined as horsepower utilization) and availability; and projected throughput versus availability, for capacity and supply.

Operational flow orders (OFO) are used to control operating conditions that threaten the integrity of a pipeline system. (Individual pipeline companies may have other names for operational flow orders such as alert days, performance cut notices or an emergency strained operating condition). OFOs request that shippers balance their supply with their usage on a daily basis within a specified tolerance band. An OFO can be system-wide or apply to selected points. Failure by a shipper to comply with an OFO may lead to penalties. Pipelines may also limit services such as parking and lending of natural gas, no-notice (the provision of natural gas service without prior notice to the pipeline), interruptible storage and excess storage withdrawals and injections.

Force majeure, if authorized by the pipeline's tariff, is a declaration of the suspension of obligations because of unplanned or unanticipated events or circumstances not within the control of the party claiming suspension, and which the party could not have avoided through the exercise of reasonable diligence.

Figure 51: Natural Gas Supply and Demand, December 1 – 31, 2022[182]



Starting the morning of December 23, pipeline operators were faced with increasing demand for natural gas after seeing supply shortfalls throughout the night of December 23 (see supply and demand pattern in Figure 51, above). Supply shortfalls peaked on December 24 at 7.1 Bcf. The mismatch between supply and demand challenged pipeline operators' ability to provide consistent, dependable natural gas operations needed by generating units. Line pack was one strategy pipelines used to handle these hourly fluctuations in supply and demand, partially to assist generators' operations.

Figure 52 below, shows that the ongoing imbalance between the gas entering and leaving the pipeline systems caused the interstate pipelines' line pack to continuously drop throughout December 24. Pipelines actively monitored their line pack and pressures and responded promptly; issuing underperformance notices to shippers to inform them that they were not supplying all of the gas they were obligated to supply. To meet confirmed nominations of customers, pipelines used line pack and/or gas from storage to try to cover shortfalls as much as possible. These efforts were successful at the onset of the storm, allowing pipelines to deliver confirmed nominations of gas to meet customers' demand. However, as the storm progressed, supply shortfalls continued and customers' demand increased to a level where some customers began taking more gas than what they supplied and/or confirmed through nominations, which contributed to low pipeline pressures. On December 24, due to the mismatch of shippers' receipt and delivery volume, multiple shippers' confirmed nominations were reduced to match their supply of gas into the pipeline.

Figures 53 and 54, below, show the notices issued by the pipelines in advance of the Event on December 20 as well as during the Event from December 21 to 26. Force majeure and OFO issuances peaked on December 23, while critical notices peaked on December 24. One pipeline had compressor station outages that led to three force majeure issuances, affecting 93 firm shippers; another issued five force majeures from December 23 to 25 due to freezing-related compressor station outages, affecting 63 firm shippers.

182 Source: S&P Global Commod ty ns ghts, ©2023 by S&P Global nc.

Figure 52: Average of Normalized Line Pack Pressures For the 15 Interstate Pipelines Surveyed, December 20 – 26, 2022

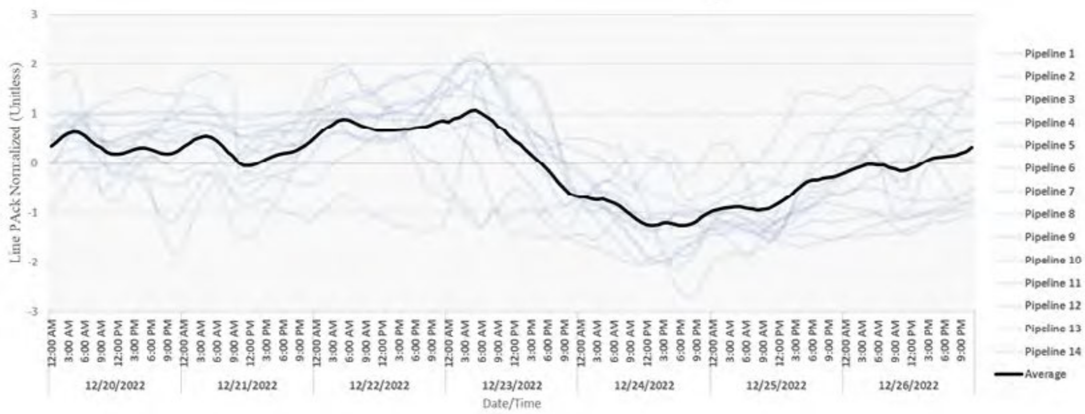


Figure 53: Interstate Natural Gas Pipeline Notices Issued, December 20 – 26, 2022

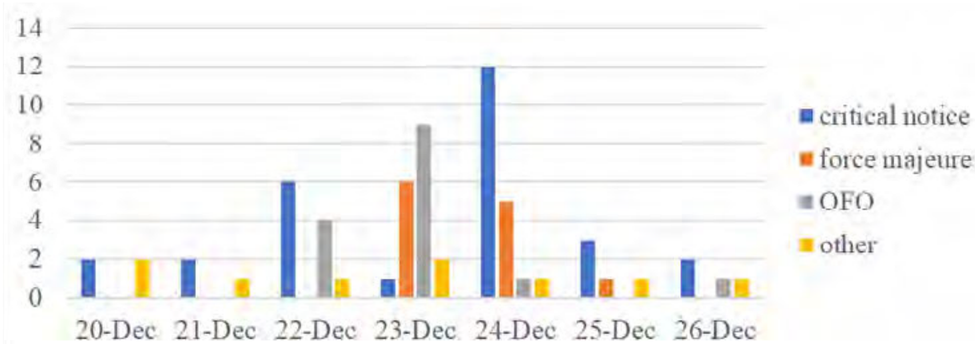
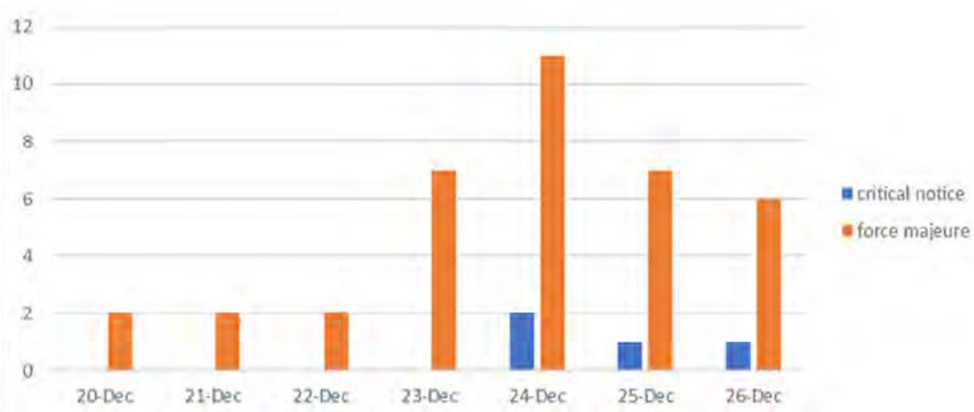


Figure 54: Ongoing Notices with Associated Flow Reductions, December 20 – 26, 2022



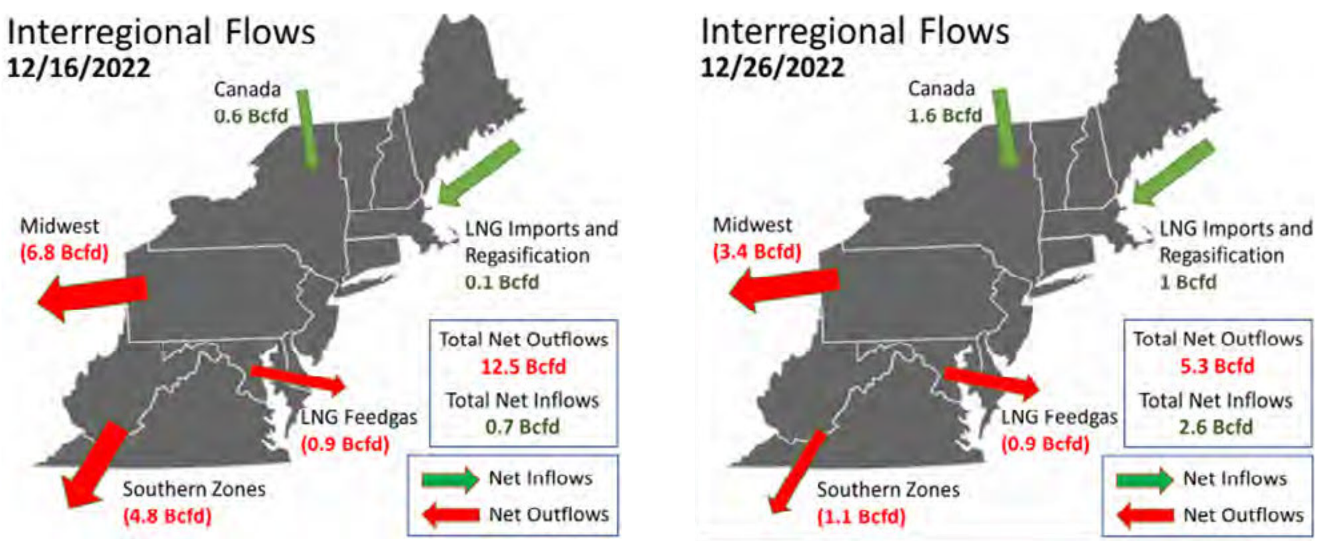
Low pipeline pressures caused by reduced gas supply entering pipelines combined with increased demand also resulted in issues at interstate pipeline interconnections with other pipelines, where shippers' gas supply quantities were inconsistent with shippers' confirmed nominations on the receiving pipeline; resulting in confirmed nominations that failed to align with the quantity of gas flowing. These issues caused imbalances between supply and demand at pipeline interconnection points, requiring some pipelines to implement scheduling restrictions and forcibly reduce previously confirmed nominations. The scheduling restrictions and forcible reduction of confirmed nominations may not have been necessary if non-performing shippers had acted to address their lack of performance. The pipelines had to contact those shippers repeatedly to find out how they planned to balance their gas flows and in some instances were unable to do so before it became necessary to implement scheduling restrictions and reduce nominations.

Several of the pipelines communicated with PJM or NYISO during the Event. These discussions allowed the pipelines to obtain useful information, for example, about PJM's load forecast or burn profiles for gas generators, and to share the performance of their systems and available capacity with the BAs. One pipeline provided PJM with a list of receipt points that were underperforming according to their nominated levels.[183]

2. INTERREGIONAL NATURAL GAS FLOW PATTERN CHANGES

As weather affected natural gas supply, demand, and pipeline operations, the movement of natural gas between regions in the eastern half of the United States changed. The Northeast region reduced outflows to neighboring regions and increased imports from Canada, while the Southeast region simultaneously increased outflows to the Midwest, decreased outflows through LNG exports, and had less access to Northeast supply.

Figure 55: Natural gas flows into and out of the U.S. Northeast region[184]



Since the dramatic growth of shale natural gas production in the Northeast began over a decade ago, the region has produced substantially more natural gas than it consumed, allowing for net outflows of

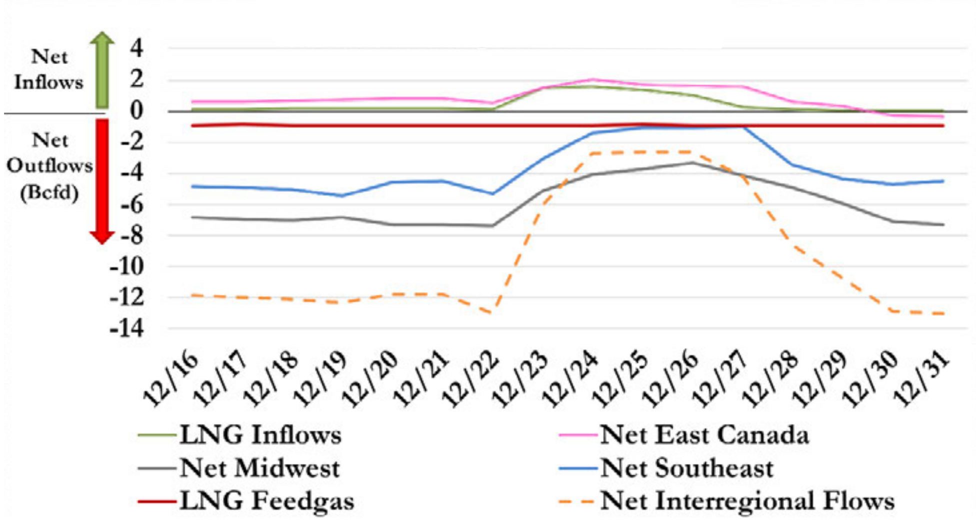
183 W nter Storm Ell ott h t on a hol day weekend. Th s created pressure on p pel nes' commun cat ons teams because of an ncrease n sh pper nqu r es due to the large volume of confirm ng party reduct ons they ssued. Th s requ red some of the p pel nes to call n vacat on ng staff.

184 Flow s ze arrows are approx mate. Reg on borders are general zed and may not reflect modeled p pel ne zones. Source: S&P Global Commod ty ns ghts, ©2023 by S&P Global nc.

natural gas to the south and west most of the time.[185] As seen in Figure 55 above, however, by the end of the Event, net scheduled outflows declined to just 5.3 Bcfd, compared to typical outflows of about 12.5 Bcfd (as measured a week earlier). The Northeast also typically sees substantial imports from Canada over the winter, and during the Event the Northeast increased its imports from Canada, with most of the LNG imports received coming from the Saint John LNG facility in New Brunswick, Canada. Net flows toward the southeast fell 4.8 Bcfd on December 16 to just over 1 Bcfd on December 26, which was the biggest portion of the reduction in total net outflows from the Northeast.

The change in flow patterns was not enough to change the Northeast into a net importer of natural gas, but, as seen in Figure 56 below, overall net outflows from the region reached a low of just under three Bcfd over the Christmas weekend. Flows did not return to their pre-storm levels of about 12 Bcfd, until December 30, 2022. Net outflows from the Northeast to the Midwest reduced by half during the Event as shippers in the Northeast kept more gas in-region and drops in production meant less gas was available after meeting Northeast regional demand. Cove Point LNG in Maryland consistently received flows for export throughout the Event, but also appears to have delivered significant volumes of natural gas back onto the pipeline system from its on-site storage at the same time.

Figure 56: Net Interregional Flows From the Northeast Over the Second Half of December 2023[186]



For the last decade, the Southeast region typically has received substantial net inflows, reversing the historic northwards flow direction on many of the major interstate pipelines. The Midwest market has in the recent past been supported by Northeast outflows, but during the Event Northeast outflows to the Midwest declined, creating room for flows from the Southeast. As a result, flows from the Northeast declined substantially while the Southeast increased net outflows to the Midwest. LNG feed gas demand declined, possibly due to higher supply costs for exporters that rely on spot purchases or difficulty in obtaining transportation capacity for exporters that use interruptible transmission. As seen in Figures 57 and 58 below, some

185 The data presented n th s sect on s based on scheduled ntraday Cycle 3 nom nat ons, wh ch may not reflect actual p pel ne flows due to rregular rece pts by sh ppers.

186 Source: S&P Global Commod ty ns ghts, ©2023 by S&P Global nc.

amount of LNG regasification occurred in the Southeast during the Event, likely at LDC storage facilities and possibly at some LNG export facilities.

Figure 57: Natural Gas Flows Into and Out of the U.S. Southeast Region[187]

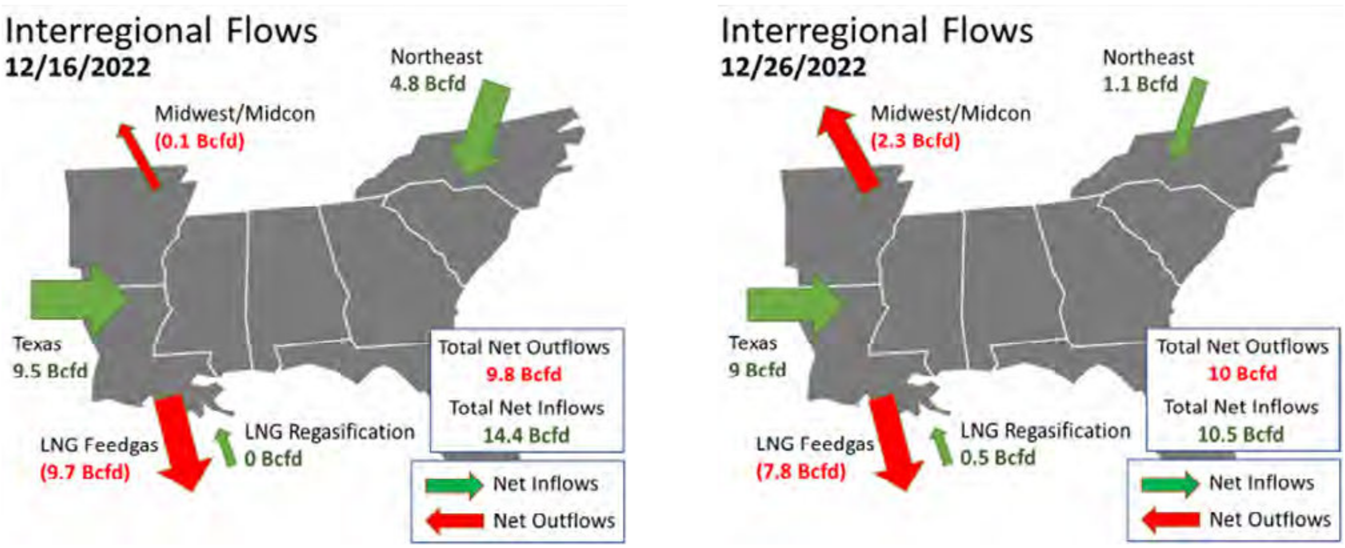
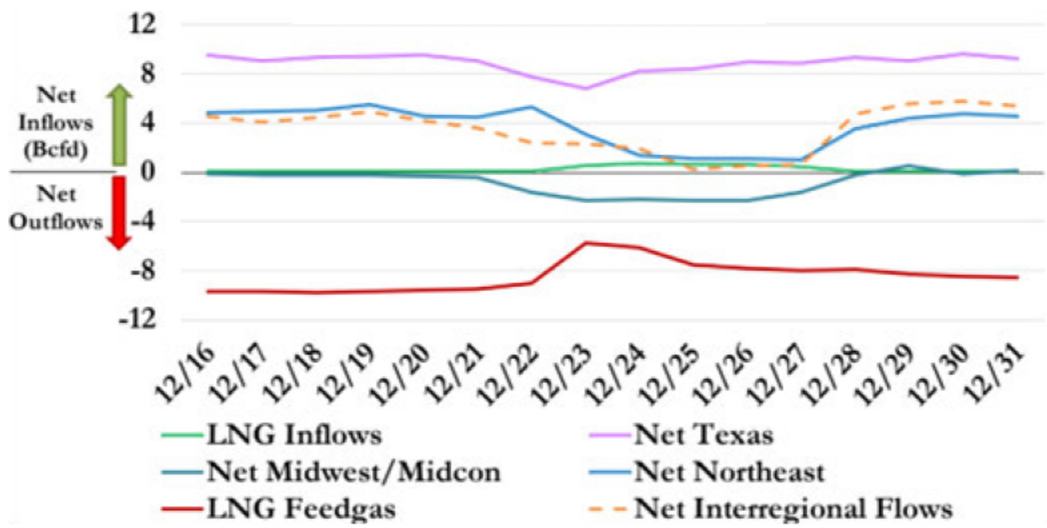


Figure 58: Interregional Flows from the Southeast over the second half of December 2023[188]



a. Storage Operations

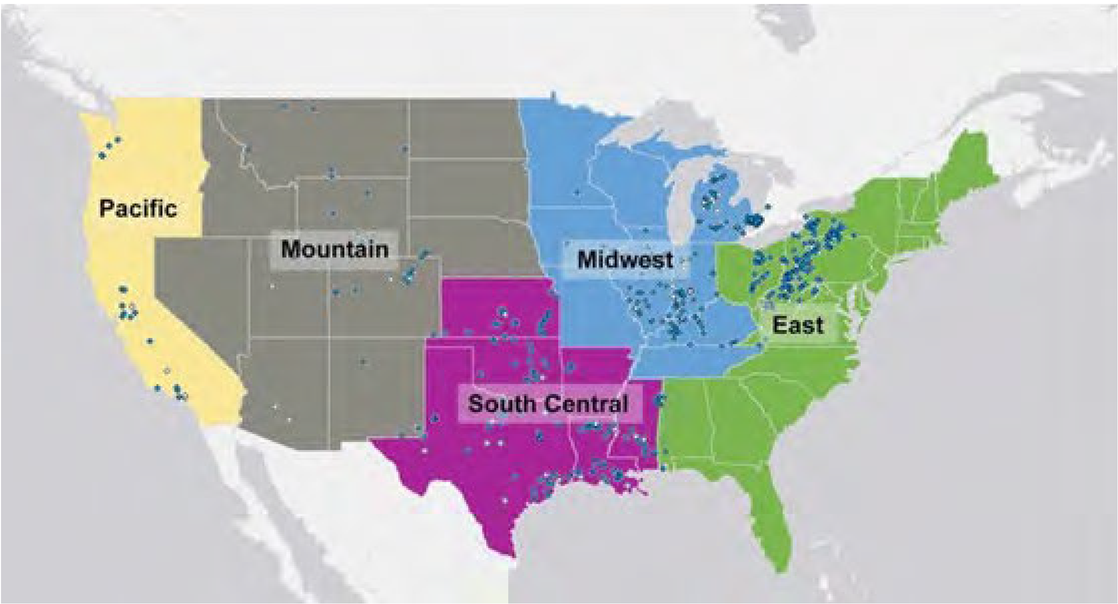
The U.S. Energy Information Administration (EIA) collects and provides weekly estimates of working gas volumes held in underground storage facilities in the lower 48 states and at five regional levels. EIA breaks down regions

187 Flow s ze arrows are approx mate. Reg on borders are general zed and may not reflect modeled p pel ne zones. Source: S&P Global Commod ty ns ghts, ©2023 by S&P Global nc.

188 Source: S&P Global Commod ty ns ghts, ©2023 by S&P Global nc.

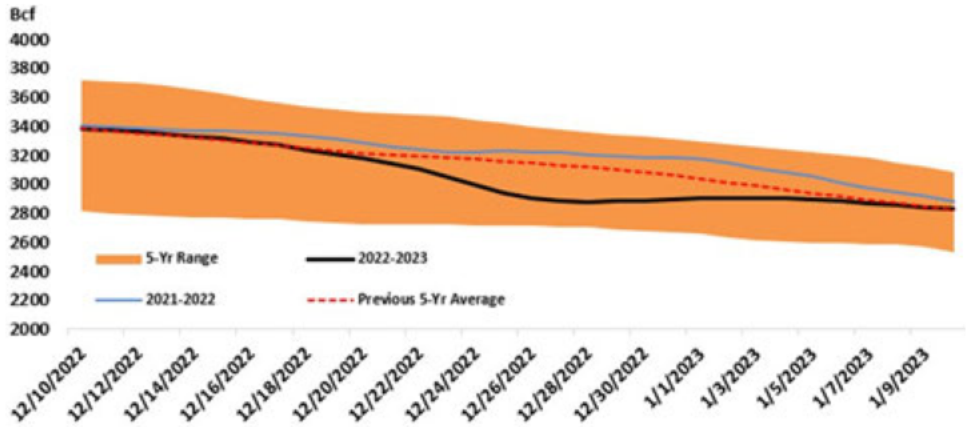
for natural gas storage into the Pacific, Mountain, Midwest, South Central, and East. These are geographically-defined regions and the storage fields are concentrated in the South Central, East, and Midwest regions (see Figure 59, below). Changes in these gas inventories on a weekly basis primarily reflect net withdrawals or injections.

Figure 59: Natural Gas Storage Field Regions of the U.S.



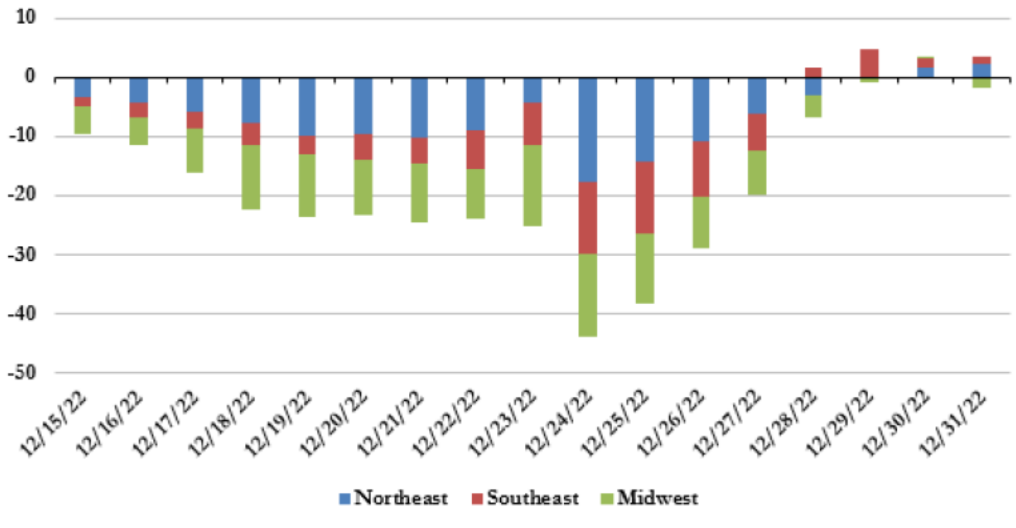
According to S&P Global Insights data there was a notable decline in inventory of stored natural gas during the Event, which reflected reliance on stored natural gas as natural gas production fell and demand increased. Although the natural gas storage levels did not dip below the lowest level reflected in the five-year range, they did dip below both the five-year average and levels seen the year before (see Figure 60, below). S&P uses different regions from EIA, which vary slightly in the Event Area (e.g., Ohio and Kentucky are in the Northeast, not the East, and there is no South Central, only Southeast, Texas and Midcon Producing (Oklahoma, Arkansas, and Kansas).

Figure 60: Natural Gas Storage Levels: November 18, 2022 – February 3, 2023, and Five-Year Average for Same Period[189]



The majority of withdrawals during the Event were in the South Central, Midwest, and East Regions (see Figures 61 and 62, below). Once the storm passed and temperatures rose, gas returned to storage and the South Central region experienced net positive injections. During the Event, 235 Bcf of natural gas was withdrawn from storage nationwide to meet the heightened natural gas demand, a 55.5 percent increase in withdrawals from storage as compared to the five days prior (December 16-21). Regionally, the three most affected regions of the Northeast, Southeast, and Midwest withdrew 160.0 Bcf of natural gas from storage, nearly 70 percent of all withdrawals from storage in the U.S.

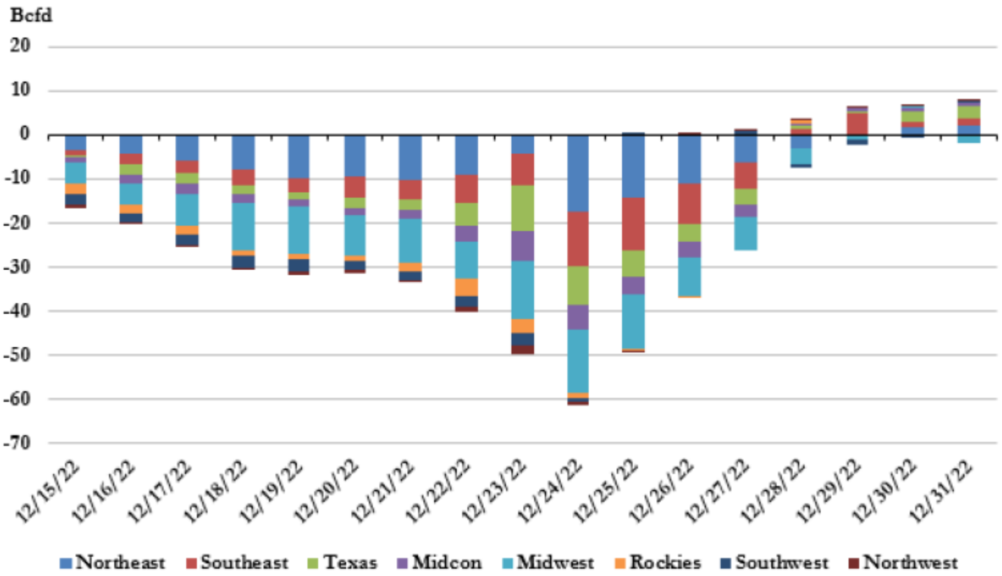
Figure 61: Natural Gas Storage Net Withdrawals From the Relevant Regions: December 15 – December 31, 2022[190]



189 Source: S&P Global Commod ty ns ghts, ©2023 by S&P Global nc.

190 F gures 61 and 62: source: S&P Global Commod ty ns ghts, ©2023 by S&P Global nc.

Figure 62: Natural Gas Storage Net Withdrawals in the U.S.: December 15 – December 31, 2022



c. Natural Gas-Fired Generating Units Faced with Loss of Interruptible Transportation, Inability to Find Sufficient Supply, and Force Majeure Cutoffs of Firm Transportation

The mismatch between the availability of gas and the demand from natural gas-fired generating units on December 23 and 24 had an immediate and substantial impact on generation. Natural gas-fired generating units that responded to inquiry data requests relayed their experiences in this period:

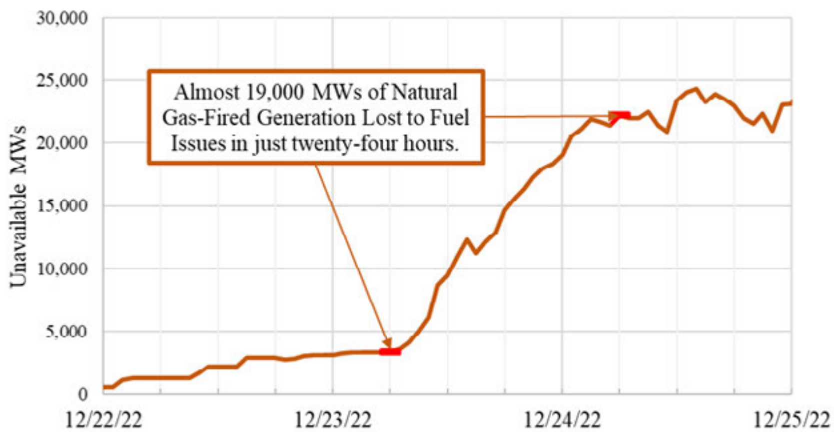
- A 300 MW+ fossil steam unit in SPP cut its generation in half early on December 23 because the gas supplier under its interruptible pipeline delivery arrangement was experiencing a supply limitation.
- An 800 MW+ combined cycle unit in PJM with a firm supply contract reported, on the morning of December 23, that it was forced to cease generating entirely because "gas fuel [was] unavailable."
- Four affiliated gas turbines in PJM, whose collective capacity was in excess of 800 MW, reported on December 23 that fuel unavailability due to market conditions had caused them to stop generating.
- Six centrally-located affiliated gas turbine units owned by a vertically-integrated utility, each with a capacity of nearly 200 MW, reduced their generation by more than 50 percent on the afternoon of December 23 because their pipeline was unable to provide the minimum delivery pressure to the units.
- In the late afternoon of December 23, a gas turbine located in PJM with nearly 200 MW capacity ceased generation because its gas supplier was unable to meet its needs under its firm pipeline delivery arrangement.

These individual narratives—just a handful of examples from many—illustrate the larger collective experience of natural gas-fired generating units during this critical period. On December 23 and 24, more than 41,700 MW of natural gas-fired generation reported outages, derates, or failures to start due to Fuel Issues. Figure 63, below lists the major sub-causes of Fuel Issues experienced by natural gas-fired generating units.

Figure 63: Gross Unavailable MW, Natural Gas Units Experiencing Fuel Issues, Top Sub-Causes, December 23-24, 2022

Fuel Issue - Sub-Cause[191]	December 23	December 24
nterrupt ble P pel ne Del very nterrupt on	6,268	5,485
Market ssues	5,173	9,913
F rm P pel ne Del very Curta lment	4,533	700
Gas Del very Pressure ssues	1,532	2,557
Market Pr ce Restr ct on	1,040	0
Fa lure to Fulfill F rm Supply Obl gat ons	972	2,852
Transportat on Schedul ng Constra nts	716	0
TOTAL	20,234	21,507

Figure 64: Incremental Unplanned Unavailable Generation in the Event Area, Natural Gas Units, Fuel Issues, December 22 - 25, 2022



There is a clear relationship between these outages and the system-wide struggle to obtain gas and maintain pressures described above. As illustrated in the below chart, there is a sharp upwards trend in net incremental natural gas-fired generation lost to Fuel Issues beginning the morning of December 23, just as pipelines began to experience supply shortfalls. As illustrated in Figure 64 above, starting that morning, and over the next 24 hours, nearly 19,000 MW of net incremental generation from natural gas-fired generating units were lost due to Fuel Issues.

d. Reliability-Threatening Delivery Pressure Decreases at Major Natural Gas LDC Citygate

Winter Storm Elliott greatly impacted the operations of Consolidated Edison Company of New York, Inc. (Con

191 The follow ng are descr pt ons of above sub causes: nterrupt ble P pel ne del very nterrupt on nterrupt ble p pel ne transportat on unava lable due to contractual or tar ff prov s on; Market ssues Market ssues other than h gh market pr ces, such as unable to purchase gas n short term market (could not find a gas suppl er n the market); F rm P pel ne Del very Curta lment F rm p pel ne gas transportat on curta led (reduct on of gas del ver es; Force majeure, P pel ne enforces ratable takes prov s on to tar ff levels); Gas Del very Pressure ssues Del vered gas pressure below Generator's m n mum operat ng pressure (e.g., pressure too low for generator to operate); Market Pr ce Restr ct on H gh market pr ces (chose not to purchase gas due to h gh market pr ces); Fa lure to Fulfill of Contractual Obl gat ons Fa lure of fuel suppl er to fulfill firm contractual obl gat ons (Sell ng counterparty fa ls to del ver firm gas to pr mary p pel ne rece pt po nt, force majeure on the supply); Transportat on Schedul ng Constra nts Transportat on schedul ng constra nts due to Hol day schedule (less gas scheduled than needed).

Edison),[192] the natural gas LDC for Manhattan, The Bronx, and portions of Queens and Westchester County, NY. On Christmas Eve morning, the five interstate natural gas pipelines serving Con Edison began experiencing drops in pressure at Con Edison's citygate due to production losses and operational issues. The pressures declined precipitously and at noon, the pipelines informed Con Edison that they had exhausted their line pack and storage withdrawals, and pressures would not improve until demand decreased. Con Edison managed to supply its customers with gas and maintain necessary pressure, by declaring an internal Gas System Emergency and implementing its specification for "Limiting Gas Use and Load Shedding During a Supply Curtailment or Emergency." As part of the Gas System Emergency, Con Edison activated its LNG regasification plant.

Had Con Edison's citygate pressures not recovered, it was in danger of losing pressure on, or needing to cut service to, all or large portions of its system. Even losing service to 130,000 customers would be considered a major outage and could have taken five to seven weeks to restore, depending on the availability of mutual aid. Had it lost the majority of its system, over a million customers in New York City and nearby areas would have been unable to heat their apartments and houses while the outside temperature was in the single digits, for months. Moreover, a system-wide outage would likely have caused extensive property damage due to damaged water pipes within homes and buildings. Critically, these dire circumstances occurred despite Winter Storm Elliott not qualifying as a "design day" event. LDCs designate certain parameters for "design day" events to plan gas capacity requirements, and a "design day" reflects the highest gas demand that the LDCs expect to be obligated to serve on an extremely cold winter day. The actual average temperatures on December 23 and 24 in the Con Edison service territory were 17 and 15 degrees, respectively. By contrast, Con Edison's design day is based on a zero-degree temperature variable.[193]

On December 16, Con Edison began to prepare for Winter Storm Elliott, including communicating with relevant stakeholders to coordinate in preparation for the storm. In addition to standard daily communications, weather event coordination efforts began on December 19 between Con Edison, National Grid, and Pipeline Control from Enbridge, Inc. (Texas Eastern Transmission, LP ("Texas Eastern") and Algonquin Gas Transmission, LLC ("Algonquin")) (collectively, "Enbridge"), Williams Companies Inc. (Transcontinental Gas Pipe Line Company, LLC) ("Williams"), and Iroquois Gas Transmission System, L.P. ("Iroquois") to discuss upcoming weather patterns and event preparation plans specific to the New York City market area.

