FERC - NERC - Regional Entity Staff Report:

The February 2021 Cold Weather Outages in Texas and the South Central United States

Federal Energy Regulatory Commission

North American Electric Reliability Corporation

Regional Entities

FERC, NERC and Regional Entity Staff Report

The February 2021 Cold Weather Outages in Texas and the South Central United States

November 2021

FEDERAL ENERGY REGULATORY COMMISSION

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

Acknowledgement

This report results from the combined efforts of many dedicated individuals in multiple organizations. The inquiry team (the Team) consisted of individuals from the Federal Energy Regulatory Commission (FERC or the Commission), the North American Electric Reliability Corporation (NERC), Regional Reliability Entities Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), ReliabilityFirst Corporation (RF), SERC Corporation (SERC), Texas Reliability Entity (Texas RE) and Western Electricity Coordinating Council (WECC), as well as the Department of Energy and the National Oceanic and Atmospheric Administration (NOAA), all of whom are named in Appendix A. They were assisted by other non-Team members within their respective organizations.

Contents

I. Executive Summary

This report[1] describes the severe cold weather event occurring between February 8 and 20, 2021 and how it impacted the reliability of the bulk electric system[2] ("BES" or colloquially known as the grid) in Texas and the South Central United States (hereafter known as "the Event"). During the Event, extreme cold temperatures and freezing precipitation led 1,045 individual BES generating units,[3] (with a combined 192,818 MW of nameplate capacity) in Texas and the South Central United States to experience 4,124 outages, derates or failures to start. Each individual generating unit could, and in many cases, did, have multiple outages from the same or different causes. To provide perspective on how significant the generating unit outages were, including generation already on planned or unplanned outages, the Electric Reliability Council of Texas (ERCOT) averaged 34,000 MW of generation unavailable (based on expected capacity[4]) for over two consecutive days, from 7:00 a.m. February 15 to 1:00 p.m. February 17, equivalent to nearly half of its all-time winter peak electric load of 69,871 MW.

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[1] This report is written for a reader who is already familiar with principles of energy markets, electric transmission system operations and generating unit operations. For readers who are not as familiar, the Team has linked to several resources which may be helpful:

[2] Bulk electric system generally means all transmission elements operated at 100 kV or higher and real power and reactive power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy. *See* NERC Glossary of Terms at https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

[3] A single generating unit can range from a 75 MW gas turbine, to a 1,000-MW-plus nuclear unit, to a wind farm with multiple wind turbines. For purposes of the report, only BES generating units were considered, i.e., those with a nameplate rating of 75 MW or higher.

[4] Expected capacity includes any expected seasonal capacity derates, and for intermittent resources (e.g., wind, solar resources), expected capacity is calculated based on weather conditions. For example, a 100 MW wind generation facility may be 20 MW, based on the variability of wind during the winter peak timeframe.

The Event was the fourth cold-weather-related event in the last ten years to jeopardize BES reliability,[5] and with a combined 23,418 MW of manual firm load shed,[6] the largest controlled firm load shed event in U.S. history. 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. The unplanned generation outages that escalated during the Event were more than four times as large as the previous largest event, in 2011 (65,622 MW versus 14,702 MW).

More than 4.5 million people in Texas lost power during the Event, and some went without power for as long as four days, while exposed to below-freezing temperatures for over six days.[7] At least 210 people died during the Event, with most of the deaths connected to the power outages, of causes including hypothermia, carbon monoxide poisoning, and medical conditions exacerbated by freezing conditions.[8] Among the deaths were a mother and her seven-year-old daughter,[9] and an 11-year-old boy who died in his bed,[10] who all died of carbon monoxide poisoning, and a 60-year-old disabled man who died of hypothermia.[11] A grandmother and three children trying to keep warm

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[5] In February 2011, an arctic cold front impacted the southwest U.S. and resulted in 29,700 MW of generation outages, natural gas facility outages and emergency power grid conditions with need for firm customer load shed. Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011: Causes and Recommendations (Aug. 2011) (https://www.ferc.gov/sites/default/files/2020-07/OutagesandCurtailmentsDuringtheSouthwestColdWeatherEventofFebruary1-5-2011.pdf) (hereafter, 2011 Report). In January 2014, a polar vortex affected Texas, central and eastern U.S., triggering 19,500 MW of generation outages, natural gas availability issues and resulted in emergency conditions including voluntary load management. NERC "*Polar Vortex Review*" (Sept. 2014), https://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf (hereafter Polar Vortex Review). And in January 2018, an arctic high-pressure system and below average temperatures in the South Central U.S. resulted in 15,800 MW of generation outages and the need for voluntary load management emergency measures. See South Central United States Cold Weather Bulk Electric Systems Event of January 17, 2018 (July 2019), https://www.ferc.gov/sites/default/files/2020-07/SouthCentralUnitedStatesColdWeatherBulkElectricSystemEventofJanuary17-2018.pdf (hereafter, 2018 Report).

[6] Manual firm load shed, often referred to as rolling or rotating blackouts, is when BES operators order a percentage of the demand or load to be temporarily disconnected, to avoid system instability or other system emergencies. Customers lost electric distribution service due both to manual firm load shed, as well as to weather-related unplanned outages (such as downed power lines). In addition to being the largest controlled firm load shed event in U.S. history, the Event was also the third largest in quantity of outaged megawatts (MW) of load after the August 2003 northeast blackout and the August 1996 Western Interconnection blackout.

[7] Paul Takashi, *I lost my best friend: How Houston's winter storm went from wonderland to deadly disaster*, Houston Chronicle (May 25, 2021), https://www.houstonchronicle.com/news/investigations/article/failures-of-power-series-part-2-blackouts-houston-16189658.php.

[8] Andrew Weber, *Texas Winter Storm Toll Goes Up to 210, Including 43 Deaths in Harris County*, Houston Public Media (July 14, 2021), https://www.houstonpublicmedia.org/articles/news/energy-environment/2021/07/14/403191/texas-winter-storm-death-toll-goes-up-to-210-including-43-deaths-in-harris-county/.

[9] ABC 13 Staff, *Carbon Monoxide "We tried our best to save them"*, ABC 13 Eyewitness News (February 17, 2021), https://abc13.com/houston-woman-and-daughter-die-from-carbon-monoxide-poisoning-mom-after-leaving-car-running-inside-garage-dangers-during-texas-winter-storn-storm-2021/10348847/

[10] KHOU Staff, *Autopsy Results Released for 11-Year-Old Who Died During the Texas Winter Freeze,* KHOU 11 News Channel (May 12, 2021) https://www.khou.com/article/news/local/conroe-police-autopsy-reveals-11-year-old-boy-died-carbon-monoxide-poisoning-houston-winter-storm/285-fbae9d3f-45cd-41bb-9047-33665fef8f18#:~:text=Autopsy%20results%20released%20for%2011,their%20mobile%20home%20lost%20power.

[11] Paul Takashi, *I lost my best friend: How Houston's winter storm went from wonderland to deadly disaster*, Houston Chronicle (May 25, 2021), https://www.houstonchronicle.com/news/investigations/article/failures-of-power-series-part-2-blackouts-houston-16189658.php.

using a wood-burning fireplace died in a house fire.[12] In cities including Austin, Houston and San Antonio, over 14 million people were ordered to boil drinking and cooking water, and multiple cities ordered water conservation measures, due to broken pipes and power outages (which lowered water pressure).[13] After the city of Denton, Texas, lost its gas supply, it was forced to cut power to nursing homes and water pumping stations.[14]

Analysts with the Federal Reserve Bank of Dallas estimated that the outages caused direct and indirect losses to the Texas economy of between $80 to $130 billion.[15] A separate Federal Reserve Bank of Dallas analysis described the effect on the petrochemical and refining sector as "hurricane-level," comparable to 2008's Hurricane Ike, with a 50 percent drop in February 2021 production as compared to January. It also predicted continuing effects on the supply chain through the end of 2021 as a result of the disruptions in February.[16]

A. Synopsis of Event

In the early morning hours of February 15, 2021, an arctic front moving through Texas and the South Central U.S. began to take its toll. As temperatures dropped, more and more generating units throughout Texas failed in ERCOT. The same front led to generating units to fail to a lesser extent in the South Central U.S. footprints of Midcontinent Independent System Operator (MISO) South and Southwest Power Pool (SPP).[17] Responding to the loss of generation, and to keep the electrical system from cascading outages and total blackout, the system operators at ERCOT began to issue orders for rotating outages of electricity to customers (known as manual firm load shed). ERCOT ultimately had to shed 20,000 MW of firm load at the worst point of the Event, with SPP and MISO

[12] Anna Bauman, *Grandmother, 3 Children Dead in Sugar Land Fire,* Houston Chronicle (Feb. 16, 2021), https://www.houstonchronicle.com/news/houston-texas/houston/article/Sugar-Land-fire-fatalities-15953492.php%20https://www.google.com/amp/s/abc13.com/amp/sugar-land-house-fire-children-killed-deadly/10352669

[13] Talal Ansari, *New Winter Storm Threatens Fragile Power Grids in Texas, Other Parts of U.S.*, The Wall Street Journal New (Feb. 22, 2021), https://www.wsj.com/articles/new-winter-storm-threatens-fragile-electrical-grids-in-texas-other-parts-of-u-s-11613588298; Elizabeth Findell, *Texas Cities Under Boil-Water Orders*, The Wall Street Journal (Feb. 19, 2021), https://www.wsj.com/articles/texas-cities-under-boil-water-orders-11613671450.

[14] Community Emergency Preparedness Committee, *City of San Antonio Community Emergency Preparedness Committee Report: A Response to the February 2021 Winter Storm* (Jun. 24, 2021), https://www.sanantonio.gov/Portals/5/files/CEP%20Report%20Final.pdf; Russell Gold, *Inside One Texas City's Struggle to Keep Power and Water Going*, The Wall Street Journal (Feb. 17, 2021), https://www.wsj.com/articles/texas-city-deals-with-no-power-no-water-during-big-chill-11613590412.

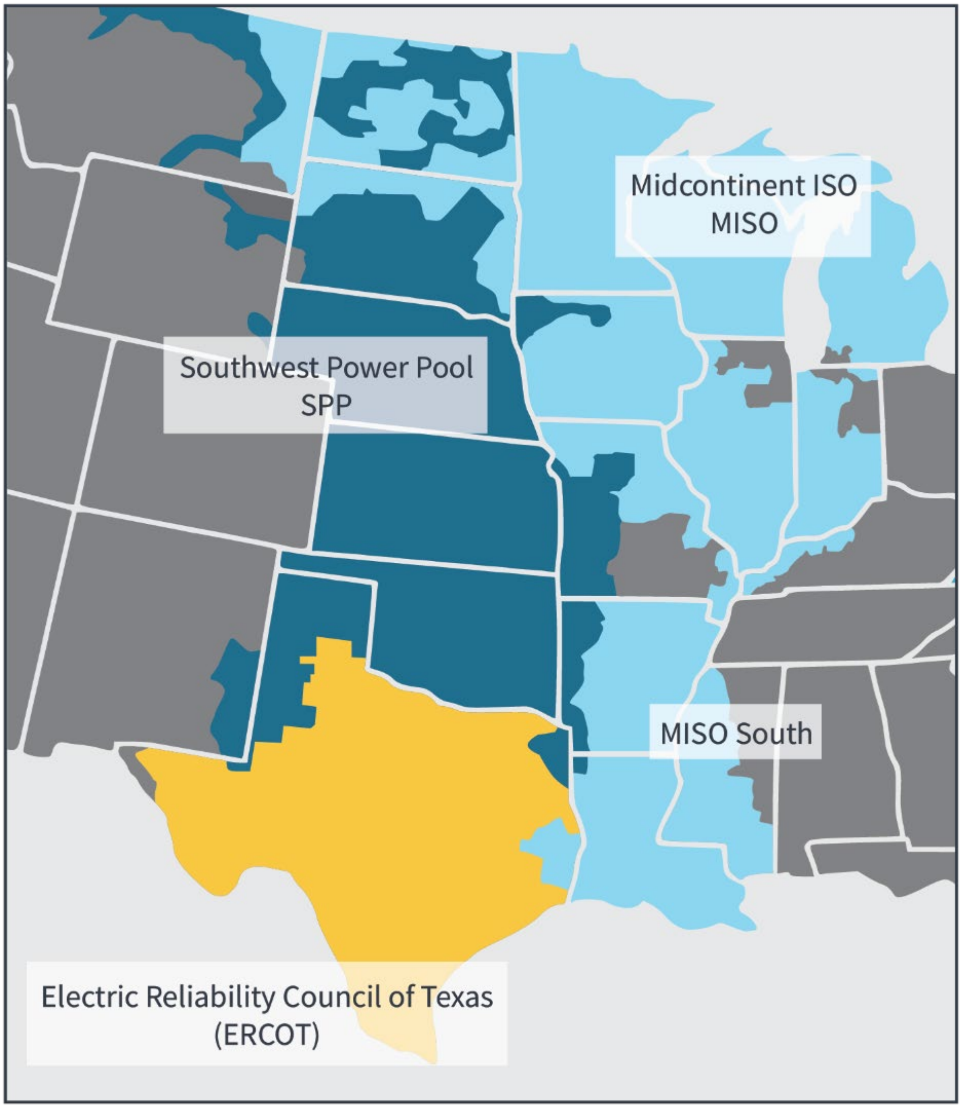
[15] Garrett Golding et al., *Cost of Texas' 2021 Deep Freeze Justifies Weatherization*, Dallas Fed Economics (Apr. 15, 2021), https://www.dallasfed.org/research/economics/2021/0415.

[16] Jesse Thompson, *Texas Winter Deep Freeze Broke Refining, Petrochemical Supply Chains*, Southwest Economy (Second Quarter 2021), https://www.dallasfed.org/research/swe/2021/swe2102/swe2102c (Texas holds nearly 75 percent of "basic U.S. chemical capacity," relied upon by global supply chains, and as much as 80 percent of this capacity was offline after the storm).

[17] See Figure 1 below for map of the Event Area: ERCOT, SPP and MISO South. Except for the figures regarding the entire MISO footprint in section II.B. below, the Team gathered data about and focused on MISO South, because the bulk of the manual load shed and unplanned generation outages experienced in MISO occurred in MISO South.

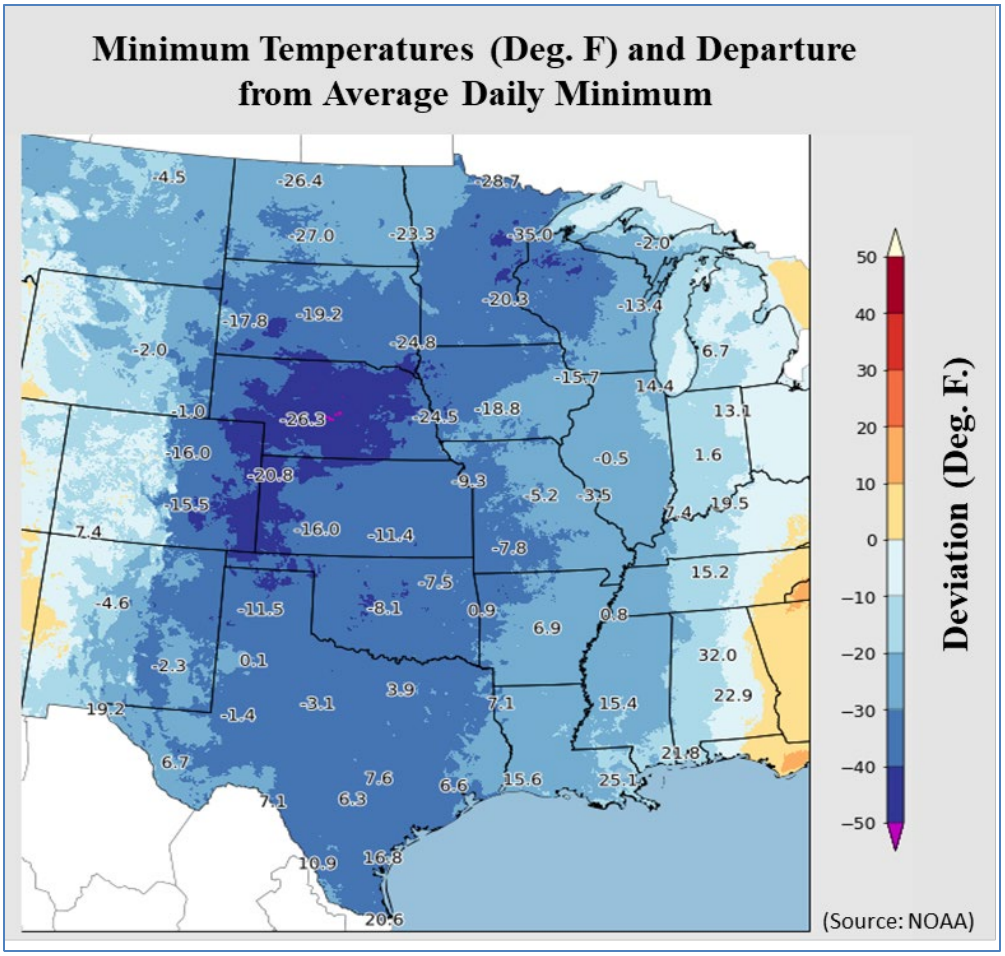
operators shedding a combined total of 3,418 MW of firm load on February 15 and 16, at their worst points.

Figure 1: Event Area: ERCOT, SPP and MISO South



A confluence of two causes, both triggered by cold weather, led to the 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.[18] 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.

Figure 2: Severe Cold Weather Conditions – February 15, 2021



ERCOT, MISO and SPP all knew from weather forecasts and warnings issued by NOAA and other meteorologists beginning in early February that an arctic cold front was expected. All three issued cold weather preparation notices to their generation and transmission operators based on when the cold weather was expected to reach their respective footprints: ERCOT and SPP on February 8, and MISO on February 9. Temperatures began to drop below freezing in ERCOT and SPP on February 8, but low temperatures dropped even lower during the week of February 14, reaching their nadir on February 15 and 16. Daily low temperatures for February 15 in the Event Area were as much as 40

[18] Hereafter, "natural gas fuel supply issues" means the reduction in natural gas fuel supply caused by a combination of natural gas production declines, related natural gas pipeline pressure issues, and terms and conditions of electric generating units' natural gas commodity and transportation contracts.

to 50 degrees[19] lower than average daily minimum temperatures for February 15, as shown in Figure 2, above. In addition to the arctic air, the cold front brought periods of freezing precipitation and snow to large parts of Texas and the South Central U.S., starting February 10, and extending into the week of February 14, 2021.

Unplanned outages of natural gas wellheads due to freeze-related issues, loss of power and facility shut-ins[20] to prevent imminent freezing issues, beginning on approximately February 7, as well as unplanned outages of natural gas gathering and processing facilities, resulted in a decline of natural gas available for supply and transportation to many natural gas-fired generating units in the South Central U.S. Once natural gas supply outages began at the wellhead, they rippled throughout the natural gas and electric infrastructure, causing processing outages and reductions, pipeline declarations of Operational Flow Order (OFO)s[21] and force majeure, and outages and derates of natural gas-fired generating units. U.S. natural gas production in February 2021 experienced the largest monthly decline on record.[22] Between February 8 and 17, the total natural gas production in the U.S. Lower 48 fell by 28 percent. In the Event Area, Texas, Oklahoma, and Louisiana gas production at its lowest point of February 17 declined by an estimated 21 Bcf/d, exceeding a 50 percent decline when compared to average production in January 2021. Average production declines in those three states constituted over 80 percent of the total production declines across the lower 48 states during the period from February 15-20 when compared to average production in January 2021. Most producing regions of the U.S. saw a sharp decline and recovery associated with temperature—when temperatures fell, regional production dropped, and as temperatures rose after the Event, regional production recovered, ultimately to pre-Event levels by late February.[23]

During the week of February 7, ERCOT and SPP experienced rising load, as well as increasing generating unit outages, primarily caused by wind turbine blade freezing as a result of freezing precipitation, and natural gas fuel supply issues. Although ERCOT and SPP issued several alerts, they did not have to take any emergency actions because enough generation remained online to meet load.

But the week of February 14 brought far colder weather, and ERCOT, SPP and MISO all faced emergency conditions simultaneously. Temperatures dropped as low as six degrees in Austin, eight degrees in Dallas and ten degrees in Houston. Unplanned generating unit outages and derates in ERCOT escalated sharply in the late-night hours of February 14 into the early morning hours of February 15, and ERCOT set an all-time winter peak record for system load of 69,871 MW at 8:00 p.m. on February 14. The combination of high load and increasing unplanned generating unit outages caused ERCOT's Physical Responsive Capability to drop below acceptable levels, and at

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[19] All temperatures will be in Fahrenheit unless otherwise stated.

[20] A shut-in well is a well that has been shut off so that no natural gas is flowing or being produced. *See* American Gas Association (AGA) Natural Gas Glossary, at https://www.aga.org/natural-gas/glossary/, "Shut-In" and "Shut-In Well" definitions. Some entities performed pre-emptive shut-ins to protect components from freezing, which resulted in well outages.

[21] See sidebar on Pipeline Communications on page 71.

[22] Mike Kopalek & Emily Geary, February 2021 weather triggers largest monthly decline in U.S. natural gas production, Today In Energy (May 10, 2021) https://www.eia.gov/todayinenergy/detail.php?id=47896

[23] Modeled data provided by IHS (www.ihsmarkit.com/index.html).

12:15 a.m., it issued the first stage of an Energy Emergency Alert (EEA),[24] EEA 1, which allowed it to deploy demand response resources.

Beginning in the early hours of February 15 at approximately 12:18 a.m., the ERCOT Interconnection frequency,[25] which measures the balance of supply and demand on the BES and is thus a critical indicator of BES reliability status, began to fall below the normal band level. At first ERCOT was able to recover its frequency to normal levels through deployment of load management measures, but it continued to suffer generating unit outages and needed to order its first 1,000 MW of load shed at 1:20 a.m. As system frequency continued to fall, ERCOT BA operators ordered an additional 1,000 MW of load shed, but generating units continued to fail and frequency declined to the point that ERCOT operators had only nine minutes to prevent approximately 17,000 MW of generating units from tripping due to underfrequency relays, which could potentially cause a complete blackout of the ERCOT Interconnection. ERCOT system frequency eventually bottomed out, and finally rose above the generator trip level after remaining below for over four minutes. However, unplanned generating outages continued, and ERCOT system operators continued to shed firm load to balance demand against the massive generating unit losses. For over two days, including generating units already on planned or unplanned outages when the Event began as well as unplanned outages that began during the Event, ERCOT averaged 34,000 MW of generation outages (based on expected capacity). To balance ERCOT's load against those staggering generation losses, ERCOT operators continued to order firm load shed, lasting nearly three consecutive days, and peaking at 20,000 MW by 7 p.m. on February 15.

SPP and MISO in the Eastern Interconnection also faced challenges balancing rising load with rapidly decreasing generation. SPP averaged 20,000 MW of generation unavailable (based on expected capacity) for over four consecutive days, from February 15 to 19, and MISO South averaged 14,500 MW of generation unavailable for two consecutive days, from February 16 to 18. As a result, each had its own energy and transmission emergencies, starting on February 15. Unlike ERCOT, which can only import slightly more than 1,000 MW over its direct current ties, SPP and MISO imported power from other Balancing Authorities to make up for their increasing load levels and generation shortfalls, because the eastern part of the Eastern Interconnection did not have the same arctic weather conditions. Specifically, MISO was able to import large amounts of power from neighbors to the east (e.g. PJM Interconnection, LLC), and SPP was able to transfer some of that power through MISO. Those east-to-west transfers into MISO peaked at nearly 13,000 MW on February 15. The heavy transfers, combined with the widespread generation outages, created local and system-wide transmission emergencies on February 15 and 16, which required MISO operators to order a combined 2,000 MW of firm load shed (non-coincident). On the same days, SPP experienced transmission emergencies on a system-wide basis, although they did not result in any firm load shed. SPP ordered shed firm load on February 15 and 16 for energy emergencies for a total of over four hours spread over the two days, reaching 2,718 MW at its worst point following MISO's curtailment SPP's import power due to MISO's transmission emergency. On the evening

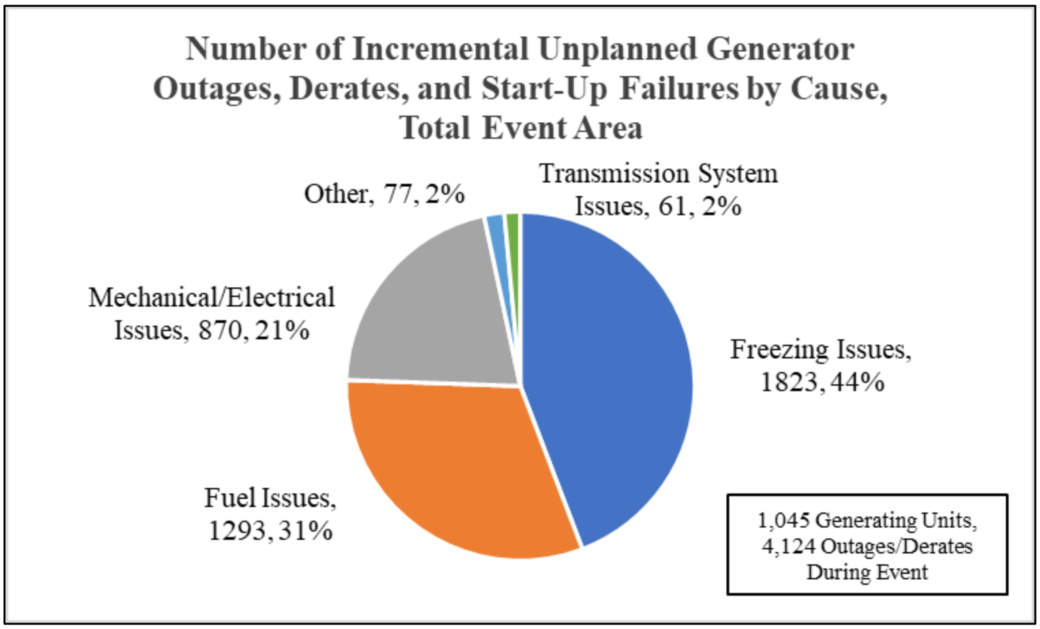
[24] See Appendix K for a description of the levels of alerts and Energy Emergencies.
[25] Interconnection frequency is measured in Hertz (Hz). *See* NERC Glossary of Terms, Actual Frequency.