On December 21, Con Edison notified its interruptible customers that they were being curtailed and issued OFOs. Additionally, due to colder trending forecasts and overlapping restrictions with Kinder Morgan Inc. (Tennessee Gas Pipeline Company, LLC), Con Edison activated its compressed natural gas (CNG) station and scheduled it to capacity. As the storm worsened, Con Edison issued additional curtailment notices to customers with dual-fuel interruptible and off-peak firm sales and transportation covering December 23 through 27. Also on December 23, Con Edison placed its liquid natural gas facility on stand-by. On December 24 Con Edison

192 Con Ed son and ts aff l ated compan es ma nta n a portfol o of contracts w th vary ng lengths of exp rat on and flex b l ty. The compan es have entered nto supply agreements that are des gned to prov de rel able serv ce to firm natural gas customers under des gn day w nter cond t ons n the serv ce areas. These contracts nclude firm gas supply (100 percent domest c or LNG), firm p pel ne transportat on, product on area and market area storage, firm peak ng serv ces, LNG, and c tygate baseload suppl es. Con Ed son had contracted for more nterstate p pel ne capac ty and natural gas commod ty than requ red to meet customer demand on December 24.

193 Con Ed son uses a weather concept called "Temperature Var able" (TV) as a reference po nt n the weather adjustment process. The TV s used n calculat ng and forecast ng future system peak demands, cons der ng extreme w nter weather cond t ons (susta ned low temperatures over two Gas Day per ods). The gas day average (GDA) temperature s a 24 hour ar thmet c average start ng at 10 a.m. us ng the Central Park Nat onal Weather Stat on dry bulb temperature. The formula for calculat ng the system TV on a da ly bas s ncorporates two days' worth of GDA's. The current day's GDA s we ghted at 70 percent and the prev ous day's GDA at 30 percent.)

issued OFOs that restricted short positions to two percent of gas scheduled through the Event and began hourly transportation restrictions to 1/24th of schedule. At this time, all of Con Edison's upstream interstate pipelines had imbalance OFOs in place restricting the availability of unscheduled gas. Con Edison's upstream pipelines also began reporting various issues including operating constraints, receipt points underperforming, upstream low pressures, compressor station issues, force majeure, and maxed out line pack.

The Con Edison system performance continued to be within expected operating ranges through December 23. Despite interstate pipeline pressures beginning to fall at Con Edison's metering and regulating stations (which measure and control the pressure of gas and interconnect with interstate pipelines), the impacts on supply to Con Edison were within normal expectations through the morning of December 24. However, for the Intraday 1 (ID1) nomination cycle on December 24, interstate pipelines began to restrict underperforming meters. At that time, Con Edison was not notified of the specific reason for pipeline restrictions or reductions by marketers or producers. Due to the reduced supply and continuing high demand, the average meter station inlet pressure (reflecting the interstate pipelines' low pressure issues) for Con Edison declined rapidly and reached its lowest levels between the nomination deadline and scheduling for the December 24 ID1 cycle from 11:00 a.m. to 2:00 p.m. ET. The average pressure fell from 806 pounds per square inch gauge (psig) at 12:00 a.m. on December 23 to 441 psig at 2:00 pm on December 24. Con Edison Gas Control began implementing emergency measures after the interstate pipelines notified Con Edison that they had depleted their line pack, had no more ability to withdraw from storage, and would continue to have low interstate pipeline pressures until demand decreased. A likely contributing factor exacerbating pipelines' integrity issues was that some generators may have flowed in excess amounts over their confirmed nominations. The pipelines used line pack and gas from storage to meet the incremental demand, but as the Event progressed, the supplementary demand volumes in conjunction with continuing supply shortfalls led to low pressures and the reduction of confirmed nominations. Con Edison, given its downstream location near the end of the interstate pipelines, was disproportionately impacted by the deteriorating pipeline conditions, through no fault of its own.

e. LDC Gas System Emergency, Orders for Fuel Curtailments to Natural Gas-Fired Generation, and Public Appeals to Reduce Gas Demand

On December 24 at 1:26 p.m., Con Edison management declared an internal Gas System Emergency and dispatched its LNG facility, which ramped up to maximum dispatch, because the interstate pipelines serving Con Edison's citygate said that their pressures were not recovering. Later that day, at 2:14 p.m., Con Edison Gas Control declared Gas System Condition Red, which meant that "gas supply through gate station(s) . . . [was] . . . severely limited or completely interrupted resulting in imminent risk to more than 500 services." This Condition Red remained in place until December 26 at 10 a.m. In accordance with its "Guidelines for Major Contingencies on the Gas System" specification, Con Ed "order[ed] electric and steam generation stations to . . . completely curtail gas use." Con Edison had already dispatched its LNG Plant at 2 p.m., another step allowed under Gas System Condition Red. At 6:30 p.m. that evening, Con Edison issued a public appeal to reduce demand. Under the specification for Limiting Gas Use and Load Shedding During a Supply Curtailment or Emergency, Con Edison had 11 steps to mitigate a supply shortage or to limit gas during an emergency, which progresses from taking steps to increase the supply of natural gas to firm customer load shedding. Con Edison implemented actions through at least step 7, public appeals to reduce demand, before the Gas System Emergency abated. Figure 65 shows the average meter station inlet pressure on December 21-27, relative to the declaration of the Gas System Emergency and Gas System Condition Red. Figure 66, below, shows how the meter station inlet pressures for the five interstate pipelines serving Con Edison's citygate declined precipitously on Christmas Eve, before recovering on Christmas through December 27.

Figure 65: Con Edison Average Meter Station Inlet Pressure (PSIG), December 21 - 27, 2022

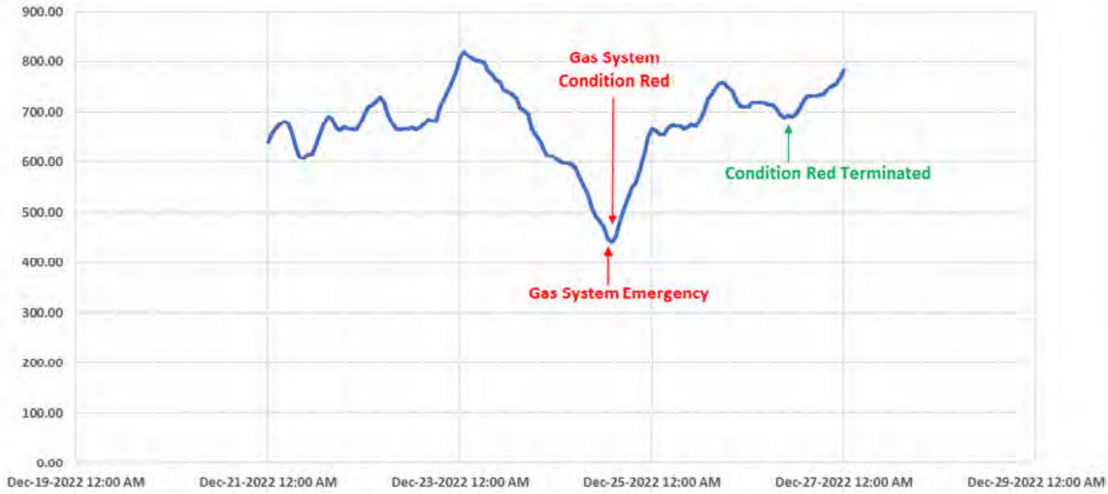
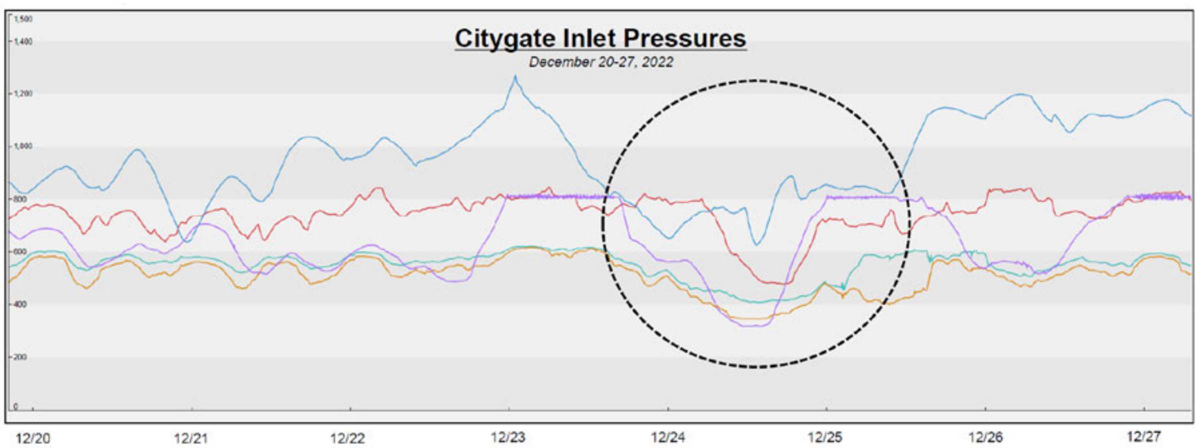


Figure 66: Con Edison Citygate Inlet Pressures, December 20 - 27, 2022



Efforts to address the situation continued on Christmas Day. Con Edison ramped down its LNG facility due to increasing pipeline pressures at its citygate and to preserve asset inventory, placing the LNG facility back on standby status at 8:13 a.m. Pressures at the citygate were recovering but the pipelines reported in a 7 a.m. call that line pack was still depleted. On December 26, Con Edison finally terminated its Gas System Condition Red.

C.Post-Event Actions by Affected Entities, Government Agencies and State Governments

1. ACTIONS BY AFFECTED ENTITIES

Several of the affected entities later conducted comprehensive reviews of the performance of their systems during Winter Storm Elliott. TVA created an "After Action Report" which included several recommendations to improve energy supply, real-time load forecasting and operations, emergency protocols, and customer and stakeholder engagement.[194] TVA has committed to adding 10,000 to 14,000 MW of new generation by 2030 to help meet demand. It is currently in the process of building 3,800 MW of new generation, including solar energy, energy storage, combustion turbines, and combined-cycle natural gas. It is also investing in infrastructure, enhancing its transmission systems, and building a new Systems Operations Center.[195]

PJM prepared an "Event Analysis and Recommendation Report," outlining the lessons learned from Winter Storm Elliott and improvements it plans to make.[196] These included improving generator performance, enhancing forecasting and modeling, and tackling long-standing gaps in gas-electric coordination. PJM is working on developing improvements through its Critical Issue Fast Path stakeholder process. PJM recently submitted proposed enhancements to the capacity market rules that address certain recommendations from its report, including, but not limited to, enhanced risk modeling, refined resource accreditation, updates to the balancing ratio, and changes to bonus eligibility for Demand Resources and Energy Efficiency Resources.[197]

LG&E/KU prepared two event summary reports, one for its Generation, Transmission and Distribution operations, and one for its Gas operations. It is looking at potential process improvements, such as public messaging and projects at plants to minimize valve freezing and other cold weather impacts.[198] Santee Cooper developed a historical average forced outage rate for units during extreme events to estimate how much additional reserves should be considered during this type of event.

2. ACTIONS BY GOVERNMENT AGENCIES AND STATE GOVERNMENTS

On August 25, 2023, the South Carolina Office of Regulatory Staff filed a report titled "Inspection and Examination Report of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC: December 2022 Winter Storm Outages and Blackouts."[199] The report identified five key causes for the rolling outages (firm load shed), which impacted over 500,000[200] customers across North and South Carolina, ranging from three to ten hours each: (1) Duke[201] significantly underestimated demand, failed to update its forecast estimates, and did not make

194 Tennessee Valley Author ty After Act on Report, at 20 21, https://blox mages.newyork1.v p.townnews.com/local3news.com/content/tncms/assets/v3/ed tor al/4/3e/43e4b436 eb67 11ed a87a 530b1c4c2bd9/645537f5cd9d7.pdf.pdf).

195 *Id.* at 22.

196 PJM, W nter Storm Ell ott Event Analys s and Recommendat on Report ("PJM Report"), pages 2 3, https://www.p m.com/ /med a/l brary/reports not ces/spec al reports/2023/20230717 w nter storm ell ott event analys s and recommendat on report.ashx .

197 *See PJM Interconnection, L.L.C.,* Docket No. ER24 98 000 (Oct. 13, 2023); *PJM Interconnection, L.L.C.,* Docket No. ER24 99 000 (Oct. 13, 2023). PJM has stated that t w ll cont nue to engage w th stakeholders on recommendat ons from the PJM Report.

198 *Talking Points*,https://lge ku.com/employee resources/ce/talk ng po nts/2023/01/w nter storm ell ott (last v s ted Oct. 26, 2023).

199 nspect on and Exam nat on Report of Duke Energy Carol nas, LLC and Duke Energy Progress, LLC December 2022 W nter Storm Outages and Blackouts, Docket No. ND 2023 1 E (Aug. 25, 2023), ec372380 8639 406e 816e fc9fe0d45cfd (sc.gov)

200 https://news.duke energy.com/releases/duke energy updates north carol na ut l t es comm ss on on w nter storm ell ott emergency outage event#:~:text CHARLOTTE%2C%20N.C.%20%E2%80%93%20Leaders%20from%20Duke,from%20occurr ng%20that%20way%20aga n

201 DEC and DEP.

supply planning adjustments; (2) Duke experienced multiple failures at various plants, some due to planned maintenance and others due to operational issues that forced them to shut down, such as cracks in the insulations and frozen instruments; (3) power purchases from neighboring utility companies were curtailed; (4) power generation contracted by other utilities failed; and (5) the automated software tool to manage the rotating outages failed, causing significant delays as Duke had to manually restore power. The report also discussed Duke's delay in communicating with customers. The outages began between 6:15 and 6:25 a.m. on December 24. The report found Duke began notifying customers one hour later. The investigation also found Duke told customers the timeframe for power restoration would be 30 to 60 minutes, when in fact it took several hours.

Ultimately, the report found that there is "room for improvement" in Duke's cold weather preparedness plans for its generation facilities. The investigation made several recommendations, including ensuring that doors and louvers that could expose equipment to the elements are left closed, and installing heaters. The investigation also recommended Duke enhance staffing and the frequency of operators making rounds during severe winter weather events. On August 29, 2023, Duke submitted a letter[202] to the Public Service Commission responding to the report, which took issue with several of its findings, including with the report's statement that Duke failed to respond to supply adequacy risk, asserting that Duke did respond and made purchases to increase operating reserves where they were forecasted to be below target. Duke also said that the models used by the industry to forecast power demand "look backwards in time" for similar circumstances, and that a similar day in December did not exist. However, the letter stated that Duke has created a corrective action plan, and that it has completed 76 of the 101 action items in the plan, with the action items in progress.

The Kentucky Public Service Commission has been using a preexisting docket regarding approval of a demand side management plan and approval of fossil fuel-fired generating unit retirements to obtain data from LG&E/KU regarding the Event, but has not issued any findings.[203] On February 17, 2023, the Kentucky Attorney General sent LG&E/KU an initial request for information.[204] The inquiry asked the companies to "[p]rovide a detailed, thorough and comprehensive explanation regarding the causes of the rolling blackouts [firm load shed] the Companies instituted during Winter Storm Elliott[…]." On March 10, 2023, LG&E/KU provided their responses to the initial data requests.[205] This included a summary of events prepared by LG&E/KU.[206] In this summary, the companies stated that the rolling blackouts were caused by interstate gas pipeline pressure limitations, mechanical issues, and other cold weather issues. The companies explained that the projected net peak load was far lower than the actual peak load on December 23. Three of the companies' units were offline during this time and not expected to be needed. The supplier for two of the plants also failed to meet its contractual obligations, and there were interruptions in energy deliveries. LG&E/KU explained that as the conditions across the regional grid began to deteriorate, they executed their Capacity and Energy Emergency Operating Plan in order to restore system balance.

202 36b057d1 aba3 47d5 9bbe 4a9f2d4fbb0f (sc.gov)

203 The record was closed as of September 15, 2023, and the Comm ss on stated that t w ll ssue a dec s on after October 5, 2023. The docket d d not show a dec s on as of the morn ng of October 30. *Winter Storm Elliott Events in the LG&E and KU Balancing Authority Area (BAA)*(Dec. 24 25, 2022), https://psc.ky.gov/pscecf/2022 00402/r ck.lovekamp%40lge ku.com/03102023103319/03 AG DR1 LGE KU Attach to Q13%28l%29 Att 1 W nter Storm Ell ott LKE Event Summary.pdf.

204 *Kentucky Coal Association First Data Request (filed Feb. 17, 2023)* https://psc.ky.gov/pscecf/2022 00402/mmalone%40hdmfirm.com/02172023095137/F rst Data Requests to Compan es.final.pdf; *Attorney General Data Requests* (Feb.17, 2023), https://psc.ky.gov/pscecf/2022 00402/rate ntervent on%40ky.gov/02172023023845/23..02.17 AG DR 1 2022 00402 F NAL.pdf.

205 *Kentucky Utilities Co. & Louisville Gas and Electric Co. Response* (Mar. 10, 2023),https://psc.ky.gov/pscecf/2022 00402/r ck.lovekamp%40lge ku.com/03102023103319/02 AG DR1 LGE KU Responses.pdf.

206 *Winter Storm Elliott Events in the LG&E and KU Balancing Authority Area* (BAA) (Dec. 23 24, 2022), https://psc.ky.gov/pscecf/2022 00402/r ck. ovekamp%40 ge ku.com/03102023103319/03 AG DR1 LGE KU Attach to Q13%28 %29 Att 1 W nter Storm E ott LKE Event Summary.pdf.

IV. ANALYSIS AND FINDINGS

A. Overview of Event Causes

Three causes accounted for 96 percent of the generating unit outages, derates or failures to start, based on number of MW: Mechanical/Electrical, Freezing, and Fuel Issues, as shown in Figure 67. Natural Gas Fuel Issues, (the larger portion with small dots in the orange pie segment) were 20 percent of all causes (and 83 percent of outages caused by Fuel Issues).[207] Figure 68, below, illustrates the generating unit outages by fuel type over the course of the Event. Natural gas-fired units represented 47 or 63 percent of the incremental unplanned generation loss, based on number of outages or MW, respectively.[208] Unplanned outages of natural gas- and coal-fired generating units began to rise on December 22 and rose steadily into December 23. Early on December 23, the rate of outages of natural gas-fired generating units rose sharply, and this trend continued throughout December 23. This is consistent with what Balancing Authorities told the Team, especially in PJM and MISO: that multiple natural gas-fired generating units reported their inability to perform during that period, in many cases, only when called to find out why they had not come online.[209] Natural gas-fired generating unit outages peaked at nearly 60,000 MW for the Event Area by midday on December 24. Natural gas-fired generating units played such a large role in the Event due to the large percentage of natural gas-fired generation in the Event Area (nearly 42 percent, see Figure 11), and the multiple outage causes which affected this fuel type (Fuel Issues, Freezing Issues and Mechanical/Electrical Issues not directly caused by freezing). According to the NAESB Report, "trends in electrification coupled with the growth in renewable resources and the retirement of coal-fired generation, likely mean there will be a greater reliance upon electricity produced by natural gas as a balancing resource."[210]

Freezing Issues caused 31 percent of all generating unit outages, and over 75 percent of Freezing Issues occurred at ambient temperatures that were above the GOs' documented operating temperatures.[211] Both open-frame generating units, common throughout the south, and natural gas production infrastructure, with its associated water, are known to be vulnerable to freezing. In addition, wind turbines are known to be vulnerable to blade icing because of freezing precipitation. Coal-fired units can be vulnerable to frozen coal piles or difficulty processing wet coal, especially if the coal piles remain undisturbed during periods of freezing precipitation.[212] The extent to which generating units of all types still experienced outages, derates and failures to start to Freezing Issues continues to be a major concern. Freezing Issues and Fuel Issues combined to cause 55 percent of all unplanned generating unit outages, derates and failures to start during the Event, as shown in Figure 67 below (as measured by MW). Mechanical/Electrical Issues, responsible for an additional 41 percent of outages, derates and failures to

207 Natural Gas Fuel ssues nclude the comb ned effects of decreased natural gas product on; cold weather mpacts and mechan cal problems at product on, gather ng, process ng and p pel ne fac l t es result ng n gas qual ty ssues and low p pel ne pressure; supply and transportat on nterrupt ons; curta lments and fa lure to comply w th contractual obl gat ons. Add t onally, t ncludes sh ppers' nab l ty to procure natural gas due to t ght supply, proh b t ve, scarc ty nduced market pr ces, or m smatches between the t m ng of the natural gas and energy markets.

208 Unless otherw se nd cated, w th n th s sect on values expressed as percentages correspond to the total amount of ncremental generat on lost   *i.e.* unava lable MW   as reflected n data prov ded by generat ng un t owners and/or operators. *See* Append x C.2 for a breakdown of outages, derates and fa lures to start by fuel type, among other analyses.

209 *See* Sect on   .B.1.a) regard ng M SO and PJM exper ences regard ng generator reported fuel ssues on December 23.

210 NAESB Report at 67.

211 *See* note 61 for an explanat on of the var ous methods GOs can choose to document an operat ng temperature and how the Team calculated th s stat st c.

212 Th s can be m t gated by cont nuous movement of the coal p le (us ng bulldozers or s m lar equ pment) dur ng freez ng prec p tat on/extreme cold weather cond t ons.

start, also increased as temperatures fell and decreased as temperatures rose, but unlike Freezing Issues, the method by which the cold affected the generating unit was less obvious.

Figure 67: Total MW Loss of Incremental Generation Outages, Derates, and Failures to Start (Outaged MW) by Cause, December 21-26, Total Event Area

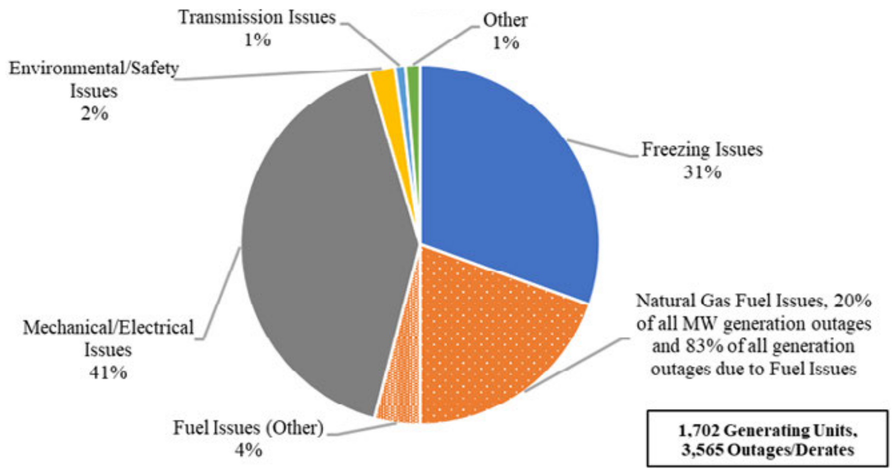


Figure 68: Generation Outages, Derates, and Failures to Start (MW) by Fuel Type, December 21-26, Total Event Area

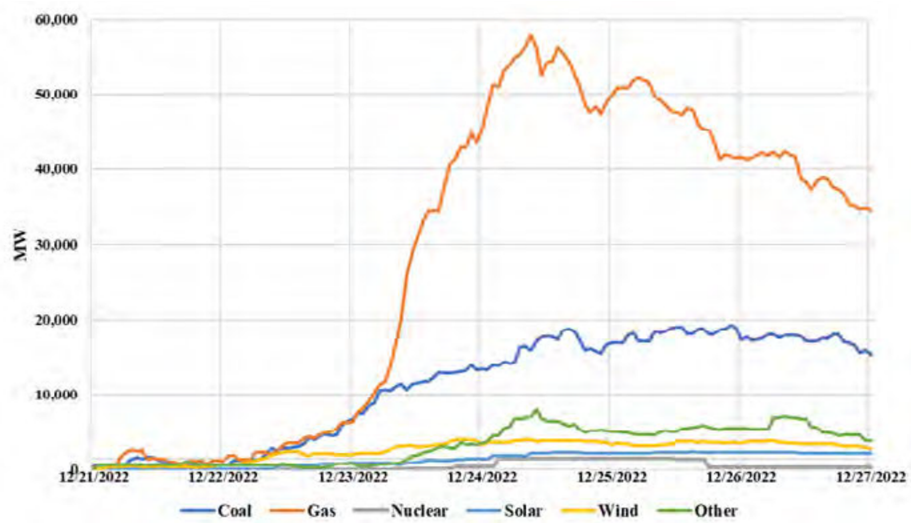
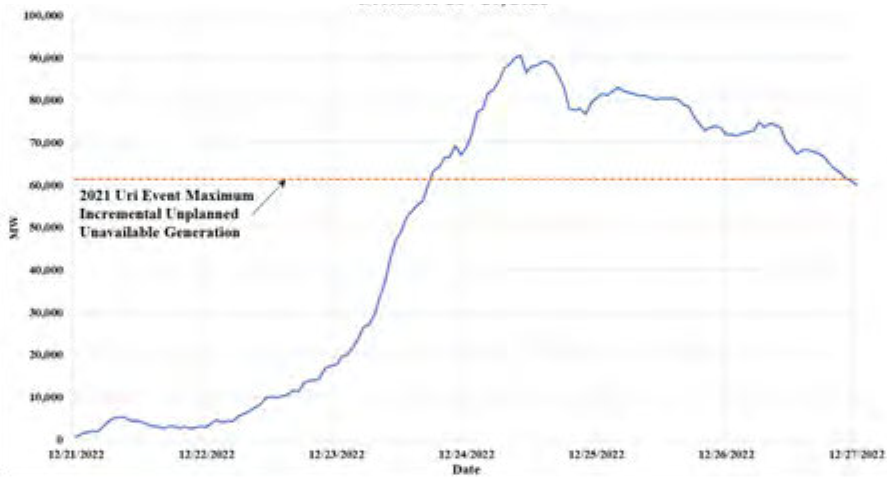


Figure 69: Incremental Unplanned Coincident Unavailable Generation in the Event Area, December 21-26, Total Event Area



At its worst point, the U.S. portion of the Eastern Interconnection had over 127,000 MW of generating outages, including outages that began before the Event, equivalent to **18 percent** of the U.S. portion of the anticipated resources in the Eastern Interconnection.[213] The peak coincident incremental unplanned unavailable generation in the Event (90,500 MW), as shown in Figure 69, above, was roughly 50 percent larger than the peak magnitude of coincident incremental unavailable generation during Winter Storm Uri (represented by the red dotted line in Figure 69), although the Uri event lasted more than twice as long (13 days versus six days).

213 Accord ng to the NERC 2022 2023 W nter Rel ab l ty Assessment. *See* note 12.

B. Causes of Generating Unit Outages During the Extreme Cold Weather

1. SUMMARY

An analysis of the data collected in connection with Winter Storm Elliott reiterates the relationship between the onset of freezing temperatures and the rise of generation loss caused by Freezing Issues, by Mechanical/Electrical Issues strongly correlated to declining temperatures, or by Fuel Issues whose root cause can be traced to the onset of extreme cold weather, as shown in Figure 70, below.

Winter Storm Elliott, and its impact on generation, is notable for two material reasons.

First, the scale of generation lost during Winter Storm Elliott is unprecedented, with a peak incremental unplanned generation loss totaling 90,500 MW. This reflects generation loss at 1,702 individual generating units spread over 3,565 discrete unplanned outages or derates. This incremental unplanned generation loss during Winter Storm Elliott, after the catastrophic effects of Winter Storm Uri just one year earlier, raises a concerning alarm about the ability of the grid to handle extreme cold weather events.

Second, Mechanical/Electrical Issues related to extreme cold weather events (as distinguished from Freezing Issues) rose as temperatures fell, a pattern seen in every extreme cold weather inquiry event since 2018. The 2021 Report noted that as temperatures fell, generation losses attributed to Mechanical/Electrical Issues increased[214] and that "[i]n the 2018 event, a similar pattern was evident—the total generating unit outages were correlated with temperatures—again, as temperatures fell, the incidence of unplanned outages and derates increased."[215] As reported in the 2021 Report, these outages may be caused by the impact of extreme cold weather on mechanical and thermal stress, thermal cycling fatigue and other effects of cold weather such as embrittlement and gelling of fuels and lubricants.[216]

2. MECHANICAL AND ELECTRICAL ISSUES

a. Summary Analysis

Overall, generating units reported 1,418 unplanned outages, derates or failures to start for various reasons linked to Mechanical/Electrical Issues – accounting for 40 percent of all generation losses reported during the Event and peaking at more than 31,000 MW of incremental unplanned generation loss during the Event. Most manifested as forced outages (48 percent) or forced derates (43 percent).

Within the Mechanical/Electrical Issues category, the most significant individual sub-cause of outages was Equipment Failures/Issues by a wide margin (72 percent). Other than Equipment Failures/Issues, the only other sub-cause within the Mechanical/Electrical Issue category that had a material presence (approximately 10 percent) was Control System Issues. No other single sub-cause identified by GOs/GOPs materially contributed to lost generation attributable to Mechanical/Electrical Issues.

b. Relationship Between Freezing Conditions and Mechanical/Electrical Issues

As indicated in Figure 71, below, over 80 percent of the incremental unplanned MW lost to Mechanical/Electrical Issues occurred when generating units began to experience below-freezing temperatures.

214 *See* Recommendat on 11 and F gure 105 n 2021 Report.

215 *See* 2021 Report at 217.

216 *See* 2021 Report at 215 217.

Figure 70: Incremental Unplanned Unavailable Generation in the Event Area, Primary Event Causes, December 21 - 26, 2022

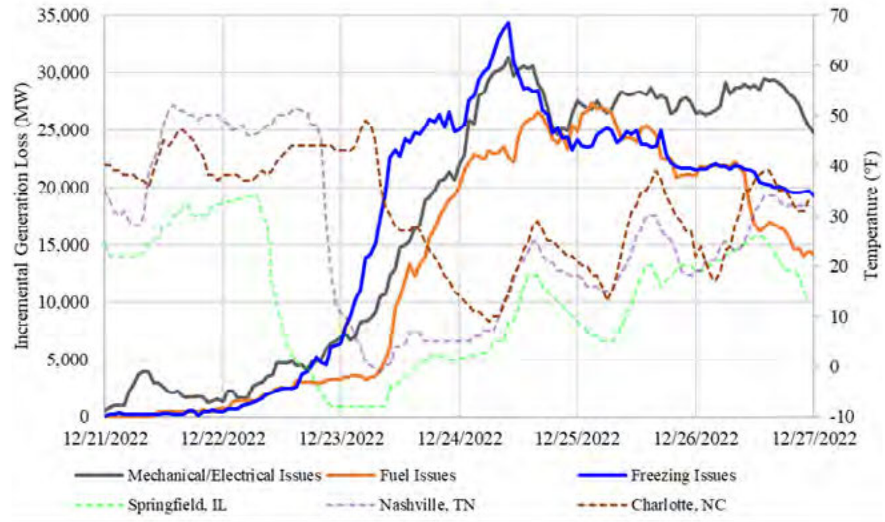
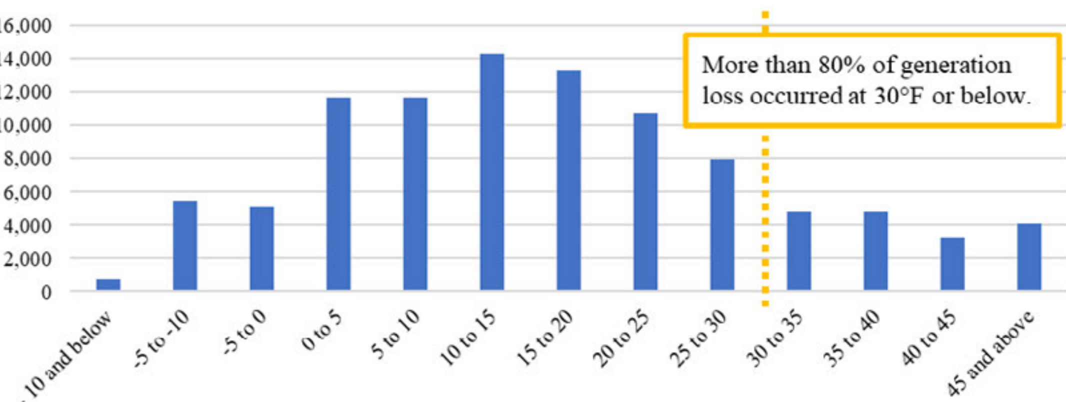
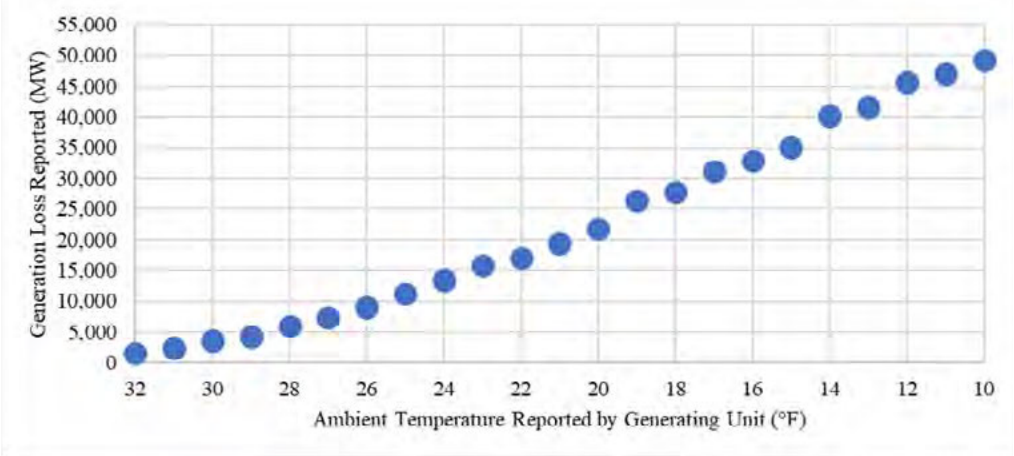


Figure 71: Generation Loss, Mechanical/Electrical Issues by Temperature (°F) Reported at Time of Outage, December 21-26 2022



As illustrated below, generating units steadily lost generation due to Mechanical/Electrical Issues as temperatures declined. In aggregate, generating units reported more than 49,000 MW of lost generation due to Mechanical/Electrical Issues in temperatures between 32 degrees and 10 degrees, as seen in Figure 72, below.

Figure 72: Cumulative Gross Generation Loss, Mechanical/Electrical Issues by Temperature (°F) Reported by Generating Unit, December 21-26, 2022

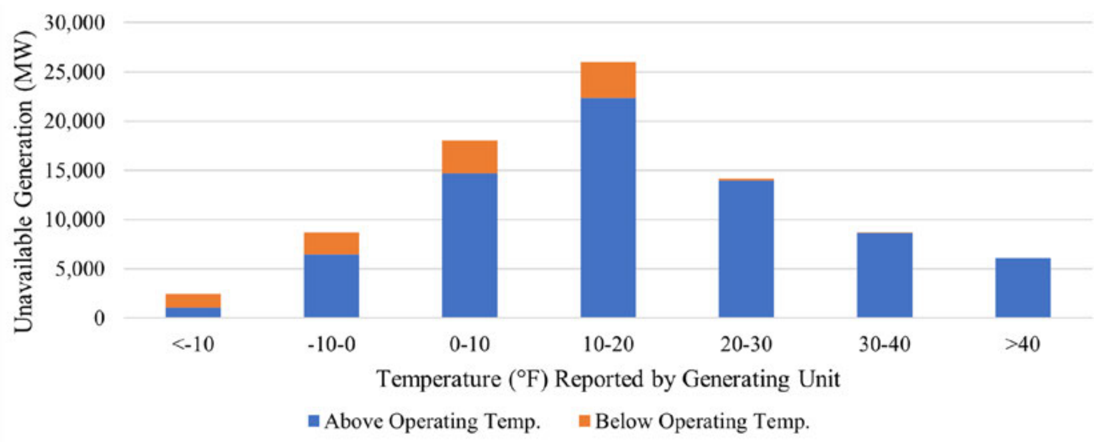


Not every generating unit that experienced a Mechanical/Electrical Issue in below-freezing conditions during Winter Storm Elliott did so *because of* extreme cold weather conditions. The Team believes it is reasonable to conclude that a material portion of Mechanical/Electrical Issues are causally connected to these extreme cold weather conditions. This relationship is supported by reasonable inferences drawn from the numerical data provided by generating units, as well as by narrative responses provided by units explaining their Mechanical/Electrical Issues. Some units that reported Mechanical/Electrical Issues in below-freezing conditions explicitly linked those Mechanical/Electrical Issues to the impacts of cold weather. For example, one generating unit reported that generation was lost because "[g]enerator gas temperature became too low due to ambient temperature." Another claimed that the generating unit "would not start due to oil temperature too low." However, even without considering these explicit claims, many units reported a range of issues that Team members believe, based on their review of the data provided, were likely or probably caused by cold weather conditions. For example:

- Increased oil viscosity with colder ambient temperature (or colder cooling water) was a common issue in the Event:
  - Losses in fuel oil pressure can be caused by cold-induced high viscosity, leading to inability to operate a unit on fuel oil.
  - Wind turbine generators may also suffer from high oil viscosity (lubricant or hydraulic controls), creating pitch problems seen in the Event.
- Many generating units reported material dimensional changes (*i.e.,* shrinkage) during the Event, which may add stress in mechanical systems.

The data also suggest that the ***extreme*** nature of these cold weather events—that is to say, unusually quick drops in temperature, high winds and/or atypical combinations of conditions—may play a role in generation loss due to Mechanical/Electrical Issues.

Figure 73: Generation Loss, Mechanical/Electrical Issues, December 21-26, 2022



As shown in Figure 73, above, comparing generating units' documented operating temperature to the ambient temperature conditions that they reported while experiencing Mechanical/Electrical Issues revealed a clear and disturbing outcome. A substantial majority of generation losses due to Mechanical/Electrical Issues (87 percent) occurred at an ambient temperature above the generating units' documented operating temperature.[217]

Using only the units' ambient design temperature, for those units that provided that temperature, nearly 39,000 MW of generation was lost due to Mechanical/Electrical Issues where units (a) reported freezing or below-freezing ambient temperatures in connection with the generation loss, (b) provided an ambientdesign temperature, and (c) where the ambient design temperature was 10 degrees or more below the temperature at which the Mechanical/ Electrical Issue occurred.

The data available suggests that some portion of the Mechanical/Electrical Issues outages may have been more appropriately categorized as Freezing Issues, and that the remainder illustrate a relationship between mechanical/electrical component malfunction and temperature that, to date, has not been fully explored or understood. Given the large percentage (40 to 41 percent, by number of units and MW, respectively) and MW losses (150,569 MW) caused by Mechanical/Electric Issues, better understanding the relationship between mechanical/electrical component malfunctions and temperatures is critical to improving future extreme cold weather performance by generating units. The Team believes an improved understanding can and should be evaluated on both a unit-by-unit basis—which the Team hopes can be obtained, in part, through the practices advanced in Recommendation 1—and on a systematic basis—through the study advanced in Recommendation 2.

3. FREEZING ISSUES

a. Summary Analysis

Data collected from generating units related to Freezing Issues during Winter Storm Elliott demonstrated similar trends to the data analyzed in the 2021 Report. Overall, units reported 1,030 distinct Freezing Issue-related

217 Th s figure s based only on un ts that prov ded amb ent temperature cond t ons for the r un ts exper enc ng outages not all un ts reported amb ent temperatures as requested. t s also based on the h ghest of the (up to three) temperatures that the ent ty could have prov ded: amb ent des gn temperature, h stor cal operat ng temperature, or current cold weather performance temperature determ ned by an eng neer ng analys s. *See* also, note 61. Other mater als related to the Report, nclud ng the presentat on g ven by Team members on September 21, 2023, stated that nearly 80 percent of Mechan cal/Electr cal ssues occurred above a generat ng un ts' m n mum operat ng temperature. That figure was based on a conservat ve earl er analys s of the data collected.

unplanned outages, derates, or start-up failures, which, combined, caused 110,962 MW of generation loss at various times during the Event,[218] and as illustrated in Figure 67, above, were 31 percent of the total MW of generation outages, derates, and failures to start during the Event. Variations by approximate U.S. geographic region basis in the Event Area for all unplanned generation MW outages due to **Freezing Issues** (as compared to other outage causes, e.g., Mechanical/Electrical Issues or Fuel Issues) are shown in Figure 74, below.

Figure 74: Variation by Approximate U.S. Geographic Region in the Event Area for Unplanned Unavailable Generation (MW) due to Freezing Issues

Approximate U.S. Geographic Region	Unplanned Unavailable Generation Due to Freezing Issues(Percent of MW)
New York	5%
M dAtlant c/M dwest	27%
Central/South Central	33%
Southeast	43%
Total Event Area	**31%**

Most BA footprints located in the southeast portion of the Event Area experienced higher percentages of unplanned generation outages due to Freezing Issues as compared to other geographic regions––especially compared to the northern portions of the Event Area.[219]

The specific types of Freezing Issues were similar to those seen during Winter Storm Uri. A substantial number of outages were linked to frozen transmitters, frozen sensing lines, or other frozen instrumentation – approximately 42 percent of all generation lost to Freezing Issues (Figure 75, below). As in the 2021 event, Freezing Issues caused a large percentage of unplanned wind generation outages and derates — 53 percent (by MW) or 40 percent (by number of outages). Freezing Issues caused 75 percent (by MW) and 43 percent (by number of outages) of unplanned outages and derates of nuclear units. Historically, Freezing Issues have been rare in nuclear units, due in part to their enclosed design.[220]

b. Existing and Pending Reliability Standards

Two sets of mandatory NERC Reliability Standards applicable to GOs—NERC Standard EOP-011-2, and the forthcoming EOP-012-1—are of particular relevance here.

In August 2021, the Commission approved the adoption of EOP-011-2, effective April 1, 2023, as part of a package of cold weather Reliability Standards.[221] As part of these updates, EOP-011-2 was revised to make clear that the GO is the “entity responsible for compliance” with the extreme cold weather Reliability Standards. This

218 Th s value s d st nct from the 90,500 MW of ncremental co nc dent unplanned outages dur ng the Event, wh ch s was the level of unplanned generat on outages, derates, and fa lures to start for all causes the gr d operators n the Core Event Area were faced w th at approx mately 10:00 a.m. on December 24, 2022. The 111,000 MW represents the MW of generat on capac ty outages, derates, and fa lures to start that were due to Freez ng ssues at var ous t mes dur ng the ent re Event, from December 21 26, 2022.

219 Open frame generat on fac l t es, wh ch are common throughout warmer cl mates n the U.S., are des gned and constructed w thout enclosed bu ld ng structures to avo d excess ve heat bu ld up n the summer but are more vulnerable to freez ng. *See* 2011 Report, Append x: Power Plant Des gn for Amb ent Weather Cond t ons, and 2021 Report at 162.

220 *See* Append x C.2., Add t onal Charts and F gures for Unplanned Generat on Outages Dur ng Event, Unplanned Generat on Outages by Fuel Type.

221 *See N.* Am. Elec. Rel ab l ty Corp., 176 FERC ¶ 61,119 at P 1 (2021).

required GOs to "develop, implement, and train on their extreme cold weather preparedness plans."[222]

Figure 75: Unavailable MW by Balancing Authority, Freezing Issues, December 21 - 26, 2022[223]

Equipment Category	Components and Systems Impacted	Event Count	MWs Outaged or Derated
Turbine Blades	[redacted]	[redacted]	[redacted]
Instrumentation	[redacted]	[redacted]	[redacted]
Other Equipment Freezing Problems	[redacted]	[redacted]	[redacted]

[redacted]

Requirement R7 requires each GO to "implement and maintain one or more extreme cold weather preparedness plan(s) for its generating units" linked to each unit's "design temperature, . . . historical operating temperature, or . . . current cold weather performance temperature determined by an engineering analysis."[224]

More recently, in February 2023, the Commission approved new Reliability Standard EOP-012-1 – Extreme Cold Weather Preparedness and Operations. The new standard builds on EOP-011-2, "enhance[] the reliable operation of the [grid] by requiring generator owners to implement freeze protection measures, develop enhanced extreme cold weather preparedness plans, implement annual trainings, draft and implement corrective action plans to address freezing issues, and provide certain extreme cold weather operating parameters to Reliability Coordinators, Transmission Operators, and Balancing Authorities for use in their analyses and planning."[225]

The crux of these standards is that generating units are expected to have an extreme cold weather preparedness plan tethered to one or more of the minimum operating temperatures associated with the unit – ambient design, historical operating minimums, or an extreme cold weather performance temperature determined by an engineering analysis. This minimum operating temperature is conveyed to that generating unit's Balancing Authority so that it may rely on the temperature information in connection with planning and dispatch decisions.

c. Operating Parameters Provided by Generating Units

The vast majority of generating units that provided data for this report had obtained an ambient design temperature, minimum historical operating temperature, or extreme cold weather performance temperature determined by an engineering analysis. Of generating units that responded to the data request,[226] 67 percent

222 *Id.* at PP 4, 6.

223 "Other freeze related ssue" ncludes freeze related sub causes external to the generat ng un t such as frozen coal or ce on transm ss on l nes.

224 *See* EOP 011 2 R7.3.2. RSCompleteSet.pdf (nerc.com).

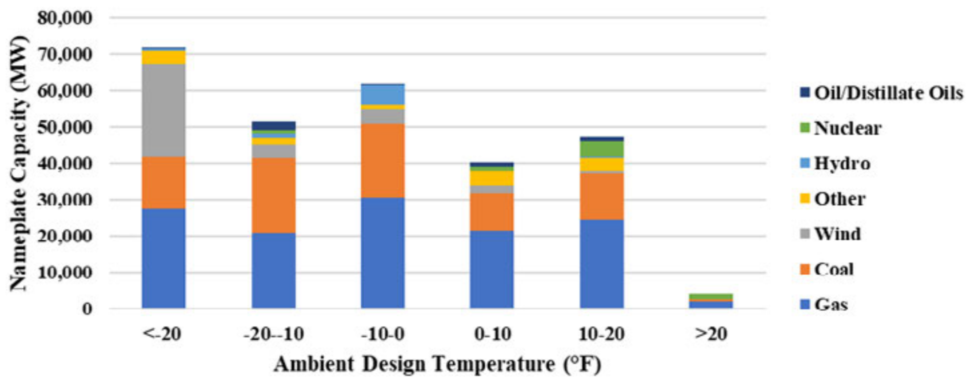
225 N. Am. Elec. Rel ab l ty Corp., 182 FERC ¶ 61,094 at P 36 (2023). The effect ve date for Rel ab l ty Standard EOP 012 1 s October 1, 2024.

226 Unless otherw se noted, percentages n th s sect on are based on the nameplate capac ty of the generat ng un ts that prov ded the necessary data.

reported a minimum design temperature. A slightly higher percentage, 74 percent, reported a historical minimum operating temperature, and very few units, only eight percent, reported an extreme cold weather performance temperature determined by engineering analysis.

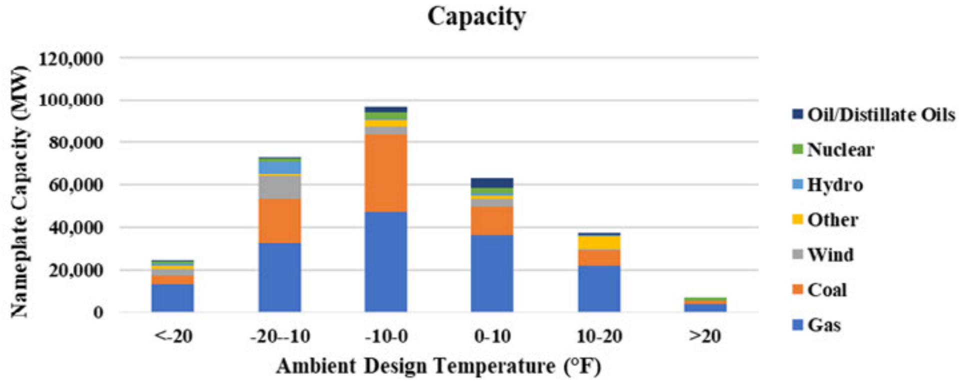
As illustrated in Figures 76 and 77, below, approximately two-thirds of the generating unit capacity (measured by nameplate MW) that responded with an ambient design temperature or a historical minimum operating temperature indicated a design temperature or a historical minimum operating temperature below zero degrees. More than 80 percent of units responded with an ambient design temperature below 10 degrees. Ambient design temperatures of coal units were spread across temperatures ranging from less than -20 up to 20 degrees. Similarly, ambient design temperatures of natural gas units were spread mostly across those ranges, except for a few units that had temperatures over 20 degrees. Over 80 percent of wind and one hundred percent of the solar units reported ambient design temperatures below zero degrees.

Figure 76: Ambient Design Temperature by Fuel Type and Total Capacity



The primary takeaway from this data is that of the units that reported outages, derates, or failures to start during the Event, nearly 84 percent of the total unit capacity reported a "documented operating temperature"—that is to say, the highest of their stated design temperature, historical minimum operating temperature, or an extreme cold weather performance temperature determined by an engineering analysis, of 10 degrees or lower. Although these data suggest that the generating units impacted by Winter Storm Elliott were, at a minimum, designed to operate or had successfully operated in extreme cold, over 63,000 MW (over 75 percent) of generation had outages, derates or failed to start due to Freezing Issues at temperatures above their documented operating temperature during the Event, as discussed below.

Figure 77: Historical Minimum Operating Temperature by Fuel Type and Total Capacity

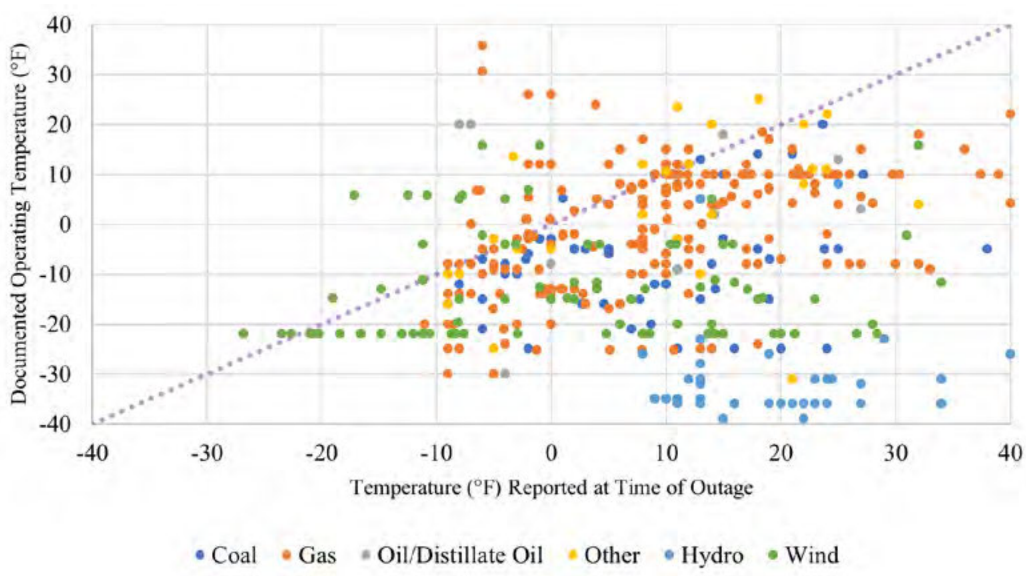


d. Freezing Above Documented Operating Temperature

A substantial majority of generation loss by units that reported Freezing Issues occurred at temperatures that were above the documented operating temperature thresholds incorporated into EOP-011-2, Requirement R7. Generating units of all primary fuel types—with the exception of a small number of generating units whose primary fuel type was oil—reported Freezing Issues well above their documented operating temperature.

In sum, generators did not perform according to their documented operating temperature. The scatter plot (Figure 78, below) compares the ambient temperatures reported by generating units with Freezing Issues to the documented operating temperature of that unit. The diagonal line represents the points at which the ambient temperature and documented operating temperature are equal. A substantial majority all of the generating unit outages plotted fall below (or the right of) the line, meaning that their outage occurred at temperatures above their documented operating temperature.

Figure 78: Temperature Reported at Time of Outage versus Documented Operating Temperature for Generators with Freezing Issues



e. Impact of Wind and Precipitation on Freezing Issues

The Team reviewed data to evaluate the impact of other weather conditions—wind and precipitation—on generating units reporting Freezing Issues. Wind can have a cooling effect that may cause unexpected Freezing Issues below ambient design temperatures. Precipitation coupled with freezing temperatures can also greatly impact generating unit operations during extreme cold weather events. This review did not reveal significant or clear trends—in part because the low number of units experiencing Freezing Issues below their minimum operating temperature frustrates a comparative analysis on those grounds.

On average, the wind speeds reported for units that had Freezing Issues above their document operating temperature averaged 16 mph, while wind speeds reported for units that had Freezing Issues below their minimum operating temperature averaged 20 mph. These two data points suggest that the cooling effect of wind did not substantially affect whether a given generating unit would experience a Freezing Issue above or below its minimum operating temperature. See Figure 79, below.

Precipitation affected whether a unit would fail above its documented operating temperature for some fuel types, such as oil and wind, but not for others fuel types such as natural gas and coal. Figure 80 below, breaks down performance by fuel type.

Protecting generator cold weather critical components from extreme cold weather is not complicated. Freeze protection measures -- such as heat trace, insulation, wind breaks, or targeted roofing to protect insulation from getting wet—have been used for years to prevent failure. What makes the difference between successful operation for the duration of an extreme cold weather event and unplanned outages due to freezing? Observations over multiple extreme cold weather events suggest that improved outcomes are associated with attention to detail, consistency in implementing the plan for protecting generator cold weather critical components, and preventing complacency when preparing for winter. Several entities involved in the Event shared stories about generating units lost because seemingly insignificant areas were insufficiently protected. For example, one entity had a false floor in its unit, and did not realize that a pipe was not insulated beneath the floor. The small section of pipe under the floor froze and caused the unit to trip.

Figure 79: Average of Wind Speed Reported for Units with Freezing Issues Comparing Above/Below Documented Operating Temperature

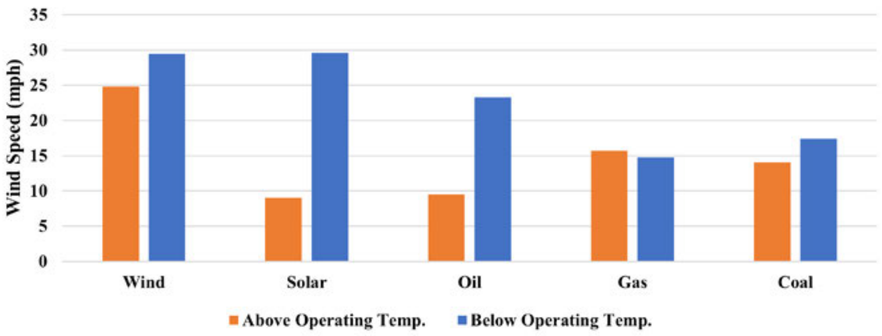
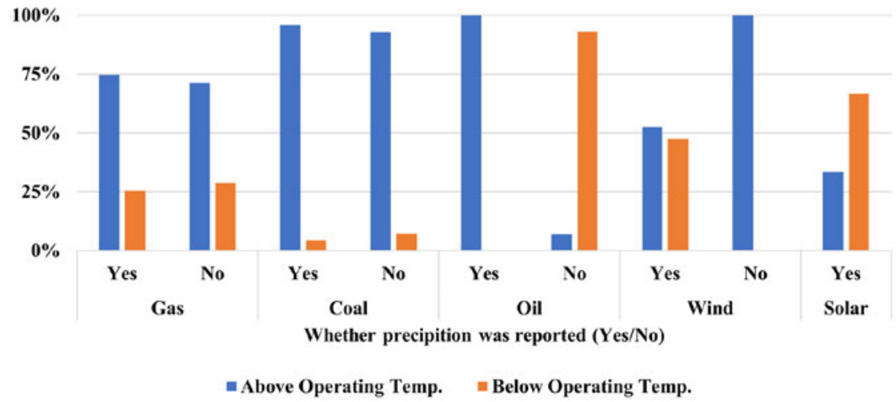


Figure 80: Precipitation Reported for Units with Freezing Issues Comparing Above/Below Documented Operating Temperature



The Lesson of Consecutive Cold Weather Events: Consistency, Attention to Detail, and a Sense of Urgency are Critical to Effective Cold Weather Preparation

As described more fully below, there have twice been extreme cold weather events that resulted in no load loss shortly after a similar event during which firm load was shed.

The first set of events occurred in February, 2011. In early February 2011, ERCOT, Salt River Project, and El Paso Electric Company needed to shed firm customer electric load, over 4,000 MW total, due in part to generating unit outages caused by freezing. On February 10, 2011, cold temperatures returned to Texas. "Actual temperatures in the ERCOT region averaged a low of 19 degrees with a 12-degree wind chill."[227] Yet ERCOT did not shed either firm or interruptible load despite setting a new winter peak of 57,915 MW.[228]

The 2011 Report found that "ERCOT avoided service interruptions on February 10 largely because there were far fewer forced outages."[229] While weather differences also played a role,[230] **the 2011 report found that "repairs made and protective measures taken during the event of February 2 remain[ing] in place" were a significant factor.**[231] GOs/GOPs had addressed vulnerabilities including "re-routing piping or moving vulnerable equipment, correcting transformer oil levels at wind farms, and adding freeze-resistant chemicals.

227 2011 Report at 99.

228 2011 Report at 99.

229 2011 Report at 99.

230 The February 10 ow of 19 degrees was the same as the February 2 ow, however the w nd ch was ower on February 2 and ow temperatures dur ng the ear er event were more pers stent, rema n ng n the ow twent es for four days w th w nd ch s between 10 and 14 degrees. 2011 Report at 99.

231 Generator owners had " nstalled w nd breaks, nclud ng tarps or enclosures, added portable heaters or heat lamps, repa red or added nsulat on, and repa red or added heat trace. One generator changed ts procedures for mon tor ng the rel ab l ty of ts heat trace. Some generators also cont nued the r ncreased level of staff ng to address freeze protect on ssues, and others changed elements of the r control log c to prevent un ts from automat cally tr pp ng." 2011 Report at 100.

At least five generators kept units running, started units earlier or took other measures to keep from having a cold start. After so many static sensor and other lines froze the week before, some units left water lines draining, or took other measures to keep water flowing."[232]

The second set of events occurred in January 2014 and February 2015. On January 6 and 7, 2014, parts of the Eastern Interconnection experienced a "polar vortex," with "temperatures 20 to 30 [degrees] below average, and some areas [35 or more degrees] below their average temperatures."[233] As NERC noted in its "Polar Vortex Review," "these lower temperatures had a drastic impact on load, with many of the RCs/BAs [e.g., MISO, PJM, TVA, VACAR-South RC (including Duke), and Southern/Southeastern-RC] reporting record or near-record winter peak demands. PJM exceeded its historic winter peak on both January 7 and January 8, 2014, and MISO reported that they exceeded their historic winter peak for three straight days (January 6–8, 2014)."[234] Due to the high loads and unplanned generating unit outages, including an estimated 19,500 MW of generation outages due to "cold weather conditions," and "a significant reduction of generating capacity due to curtailments and interruptions of natural gas delivery," affected entities needed to use "load reduction procedures such as voltage reduction, interruptible loads, and demand-side management," and in one case, to shed 300 MW of firm load, to maintain system reliability.[235]

A little more than a year later, severe cold temperatures hit the Eastern Interconnection again. "Numerous cities [in the Eastern Interconnection] hit their daily low-temperature records during February 2015. Due to the low temperatures and associated high electricity demand for heating needs, PJM set a new wintertime peak demand record of 143,086 megawatts the morning of February 20, 2015 . . . The new peak record surpassed the previous all-time winter peak . . . set [during the Polar Vortex]. Although the new record winter peak was set during this time frame, no emergency demand response or any other capacity emergency actions were required. Many other areas also set all-time record winter peaks in 2015."[236] PJM and DEP set winter peak load records in 2015 that remained unbroken during the Event, and DEC broke its 2015 record by less than 150 MW.[237] Yet "[g]enerator performance in . . . February of 2015 showed improvement over 2014 with improved overall forced outage rates." or example, PJM's forced outage rate dropped from 22 percent to 13.4 percent.[238] NERC attributed this improvement to "steps generation owners . . . initiated after the winter of 2014."[239] NERC used GADS[240] data to compare winter 2015 equivalent forced outage rates (EFOR) to those during the polar vortex in 2014 and to previous years' rates.[241]

232 2011 Report at 100.

233 Polar Vortex Rev ew at .

234 Polar Vortex Rev ew at v .

235 Polar Vortex Rev ew at 2,4.

236 NERC 2015 W nter Rev ew, December 2015, at v. https://www.nerc.com/pa/rrm/ea/ColdWeatherTra n ngMater als/2015_W nter_Rev ew_December_2015_F NAL.pdf

237 *See* Table 2, n 2015 NERC report. Southern Company and TVA st ll d d not break the r 2014 w nter peak load records.

238 NERC 2015 W nter Rev ew, December 2015, at v.

239 NERC 2015 W nter Rev ew, at v.

240 *See* note 44.

241 NERC 2015 W nter Rev ew, at 1.

NERC provided examples of preparations taken by the generating unit owners, including:

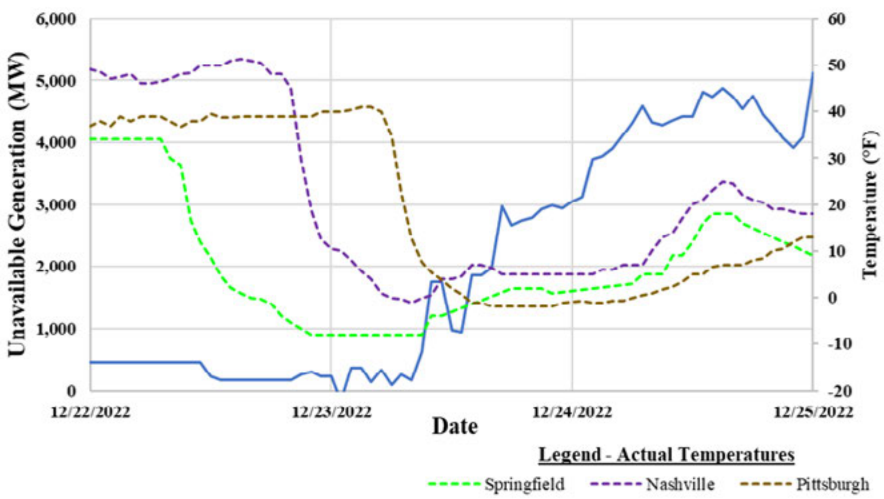
- Owners started units earlier than expected, due to anticipated colder temperatures, helping to mitigate the risk of taking more time to start.
    - Keeping stations in service overnight with a reduced output level was beneficial to ensuring that the unit would stay warm and online when needed for the peak.
- Proactive staffing of typically unmanned stations enabled more rapid response.
- Many generating units in the PJM footprint participated in prewinter operational testing, and those that did, had a lower rate of forced outages than those that did not.

But seven years later, faced with peak loads that were generally lower than in 2014 or 2015, many of the same BAs experienced high rates of forced outages. PJM, for example, found that despite many measures undertaken in the wake of the Polar Vortex, its Capacity Resource forced outage rate was worse in the Event than in the Polar Vortex (24 percent versus 22 percent).

4. BLACKSTART UNITS

Of significant concern is that blackstart-designated generating units totaling 19,000 MW experienced forced outages, derates or failures to start during the Event. Blackstart-designated units are those that claim the ability to be started without the aid of external power sources. Given this unique functionality, blackstart units serve a critical grid reliability function—restarting the grid in the event of its failure. It is, therefore, disconcerting that generation loss due to the unavailability of blackstart-designated units coincided with the arrival of extreme cold weather conditions and the corresponding acceleration of generation loss throughout the bulk electric system.

Figure 81: Unavailable Generation - Blackstart-Capable Generating Units, December 22 - 24, 2022



242 NERC 2015 W nter Rev ew at 6.

Figure 82: Unavailable Generation in the Event Area, Blackstart-Capable Generating Units, By Primary Cause

Blackstart Units – Reported Event Cause	Event Count	Unavailable MW
Mechan cal/Electr cal ssues	89	7,737
Fuel ssues	86	6,717
Freez ng ssues	61	3,565
Env ronmental/ Safety ssues	6	810
Transm ss on System ssues	6	261

Figure 83: Unavailable Generation in the Event Area, Blackstart-Capable Generating Units, By Primary Cause and Dual Fuel Capability

Blackstart Units Type	Freezing Issues (MW)	Fuel Issues (MW)	Mechanical/Electrical Issues (MW)	Other (MW)
Gas Only	1,266	5,060	1,200	0
Gas/O l	1,678	920	3,607	561
Other	621	737	2,910	510
Total	3,565	6,717	7,737	1,071

Altogether, 155 blackstart-designated generating units (119 of which were natural gas-fired) reported more than 248 discrete outages, derates or failures to start. Of these, 29 percent reported *multiple* outages, and 23 percent were start-up failures—*i.e.* units that failed to perform the essential function of blackstart units.

Blackstart generation loss unit types included natural gas-fired, dual-fuel capable, and other primary fuel types.

5. HIGH WIND SHUTOFFS

Most conventional wind turbines are designed to operate at wind speeds of no more than 55 mph and must shut down when wind speed exceeds those levels.[243] Excluded from the foregoing analysis of Freezing Issues and Mechanical/Electrical Issues were wind turbine units that reported generation loss due to high winds—High Wind Shutdown—as the cause of their forced outage. Some generating units reported unique outages lasting only a handful of minutes on a turbine-by-turbine basis, resulting in hundreds of spreadsheet lines—but ultimately these shutoffs did not constitute a significant source of generation loss during Winter Storm Elliott. In aggregate, Generation Owners attributed fewer than 1,000 MW of generation loss to High Wind Shutdowns.

6. FUEL ISSUES

Fuel Issues accounted for 24 percent of all generation lost during the Event—a cumulative total of more than 86,000 MW—and were the third largest cause of unplanned

243 *See*, Off ce of Energy Eff c ency & Renewable Energy, *How Do Wind Turbines Survive Severe Storms?* (June 20, 2017), https://www.energy.gov/eere/art cles/how do w nd turb nes surv ve severe storms ("When the anemometer reg sters w nd speeds h gher than 55 mph (cut out speed var es by turb ne), t tr ggers the w nd turb ne to automat cally shut off.").

outages, derates and failures to start. In total, 452 generating units reported 730 distinct forced outages, derates or failures to start during the Event due to Fuel Issues. Natural gas-fired generating units experienced the overwhelming majority of Fuel Issues: 71,423 MW of natural gas-fired generating unit outages and derates were 83 percent of all Fuel Issue-caused generation outages and derates during the Event, as shown in Figure 84, below.[244] For natural gas-fired generation alone, comparing the outages during the Event caused by Natural Gas Fuel Issues to Freezing Issues and Mechanical/Electrical Issues, Natural Gas Fuel Issues caused nearly one-third (31 percent, by MW) of natural gas-fired generating units' unplanned outages and derates.[245]

Figure 84: Unplanned Unavailable Generation in the Event Area Caused by Fuel Issues, December 21-26, 2022

Generating Unit Primary Fuel Type	Unplanned Outages During Event (MW)	Percent of Unplanned MW Outages Due to Fuel Issues
Gas	71,423	83%
Coal	13,439	16%
Other	1,602	2%

Fuel-Issue-caused natural gas-fired generation outages (referred to as the sub-cause "Natural Gas Fuel Issues" described earlier in the Report) include the combined effects of decreased natural gas production; cold weather impacts and mechanical problems at production, gathering, processing and pipeline facilities resulting in gas quality issues and low pipeline pressure; supply and transportation interruptions; curtailments and failure to comply with contractual obligations. Additionally, it includes shippers' inability to procure natural gas due to tight supply, prohibitive, scarcity-induced market prices, or mismatches between the timing of the natural gas and energy markets.

See Figure 85, below, for information on the contractual arrangements held by some of the GOs/GOPs involved in the Event.

Each subset of the 71,423 MW of natural gas-fired generating unit outages and derates due to Natural Gas Fuel Issues total tells a distinct story:

- Nearly 7,500 MW of generation outages were linked to gas delivery pressure issues, reflecting the difficulty natural gas pipelines and other distribution points faced in responding to production losses. Another 2,000 MW was linked to transportation constraints.
- Market Issues and Market Price Restrictions accounted for approximately 24,000 MW of generation loss—reinforcing how surging demand and production losses impacted generating units. Somewhat paradoxically, GOs/GOPs of natural gas-fired generating units attributed more generation loss to the failure of gas suppliers to satisfy firm supply commitment and/or pipeline firm curtailments (16,500 MW of cumulative generation loss) than to interruptible pipeline interruptions

244 Th s s n part because natural gas fired generat ng un ts were the most common (over 41 percent of the generat on capac ty n the Event Area, as seen n F gure 11). Natural gas fired un ts were also the most common n pr or extreme cold weather events (2011: ERCOT 52 percent; 2021: ERCOT 52 percent, M SO South 60.6 percent, SPP 38.5 percent). The only other un ts that exper enced mater al generat on loss due to Fuel ssues dur ng W nter Storm Ell ott were coal un ts. Fuel ssues for all fuels other than gas and coal, comb ned, accounted for two percent of all unplanned outages, derates and fa lures to start.

245 *See* Append x C.3. Causes of Unplanned Generat on Outages, by Fuel Type of Generat on.

(14,000 MW of cumulative generation loss). This finding was supported by the Team's cross-check of the causes claimed against data provided by the GOs/GOPs of those generating units about their contractual arrangements.

Figure 85: Generating Unit Natural Gas Commodity and Transportation Contracts

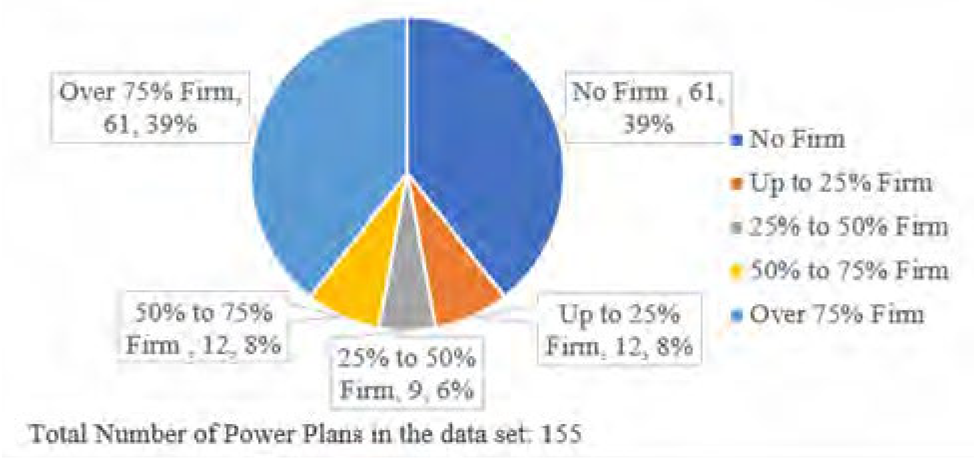
Generating Unit Natural Gas Commodity and Transportation Contracts										
Type of Gas Commodity and Transportation Contract:	MISO		PJM		Southern		SPP		Other BAs	
	Generators	Percent	Generators	Percent	Generators	Percent	Generators	Percent	Generators	Percent
Firm Commodity/Firm Transportation	53	38%	61	37%	0	0%	0	0%	28	26%
Firm Commodity/Mixed Transportation	0	0%	1	1%	0	0%	0	0%	0	0%
Firm Commodity/Non-Firm Transportation	8	6%	26	16%	0	0%	0	0%	0	0%
Non-Firm Commodity/Non-Firm Transportation	28	20%	18	11%	2	5%	27	34%	9	8%
Non-Firm Commodity/Mixed Transportation	3	2%	0	0%	0	0%	15	19%	2	2%
Non-Firm Commodity/Firm Transportation	20	14%	11	7%	0	0%	17	21%	0	0%
Mixed Commodity/Mixed Transportation	11	8%	21	13%	0	0%	16	20%	20	19%
Mixed Commodity/Firm Transportation	7	5%	3	2%	14	38%	0	0%	14	13%
Mixed Commodity/Non-Firm Transportation	8	6%	17	10%	21	57%	3	4%	28	26%
Did not provide information re: commodity contract type	1	1%	2	1%	0	0%	2	3%	0	0%
No contract or did not provide information about transportation contract type	2	1%	7	4%	0	0%	0	0%	5	5%
Total	141	100%	167	100%	37	100%	80	100%	106	100%

During the Event, unplanned natural production outages due to freeze-related issues, road conditions, loss of power and unplanned outages of gathering and processing facilities decreased the natural gas available for supply and transportation to many natural gas-fired generating units in the Eastern Interconnection. Out of the **61** power plants[246] that reported having at least 75 percent of their fuel requirement under firm transportation, only **25** reported also having at least 75 percent of the fuel needed for their winter

246 The Team had a sample s ze of sl ghtly over 200 generat ng plants that prov ded most of the requested nformat on about fuel contract ng pract ces. Generator owners prov ded fuel contract data on a plant bas s, wh ch often ncluded mult ple generat ng un ts. The Team removed plants that d d not answer the requests for the r total or da ly gas natural gas requ rements, result ng n a l st of 155 plants.

peak operation under firm supply contracts. The Team focused on GOs/GOPs that provided their fuel requirements. As shown in the figure, the plants were nearly evenly split between those that had no firm transportation at all, and those that had over 75 percent of their natural gas fuel requirements supported by firm transportation.