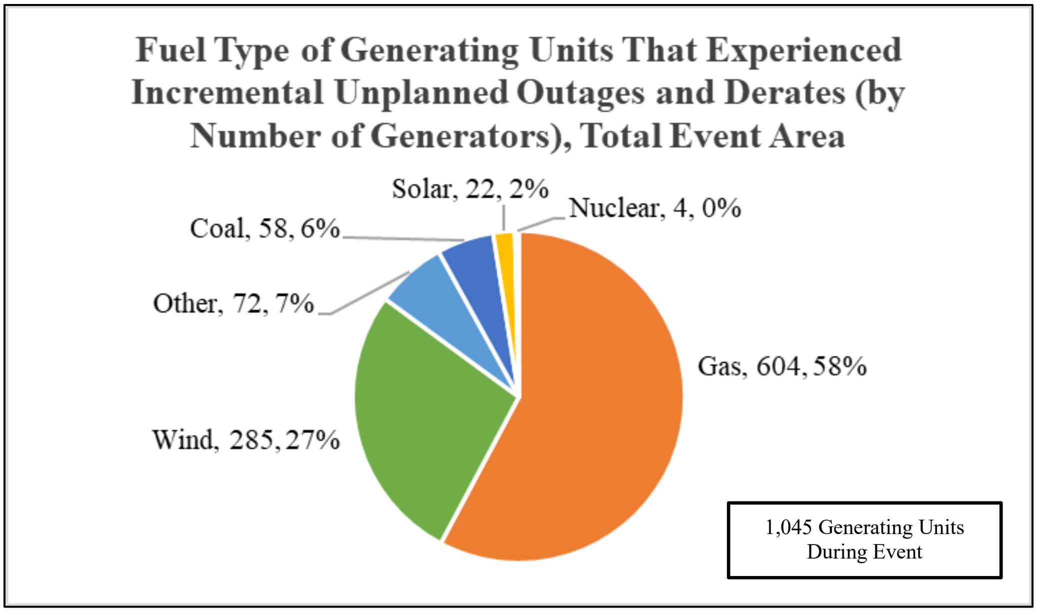
of February 16, MISO ordered firm load shed that lasted over two hours, reaching 700 MW at its worst point for an energy emergency in MISO South.

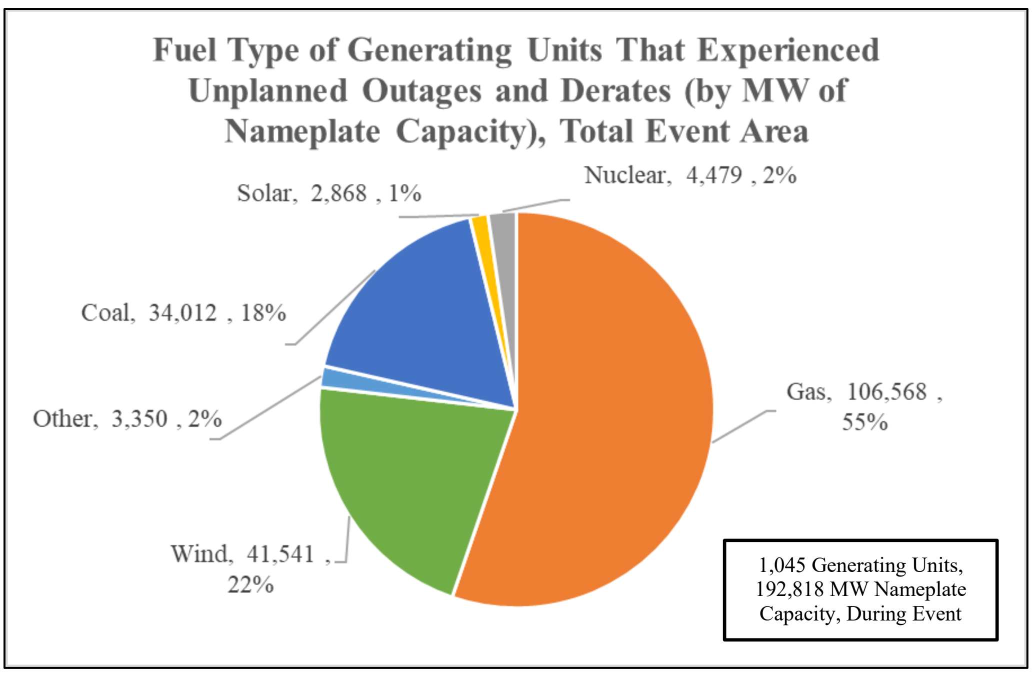
B. Key Findings and Causes

From February 8 through 20, in the Event Area, a total of 1,045 individual generating units—58 percent natural gas-fired, 27 percent wind, six percent coal, two percent solar, seven percent other fuels, and less than one percent nuclear—experienced 4,124 outages, derates or failures to start. Of those outages, derates, and failures to start, 75 percent were caused by either freezing issues (44.2 percent) or fuel issues (31.4 percent), as shown in Figure 3, below.

Figure 3: Incremental Unplanned Generating Unit Outages, Derates and Failures to Start, Total Event Area: by Cause, by Fuel Type, and by MW of Nameplate Capacity





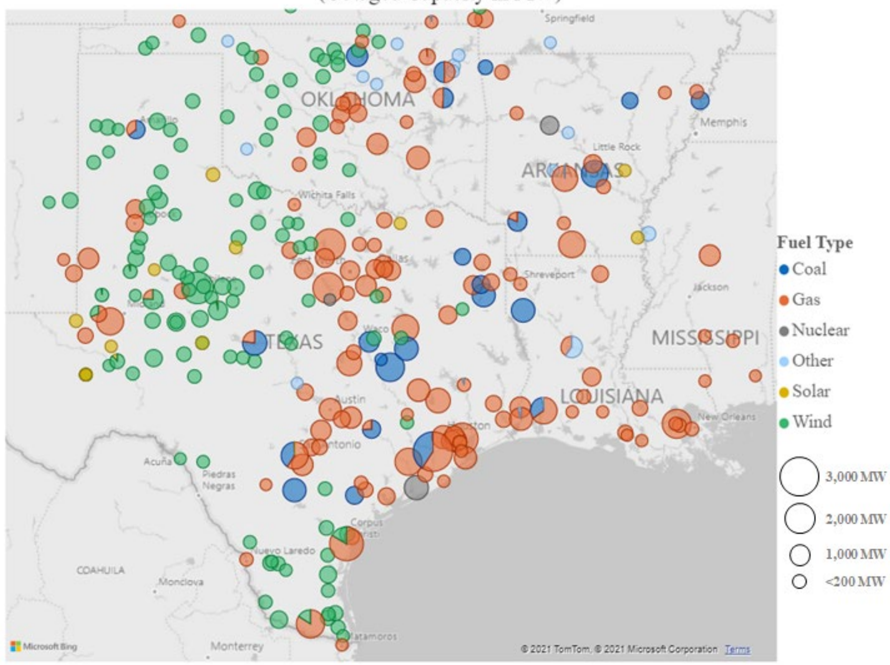


Natural gas fuel supply issues caused the majority, 87 percent, of the 31.4 percent of outages and derates due to fuel issues, and caused 27.3 percent of all outages, derates and failures to start during the Event.

In addition to the 44.2 percent of outages and derates caused by freezing issues, the 21 percent caused by "mechanical/electrical issues" also indicated a relationship with the cold temperatures—as temperatures decreased, the number of generating units outaged or derated due to mechanical/electrical issues increased. Figure 4, below depicts the locations of the generation outages, derates and failures to start during the Event.

Figure 4: Location and Fuel Type of Unplanned Generation Outages and Derates During the Event (Outaged Capacity in MW)

Location and Fuel Type of Unplanned Generation Outages and Derates During the Event (Outaged Capacity in MW)



Despite multiple prior recommendations by FERC and NERC, as well as annual reminders via Regional Entity workshops, that generating units take actions to prepare for the winter (and providing detailed suggestions for winterization),[26] 49 generating units in SPP (15 percent, 1,944 MW of nameplate capacity), 26 in ERCOT (7 percent, 3,675 MW), and three units in MISO South (four percent, 854 MW), still did not have any winterization plans, and 81 percent of the freeze-related generating unit outages occurred at temperatures above the unit's stated ambient design temperature. Generating units that experienced freeze-related outages above the unit's stated ambient design temperature represented about 63,000 MW of nameplate capacity.

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[26] 2011 Report, Recommendations 11, 14-19 https://www.ferc.gov/sites/default/files/2020-07/OutagesandCurtailmentsDuringtheSouthwestColdWeatherEventofFebruary1-5-2011.pdf, 2018 Report, Recommendation 1 https://www.ferc.gov/sites/default/files/2020-07/SouthCentralUnitedStatesColdWeatherBulkElectricSystemEventofJanuary17-2018.pdf.

C. Recommendations

Key Recommendations[27]. In response to the continued failures of generating units due to freezing issues, the Team recommends revising the mandatory Reliability Standards to require:

- Generator Owners (GOs) to identify and protect cold-weather-critical components (1a and 1b);
- GOs to retrofit existing generating units, and when building new generating units, to operate to specific ambient temperatures and weather based on extreme temperature and weather data, and account for effects of precipitation and cooling effect of wind (1f);
- GOs/ Generator Operators (GOPs) to perform annual training on winterization plans (1e);
- GOs that experience freeze-related outages to develop Corrective Action Plans (1d);
- GOs/GOPs to provide the BA with the percentage of the total generating unit capacity that the BA can rely upon during the "local forecasted cold weather" (1g); and
- GOs to account for effects of precipitation and accelerated cooling effect of wind when providing temperature data to BAs (1c).

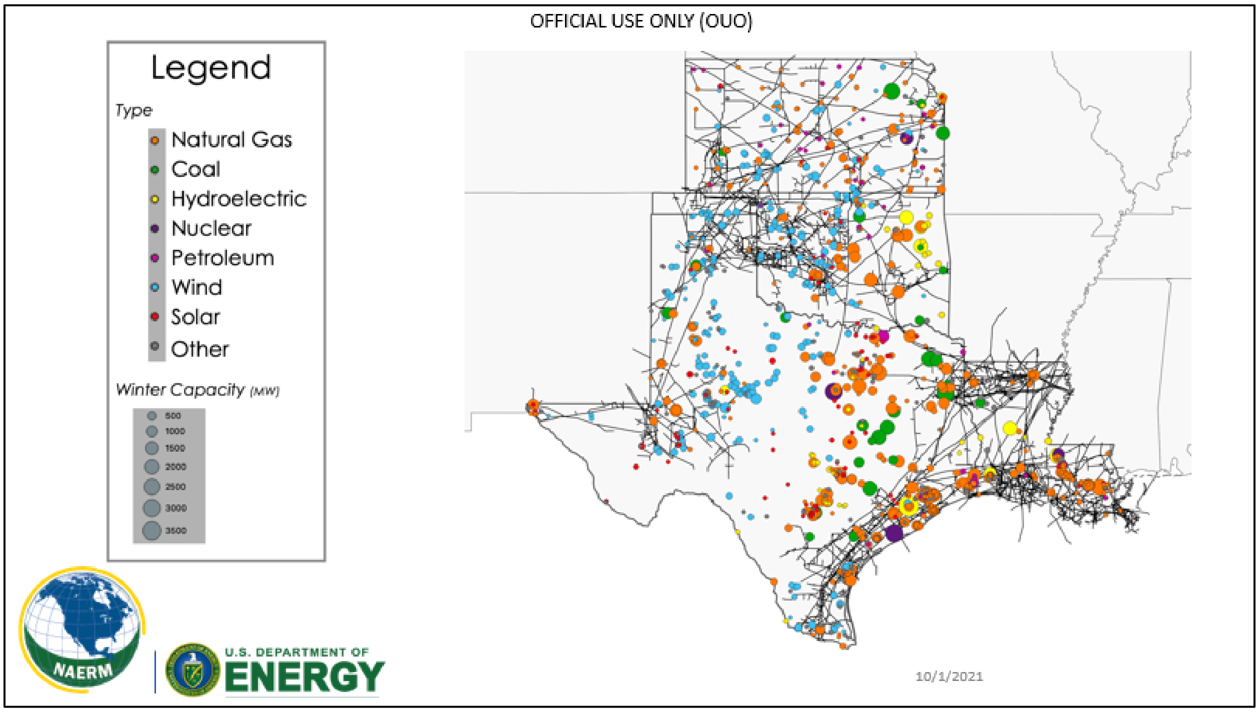
In addition to revising the Reliability Standards, the Team also recommends that GOs have the opportunity to be compensated for the costs of retrofitting their generating units to perform at specified ambient temperatures (or designing any new units to do so) (2); that FERC, NERC and the Regional Entities host a joint technical conference to discuss how to improve the winter readiness of generating units before the recently-approved Reliability Standards revisions[28] become effective (3); and that GOs'/GOPs' freeze protection plans include certain times for inspection and maintenance (e.g., before and after winter and before specific cold weather events) (4).

Regarding natural gas fuel issues, the second largest cause of the generating unit outages, the Team recommends that Congress, state legislatures and regulatory agencies with jurisdiction over natural gas infrastructure facilities require those natural gas facilities to implement and maintain cold weather preparedness plans (5); that natural gas infrastructure facilities undertake voluntary measures to prepare for cold weather (6); and that GOs/GOPs identify the reliability risks related to their natural gas fuel contracts so that they can provide the BAs with the percentage of total generating unit capacity that the BA can rely upon during the "local forecasted cold weather" (8). To address the recurring challenges stemming from natural gas-electric infrastructure interdependency, as shown in part by Figure 5 below,[29] the Team recommends that FERC consider establishing a forum

[27] Each Recommendation number is in parentheses after the summary of the Recommendation.
[28] In August, the Commission approved revisions to the NERC Reliability Standards to address cold weather, including a new requirement for generating units to have a cold weather preparedness plan. However, the effective date for these revisions is April 1, 2023. See 176 FERC ¶ 61,119 (August 2021).
[29] Figure 5, used by permission of the Department of Energy, shows the locations of both electric generating units, and the interstate natural gas pipelines available to deliver fuel to natural gas-fired generating units. The Team thanks the

to identify concrete actions to improve the reliability of the natural gas infrastructure system[30] necessary to support the BES (7).

Figure 5: Interdependency of Electric and Natural Gas Infrastructure, South Central U.S., and Texas



The Team also recommends three additional revisions to the Reliability Standards: to protect critical natural gas infrastructure from manual and automatic load shedding in order to avoid adversely affecting BES reliability (1i); to require Balancing Authorities' operating plans to prohibit use of critical natural gas infrastructure loads for demand response (1h); and to separate the circuits that will be used for manual load shed from circuits used for underfrequency load shed (UFLS) and use the UFLS circuits only as a last resort (1j).

Other Recommendation Areas. In addition to the Reliability Standards revisions, the Team makes recommendations in areas including seasonal reserve margin calculations (9), effects of cold weather on mechanical fatigue (11), increasing the flexibility of manual load shedding (10), GO/GOP use of weather forecasts (12), coordination of protective relay settings associated with generator underfrequency relays (13), coordination of UFLS relay settings with generating unit time-delay

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Department of Energy for sharing its North American Electric Resilience Model (NAERM). The NAERM is intended to bring together models of multiple types of infrastructure in the United States, such as natural gas, electric, telecommunications, water, etc., and simulate various contingencies. DOE used the NAERM to prepare Figure 5 and the NAERM was helpful to the Team in understanding interdependencies between the natural gas infrastructure and bulk-electric systems.

[30] "Natural gas infrastructure" refers to natural gas production, gathering, processing, intrastate and interstate pipelines, storage and other infrastructure used to move natural gas from wellhead to burner tip.

protection systems (22), increasing real-time monitoring of gas wellheads (14), emergency response centers for severe weather events (15), improving near-term load forecasts for extreme weather conditions (16), analyzing intermittent generation effects to improve load forecasts (17), rapidly-deploying demand response (18), additional load shed training for system operators (21), retail incentives for energy efficiency improvements (19), reducing the time for generation and transmission outages to be reported (23), and studies of large power transfers during stressed conditions (20). Finally, the Team recommends additional study in five areas: black start unit reliability (26), additional ERCOT connections to other interconnections (25), potential measures to address natural gas supply shortfalls (24), potential effects of low-frequency events on generators in the Western and Eastern Interconnections (27), and guidelines for identifying critical natural gas infrastructure loads (28).

II. Introduction

A. Inquiry Process

On February 16, 2021, while the Event was still occurring, the Commission and NERC jointly announced a FERC-NERC-Regional Entity staff inquiry "into the operations of the BES during the extreme winter weather conditions currently being experienced by the Midwest and South Central states in February 2021."[31]

Staff from FERC, NERC and all six of the Regional Entities quickly formed a team (the Team) of over 50 subject-matter experts and identified the scope of the inquiry to include: assessing what occurred during the Event, identifying commonalities with previous cold weather events and any lessons that should be incorporated in the development by NERC of cold weather Reliability Standards, and making recommendations to avoid similar events in the future. The scope did not include potential market manipulation or market design issues, which were being examined by the Commission's Office of Enforcement, among others, but rather would focus on reliability of the BES. As with other inquiries, the purpose was not to determine whether there may have been violations of applicable regulations, requirements, or standards subject to the Commission's jurisdiction, but to make findings and recommendations with the aim of preventing future events.

The Team was divided into three sub-teams with specific expertise: Generation, Natural Gas, and Grid Operations and Planning. Each sub-team requested data directly from the affected entities, including Generation Owners, Balancing Authorities, Reliability Coordinators, Transmission Operators, and natural gas infrastructure entities. In total, the Team issued over 400 data requests. Team members had multiple virtual meetings with ERCOT, MISO and SPP, as well as representative natural gas infrastructure entities, to understand their operations during the Event, and followed up with countless calls and emails to clarify and confirm data. Due to the COVID-19 Pandemic, the Team was unable to perform site visits, but Team members had visited many of the involved entities previously, including ERCOT, MISO, SPP, and multiple types of generating units that experienced freezing issues in 2011.

The Team analyzed the data for several purposes: establishing an evidence-based description of the Event, determining the causes of the BES disruptions, including record levels of manual firm load shed in ERCOT, and preparing preliminary findings and recommendations. After the Team prepared its first set of preliminary findings and recommendations, it conducted outreach calls, during which it read the preliminary findings and recommendations and solicited comments, issues

[31] **Press Release,** FERC, NERC to Open Joint Inquiry into 2021 Cold Weather Grid Operations | Federal Energy Regulatory Commission (Feb. 16, 2021)

and questions.[32] The Team fact-checked report drafts with ERCOT, MISO and SPP, as well as through multiple levels of Team and FERC, NERC and Regional Entity management review. The Team also reviewed other reports on the Event, some of which are cited in this report.

B. System Overview

1. Reliability Roles

NERC categorizes the entities responsible for planning and operating the BES in a reliable manner into multiple 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 Coordinators (PCs), and Transmission Planners (TPs). Several of the affected entities, especially ERCOT, MISO and SPP, played multiple reliability roles during the Event.[33]

2. Description of Affected Electric Grid Entities

ERCOT. ERCOT is an Independent System Operator (ISO)[34] that covers approximately 75 percent of the landmass in Texas, excluding the El Paso Area, part of the northern panhandle, and part of east Texas north and east of Houston to the Louisiana border. ERCOT manages 90 percent of the load in Texas as a BA, serves as the RC,[35] and operates the Texas energy and ancillary services markets.[36] ERCOT schedules power over 46,500 miles of transmission lines and monitors over 700 generating units.[37] ERCOT's generation fleet is composed of 52 percent natural gas, 25 percent wind, 12 percent coal, four percent nuclear, five percent solar, and one percent storage/other (see Figure 6 below). ERCOT is a summer peaking region and experienced its highest peak demand (or

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[32] The Team conducted this outreach with ERCOT, MISO, SPP, the Texas Public Utility Commission, the Texas Railroad Commission, and trade groups including Edison Electric Institute, National Association of Regulatory Utility Commissioners, National Rural Electric Cooperative Association, Interstate Natural Gas Association of America, Natural Gas Supply Association, Electric Power Supply Association, ISO/RTO Council, American Public Power Association, North American Transmission Forum, Electricity Consumers Resource Council, the American Clean Power Association, Northwest Public Power Association, Solar Energy Industries Association, and the Western Interconnection Compliance Forum.

[33] Appendix J describes the Categories of NERC Registered Entities who operate the BES.

[34] ISOs and RTOs do not own transmission or generation assets, but rather dispatch them over a large footprint, as well as operating energy markets and other related markets (capacity, ancillary services). For reliability purposes, they tend to serve at least two important reliability functions, the Balancing Authority, which balances load and generation, and the Reliability Coordinator, which oversees reliability of the bulk electric system over a wide area.

[35] In addition, ERCOT also serves as a Balancing Authority (BA), Planning Authority (PA)/Planning Coordinator (PC), and shares Transmission Operator (TOP) duties with transmission utilities in its footprint.

[36] Unlike some ISOs/RTOs, ERCOT does not have a capacity market.

[37] http://www.ercot.com/

"load") to date on August 12, 2019, when its load reached 74,820 MW.[38] ERCOT expected to, but did not, surpass this record in summer 2021.[39]

In the ERCOT market, Qualified Scheduling Entities (QSEs) submit bids and offers on behalf of generating units or load serving entities. QSEs submit offers to sell and/or bids to buy energy in the day-ahead market and the real-time market. The QSE is also responsible for submitting a Current Operating Plan for all generating units it represents and for offering or procuring ancillary services as needed to serve its represented load.[40] Most of the communication during normal and emergency operations is between ERCOT and the QSEs, and the QSEs are responsible for coordinating with the individual generating units or other entities represented.

MISO and SPP. MISO is an ISO that operates the power grid across 15 states and the Canadian province of Manitoba, and serves as a BA and RC, among other reliability roles.[41] MISO operates 65,800 miles of transmission lines, and experienced its highest peak load to date, 130,917 MW, on July 20, 2011.[42] MISO's generating capacity is 198,933 MW, comprised of 42 percent natural gas-fired generation, 29 percent coal, 19 percent renewables and 8 percent nuclear generation. Only the MISO South area of its footprint was involved in the Event, and it has a fleet which is 61 percent natural gas, 17 percent coal, 13 percent nuclear, nine percent other, and notably, has no wind (see Figure 6, below).[43] Currently, MISO operates one of the largest energy and operating reserve markets, with annual gross transactions of $22 billion.[44] MISO and SPP are in the Eastern Interconnection and share a common border.

SPP is a Regional Transmission Organization (RTO), a BA and a RC that operates a 552,885-square-mile area that includes all or portions of 14 states: Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas and Wyoming.[45] SPP operates 70,025 miles of transmission lines, and experienced its highest peak load of approximately 51,037 MW on July 28, 2021.[46] 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.[47] SPP's integrated marketplace includes a day-ahead market with transmission congestion rights, a reliability unit commitment process, a real-time balancing market, and the incorporation of price-based operating reserve procurement.[48]

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38 ERCOT Factsheet, February 2021, http://www.ercot.com/content/wcm/lists/219736/ERCOT_Fact_Sheet_2.12.21.pdf

39 Press Release, Record electric demand expected this summer, http://www.ercot.com/news/releases/show/230649 (May 6, 2021).

40 ERCOT, Qualified Scheduling Entities, http://www.ercot.com/services/rq/qse

41 MISO also serves as a Planning Authority/Planning Coordinator, and Transmission Operator. SPP also serves as a Planning Authority/Planning Coordinator.

42 MISO Corporate Fact Sheet, https://www.misoenergy.org/about/media-center/corporate-fact-sheet/

43 *Id.*

44 *Id.*

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

46 *Id.*

47 *Id.*

48 *Id.*

The following Figure 6 depicts the installed capacity[49] of generation resources by fuel type at the time of the Event. Natural gas-fired generation comprises the largest proportion of the generator fleets in all three footprints within the Event Area.

Figure 6: Installed Generation Capacity (MW) by Fuel Type

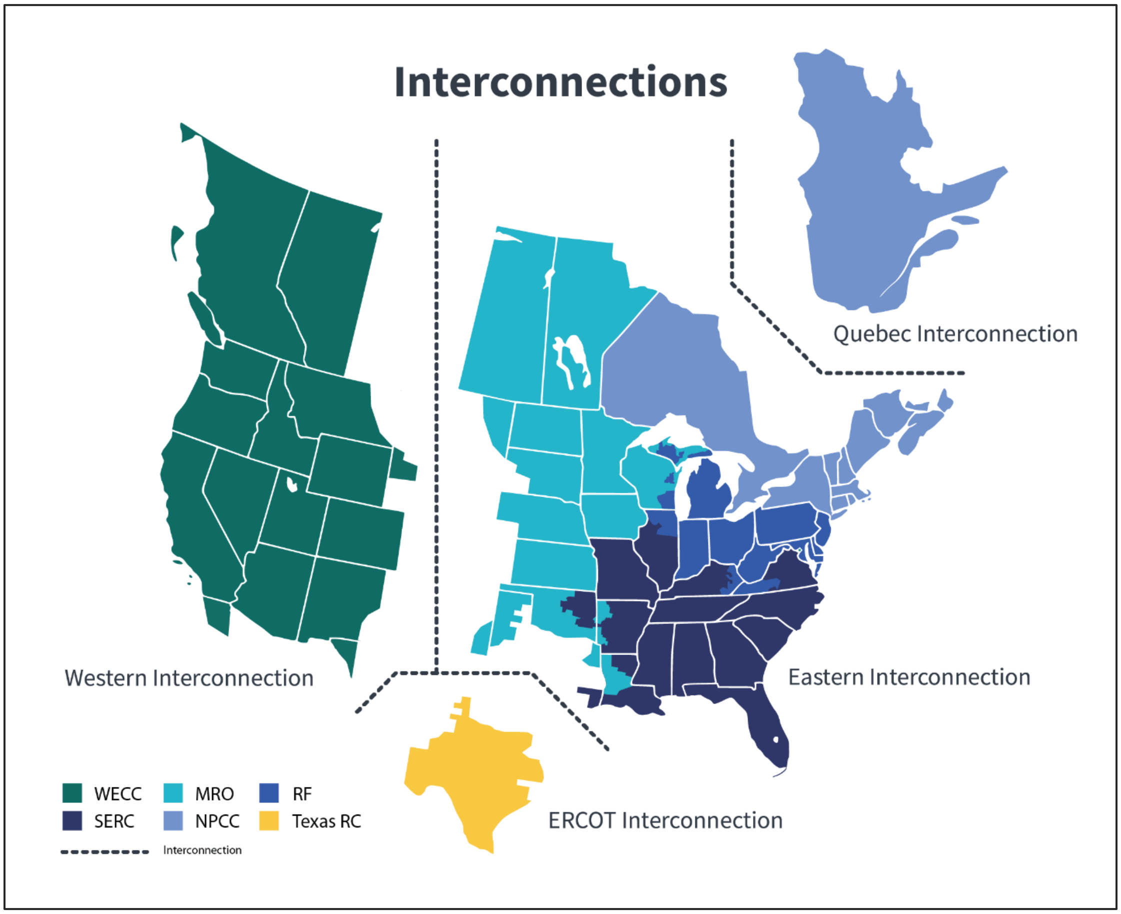
Fuel	ERCOT		SPP		MISO South	
Type	MW	Percent	MW	Percent	MW	Percent
Coal	14,703	11.9%	22,899	24.3%	7,221	17.2%
Natural Gas	64,202	52.2%	36,310	38.5%	25,364	60.6%
Nuclear	5,268	4.3%	2,061	2.2%	5,346	12.8%
Other	1,268	1.0%	5,115	5.4%	3,791	9.1%
Solar	6,202	5.0%	235	0.2%	143	0.3%
Wind	31,414	25.5%	27,612	29.3%	---	---
TOTAL MW	123,057		94,232		41,865	

3. Interconnections Between Affected Entities and Other Parts of the Electric Grid

ERCOT operates as a functionally separate interconnection (as shown in Figure 7 below), although it has four asynchronous ties with other interconnections. There are two Direct Current (DC) transmission tie lines[50] between ERCOT and the Eastern Interconnection through SPP: The North Tie, and the East Tie.[51]

[49] Installed or nameplate capacity differs from effective (also known as accredited capacity, especially for renewable resources such as wind and solar). Installed capacity is the total maximum capacity of the generating unit, whereas effective capacity takes into account forecasted weather, or temporary limitations for thermal units, to predict the percentage of the unit's capacity that will be available for a given day.
[50] For DC transmission lines, the flow of power is controlled (i.e., scheduled), rather than flowing continuously as on synchronous ties.
[51] ERCOT DC Tie Operations Document, Version 3, July 31, 2020, Section 1.3.

Figure 7: Electric Interconnections Map

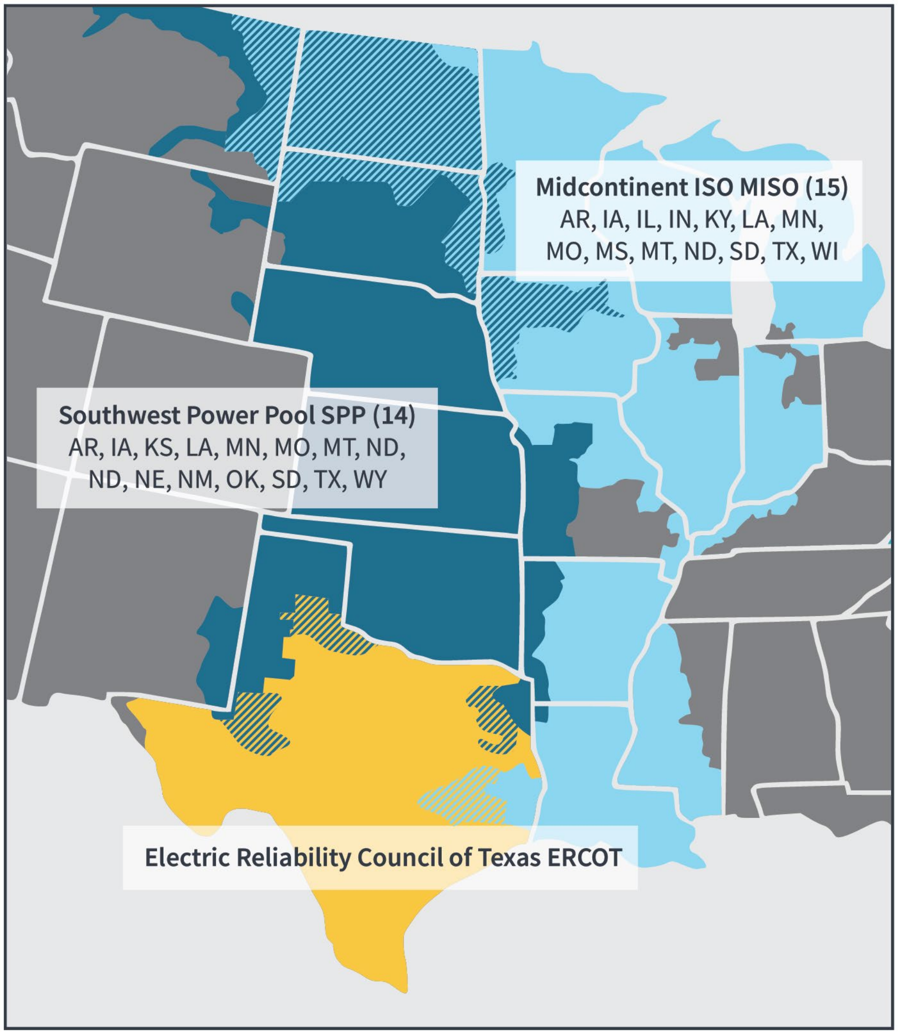


In addition, there are two DC ties between ERCOT and Mexico's Grid Operator CENACE: The Laredo Variable Frequency Tie, and the Railroad Tie.[52] The maximum amount of energy that can be simultaneously imported on all of the ties into ERCOT is 1,220 MW, with 820 MW of that via the North and East Ties to the Eastern Interconnection.[53] SPP is bound to the west and south by DC ties that electrically separate the Eastern Interconnection from the Western Interconnection (seven DC tie lines) and ERCOT (two DC tie lines). MISO and SPP's common border, or seam, is shown in Figure 8, below.

[52] *Id.*

[53] *Id.*, Figure 1.3.

Figure 8: MISO and SPP Regional Transmission Organization Footprints



SPP's footprint is located at the westernmost edge of the Eastern Interconnection. SPP's tie-line capacity is predominantly with the MISO BA, and is far more extensive than ERCOT's DC tie-line capacity with SPP. SPP has a strong network of alternating current (AC) transmission tie-lines with MISO and other BAs east of its footprint, which allowed power to be imported from those BAs. Figure 9 shows the extent of tie-lines, by voltage level, between MISO and SPP.

Figure 9: Transmission Tie Lines Between MISO and SPP BAs

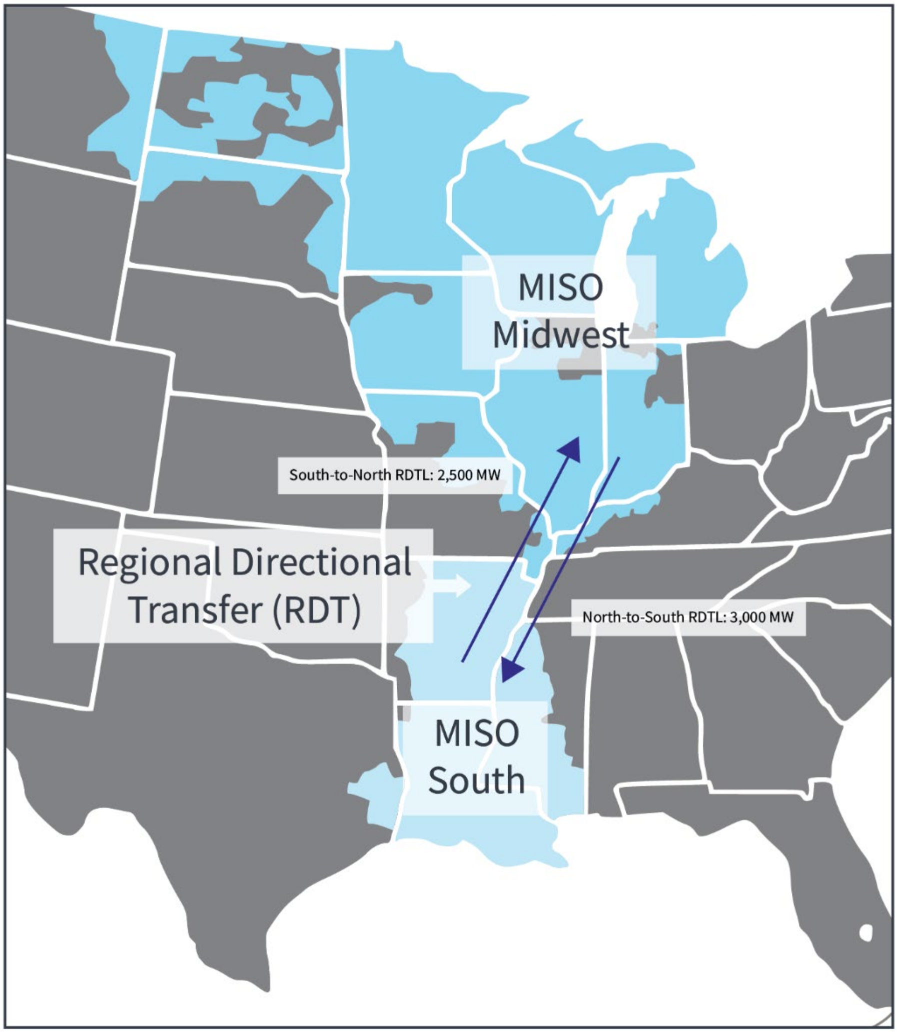
Voltage Level (kV)	Number of Tie-lines between MISO and SPP
69	85
115	30
138	5
161	41
230	13
345	16
500	3
Total	193

SPP's and MISO's transmission tie line connectivity is such that if large amounts of power (e.g., several thousand MW) need to be imported into or exported between SPP and other BAs in the eastern portion of the Eastern Interconnection (i.e., east-to-west or west-to-east directions), the power transfer flow is primarily through MISO's transmission system, and actual transfer capability is dependent on system conditions.[54] Similar to having many tie lines with SPP, MISO has 263 AC transmission tie lines to other BAs located within the Eastern Interconnection (e.g., PJM Interconnection LLC (PJM), Tennessee Valley Authority (TVA), Southern Company Services, Inc. – Trans).

MISO and SPP are parties to a Joint Operating Agreement designed to address power flows and improve operations along their seam. MISO has two regions within its BA area, joined by a single firm transmission path: MISO Midwest, to the north, and MISO South. As illustrated in Figure 10 below, MISO limits the amount of power it transfers intra-market, referred to as its Regional Directional Transfer Limit (RDTL), under an agreement with SPP and other six other BAs, to 3,000 MW from north-to-south (1,000 MW firm and 2,000 MW non-firm, as-available) and 2,500 MW from south-to-north (1,000 MW firm and 1,500 MW non-firm, as-available).

[54] While the total AC tie line capacity, calculated by adding the total capacity of all tie lines between the BAs at issue, may indicate a large transfer capacity, the actual ability to transfer power will be dependent on system conditions at the time of transfer, including ambient temperatures, generation outages and dispatch, transmission outages and derates, all of which drive actual power flows on transmission lines and can limit available transfer capability.

Figure 10: MISO Midwest to MISO South Intra-Market Regional Directional Transfers (RDT) and Associated Regional Directional Transfer Limits (RDTL)



C. Background on Preparation for Winter Peak Operations

1. Generation and Natural Gas Facilities' Preparedness

In the northern regions of the U.S., most energy production facilities are designed and constructed with the boilers, turbines/generators, and certain ancillary equipment housed in one or more enclosed buildings. In the colder months, heat radiating from boilers, other generation equipment, and supplemental heaters can generally maintain temperatures at a high enough level to prevent freezing. Enclosed areas are generally designed and constructed with fresh air inlets and roof-mounted exhaust ventilators for cooling during hot weather.

In the southern U.S., many generation facilities are designed and constructed without enclosed building structures, leaving the boilers, turbine/generators, and other ancillary systems exposed, in order to avoid excessive heat buildup. In the colder months, when temperatures may fall below freezing, these facilities are at risk of experiencing freezing issues.

Other energy production facilities are also at risk of being impacted by cold weather, including wind turbine generators, solar resources, and natural gas infrastructure. At natural gas production facilities, steps need to be taken to avoid wellhead "freeze-offs." Natural gas wells produce fluids containing water in addition to natural gas, which need to be transported through flowlines (pipes) at each well facility for storage and processing. When temperatures fall below freezing, fluid-handling equipment can experience freezing issues and potentially halt the production of natural gas.

Regardless of their location in the U.S., owners and operators of generating units and natural gas infrastructure facilities typically implement specific freeze protection or "winterization" plans for their facilities to function during extreme cold ambient temperature and weather conditions experienced at their locations. For exposed units in the southern U.S. and some natural gas infrastructure, winterization may involve a combination of permanent heated enclosures to protect equipment from cold, heat tracing, insulation, wind breaks, temporary or permanently-installed heating equipment, and other weather protection measures.[55]

Proper training of energy production facility operators on the facility's winterization plan is critical to ensure they will be prepared to take necessary actions before and during extreme cold weather events. At a minimum, training should include all operators annually reviewing site-specific winterization procedures. Less-experienced operators could be asked to perform the facility's cold weather checklist with more- experienced operators. Some entities conduct "lessons learned" exercises following major weather events, including severe cold weather events. As part of a lessons learned exercise, an entity would review its performance during the severe weather event, determine root causes of any weather-related problems, and develop additional best practices for similar events in the future. In many cases, entities incorporated the takeaways from those exercises into their winterization procedures. Some entities consider best practices from neighboring facilities or industry partners to keep their winterization plans comprehensive and up-to-date.

[55] Other more specific freeze-protection measures are discussed in sections III.A.3 and III.A.5, and Recommendation 6 (Natural gas freeze protection measures).

2. Grid Operations Entities' Seasonal Preparedness

a. Winter Season Reliability Assessments

Electric grid entities such as BAs and PCs typically perform seasonal reliability assessments in advance of each winter to determine available generation reserves during winter peak conditions. The assessments included forecast peak loads, generation capacity and projected reserves.

Peak load forecasts. Entities typically produce a 50/50 peak load forecast[56] for the upcoming winter season, which is based on quantitative analysis of data and assumptions, including but not limited to, historical winter peak load data and associated weather conditions, and economic factors. Many entities also produce a 90/10 peak load forecast,[57] which, similar to the 50/50 forecast, is based on quantitative analysis of historical data. Both forecasts are influenced by the historical actual peak loads that are used as inputs to their statistical analyses.

Expected generation capacity. Based on individual generating unit and other resource capacities (e.g., demand response, battery storage, etc.) that are expected to be available during winter peak conditions, entities determine the total anticipated resources they expect to be available to meet the forecast winter peak load. Data and assumptions typically include any expected seasonal capacity derates, and for intermittent resources (e.g., wind, solar resources), entities calculate an "expected" capacity. For example, the expected capacity for a 100 MW wind generation facility may be 20 MW, based on the variability of wind during the winter peak.

Projected reserves for peak conditions. Winter assessments typically account for generating unit scheduled/planned outages expected to occur during winter peak load, 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 forecasts, or whether there will be an expected shortfall.

The outputs of these assessments are typically provided in the form of reports that are presented in the fall for the entities' own use (e.g., RTO/ISO) and may be shared with companies within the BA footprint or that are RTO/ISO members. The reports are used to assist BA operations staff in preparing for the winter and for training for the upcoming winter season. In addition, data from the winter assessment, such as the 50/50 peak load forecasts and predicted reserve margins, are provided to NERC for development of its winter reliability assessment reports (WRA). NERC's WRA report identifies, assesses, and reports on areas of concern regarding the reliability of the North American BES for the upcoming winter season, including reporting anticipated resource adequacy reserve margins for regional operating areas (e.g., ERCOT, MISO and SPP). NERC's reports are made publicly available and are widely referred to by industry and policymakers.

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

Probabilistic approach to assess demand and resources. NERC also uses operational risk analysis as part of its seasonal assessment. Operational risk analysis 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 addition, some Regions calculate seasonal probabilistic indices, such as loss of load expectation (LOLE), loss of load hours (LOLH), and expected unserved energy (EUE) that represent the most up-to-date studies on resource adequacy risk.

b. ERCOT's, MISO's and SPP's Winter 2020/2021 Seasonal Assessments

ERCOT, SPP and MISO performed seasonal assessments in advance of the 2020/2021 winter to determine available generation reserves during winter peak conditions. The assessments included forecast peak loads, generation capacity and projected reserves. Figure 11, below, provides a summary of peak load forecasts versus actual peak loads during the Event.

Figure 11: Winter 2020/2021 Peak Load Forecasts and Actual Loads for Event Area

		ERCOT	SPP	MISO South
Previous All-Time Winter Peak/Date:		65,750 1/17/2018	43,584 1/17/2018	32,100 1/17/2018
2020/2021 50/50 Forecast Winter Peak:		57,699	42,062[58]	28,459
2020/2021 90/10 Forecast Winter Peak:		67,208	44,452[59]	29,562
Feb. 2021 Actual Peak Load/ Date of Occurrence:		69,871 2/14/2021	43,661[60] 2/15/2021	29,946 2/15/2021
Feb. 2021 Estimated Peak Load w/o load management/ Date of Occurrence:		76,819 2/15/2021	47,000[61] 2/16/2021	30,977 2/15/2021
% Actual Peak Was Above Forecasts	**50/50:**	20.0%	3.8%	5.2%
	90/10:	2.9%	-1.8%	1.3%
% Estimated Peak Was Above Forecasts	**50/50:**	33.1%	11.7%	8.9%
	90/10:	14.3%	5.7%	4.8%

ERCOT Load Forecasts and Projected Reserves. ERCOT's Winter 2020/2021 Seasonal Assessment of Resource Adequacy (SARA) focused on the availability of sufficient operating reserves to avoid emergency actions such as deployment of voluntary load reduction resources.[62] Based on its winter SARA, ERCOT believed that it could meet its projected winter peak demand of 57,699 MW with available generation and imports (based on normal weather conditions). ERCOT's extreme winter forecast was 67,208 MW, higher than its previous all-time winter peak demand record of 65,750 MW, set on January 17, 2018. To meet that extreme peak demand, ERCOT had projected resource capacity of 82,513 MW, leaving reserves of only 1,352 MW, considering a 90/10 extreme load scenario combined with additional generation reductions of 13,953 MW.[63] See Figure 12 below, which summarizes ERCOT's projected SARA for the 2020/2021 winter season. It uses

[58] From NERC 2020-2021 Winter Reliability Assessment, without demand response. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2020_2021.pdf
[59] *Id.* (SPP's 90/10 is calculated for NERC by increasing the 50/50 by 5 percent).
[60] Peak load may have been affected by the impacts of conservation efforts (e.g., SPP EEA 2 conservation declarations).
[61] SPP set a new winter peak load of 43,661 MW the morning of February 15 and likely would have reached a wintertime peak of 47,000 MW [on February 16] if not for conservation and curtailments. *See*: https://spp.org/documents/65037/comprehensive%20review%20of%20spp's%20response%20to%20the%20feb.%202021%20winter%20storm%202021%2007%2019.pdf
[62] ERCOT releases its SARA one to two months before each season. ERCOT'S SARA is intended to illustrate the range of resource adequacy outcomes that might occur.
[63] This generation outage figure represented the 95th percentile of expected generation outages, according to ERCOT.

an operating reserve threshold of 2,300 MW to indicate the risk that an EEA 1 might be triggered during the time of the forecasted seasonal peak load. This threshold level was intended to be roughly analogous to the 2,300 MW Physical Responsive Capability threshold for EEA 1.[64]

Figure 12: ERCOT Winter 2020/2021 Seasonal Assessment of Resource Adequacy[65]

ERCOT Winter 2020/2021 SARA: Range of Potential Risks

	Forecasted Season Peak Load	Extreme Peak Load / Typical Generation Outages During Extreme Peak Load	Forecasted Season Peak Load / Extreme Low Wind Output	Extreme Peak Load / Extreme Generation Outages During Extreme Peak Load
Total Resources, MW	82,513	82,513	82,513	82,513
Forecasted Season Peak Load	57,699	57,699	57,699	57,699
Seasonal Load Adjustment	-	9,509	-	9,509
Typical Maintenance Outages, Thermal	4,074	4,074	4,074	4,074
Typical Forced Outages, Thermal	4,542	5,339	4,542	5,339
95th Percentile Forced Outages, Thermal	-	-	-	4,540
Low Wind Output Adjustment	-	-	5,279	-
[d] Total Uses of Reserve Capacity	8,616	18,922	13,895	23,462
[e] Capacity Available for Operating Reserves, Normal Operating Conditions (c-d), MW. Less than 2,300 MW indicates risk of EEA1	**16,198**	**5,892**	**10,919**	**1,352**

As shown in Figure 12, in addition to the "Forecasted Season Peak Load" base scenario, ERCOT develops several other scenarios shown in the adjacent table columns by varying the values of various load forecast and resource availability parameters. Although ERCOT seemingly had a generous reserve margin going into the winter of 2020/2021, its reserve margins were slimmer when

64 Physical Responsive Capability is a real-time measure of resources that can quickly respond to system disturbances. In contrast, the SARA operating reserve reflects additional capacity assumed to be available before energy emergency procedures are initiated, such as from resources qualified to provide non-spinning reserves. The amount of operating reserves available may increase relative to what is included in the SARA if the market responds to wholesale market price increases and anticipated capacity scarcity conditions. Given these considerations, ERCOT believes that the 2,300 MW reserve capacity threshold is a reasonable indicator for the risk of EEAs, given the uncertainties in predicting system conditions months in advance.

65 http://www.ercot.com/content/wcm/lists/197378/SARA-FinalWinter2020-2021.pdf.

ERCOT accounted for additional risks. Under the extremely low wind generation output scenario,[66] ERCOT expected to lose about 5,279 MW of wind generation, lowering the expected wind forecast to 1,791 MW and leaving its reserves at 10,919 MW. When adjusted for extreme peak load and typical outages,[67] ERCOT's reserves were even lower, estimated at 5,892 MW. ERCOT's most extreme scenario, adjusting for extreme peak demand and extreme outages (but not including low wind conditions), indicated that ERCOT would have only 1,352 MW of operating reserve capacity if those conditions materialized.[68] The variation in these parameters is based on historic ranges of the parameter values or known changes expected in the near-term. The SARA is not intended to predict the likelihood of any of these scenario outcomes.

ERCOT does not classify flows across its DC ties as firm capacity because such flows are scheduled as day-ahead energy transactions. However, in its SARA, ERCOT assumed an expected amount of net imports based on the average amount of net imports reported during winter 2013/2014 EEA intervals. ERCOT's reflected demand response based on the peak demand forecast during the period from January 2015 to August 2020. The demand response impact is embedded in the forecast and is not available as a separate forecast component, and there are no assumptions regarding future incremental changes to demand response impacts. Because ERCOT's SARA is intended to show the risk of entering EEA 1, load resources are not accounted for, since they are only available after an EEA is declared.

MISO Load Forecasts and Projected Reserves. MISO performs seasonal load assessments for its entire footprint and for the North/Central and South sub-areas. MISO 90/10 zonal load forecasts are developed by applying a Load Forecast Uncertainty value, calculated at the zonal level, to the LSE-submitted 50/50 load forecasts for each Local Resource Zone. The Load Forecast Uncertainty values are based on the actual highest summer peak load day for each of the past 30 years.

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[66] Both maintenance and forced outages for wind and solar are accounted for in the peak average capacity contribution values, based on historical wind and solar capacity factors for seasonal peak load hours. At the time of the forecast, ERCOT had a wind fleet with nameplate capacity of approximately 24,962 MW. The total forecast wind generation (existing and planned) in the SARA was 7,070 MW. Existing wind generation reflected in the SARA was 6,142 MW (divided into three categories: 1,480 MW of coastal wind resources (based on 43 percent of installed capacity); 1,411 MW of panhandle wind resources (based on 32 percent of installed capacity), and 3,251 MW of other wind resources (based on 19 percent of installed capacity)). ERCOT's SARA also included an estimate for planned wind resources of 928 MW with a nameplate capacity of 3,794 MW (based on in-service dates provided by developers) (divided into two categories: 371 MW of planned coastal wind and 557 MW of planned other wind).

[67] ERCOT's reported generation capacities include (1) winter net maximum sustained ratings, and (2) winter peak average capacity contributions, the methodologies for which are documented in ERCOT Nodal Protocols (Section 3.2.6.2.2). Generation capacities reflect what is expected to be available at the time of the winter peak load. University of Texas at Austin Energy Institute, *The Timeline and Events of the 2021 Texas Electric Grid Blackouts* (hereafter UT Report) (July 2021) at 15, Fig. 2a. UTAustin_(2021)_EventsFebruary2021TexasBlackout_(002)FINAL_07_12_21.pdf The SARA reports capacity available for operating reserves, which accounts for scenario variations in forecasted peak load, forced and maintenance outages, and wind output. Thermal and hydro forced outage scenario assumptions are based on the historical average of planned outages for December through February weekdays, hours ending 7 a.m. - 10 a.m., for the last three winter seasons (2017/18, 2018/19, and 2019/20), which assumed total maintenance and forced outages of 8,616 MW.

[68] ERCOT's SARA did not include a scenario with low wind, extreme load and thermal outages; the result would have shown a capacity deficit of -3927 MW to serve load and reserve needs.

Planned, scheduled, and forced outages are included in the reserve values by subtracting the historical planned plus forced generation outage totals (sourced from GADS)[69] from monthly projected available capacity. MISO calculates the probable generation capacity scenario by taking the five-year average of planned plus forced monthly generation outages during the single-highest monthly (December through February) peak demand days for the last five years. MISO calculates the low generation capacity scenario by using the single highest amount of planned plus forced generation outages for each month evaluated in a season for the last five years (e.g., December to February 2016 to 2020). MISO includes firm imports offered into the Planning Resource Auction in its winter capacity totals and nets out MISO resources with capacity arrangements outside of MISO. MISO performs steady state AC contingency analysis, and thermal, voltage stability and phase angle analysis during energy transfer simulations.

MISO did not anticipate resource availability issues for winter 2020/2021 based on prior winter readiness and fuel deliverability surveys anticipating robust fuel deliverability and multiple measures taken to prepare units for potential severe winter weather. For MISO South, it forecast demand under the 50/50 scenario of 28,459 MW, and 29,562 MW under the 90/10 extreme conditions scenario.

Based on MISO's winter assessment, Figure 13 below provides a summary of its projected capacity and reserves for the 2020/2021 winter season. MISO does not perform a separate seasonal assessment for its MISO South region.