Figure 86: Number of Power Plants by the Level of Firm Transportation Service Contracts Covering Their Natural Gas Fuel Requirements

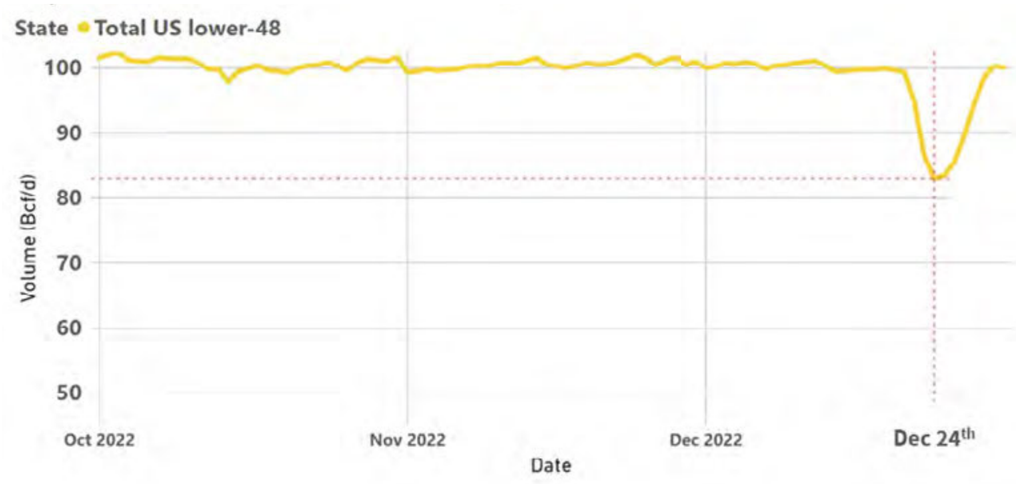


C. Causes of Natural Gas Supply and Delivery Facility Outages[247]

1. SUMMARY

As Winter Storm Elliott moved across North America and temperatures dropped, natural gas production in the lower 48 states declined, with volumes on December 22 decreasing 4,411 MMcf/day from the previous day. The largest daily decline in natural gas production – 8,368 MMcf/day – occurred between December 22 and December 23. Dry natural gas production for the lower 48 U.S. saw an 18 percent decline, falling to a low of 82.9 Bcf/day on December 24, 2023, as shown in Figure 87, below.

Figure 87: Daily Dry Natural Gas Production (November - December 2022)[248]



Winter Storm Elliott primarily affected the Marcellus and Utica Shale formations. Marcellus Shale production volumes reached a low of 21,856 MMcf/d on December 24 (23 percent decrease compared to maximum production on December 19). Utica Shale production volumes reached a low of 3,017 MMcf/d on December 26 (54 percent decrease compared to maximum production on December 19). Focusing on states, the largest natural gas production decreases in the Event Area occurred in Pennsylvania, Ohio, and West Virginia, whereas Louisiana production was relatively unaffected. Ohio saw the largest relative decline compared to maximum production volumes for December, reaching a low of 3,018 MMcf/d on December 26 (54 percent decline compared to production on December 17). Pennsylvania and West Virginia both reached their lowest production volumes of 16,226 MMcf/d (22 percent decline compared to production on December 20) and 5,630 MMcf/d (26 percent decline compared to production on December 18), respectively, two days prior on December 24. Figures 88 and 89[249] show the declines by state over time, and the geographic locations of the volumetric outages, respectively.

247 Unless otherw se stated, the source of data for th s sect on s the sample of producers, gatherers, processors, and p pel nes that responded to the Team's data requests.

248 Source: S&P Global Commod ty ns ghts, ©2023 by S&P Global nc.

249 Source for both figures: S&P Global Commod ty ns ghts, ©2023 by S&P Global nc.

Figure 88: Sum of Natural Gas Production Volume, by Date and State (October - December 2022)

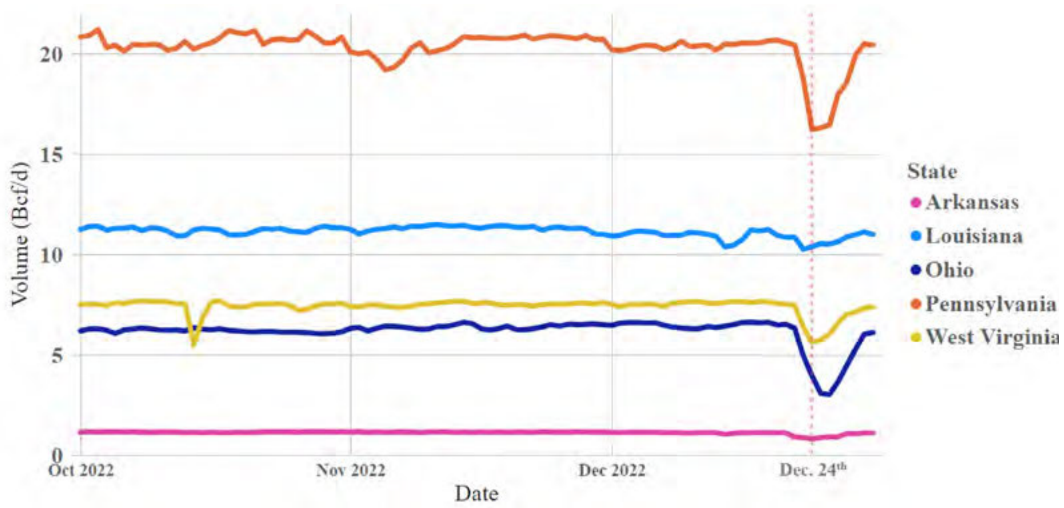
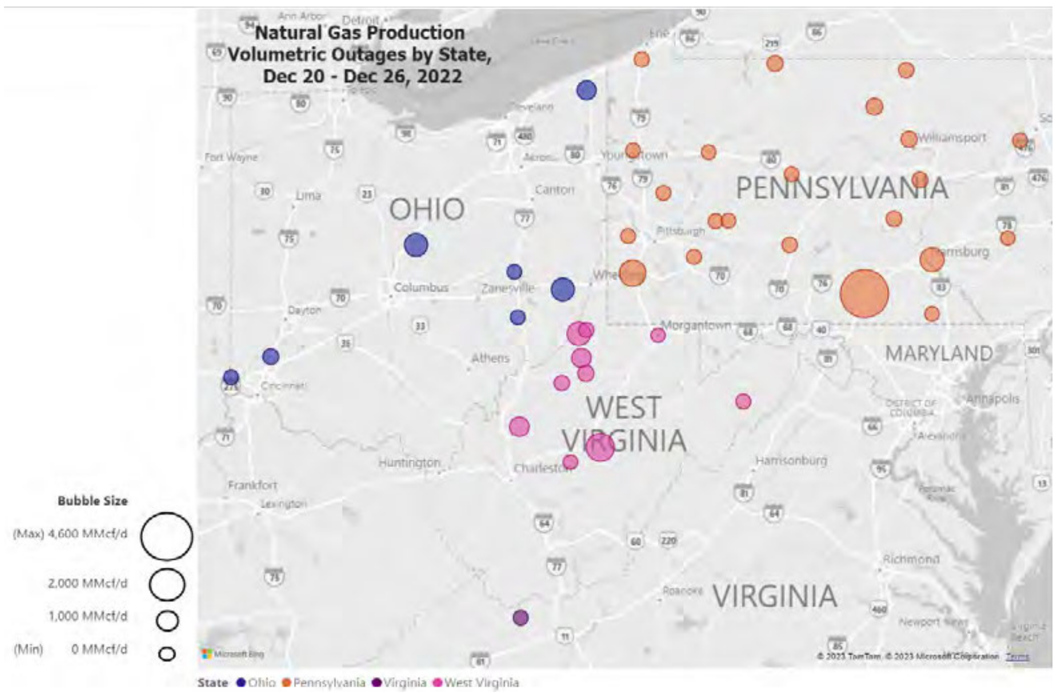


Figure 89: Natural Gas Production Volumetric Outages by State, December 20 – 26, 2022



Certain pipeline injection points were especially affected. Westmoreland, Pennsylvania, declined by over 6.8 Bcf over the Gas Days of December 21-26, compared to expected production, and Greene, Pennsylvania, declined by over 3 Bcf. Other points experiencing declines over one Bcf included Calhoun and St. Clair Pennsylvania, Monroe, Ohio and Marshall, West Virginia.[250]

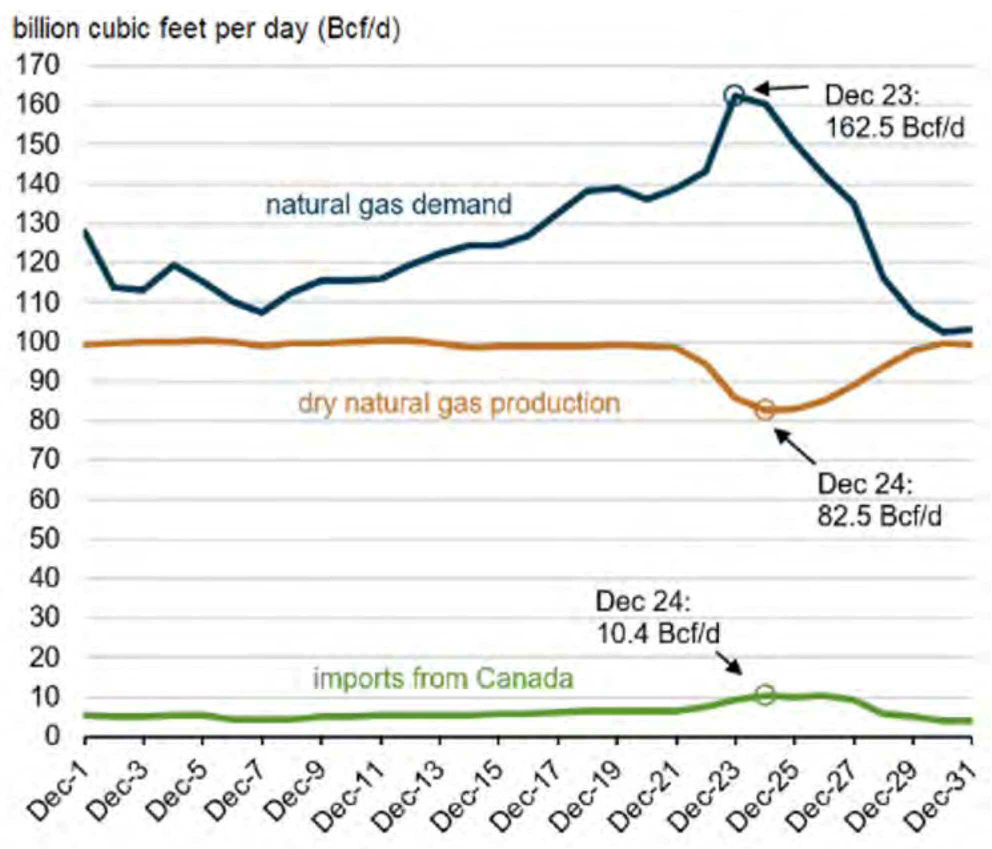
The last time U.S. natural gas production rapidly declined to this degree was during Winter Storm Uri.

250 *See* F gure 50 for a map of rece pt po nts exper enc ng supply shortages.

Record natural gas demand during Winter Storm Elliott was met by increasing withdrawals from storage and pipeline imports from Canada. Natural gas pipeline imports from Canada supplied 10.4 Bcf of natural gas to the United States on December 24, the highest daily natural gas imports from Canada since February 2007.[251]

Figure 90 below shows record peak demand for natural gas on December 23 and the production nadir on December 24.

Figure 90: Daily Natural Gas Supply and Demand in the Lower 48 States, December 1 – 31, 2022[252]



It is important to note that natural gas demand, as that term is used by the U. S. Energy Information Administration, is the sum of actual gas consumption, natural gas and LNG exports, pipeline losses and fuel gas. EIA's natural gas demand does not include the gas that would have been burned by dispatched natural gas-fired generating units rendered unavailable due to Natural Gas Fuel Issues, Freezing Issues, or other causes. Put another way, although EIA reported record demand for December 23, that figure under-represented the potential natural gas demand because it excluded natural gas that generators would have consumed had they not experienced an outage, derate, or failure to start.

The December 23 demand for gas of 162.5 Bcf included estimated total consumption of natural gas in the lower 48 states of 141 Bcf – a record daily high (exceeding the previous record daily high of 137.4 Bcf set on January

251 Natural Gas Weekly Update, January 19, 2023 U.S. Energy nformat on Adm n strat on, (last v s ted November 3, 2023).

252 Source: S&P Global Commod ty ns ghts, ©2023 by S&P Global nc.

1, 2018) and 21.5 Bcf of exported gas, pipeline losses, and fuel gas. Figure 91, below, shows the relative shares of natural gas consumption for natural gas fired-generating units ("PowerBurn"), industrial production, residential and commercial use ("ResComm"), and LNG feedgas for the Event Area. Power burn and residential and commercial use consumed similar shares until the onset of the extreme cold weather, when residential and consumer usage spiked. LNG feedgas decreased by nearly 20 percent, mostly in the Southeast as shown in Figure 92, below. Figure 92 shows the overall and relative increase (or decrease) in the various sectors' natural gas consumption for the Northeast, Midwest and Southeast regions, combined. Residential and commercial use had the largest percentage increase by far, at nearly 50 percent, with pipe losses coming in second, increasing by a third.

Figure 91: Northeast/Midwest/Southeast Natural Gas Consumption[253]

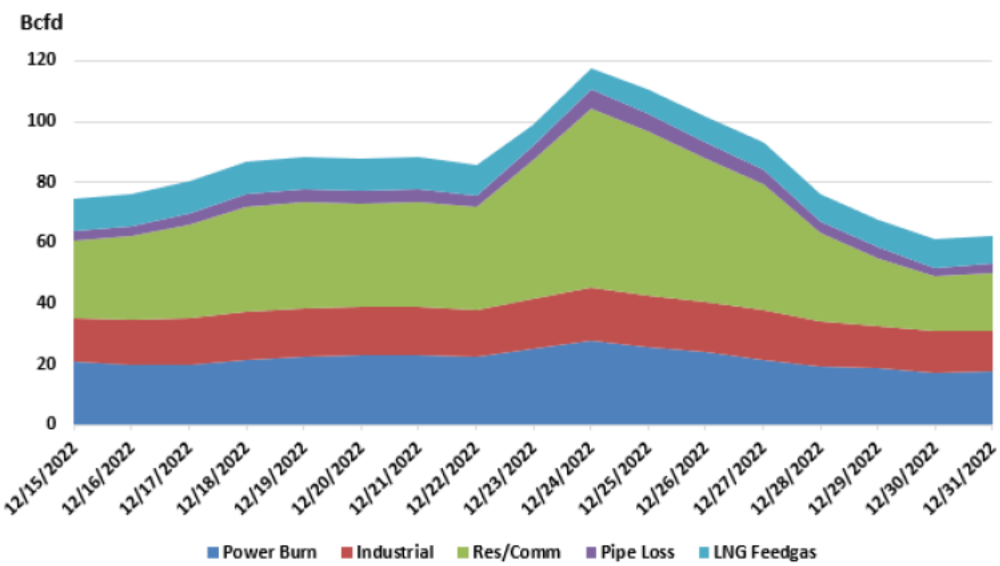


Figure 92: Overall and Relative Increase in Natural Gas Consumption for the Northeast, Midwest and Southeast Regions[254]

Bcfd	December 15-20 Average	December 21-26 Average	Percent Change
Northeast/M dwest/Southeast Natural Gas Demand	82.3	100.5	22.1%
Power Burn	21.2	24.6	15.8%
Res/Comm	31.4	46.0	46.5%
ndustr al	15.3	16.5	7.9%
LNG Feedgas	10.6	8.5	19.8%
P pe Loss	3.9	5.0	29.2%

253 Source: S&P Global Commod ty ns ghts, ©2023 by S&P Global nc.

254 Source: S&P Global Commod ty ns ghts, ©2023 by S&P Global nc.

2. NATURAL GAS PRODUCTION DECLINES

The Team sought to gather information from the largest producers in the area that experienced the greatest decreases in natural gas production. Based on the Team's analysis of publicly-available information and data from S&P Global Community Insights, the Team focused its data collection efforts on a sample of 12 large producers in Pennsylvania, Ohio and West Virginia. Eight producers with operations in Pennsylvania, Ohio, West Virginia, and Virginia – representing over 15,000 natural gas wells – provided responses to questions about estimated marketed production declines during Winter Storm Elliott.[255] Producers were asked to identify production volume declines by date and county, and to identify an associated cause for the declines. Only 38 to 53 percent of the production entities provided the requested data for December 23 to 26,[256] the days with the most substantial production losses, as shown in Figure 93, below. One producer did not provide any information after several attempts by the Team.[257] The Team grouped them into the following categories: Freeze-offs; Downstream Issues; Access to roads cut-off; Proactive Reduction in Sales.[258]

Figure 93: Natural Gas Marketed Production Volume Declines, December 20 – 26, 2022

Date	Marketed Production Volume Decline MMcf/d with Causes	Total Marketed Production Volume Decline (MMcf/d)	% of Data
12/20/2022	541.24	718.82	75%
12/21/2022	569.87	838.19	68%
12/22/2022	532.48	854.27	62%
12/23/2022	2,044.46	3,869.75	53%
12/24/2022	1,579.86	4,209.68	38%
12/25/2022	1,878.98	4,416.39	43%
12/26/2022	1,743.17	3,832.59	45%

All but one producer identified freeze-offs as a primary cause of production reductions, including frozen production equipment as well as wellhead freeze offs. Seven of the 10 producers identified downstream issues

255 n total, 10 producers responded to the data request, but only e ght prov ded the data on the est mated marketed product on decl nes. *See* footnote 100 wh ch descr bes the relevant reg ons the ent t es were asked to prov de product on data.

256 Th s s an example of an ssue the Team faced when gather ng nformat on from non jur sd ct onal ent t es.

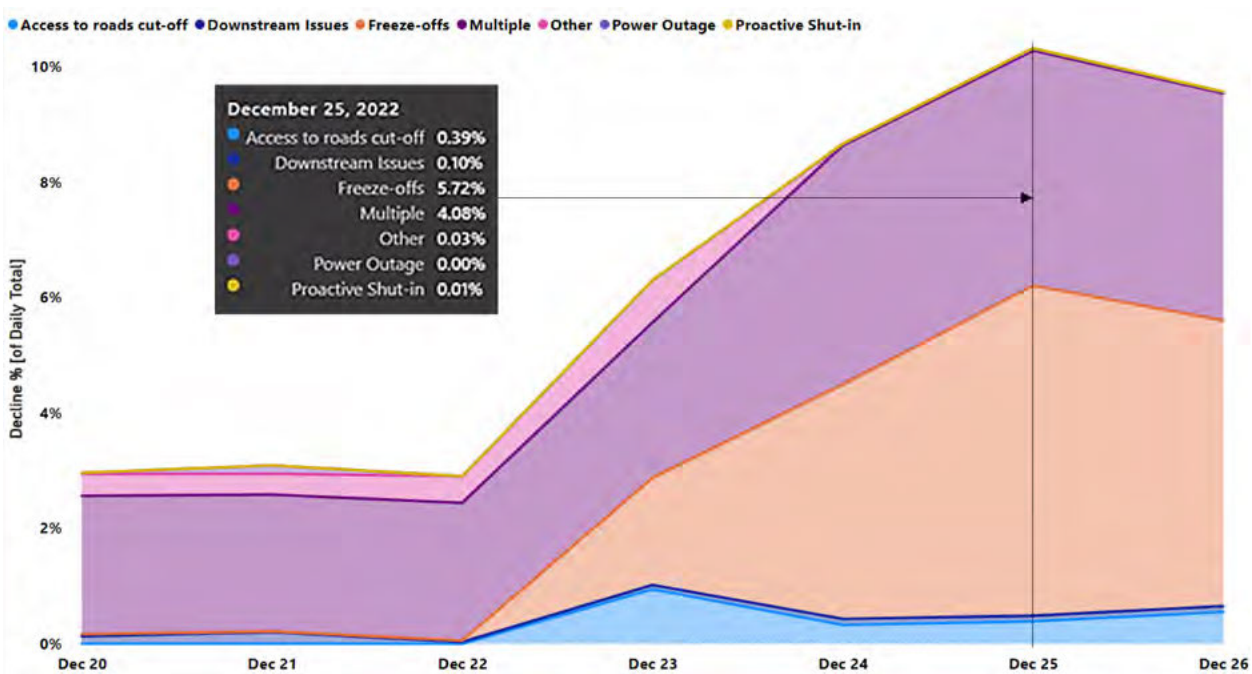
257 Deta s regard ng the way n wh ch th s producer responded ustrate the benefits that w obta n f an agency or ent ty s g ven jur sd ct on over the re ab ty of the natura gas system. The Team n t a y tr ed to contact the producer v a wr tten data requests. When the producer d d not respond, the Team assumed that the data requests had not been rece ved or had reached the wrong person ssues that had ar sen w th other producers and that cou d be reso ved v a a phone ca . The Team contacted the producer and was referred to a spec fic nd v dua . He, however, d d not return ca s. The Team fina y managed to reach h m n h s off ce, and he sa d that t was h s understand ng that cooperat on w th the Team was "vo untary." A though the Team exp a ned the mportance of cooperat on n he p ng to te the ent re story of what happened dur ng W nter Storm E ott, he sa d on y that he wou d d scuss t w th others at the producer and wou d ca back n a week or two. The Team never heard from h m aga n.

258 The Team had to group the causes prov ded nto overarch ng categor es s nce there was a s gn ficant var at on n the causes used/prov ded n the responses. Th s s also another reason why an agency or ent ty w th jur sd ct on over the rel ab l ty of the natural gas system could prove benefic al by creat ng some level of standard zat on or un form ty n outage/operat onal mpacts cause des gnat ons that could support mean ngful analys s (compare, e.g., GADS data spec ficat ons for BES GOs/GOPs to prov de data about generat ng un t outages Generat ng Ava lab l ty Data System (GADS) (nerc.com)).

as a significant driver of production declines; these issues included outages in gathering systems, compressors, and processing plants, as well as pipelines that could not take the gas from the producers,[259] which caused idling of producer equipment, which itself exacerbated production equipment freezing and caused further reductions in natural gas production. Five out of 10 identified poor road conditions, which prevented personnel and, in some cases, water hauling trucks, from reaching remote sites, although this was not as common as during Winter Storm Uri. Finally, two producers proactively reduced the volume of contractual sales during the Event because they expected production declines.

Figure 94, below, illustrates the decline by category calculated against the daily estimated production as reported by producers. Figure 95 breaks down the causes of production losses on December 23 to 26. Freeze-offs peaked as the leading cause of production declines on December 24 and 25, while downstream issues peaked on December 23.

Figure 94: Natural Gas Daily Production Decline by Cause, December 20 – 26, 2022



259 One p pel ne stated that lead ng up to and on the even ng of December 23, they started to pack the r l nes n preparat on for h gh demand on December 24. The h gh pressure temporar ly prevented producers from be ng able to move the r gas onto the p pel ne. The same p pel ne also had a lag n demand load on the morn ng of December 24, caus ng pressures to rema n h gh, wh ch exposed producers to further freez ng vulnerab l t es as they could not move the r supply onto the p pel ne system at that t me.

Figure 95: Total Percentages of Natural Gas Daily Production Decline by Cause, December 23 – 26, 2022

	Production Event Causes on December 23rd	
	Natural Gas Infrastructure Condition	Facility Event Causes
Freeze-offs	Equipment freezing at well/gathering facilities.	16.6%
Downstream Issues	Third party/downstream issues (e.g., processing plant down)	44.5%
Access to roads cut-off	Road/access to well/gathering facilities	8.4%
Multiple	Multiple Issues (combination of two or more of above issues)	24.0%
Other Issues, Unrelated Issues	Proactive shut-in	0.0%
	Other Issues	6.5%
Total		100.0%

	Production Event Causes on December 24th	
	Natural Gas Infrastructure Condition	Facility Event Causes
Freeze-offs	Equipment freezing at well/gathering facilities.	46.9%
Downstream Issues	Third party/downstream issues (e.g., processing plant down)	1.2%
Access to roads cut-off	Road/access to well/gathering facilities	3.8%
Multiple	Multiple Issues (combination of two or more of above issues)	47.8%
Other Issues, Unrelated Issues	Proactive shut-in	0.0%
	Other Issues	0.3%
Total		100.0%

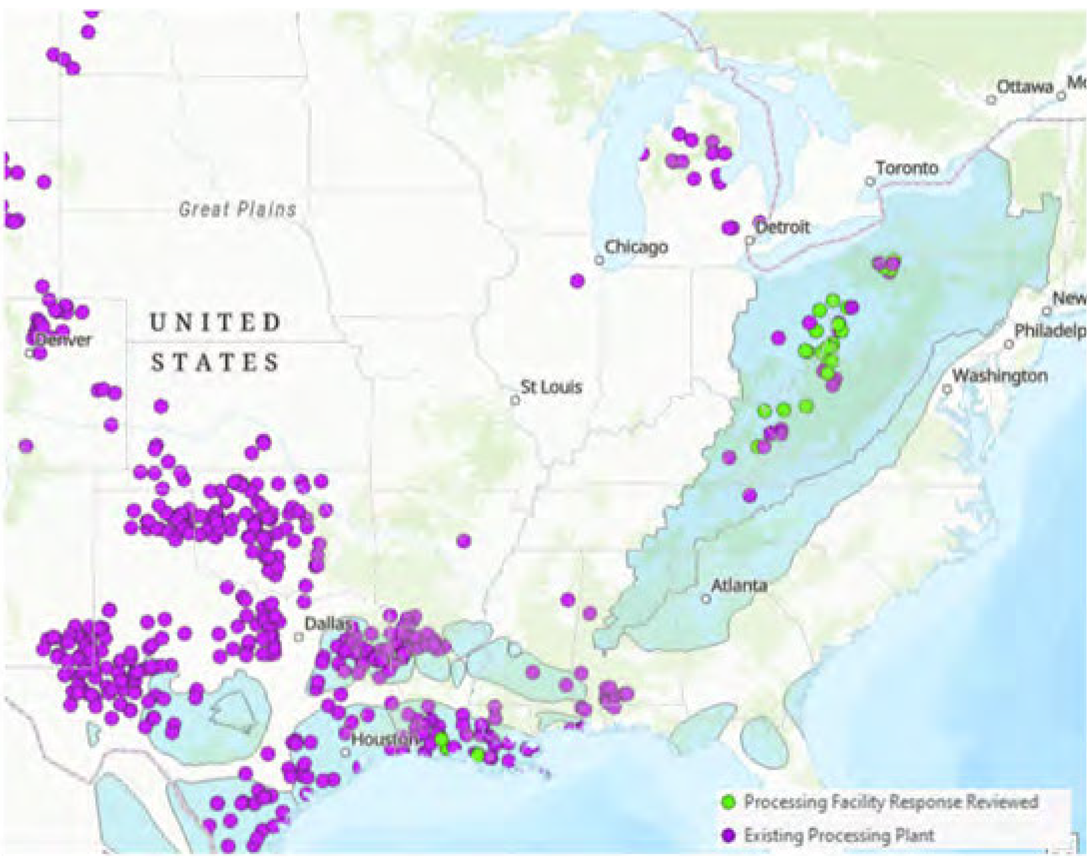
	Production Event Causes on December 25th	
	Natural Gas Infrastructure Condition	Facility Event Causes
Freeze-offs	Equipment freezing at well/gathering facilities.	55.4%
Downstream Issues	Third party/downstream issues (e.g., processing plant down)	1.0%
Access to roads cut-off	Road/access to well/gathering facilities	3.7%
Multiple	Multiple Issues (combination of two or more of above issues)	39.5%
Other Issues, Unrelated Issues	Proactive shut-in	0.1%
	Other Issues	0.3%
Total		100.0%

	Production Event Causes on December 26th	
	Natural Gas Infrastructure Condition	Facility Event Causes
Freeze-offs	Equipment freezing at well/gathering facilities.	51.8%
Downstream Issues	Third party/downstream issues (e.g., processing plant down)	1.0%
Access to roads cut-off	Road/access to well/gathering facilities	5.7%
Multiple	Multiple Issues (combination of two or more of above issues)	41.1%
Other Issues, Unrelated Issues	Proactive shut-in	0.1%
	Other Issues	0.3%
Total		100.0%

3. NATURAL GAS PROCESSING

The Team obtained data from a total sample size of 26 natural gas processing plants located in the Texas-Louisiana-Mississippi Salt Basin (8) and Appalachian Basin (18). However, the Report focuses on the Appalachian Basin because it experienced the largest decrease in natural gas supply during the Event. Data regarding the Texas-Louisiana-Mississippi Salt Basin is in Appendix D. See Figure 96, below for depiction of geographic locations of the processing facilities.

Figure 96: Natural Gas Processing Facilities in Event Area



As shown in Figure 97 below, temperatures declined drastically on December 23. Weather stations in Morgantown, West Virginia, which is located within the Appalachian Basin, captured temperatures ranging from 46 degrees to -2 degrees on December 23. This decline continued December 24, over the course of which the average temperature in Morgantown was 29 degrees below the historical normal.[260]

Figure 97: Morgantown, WV Actual Daily Temperatures

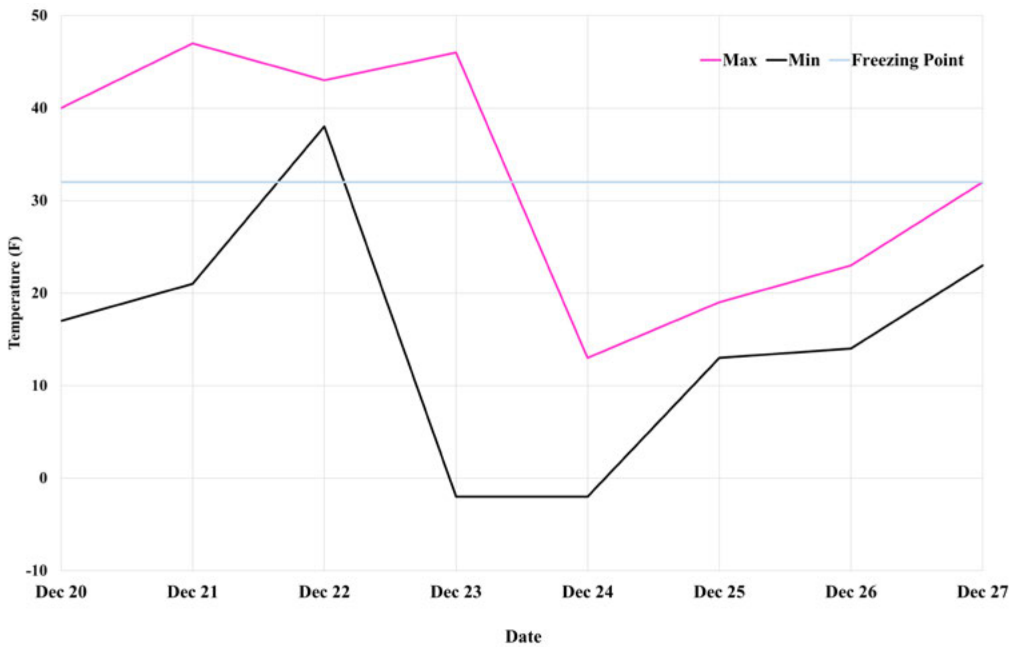
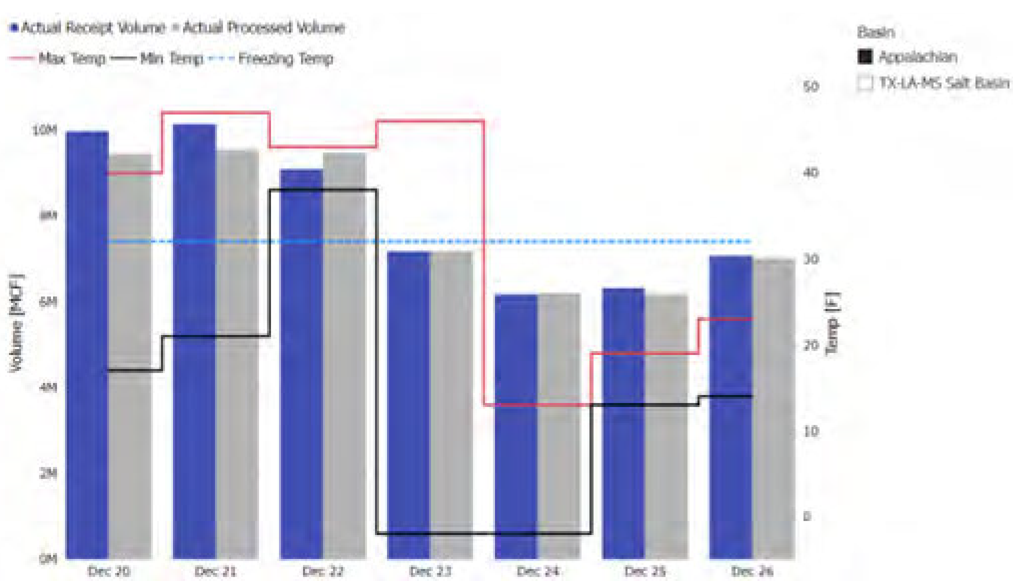


Figure 98: Appalachian Basin Processing Facility Receipt Volume and Processed Volume, December 20 – 26, 2022



260 *See* F gure 25 for departures from normal lows for December 25.

As temperatures plunged, natural gas demand increased, while at the same time, the volume of gas received by processing facilities declined, as seen in Figure 98, above.

Some processing facilities that participated in the inquiry reported they did not receive the full contracted amount of gas supply from producers. Despite not receiving all the gas they expected, processing facilities reported that they processed all the gas they received on the days that receipt volume was most decreased.

Processing losses, analyzed by the day of maximum losses in each basin, were largely caused by reduced gas supply, which in turn was caused by producers' equipment freezing or pressure issues in their gathering pipeline systems. However, as shown in Figure 99 below, as it became colder, some processing facilities also experienced mechanical outages/failures, power outages, and plant equipment Freezing Issues. Overall, the top causes in both basins are, in order, reduction in receipt volumes, producer freeze/pressure issues (these would also cause a reduction in receipt volumes but some producers expressly identified these causes), power outages, and processing facility mechanical outages. As shown in Figure 100, on the December 23 (the second) table, reduced natural gas receipts were by far the largest cause of lost processing facility volume, accounting for 71 to 84 percent of those losses. Processing facility Freezing Issues caused 10 to 16 percent of the lost processing volume, and curtailment or loss of power supply, which had been a substantial cause in the 2021 Event, maxed out at 5.6 percent. Only 25 percent of the 26 processing plants were protected from power outages by local power provider critical load designation agreements.

Figure 99: Appalachian Basin Event Processing Facility Event Causes—Dec. 22 – 29, 2022

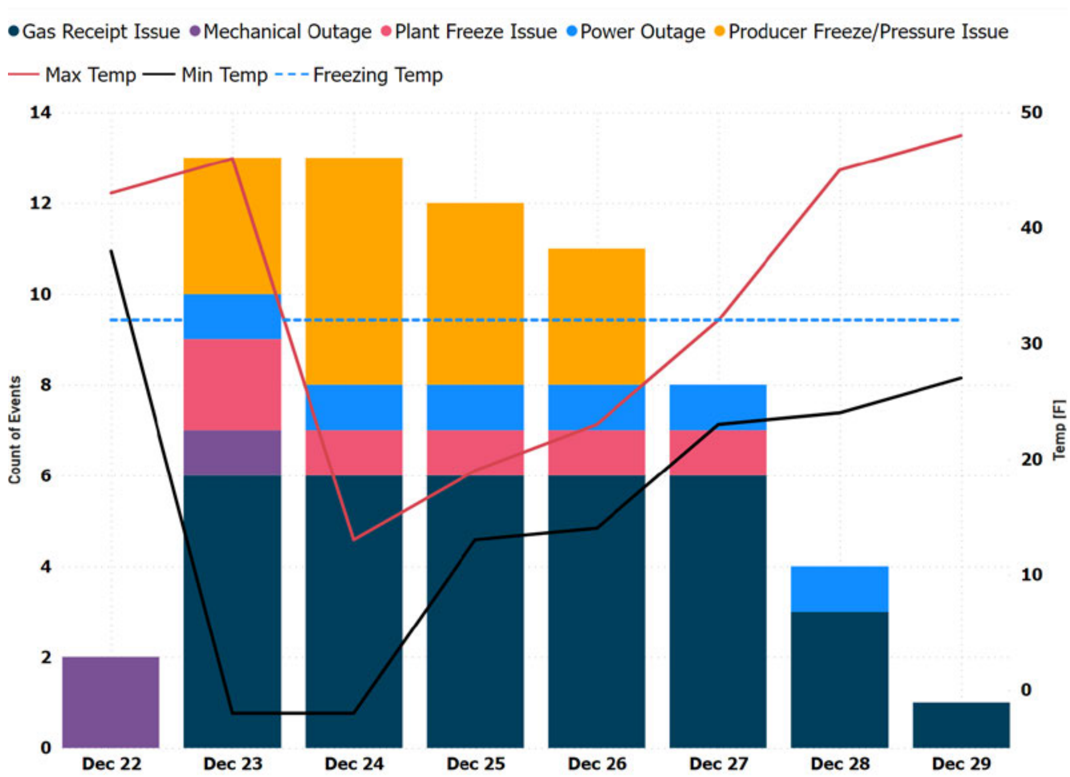


Figure 100: Processing Facilities Event Causes, December 22 – 26, 2022

Processing Facility Disruption Event Causes on December 22		
Cause	Natural Gas Infrastructure Conditon	Facility Event Causes
Freezing Temperature and Weather Conditions	Reduced Natural Gas Receipt from Production/Gathering/Facilities	71.4%
	Freezing Issues at Processing Facilities	0%
Loss of Power	Processing Facilties- Loss of Power Supply or curtailmennt	0%
Other issues	Mechanical Outage - Non weather Related	28.6%
Total		100%

* There were a total of 7 causes of processing plant events occuring on December 22

Processing Facility Disruption Event Causes on December 23		
Cause	Natural Gas Infrastructure Conditon	Facility Event Causes
Freezing Temperature and Weather Conditions	Reduced Natural Gas Receipt from Production/Gathering/Facilities	72.2%
	Freezing Issues at Processing Facilities	16.6%
Loss of Power	Processing Facilties- Loss of Power Supply or curtailmennt	5.6%
Other issues	Mechanical Outage - Non weather Related	5.6%
Total		100%

* There were a total of 18 causes of processing plant events occuring on December 23

Processing Facility Disruption Event Causes on December 24		
Cause	Natural Gas Infrastructure Conditon	Facility Event Causes
Freezing Temperature and Weather Conditions	Reduced Natural Gas Receipt from Production/Gathering/Facilities	81.82%
	Freezing Issues at Processing Facilities	13.60%
Loss of Power	Processing Facilties- Loss of Power Supply or curtailmennt	4.500%
Other issues	Mechanical Outage - Non weather Related	0%
Total		100%

* There were a total of 22 causes of processing plant events occuring on December 24

Processing Facility Disruption Event Causes on December 25		
Cause	Natural Gas Infrastructure Conditon	Facility Event Causes
Freezing Temperature and Weather Conditions	Reduced Natural Gas Receipt from Production/Gathering/Facilities	84.2%
	Freezing Issues at Processing Facilities	10.5%
Loss of Power	Processing Facilties- Loss of Power Supply or curtailmennt	5.3%
Other issues	Mechanical Outage - Non weather Related	0%
Total		100%

* There were a total of 19 causes of processing plant events occuring on December 25

Processing Facility Disruption Event Causes on December 26		
Cause	Natural Gas Infrastructure Conditon	Facility Event Causes
Freezing Temperature and Weather Conditions	Reduced Natural Gas Receipt from Production/Gathering/Facilities	83.3%
	Freezing Issues at Processing Facilities	11.1%
Loss of Power	Processing Facilties- Loss of Power Supply or curtailmennt	5.6%
Other issues	Mechanical Outage - Non weather Related	0%
Total		100%

* There were a total of 18 causes of processing plant events occuring on December 26

4. NATURAL GAS DELIVERY

The interstate natural gas pipeline facilities experienced 19 equipment issues which directly affected shippers, including Generation Owners and LDCs. The largest reported cause of equipment issues was weather/freezing issues, followed by mechanical issues (see Figure 101, below). The cold temperatures caused valves and compressor units at varying locations along the pipeline system to freeze, reducing or preventing the flow of gas through the facilities (see Figure 102, below). Eight force majeures, five of which were due to freezing, affected a total of 156 firm customers.[261] Yet a sampling of the force majeure provisions of interstate natural gas pipeline tariffs indicates that they either expressly included language that used “freezing of pipelines [or pipes or lines]” as examples of force majeure, even though pipeline owners can take measures to avoid

261 *See* Sect on .B.4(a)(3).

freezing of pipeline equipment; or they included broad language about "unscheduled repairs" or "mechanical or physical failure that affects the ability to transport gas," which could be interpreted to include freezing-related issues."[262] Similarly, the force majeure clause in the NAESB "Base Contract for Sale and Purchase of Natural Gas" expressly includes "weather related events affecting an entire geographic region, such as low temperatures which cause freezing or failure of wells or lines of pipe." Using express inclusions or broad language in force majeure clauses disincentivizes natural gas infrastructure entities from taking steps to ensure that natural gas will be available when it is most needed, during an extreme cold weather event.

Figure 101: Pipeline-Reported Equipment Issues Directly Affecting Shippers – Cause Breakdown

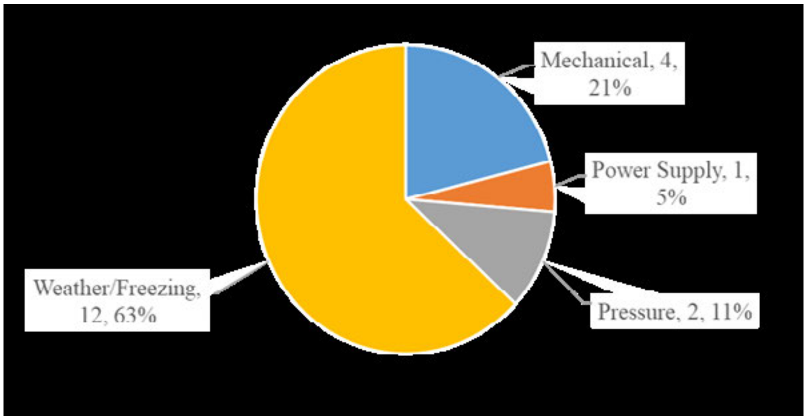
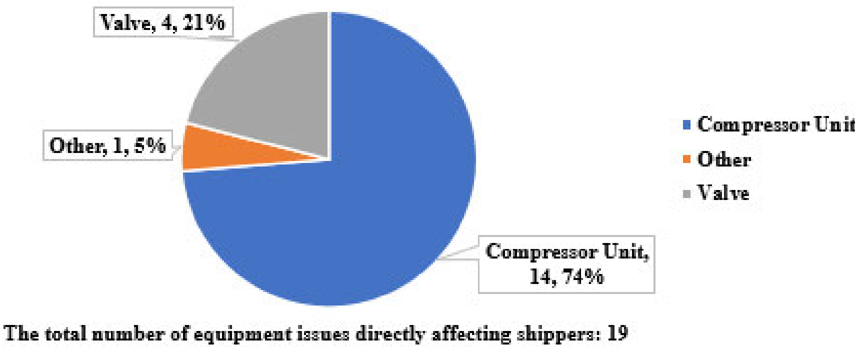
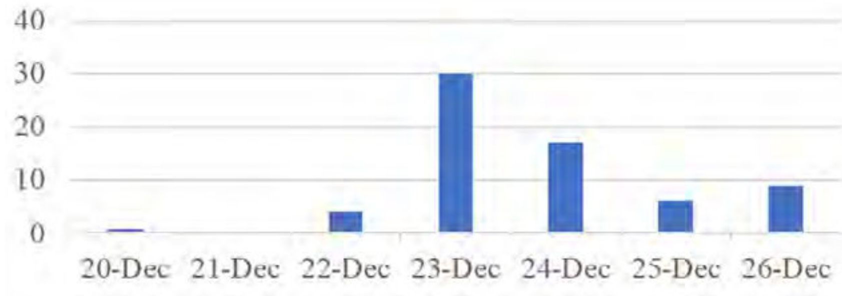


Figure 102: Pipeline-Reported Equipment Issues Directly Affecting Shippers by Equipment Type



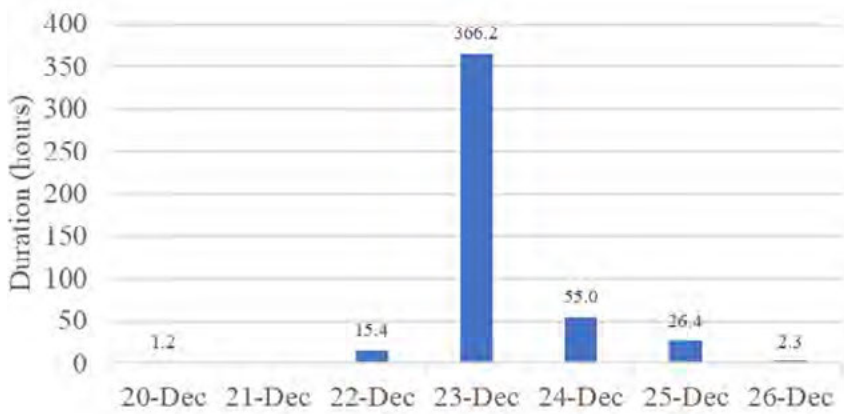
262 Rock es Express P pel ne, LLC, Tar ffs, § 21.2 Force Majeure (3.0.0), Columb a Gas Transm ss on. LLC, Basel ne Tar ffs, Gen. Terms & Cond t ons, § 15.1 Force Majeure (0.0.0), Northern Natural Gas Co, Gas Tar ffs, Sheet No. 217, G T and C § 10 Force Majeure (1.0.0), Transcont nental Gas P pe L ne Co. F fth Rev sed Volume No. 1, Prov s on and Contract Ent tlements, § 11 Force Ma eure (5.0.0).

Figure 103: Pipelines - Total Power Outages Reported



Eight of the 15 pipelines reported a total of 53 instances of commercial power loss at their facilities from December 20-26 (shown in Figure 103 above), averaging approximately nine hours in duration, although some lasted longer than three days (see Figure 104, below). Only one power outage impacted shippers because the compressor stations used redundant compressor units powered by gas-fueled backup or portable generation. Of the 15 pipelines that provided data, only four have facilities designated as critical with their electricity provider. Some pipelines stated that they did not see the need to designate critical facilities, while others stated that they prefer to communicate with electric providers during any load shedding events. One pipeline stated that it performed a study following the Event and did not identify any critical site within the service territory of its power provider.

Figure 104: Total Duration of Pipeline Power Outages



D.Grid Entities' Preparedness and Emergency Operations

1. SHORT-TERM LOAD FORECASTING ANALYSIS

A significant majority of the short-term forecasts (4-, 3-, 2-, and next-day peak load forecasts for actual peak loads) for all eight BAs underestimated the actual peak demand. There were only eight instances of the 64 short-term forecasts that overestimated the actual peak demand. The Mean Average Percent Error (MAPE) for all the short-term forecasts for the peak load of December 23 was approximately 11.25 percent and the MAPE for all the short-term forecasts for the peak load of December 24 was approximately 8.51 percent; with an average MAPE of 9.88 percent for both days for all eight BAs. The short-term forecasts generally improved as the day for the forecast peak demand approached, as shown in Figures 19 and 20, in Section III.

The Team identified some of the possible reasons for the underestimation of the actual peak demand: inaccurate weather forecasts, changes in consumer behavior, especially on peak, and changes to the grid (e.g., addition of non-conforming loads or population growth). The Team also found that many of the entities' models lacked the data history (e.g., similar historical days) for the holiday weekend winter peak extreme cold weather conditions forecast. Some BA operators made manual adjustments to the load forecasts to attempt to make them more realistic. Those that used an "adder" to account for potential load forecast error (LG&E/KU, Santee Cooper) had the lowest MAPE for December 24.

While weather-related factors were important, those that did "backcasts" found that their load forecasts were still off even after being corrected for temperature, so clearly temperature was only one factor, although an important one. Multiple entities noted the difficulty of predicting load for a holiday weekend, when there may be few holiday weekends within the historical data available to the model, and few or none of those may coincide with colder-than-ordinary weather. The combination of a holiday weekend plus extreme cold weather made reliance on prior similar days especially challenging. Most entities expected holidays to lower load, but because of the extreme cold, did not see this pattern emerge. A couple of entities mentioned that they had experienced load growth within their service territory, and the importance of being aware of where this load growth is occurring and its composition (is it residential? Data centers? Commercial? Industrial?)

Another important element to identify in an entity's load is the presence of resistive heating. As explained in the 2021 Report in connection with Recommendation 16,[263] as temperatures drop below zero, homes with heat pumps must rely on electric resistance heating, and the hourly electric demand in kilowatts increases sharply as temperatures decline, to up to four times as much as at 32 degrees, once the temperature reaches minus 10.[264] Multiple entities mentioned the fact that temperatures dropped extremely quickly from relatively temperate temperatures to abnormal lows for their area. When temperatures drop very quickly, but homeowners keep their heat set at the same temperature, heating units must run constantly to try to maintain a steady temperature, rather than cycling as is expected and calculated for "normal" winter load forecasts. Some mentioned the severity of the cold—for one entity, three standard deviations beyond their normal December lows—so that they did not have loads at those temperatures in the historical sample of loads used in the load forecasting models (three years for the majority of the entities).

263 "BAs should have staff w th spec al zed knowledge of how weather mpacts load, nclud ng the effects of heat pump backup heat ng and other supplemental electr c heat ng . . ." 2021 Report at 225

264 2021 Report at 225 and F gure 108.

2. ANALYSIS OF OPERATIONAL PLANNING PROCESSES

As summarized earlier in Section III, the BAs thought prior to the Event that they individually had sufficient resources to meet their respective expected forecast electricity demands. They anticipated the possibility of some level of unplanned generation outages from the winter storm; they were proactive in their preparation efforts. To determine steps the BAs could take to improve their processes, the Team considered the following outcomes from the Event:

- Most of the BAs underforecast their peak electricity demands experienced on December 23-24.
- The BAs did not anticipate the significant level of unplanned generation outages and derates that would occur during the storm, or the rates at which they would occur, which were similar to the outage rates experienced in Texas during Winter Storm Uri in 2021.[265]
- Many natural gas-fired generating units were unavailable because they had not made advance arrangements for natural gas fuel supply for when they ultimately would be committed to operate, and by the time they were notified of their commitment, natural gas supplies were not available.
- The entities thought that they had sufficient reserves to meet their anticipated peak electricity demands, but the severity and widespread nature of the storm, which left multiple neighboring entities in the same position, forced them into a reactionary state of operation, with limited flexibility, options, or time. As a result, several entities needed to shed firm load.

Short-term planning processes typically use deterministic methods and calculations to develop short range resource plans for the next day or several days in advance of the operating day, with plans easily adjusted for the unplanned outage of one or two generation resources through deterministic recalculations. However, the Team found that preparation for another event like Winter Storm Elliott and other extreme cold weather events would benefit from considering a wider range of outcomes representing greater uncertainty, multiple days in advance of the extreme cold weather operating day in risk areas such as:

- Load forecast
- Generation extreme cold weather availability
- Generation fuel availability
- Multiple-neighboring entity impact
- Transmission system constraints

The Team recognizes consideration of this wider range of outcomes may be seen as suggesting use of long-range planning "probabilistic methods" in the control room. However, because these cold weather events have repeatedly revealed significant differences between what was expected and what the operators actually faced, the Team finds that considering a wider range of outcomes representing greater uncertainty should aid in preparation and decision-making multiple days in advance of future extreme cold weather events like Winter Storm Elliott.

3. ANALYSIS OF EMERGENCY OPERATING CONDITIONS AND COORDINATION

a. Coincident high electricity demands, unplanned generation outages and derates, and many Energy Emergency Alerts

Several of the Core BAs' resource assessments and scenarios for the winter 2022-2023 season relied

265 Sect on .B.1. above, descr bes TVA's unplanned generat on outages wh ch ncreased by 6,000 MW from shortly before 1:00 a.m. to 8:00 a.m. on December 23. W th n the PJM footpr nt, unplanned outages and derates began to escalate shortly after 4 a.m. on December 23, and then from about 8:00 a.m. to 5:00 p.m., they rap dly escalated at a rate of over 2,200 MW per hour. The TVA and PJM exper ences were s m lar to the rate of ncrease n generat on outages and derates that was exper enced n the February 2021 event n the ERCOT footpr nt, from February 14, 10:00 p.m. to February 15, 1:00 p.m. (3 hour per od). *See* 2021 Report at 130

on the availability of external generation resources (i.e., purchase power/import power schedules and emergency energy availability) to meet winter season reserve targets. This reliance is dependent on both availability of the power to be imported and on the interregional transfer capability to deliver the power. Some of the BAs' approaches to reliance on external generation resources in planning to serve higher than normal winter peak load levels combined with higher levels of resource outages are as follows:

- One BA identified use of firm transmission (for importing power), combined with economic interruptible energy products for reserves coverage, of 505 MW, 1,519 MW, and 205 MW, for the months of December 2022, January 2023, and February 2023, respectively, to meet its winter reserve above normal load/above normal resource outage scenario margins.
- Another BA assumed 1,000 MW in purchases as part of its 2023 winter season planning and sensitivity analysis.
- One BA calculated a negative reserve margin based on its 90/10 load forecast coupled with expected generation outages, even with use of demand response measures (implying a likely need for purchase power during extreme cold weather conditions).
- Another BA calculated a negative reserve margin based on its 90/10 load forecast without accounting for any generation outages, and with use of demand response measures (again, implying likely need for purchase power during extreme cold weather conditions).

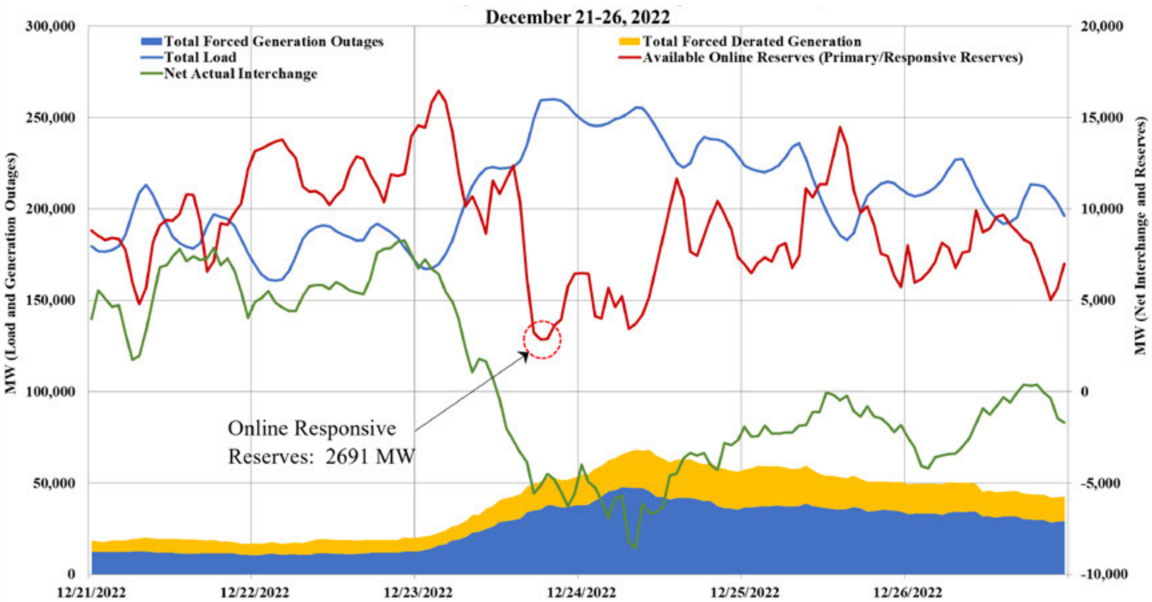
As described above in Section III, during the Event, many BAs in the U.S. Eastern Interconnection had to declare energy emergencies, with some shedding firm load. Most BAs experienced their highest levels of unplanned generation outages and derates and winter peak loads within several hours of one another as Winter Storm Elliott blanketed their footprints simultaneously.[266] A BA's reliance on purchased or import power to meet its system load plus reserves often meant the difference between having to shed load or not. See Figure 39.

System load in the U.S. portion of the Eastern Interconnection increased by 132,000 MW during a 14-hour period coinciding with the arrival of Winter Storm Elliott. By 10 a.m. on December 24, system load levels for several BAs were well above 90 percent of their respective peak loads during Winter Storm Elliott, and most of those BAs had already invoked load management measures (EEA 2) or even firm load interruptions, reducing the percentages which are shown in Figure 39, above. Had the load management and firm load shed measures not been in place, the December 24 peak would have been close to the December 23 evening peak of 482,444 MW (shown in Figure 39, above).

The affected BAs arranged for purchase power imports to cover forecast or actual declining reserves positions that reflected their own unplanned generation outages and derates coupled with rising forecast and actual system loads for December 23 and 24. Those BAs that anticipated potential need and already had prior arrangements for purchase power took steps to schedule those deliveries with the purchase-selling entity (within the source BA) for the coldest days. Because many of the BAs that were in need are directly connected via AC ties as illustrated in Figure 12 (listing the tie lines between BAs), arranging for purchase power imports from a purchase-selling entity within an adjacent BA during less extreme circumstances would normally be fairly straightforward, especially for BAs directly connected to each other like PJM and Duke, or PJM and TVA. But most of the directly-neighboring BAs found themselves simultaneously experiencing Energy Emergencies and did not have energy to share with their neighbors.

266 The five extreme cold weather events n the past 11 years (2011, 2014, 2018, 2021, and 2022) covered large geograph c reg ons. Dur ng the 2018 and 2021 events, generat on reserves ex sted n d stant operat ng footpr nts where the extreme cold weather event was not as ntense or had not yet mpacted those areas, wh ch afforded the opportun ty for power transfers, l m ted by transm ss on constra nts.

Figure 105: Total Reserves, Generation Outages and Derates, and Load for Event Area: December 21 - December 26, 2022



b. Health of the Eastern Interconnection during Winter Storm Elliott peak electricity demand

The Core Event Area and the U.S. portion of the Eastern Interconnection were experiencing the highest winter electricity demands during Winter Storm Elliott, as shown in Figure 39, above. Meanwhile, while system loads were peaking across the Interconnection, total unplanned generation outages and derates were climbing as shown in Figure 69, above. To gain perspective on the overall health of the Interconnection during this most critical period of the Event, the Team estimated the remaining responsive reserves. The Team reviewed:

- the total online/synchronized reserves in the Core Event Area (see Figure 105),
- the system load of the U.S. portion of the Eastern Interconnection (see Figure 39), and
- total unavailable generation in the U.S. portion of the Eastern Interconnection during the Event (see Figure 37).

The Team found that there were periods during the evening of December 23 and the morning of December 24 when the "potential responsive reserves" (which included online and any offline resources) were lowest while system demand was at its highest levels, as illustrated in Figure 105, below. The Team notes that its estimates of how low responsive reserves dropped are conservative, since they may include offline capacity, and do not account for additional offline capacity in other portions of the Eastern Interconnection.[267] During this same period, Eastern Interconnection frequency excursions were common. Figure 106, below, illustrates one-minute-average system frequency, which declined below 59.95 Hz several times on the evening of December 23 and the morning of December 24 during periods of low responsive reserve capacity.

267 The Team conservat vely est mated capac ty; the actual capac ty shortage could have been worse as the Team d d not account for any offl ne capac ty n Canada or the Flor da pen nsula (.e., other port ons of the Eastern nterconnect on), wh ch were not w th n the Event Area.

Figure 106: Eastern Interconnection Frequency: December 23, 4:00 p.m. to December 24, 12:00 p.m.

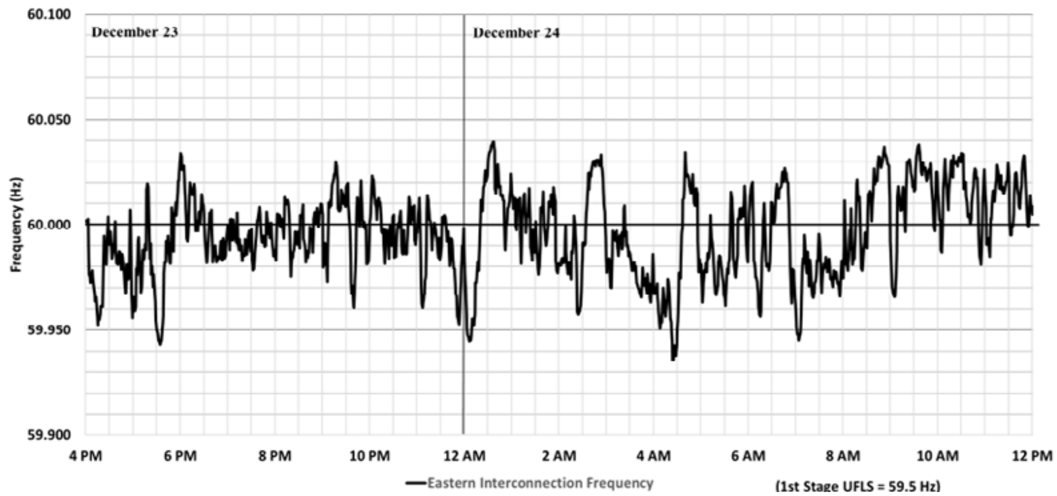
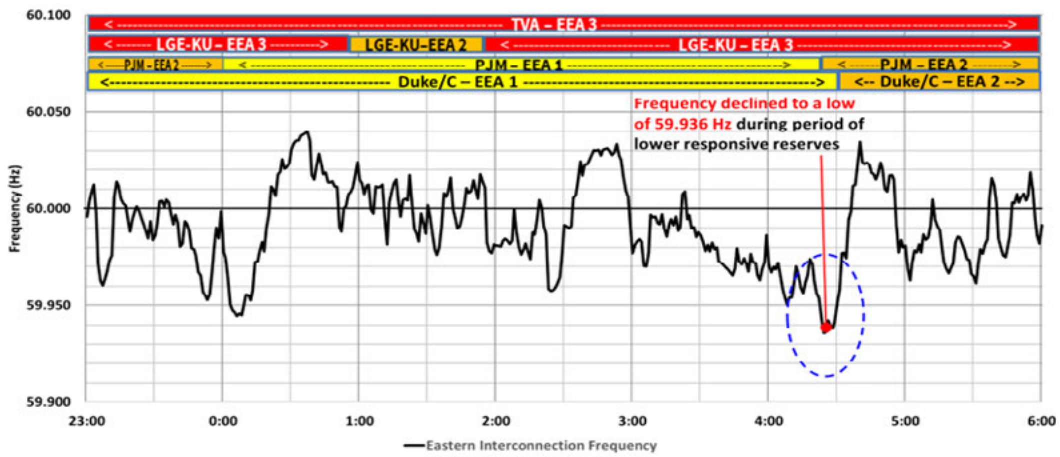


Figure 107: Eastern Interconnection Frequency: December 23, 11:00 p.m. to December 24, 6:00 a.m.



As seen in Figure 107 above, at about 5:40 p.m. on December 23, the Eastern Interconnection frequency decreased to a one-minute average of 59.943 Hz, and dropped to its lowest point during the Event, 59.936 Hz, at about 4:25 a.m. on the morning of December 24. Based on this limited review, the Team is concerned that, accounting for next contingencies (e.g., large generation outage, single point of failure contingency), the Eastern Interconnection appears to have been at risk of potential instability during this timeframe of escalating winter system demands, rapidly escalating unplanned generation outages and derates, and declining responsive reserves.[268]

c. Grid Communications and Coordination

Before and during the Event, RCs remained in contact with each other, as well as with their member BAs, either directly via voice communication or through the NERC-managed Reliability Coordinator Information System (RCIS). RCs were able to communicate EEAs and other emergency measures they took during the Event on the

268 The study should also cons der how close the nterconnect on may have been to an underfrequency load shed event.

RCIS message system. All RCs have read and write access to the RCIS. Although they do not have write access to the RCIS, BAs and TOPs can request read access to the system. Given the valuable information shared by RCs on the RCIS during emergency events, BAs that have not already done so should request access to the RCIS system and monitor those communications during extreme cold weather events, at a minimum. BAs can also ask their RC to communicate on RCIS their ability, or lack thereof, to provide energy to other BAs experiencing energy shortages during emergencies. This practice could reduce the number of entities that a BA short on energy would need to contact in an emergency.

Generally, many of the RCs have a daily operational call, as well as ad hoc calls and other communications as system conditions dictate. Examples of some of the standing calls relevant to the Event include: (1) NPCC has a brief standing daily 9:30 a.m. call (which includes PJM, MISO, and others), which can be initiated by any RC, and any follow up items from these calls are assigned to control room managers;[269] (2) MISO has a standing daily 8:00 a.m. MISO RC coordination conference call, which includes TOPs and BAs within the MISO Reliability Coordination Area, as well as neighboring RCs, including PJM, SPP, and TVA.

Before and during the Event, RCs coordinated on specific issues and concerns affecting their systems, including the following:

- VACAR-South RC coordinated with adjacent RCs on two potential thermal overloads, one involving a tie line between DEP and PJM and the other involving a tie line between Santee Cooper and Southern. In both cases, the potential overloads were mitigated through the use of adjusted ratings.
- SPP RC agreed to allow an additional increase in the RDT on Saturday, December 24, for an emergency energy request that TVA made from MISO.
- TVA RC coordinated with PJM RC to mitigate real-time overloads within the PJM/AEP footprint on the morning of December 23, and PJM and TVA RCs also coordinated to resolve low voltage conditions observed in the East Kentucky Power Cooperative area.

When conditions permitted, entities directly impacted by the storm provided neighboring entities with emergency energy. Examples included:

- PJM, Duke, MISO, and Southern provided emergency energy to TVA,
- TVA provided emergency energy to LG&E/KU,
- Florida Power and Light and MISO provided emergency energy to Southern, and
- Southern provided emergency energy to DESC.

As described earlier, PJM was able to leverage its simultaneous activation of reserves/SAR procedure with NPCC during the Event.[270] During the evening of December 23, for example, PJM asked NPCC for reserves support (up to 1,500 MW) during the period that PJM activated its Synchronous Reserves emergency procedure. The Team found that the entities communicated and cooperated well during the Event, doing as much as possible to assist their neighboring BAs even while under their own systems were experiencing emergency conditions.

269 *See*, Northeast Power Coord nat ng Counc l, nc., NPCC Emergency Preparedness Commun cat ons Procedures (Sept. 2, 2022), https://www.npcc.org/content/docs/publ c/program areas/standards and cr ter a/reg onal cr ter a/procedures/c 01 emergency preparedness procedure.pdf. (outl n ng procedures for NPCC ad hoc call).

270 *See* R22 and Attachment B of the NPCC Reg onal Rel ab l ty Reference D rectory # 5 Reserve https://www.npcc.org/content/docs/publ c/program areas/standards and cr ter a/reg onal cr ter a/d rector es/d rectory 5 reserve 20200426.pdf.

E. Variable Energy Resources’ Performance and Uncertainty Analysis

Variable energy resources (VERs) such as wind and solar were part of the energy supply mix during the Event. During the Event, solar and wind comprised 1.94 percent and 1.12 percent of installed capacity, respectively, in the core Event Area, as noted in Figure 11. For PJM, solar and wind comprised 1 percent and 2 percent, respectively, of the net installed generation capacity. Figure 108, below, illustrates the actual generation output by VERs, as a percentage of the total generation production output in the PJM footprint during the Event.

Figure 109, below, shows day-ahead versus actual production profiles of both wind and solar resources in PJM during the Event. Winter Storm Elliott occurred shortly after the winter solstice,[271] resulting in a relatively narrow potential solar production time window each day during the Event.

Figure 108: PJM Percent VER Actual Generation Production Output, December 21 – 26, 2022

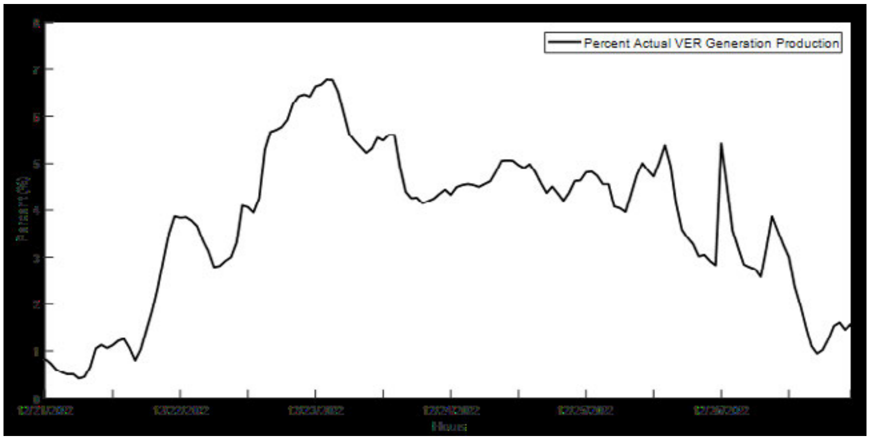
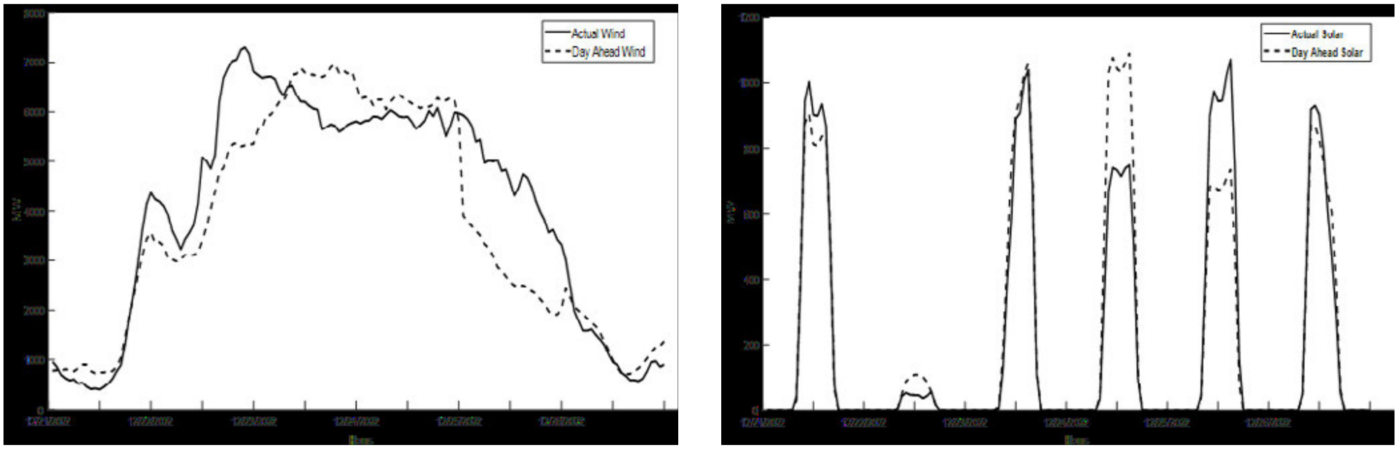


Figure 109: PJM Day-Ahead and Actual Hourly MW Wind and Solar Production, December 21 – 26, 2022



271 W nter So st ce for the Northern Hem sphere was December 21, 2022 4:47 p.m. The w nter so st ce marks the shortest day and ongest n ght of the year.

Figure 110: MISO Actual Wind Generation – Storms Uri (2021) and Elliott (2022)[272]

The limited availability of solar production time during winter, when daylight hours are shorter, highlights the value of storing energy from solar production for when it is needed most during the winter non-daylight peak load timeframes. For example, DESC noted that on the morning of December 24, their solar resources began to produce energy, which, while after the morning peak, contributed to DESC's ability to pump water at its pumped storage facility so that its capacity would be available for the December 24 evening peak and the December 25 pre-dawn morning peak.

Wind energy production in higher-penetration areas west of the core Event Area (SPP, MISO) was high, especially during the onset of the Event on December 22 and 23. Figure 110, above, shows a wind production comparison between Winter Storm Uri and Winter Storm Elliott in MISO.

For SPP, wind resources performed above accredited capacity on December 22 at 17,900 MW, coinciding with high SPP system load. With high system loads expected to continue, SPP had to anticipate uncertainty including whether the forecast for high wind levels would hold, and the extent to which wind farms would be shut down or derated for low ambient temperatures or high wind cutoff. The actual wind generation output level slowly decreased after the December 22 peak load and reached its lowest level of 2,700 MW 20 hours later, on December 24 at 6 p.m.[273] SPP's experience illustrates the challenge of aligning VER production levels with power grid needs. Absent energy storage opportunities, the higher variability of wind and solar production increases the demand for dispatchable generation with high ramping capacity[274] to balance generation with load during times when wind or solar power is low, and the system is near peak demand.

Understanding and modeling uncertainties with VER production in the operations planning horizon can help minimize reliability and resource adequacy risks, especially at times of system stress, such as during extreme cold weather events. Shifting from deterministic to probabilistic methods for resource availability/adequacy analyses can better model the uncertainties surrounding VER production. See Recommendation 8 in section V.

272 Repr nted w th perm ss on of M SO.

273 SPP Report at 6.

274 *See* Department of Energy, *Importance of Flexible Electricity Supply* (May 2011), https://www1.eere.energy.gov/solar/pdfs/50060.pdf.