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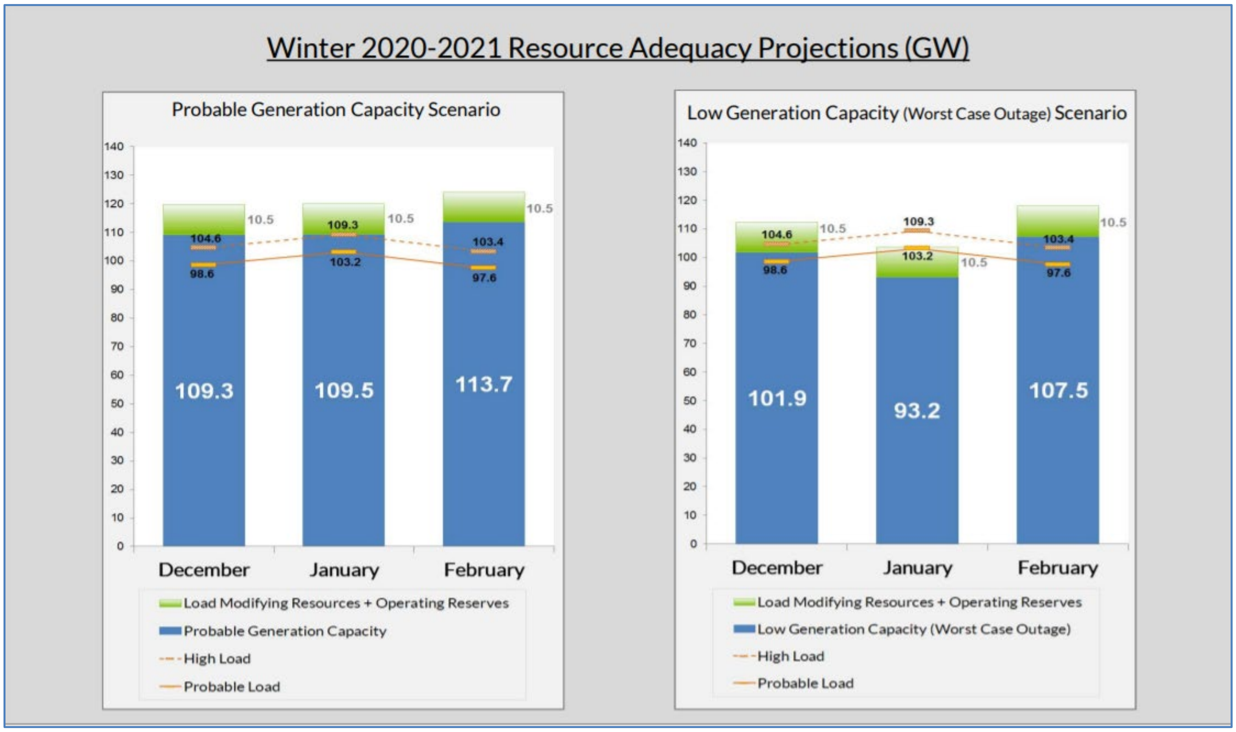
[69] Generating Availability Data System (GADS) is a mandatory industry program for tracking information about outages of conventional generating units that are 20 MW and larger. [Generating Availability Data System (GADS) (nerc.com)]()

Figure 13: MISO Winter 2020-2021 Resource Adequacy Projections (GW)[70]



For its seasonal resource assessments, MISO produces two scenarios: (1) a probable generation capacity scenario and (2) a low generation capacity scenario (see Figure 13, above). The difference between these two scenarios is the amount of cumulative historical generation outages that are subtracted from expected seasonal capacity to arrive at a monthly available capacity projection. In the probable generation capacity scenario, MISO uses the five-year average amount of cumulative monthly generation outages that occurred during the single highest monthly peak demand days from each of the five most recent years. For the low generation capacity scenario, MISO uses the single highest amount of cumulative generation outages during the most recent five years for each month evaluated in a season. For its 90/10 Load/Low Generation Capacity Scenario, MISO projected a 2020/2021 winter peak reserves deficit of 5,591 MW. Like ERCOT, MISO projected that adequate resources would likely be available to meet the expected winter demand forecast but recognized that winter scenarios with high generation outages and high demand could drive operational challenges.[71]

SPP Load Forecast and Projected Reserves. SPP performs seasonal load assessments for its entire footprint and for 22 sub-areas. SPP relies on peak load forecasts submitted by the transmission owners and load-serving members, which are responsible for calculating load forecasts

[70] https://cdn.misoenergy.org/20201027%20Winter%20Readiness%20Workshop%20Presentation486841.pdf at page 42.

[71] *2020-2021 MISO Winter Readiness Forum*, (Oct. 27, 2020), 42, https://cdn.misoenergy.org/20201027%20Winter%20Readiness%20Workshop%20Presentation486841.pdf

and submitting the forecasts to SPP according to Reliability Standard MOD-032. To produce its 50/50 scenario peak load forecast, SPP uses non-coincident peak load forecasts submitted and applies outages to the models, including those scheduled and other systematically selected unscheduled transmission and generation outages (to account for future system outage uncertainties). SPP performed thermal and voltage contingency analysis on the SPP RC footprint. Additionally, SPP performed voltage security assessment scenarios for areas deemed susceptible to voltage issues.

As part of its seasonal assessment, SPP performs transfer studies to stress its system. The transfer studies are internal to SPP; it does not currently perform any interregional studies. However, SPP and MISO do regularly share the results of their internal studies with each other. SPP considers MISO-submitted data (e.g., load, transmission and generation outages and net scheduled interchange) in its outage coordination, operational planning analyses and next-day studies.

In its seasonal assessment for winter 2020/2021, SPP stated that "the operating capacity for the 2020-21 winter season is expected to be sufficient for normal operating conditions; however, under severe conditions, localized or brief capacity constraints may occur expected to have resources sufficient to meet its expected load." SPP expected a 42,062 MW peak load under its 50/50 scenario. In SPP's winter 2020-21 transmission assessment, operations within the SPP RC and eastern RC area footprints were expected to be normal given the expected scheduled outages.

SPP provided inputs into NERC's 2020/2021 Winter Reliability Assessment for reserve margin projections. Figure 14, below lists SPP's anticipated reserve margin data, along with ERCOT's and MISO's data that were submitted as inputs to NERC's report.

Figure 14: Publicly-Reported Reserve Margins for Winter 2020/2021 (SPP, ERCOT and MISO)[72]

Data From NERC 2020-2021 Winter Reliability Assessment (November 2020)			
	ERCOT	SPP	MISO
Demand, Resource, and Reserve Margins	2020–2021 WRA	2020–2021 WRA	2020–2021 WRA
Demand Projections	Megawatts (MW)	Megawatts (MW)	Megawatts (MW)
Total Internal Demand (50/50)	57,699	42,062	103,167
Demand Response Available	2,764	252	4,536
Net Internal Demand	54,935	41,811	98,631
Resource Projections	Megawatts (MW)	Megawatts (MW)	Megawatts (MW)
Existing-Certain Capacity	80,715	66,277	144,736
Tier 1 Planned Capacity	1,359	298	574
Net Firm Capacity Transfers	210	(36)	1,405
Anticipated Resources	82,284	66,539	146,715
Existing-Other Capacity	614	-	6,390
Prospective Resources	82,898	66,539	153,557
Resource Projections	Percent (%)	Percent (%)	Percent (%)
Anticipated Reserve Margin	**49.8%**	**59.1%**	**48.8%**
Prospective Reserve Margin	50.9%	59.1%	55.7%
Reference Margin Level	13.8%	15.3%	18.0%
Extreme Winter Peak Demand (MW)	67,200	44,200	109,900

ERCOT, SPP and MISO anticipated winter reserve margins of 49.8 percent, 59.1 percent, and 48.8[73] percent, respectively, in the NERC winter reliability assessment. Planning reserve margins are designed to assess the overall capacity supply of the system and do not necessarily predict how the system will perform on a given day.

[72] *See* NERC 2020/2021 WRA (November 2020), at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2020_2021.pdf.
[73] This winter reserve margin is for the entire MISO footprint. MISO does not calculate a separate winter reserve margin for MISO South.

c. Generator workshops, fuel surveys, and site visits by BAs

ERCOT. ERCOT initiated a winter weatherization spot check program during the 2011/2012 winter season, following the February 2011 cold weather event. From winter 2011/2012 until winter 2019/2020, ERCOT and Texas RE staff typically visited 75-80 generating units per year to assess their readiness for the upcoming winter season and suggest potential improvements. Texas RE calls its visits "site visits," and although ERCOT and Texas RE normally visit generating units jointly, the purpose of their visits is slightly different, as discussed below. For winter 2020-2021, due to COVID-19 Pandemic concerns, the program was conducted remotely.

ERCOT and Texas RE attempted to visit larger coal and gas-fired generation facilities at least once every three years and prioritized the units based on issues experienced during prior winter seasons and the need to follow up on recommendations from previous site visits.[74] ERCOT focused its spot checks on Public Utility Commission of Texas rules and ERCOT Nodal Protocols, and to standardize its review, ERCOT developed a comprehensive checklist of items to evaluate. Texas RE focused its site visits on recommendations from the 2011 Southwest cold weather report, the NERC Generating Unit Winter Weather Readiness Reliability Guideline and information gathered from NERC's Generating Availability Data System (GADS).[75] ERCOT's checklist included questions related to winterization and maintenance, and improvements to the winterization plan based on previous winter lessons learned and previous site visit recommendations. The site visit team reviewed each unit's winter weatherization plan and its procedures for cold weather events. If the unit experienced freeze issues the previous winter, the team physically examined the element(s) which froze or forced a trip and reviewed the measures that the generating unit took to protect the element from freezing again. The team also reviewed maintenance records for freeze protection measures such as heat tracing, insulation, and instrument air systems, as well as for dual-fuel units. At the end of each site visit, ERCOT and Texas RE staff provided a summary of comments, best practices, or recommendations for improving the generating unit's winterization activities. If deficiencies were identified, ERCOT or Texas RE staff scheduled a follow-up visit before the next winter.

In addition to the winter weatherization site visit program, ERCOT and Texas RE hosted a winter preparation workshop in September of each year before 2020. The workshops focused on the common causes of outages due to cold weather from the previous winter, review of the upcoming winter weather forecast, review of common issues and recommendations from the previous year's site visits, and presentations from generating companies on improvements made and best practices. Prior to the Event, ERCOT had seen reductions in the MW of generating units tripped or derated due to frozen instrumentation during cold weather events, as seen in Figure 15, below.

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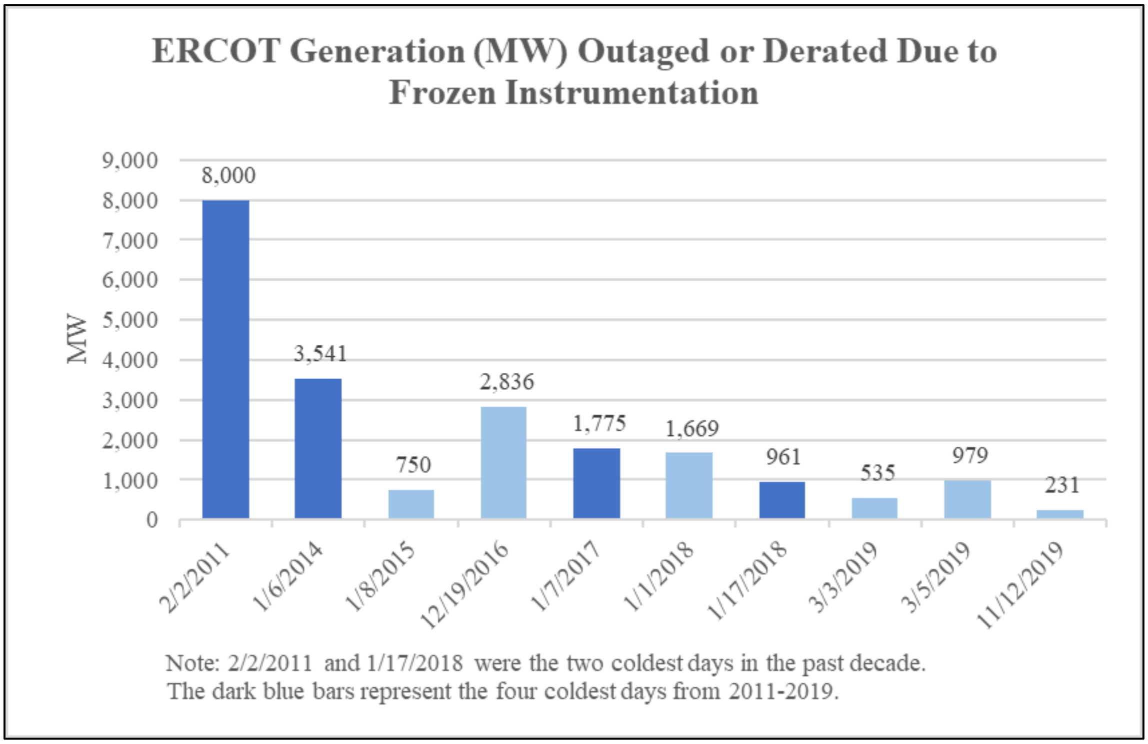
[74] Each visit is both an ERCOT spot check and a Texas RE site visit but will hereafter be referred to as the site visit except to describe the focus of each entity.

[75] Reliability Guideline Generating Unit Winter Weather Readiness – Current Industry Practices – Version 3, https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_Generating_Unit_Winter_Weather_Readiness_v3_Final.pdf#search=winter%20reliability%20guideline(hereafter, Reliability Guideline).

Figure 15: ERCOT Generation (MW) Outaged or Derated Due to Frozen Instrumentation



ERCOT's winter weatherization spot check program has continued to evolve since its inception, learning lessons from various events. After the 2014 Polar Vortex event, knowledge and identification of facility critical components became a point of emphasis, including maintenance of heat tracing and insulation systems associated with those critical components, as well as tracking heat tracing test records. After the January 2018 event, ERCOT prioritized incorporating instrument air systems into the weatherization programs.

ERCOT and Texas RE staff recognized that their programs could still be improved. For example, staff can only assess whether the generating unit is implementing or executing its winterization plan but find it difficult to assess the quality of the plan, unless the unit experienced freezing incidents during a previous winter event. Generating units are not currently required to weatherize to a common ambient temperature design[76] or for the accelerated cooling effect of wind (in fact many GOs did not know the design temperature for their facilities). Specific knowledge of the insulation and heat tracing systems for a facility is critical as different types of heat trace cable may require different testing and maintenance methods.

ERCOT also required GOs and GOPs to submit an annual declaration, stating that it has or will complete all weather preparations required by its weatherization plan for equipment critical to the

[76] *See* Recommendation 1.f. (recommending that the Reliability Standards be revised to require GOs to retrofit existing generating units, or design any new units, to operate to specified ambient temperatures, wind, and precipitation).

reliable operation of the generating unit.[77] Declarations are due between November 1 and December 1 of each year.[78] This process is designed to ensure that all generating units have followed their weatherization plans. Ninety-six percent (147 of 153) of GOs/GOPs surveyed within ERCOT had submitted a declaration of completion of preparation for winter 2020/2021. Seven entities reported outstanding winter preparations for 18 natural gas-fired generating units, including protections as critical as heat trace repair and replacement, wind breaks, and insulation of transmitter sensing lines, that were not expected to be completed until as late as December 23, 2020.[79] Given that GOs/GOPs can delay such critical preparations until well after the onset of cold weather, it appears that there is no meaningful follow-up process when entities fail to complete their winter preparations by the December 1 deadline.

Whether the declarations are effective at achieving winter preparations is debatable. The required declarations are not used to measure the generating unit's performance; even if the weatherization plans are followed, the declaration does not guarantee a generating unit will remain fully operational throughout the winter season or during extreme weather conditions.

MISO and SPP. Unlike ERCOT, neither MISO nor SPP conduct site visits of generating unit winter preparations. SPP conducts a summer preparedness workshop in the spring and a winter preparedness workshop in the fall, which GOs/GOPs as well as TOPs can attend. Its annual winter preparedness workshop includes presentations on weather forecasts by meteorologists, seasonal assessments by the outage coordination team, critical communication types, the NERC Reliability Guidelines, and a tabletop discussion on business continuity. SPP held its winter 2020/2021 preparedness workshop on September 29, 2020.[80] Attendance is voluntary, and SPP has typically seen high participation rates. In the fall of 2019, SPP conducted a voluntary generating unit winter weather preparedness survey. The survey asked questions regarding winter preparation plans (especially for critical equipment), previous winter freeze issues, generating unit minimum temperature, experience below that temperature, generating unit winterization improvements, heat trace and insulation inspections, cold weather drills/training, start-up requirements, and alternate fuel sources. Most GOPs did not respond to the voluntary generation winter preparedness survey conducted by SPP, which also asked about fuel supply. SPP does not conduct a survey covering transmission winter preparedness, but SPP TOPs can participate in the winter preparedness workshop.

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[77] Required as part of ERCOT's Nodal Protocols, which outline the procedures and processes used by ERCOT and market participants for the orderly functioning of the ERCOT system and nodal market. http://www.ercot.com/mktrules/nprotocols. The Public Utility Commission of Texas (PUCT) recently revised its rules to require these declarations to be executed by the GO's highest-ranking officer with binding authority. 51840_101_1160359.PDF (texas.gov)

[78] *See* Section 3.21, Part (3) of ERCOT's Nodal Protocols.

[79] Of the four percent of the entities (six of 153) that did not submit a declaration, two are solar operators (500 MW capacity) that stated weatherization practices are not applicable to their facilities; two entities are new solar operators (250 MW capacity) that had not yet received the declaration from ERCOT, and two entities (100 MW gas/250 MW wind capacity) did not respond to this question.

[80] NERC 2020-2021 Winter Reliability Assessment, at 26, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2020_2021.pdf (Nov. 2020).

MISO reviewed recommendations from previous FERC-NERC joint reports on cold weather events to improve its winter readiness training. MISO conducted its winter 2020/2021 readiness forum on October 27, 2020. This workshop covered such topics as winter lessons learned and operations guidelines, extreme cold weather preparedness and procedures, winter 2019 maximum generation and turbine issues, generation and transmission assessments, and fuel surveys. MISO shared its October 23, 2018 Winterization Guideline and presentations on "Generation Performance During Severe Cold Temperatures" and its 2020/2021 Winter Resource Assessment. MISO's 2020 generator winterization survey had a 71 percent response rate, while its natural gas fuel survey response rate was 83 percent.[81] Participation in both surveys has improved between 2019 and 2020, and over 95 percent of the GOs/GOPs that responded to the survey said that they have a plan to prepare for winter 2020. However, updating winter preparation plans every winter is ideal and the majority had not updated their plans in the last three years. While 43 percent of MISO GOs/GOPs had made changes to their winterization plans in the past three years, only 36 percent of SPP and 27 percent of ERCOT GOs/GOPs had done so.[82]

d. Preparedness for Emergency Operations

RCs, BAs, TOPs and TOs typically perform load shed drills as part of their required emergency operations training.[83] TOPs have load shed procedures which cover both operator-controlled manual and automatic load shed. The Reliability Standards do not prohibit TOPs from using automatic load shed configured circuits (e.g., underfrequency load shed, undervoltage load shed circuits) for manual load shed, but do require TOPs to minimize the overlap of with automatic load shedding.[84]

[81] Forty-two percent reported that they have access to firm transportation and/or dual fuels, 39 percent reported a mix of firm and interruptible transportation, and 10 percent reported interruptible gas supply only.
[82] Examples of changes made to winterization plans included: upgrading or completely replacing existing freeze protection equipment; adding new heat tracing cables, control panels and instrument enclosures; increasing the number of enclosures built around critical equipment that had experienced freezing in years past; discussing lessons learned prior to and after the winter season; adding dew point monitoring to the air system; adding an additional hydrogen trailer onsite; and building cold weather shelters around instrument transmitters, instrument air dryers, instrument air compressors, vacuum pumps, and seal oil regulators, among other vulnerable equipment. Some of the most common changes made to winterization plans in the past three years are changes to annual weatherization checklists, and incorporating lessons learned from the previous winter, leading to a process of continuous improvement.
[83] Reliability Standard PER-005-2 – Operations Personnel Training, Requirement R4: Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner that (1) has operational authority or control over Facilities with established Interconnection Reliability Operating Limits (IROLs), or (2) has established protection systems or operating guides to mitigate IROL violations, shall provide its personnel identified in Requirement R1 or Requirement R2 with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES.
[84] EOP-011-1 - Emergency Operations, Requirements R1, 1.2.5 and Requirement R2, 2.2.8.

i. Manual and Automatic Load Shed Plans[85]

ERCOT. Transmission Operators in ERCOT are responsible for developing an emergency operations plan to mitigate operating emergencies,[86] which includes provisions for operator-controlled manual load shedding that minimizes the overlap with automatic load shedding[87] and is capable of being implemented in a timeframe adequate to mitigate the emergency.[88] Transmission Service Providers and Distribution Providers (DP) have the responsibility for determining exactly which circuits are to be disconnected during a load shed event.

Not all distribution circuits are eligible for manual or automatic load shedding. Some are protected due to the presence of so-called critical loads. Critical loads, within ERCOT, are "loads for which electric service is considered crucial for the protection or maintenance of public safety; including but not limited to hospitals, police stations, fire stations, critical water and wastewater facilities, and customers with special in-house life-sustaining equipment," and further identified by the Public Utility Commission of Texas (PUCT) as "military facilities, facilities necessary to restore the electric utility system, law enforcement organizations and facilities affecting public health, and communication facilities." [89] PUCT rules identify four classifications of customers as critical loads: (1) Critical Load Public Safety Customer; (2) Critical Load Industrial Customer; (3) Chronic Condition Residential Customer; and (4) Critical Care Residential Customer.[90] To be designated under the first two categories, the entity (e.g., a gas pipeline facility) must notify its Transmission and Delivery Utility (TDU), which reports to the PUCT annually the number of critical load customers for each customer class. BAs and RCs are not aware of potential critical loads, including natural gas infrastructure loads, that may impact generating units unless the critical load entity has notified its TDU.

[85] All three BAs' and their TOPs' manual load shed plans were designed for implementing and rotating much smaller increments of firm load shed than the 20,000 MW of firm load shed ordered by ERCOT during the Event.
[86] NERC Standard EOP-011-1 Emergency Operations requires that each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area.
[87]There are generally two methods used for conducting automatic load shedding. Underfrequency Load Shedding (UFLS) is used to balance generation and load when a system event, such as the loss of a large generating unit or multiple generating units occurs, causing a significant drop in frequency throughout an interconnection or islanded area. The use of UFLS can be looked upon as an automatic response associated with a decline in frequency in order to rebalance the system. UFLS protection schemes, through the use of relays, take a stepped approach to opening designated breakers after specific frequency thresholds are passed in order to shed load and reverse declining system frequency. Typically, when the threshold is met, the trip occurs in 30 cycles (.5 seconds). The Reliability Standards PRC-006-5 and PRC-008-0 define UFLS requirements. Undervoltage Load Shedding (UVLS), which is very similar to UFLS, trips load offline to prevent or avoid voltage collapse scenarios which can lead to cascading outages, through the use of specific voltage settings - not frequency settings. When predetermined voltage levels and timing requirements are met, a signal is sent to open designated circuit breakers shedding load to improve system voltage. The NERC Standards PRC-010-2 and PRC-011-0 define UVLS requirements.
[88] ERCOT Nodal Operating Guides, at 8L-1, Section V (D).
[89] Public Utility Commission of Texas Rules, Chapter 25 Rules, Subchapter A , Section 25.5; ERCOT's Operating Guidelines, Chapter 4, Emergency Operations, Section 4.5.2.
[90] Public Utility Commission of Texas Rule 25.497 (16 Tex. Admin. Code § 25.497).

ERCOT requires that UFLS relays should be set to provide relief when specific frequency thresholds are met.[91] In the event of an underfrequency event, each TOP is required to provide load relief by shedding the required percentage of its Distribution Provider-DSP-connected load and transmission-level customer load using automatic underfrequency relays.[92] Twenty-five percent of the DP and TOP load within ERCOT should be equipped with UFLS. Specifically, ERCOT requires that at the frequency threshold of 59.3 Hz, at least five percent of the TO load should be shed; at 58.9 Hz, the amount of load shed increases to at least 15 percent, and at 58.5 Hz, the required load shed is at least 25 percent.[93] Prior to the peak load each summer, ERCOT surveys each TOP's compliance with the automatic load shedding requirements.[94]

DPs are required to ensure that loads equipped with underfrequency relays are dispersed geographically throughout the ERCOT region to minimize the impact of load shedding within a given geographical area. Customers equipped with underfrequency relays shall be dispersed without regard to which Load Serving Entity serves the customer. If a loss of load occurs due to the operation of underfrequency relays, a DP may rotate the physical load interrupted to minimize the duration of interruption experienced by individual customers or to restore the availability of underfrequency load-shedding capability. The initial total amount of underfrequency load shed cannot be decreased without the approval of ERCOT. TOPs, in coordination with DPs, are required to make every reasonable attempt to restore load, either by automatic or manual means, to preserve system integrity.[95]

ERCOT Nodal Protocols and NERC Reliability Standard PRC-024-2 (Generator Frequency and Voltage Protective Relay Settings) allow generating units to automatically trip offline, or automatically shut down and disconnect from the grid, if the grid frequency drops to 59.4 Hz or below for more than nine minutes. If generator underfrequency relays are installed and activated to trip the unit, these relays shall be set such that the automatic removal of individual generating units from ERCOT's system meets the following requirements, shown in Figure 16, below:[96]

[91] ERCOT's Nodal Operating Guide, Section 2.6, at 2-36 (February 5, 2021).
[92] *Id.* at 2-20.
[93] *Id.*
[94] *Id.* at 2-21.
[95] *Id.* at 2-21.
[96] *Id.* at 2-22.

Figure 16: ERCOT Generator Underfrequency Trip Setting Guideline

Frequency Range	Delay to Trip
Above 59.4 Hz	No automatic tripping (Continuous operation)
Above 58.4 Hz up to and including 59.4 Hz	Not less than 9 minutes
Above 58.0 Hz up to and including 58.4 Hz	Not less than 30 seconds
Above 57.5 Hz up to and including 58.0 Hz	Not less than 2 seconds
57.5 Hz or below	No time delay required

MISO. In MISO, Local Balancing Authorities (LBAs) are responsible for individual load shed programs and perform actual load sheds as directed by the MISO BA, including rotation of load and taking into account critical load identification. MISO requires the LBAs to maintain the minimum MISO-directed load shed at all times, until it directs load to be restored. Each individual LBA has internal procedures for their own specific load shed processes.

Most MISO TOs and DPs have a three-stage UFLS program initiated at 59.3, 59.0 and 58.7 Hz, shedding anywhere from 24 to 43 percent of their respective load. Other TOs and DPs have a five-step UFLS program initiated at 59.3, 59.0, 58.7, 58.5 and 58.3 Hz, shedding approximately 30 to 42 percent of their load. Additionally, there are several small municipal TOs and DPs that are expected to shed 100 percent of their load in one step.

SPP. SPP BA's Emergency Operating Plan requires its TOPs and DPs to have the capability to implement its firm load shedding plan "within a timeframe adequate to the emergency." SPP relies on the TOPs and DPs to manage their load shedding procedures and curtail their pro rata share of firm load.