V. RECOMMENDATIONS[275]

A. Generator Cold Weather Reliability

Each successive analysis of extreme cold weather events has highlighted the need for generating units to proactively prepare for the onset of cold weather events.[276] Each inquiry report has built on previous analyses and findings to explain how generating units can best achieve that end. In August 2021, the Commission approved the adoption of EOP-011-2, effective April 1, 2023, in response to a recommendation from the 2018 Report, and required Generator Owners to have cold weather preparedness plans for their units. The 2021 Report took the next logical step by recommending that generating units be required to "(i) identify cold-weather-critical components and systems and (ii) identify and implement freeze protection measures for those components and systems."[277] The 2021 Report also recommended that generating units that experienced unplanned outages due to freezing should be required to develop Corrective Action Plans to guard against future outages.[278]

More recently, the Commission has approved revisions to the NERC Reliability Standards, in EOP-012-1, that implemented recommendations from the 2021 Report.[279] These changes, the Commission found, "represent[] an improvement to the Reliability Standards and enhance[] the reliable operation of the Bulk-Power System by requiring generator owners to implement freeze protection measures, develop enhanced cold weather preparedness plans, implement annual trainings, draft and implement corrective action plans to address freezing issues, and provide certain cold weather operating parameters to Reliability Coordinators, Transmission Operators, and Balancing authorities for use in their analyses and planning."[280] These modifications have not yet become effective.

Recommendation 1(a): Findings support the need for prompt development and implementation of the remaining recommended revisions to the Reliability Standards from 2021 Report Key Recommendation 1 to strengthen generators' ability to maintain extreme cold weather performance.

Despite the fact that nearly two thirds of all generating units that provided data indicated that they had begun to make improvements to their cold weather preparedness plans in response to the findings of the 2021 Report, and that many units had already begun to implement improvements required under EOP-011-2, R7.3.2, prior to its effective date of April 2023, 111,000 MW of generating units in the Event footprint still experienced unplanned outages, derates or failures to start due to Freezing Issues.[281] The Team considered whether to recommend additional mandatory Reliability Standards, but with many important Standards either approved, but not yet effective, or still in the drafting stage (e.g. identification of generator cold weather critical components, developing Corrective Action Plans

275 Because the recommendat ons are ntended to be shared w dely and may be shared w thout the rema nder of the Report, terms that have been otherw se been abbrev ated elsewhere n the Report, such as GOs/GOPs for Generator Owners/Operators, w ll be spelled out the first t methey are used n each recommendat on.

276 *See* 2021 Report at 185 86.

277 *See* 2021 Report at 185 86, Recommendat ons 1(a) and (b).

278 *See N. Am. Elec. Reliability Corp.,* 176 FERC ¶ 61,119, at P 1 (2021).

279 The first of ts Requ rements become effect ve October 1, 2024.

280 *N. Am. Elec. Reliability Corp.,* 182 FERC ¶ 61,094, at P 36 (2023).

281 An encourag ng find ng was that roughly two th rds of all generat ng un ts sa d they had begun to make mprovements to the r cold weather preparedness plans n response to the find ngs of the 2021 Report.

to operate at Extreme Cold Weather Temperatures), this recommendation focuses instead on fully implementing the recommendations already made in response to the 2021 Report. That over 75 percent of the generating units with unplanned outages due to Freezing Issues failed above their documented minimum operating temperatures suggests that work in this area is not yet complete. For additional background and analysis relevant to Recommendation 1(a) see section IV.B.3., above.

Recommendation 1(b): Findings from the Report support the need for robust monitoring by NERC and the Regional Entities of compliance with the currently-effective and approved generator cold weather Reliability Standards, to determine if reliability gaps exist. NERC should identify the generating units that are at the highest risk during extreme cold weather and work with the Regional Entities (and Balancing Authorities, if applicable) to perform cold weather verifications of those generating units until all of the extreme cold weather Standards proposed by the 2021 Report are approved and effective. (Verify highest risk units by Q4, 2023; implement by Q3, 2024)

As mentioned in 1(a), the Team considered recommending additional Reliability Standards, including for several of the sub-parts of Recommendation 1, but was persuaded to focus on fully implementing the 2021 Report recommendations. Robust compliance monitoring of the currently-effective and approved extreme cold weather Standards can help to discern whether there are patterns which suggest that sub-parts of Recommendation 1 may need to be added to the Standards. For example, if compliance monitoring were to show that large numbers of Generator Owners/Operators were not fully-prepared for winter until mid-December or later, it may suggest that Recommendation 1(g) should be considered for addition to the Standards.

Given that the Extreme Cold Weather Preparedness and Operations Reliability Standards will not be fully effective until May 2028, and that generating units continue to experience high volumes of unplanned outages due to the top three causes of Freezing and Fuel issues as well as Mechanical/Electrical Issues, the Team considered what could be done in the meantime to improve generating unit performance to enhance the reliable operation of the grid. The Team recommends identifying those units at the highest risk of unplanned outages due to Freezing Issues (based on generating units' performance in previous events, their responses to NERC's Level 3 Alert or other criteria) for expedited cold weather verifications. The Team also recommends additional near-term, but slightly less expedited, cold weather verifications as explained in the next recommendation.

Recommendation 1(c): Generator Owners/Operators should assess their own freeze protection measure vulnerability, and NERC or the Regional Entities should perform targeted cold weather verifications pursuant to a risk-based approach.

Generator Owners/Operators should not wait for an extreme cold weather event to occur in their Balancing Authority Area, but should learn from the experiences of others, as well as the many resources available.[282] Based on the guidance provided by the Report, the 2021 Report, and the resources available from NERC and the Regional Entities, GOs/GOPs should assess their own freeze protection measures protecting generator cold weather critical components, and determine whether the generator cold weather critical components continue to be vulnerable to extreme cold, the accelerated cooling effect of wind, and precipitation. To determine whether GOs/GOPs are implementing the currently-effective cold weather Reliability Standards, NERC and the Regional Entities should conduct targeted cold weather verifications, using a risk-based approach. The GOs/GOPs selected would not be those considered at the highest risk of unplanned outages due to Freezing Issues, (i.e., those that are targeted by Recommendation 1(b)), but should be those in the next tier of risk and below. These verifications

282 *See* note 52 for a l st of resources.

should continue until all of the Reliability Standards revisions recommended by Key Recommendation 1 of the 2021 Report have become effective. For additional information in support of Recommendation 1(c) see Key Recommendation 1 in the 2021 Report.

Recommendation 1(d): Generator Owners/Operators of generating units that have experienced outages, derates, or failures to start above their documented operating temperature limits should consider conducting engineering design reviews to: (1) evaluate the accuracy and completeness of existing design information (including as it relates to the documented operating temperature limits) and calculated extreme cold weather operational thresholds: (2) evaluate whether existing freeze protection measures are adequate to protect their identified generator cold weather critical components; (3) evaluate whether design features to address cold weather and freezing conditions are being optimally implemented; (4) evaluate the impact of any modifications or additions to the original design on the documented operating temperature limits; (5) evaluate whether any modifications or additions resulted in new generator cold weather critical components; (6) evaluate the impact a unit's "cold" versus "hot" status has on its design limits, including the identification of a "cold start-up" temperature for each unit, if applicable; and (7) determine whether the generating unit's operating characteristics have been altered in a way that creates a potential "weak link" component.

The Team recommends that Generator Owners/Operators consider taking additional steps to ensure the reliability of their generating units for the substantial number of units that, during Winter Storm Elliott, experienced Freezing Issues at temperatures above their documented operating temperature limits. The failures above the units' documented operating temperature limits suggest that the information relied upon by many generators may be inaccurate or may no longer be valid after modifications made to the generating units. Generator Owners/Operators that have experienced unplanned outages, derates, or failures to start due to freezing during extreme cold weather events should consider reviewing their documented operating temperature limits, with appropriate expert assistance, to determine whether modifications have changed their limits or whether the limits should be changed for some other reason. A generating unit may have a higher "cold" low temperature limit (the temperature at which it can start in extreme cold weather, when it has not already been running, versus the "hot" temperature, at which it can run continuously). Identifying these temperatures and sharing them with the BA is critical. However, the Team cautions against GOs/GOPs simply raising their documented operating temperature limits to temperatures above those at which the units failed during the Event, without analyzing whether the units could perform at lower temperatures with appropriate protection of their cold weather critical components.

Recommendation 1(e): Generator Owners/Operators should consider conducting operational/functional testing of their "active" freeze protection systems.

Generator Owners/Operators should consider conducting operational and functional testing of their "active" freeze protection systems (e.g., heat trace circuitry/controls, partial discharge recirculation systems) on at least an annual basis, and always prior to winter, to ensure their continued functionality during extreme cold weather events. Like other systems, active freeze protection systems are subject to wear and tear over time. For instance, even a small section of inoperable heat trace system or circuit can leave a critical component unprotected, leading to a freezing-related outage. A heat trace system that no longer properly alarms for circuits that are inoperable will not warn the GO/GOP that its critical components are vulnerable to freezing.

Recommendation 1(f): Generator Owners/Operators should communicate their low temperature limits, and changes to those limits, to their Balancing Authority and Reliability Coordinator on a real-time basis.

Discussions with Balancing Authority representatives while preparing the Report underscored the substantial efforts that BA personnel took in real time to activate generation; only for them to learn that that the generation was unavailable. As noted in PJM's analysis of its own response to Winter Storm Elliott, on the afternoon of December 24, 2022, its operational situation was "strained" in part because of a lack of reliable information of this kind:

> *PJM had put generation resources on notice, through Advisories and Alerts, of PJM's need for them to be prepared to run. PJM relied on Generator Owner/operator-submitted data and believed these reserves were available. In many cases, this data did not reflect the actual capability of the generator and PJM would only learn of the generation resource failures at the time PJM was expecting these resources to begin to run.*[283]

Balancing Authorities seeking to address cold weather events should not be expected to learn such information on an ad hoc basis while simultaneously attempting to respond to worsening generation conditions and/or increased load. The onus should be placed on generating units to communicate and update such information, in real time, to BAs. If a GO/GOP knows that there is a meaningful difference between its cold start-up temperature and the temperature at which it can continue to operate when warm, the GO/GOP should inform the BA, so that the BA can consider the generating unit for pre-operational warming in advance of extreme cold weather events. Before an extreme cold weather event, GOs/GOPs should consider whether high winds or precipitation might affect their ability to perform at the documented low temperature limit(s) that they provided to the BA. Generator Owners/Generator Operators should update this data in real time, and BAs should consider amending their tariffs or procedures to require real-time updates if not already required. BAs should use all information provided by GOs/GOPs regarding the operating limits of their generating units to the fullest extent possible in their operations.

Recommendation 1(g): Generator Owners/Operators should complete their preparations for winter, including implementing their winter preparedness plans and inspecting and maintaining their generating units' freeze protection measures, no later than the earliest first freeze date for the generating unit's location, as determined by National Oceanic and Atmospheric Administration data.[284] Generator Owners/Operators should maintain those preparations until after the last freeze date, as provided by the same data. Those preparations are in addition to any preparations, inspection or maintenance done in anticipation of a specific extreme cold weather event.

Although annual inspections and maintenance of generating units' freeze protection measures are required by EOP-011-2 R 7.2, some evidence suggests that Generator Owners/Operators may not have completed freeze protection maintenance on all of their units before Winter Storm Elliott hit, relatively early in the winter. Winter Storm Elliott is not the only proof that the worst weather can happen early in the season—in the 2021 Report, Appendix B examined five extreme cold weather events that impacted Texas and the South Central U.S. Two of those events happened in December, one in January, and two in February. December is too late for GOs/GOPs to be finishing their preparation for winter.

(1(c) to 1(g): Implement as soon as possible, but by no later than Q4, 2025)

Recommendation 2: NERC should initiate a technical review of the individual causes of cold-weather-related unplanned generation outages caused by Mechanical/Electrical Issues during the Event to identify the root causes of these failures with the goal of determining what can be done to reduce the frequency of these outages during extreme cold weather events. The study should also consider whether additional Reliability Standards are appropriate to address the root causes of these issues. The study should be conducted by

283 PJM Report at 28.

284 *National Weather Service Frost and Freeze Information* (Sept. 2022), https://www.weather.gov/ wx/fallfrost nfo.

either an independent subject-matter expert such as the Electric Power Research Institute or an academic institution, with participation by Generation Owners/ Generation Operators on scoping and providing generating-unit-specific technical expertise. (Initiate Technical Review by Q1, 2024)

Successive reports reviewing cold weather events have consistently demonstrated a steady relationship between decreasing temperatures and a rise in Mechanical/ Electrical Issues in generating units. The 2021 Report suggested that further analysis was required by Generation Owners to "understand the impact of extreme cold weather on mechanical/electrical failures, so that GOs can identify possible methods of reducing the incidence of unplanned outages, derates and failures to start due to [Mechanical/Electrical Issues] during similar events."[285] The persistence of these issues, even in the face of increased awareness, suggests further action needs to be taken.

An independent subject matter group with knowledge of electrical generator design and operations, as well as materials science, among other topics, should study the relationship between Mechanical/Electrical Issues and cold weather events. The study should analyze the types of Mechanical/Electrical Issues experienced by generating units during extreme cold weather events; the types of components and systems most vulnerable to these events; methods and best practices to prevent Mechanical/Electrical Issues from affecting those components and systems; and any other information deemed relevant. Further, the study should differentiate between Mechanical/Electrical Issues caused by extreme cold weather events, and those that simply occurred during such events (e.g., boiler tube leaks).

Recommendation 3: A joint NERC-Regional Entity team, collaborating with FERC staff, should study the overall availability and readiness of blackstart units to operate during cold weather conditions. This study should cover all portions of the U.S. not already studied, and should incorporate existing literature, studies, reports, and other analyses as to the availability and readiness of blackstart units. The scope of the study should include:

- **an evaluation of existing blackstart restoration plans, including a review of potential single points of failure related to natural gas system dependence;**
- **an evaluation of the sufficiency of existing blackstart availability, readiness, and testing criteria, including whether unscheduled, unannounced, or criteria-based testing (e.g., those used in ERCOT) would improve reliability during cold weather events;**
- **the need for ensuring that generating units with dual-fuel capability providing blackstart service have appropriate fuel storage (as determined by the Balancing Authority);**
- **the need to require blackstart generators to test their fuel switching capabilities seasonally;**
- **the need to require additional fuel storage due to import constraints;**
- **the need for Transmission Operators to incorporate generating units' cold weather preparations into the qualification process for certifying generators as blackstart units; and,**
- **any other subject areas identified as areas of substantial interest or concern in the report issued as a result of ongoing efforts to study blackstart unit availability and readiness in ERCOT.[286] (Initiate study by Q1, 2024)**

Over 19,000 MW of blackstart designated generating units (155 units) incurred outages, derates, or failures to start during the Event. Of the 155 units, 119 were natural-gas fueled units (accounting for just under 75 percent of all generation lost by blackstart designated units). These failures were not geographically or causally isolated, instead, they covered the entire area impacted by the Event, arose from Freezing Issues, Mechanical/Electrical Issues, and Fuel Issues, and impacted gas, oil and dual-fuel capable units.

285 2021 Report at 218 (Recommendat on 11).

286 *See* 2021 Report Recommendat on 26.

The readiness and availability of blackstart units is paramount to the reliability of the grid during extreme weather scenarios, and the breadth (both in numbers and causes) of the outages and derates to blackstart units during Winter Storm Elliott suggests the need for systematic evaluation of the readiness of these units. For additional background and analysis relevant to Recommendation 3, see Section IV.B.4.

B. Natural Gas Infrastructure Cold Weather Reliability

Recommendation 4: Legislation by Congress and state legislatures (and/or regulation by entities with jurisdiction over natural gas infrastructure reliability) is needed to establish reliability rules for natural gas infrastructure necessary to support the grid and natural gas local distribution companies that address the needs described in 4(a), (b) and (c).

The 2021 Report noted that “the reliability of the BES depends, in large part, on the reliability of the natural gas infrastructure system, but unlike the BES, with its mandatory Reliability Standards enforced by FERC and NERC, the reliability of the natural gas infrastructure system rests largely on voluntary efforts.”[287] In February 2011, extreme cold weather in Texas and New Mexico “resulted in widespread wellhead, gathering system, and processing plant freeze-offs in the Permian and San Juan basins,” reducing flow by approximately 20 percent, a much greater extent than had occurred up to that point. LDCs interrupted gas service to more than 50,000 customers in New Mexico, Arizona, and Texas, including the cities of El Paso, Texas, Tucson, Arizona and Taos, New Mexico. While some LDCs were able to restore service within hours because they had only cut a few customers, it took one LDC a week to restore 4,300 customers, using a workforce of 700. The 2011 Report recommended that state legislators and regulators, working with “all sectors of the natural gas industry. . . should determine whether production shortages during extreme cold weather events can be effectively and economically mitigated through the adoption of minimum, uniform standards for the winterization of natural gas production and processing facilities.”[288] The 2011 event highlighted the increasing interdependency of natural gas infrastructure and the BES.[289]

In Winter Storm Uri, Natural Gas Fuel Issues were “the second-largest cause of generating unit outages that left residents without heat and light and energy in ERCOT for nearly three days, during freezing temperatures,”[290] even though that event did not involve LDCs interrupting service to customers. Texas natural gas production declined during Winter Storm Uri by 70.1 percent, Oklahoma, by 56.8 percent, and Louisiana, by 53.5 percent,[291] while the lower 48 states’ production declined by 28 percent.[292] Like the 2011 Report, the 2021 Report recognized that freezing at the wellheads and other natural gas infrastructure facilities, as well as weather-related road conditions, caused the majority of the gas production decline that contributed to the Natural Gas Fuel Issues. To prevent recurrence of these dramatic drops in production in areas on which the entire United States relies for the production of natural gas, the 2021 Report recommended that “Congress, state legislatures, and regulatory agencies with jurisdiction over natural gas infrastructure facilities should require those natural gas infrastructure facilities to implement and maintain cold weather preparedness plans,

287 2021 Report at 197.

288 2011 Report at 126 132, 212, 214.

289 As the 2021 Report recorded, “ a]fter the 2011 event, the Comm ss on n t ated a proceed ng (Docket No. AD12 12 000) n early 2012, request ng comments on quest ons about top cs nclud ng market structure and rules, schedul ng, commun cat ons, nfrastructure, and rel ab l ty.” The Comm ss on convened five reg onal conferences and ssued two orders wh ch enhanced p pel ne commun cat on w th gr d ent t es and ncreased p pel ne schedul ng flex b l ty. The 2021 Report noted “some aspects of the problem are e ther outs de the Comm ss on’s] author ty or requ re cooperat on among jur sd ct ons” (e.g. the natural gas product on shortages). 2021 Report at 201.

290 2021 Report at 197.

291 As compared to January product on. 2021 Report at 174. The Team used January so that t could compare the 2011 event, wh ch happened February 1 5.

292 As compared to February 8 product on. 2021 Report at 174.

including measures to prepare to operate when specific cold weather events are forecast."[293]

Despite the 2011 and 2021 recommendations for protecting natural gas infrastructure, including wellheads, from extreme cold weather, production remained insufficiently protected during the Event, which led to a reliability-threatening Gas Emergency for Con Edison in New York City. Had its entire system been cut off, Con Edison said it would have taken "many months" to restore service to its million-plus customers, even with mutual assistance, leaving natural gas customers without heat in the middle of winter. No regulatory entity is tasked with ensuring the *reliability* of the natural gas fuel supply relied upon by the BES/grid. The Team recommends that Congress exercise its regulatory power over natural gas infrastructure necessary to ensure grid reliability. Congress could consider whether additional or exclusive authority for natural gas infrastructure reliability should be placed within a single federal agency, as it did with bulk power system reliability in 2005, when it added section Federal Power Act section 215.[294]

Recommendation 4(a): Because extreme cold weather events have repeatedly impaired the production, gathering, processing, and transportation of natural gas, the reliability rules suggested in Recommendation 4 should address, among other topics, the need for natural gas infrastructure reliability rules, from wellhead through pipeline, requiring cold weather preparedness plans, freeze protection measures, and operating measures for when extreme cold weather periods are forecast, and during the extreme cold weather periods.

The last two extreme cold weather events resulted in substantial natural gas wellhead production declines in key locations. In 2021, Texas, Oklahoma and Louisiana saw 50-percent-plus declines, with Texas most impacted with a 70.1 percent decline. In the Event, the Marcellus and Utica Shale formations of the Appalachian Basin declined by 23 and 54 percent, respectively. "On its own, the Appalachian Basin would have been the third-largest natural gas producer in the world [for] the first half of 2021, behind Russia and the rest of the United States."[295] The largest percentage of natural gas production declines were freeze-related in the Event, and this was also true in 2021.[296]

Unlike in Winter Storm Uri, the natural gas production areas most affected during the Event were in areas that routinely experience cold weather. All of the gas producing entities that provided data about outages and disruptions to their facilities had implemented some cold weather preparedness activities for winter. The combination of the rapid temperature drops, and strong winds defeated many of the protections that were put in place. The interrelated nature of the natural gas supply chain added to its vulnerability. See generally IV.C. Each

293 Key Recommendat on 5, 2021 Report at 194. Recogn z ng that mandatory natural gas nfrastructure rel ab l ty rules would not l kely be n place for the upcom ng w nter, the 2021 Report also recommended mult ple pract ces that natural gas nfrastructure ent t es could voluntar ly mplement. Some could be qu ckly mplemented, such as obta n ng emergency back up generators, pre dra n ng storage tanks before severe weather, or mann ng key fac l t es around the clock. Key Recommendat on 6, 2021 Report at 194.

294 The NAESB Forum Cha rs recommended "**a natural gas reliability organization akin to the one currently responsible for electric reliability, NERC**," NAESB Report at 3 (emphas s n or g nal). S m larly, the Nat onal Academy of Sc ence, n ts 2021 report on the Future of Electr c Power n the U.S., [The Future of Electr c Power n the Un ted States The Nat onal Academ es Press], recommended that the Comm ss on "des gnate a central ent ty to establ sh standards for and otherw se oversee the rel ab l ty of the nat on's natural gas del very system. Congress should also author ze FERC to requ re greater transparency and report ng of cond t ons occurr ng on the natural gas del very system to allow for better s tuat onal awareness as to the operat onal c rcumstances needed to help support electr c system rel ab l ty." [Nat onal Academy of Sc ences (nasonl ne.org)].

295 Cor nna R cker and Warren W lczewsk , Shale natural gas product on n the Appalach an Bas n sets records n first half of 2021, Today n Energy (Sept.1, 2021) [U.S. Energy nformat on Adm n strat on E A ndependent Stat st cs and Analyhttps://www.e a.gov/today nenergy/deta l.php? d 49377s s].

296 F fty e ght percent of product on decl nes n the 2021 event were caused by freez ng or severe cold weather, nclud ng "product on decl nes d rectly caused by freez ng, preempt ve shut ns to protect natural gas fac l t es from freeze related mpacts, and poor road cond t ons (due to prec p tat on) that prevented the removal of flu ds from product on s tes or access to fac l t es to make necessary repa rs." 2021 Report at 175.

part of the natural gas supply chain is dependent upon the reliability of other sections, which increases the importance of requiring all sections of the natural gas supply chain to protect against the effects of extreme winter weather. Regulators should develop winterization guidelines to protect and continue the operations of production, gathering and processing system facilities during extreme weather events.[297] Those guidelines should address issues arising from low temperature and high winds, as well as precipitation (if precipitation meaningfully worsens the effect of cold on the applicable natural gas infrastructure).[298]

Recommendation 4(b): The reliability rules suggested in Recommendation 4 should address, among other topics, the need for regional natural gas communications coordinators, with situational awareness of the natural gas infrastructure similar to the grid's Reliability Coordinators, that can share timely operational communications throughout the natural gas infrastructure chain and communicate potential issues to, and receive grid reliability information from, grid reliability entities.

During the Event, both Balancing Authorities and natural gas infrastructure entities such as Local Distribution Companies had limited situational awareness as to the extent to which natural gas production losses rippled through the interconnected systems. PJM headed into the operating day of December 23 expecting approximately 158,000 MW of available generation to meet a forecast load of 127,000 MW. But PJM did not anticipate the rapidly escalating generation outages that peaked at over 46,000 MW early on December 24, 70 percent of which were natural-gas-fired units.[299] PJM was unaware of the magnitude of the natural gas production losses despite the fact that PJM's Gas Electric Coordination Team conducts daily reviews during the winter months (November through March) of the interstate pipeline bulletin boards to assess pipeline operating conditions, identify potential natural gas supply risks to the natural gas-fired generation fleet, and provide daily gas risk assessment reports to its dispatch personnel. Con Edison also did not anticipate that it would be notified of potential severe operating pressure reductions that would not recover unless demand was reduced. Pipelines necessarily had to have been aware of decreasing receipts at various points as pressures began to drop. While producers may have had flexibility to make up their nominations over the course of a day, shippers were unaware of what was happening in real time and did not know that the gas they had purchased and nominated had not been delivered to the pipeline until notified of sometimes very large cuts in nominations on December 24.

Operating personnel at the wellhead communicate with gatherers and processors to which they deliver their gas, gatherers and processors communicate their operational issues to the pipelines to which they deliver gas, and pipelines communicate operational issues to their shippers. Although natural gas infrastructure entities often communicate marketing information to end-use customers, in accordance with contractual obligations, it is not the norm for them to communicate with grid operators (e.g., BAs and RCs). Instead, news of operational issues is often communicated in piecemeal fashion from the affected operator to the next operator in the gas production and delivery chain. Absent any informal arrangement to share information, grid operators and Generator Owners/Operators typically receive information about pipeline operational issues only in the form of operational flow orders and critical notices, which often are issued many hours after the issues begin to occur upstream. There is no natural gas infrastructure entity that has the system-wide view as

297 Th s recommendat on s also cons stent w th Recommendat on 16 from the NAESB Report, wh ch stated, n part, that "appl cable state author t es should cons der the development of weather zat on gu del nes appropr ate for the r reg on/jur sd ct on . . .." NAESB Report at 58 59.

298 *See* 2021 Report at 194 95 (Recommendat on 6, wh ch ncluded a long l st of measures that natural gas nfrastructure ent t es could use to protect aga nst freez ng and other cold related l m tat ons).

299 *See* PJM Report at 2.

the RC does for the grid. The NAESB Report recognized the "importance of a wide-area view of natural gas system operations to help ensure reliability and the value of being able to access timely data to assist in operational planning, particularly during critical events or anticipated critical events."[300] While interstate pipelines are required to post certain information on their electronic bulletin boards, intrastate pipelines generally have no such requirements.

Multiple entities, including gas and electric trade groups, BAs and RCs, and GOs, described various information gaps existing in the operations of natural gas infrastructure. Many requested that intrastate pipelines be required to post data similar to what interstate pipelines post on their electronic bulletin boards.[301] A generation trade group noted that increased intrastate transparency would assist "particularly in the posting of actual flow data that can assist in validating force majeure claims and posting of available capacity to assist in identifying locations for additional supply/capacity."[302] An Regional Transmission Organization/Independent System Operator complained about the timeliness of information, noting that "last minute force majeure calls" were the only information they received about availability of commodity during the Event.[303] One entity pointed out that "[s]ince most intrastate pipeline operators also own and operate interstate pipelines, they already have the necessary infrastructure and knowledge of how to accomplish this information sharing at minimal cost and effort."[304] Finally, one trade group argued that the intrastate pipelines' lack of transparency combined with their ability to control both capacity and transportation posed a reliability risk:

> The lack of separation between pipeline operational and marketing functions allows intrastate pipelines to operate as regional monopolies and exert market power in the pricing of gas supply services particularly during time of high demand during extreme weather events, such as Winter Storm Uri. Customers are then forced to choose between exorbitant prices or the real prospect of having no access to natural gas supplies. This lack of competitive choice affects both the system reliability as well as the cost to gas and electric end-use customers.[305]

Based on their experience during the Event, shippers indicated that helpful changes would include providing information *linked to specific receipt points, as soon as possible, updated as often as possible, that included information about the volumetric effect at various receipt points if possible.* NAESB Report Recommendation 1 suggested that FERC could improve the timeliness of information available by directing NAESB to revise its business practice standards related to the timely reporting of natural gas pipeline informational website

300 November 8, 2022 GEH Forum Meet ng Staff Notes (NAESB Report at 18 n.68). The NAESB Report found that some nformat on shar ng between natural gas and gr d ent t es was supported by FERC Order No. 787, wh ch perm ts the commun cat on between certa n part es of operat onal nformat on to support rel ab l ty of natural gas and electr c systems, as well as the NAESB WEQ and WGQ Bus ness Pract ce Standards, ncorporated by reference as part of 18 C.F.R § 38.1(a) and 18 C.F.R § 284.12. However, t also noted that some BAs and RCs (a/k/a SOs/RTOs n the r market roles) stated that there are challenges n access ng and analyz ng such nformat on. (NAESB Report at 18 nn. 69, 71).

301 *See*, e.g., comments of Electr c Power Supply Assoc at on, (Page 93, GEH Survey Response Comment Subm ss ons February 27, 2023) https://naesb.org/pdf4/geh030323w5.docx; comments of Texas Compet t ve Power Advocates, Page 144, GEH Survey Response Comment Subm ss ons February 27, 2023) https://naesb.org/pdf4/geh030323w5.docx; comments of Process Gas Consumers Group and Amer can Forest & Paper Assoc at on, Page 144, GEH Survey Response Comment Subm ss ons February 27, 2023) https://naesb.org/pdf4/geh030323w5.docx

302 (Page 144, GEH Survey Response Comment Subm ss ons February 27, 2023) https://naesb.org/pdf4/geh030323w5.docx.

303 Comments of PJM nterconnect on, LLC, comb ned comment record at page 258.
PJM (Page 118, GEH Survey Response Comment Subm ss ons February 27, 2023) https://naesb.org/pdf4/geh030323w5.docx.

304 Comments of Texas Compet t ve Power Advocates, comb ned comment record at page 284.
TCPA (Page 144, GEH Survey Response Comment Subm ss ons February 27, 2023) https://naesb.org/pdf4/geh030323w5.docx.

305 Comments of Texas Compet t ve Power Advocates, comb ned comment record at page 288.
TCPA (Page 148, GEH Survey Response Comment Subm ss ons February 27, 2023) https://naesb.org/pdf4/geh030323w5.docx.

posting data;[306] enabling the data to be accessible to grid operators as soon as it is reported and available. Additionally, to address the fact that BAs and RCs are reliant on 24/7 operations while some natural gas infrastructure and marketing entities are not available around the clock, NAESB Report Recommendation 7 suggests that natural gas infrastructure operations be fully functioning on a 24/7 basis in preparation for and during events in which extreme cold weather is forecast.[307]

RCs and BAs could use improved information provided to better plan their operations during periods of extreme cold weather. BAs could dispatch more or different generation. For example, PJM could have dispatched long-lead-time units had it known the number of natural gas-fired generating units that would likely have failed to perform. Natural gas-fired generators could seek or activate alternate fuel supply or transportation arrangements (e.g., fuel oil (for dual-fuel units), natural gas storage, switch transportation to another pipeline if the facility is served by more than one pipeline). LDCs could act more quickly to preserve their system reliability (both for their commercial and residential customers as well as to maintain deliveries to any behind-the-citygate generation)[308] and reduce their draw on already-challenged pipelines during extreme cold weather conditions. For example, Con Edison used its LNG facility to preserve necessary system pressure at its citygate, but would have started it earlier, had it known how production declines were likely to affect delivery at receipt points.[309] Recommendation 4(b) differs from Recommendation 5 primarily in scope and timing, as well as prerequisites for achieving the outcome. Recommendation 4(b) seeks natural gas infrastructure entities that have the tools and authority to have the wide-area view, like a Reliability Coordinator does for the grid, and will likely rely on legislation and/or regulation; Recommendation 5 seeks near-term improvements in information sharing that do not require legislation or regulation.

Recommendation 4(c): The reliability rules suggested in Recommendation 4 should address, among other topics, the need to require natural gas infrastructure entities to identify those natural gas infrastructure loads that should be designated as critical for priority treatment during load shed and provide criteria for identifying such critical loads.

Recommendations from the 2011 Report[310] and the 2021 Report[311] highlighted the importance of Transmission Owners/Operators and Distribution

306 For example, operat onally ava lable capac ty, total scheduled quant ty, and any other data necessary to ass st reg onal operators n ma nta n ng system rel ab l ty. The NAESB Report noted, "There was substant al support from both electr c and natural gas part c pants to explore ways to streaml ne and add eff c enc es to the report ng, post ng, and data shar ng processes of natural gas p pel nes (NAESB Report 17 n.62).

307 To address these d fferences, NAESB Recommendat on 7 suggested that " s]tate publ c ut l ty comm ss ons and appl cable state author t es n states w th compet t ve energy markets should engage w th producers, marketers and ntrastate p pel nes to ensure that such part es' operat ons are fully funct on ng on a 24/7 bas s n preparat on for and dur ng events n wh ch extreme weather s forecast to cause demand to r se sharply for both electr c ty and natural gas, nclud ng dur ng weekends and hol days. (States could cons der the approaches adopted n FERC regulat ons affect ng the nterstate p pel nes.) n nstances where state author t es lack enabl ng author ty to take such act ons, the FERC should adopt regulat ons to ach eve dent cal outcomes w th n ts author ty."

308 For example, Con Ed son's d str but on system served 19 generat ng un ts.

309 More accurate and t mely nformat on from upstream ent t es could also help LDCs when to use the r demand response and requests for voluntary customer conservat on. Both are mportant tools for manag ng the t ght cond t ons dur ng extreme cold weather events. The NAESB Report recommended that State publ c ut l ty comm ss ons encourage LDCs w th n the r jur sd ct ons to "structure ncent ves for the development of natural gas and electr c demand response programs" and "to prov de voluntary conservat on publ c serv ce announcements for res dent al, commerc al and ndustr al customers" " n preparat on for and dur ng events n wh ch demand s expected to r se sharply for both electr c ty and natural gas." NAESB Report, Recommendat ons 10 and 11, at 44 45. NAESB Recommendat on 10 was supported by 91 percent of the Wholesale Gas Market and 91 percent of the Wholesale Electr c Market, as those terms are defined n the NAESB Report. d. at 44 45. NAESB Recommendat on 11 was supported by 93 percent of the Wholesale Gas Market and 100 percent of the Wholesale Electr c Market, as those terms are defined n the NAESB Report. d. at 45.

310 Recommendat on 25, 2011 Report at 211 12.

311 Key Recommendat on 1 , 2021 Report at 208.

Providers performing critical load reviews of gas production and transmission facilities and prioritizing critical loads during load shed. Few natural gas facilities were impacted by power outages during the Event, as compared to Winter Storm Uri, because the volume of load shed paled in comparison to ERCOT's 20,000 MW during Winter Storm Uri. But the Team was concerned to find that few natural gas infrastructure entities designated *any* of their facilities as critical loads to their local electricity provider.

All 10 of the natural gas producers who provided information in conjunction with the inquiry responded that they do *not* identify *any of their facilities* as protected or as critical loads even though winterization systems including heat trace can be dependent upon utility-provided electric power. Their utility-powered natural gas production facilities also have no, or limited, alternate or backup power. The Team is aware of producers that do rely on the grid for their electricity but have not identified any of their facilities as critical loads.

Of the two gathering system operators from whom data were collected, one indicated that its gathering system compression facilities do not depend on utility/grid power, but it does depend on the utility power to operate air compressors to maintain emergency shut- down valve positions, start the units and operate control equipment within the facility. Gas-fired backup generators are available at the stations in the event of a power outage to the air compressors/system at the majority of their facilities. The second entity indicated that utility power is its primary source of power. Several of its facilities rely heavily on electricity for gas compression and delivery capacity for a significant portion of their operations, and a loss of electrical power would result in the inability to transport and process large quantities of gas. Only 25 percent of the 26 processing plants that provided data were protected from power outages by local power provider critical load designation agreements.

Of the 15 interstate pipelines that provided data to the Team, four stated that they have facilities designated as critical with their power provider, and 11 provided reasons for not designating any facilities.[312] In total, four pipelines designated 60 facilities as critical. The majority of those facilities (42) are owned by a single pipeline. Pennsylvania had the most identified in a single state, with nine.[313]

The Team recommends that legislative and regulatory actions be taken to either establish criteria for natural gas infrastructure facilities to be designated as critical or create or designate an agency or entity to establish such criteria. The critical facilities identified should then be required to register with or otherwise communicate to their electric service necessary information about their critical natural gas infrastructure facilities such as location. Facilities could include producers, gathering/compressing facilities, processing facilities, and both intrastate and interstate pipelines. Legislators or regulators can look to the collaboration between the Public Utility Commission of Texas and the Texas Railroad Commission on rules for designating natural gas facilities and entities as critical, which was required by Texas House Bill 3648, in the wake of Winter Storm Uri's devastating effects on Texas. On November 30, 2021, the Public Utility Commission and Railroad Commission separately adopted rules to codify HB 3648 and establish new regulations for electric utilities and natural gas entities to ensure critical natural gas facilities are appropriately identified.[314]

312 *See* Sect on V.C.4 for a d scuss on of the reasons g ven for not dent fy ng fac l t es as cr t cal.

313 The other states and number of cr t cal fac l t es dent fied were V rg n a (6), New York (5), Kentucky (4), Alabama (3), Tennessee, M ss ss pp , Oh o, Georg a, and New Jersey (all w th two or fewer).