In SPP, each UFLS entity (primarily TOPs, some DPs) with a total forecasted peak load in the SPP annual data request of more than 100 MW is required to develop and implement an automatic UFLS program that sheds a minimum of 10 percent of load at each UFLS step in accordance with the table containing frequency thresholds, as shown in Figure 17, below:

Figure 17: SPP Underfrequency Load Shed Frequency Thresholds

UFLS Step	Frequency (hertz)	Minimum accumulated load relief as percentage of forecasted peak Load (%)	Maximum accumulated load relief as percentage of forecasted peak Load (%)
1	59.3	10	25
2	59	20	35
3	58.7	30	45

Coordination with natural gas infrastructure by BAs. Within the SPP footprint, manual load shed plans and procedures for several TOPs and DPs contained steps and measures to minimize the potential of natural gas infrastructure of being used for firm load shed. Examples included identification of circuits supplying natural gas infrastructure as critical to protect from manual load shed, exclusion of sub-transmission and distribution circuits supplying natural gas infrastructure from the UFLS and manual load shed circuit lists within the manual and UFLS load shed procedures, and statements within the manual load shed procedures that load shed for identified critical natural gas and/or water facilities should only be executed as a last resort to maintain system reliability.

ii. Emergency Operations Training

ERCOT. Texas PUCT rules require that a market entity shall conduct or participate in one or more drills annually to test its emergency procedures if its emergency procedures have not been implemented in response to an actual event within the last 12 months. ERCOT does conduct winter storm and other drills (e.g., hurricane drills) biennially, as well as annual winter preparedness workshops. ERCOT also has multiple procedures for cold weather emergencies. ERCOT held a 2020 black start training session, but all other training sessions in 2020 were cancelled due to the pandemic. Black start training includes training associated with response to emergency recovery from frequency excursions.

ERCOT's system operator certification exam covers emergency operations topics, and system operators have available emergency procedures including several to provide advance notice to ERCOT system entities of approaching extreme cold weather. ERCOT's procedures allow operators the flexibility to send notifications multiple days in advance and include scripts that direct GOs/GOPs to take various actions to prepare for imminent cold weather, including reviewing and implementing winterization procedures, updating operating plans, and reviewing outages. ERCOT's procedures also address potential fuel issues, for example, requiring system operators to evaluate the weather forecasts for extreme conditions that could potentially lead to fuel supply problem, and directing shift supervisors to consider fuel switching.

TOPs and DPs normally perform load shed drills, and some entities conduct in-house load reduction drills with their system operations staff annually. Due to the pandemic, ERCOT did not conduct its winter 2020 load shed drills. The load shed drills fall into four broad categories: load shedding, system restoration, emergency operating procedures, and severe weather drills.

MISO and SPP. MISO performs load shed instruction drills with each of its LBAs monthly, coupled with testing of their emergency communications systems. Most TOPs and DPs in the MISO and SPP footprints typically perform load shed drills as part of their emergency operations training. All SPP TOPs and DPs voluntarily participate in SPP's annual load shed drills, which simulates an actual load shed event.[97] SPP also performs quarterly testing via a dedicated web-based Reliability Communication Tool (RCOMM). As part of the test, an electronic notice is sent by the SPP RC to all TOPs, requesting a test amount of load be shed. TOPs acknowledge the message, enter the test load amount, and submit the response to SPP.

[97] SPP has only had one TOP miss the drill, due to a system emergency.

D. Prior Cold Weather Events and Recommendations

Extreme cold weather has jeopardized the reliable operation of the BES four times in the past 10 years, including the Event. From February 1 to 5, 2011, an arctic cold front impacted the southwest U.S. and resulted in numerous generation outages, natural gas facility outages and emergency power grid conditions and caused 6,886 MW of firm customer load shed in ERCOT, El Paso Electric and Salt River Project.[98] The January 2014 Polar Vortex event affected Texas, the Central and Eastern U.S., and resulted in generation outages, natural gas availability issues and less than 300 MW of firm load shed. And in January 2018, an arctic high-pressure system and below-average temperatures in the South Central U.S. resulted in many generation outages, and no firm load shed, but required voluntary load management emergency measures.[99]

Appendix B, which compares the weather conditions of the Event with past cold weather events in addition to the four BES events above, makes clear that although the Event was unusually cold, severe cold and freezing precipitation are far from unprecedented for winter in the Event Area. For example, other prior cold weather events had lower average daily temperatures for some days during each event.[100] For two of the five events, Houston and Jackson experienced at least one day for each of the week-long periods where the average daily temperature was below 10 degrees, and Dallas and Jackson experienced at least one day for each of the week-long periods where the average daily temperature was below 5 degrees. In all five events, average daily temperatures were below freezing in Dallas, Houston, and Jackson, for at least three days out of the week-long periods. The 1983 event had seven separate recorded cold fronts, while the 1989 event is still the coldest recorded winter in the Houston and Galveston areas, with 14 days below freezing over two to three weeks, and lows below those seen during the Event. The 1983, 2011 and 2018 events all had significant freezing precipitation, like the Event.

After each of the four BES events in the last ten years, one or more of the Commission, NERC, and/or the Regional Entities issued reports with recommendations to prevent similar events from recurring. Below the Team highlights the recommendations most relevant to the Event.[101]

1. 2011: ERCOT and Southwest

A joint FERC-NERC-Texas Reliability Entity report on the 2011 ERCOT and Southwest weather event was published in August 2011 and made 26 electric recommendations, in areas including

[98] SPP experienced weather-related generation outages and decreased natural gas supply, and several entities within SPP declared EEAs 1 to 3, but none shed firm load.
[99] This event was a near-miss. Although MISO and SPP did not need to shed firm load, MISO system analysis showed that if it lost its worst single contingency generation outage of over 1,000 MW, it would need to rely on post-contingency manual firm load shed to maintain voltages within limits and shed additional firm load to restore reserves. 2018 Report at 9-10.
[100] *See* Figures 115-117 in Appendix B.
[101] Appendix B compares the weather conditions of select extreme cold weather events that have occurred in the U.S. over the past 40 years, to gain understanding of the characteristics of these weather systems and how they can vary, including their temperature variations, their durations, and other weather conditions including precipitation and wind.

planning and reserves, coordination with GOs/GOPs, communications, load shedding and generating units' winterization, plant design, maintenance of freeze protection, and training on winterization. Among the recommendations that could have helped prevent the Event if followed were the following:

- GOs/GOPs inspect and maintain heat tracing equipment and thermal insulation, erect adequate wind breaks and enclosures, based on an engineering assessment, develop and annually conduct winter-specific and plant-specific operator awareness and maintenance training (including the capabilities and limitations of freeze protection and methods for checking insulation integrity and heat tracing reliability) (##15-19)
- Consider designing any new plants and modifications to existing plants (unless committed solely for summer peaking) to be able to perform at the lowest recorded ambient temperature for the nearest city (factoring in accelerated heat loss due to wind speed) (#12)
- Assess the temperature design parameters of existing generating units (#13)
- TOPs and BAs obtain from GOs/GOPs forecasts of real output capability in advance of a severe weather event, which forecasts should take into account both the temperature beyond which availability of the generating unit cannot be assumed, and the potential for natural gas curtailments (#9), and
- TOPs and DPs conduct critical load review for gas production and transmission facilities (#25).

2. 2014: Polar Vortex

In September 2014, NERC staff published a report analyzing the January 2014 Polar Vortex event. NERC staff noted that natural gas units in two of the Regional Entity areas experienced higher-than-expected outage rates during the event,[102] and noted, "[t]his observation validates the concerns that NERC raised in the *2013 Long-Term Reliability Assessment* on increased dependence on natural gas for electric power."[103] In the Northeast, as units switched from gas to oil, some oil suppliers began to run low, which led to generation owners limiting run hours for their units—affecting approximately 2,000 to 3,000 MW of generation.[104]

NERC staff made ten recommendations, and those most relevant to the Event included:

- Examine natural gas supply issues; electric industry, gas suppliers, markets and regulators work to identify issues with natural gas supply and transportation, implement actions to allow generators to be able to secure firm supply and transportation at a reasonable rate.

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[102] Polar Vortex Review at 18.

[103] *Id.* at 8, NERC, 2013 Long-Term Reliability Assessment http://www.nerc.com/pa/RAPA/ra/Reliability_Assessments_DL/2013_LTRA_FINAL.pdf, at 35.

[104] PJM, *Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events*, Nat'l Hydropower Ass'n (May 8, 2014), https://www.hydro.org/wp-content/uploads/2017/08/PJM-January-2014-report.pdf.

- Review and update generating unit winterization (including procedures and training) as a result of lessons learned from the event, generating units should follow the Reliability Guideline.
- Entity winter assessments should include base assumptions and stress cases for the loss of varying amounts of natural gas-fired generation.
- Continue to improve awareness by BAs and RCs of the fuel status of generating units, including improved awareness of pipeline system conditions.
- GOs/GOPs should work to protect against outages within the ambient temperature design of the generating unit and determine if modifications should be made.
- Prepare to take proactive actions to secure waivers (market, environmental, fuel, etc.) from the appropriate entities when needed during emergencies.

3. 2018: South Central U.S.

A joint FERC-NERC-Regional Entity inquiry report published in July 2019 made thirteen recommendations, including a recommendation for potential new or revised Reliability Standards to address the need for generating units to prepare for cold weather and the need for BAs and RCs to be aware of specific generating unit limitations, such as ambient temperatures or fuel supply. (#1) This recommendation led to the Reliability Standards revisions approved by the Commission in *Order Approving Cold Weather Reliability Standards*, 176 FERC ¶ 61,119 (2021). Other recommendations relevant to the Event included:

- PCs and TPs should jointly develop and study more-extreme condition scenarios to be prepared for seasonal extreme conditions, including removing generating units entirely to model outages known to occur during cold weather and modeling system loads that accurately test the system for the extreme conditions being studied. (#7)
- Neighboring RCs should perform seasonal transfer studies and sensitivity analyses that model same-direction simultaneous transfers to determine constrained facilities. Among the scenarios suggested was simultaneous generating unit outages in adjacent RC footprints and increasing simultaneous transfers to a level where constraints cannot be fully mitigated. (#8)

Figure 18 provides a comparison of the four BES events' generating unit outages and load shed.

Figure 18: Comparison of Events' Effects on Bulk Electric System Generation and Resulting Need for Load Shed

	Feb. 1-5, 2011	**Polar Vortex Jan 6-8, 2014**	**2018 Event Jan 15-19, 2018**	**2021 Event Feb 8-20, 2021**
Deviation from Average Daily Temperature	17 to 36 deg F[105] below average	20 to 30 deg F[106] below average	12 to 28 deg F[107] below average	40 to 50 deg F[108] below average
Unavailable Generation Due to Cold Weather, at Worst Point (MW)	14,702[109]	9,800[110]	15,600[111]	65,622[112]
Causes of Unavailable Generation	Freezing Issues, Mechanical/ Electrical Issues, Natural Gas Fuel Issues	Freezing Issues (cold weather), Natural Gas Fuel Issues	Freezing Issues, Mechanical/ Electrical Issues, Natural Gas Fuel Issues	Freezing Issues, Natural Gas Fuel Issues, Mechanical/ Electrical Issues
Energy Emergency(s) Declared/ Highest Level	Yes/ EEA 3	Yes/ EEA 3	Yes/ EEA 2	Yes/ EEA 3
Maximum Firm Load Shed (MW)	5,411.6	300[113]	0[114]	23,418 (ERCOT 20,000, SPP 2,718, MISO South 700)
Overall Duration of Firm Load Shedding	ERCOT: 7 hours, 24 minutes	3 hours	N/A	ERCOT: over 70 hours, SPP: over 4 hours MISO South: over 2 hours

[105] NOAA weather data.
[106] Polar Vortex Review at iii.
[107] 2018 Report at 31.
[108] NOAA NWS_WPC_Overview_February_2021.pdf (texasre.org), pg. 24.
[109] 2011 Report at 79.
[110] 2014 Report at 2, in the southeastern U.S.
[111] 2018 Report at 34 and 47.
[112] The non-coincident Event Area peak of unplanned generation outages and derates was 65,622 MW, which occurred at different points in time: in ERCOT on February 15 at 1:05 p.m., MISO South on February 16 at 5:01 p.m., and SPP on February 17 at 12:17 a.m. The coincident peak of incremental unavailable generation in the Event Area was 61,305 MW, as shown in Figure 66a.
[113] Polar Vortex Review at iii.
[114] EEA 2/voluntary load management occurred.

III. Chronology of Events

A. Forecasts and Preparations for the Winter Storm[115]

1. Early Weather Forecasts Aided ERCOT, MISO and SPP in Predicting Severe Cold Weather

By late January/early February, ERCOT, SPP and MISO anticipated that severe cold weather was likely to occur in February. Both ERCOT and MISO employ meteorologists who assessed NOAA's forecast models and longer-term weather forecasts, and all three had weather forecasts provided by vendors which indicated the likelihood for extreme cold weather over the next two weeks. Armed with this information, the three RCs/BAs were able to issue early forecasts and preparation notices to GOs, GOPs, TOPs, and others within their footprints that the weather was going to turn much colder.

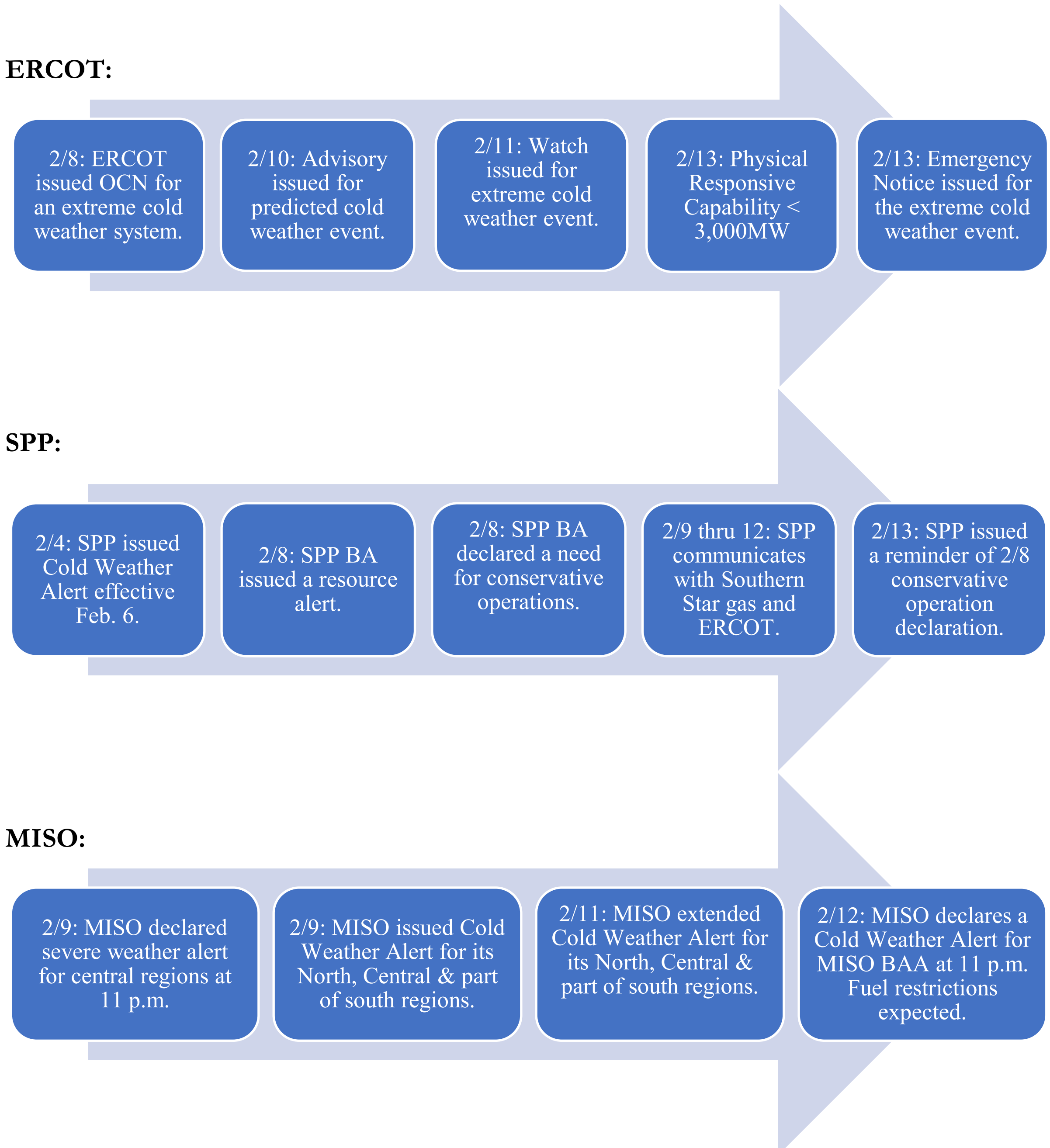
2. Notices Issued by Grid Entities in Advance of Severe Cold[116]

Aware of the impending cold weather, ERCOT, MISO and SPP began to warn other entities and to instruct them to prepare. The following Figure 19 and subsequent paragraphs summarize the information and notices ERCOT, MISO and SPP issued.

[115] Although many commentators refer to the weather event as "Winter Storm Uri," the Report does not, because NOAA did not. *But see* UT Report at 7.

[116] Here, alert is used generically to refer to any of the multiple communications that the BAs and RCs primarily used to communicate system conditions during the Event. *See* Appendix K for a description of the various levels of alerts and Energy Emergencies used by ERCOT, MISO and SPP. Appendix C contains an example RC alert issued during the Event. OCN, or Operating Condition Notice, is the lowest level of communication used by ERCOT in anticipation of an emergency condition.

Figure 19: Alerts Issued in Advance of the Coldest Weather, February 8-13, 2021



<u>ERCOT</u>. As early as January 28, ERCOT's resident meteorologist began communicating the mid-February potential for severely cold weather, with temperatures along the lines of the 2011 event. From that day onward, the meteorologist sent daily internal email communications, which included temperature and precipitation forecasts as well as subject matter commentary to ERCOT staff (system operations, outage coordination, load forecasting, various executives, other targeted employees) and published information on the ERCOT website.[117]

On February 8, 2021, ERCOT issued two Operating Condition Notices (OCN) to QSEs and TOs. In the morning, ERCOT issued an OCN (via its hotline and posted on its website) for predicted freezing precipitation for the Panhandle and North areas of the ERCOT region beginning Wednesday evening, February 10 through Thursday, February 11. That evening, ERCOT issued a second OCN for an extreme cold weather system approaching Thursday, February 11 through Monday, February 15, with temperatures anticipated to remain at or below freezing. QSEs were instructed to update ERCOT as soon as practicable on changes to generating units' availability and capability; review fuel supplies, prepare to preserve fuel to best serve peak load; notify ERCOT of any known or anticipated fuel restrictions; review planned resource outages and consider delaying maintenance or returning from outage early; review and implement winterization procedures; and notify ERCOT of any changes or conditions that could affect system reliability. ERCOT instructed TOs to review planned and existing transmission outages for the possibility of canceling outages or restoring equipment; review and implement winterization procedures; and notify ERCOT of any changes or conditions that could affect system reliability.

On February 11, 2021, ERCOT issued a Watch, in which, in addition to steps already taken under the OCN, ERCOT instructed QSEs to implement winterization and emergency operating procedures including pre-warming of generating units.[118] Eventually on February 13, 2021, ERCOT issued an Emergency Notice for extreme cold weather on its public website.

MISO. Beginning on February 9, MISO began to communicate with its members about the upcoming severe weather, by issuing a Cold Weather Alert effective for February 13 to 15, which was extended through February 16 on February 11.[119] On February 10 and 11, it issued Informational Advisories reminding generating units to update MISO on fuel availability and implement their winterization or maintenance. On February 13, MISO committed all long-lead generating units and issued a Capacity Advisory for MISO South. On February 14, MISO issued a Maximum Generation Emergency Alert for MISO South, which required generating units to suspend maintenance activities, effective February 15.

SPP. SPP issued a Cold Weather Alert on February 4, 2021, effective February 6. On Monday, February 8, 2021, SPP escalated to a Resource Alert, which triggers generating units to complete any

117 Closer to the Event, on February 4, 2021, ERCOT's meteorologist, in his market information forecast, warned market participants that the forecast suggested a likelihood that the cold air would "push all the way through Texas by the second half of next week," and noted that "next Friday through the weekend (i.e. February 12 to 14) has the potential to be the coldest period of the winter." ERCOT Review of February 2021 Extreme Cold Weather Event – ERCOT Presentation, at 9, http://www.ercot.com/content/wcm/key_documents_lists/225373/Urgent_Board_of_Directors_Meeting_2-24-2021.pdf; ERCOT Market Information forecast for February 4.

118 This was a recommendation from the 2011 Report. 2011 Report at 60-61.

119 *The February Arctic Event February 14-18, 2021*, Miso Energy, 15 https://cdn.misoenergy.org/2021%20Arctic%20Event%20Report554429.pdf.

preparations, ensure that they can meet their commitments and report any fuel shortages.[120] On Tuesday, February 9, 2021, SPP declared Conservative Operations,[121] and on Thursday, February 11, it began committing long-lead generation through its reliability assessment process instead of its normal day-ahead commitment process.

3. Winter Preparations by Generator Owners and Operators and Responses to Alerts[122]

The Team reviewed how generating units prepared for cold weather in the ERCOT, SPP and MISO footprints. Depending on the type of fuel, generating units took specific actions to ensure they would remain in operation during the Event.

Wind units in ERCOT and SPP prepared by performing annual service and winterization checks, canceling planned maintenance, ordering additional nitrogen[123] for maintaining the hydraulic braking system, activating the emergency response team to assist in coordination, providing continuous personnel coverage at the facilities, checking operational conditions of critical heating systems, notifying contractors of the need to be available during the Event, ensuring road access, and modifying on-site inspection rounds to more closely monitor the turbines for ice buildup. In SPP, one large GO activated its Emergency Response Team before the storm to provide support and coordination for all units, which triggered daily meetings and activities across a broad geographic area. Emergency Response Team members mobilized throughout Texas and Oklahoma to be staged at high-impact locations.

Solar units in ERCOT and MISO South prepared inverters by checking the functionality of heaters, ensuring adequate temperature settings and functioning alarms, and activating emergency response teams.

Natural gas-fired units across all regions prepared for the Event by, among other things, deploying emergency plans and adding personnel, including operators to more frequently check freeze protection (and quickly address any issues); checking natural gas inventories and placing natural gas commodity orders in advance; testing heating supplies and protective equipment; installing temporary heat tracing, tarps, and insulation to prevent equipment from freezing; verifying that pumps were running; checking temperature gauges; replenishing cold weather gear; placing snow

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[120] *A Comprehensive Review of Southwest Power Pool's Response To The February 2021 Winter Storm Analysis and Recommendations,* Southwest Power Pool, 27 (Aug. 2011), https://www.spp.org/documents/65037/comprehensive%20review%20of%20spp's%20response%20to%20the%20feb.%202021%20winter%20storm%202021%2007%2019.pdf.

[121] Conservative Operations is declared when SPP determines there is a need to operate its system conservatively based on weather, environmental, operational, terrorist, cyber or other events.

[122] Although many of these preparations happened shortly before the Event, some started before the winter.

[123] Nitrogen is used as part of a braking system to prevent the wind turbine from operating at speeds that would damage the blades. Over time, the nitrogen level in the cylinder can drop and needs to be refilled. *Improve Wind Turbine Safety with a Piston Accumulator Retrofit,* Power (Sept. 21, 2020), https://www.powermag.com/improve-wind-turbine-safety-with-a-piston-accumulator-retrofit/.

removal equipment and portable generators connected to batteries on site; opening water valves and low-point drains; checking that freeze protection panels are in service and all circuits are energized; and, for dual-fuel[124] units, filling condensate systems to prepare for water injection usage if required to change to fuel oil. In SPP, some GOPs reported testing units prior to the Event for black start capability and full speed no load tests. A GO/GOP in SPP reported ensuring snow and ice removal equipment and supplies were available and portable generators and heaters deployed around the plant as necessary. In MISO South, some GOs/GOPs reviewed and updated winterization checklists for each site annually to add newly-installed equipment (equipment is added to the list based on previous freezing experience) and remove retired equipment, and placed certain equipment in service when the ambient temperature reached a pre-selected point. For example, some GOs/GOPs had their lube oil cooling water pumps placed in continuous service when the temperature is expected to be 25 degrees or less for at least eight hours. GOs/GOPs also established firm gas transportation arrangements and exclusive provider agreements with gas suppliers and review cold weather event procedures with operations and maintenance groups at the beginning of the winter season. Plant personnel reviewed open work orders that could affect plant operation and completed maintenance activities prior to the onset of the Event. Plant personnel drained the inlet air chiller coils and filled the demineralized water tanks to maximum capacity in preparation for the Event. Beginning on February 15, plant personnel from one GO were onsite 24 hours a day until conditions in MISO South improved. Extra operations staff sequestered onsite overnight to ensure adequate operations coverage during inclement weather and deteriorating road conditions.

Oil-fired generating units also performed maintenance, checked heat tracing, and checked temperature gauges. In addition, they prepared by insulating critical control valves, test-starting black start diesel units, procuring extra fuel oil and filling fuel and storage tanks onsite, staging additional diesel heaters and barriers/wind breaks, and verifying pumps, heaters and igniters were operational. Dual-fuel generators that would normally burn natural gas also burned a mixture of gas and oil to conserve gas.

Coal-fired generating units across all regions, like other types of generators, placed and inspected insulation, added heaters around critical components (e.g., coal mills), and brought in additional operations and maintenance personnel to prepare for and respond to the Event. GOs/GOPs with coal-fired generating units in ERCOT also prepared by coating coal cars to prevent coal from sticking due to freezing and maintaining water flow through piping in offline systems. To obtain maximum performance from coal units, facilities located in Texas worked with the Texas Commission on Environmental Quality to relax emissions constraints on February 15. In SPP, an entity started auxiliary boilers early for additional building heat. In MISO South, preparations included inspecting heat tracing and insulation, installing wind breaks, and checking inventory of ice melt.

[124] *See* Fuel Switching: A Missed Opportunity, for more information on dual-fuel units (p. 225).

4. Near-Term Grid Preparations Taken in Advance of Severe Cold Weather

a. Short-Term Load Forecasts

ERCOT. ERCOT produces a seven-day ahead hourly load forecast for each of the weather forecast zones in its footprint, using data from two weather vendors. Beginning the week of February 7, ERCOT deviated from its typical practice of using a single forecast model for an entire 24-hour day and used multiple forecast models to better reflect load variations at different points during the day.

SPP. SPP uses weather forecast data to generate seven-day hourly load forecasts used for operational planning studies and assessments. This information is also used to determine any risks and uncertainty associated with generation or transmission availability. SPP's uncertainty response team, who account for risks including weather, load, wind, and resources, advised the real-time system operators in advance of the severe cold weather that the load forecasts for the week of February 14 may be understated.

MISO. MISO generates a temperature forecast tracking dashboard daily. The dashboard consists of an hourly look-ahead temperature forecast for the remainder of the current day and the next six days, for each of MISO's five weather zones.

The following Figures 20 - 22 compare short-term load forecasts developed by ERCOT, MISO (for its MISO South region) and SPP to the actual peak system loads for February 15, 2021, for each of their respective footprints.

Figure 20: ERCOT's Near-term Peak Load Forecasts and Percent Error for ERCOT: 5-day, 4-day, 3-day, 2-day, and 1-day ahead of February 15, 2021

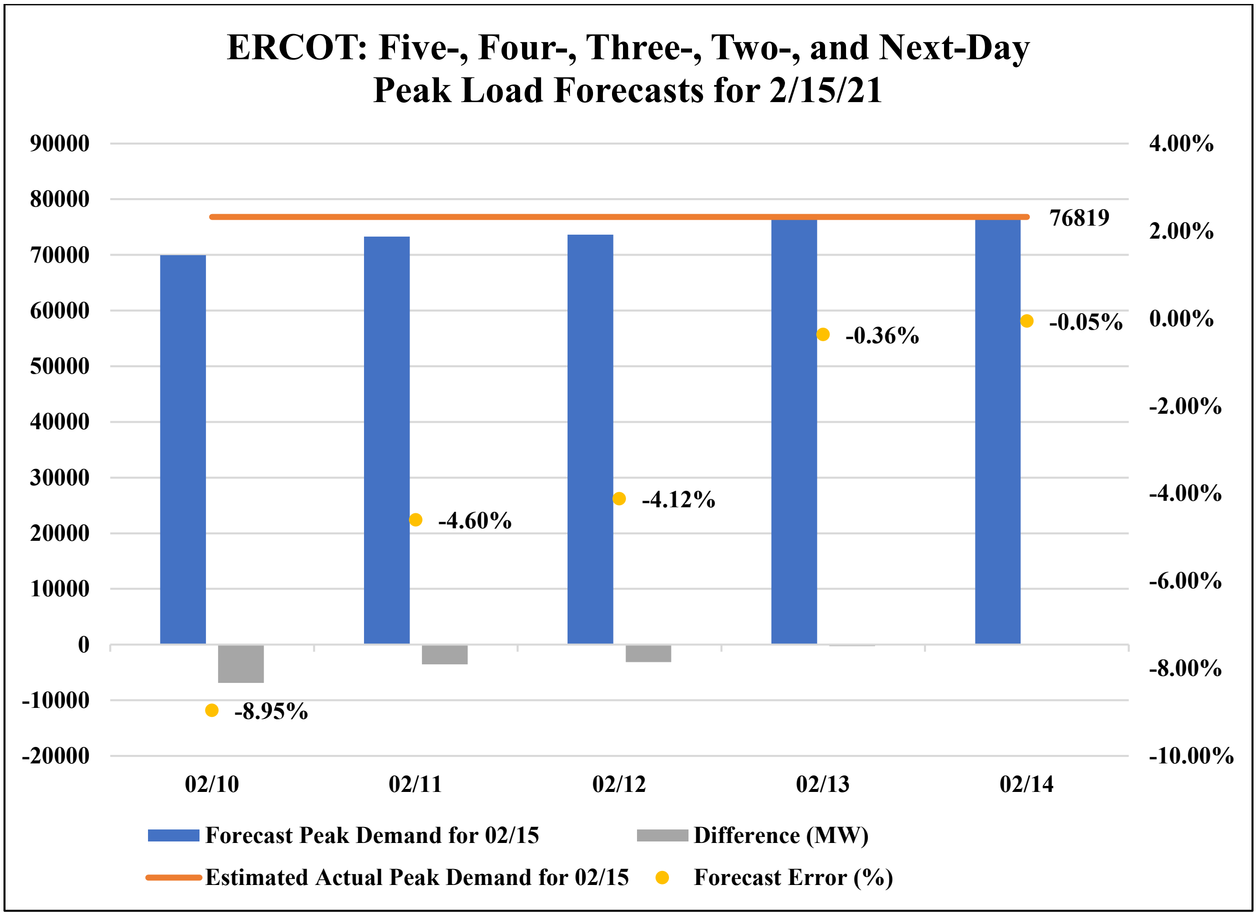


Figure 21: MISO's Near-term Peak Load Forecasts and Percent Error for MISO South: 5-day, 4-day, 3-day, 2-day, and 1-day ahead of February 15, 2021

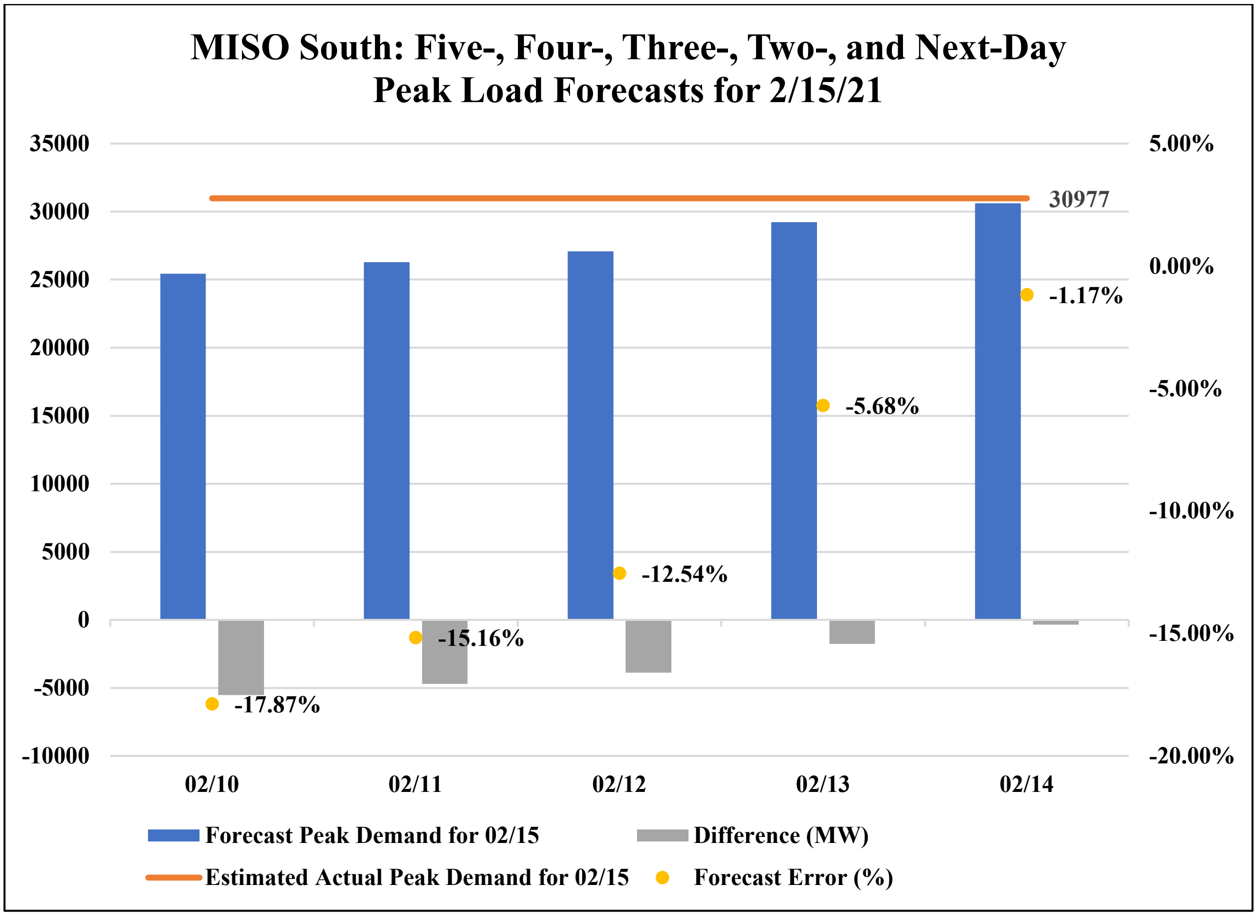
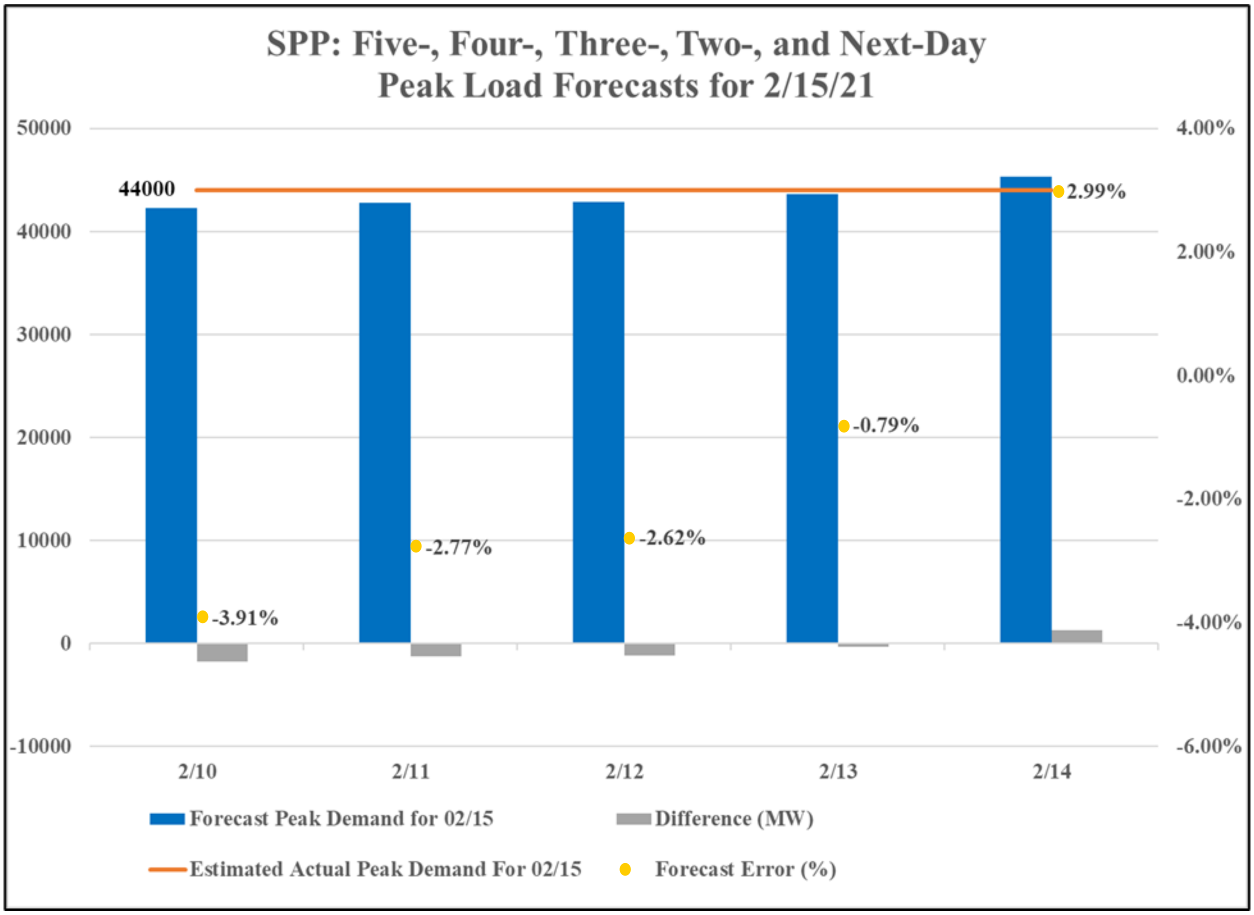


Figure 22: SPP's Near-term Peak Load Forecasts and Percent Error for SPP: 5-day, 4-day, 3-day, 2-day, and 1-day ahead of February 15, 2021



MISO's five-day, four-day, and three-day-ahead peak load forecast errors shown in Figure 21, above, in forecasting the "estimated" MISO South peak load for February 15, 2021 were larger (approximately 17.9 percent/5,500 MW, 15.2 percent/4,700 MW, and 12.5 percent/3,900 MW lower than actual peak load, respectively) than forecast error rates for the same period for the other BAs involved in the event. ERCOT's and SPP's load forecasts comparable to this timeframe (shown above in Figure 20 and 22, respectively) were more accurate (with error rates ranging from nine to four percent lower than actual peak load for five-days-out, 4.6 to 2.8 percent lower than actual for four-days-out, and 4.1 to 2.6 percent lower than actual for three-days-out). As shown in Figures 20 to 22 above, all of the BAs' load forecast errors trended towards zero percent as February 15 approached and ranged between 2.99 percent above to 1.17 percent lower than the actual peak demand for the day-ahead load forecast.

b. Total Unavailable Generation before February 8

Prior to the Event,[125] ERCOT had 3,079 MW of planned generation outages, and 10,633 MW of unplanned generation outages and derates (for total unavailable generation of 13,712 MW); MISO South had 1,793 MW of planned generation outages, and 1,406 MW of unplanned generation outages and derates (for a total of about 3,199 MW of unavailable generation); while SPP had 6,238 MW of planned generation outages, and 11,264 MW of forced generation outages and derates (for a total of 17,502 MW of unavailable generation). These outages and derates are shown in Figures 23 and 24, below.

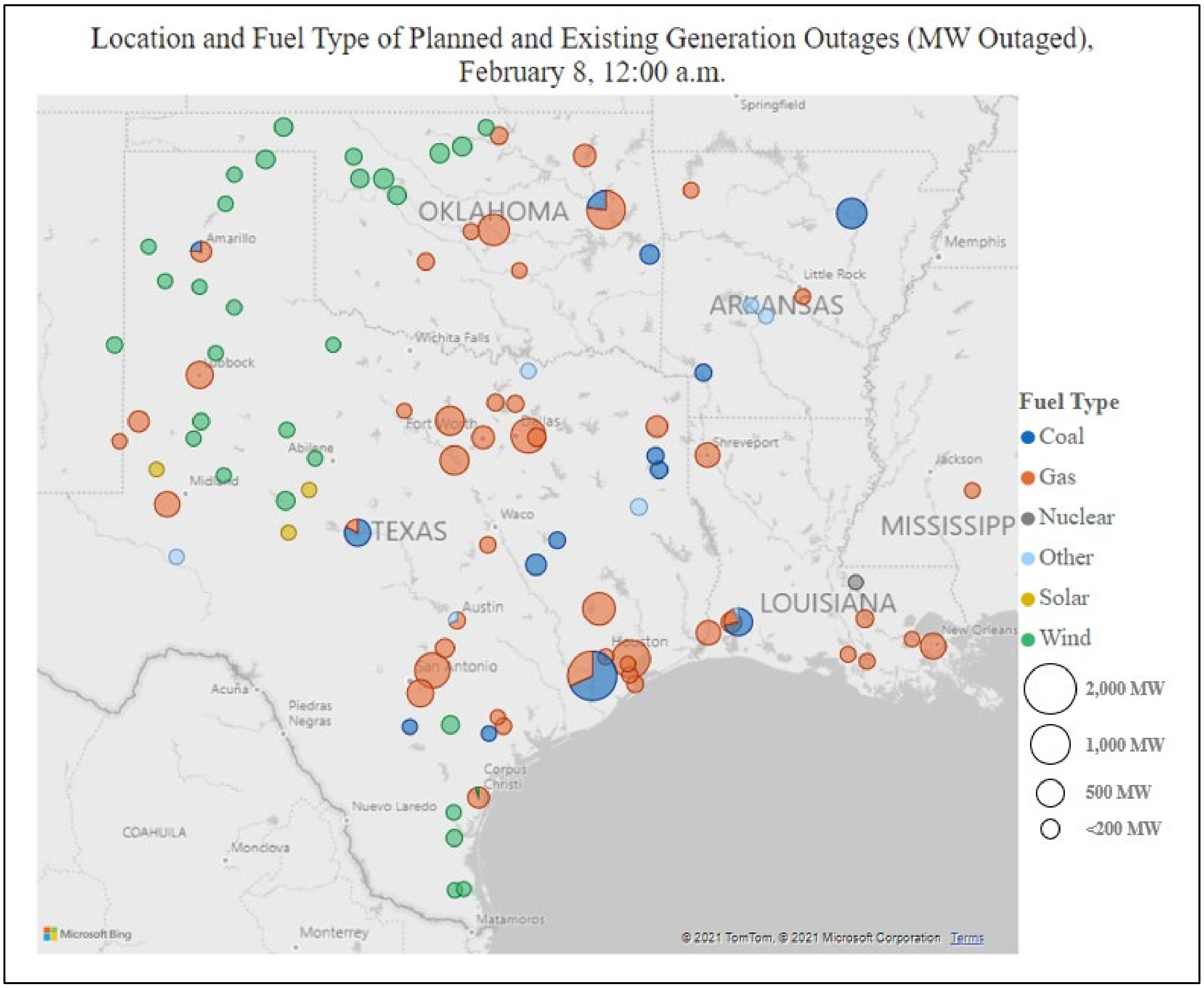
Figure 23: Total Unavailable Generation (MW) Prior to Event and Percent of Installed Capacity[126]

Total Unavailable Generation (MW) Prior to Event¹ and Percent of Installed Capacity			
	ERCOT	**MISO South**	**SPP**
Planned Generation Outages	3,079 (2.5%)	1,793 (4.3%)	6,238 (6.6%)
Unplanned Generation Outages	10,633 (8.6%)	1,406 (3.3%)	11,264 (12.0%)
Total Unavailable Generation	13,712 (11.1%)	3,199 (7.6%)	17,502 (18.6%)
Total Installed Capacity	123,057	41,865	94,232

125 As of 12:00 a.m. on February 8, 2021.

126 Just prior to the Event, the unplanned (or forced) generation outages and derate percentages of the total installed capacity for ERCOT, MISO South and SPP were 8.6%, 3.3% and 12.0%, respectively, as shown in Figure 23, above. These percentages were lower than the generation annual Weighted Equivalent Forced Outage Rates (WEFOR) for 2020 for TRE (covers Texas, including ERCOT), SERC (predominantly covers southern U.S., including MISO South), and for MRO (covers large portion of SPP) were 9.4%, 7.5%, and 13.9%, respectively. According to NERC, "WEFOR measures the probability that a group of units will not meet their generating requirements because of forced outages or forced derates. The weighting gives larger units more impact to the metric than smaller units." General Availability Review (Weighted EFOR) Dashboard (nerc.com).

Figure 24: Location and Fuel Type of Planned and Existing Forced Generation Outages in ERCOT (MW Outaged), February 8, 12:00 a.m.[127]



c. Generation and Transmission Returned to Service/Outages Cancelled

In ERCOT, the Outage Coordination group worked closely with TOs to return transmission outages to service. Beginning February 8, ERCOT outage coordination staff began evaluating outaged facilities that could be placed back in service. ERCOT staff evaluated priority transmission outages with long restoration times and notified transmission entities to cancel or withdraw priority outages that could be restored to service by February 12. Ultimately, ERCOT canceled or rejected 75 transmission outages from February 8 to February 22. ERCOT staff also reviewed planned

[127] Figure 24 is a baseline, while Figures 34, 68, and 74 are a time series showing how the unplanned outages grew during the Event. The purpose of the time series is to give a sense of how widespread the outages were geographically, how they varied in fuel type, and how they worsened over time.

generation outages to identify those that could potentially return to service early, resulting in the cancellation of 75 planned generation outages on 53 generating units.

As early as February 8, MISO staff began reaching out to generating units in the Event Area, asking that they defer maintenance and refueling outages and return generating units to service. MISO succeeded in postponing some significant outages, for example, the maintenance outage, planned to start on February 13,[128] of a 1,000 MW-plus nuclear unit, and the suspension/retirement of a 411 MW natural gas-fired generating unit, and in total canceled or revoked 168 generating unit outages planned between February 8 and February 22.

SPP's outage coordination team contacted all TOPs and GOPs with outages scheduled during the period of February 9 through February 20 and requested that any outage that was not designated as "emergency" or "forced-priority" be rescheduled. SPP then denied or rescheduled all non-emergency or non-forced outages during that period, canceling or denying 19 generating unit outages planned to start between February 9 and February 22. On February 12 and February 14, SPP held conferences with its Operating Reliability Working Group to clearly communicate expected grid conditions. TOs and TOPs were asked about changes or adjustments that were made between February 7 and 13 to any transmission outage plans or ongoing transmission outages for the week beginning February 14, such as postponing a planned outage that had not begun to a later time during the approved scheduled window, rescheduling a planned outage that had not begun to an entirely different scheduled window, recalling an outage that had begun to be completed at another time, or cancelling an outage, planned or ongoing, altogether. Of the TOs/TOPs that responded, 64.6 percent indicated that changes were made to current and planned transmission outages prior to the Event. The remaining 35.4 percent either had no outages planned or made no changes to ongoing transmission outages.[129]

d. Generation Committed Early for Reliability

On Thursday, February 11, MISO committed long-lead generation of approximately 3 GW in the North/Central region and approximately 5.5 GW in the South region in preparation for the winter storm. Long-lead generators are generators with a time to start time greater than 24 hours, during which they may need to take specific actions including fuel procurement, staffing, or startup procedures. On February 11, SPP also began committing generation, regardless of start-up lead time, through its reliability assessment process instead of its normal day-ahead commitment process, which meant even generating units with a short lead time for start-up were committed, along with long-lead generators. SPP continued this approach through the week of February 14 using its multiday reliability commitment process, [130] to improve the chance for fuel procurement by the generators.

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[128] According to MISO, it paid over $5.1 million dollars to compensate the GO for this delay.

[129] Depending on the nature of the work, some ongoing transmission outages are impossible to restore until completion of work; for example, a substation or transmission line construction project that has begun and involved removal of equipment.

[130] *See* section III.B.4.(b) for description of SPP's multiday reliability commitment process.

Fuel procurement was of special concern during the Event because it was a holiday weekend (Presidents' Day). SPP committed natural gas-fired generating units earlier than normal to give them the ability to purchase supplemental gas supplies ahead of a long holiday weekend. Natural gas supply trading and pipeline transportation nominations occur every day for delivery the next flow day; however, standard next day gas trading occurs only on business days. Next-day trading for flow days Saturday, Sunday and Monday occurs on Fridays, with exceptions for holidays. Some less-liquid markets offer products that break up the weekend package or trade during the weekend itself. Due to the Presidents' Day holiday, natural gas units committed by the early morning of Friday, February 12 for Saturday February 13 to Tuesday, February 16 had better options for procuring natural gas than units that received commitments on a day-by-day basis throughout the weekend. Natural gas-fired units committed during the holiday weekend or for only part of the holiday weekend had limited options for procuring gas supply and transportation.

5. Near-Term Preparations by Natural Gas Infrastructure[131]

Production. Production facilities' preparation for the Event began up to a week prior to the Event and focused on three main areas: freeze protection, fluid management and staffing/communications.[132] Freeze protection measures included: ensuring supplies of methanol, other hydrate suppressants,[133] and antifreeze; burying and upsizing sensing lines; and adding heat tracing, tarps, barriers, and insulation. Fluid management measures included drawing down oil and water tanks, securing generators for backup power at critical facilities (saltwater disposal wells, water transfer systems), securing additional frac tanks, and preparing for other water/oil management procedures (i.e., agreements with gatherers and processors to flow oil, water, and gas through various pipelines in order to maintain production).[134] Staffing and communications measures included prioritizing field operations in the affected production basins, and increasing internal and external (with midstream gathering, processing, and gas sales counterparties) communications.

A limited number of gas production facilities decided to proactively shut in their wells before the Event began, which eliminated the need for other preparation measures. Gas production facilities primarily decided to proactively shut in their wells for one of two reasons: (1) safety, environmental and asset protection, aimed at quick recovery of operations post-Event; or (2) focusing resources on wells viewed as more productive (whether based on higher flow/volume or the composition/ratios of liquids and gas) and minimizing resource allocation to less-productive wells.

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131 Unless otherwise stated, the source of data for this section is the sample of producers, processors and pipelines that responded to the Team's data requests. *See* Appendix I.

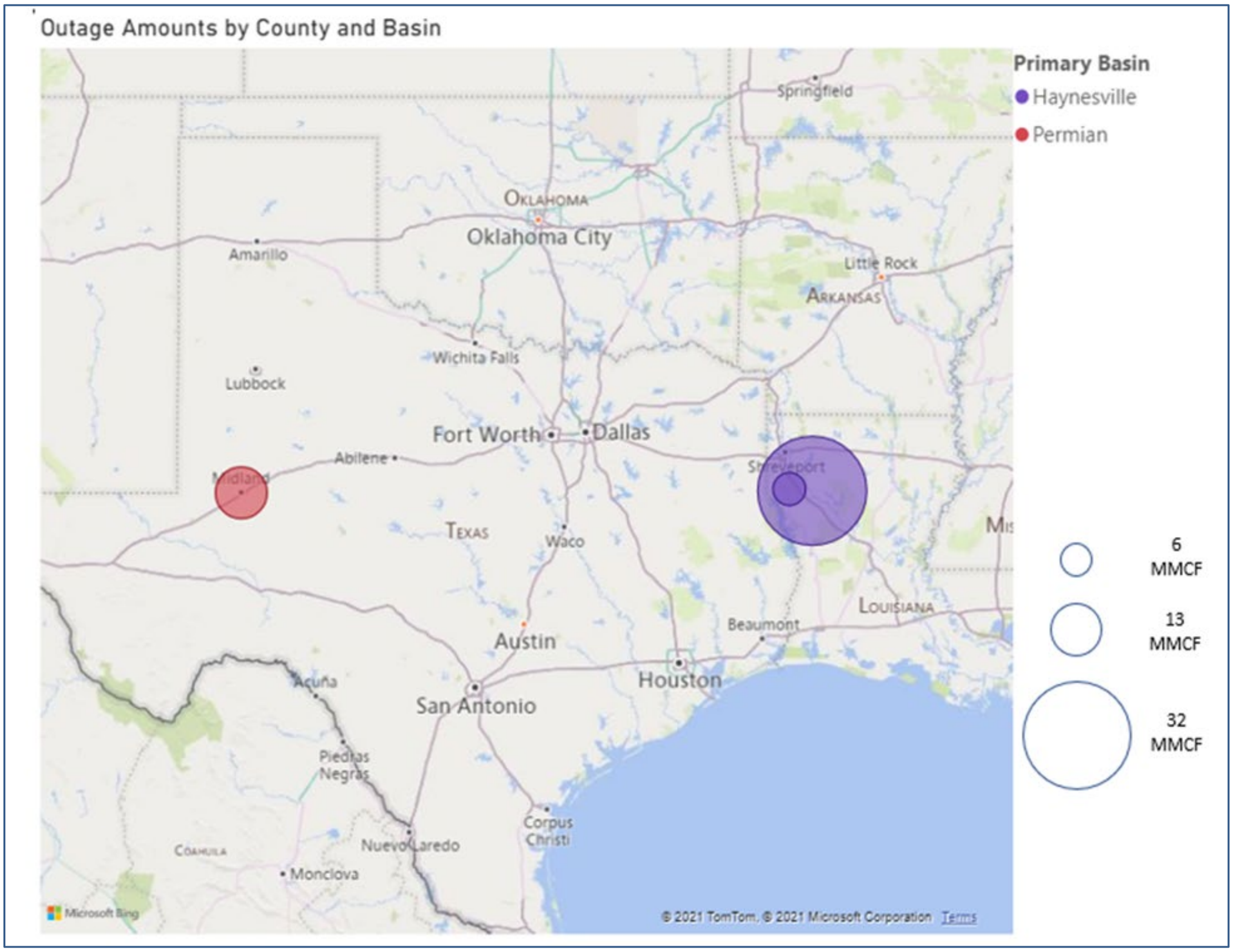
132 Producers also stockpiled necessary equipment such as heating devices, and batteries for instrumentation and electronics/control/communications equipment power.