314 https://www.puc.texas.gov/ ndustry/electr c/cng/default.aspx

C. Natural Gas-Electric Coordination for Cold Weather Reliability

Recommendation 5: The North American Energy Standards Board should convene natural gas infrastructure entities, electric grid operators, and LDCs to identify improvements in communication during extreme cold weather events to enhance situational awareness. (Q2, 2024)

This Recommendation differs from Recommendation 4b in that it does not seek legislation or regulation but seeks near-term options for enhancing situational awareness among natural gas infrastructure and electric grid entities. The Team recognizes that producers, processors, interstate and intrastate pipelines, as well as grid operators such as Balancing Authorities and Reliability Coordinators, could improve their real-time coordination and communication to some extent without the need for a Reliability Coordinator-equivalent for natural gas infrastructure.

There is a need for improved communication among the operators of production facilities (producers, gatherers, processors) and the timely dissemination of this coordinated communication from the production facilities to other natural gas infrastructure entities, BAs, shippers, and end-use customers (i.e., Local Distribution Companies). Discussions should include what should be communicated, how it should be communicated, and to whom it should be communicated. In particular, operators of gas production facilities should provide information to the extent that they are aware of situations that may have potential adverse impacts on the BAs, pipelines, LDCs, and/or shipper reliability, whether such information becomes available before or during extreme weather events. Ideally those communications would include aggregated volume data or confirmed scheduled quantities for key upstream receipt points on the pipeline systems. Information about operational issues (e.g., location, estimated duration of outage) should be communicated to BAs, LDCs, and shippers so they can anticipate and plan for potential critical notices, OFOs or force majeures, rather than react after those notices are issued. Communication can occur without endangering sensitive commercial information, as it does on the BES grid side, by, among other methods, separating the operational employees who share information from the marketing employees.

NAESB Report Recommendations 2 and 3 identified a potential tool that can be used to accomplish the desired information sharing—Argonne National Laboratory's *NGInsight* Tool.[315] The tool makes it possible to identify the potential impact of weather or other critical events on overall natural gas supply.[316] Additionally, through machine learning informed by electric wholesale market participant input, *NGInsight* can rank the severity of natural gas pipeline notifications posted on EBBs to further enhance situational awareness.[317] For more information about how information sharing could be used to improve natural gas and grid system reliability, see Recommendation 4(b).

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315 Accord ng to the Forum Report, NG ns ght "collects EBB data and prov des near real t me ass m lat on of nformat on from approx mately 75 percent of nterstate and offshore natural gas p pel nes, creat ng a nat onal level v ew of natural gas system s tuat onal awareness. Argonne Nat onal Laboratory Presentat on June 29, 2023 (Page 3, Argonne Nat onal Laboratory) (NAESB Report n.101). The data collected and d splayed by the tool nclude nformat on that dent fies unsubscr bed capac ty, total scheduled quant ty as a funct on of state, county, and/or p pel ne as well as cr t cal and non cr t cal not ces, and the tool has the ab l ty to layer other relevant datasets, such as ut l ty serv ce terr tor es and weather alerts. Argonne Nat onal Laboratory Presentat on June 29, 2023 (Pages 3 4, Argonne Nat onal Laboratory) (NAESB Report n.102). NAESB Report Recommendat on 2 noted that the Comm ss on should "take steps to fac l tate the expans on of the Argonne Nat onal Laboratory NG ns ght tool, w th fund ng from a federal governmental agency, such as the Department of Energy," wh le acknowledg ng the mportance of secur ty and market protect ons. NAESB Report at 21. Th s recommendat on rece ved support from 46 percent of the Wholesale Gas Market and 85 percent of the Wholesale Electr c Market, as those terms are defined n the NAESB Report. d. at 19 20.

316 Argonne Nat onal Laboratory Presentat on June 29, 2023 (Pages 3 6, Argonne Nat onal Laboratory) (NAESB Report n. 103).

317 Argonne Nat onal Laboratory Presentat on June 29, 2023 (Page 5, Argonne Nat onal Laboratory) (NAESB Report n. 104).

Recommendation 6: The Commission should consider whether to order Commission-jurisdictional natural gas entities to provide the Commission with one-time reports describing their roles in assessing and responding to natural gas supply and transportation vulnerabilities in extreme cold weather events.

As discussed in Section IV.C.4 above, freezing was a significant cause of pipeline equipment outages that caused some flow reduction, and the primary cause of pipeline equipment outages directly affecting shippers. Recommendation 6 is based in part on the various preparations for Winter Storm Elliott that pipelines shared with the Team. The Team surveyed a total of 15 interstate pipelines within the Event Area. Pipelines shared common practices in the planning and preparation for Winter Storm Elliott, specifically in areas such as proactively monitoring weather forecasts, manning key facilities, issuing critical notices, increasing line pack, and putting storage facilities on stand-by. However, these measures were assigned different priorities by different pipelines and implemented in different ways depending on the location, design, and size of each individual pipeline system. For example, some pipelines issued pre-emptive Operational Flow Orders (OFOs) prior to the start of the Event, whereas others issued generic notices alerting customers of extreme conditions. Internal (gas control, operations, scheduling, storage, commercial personnel) and external (RTOs, customers, utilities) stakeholder meetings also occurred with varying degrees of frequency among the pipelines. These meetings aired concerns about reliability issues, nominations, and scheduling as applicable to each pipeline's system.

If the Commission were to proceed with an order regarding the one-time reports, it could consider asking the FERC-jurisdictional entities to analyze their experiences in Winter Storms Uri and Elliott, and to address the entities' plan(s) for mitigating identified vulnerabilities. The collected data would allow the Commission to determine if it could take additional actions within its jurisdiction to address the risk that extreme cold weather events pose to the natural gas infrastructure system. If a FERC-jurisdictional gas entity were to submit a one-time report, it could seek CEII treatment or other protections available under the Commission's regulations, as appropriate.

Recommendation 7: An independent research group (e.g., selected National Laboratories from the Department of Energy), should perform one or more studies to analyze whether additional natural gas infrastructure, including interstate pipelines and storage, is needed to support the reliability of the electric grid and meet the needs of natural gas Local Distribution Companies. The study should include information about the cost of the infrastructure buildout. (Initiate study Q1, 2024)

In light of the Commission's role in reviewing interstate natural gas projects and other gas infrastructure (e.g., interstate natural gas storage facilities), as well as the need for sophisticated modeling, the Team recommends that an independent entity with robust modeling capabilities undertake the study. It would be ideal if one of the DOE National Laboratories would conduct the study, as they have the technical expertise and have invested in modeling of the U.S. natural gas and electric infrastructure. However, if that is not feasible, the National Academies of Science and Engineering, and the Electric Power Research Institute have also performed sophisticated grid-related studies in the past, as well as studies of natural gas issues.

The purpose of the study would be to identify additional natural gas infrastructure needs, if any, needed to ensure the continued reliability of the electric and natural gas systems, and the preferred locations of such infrastructure, if applicable, including pipeline infrastructure, natural gas storage, and other supporting systems. The study should consider the needs in light of coincident peaks of LDC demand for natural gas as well as demand from natural gas-fired generation during periods of prolonged, abnormally cold weather. The study should analyze needs on a regional basis and consider current as well as forecast future needs, in light of our evolving and interdependent energy system. The study should consider whether there will be adequate natural gas infrastructure to support new gas usage patterns by gas-fired generation to manage the increased penetration of variable, renewable energy resources and thermal resource retirements, including increased ramping requirements and seasonal resource availability, among others. In addition, the study should consider natural gas infrastructure needs during anticipated, extended extreme heat and cold weather periods. It should also consider recent patterns of natural gas production declines during extreme cold weather (e.g., Winter Storm Uri, Winter Storm Elliott).

The study should include information about the cost of the infrastructure buildout. In making this recommendation, the Team notes that two of the North American Energy Standards Board Report recommendations for additional studies concerned the cost of natural gas infrastructure, for storage and for infrastructure to provide additional firm transportation capacity.[318]

318 Recommendat on 18 sought a study about “whether market ncent v zed nvestments n strateg c natural gas storage fac l t es are suff c ent to address natural gas supply shortfalls dur ng extreme cold weather events, and f the level of nvestment s suff c ent to preserve such fac l t es for use dur ng extreme cold weather events. The study should also explore whether publ c sources of fund ng are needed for nvestment to secure suff c ent storage.” Recommendat on 19 asked for a study of “whether add t onal financ al ncent ves for the natural gas nfrastructure system, nclud ng nfrastructure to prov de add t onal firm transportat on capac ty, would help to address natural gas supply shortfalls dur ng such events l ke Ur], and further support the Bulk Electr c System’s performance dur ng extreme cold weather events.” NAESB Report at 63 64.

D. Electric Grid Operations Cold Weather Reliability

Recommendation 8: Balancing Authorities should assess whether new processes or changes to existing ones—such as multi-day risk assessment processes or advance or multi-day reliability commitments—are needed to address anticipated capacity shortages or transmission system-related reliability problems during well-forecast extreme cold weather events. In performing risk assessments or supporting multi-day reliability commitment, BAs should consider the following:

A. how to account for uncertainty in load forecasts, generating unit fuel availability and extreme cold weather availability, and the effects of extreme cold weather across multiple regions; and
B. committing generating units prior to the onset of extreme cold weather, including a means of ensuring units are compensated for their commitment costs (including the costs of obtaining fuel), even if no dispatch occurs. (Q4, 2023)

The five extreme cold weather events have revealed a set of uncertainty risks that have challenged BAs as they plan for and operate during these events. In every extreme cold weather event, BAs have faced unexpectedly high amounts of unplanned generating unit outages.[319] In four of the last five events, short-term load forecasts were lower than actual for some BAs, and in three of the last five events (the only ones that examined the issue) significant reductions in natural gas production occurred. Many natural gas-fired generating units indicated during the Event that they were unavailable because they did not have advance arrangements for natural gas fuel supply for the hours they were committed to operate, and by the time they were notified for commitment, natural gas supplies were unavailable. All of the BAs thought that they had sufficient reserves arranged to meet their forecast peak electricity demands, until they were faced with escalating unplanned outages and increased customer demand that, for most, exceeded their load forecasts. By the time that these trends were apparent, the BAs had limited flexibility, leading many of them to declare Energy Emergencies and some to shed firm customer load.

These scenarios should no longer be unexpected. BAs need to evaluate the uncertainty or risk they face when preparing for extreme cold weather events that have been forecast well in advance (and all the most serious extreme cold weather events have been forecast many days in advance) to reduce their reliability risk during these events. Evaluating risk or uncertainty, which some BAs already combine with a multi-day reliability unit commitment process, in advance of and during extreme cold weather events will best enable BAs to prepare to meet their commitments and maintain system reliability.

SPP's experience during the Event provides one example of how a BA can combine the evaluation of risk or uncertainty with multi-day unit commitment.[320] According to SPP's Winter Storm Elliott Report, "going into [Winter Storm Elliott] SPP had to anticipate uncertainty in the following areas:

- Uncertainty of accurate load forecasting for December 23, December 24, December 25 due to wind chill.
- Uncertainty if the forecast for high wind levels would hold, and to what extent wind farms would be shut down or de-rated for low ambient temperatures.
- Uncertainty if the gas resources SPP committed would be able to purchase gas.
- Uncertainty if resources SPP committed would be timely due to preheat and start-up.[321]
- Uncertainty of how many resources would trip because of freezing of equipment resulting from low temperatures and high wind chill conditions.
- Uncertainty of how much congestion SPP would

319 *See* F gure 5, wh ch reveals s m lar t es among past extreme cold weather events.

320 Th s s one example. Other BAs may have the r own methods of evaluat ng uncerta nty and/or mult day un t comm tment.

321 SPP was concerned about all gas resources comm tted, not just those comm tted n the day ahead.

experience that required re-dispatch of resources that could lock up headroom of resources.
- Uncertainty if the Missouri River would develop ice blocks preventing adequate river flow and potentially limit hydro generation and cooling water availability."[322]

SPP's Elliott experience revealed the importance of remaining flexible when evaluating uncertainty in extreme cold weather events. For example, the Missouri River freezing issue developed during the Event. During the Event, SPP's Uncertainty Response Team, [323] which helps to identify and address upcoming capacity challenges given forecast system conditions, recommended the commitment of long-lead-time generation, which SPP then committed using its Multi-Day Reliability Assessment process.[324] On December 21, SPP committed generation for December 22 and 23, to help with capacity, deliverability concerns and uncertainty; on December 22, it committed generation for Christmas Eve, and on December 23, for Christmas Day.[325]

SPP also "committed several GW of primarily gas generation ahead of time for Dec[ember] 22 through . . . 25, to cover normal long-lead time units as well as help ensure there was a sufficient amount of gas procured to cover the forecast obligations (a portion of short-lead-time gas units),"[326] through its Multi-Day Reliability Assessment process. This advanced commitment process is particularly helpful if the extreme weather event is expected to occur over the weekend, on a Monday, or on a Tuesday following a holiday weekend, given the limited natural gas market liquidity during these periods. SPP also committed natural gas units that were not long-lead units early so that they could obtain natural gas in advance of Winter Storm Uri and believes that it enabled more units to operate during the worst of the Winter Storm Uri event.[327]

The Team notes that the North American Energy Standards Board Report recommended that Independent System Operators/Regional Transmission Organizations "adopt multiday unit commitment processes to better enable the industry to prepare for and provide reliable service during events in which weather is forecast to cause demand to rise sharply for both electricity and natural gas," and it received 90 percent support from both the gas and electric wholesale quadrants.[328] Additionally, the PJM Report recommended that it "[e]valuate the current multi-day commitment process for use during expected critical

322 SPP Report at 6 7.

323 Da ly evaluat ons flag uncerta nty r sks for the next seven days. The URT appl es uncerta nty factors for load forecast, w nd forecast and resource (generat on outage) error. The URT puts h stor cal data nto "b ns" for w nd forecast error, load forecast error, and generat on outage error, analyzes what weather cond t ons are assoc ated w th part cular ranges of error and then appl es uncerta nty error percentages to ava lable offl ne and onl ne capac ty for every hour for the next seven days. Th s refined "scal ng" process results n, for example, nstead of pred ct ng the poss b l ty of 500 MW of error on a part cular day, pred ct ng 100 MW of error for hour 0700, 200 MW of error for hour 1900, and so on. SPP analyzes for co nc dental error the percentage chance of all of the errors happen ng at the same t me. They look at 50/50, 90/10, and 99.5 percent l kely scenar os, all of wh ch are shared w th operators. f operators see nsuff c ency all the way down to the 50/50 scenar o they know t s more l kely that the system w ll exper ence nsuff c ent resources that day. Larger potent al capac ty gaps are found at the lesser percent le, and smaller gaps are more common, more l kely to be found n the 50/50 scenar o (equally l kely to happen or not happen). SPP uses the uncerta nty evaluat ons produced by the URT to help coord nate how much generat on w ll be allowed to be on planned outages, to comm t long lead t me un ts that may otherw se become unava lable (any un t for wh ch the m n mum start up or down t me s such that the un t cannot be comm tted n the day ahead market, or has another start up ava lab l ty l m t ng c rcumstance), and to prepare m t gat on plans for scenar os where analys s shows a r sk of SPP's capac ty be ng nadequate to meet ts obl gat ons.

324 The URT recommends un ts when an uncerta nty forecast mer ts the need for such un ts and such un ts may become unava lable f not acted upon.

325 SPP Report at 7.

326 SPP Report at 7. SPP has filed proposed tar ff rev s ons to clar fy the ab l ty to comm t short lead t me un ts so that they can obta n natural gas, among other proposed rev s ons.

327 n Ur , SPP needed all ava lable un ts onl ne. n Ell ott, SPP ended up need ng much more natural gas fired capac ty than the short lead t me gas un ts they had comm tted early.

328 NAESB Report at 2, 5 (Recommendat on 9).

high demand periods so as to analyze the costs and benefits of providing greater certainty of fuel supply procurement through the critical period, with a focus on weekends when the gas commodity market can be less liquid."[329]

Pre-operational warming is a practice that has been recommended since the 2011 Report to avoid unplanned freezing-related outages.[330] One way to reduce the risk of unplanned outages is for BAs use their evaluation of the uncertainty to manually commit a portion of their generating units to operate the units before the coldest temperatures arrive, even if the units are not needed to serve load at that point. Doing so will help mitigate the extra challenge created by cold-starting a unit in extreme cold conditions. If a unit fails *during* the advanced commitment, the BA will be able to identify and potentially address generation shortfalls before the extreme weather arrives. During extreme cold weather events like Winter Storms Elliott and Uri, it is not uncommon for BAs to rely on generating units that rarely operate. PJM's experience with units that had not run in four weeks or more is consistent with committing some generation before the coldest temperatures arrive, in an effort to make more generation available when it is most needed. PJM noted that 70.5 percent of units that had not run in four weeks or more before the Event experienced an outage, while only 45.5 percent of units that had run within four weeks did so, a 25 percent improvement. Both testing and manually committing generation before the coldest temperatures arrive can increase the likelihood that the unit will be available to run when needed in real time.[331]

Recommendation 9: Balancing Authorities should improve their short-term load forecasts for extreme cold weather periods by implementing the lessons and practices identified below and sharing newly identified effective practices with peer BAs for continuous improvement. (Implement sharing Q4, 2023)

In four of the last five extreme cold weather events, short-term load forecasts, or forecasts of peak electricity demand, were lower than the actual peak electricity demand, for some BAs in the Core Event Area. Accurate short-term load forecasts in advance of extreme cold weather events enable BAs to commit long-lead-time resources, plan for additional imports that may be needed to meet reserves, and notify customers in advance of potential emergency conditions, to achieve greater awareness and participation if voluntary load reduction is needed. Most BAs in the Event under-forecast load in their 5-day, 4-day, 3-day, 2-day and day-ahead load forecasts, and the Team encourages them to implement and share effective practices for improving short-term load forecasts. However, accurate load forecasts alone could not have overcome the massive volume of unplanned generating unit outages experienced by many of the BAs.

Two key practices for improving short range load forecasts are (1) understanding the drivers of the BAs' extreme cold weather load and (2) studying the drivers of BAs' under-forecast load for past events. The Team found that some entities understood the drivers of their cold weather load far better than others, and those entities performed better on their short-term load forecasts. The use of distribution-level smart meter data, combined with Artificial Intelligence (AI)-powered predictive intelligence, is a promising new approach for understanding load drivers.[332] Some entities used third-party load forecast services and participated in the load forecast process in varying degrees. Entities that were more engaged in and better understood the load

329 *See* PJM Report Recommendat on 9, at 4.

330 2011 Report at 60 61. Dur ng W nter Storm Ur , un ts reported pre operat onal warm ng n response to an ERCOT d rect ve. *See* 2021 Report at 53.

331 PJM recommended, but d d not requ re, generat ng un ts to perform a "Generat on Resource Operat onal Exerc se" before the w nter. *See* PJM Report at 10. These un ts are compensated as pr ce takers, l ke any other self scheduled un ts.

332 Th s serv ce prov des ns ghts to the gr d ent ty (e.g. how much of the load n a part cular area s dr ven by heat ng and/or cool ng, whether beh nd the meter assets may be located w th n ts footpr nt and the r hourly demand), wh ch helps to better pred ct volat l ty n demand, both as to t m ng and magn tude. The th rd party prov der used by the ent t es was nnowatts (https://www. nnowatts.com/).

forecast process, instead of treating it as a "black box" service, performed somewhat better.

Balancing Authorities identified multiple factors that played a role in underestimating short-term load as compared to actual load. For example, they noted that load forecasts were affected by a mismatch between the temperature used in the forecast versus the actual temperatures,[333] high winds,[334] blizzard conditions, and struggles to predict the exact timing of when the coldest weather would arrive. Several entities also found that they did not experience a normal load profile with a deep valley during the night—the drop in temperatures/extreme cold temperatures meant that the "valleys" were abnormally high. Another important element was identifying the presence of resistive heating in an entity's load.

The Team recognizes that some entities and regions already engage in sharing effective practices and encourages them to continue. But based on the wide variety the Team observed in load forecasting practices within the Event Area, the Team believes that sharing of effective practices can be enhanced, with the aim of improving the accuracy of short-term load forecasts. For more information on improving short-term load forecasts, see Section IV.D.1 and Figures 19-21, above.

Recommendation 10: Resource Planners and entities that serve load should sponsor joint-regional reliability assessments of electric grid conditions that could occur during extreme cold weather events. The assessment results can be used in power supply planning to reduce the risk of firm load shed.[335] (Initiate assessments, Q4, 2024)

Recommendation 10 focuses on improvements that entities responsible for planning and/or acquiring capacity and energy resources to serve firm load can make to help address the risk of firm load shed during future extreme cold weather events. As described in Section III.B, several Balancing Authorities in advance of winter 2022-2023 and during the Event relied on the availability of external generation resources (i.e., in the form of purchase power/import power schedules and emergency energy) to serve their firm load. When the Event impacted all of the adjacent BAs, resulting in curtailment of imports, that curtailment contributed to the need for firm load shed within the BAs that had relied upon imports or the possibility of emergency energy.

The types of extreme cold weather events to be studied are those that, like Winter Storms Elliott and Uri, simultaneously impact multiple operating areas and Regional Entity footprints.[336] The assessments should be conducted jointly, involving multiple planning regions, multiple Regional Entities, and/or multiple BA footprints within regions. They should consider the use of probabilistic approaches in accounting for uncertainties in availability of external generation resources, potential for simultaneous winter peak load conditions in multiple footprints, and uncertainties in deliverability of generation resources (e.g., arrangements from

333 Some ent t es performed "backcasts" (calculat ng the r load forecast w th the actual temperatures) to solate the effect of temperature from other factors.

334 "A r movement s an mportant cause of energy loss, part cular ly] n res dent al bu ld ngs, where nfiltrat on acc dental ntroduct on of outs de a r nto a bu ld ng, typ cally through cracks n the bu ld ng] commonly causes between 30 and 75 percent] of the total heat load n w nter." Edward A. Arens and Ph l p B. W ll ams, The effect of W nd Energy consumpt on n bu ld ngs, (1977), https://www.a vc.org/s tes/default/files/members_area/med as/pdf/A rbase/a rbase_00017.pdf#:~:text_W nd%20flow%20around%20a%20bu ld ng%20causes%20forced%20convect on,layer%20 tself%2C%20the%20w nd flow%20patterns%20around%20the%20bu ld ng%2C185.

335 Forms of sponsorsh p could nclude, but not be l m ted to, prov d ng nput or adv ce on the development of nterreg onal plann ng models, extreme cold weather study cases and scenar os, and/or through support of collaborat ve plann ng act v t es.

336 The February 2021 W nter Storm Ur mpacted the ERCOT nterconnect on, and M SO and SPP footpr nts n the Eastern nterconnect on (TRE, MRO, and SERC Reg onal Ent ty footpr nts); the January 2018 cold weather bulk electr c system event mpacted, M SO, SPP, TVA, and Southern n the Eastern nterconnect on (MRO and SERC Reg onal Ent ty footpr nts); the 2014 Polar Vortex mpacted both the Eastern and ERCOT nterconnect ons (MRO, RF, NPCC, SERC, and TRE Reg onal Ent ty footpr nts), and the February 2011 event mpacted ERCOT and the Western nterconnect on.

generation resources external to a load serving area).[337]

In accounting for generation resource unavailability, winter assessments typically account for generating unit scheduled/planned outages expected to occur during winter peak load timeframes, as well as an estimated amount of unplanned generation outages. The projected available resource capacity is used to calculate projected resource reserves above the 50/50 and 90/10 winter peak load forecast, or whether there will be an expected shortfall. In estimating the impact of unplanned generation outages, resource planners and entities serving firm load should consider the likelihood of higher levels of unplanned generation outages across multiple regions during extreme cold weather. As an example, NERC uses operational risk analysis as part of its seasonal assessment process, which provides an approach for determining reliability impacts from certain scenarios and understanding how various factors affecting resources and demand can combine to impact overall resource adequacy. Adjustments are applied cumulatively to anticipated capacity—such as reductions for typical generation outages/derates and additions that represent the quantified capacity from operational measures, if any, that are available during scarcity conditions (e.g., emergency maximum generation available). The effects from low-probability events are also considered.

In accounting for risks that peak load conditions may have on serving firm load, planners should consider that winter peak electricity demands during the Event in the BA footprints located from the Central Plains to the Atlantic Seaboard all occurred within a 36-hour period. A multi-area concurrent peak load scenario, coupled with many thousands of MW of unplanned generation outage scenario, compounds the risk of unavailable external generation resources or unavailability of purchase power for import, regardless of intraregional or interregional transfer capability. If a BA is experiencing a worsening capacity and energy emergency condition, it may reach a point when it must curtail all exports unless those exports are backed by installed capacity that is not already counted towards installed capacity for the BA's native load. Purchasing-selling entities[338] should understand the answer to the question "How firm is my firm power purchase?" in advance of future extreme cold weather periods.

In accounting for risks in resource deliverability, winter case extreme scenarios can be performed to determine potential constraints or limitations. For example, as part of its winter assessment, SERC performed a powerflow case simulating a MISO to SERC-East 6,000 MW power transfer to study the impact of a west-to-east transfer during peak conditions. There are related initiatives underway which can be leveraged to ultimately assist entities that serve load to evaluate risks to serving firm load during extreme cold weather periods. NERC Standards development project 2022-03 – Energy Assurance with Energy-Constrained Resources, proposes that entities (most likely BAs and RCs) conduct energy reliability assessments, and when predefined criteria are not met (criteria need not be defined in Standard), the responsible entity shall develop Corrective Action Plans, operating plans, or other mitigating actions. In addition, the Commission recently issued Order No. 896, which directs, among other things, the development of extreme cold weather benchmark events that will form the basis for assessing system performance during extreme heat and cold weather events. The base case, representing system conditions under the relevant benchmark event, will be used to study the potential wide-area impacts of anticipated extreme cold weather events.

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337 The 2018 Report recommended that Plann ng Coord nators and Transm ss on Planners should jo ntly develop and study more extreme cond t on scenar os w th model ng that ncludes remov ng generat on un ts ent rely to represent actual generat on outages (espec ally outages known to occur dur ng severe weather), versus scal ng of generat ng un t outputs, and model ng system loads so that the study accurately tests the system for the extreme cond t ons be ng stud ed. 2018 Report at 94 95 (Recommendat on 7).

338 The ent ty that purchases or sells, and takes t tle to, energy, capac ty, and nterconnected Operat ons Serv ces. Purchas ng Sell ng Ent t es may be aff l ated or unaff l ated merchants and may or may not own generat ng fac l t es. *See* NERC Glossary of Terms, at https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

Recommendation 11: A team of subject-matter experts (e.g., the Eastern Interconnection Planning Collaborative) should conduct a study of the state of the Eastern Interconnection during the evening of December 23 and early morning hours of December 24, to examine dynamic stability and system inertia, and determine how close the interconnection may have been to triggering an underfrequency load shed event. (Initiate study, Q1, 2024)

As seen in Winter Storm Uri, when the power grid suffers an extreme loss of generation resources during periods of high system demands, the grid becomes more vulnerable to a complete blackout. In that event, ERCOT operators were forced to shed larger and larger blocks of firm load, within minutes of one another, to restore frequency and avoid a blackout of the ERCOT Interconnection.[339] As discussed in Section III, and demonstrated by Figure 39, on late December 23 and early December 24, the Core Event Area and the Eastern Interconnection were experiencing their highest winter electricity demands. Figure 37 shows that, at the same time, generating unit outages were climbing. As a result, there were times on the evening of December 23 and the morning of December 24 when the potential responsive operating capacity, which included online and any offline capacity, was within 15,000 to 20,000 MW of the combined loads at the worst points. While that may appear to be an adequate level of reserves, spread over the Eastern Interconnection, and at a time when the risk of additional generating outages was high, the Team is concerned that it may not have provided a sufficient safety net.

During the same period, Eastern Interconnection frequency excursions were common, dropping below 59.95 Hz (the lower band limit for maintaining frequency) four times and dropping as low as 59.936 Hz at approximately 4:25 a.m. Based on these findings, the Team is concerned that the Eastern Interconnection could have been at risk of instability during the period of high winter electricity demands and rising generating unit outages.

The Team believes that the Eastern Interconnection Planning Collaborative,[340] in coordination with NERC, Regional Entity and FERC staff, could assess next-contingency/single-point of failure contingency conditions to assess dynamic stability of the Interconnection through modeling and assessing the Bulk Electric System conditions during the Event. Further study(s) of the Eastern Interconnection during the critical period of the evening of December 23 and early morning December 24 can be used to identify actions needed to improve situational awareness and enhance operator tools and analysis capabilities. Real-time evaluation of such system conditions in the future could provide Reliability Coordinators with visibility of dynamic system conditions (e.g., through integration into its real-time contingency analysis processes), and assist in determining what actions may be taken (remedial analysis). Enhanced operator tools for situational awareness could prove especially useful when operators are faced with future resource mix changes that potentially expose the grid to more stability risks (e.g., as “high-inertia” coal units are retired and replaced by smaller intermittent resources with less inertia).

339 *See* 2021 Report, at 133.

340 The Eastern nterconnect on Plann ng Collaborat ve (E PC) s an organ zat on that was formed n 2009 by NERC reg stered Plann ng Coord nators n the Eastern nterconnect on to perform coord nated nterconnect on w de transm ss on analys s.

VI. CONCLUSION

This report provides a detailed assessment of the Event and the impact it had on portions of the Nation's energy infrastructure and service to consumers. The recommendations are designed to address matters identified in this report that call for improvement.

APPENDICES

APPENDIX A: INQUIRY JOINT TEAM MEMBERS

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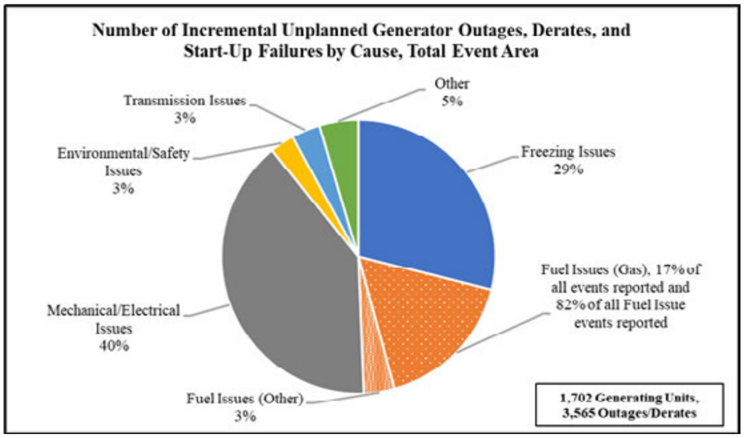
APPENDIX B: ACRONYMS USED IN THE REPORT

AC	Alternat ng Current
BA	Balanc ng Author ty
BES	Bulk Electr c System
CST	Central Standard T me
DC	D rect Current
DSM	Demand S de Management
EEA	Energy Emergency Alert
EHV	Extra H gh Voltage
EMS	Energy Management System
EOP	Emergency Operat ons Procedure
ERCOT	Electr c Rel ab l ty Counc l of Texas
ERO	Electr c Rel ab l ty Organ zat on
FERC	Federal Energy Regulatory Comm ss on
FRAC	Forward Rel ab l ty Assessment Comm tment
GO	Generator Owner
GOP	Generator Operator
HVDC	H gh Voltage D rect Current
ROL	nterconnect on Operat ng Rel ab l ty L m t
SO	ndependent System Operator
kV	K lovolt
LBA	Local Balanc ng Author ty
LMR	Load Mod fy ng Resources
MSSC	Most Severe S ngle Cont ngency
M SO	M dcont nent ndependent System Operator, nc.
MRO	M dwest Rel ab l ty Organ zat on
MVA	Megavolt Ampere
MW	Megawatt
NERC	North Amer can Electr c Rel ab l ty Corporat on
OPA	Operat onal Plann ng Analys s
PC	Plann ng Coord nator
PRC	Phys cal Respons ve Capab l ty
RC	Rel ab l ty Coord nator
RC S	Rel ab l ty Coord nator nformat on System
RDT	Reg onal D rect onal Transfer
RDTL	Reg onal D rect onal Transfer L m t
RF	Rel ab l tyF rst Corporat on
RTCA	Real T me Cont ngency Analys s
RTO	Reg onal Transm ss on Organ zat on
SCED	Secur ty Constra ned Econom c D spatch
SCRD	Secur ty Constra ned Red spatch
SERC	SERC Corporat on
SeRC	Southeastern Rel ab l ty Coord nator
SOL	System Operat ng L m t
SPP	Southwest Power Pool, nc.