133 T.F. Welker, Freeze Protection for Natural Gas Pipeline Systems and Measurement Instrumentation, https://welker.com/freeze-protection-for-natural-gas-pipeline-systems-and-measurement-instrumentation/.

134 One entity added produced water systems in 2020. Wells connected to its water gathering systems were not reliant on water haulers, which helped ensure that production remained online, and increased the percentage of its production from those wells.

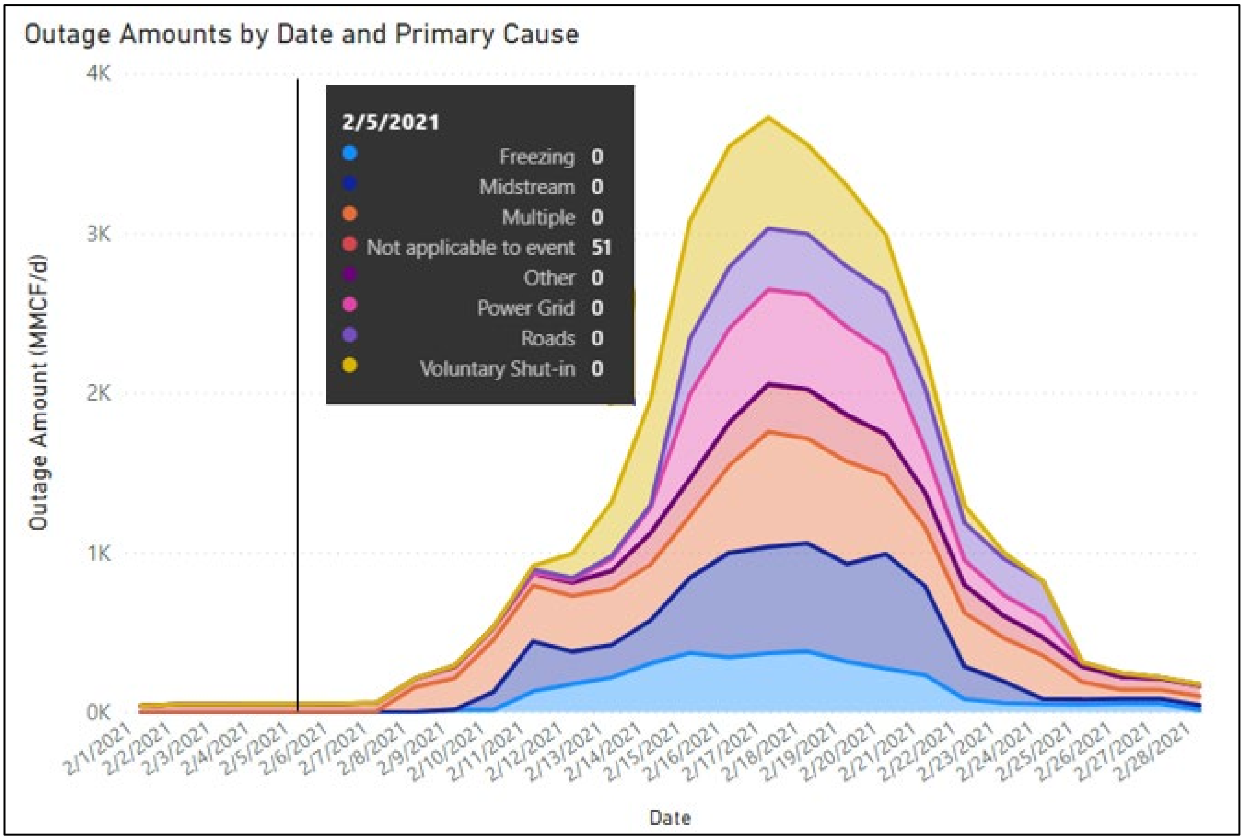
Figures 25a and 25b, below depict natural gas production outages prior to the Event (Figure 25a), based on sample of production data gathered, and the primary causes (Figure 25b).[135]

Figure 25a: Natural Gas Production Volumetric Outages by Primary Basin, Before Event (February 5)[136]



[135] Figure 25a is a baseline, while Figures 38a, 39a, 48a, 49a and 50a are a time series showing how the unplanned natural gas production outages grew during the Event. The purpose of the time series is to give a sense of how widespread the outages were, and how they worsened over time.
[136] All outage events smaller than 1 million cubic feet (MMCF) are excluded from figure.

Figure 25b: Natural Gas Production Volumetric Outages by Cause, Before Event (February 5)



Processing. Natural gas processing facilities' preparations focused on electric power supply, equipment and maintenance, and personnel. Measures taken to protect electric power supply included obtaining and maintaining backup generation for gas control centers and some critical facilities.[137] Equipment and maintenance measures included performing maintenance before the cold weather season, ensuring an adequate supply of methanol (which addresses hydrates in pipes) and critical spare parts. Personnel measures included confirming personnel availability to respond to equipment failures or other plant issues, holding daily operational update meetings, and coordinating with producers, customers and purchasers of the residue gas produced by the plant.

Pipelines. Preparation for the Event started in early February. Pipelines implemented severe/winter weather procedures to ensure the safety and integrity of their systems and many pipelines issued operational flow orders (OFOs) notifying shippers about the winter weather and the need to remain in balance.[138] Pipelines prepared for power outages and maintained appropriate levels of line pack. Before the Event, some ran prospective storage activity reports daily, or more

[137] Backup generators were only capable of providing small amounts of power and were not capable of powering an entire processing facility. Sixteen out of 50 processing plants that responded had some form of alternative power source.
[138] In general terms, shipper imbalances occur when there is mismatch between a shipper's deliveries of natural gas into the pipeline and the natural gas the shipper takes off the pipeline.

frequently as needed, to forecast storage inventory and withdrawal requirements. Other pipeline preparations before the Event included: providing additional staffing at critical field operations, including key delivery stations, compressor stations and storage fields; testing emergency generators before the event to avoid any power interruptions; staging spare batteries at meter stations; verifying that heated stands were properly functioning to prevent meter stations from freezing; testing operating plans for power outages and SCADA[139] system failure; performing proactive pressure adjustments and plate changes to stations expected to be heavily impacted; increasing communication among and within the various pipeline entities; and increasing monitoring of receipt and delivery flows.

6. Coordination in Advance of the Severe Cold Weather

a. Coordination Between Reliability Coordinators

SPP and MISO RCs began coordination on February 8. SPP and MISO exchanged information regarding transmission and generation capacity challenges. Communication between SPP and MISO RC system operator desks remained constant in real time and involved discussions of energy emergencies and coordination of transmission congestion, with real-time feedback from and to management as necessary (e.g., timing of Transmission Loading Relief (TLR) issuances, assistance to ERCOT).

Coordination between SPP and ERCOT RCs began on February 12, and covered issues related to switchable generating units, the fuel supply for those units, DC tie curtailments and restoration of interchange schedules. Switchable generation resources may or may not be physically located inside ERCOT, but are interconnected to, and registered to participate in, the ERCOT market as well as SPP's market. SPP and ERCOT coordinated on dispatching the switchable units as appropriate, given the existing system emergencies. ERCOT requested emergency assistance through the DC ties from SPP; however, because SPP was also experiencing EEAs at times, it could not provide emergency assistance. SPP did allow the switchable resources to be released into ERCOT even though SPP was in EEA 2, because SPP had a relatively lower risk of load shed than ERCOT, which was already in EEA 3 and ordering firm load shed.

The RCs used Reliability Coordinator Information System (RCIS) messages, including declarations of their respective EEAs and Transmission Emergencies, Interchange Distribution Calculator (IDC) TLR curtailments,[140] and telephone communications during the Event and discussed TLRs with other RC system operators over the phone. MISO and SPP held daily morning RC-to RC-calls to

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139 A Supervisory Control and Data Acquisition (SCADA) system operates via coded signals sent over communication channels to remote stations to monitor and provide control of remote equipment.

140 A Reliability Coordinator is the only entity authorized to initiate the TLR procedure and shall do so at its own request or upon the request of a Transmission Operator. A Reliability Coordinator may use the TLR procedure to mitigate potential or existing System Operating Limit (SOL) violations or to prevent Interconnection Reliability Operating Limit (IROL) violations on any transmission facility modeled in the IDC. *See* https://www.nerc.com/pa/rrm/TLR/Pages/TLR-Levels.aspx for more details regarding the TLR levels and associated Reliability Coordinator actions.

discuss operational awareness updates. Overall, the three RCs maintained good communication with each other as necessary to preserve reliability.

b. Natural Gas – Electric Coordination

BAs gathering natural gas supply information: MISO and ERCOT send out a fuel survey to GOPs each winter. SPP does not perform an annual survey but a biannual one, which was last performed in 2019, and it did not perform one before the 2020/2021 winter.[141] ERCOT, MISO and SPP all have some sort of system to monitor fuel supplies. MISO has a procedure for using natural gas pipeline critical notices and other information for situational awareness. Among other tools it prepares a generator fuel impact report, pipeline-generator overview map, and a daily gas outage report. MISO also requires GOPs to modify their day-ahead or real-time offers if affected by natural gas pipeline critical notices. ERCOT requires QSEs to submit and maintain a Current Operating Plan (COP).[142] If generating units are impacted by fuel supplies, in addition to updating their COPs, ERCOT also requires QSEs to submit outages or de-rates in the ERCOT Outage Scheduler.

While in conservative operations conditions on February 11, SPP received critical notices such as OFOs for the upcoming week beginning February 15. MISO had only three ongoing EBB notices on the Enable, Mississippi River Transmission, and Texas Eastern Transmission pipelines in January. Beginning the first week of February, the number of natural gas pipeline critical notices posted began to increase because of shipper imbalances (caused by natural gas production declines and the cold weather). Additionally, on February 4, generation outages reported to MISO with the cause "fuel transportation/supply issues" increased from 7 MW to 1,502 MW.

ERCOT received an email from Atmos-Pipeline Texas on February 10, stating that beginning February 12, there would be Level 4 restrictions on gas supply, meaning that generating units supplied by Atmos would be cut off completely. ERCOT also received multiple notifications and instructions regarding potential fuel supply issues from its QSEs beginning on February 8.

SPP and Southern Star had been communicating directly with each other since February 9. Other pipelines and BAs/RCs in the Event Area did not communicate directly on a regular basis before or during the Event. BAs and RCs generally relied on FERC-mandated interstate pipeline EBB information but had less visibility when relying on intrastate pipelines.

Natural gas infrastructure designation as critical/demand response: Generally, natural gas infrastructure facilities engaged in little coordination with their electric power providers prior to the Event. For instance, there was little coordination as to critical load designation and demand response programs. Natural gas infrastructure facilities vary significantly in their reliance on grid

[141] SPP will now perform annual fuel surveys.

[142] Current Operating Plan (COP) - A plan by a Qualified Scheduling Entity (QSE) reflecting anticipated operating conditions for each of the Resources that it represents for each hour in the next seven Operating Days, including Resource operational data, Resource Status, and Ancillary Service Schedule. *See* ERCOT Nodal Protocols, Section 2: Definitions and Acronyms (September 2021) - http://www.ercot.com/content/wcm/current_guides/53528/02-090121_Nodal.docx

power, use of onsite generation or alternative power sources, and the impact a loss of power would have on operations.

There was minimal gas-electric coordination between owners/operators of natural gas production facilities and their electric suppliers with respect to critical load designation. Responding entities' production facilities vary, both in scope of operating facilities and power needs. Some producers only own and operate wellheads and associated equipment. Some producers own and operate gathering systems/facilities, and/or saltwater disposal wells, which require power to maintain operations. Power requirements for natural gas production facilities may include the need for power to run operating equipment (e.g., artificial lifts, pumps, compressors, etc.) and "control power" to run instrumentation, control, communication and/or electronics equipment, the latter of which is typically powered by onsite solar or wind, backed by batteries. To the extent that a natural gas production facility used grid power, none of the natural gas production facilities identified their facilities as critical load prior to the Event. Only one natural gas production facility participated in a demand response/load as a resource program, and it chose wells that had low production volumes but large electric demand.

Natural gas processing facilities, while more engaged with their electric power providers, still had room for improvement. Eight percent of the sampled processing plants reported being designated as critical load prior to the Event, and during the Event, at least two more processing facilities attempted to obtain critical load designation to aid in power restoration. As with production facilities, processing facilities' energy demands, and back-up generation availability vary. Among the pipelines sampled by the Team, 10 of 32 indicated that one or more of their facilities had been designated as critical loads prior to the Event, but after the Event, 19 intended to update or initiate critical load designation with their local distribution utilities. Many pipeline facilities also have backup power sources, such as diesel back-up generators, for control centers, and solar panels for meter stations.

ISO-New England: Case Study in Gas-Electric Coordination

Given recent industry retirements of coal, oil, and nuclear generating units, ISO New England's (ISO-NE's) resource fleet increasingly relied on a constrained regional natural gas infrastructure, designed, and built primarily to support local gas distribution load. Given its reliance and dependence on the natural gas system, over the course of many years ISO-NE personnel have established procedures and developed tools and processes, all of which are constantly reviewed and evaluated for improvement.

A primary goal of ISO-NE gas-electric coordination operations has been to enhance situational awareness. Aided by Order No. 787,[143] ISO-NE has established unfettered communication and information exchange between ISO-NE operating personnel and regional interstate natural gas pipeline operators. ISO-NE and the

[143] Order No. 787, November 15, 2013 (https://www.ferc.gov/sites/default/files/2020-06/RM13-17-000_0.pdf) "amends the Commission's regulations to provide explicit authority to interstate natural gas pipelines and public utilities that own, operate, or control facilities used for the transmission of electric energy in interstate commerce to share non-public, operational information with each other for the purpose of promoting reliable service or operational planning on either the public utility's or pipeline's system."

interstate pipelines on which it relies share information through regular, non-emergency, communications based on established processes for both gas and electric system reliability needs.[144] For example, ISO-NE will email expected electric sector gas consumption hourly load profiles to the interstate natural gas pipelines. Pipeline operators, having been given generator burn profiles ("burn rates") and the generating units' required amount of gas nominations, based on MW commitments, are able to notify ISO-NE system operators when scheduled generating units have not secured or nominated adequate gas capacity.

ISO-NE control room personnel have established and maintained relationships with regional interstate pipeline control rooms through constant, daily interaction to achieve a high level of communication and understanding among gas and electric operators. ISO-NE control room personnel communicate daily with their contacts for the generating units to discuss fuel plans and other pertinent operational information.[145]

ISO-NE management established relationships and communication protocols with the New England states' governors and Federal and local representatives. These relationships and communications provide familiarity and coordination when the ISO needs to initiate customer appeals and demand management actions. ISO-NE holds semi-annual, pre-seasonal training/outreach activities with market participants and regional regulators, including environmental air regulators, to preview anticipated conditions and available emergency actions; highlight shared responsibilities; and enhance understanding of roles during system emergencies. ISO-NE staff have developed specialized situational awareness tools, in recognition of the fact that on some constrained days they may be operating on a very narrow margin. The Gas Utilization Tool (GUT) (see Figure 26, below, for a screen shot), developed in-house by ISO-NE staff, allows ISO-NE operations personnel to monitor the New England regional interstate pipeline system and provides real-time gas-electric system interface situational awareness by incorporating publicly-available interstate pipeline EBB data, gas schedules for individual generating units (nominations and long/short positions) and other pertinent information. This data is converted into an operator-friendly display (located on the ISO-NE control room floor), which allows for improved situational awareness and seamless access to actionable information. ISO-NE employed individuals with gas sector experience to

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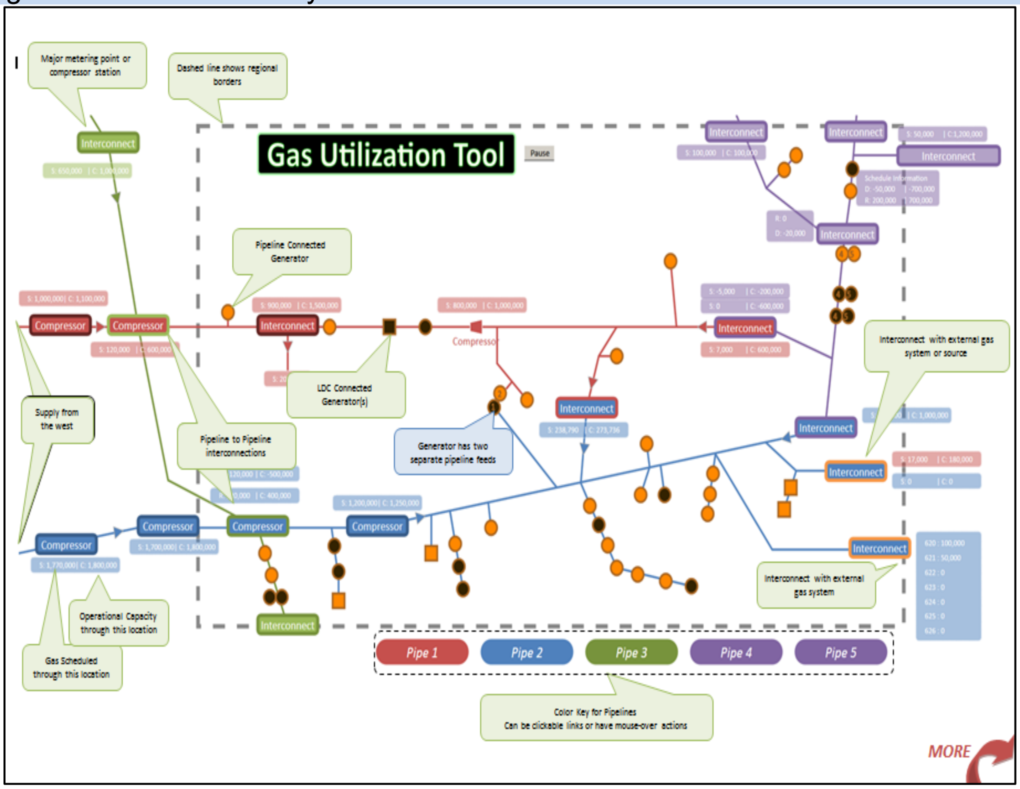
144 OP-21, Appendix B - Electric/Gas Operations Committee's (EGOC) Operations Communications Protocol, https://www.iso-ne.com/static-assets/documents/2014/08/op21b_rto_final.pdf

145 Information obtained from fuel plans and results of fuel surveys allows for an enhanced awareness of the fuel inventories (estimated number of days each generator is able to run at a specific level) and emissions limitations of the region's generation fleet, and are used in the operations planning processes, as well as in real-time operations, as necessary. In addition to the enhanced situation awareness of ISO-NE operators, fuel surveys inform the ISO New England Operating Procedure No. 21 - Operational Surveys, Energy Forecasting & Reporting and Actions During an Energy Emergency process, which in turn provides public alerts to market participants and regional stakeholders, as well as Federal and Regional (ISO-NE States) regulators and officials.

gather and interpret this data with the purpose of improving situational awareness for ISO-NE operations, which led to the development of the GUT.

Figure 26: Natural Gas System Visualization Tool – GUT[146]



ISO-NE's natural gas-fired generating units are very dependent on the regional liquid natural gas (LNG) facilities, so ISO-NE also actively monitors LNG tankers shipments and traffic, using the Marine Traffic website,[147] to anticipate fuel availability and adjust operating plans. ISO-NE operators have learned to understand the relationships between LNG tanker traffic and fuel availability for ISO-NE's generation fleet over several years of continuous monitoring and real-time operations experience.

To anticipate and prepare for potential energy adequacy issues, ISO-NE developed Operating Procedure No. 21 – Operational Surveys, Energy Forecasting & Reporting and Actions During an Energy Emergency (OP-21).[148] In addition to the specific Generator Winter Readiness Survey requirements, OP-21 establishes procedures for forecasting and declaring Energy Alerts and Energy Emergencies

[146] NERC Natural Gas and Electrical Operational Coordination Considerations Reliability Guideline, https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Gas_Electric_Guideline.pdf.
[147] MarineTraffic: Global Ship Tracking Intelligence | AIS Marine Traffic , which among other features, has a live map showing the location of global merchant shipping, based on satellite and other data.
[148] https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op21/op21_rto_final.pdf

based on a 21-day hourly look ahead at expected energy availability. ISO-NE Energy forecasting and reporting incorporates data from the Generator Fuel and Emissions Surveys, conducted weekly in the winter months and bi-weekly in non-winter months, with increased frequency, as necessary. OP-21 includes established thresholds (e.g., FMLCC2,[149] FEEA1 through FEEA3[150]) to communicate potential reliability issues to regional stakeholders; specific criteria to trigger Alert[151] and Emergency[152] declarations and associated actions by the ISO, TOPs' Local Control Centers (LCCs) and contacts for the generating units, intended to help mitigate emergencies. Through the requirements laid out in OP-21, ISO-NE takes an active coordinating role in ensuring that critical infrastructure of the interstate natural gas pipeline system is not served by electrical transmission or distribution circuits that may be subject to automatic or manual load shedding schemes. Through the requirements laid out in OP-21, ISO-NE takes an active coordinating role in ensuring that critical infrastructure of the interstate natural gas pipeline system is not served by electrical transmission or distribution circuits that may be subject to automatic or manual load shedding schemes. ISO-NE facilitates the exchange of pertinent information through sharing the results of the annual Natural Gas Critical Infrastructure Survey of each interstate natural gas pipeline company operating within New England, and LNG facilities serving the region, with New England's LCCs for their review of load shedding plans. ISO-NE also takes actions to ensure that dual-fuel resources will be able to perform when needed, including unit testing and assessment of alternate fuel availability.[153]

[149] Available resources for any hour during the 21-day forecast are expected to be less than 200 MW above those required to meet Operating Reserve requirements. Every hour during the 21-day forecast must be designated either "normal" or one of the thresholds.

[150] Available Resources during any hour of the Operating Day are forecasted to be less than those required to meet Operating Reserve requirements, and implementation of OP-4 Actions 1 through 5 (FEEA1), OP-4 Actions 6 through 11 (FEEA2), or OP-7, firm load shed (FEEA3), is being forecasted.

[151] Example of an Energy Alert Declaration Criteria: "FEEA2 or FEEA3 is forecasted to occur in at least 1 hour on 1 or more consecutive days in days 6 through 21 of the 21-day energy assessment."

[152] Example of an Energy Alert Emergency Criteria: "FEEA2 or FEEA3 is forecasted to occur in at least 1 hour on 1 or more consecutive days in days 1 through 5 of the 21-day energy assessment," or "Shedding of firm load under OP-7 is occurring or is anticipated to occur due to an actual energy deficiency resulting from a sustained shortage of fuel availability or deliverability to, or sustained environmental limitations on some or several of New England Resources."

[153] *See*, *e.g.,* Oil-Depletion and Usable-Oil Inventory Graphs https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/oil-depletion-graphs.

B. February 8-13: Freezing Precipitation and Temperatures Begin to Fall, Causing Generation Outages; Weather Expected to Worsen Next Week

- *Temperatures and Freezing Precipitation Begin to Fall*
- *Electricity Demands Increase*
- *Unplanned Generation Outages Increase*
- *Natural Gas Production Declines*
- *Weather Expected to Worsen Next Week*

Unlike an event where a disturbance on the BES occurs over a matter of a few minutes,[154] the Event spanned many days. The Event, characterized by an unanticipated and intolerable number of unplanned outages of BES generation during peak winter load conditions, actually started during the week of February 7, 2021 as ambient temperatures began to drop below 32 degrees in ERCOT, MISO, and SPP.

1. Event Area Cold Weather Conditions – February 8 – 13

While the northern areas of both SPP and MISO were already experiencing colder temperatures, in southern SPP, the leading edge of an arctic air mass moved through northeast Oklahoma into central Oklahoma during the pre-dawn hours on Monday, February 8. Sub-freezing temperatures with freezing drizzle began across parts of western Oklahoma into Oklahoma City at 7 a.m. on the morning of February 8.[155] The cold air slowly moved across the rest of the state by Wednesday, February 10. The cold air remained in place statewide through the weekend of February 13 –15.

In ERCOT, the arctic air likewise moved into north Texas during the pre-dawn hours on Monday, February 8. On this day, the ERCOT meteorologist began to understand that the next week's weather could be extremely cold, writing "[t]his is the most challenging, worrisome forecast since I joined ERCOT," and comparing the expected polar vortex disruption to the 1989 and 2011 storms, both of which caused thousands of MW of unplanned generation outages in ERCOT.[156] The cold air slowly moved into northern and central Texas by Wednesday, February 10. The Dallas-Fort Worth area experienced freezing rain on the evening of Wednesday, February 10, into Thursday, February 11. By the evening of February 11, the cold air had pushed into the entire state of Texas, and freezing rain and sleet reached almost as far south as San Antonio. The cold air remained entrenched statewide from Friday, February 12, through the weekend. On Saturday, February 13,

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[154] Arizona-Southern California Outages on September 8, 2011 Causes and Recommendations) https://www.ferc.gov/sites/default/files/2020-07/Arizona-SouthernCaliforniaOutagesonSeptember8-2011.pdf

[155] Source: National Oceanic and Atmospheric Administration NATIONAL WEATHER SERVICE SOUTHERN REGION "*Oklahoma Winter Storm and Arctic Outbreak of February 10th-19th, 2021*" (February 20, 2021) (data provided by NOAA Team members).

[156] UT Report at 92, *see also* Figure 11, above and 2011 Report at 172-179.

there were a few reports of light freezing rain near Dallas, with widespread light freezing rain near Austin and San Antonio, and even to the coast between Houston and Corpus Christi.[157]

In MISO South, the arctic air mass moved into northern Arkansas on Wednesday, February 10, approximately two days after it reached ERCOT and SPP. Ice storm warnings and winter weather advisories went into effect that evening through February 11 for freezing rain and sleet. Roads became hazardous from near Little Rock eastward, and the most intense areas of frozen precipitation led to power outages. At least half an inch of sleet piled up roughly halfway between Little Rock and Memphis, at the Little Rock Air Force Base, and at Sherwood, in the center of the state. Freezing drizzle was also reported across southern Arkansas on the morning of February 12. The cold air remained in place statewide for the next several days.[158] The cold front moved through the state of Louisiana on late Wednesday, February 10 into Thursday, February 11. Cooler air rushed southward into Louisiana and resulted in a light icing on February 12. The cold front moved southeast across the state of Mississippi during the early morning hours on Thursday, February 11. Along with the colder temperatures, an initial wave of precipitation in the form of freezing rain occurred across northwestern parts of Mississippi during the morning of February 11.[159] Northwestern Mississippi received up to a quarter inch of freezing rain, which caused trees and power lines to sag under the weight of the ice. A minor freezing rain event hit northeastern Mississippi on February 13, with accumulations of less than a tenth of an inch.[160]

2. Electricity Demands and Energy Needs Increase

As the weather turned colder, the demand for electricity in each of the BA footprints increased during the week of February 7. Figure 27, below, shows how system demands increased as a percentage of each BA's all-time previous winter peak loads in the Event Area.