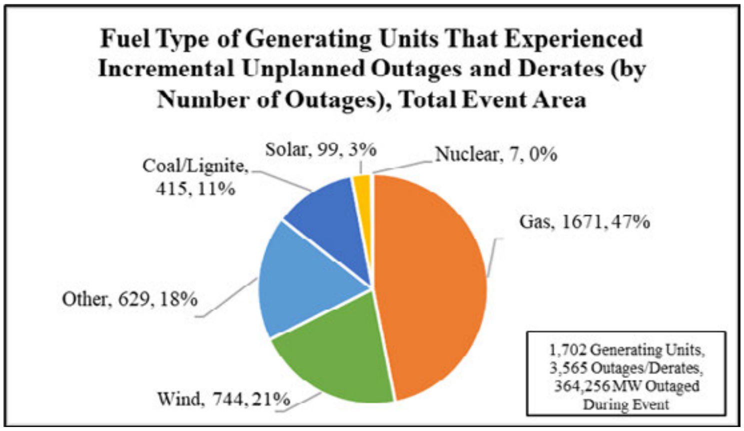
TDU	Transm ss on Dependent Ut l ty
TLR	Transm ss on Load ng Rel ef
TO	Transm ss on Owner
TOP	Transm ss on Operator
TP	Transm ss on Planner
TRE	Texas Reg onal Ent ty
TVA	Tennessee Valley Author ty
UDS	Un t D spatch System
VSA	Voltage Stab l ty Analys s
WECC	Western Electr c ty Coord nat ng Counc l

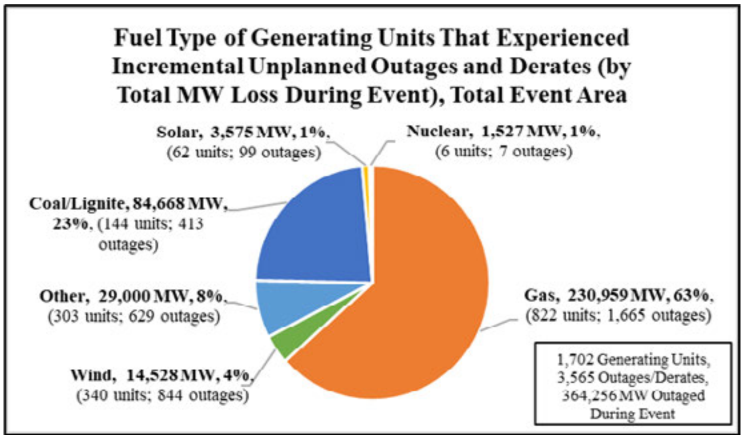
APPENDIX C: ADDITIONAL CHARTS AND FIGURES FOR UNPLANNED GENERATION OUTAGES DURING EVENT

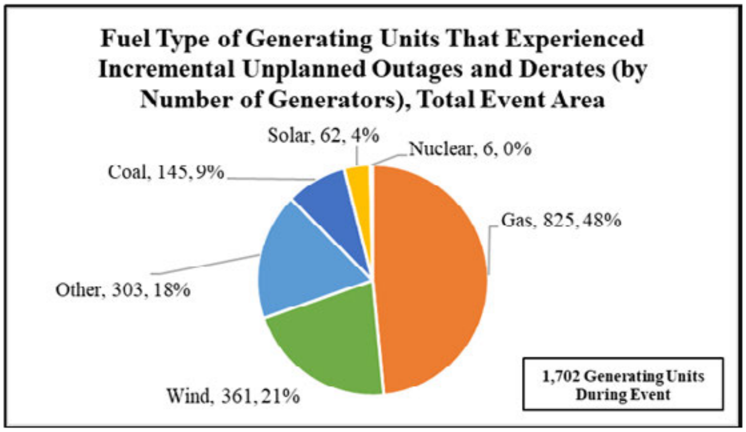
1. Number of Incremental Unplanned Generation Outages, Derates, and Failures to Start BY CAUSE, December 21-26, Total Event Area



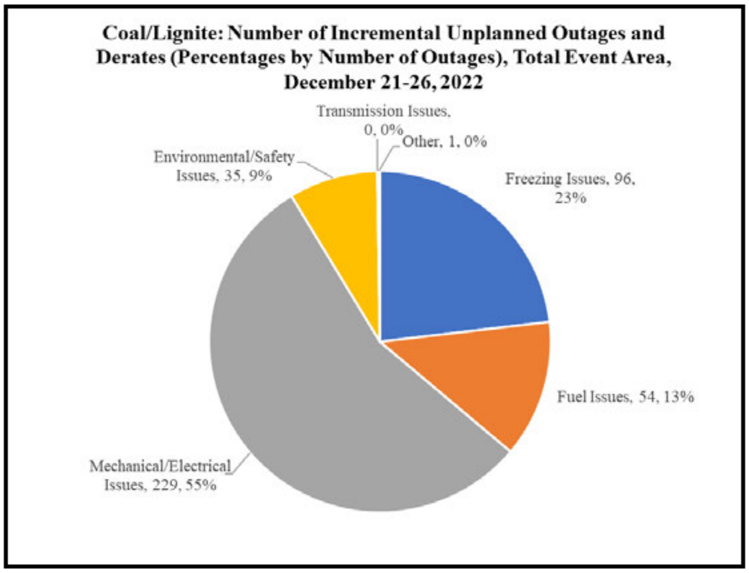
2. Unplanned Generation Outages by Fuel Type

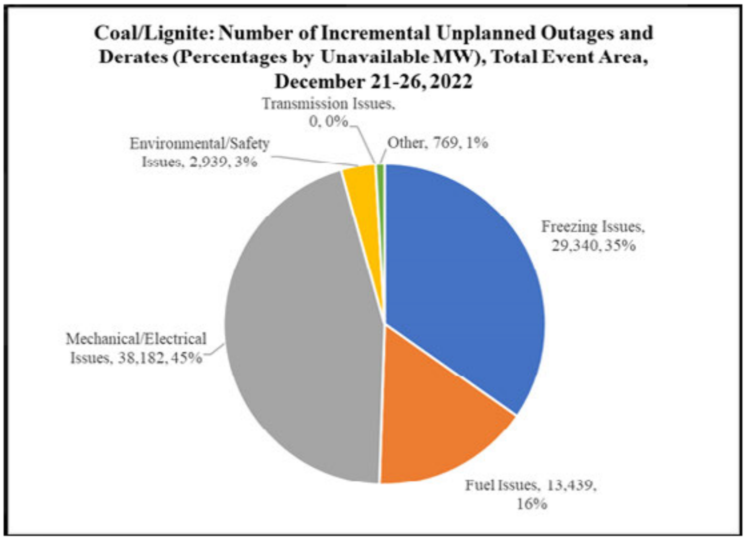


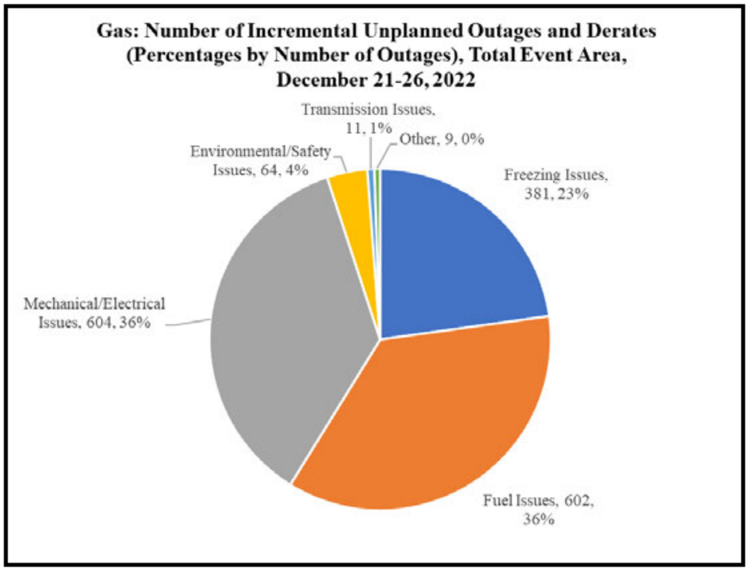


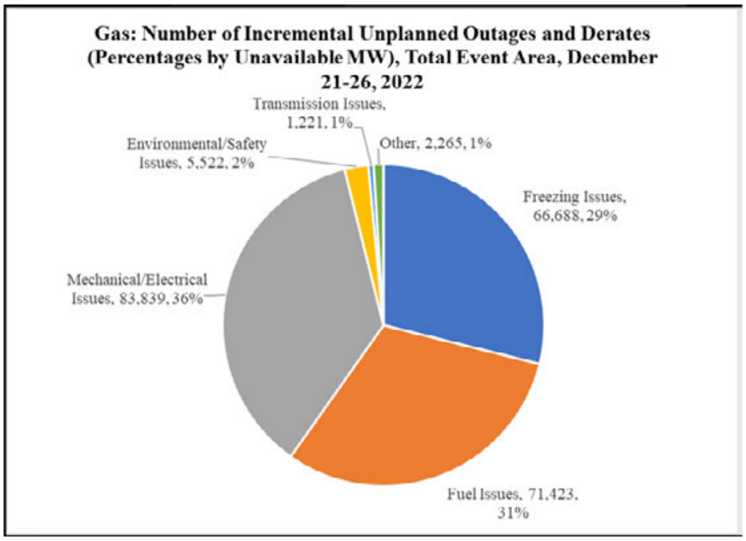


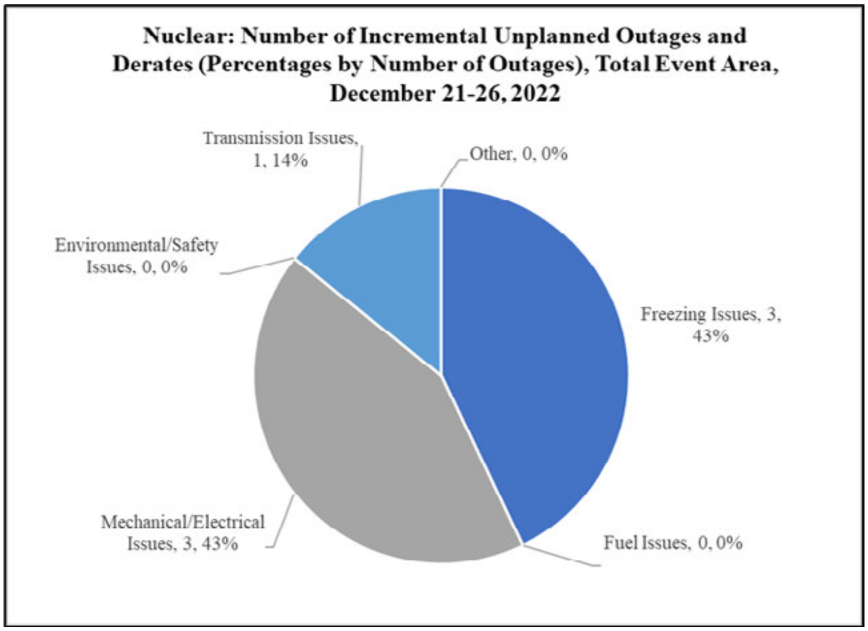
3. Causes of Unplanned Generation Outages, by Fuel Type of Generation

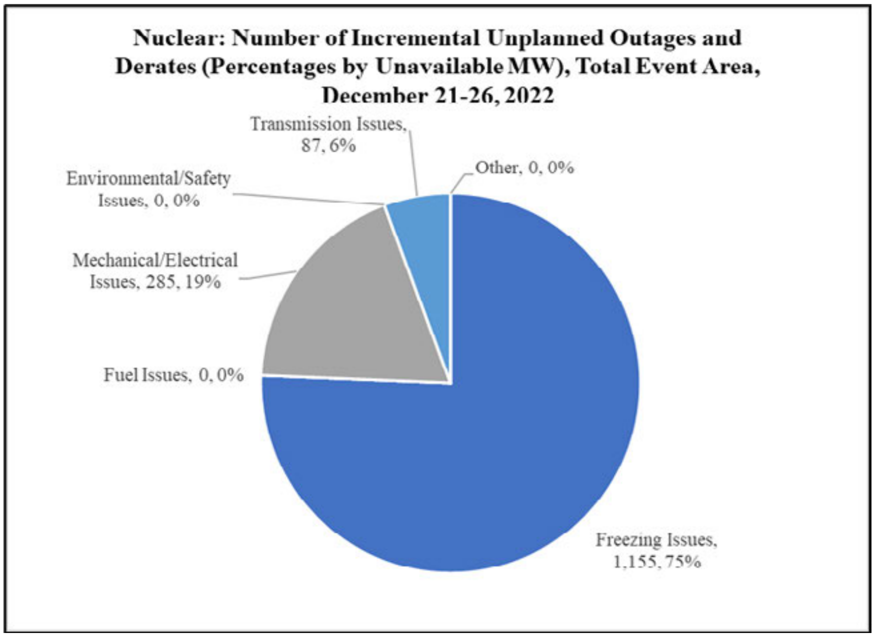


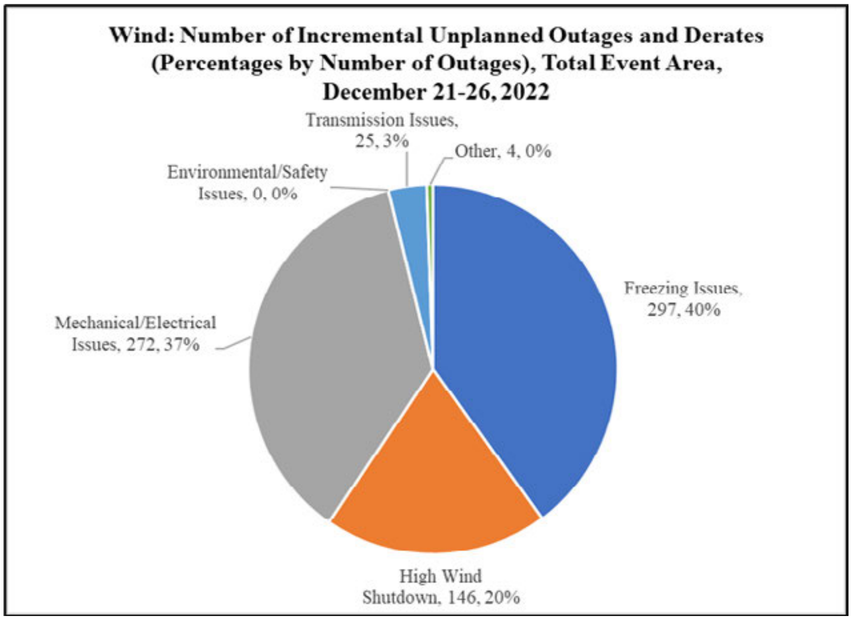



Gas: Number of Incremental Unplanned Outages and Derates (Percentages by Number of Outages), Total Event Area, December 21-26, 2022
Transmission Issues, 11, 1%
Other, 9, 0%
Environmental/Safety Issues, 64, 4%
Freezing Issues, 381, 23%
Mechanical/Electrical Issues, 604, 36%
Fuel Issues, 602, 36%

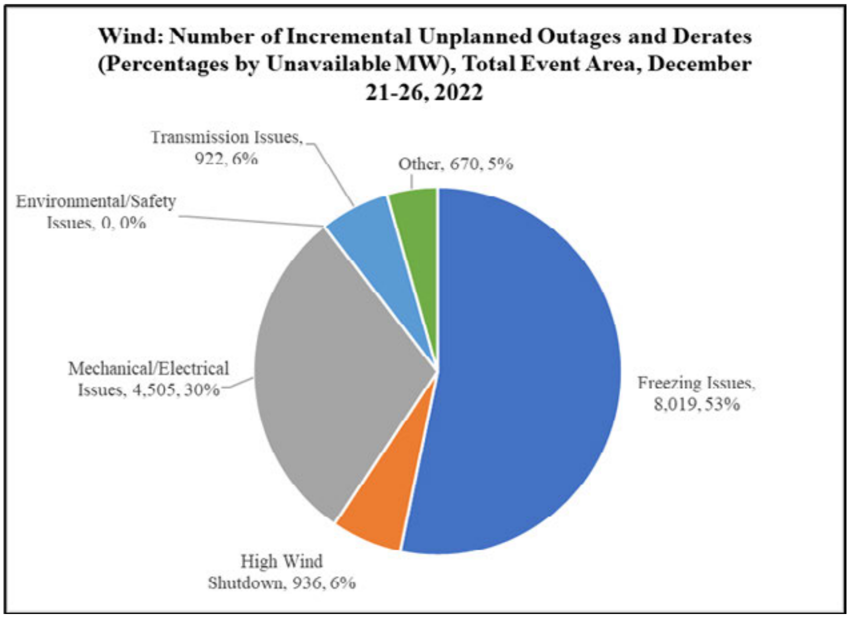

Gas: Number of Incremental Unplanned Outages and Derates (Percentages by Unavailable MW), Total Event Area, December 21-26, 2022
Transmission Issues, 1,221, 1%
Environmental/Safety Issues, 5,522, 2%
Other, 2,265, 1%
Freezing Issues, 66,688, 29%
Mechanical/Electrical Issues, 83,839, 36%
Fuel Issues, 71,423, 31%


Nuclear: Number of Incremental Unplanned Outages and Derates (Percentages by Number of Outages), Total Event Area, December 21-26, 2022
Transmission Issues, 1, 14%
Other, 0, 0%
Environmental/Safety Issues, 0, 0%
Freezing Issues, 3, 43%
Mechanical/Electrical Issues, 3, 43%
Fuel Issues, 0, 0%

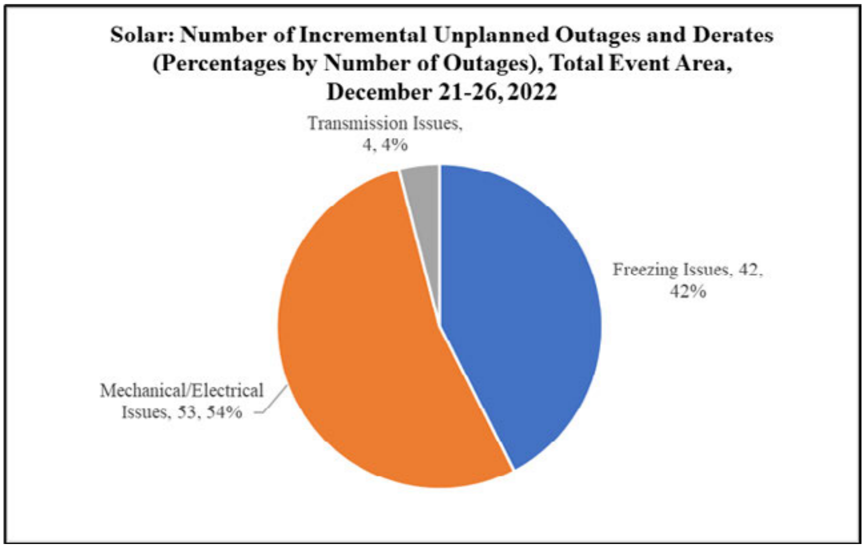

Nuclear: Number of Incremental Unplanned Outages and Derates (Percentages by Unavailable MW), Total Event Area, December 21-26, 2022
Transmission Issues, 87, 6%
Environmental/Safety Issues, 0, 0%
Other, 0, 0%
Mechanical/Electrical Issues, 285, 19%
Fuel Issues, 0, 0%
Freezing Issues, 1,155, 75%

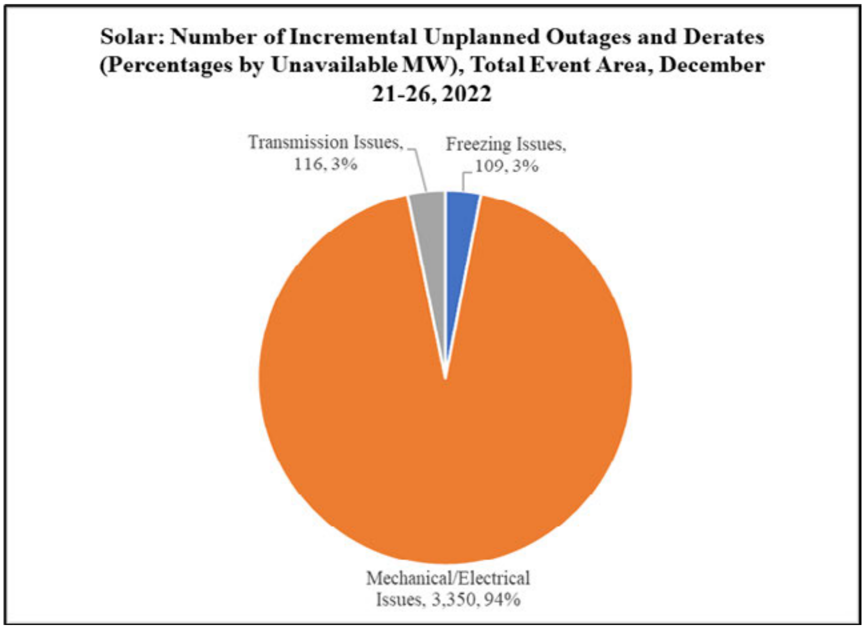


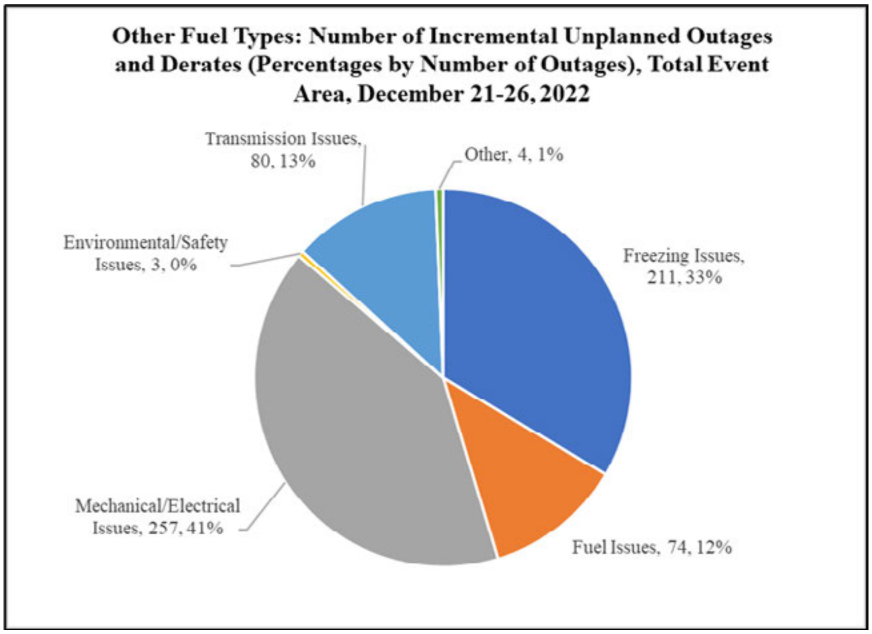
Wind: Number of Incremental Unplanned Outages and Derates (Percentages by Number of Outages), Total Event Area, December 21-26, 2022
Transmission Issues, 25, 3%
Other, 4, 0%
Environmental/Safety Issues, 0, 0%
Freezing Issues, 297, 40%
Mechanical/Electrical Issues, 272, 37%
High Wind Shutdown, 146, 20%

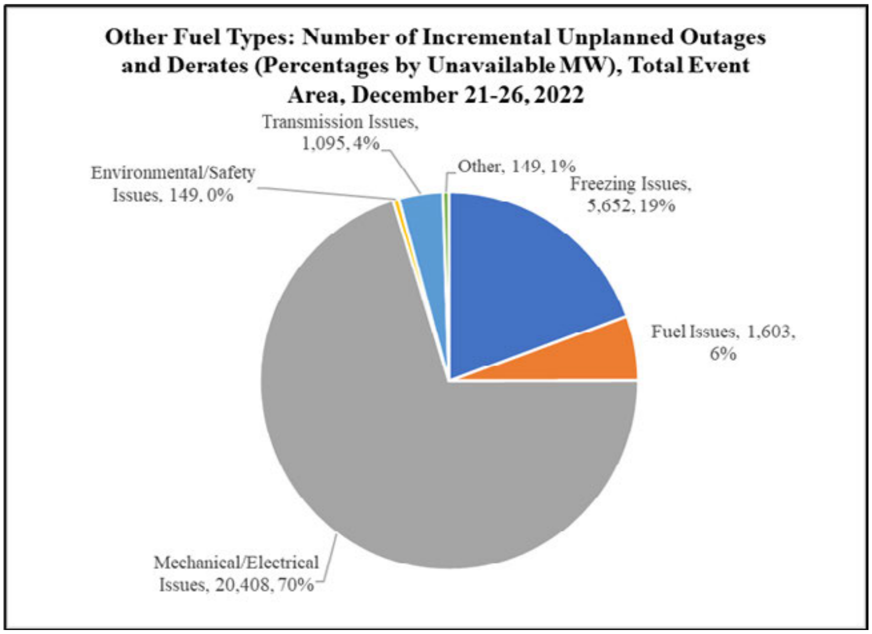


Wind: Number of Incremental Unplanned Outages and Derates (Percentages by Unavailable MW), Total Event Area, December 21-26, 2022
Transmission Issues, 922, 6%
Other, 670, 5%
Environmental/Safety Issues, 0, 0%
Mechanical/Electrical Issues, 4,505, 30%
Freezing Issues, 8,019, 53%
High Wind Shutdown, 936, 6%

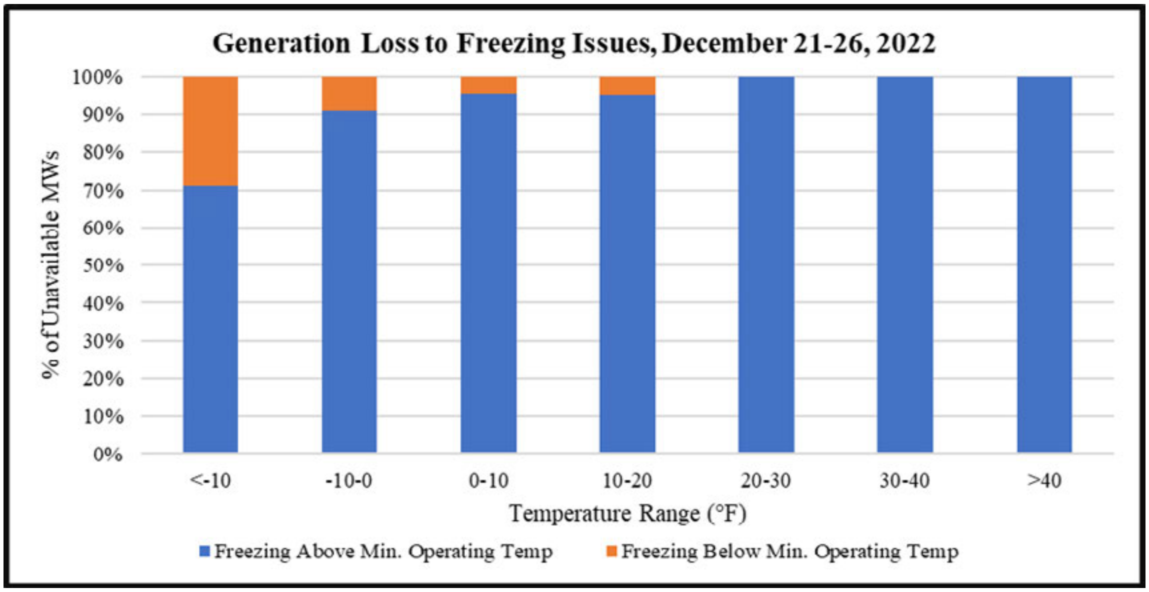

Solar: Number of Incremental Unplanned Outages and Derates (Percentages by Number of Outages), Total Event Area, December 21-26, 2022
Transmission Issues, 4, 4%
Freezing Issues, 42, 42%
Mechanical/Electrical Issues, 53, 54%

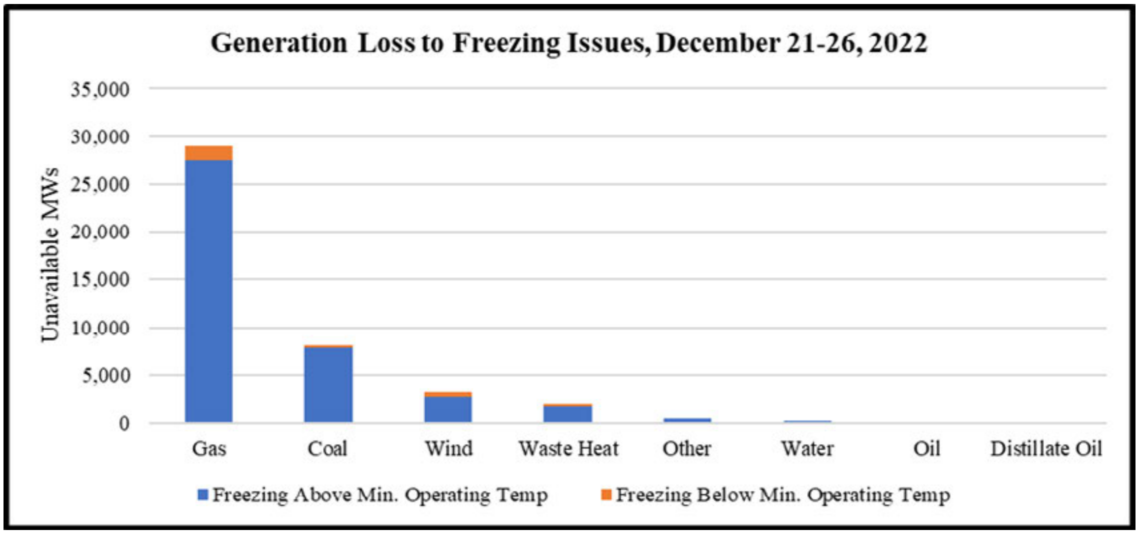

Solar: Number of Incremental Unplanned Outages and Derates (Percentages by Unavailable MW), Total Event Area, December 21-26, 2022
Transmission Issues, 116, 3%
Freezing Issues, 109, 3%
Mechanical/Electrical Issues, 3,350, 94%


Other Fuel Types: Number of Incremental Unplanned Outages and Derates (Percentages by Number of Outages), Total Event Area, December 21-26, 2022
Transmission Issues, 80, 13%
Other, 4, 1%
Environmental/Safety Issues, 3, 0%
Freezing Issues, 211, 33%
Mechanical/Electrical Issues, 257, 41%
Fuel Issues, 74, 12%

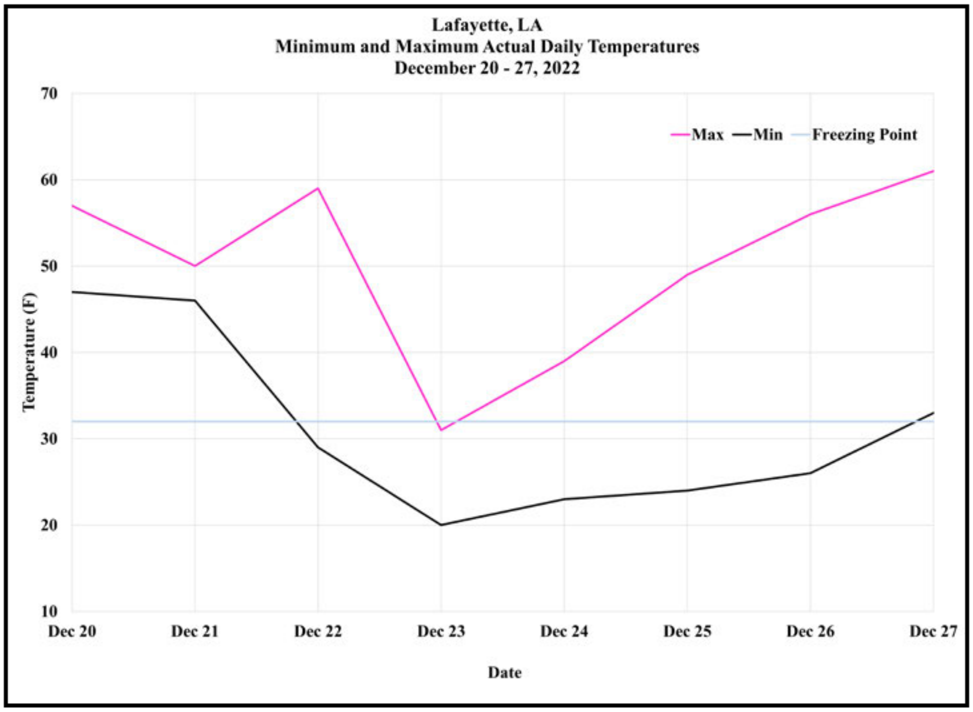

Other Fuel Types: Number of Incremental Unplanned Outages and Derates (Percentages by Unavailable MW), Total Event Area, December 21-26, 2022
Transmission Issues, 1,095, 4%
Environmental/Safety Issues, 149, 0%
Other, 149, 1%
Freezing Issues, 5,652, 19%
Fuel Issues, 1,603, 6%
Mechanical/Electrical Issues, 20,408, 70%

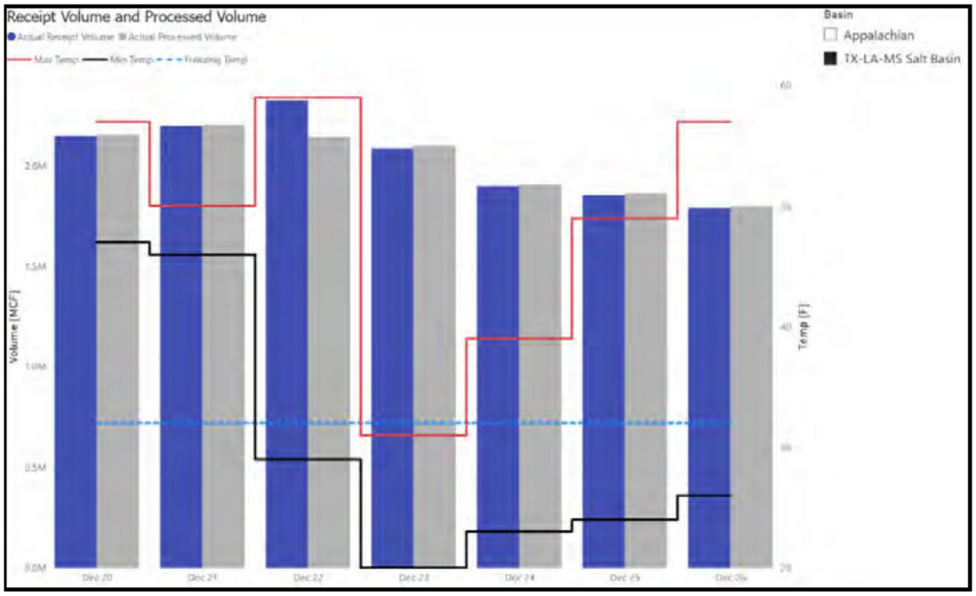
4. Cause: Freezing Issues – Additional Charts and Figures





APPENDIX D: NATURAL GAS PROCESSING DATA FOR TEXAS-LOUISIANA-MISSISSIPPI SALT BASIN





APPENDIX E: PROGRESS ON 2021 INQUIRY REPORT

FERC-NERC-Regional Entity Cold Weather Inquiry Reports - Recommendations Completion Tracking (as of October 2023)

URI Report Recommendations	URI / Percent Completed	Completion Notes		Elliott Report Recommendations (abbreviated text)
Extreme Cold Weather Event Prevention and Preparedness-Oriented Recommendations				
Rec. 1: Develop Reliability Standards for electric generator cold weather reliability	70%	Submitted Part of Ph. 2 Stds. to FERC by 11-1-23	Related to Elliott Rec.	Rec. 1: Robust implementation monitoring of freeze protection Standards to determine if reliability gaps exist
Rec. 2: Generator compensation opportunities for investments	(states)			—
Rec. 3: Generator winter readiness technical conference	100%	FERC/ERO conference held April 2022		—
Rec. 4: Generator freeze protection inspection and maintenance timing	20%	observation from Elliott event inquiry	Related to Elliott Rec.	Rec. 1: Seven recommendation sub-parts (1a-1g) for assuring freeze protection sufficiency
Rec. 5: Require natural gas facility cold weather preparedness plans and measures	20%	Now Required in Texas	Related to Elliott Rec.	Rec. 4a: Establish reliability rules for natural gas infrastructure, requiring cold weather plans, freeze protection, and operating measures for extreme cold weather periods
Rec. 6: Voluntary measures for natural gas facility cold weather preparedness	(states)		Related to Elliott Rec.	Rec. 6: Commission consider whether to have jurisdictional gas entities provide one-time reports on assessing, responding to natural gas vulnerabilities in extreme cold weather
Rec. 7: Establish natural gas-electric reliability forum	100%	NAESB, Commission Forums, NAESB Report		—
Rec. 8: Understanding generator natural gas contract risks	50%	NERC drafting new fuel assurance/risk guideline		—
Rec. 9: (Seasonal) Peak load forecasts and reserve margin calculations	100%	Incorporated in NERC Winter Assessment	Related to Elliott Rec.	Rec. 10: joint-regional reliability assessments of electric grid conditions during extreme cold weather periods, for use in power supply planning to reduce the risk of firm load
Rec. 11: Generator cold weather effects-mechanical, electrical systems	0%	observation from Elliott event inquiry	Related to Elliott Rec.	Rec. 2: Technical review of root causes of generator cold-related mechanical/electrical outages to identify prevention measures, determine if additional Standards are needed
Rec. 12: Generator use of weather forecasts for operating plans	50%	observation from Elliott event inquiry		—
Rec. 14: Natural gas production facilities SCADA control	(states)			—
Rec. 16: Improve Near-term Load Forecasts	0%	observation from Elliott event inquiry	Related to Elliott Rec.	Rec. 9: BAs should improve their short-term load forecasts for extreme cold weather periods cold weather periods by implementing the lessons and practices identified below and sharing newly identified effective practices with peer BAs for continuous improvement
Rec. 17: Analyze Intermittent Generation to improve Load Forecasts	50%	observation from Elliott event inquiry		
Rec. 19: Retail Incentives for Energy Efficiency Improvements	(states)			—
Rec. 23: Report Times for Generation and Transmission Outages	25%	observation from Elliott event inquiry		—
Rec. 24: Study: Measures to Address Natural Gas Supply Shortfalls	50%	NERC & NERC RAS	Related to Elliott Rec.	Rec. 7: Study: analyze whether additional natural gas infrastructure, including interstate pipelines and storage, is needed to support reliability of electric grid, meet needs of LDCs
Rec. 28: Study: Guidelines to Identify Critical Natural Gas Facility Loads	(states)	Now Required in Texas	Related to Elliott Rec.	Rec. 4c: Establish rules requiring designation of critical natural gas infrastructure loads for priority treatment during load shed
Average Percent Addressed (excluding state-level recs.) - URI:	**49%**			Rec. 4b: Establish rules requiring establishing regional natural gas communications coordinators, with situational awareness ofnatural gas infrastructure similar to grid's RCs
Number of state-level recommendations to help support prevention - URI:	5			Rec. 5: The North American Energy Standards Board should convene natural gas / electric grid / LDC entities to identify communication improvements during extreme cold
				Rec. 8: BAs assess whether new or modified processes, such as multi-day risk assessment processes or advance reliability commitments are needed to address anticipated capacity shortages or transmission reliability problems during extreme cold weather
Emergency Response-Oriented Recommendations				
Rec. 10: Improve rotational load shed plans	90%	NERC RAS & RTOS		—
Rec. 13: Study of ERCOT generators to review low-frequency effects	10%	PRC-024 SDT, combined with Rec. 27 effort		—
Rec. 15: Develop or enhance emergency response centers	(states)			—
Rec. 18: Additional Rapidly-Deployable Demand Response	(states)			—
Rec. 20: Perform Bi-Directional Seasonal Transfer Studies	90%	NERC RAS & RTOS		—
Rec. 21: Operator-Training Rotational Firm Load Shed Simulations	100%	NERC RTOS		—
Rec. 22: Generator Protection Settings/ UFLS Coordination	100%	ERCOT completed		—
Rec. 25: Study: Additional ERCOT Interconnection Links	100%	ERCOT, completed		—
Rec. 26: Study: ERCOT Black Start Unit Reliability	98%	FERC/ERO Report near completion	Related to Elliott Rec.	Rec. 3: Study: Black start unit reliability covering all portions of the U.S. not already studied
Rec. 27: Study: Low-Frequency Effects in Eastern, Western Interconnects	10%	NERC SME staff assigned; gathering data	Related to Elliott Rec.	Rec. 11: Study: examine potential stability risks on December 23-24 for periods of decreased frequency and low responsive reserves during Winter Storm Elliott
Average Percent Addressed (excluding state-level recs.) - URI:	**75%**			
Number of state-level recommendations to help support response - URI:	2			

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Committees, Task Forces, Forums – Acronyms Key

ERATF:	Energy Reliability Assessment Task Force
IRPWG:	Inverter-Based Resource Performance Working Group
RAS:	Reliability Assessment Subcommittee
RS:	Resources Subcommittee
RSTC:	Reliability and Security Technical Committee
RTOS:	Real Time Operations Subcommittee
SPCWG:	System Protection and Control Working Group
SPIDERWG:	System Planning Impacts from Distributed Energy Resources Working Group