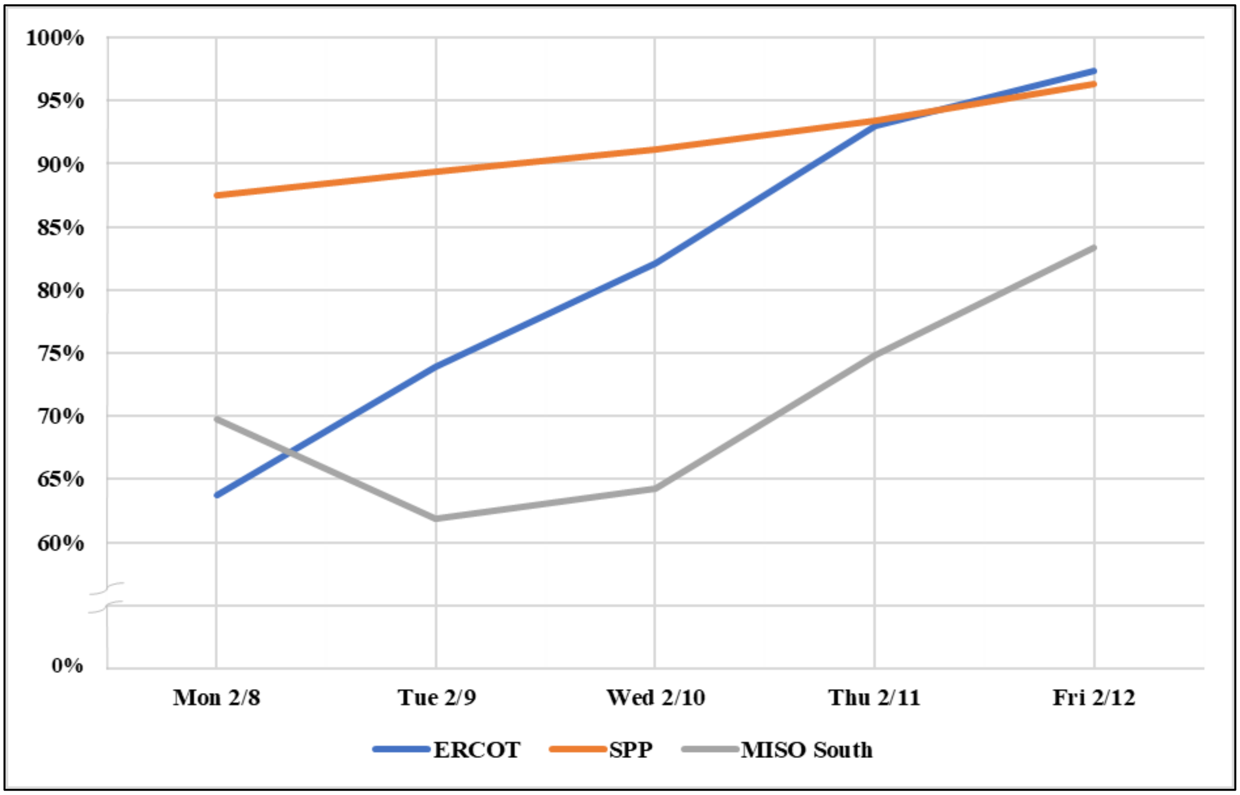
157 Source: National Oceanic and Atmospheric Administration NATIONAL WEATHER SERVICE SOUTHERN REGION "Texas Winter Storm and Arctic Outbreak of February 10-19th, 2021" (February 19, 2021) (data provided by NOAA Team members).

158 Source: National Oceanic and Atmospheric Administration NATIONAL WEATHER SERVICE SOUTHERN REGION *"Arkansas Winter Storm and Arctic Outbreak of February 10th- 20th, 2021"* (February 26, 2021) (data provided by NOAA Team members).

159 Source: National Oceanic and Atmospheric Administration NATIONAL WEATHER SERVICE SOUTHERN REGION "*Louisiana Winter Storm and Arctic Outbreak of February 10th-19th, 2021*" (February 22, 2021) (data provided by NOAA Team members).

160 Source: National Oceanic and Atmospheric Administration NATIONAL WEATHER SERVICE SOUTHERN REGION "*Mississippi Winter Storm and Arctic Outbreak - February 11th-19th, 2021*" (February 24, 2021) (data provided by NOAA Team members).

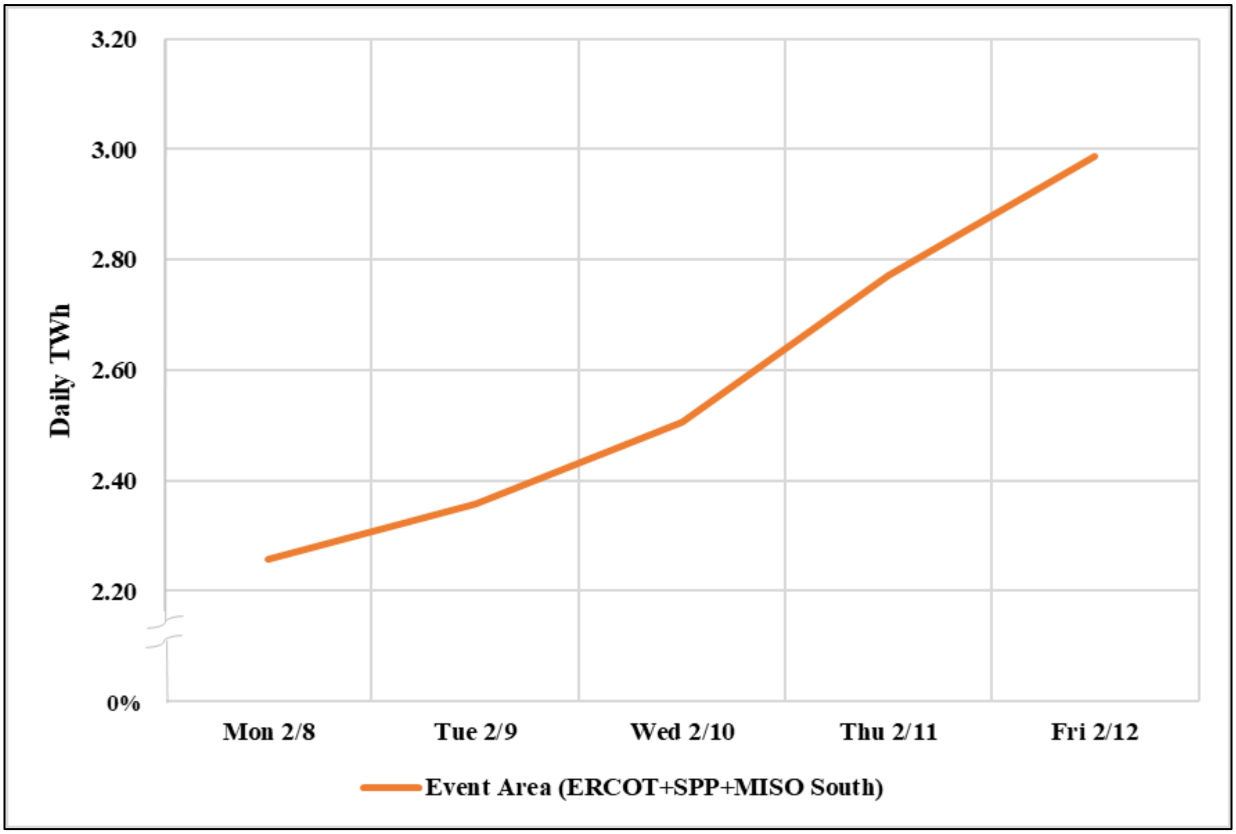
Figure 27: Mon-Fri, February 8-12: ERCOT, SPP and MISO South Daily Peak System Loads as Percentage of All-Time Previous Winter Peak Loads



By Thursday, February 11, ERCOT's and SPP's peak loads had already exceeded well over 90 percent of their previous winter peak loads. By Friday, February 12, both had exceeded 95 percent of their previous winter peak loads.[161] The combined energy needs for the Event Area increased by 32 percent, or nearly a third, from Monday to Friday, as shown in Figure 28 below.

[161] Both ERCOT and SPP previously reached all-time winter peaks of 65,750 MW and 43,584 MW, respectively, on January 17, 2018.

Figure 28: Mon-Fri, February 8-12: Increase in Energy Needs in the Event Area[162]



3. Colder Temperatures and Freezing Precipitation Begin to Impact Electric and Natural Gas Infrastructure

The below-freezing temperatures and freezing precipitation that moved into Oklahoma and Texas during the week of February 7 substantially decreased generating unit availability. Some of those generating units remained out of service and contributed to generation shortfalls during the week of February 14, when the winter peak load conditions and firm load shed occurred. See Figure 66b, below.

a. Generating Unit Freezing Issues – February 8 – 13

i. Wind Turbine Generator Freezing Issues

Wind turbine generators were the largest share of individual generating units that suffered freezing issues from February 8 to 10. Precipitation and condensation during cold weather can cause layers

[162] In Terawatt-hours (equal to 1,000 GWh).

of ice to form on turbine blades, causing balancing, bearing, and other equipment problems. Blade icing caused outages, derates or failures to start in southern SPP on February 8 and 9 (shown in Figures 29 and 30, below), followed by ERCOT on February 10 (shown in Figures 31 and 32, below). From approximately February 8 at 3:15 a.m. to February 9 at 4:15 a.m., 102 distinct generating units in SPP experienced a total of 123 generating unit outages, derates or failures to start; ice build-up on the turbine blades caused 48 outages or derates at 41 wind facilities, while temperatures below turbine operating limits causing seven derates at four wind facilities (see Figure 31, below). Cold weather-related issues affecting wind generating units accounted for 6,810 MW (nameplate), or 52 percent of the outaged generation during this period.

Figure 29: SPP Generation Outages and Derates (MW) by Cause, Wind Generating Units, February 8, 3:15 a.m. - February 9, 4:15 a.m.

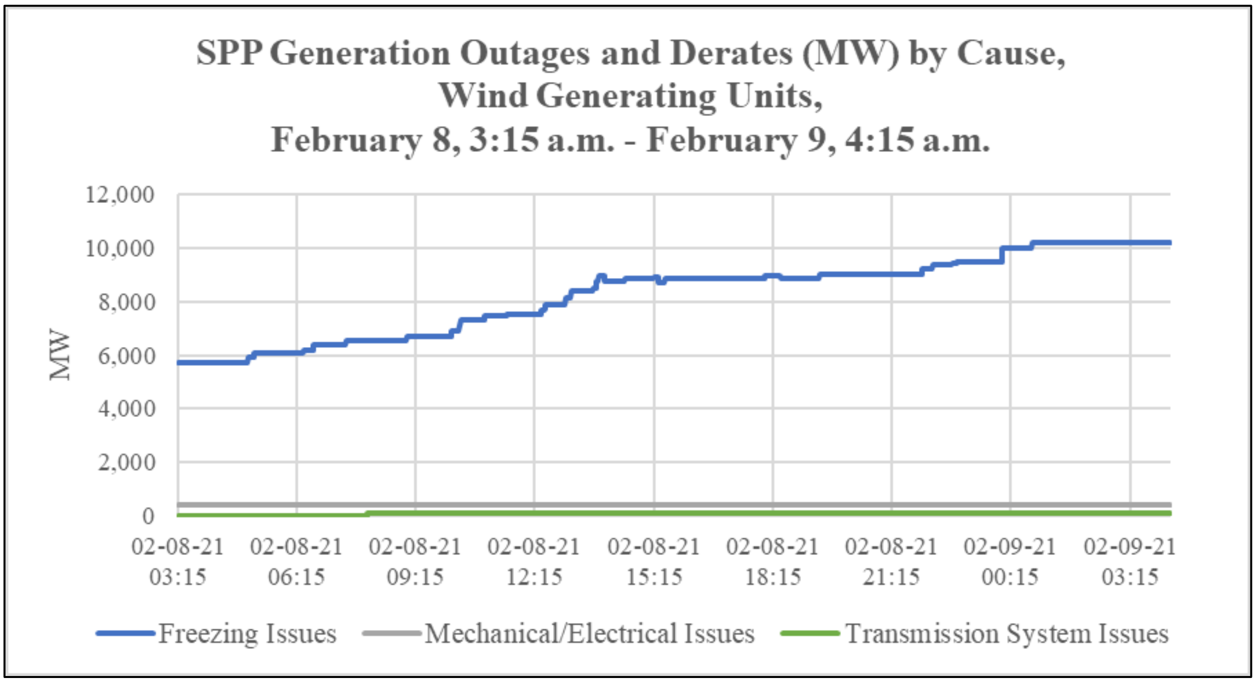
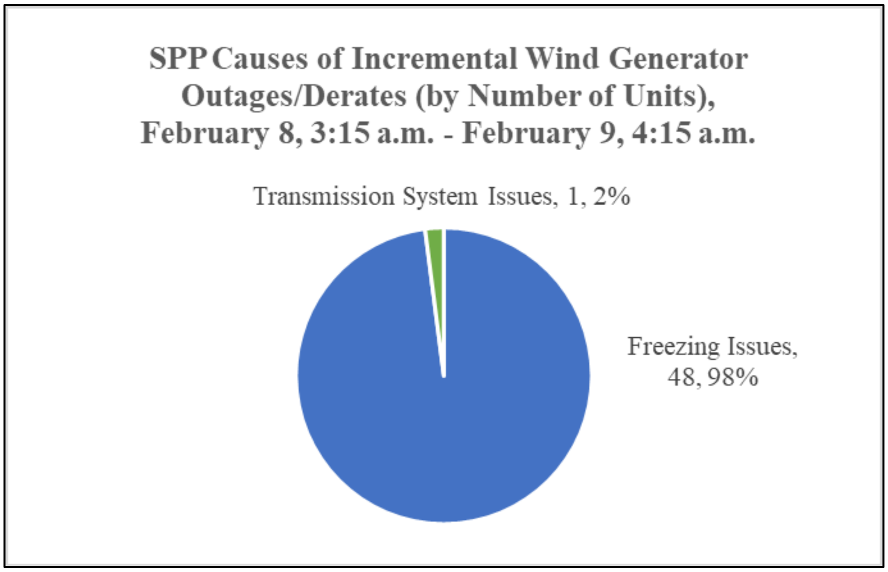
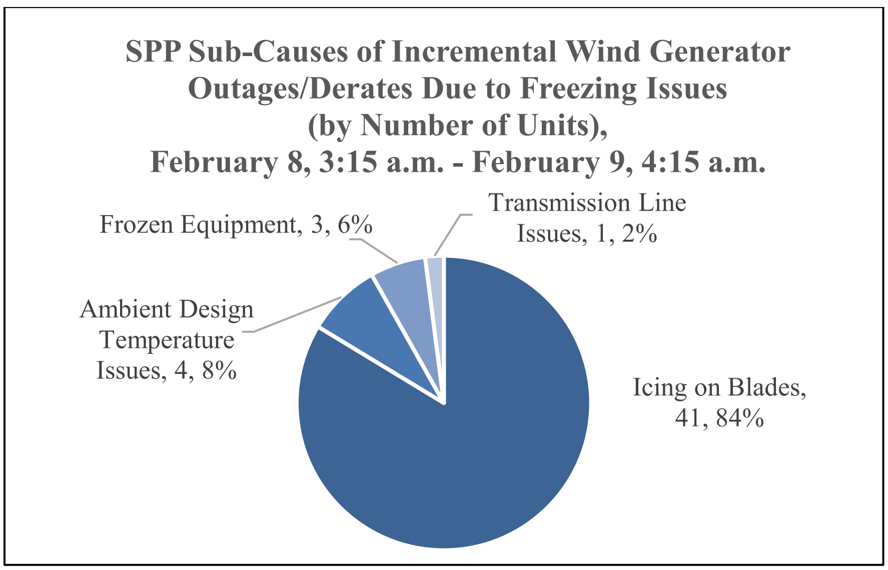


Figure 30: SPP Footprint: Wind Generator Outage and Derate Causes





In ERCOT, beginning at around midnight on February 10, 89 individual generating units experienced 107 outages, derates, and failures to start, 72 percent of which were wind (totaling 8,900 MW (nameplate)). Essentially all of the wind outages were due to icing on blades (see Figure 32, below). At about 7:00 a.m. on February 10, the wind generation outages and derates escalated, particularly due to icing on the blades. For the ERCOT footprint, Figure 31, below illustrates the trend in increased wind generation outages, and Figures 31 and 32 show the causes of wind generation outages and derates.

Figure 31: ERCOT Generation Outages and Derates (MW) by Cause, Wind Generating Units, February 10, 12:00 a.m. – 2:30 p.m.

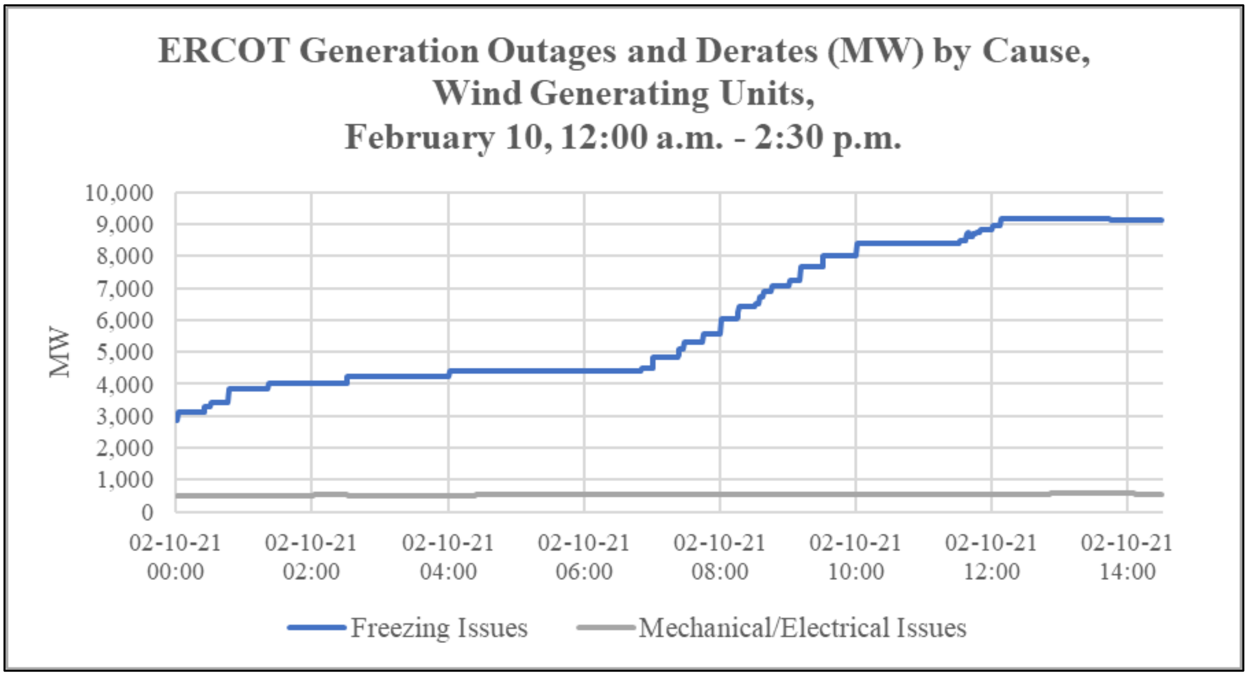
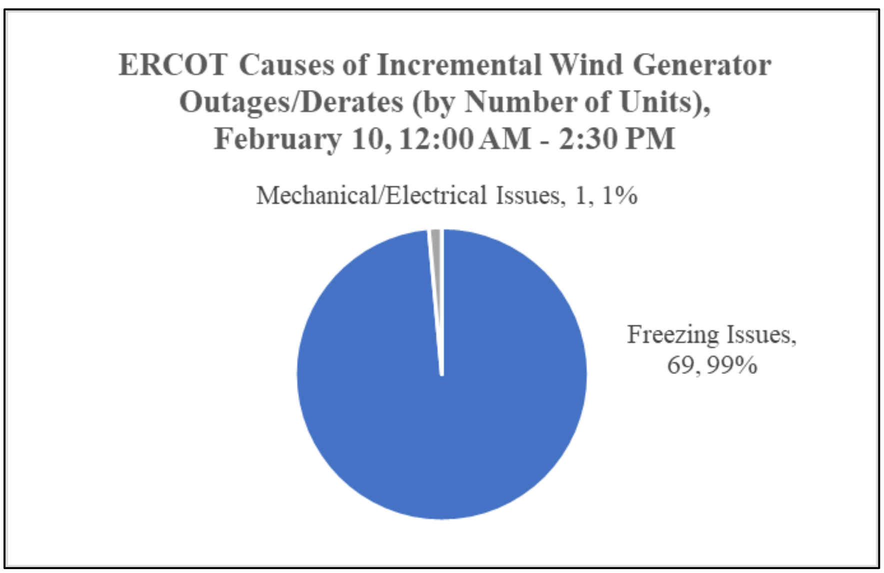
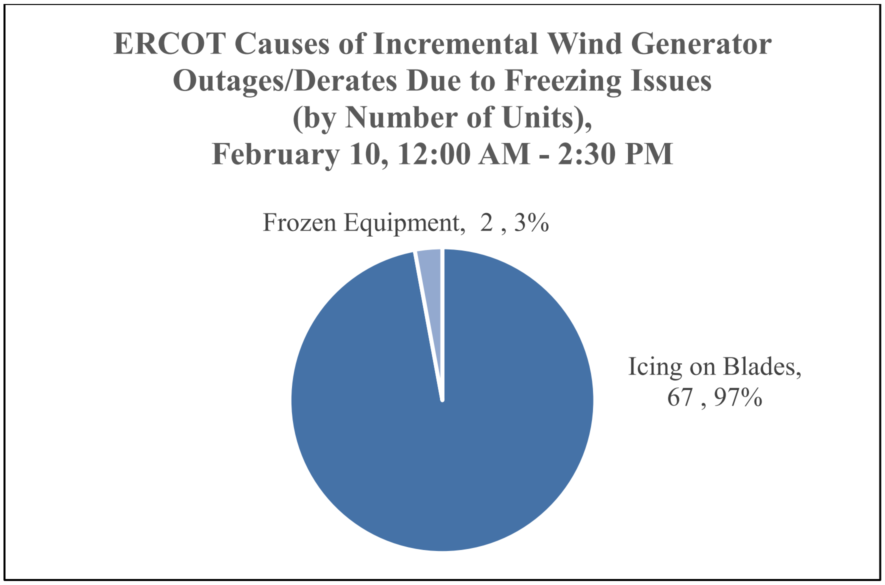


Figure 32: ERCOT Footprint: Wind Turbine-Generator Outage Causes





Figures 33 and 34 show the distribution of generation outages and derates in the Event Area on February 10 at 2:30 p.m., by cause and by fuel type, respectively.

Figure 33: Location of Unplanned Generation Outages and Derates (MW Outaged) by Cause, Total Event Area, February 10, 2:30 p.m.

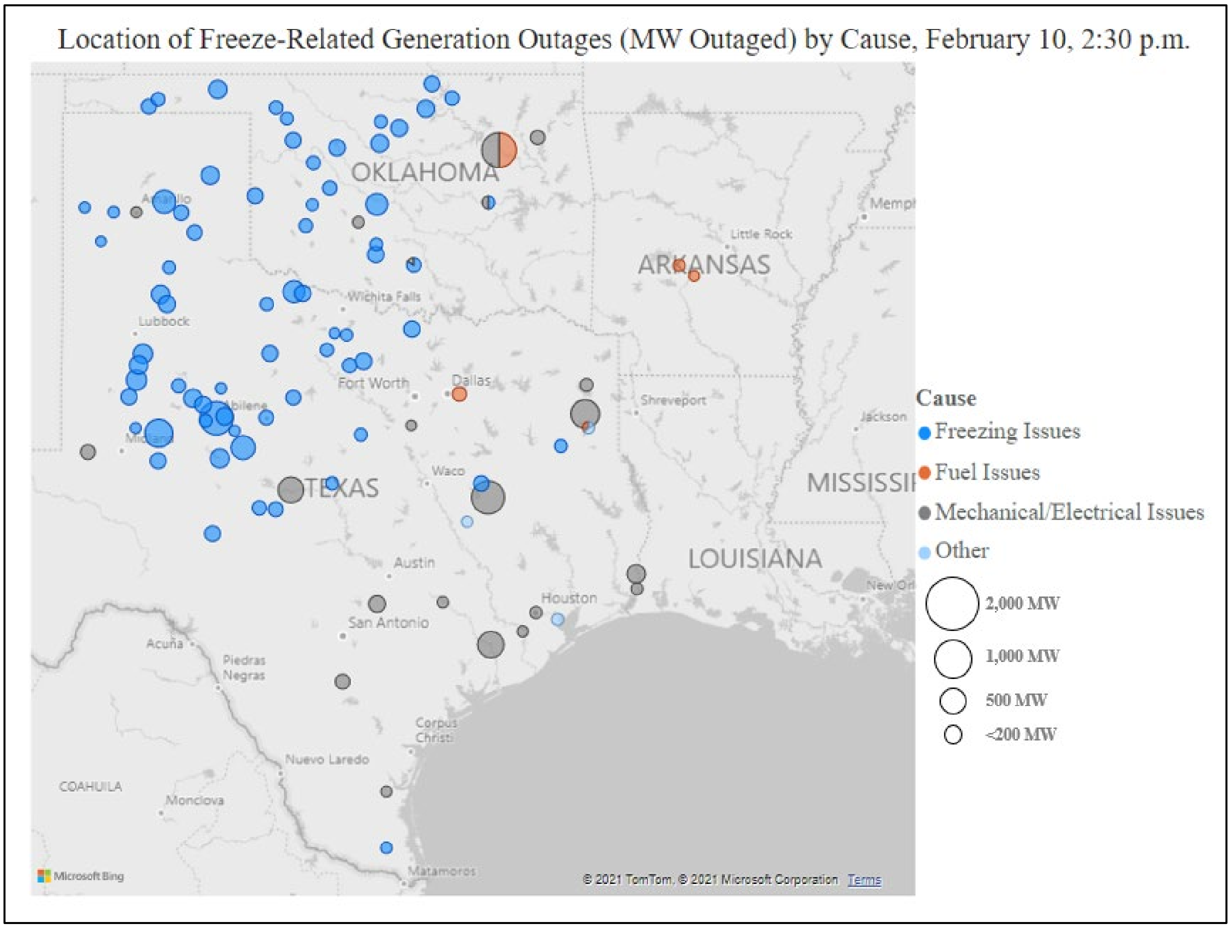
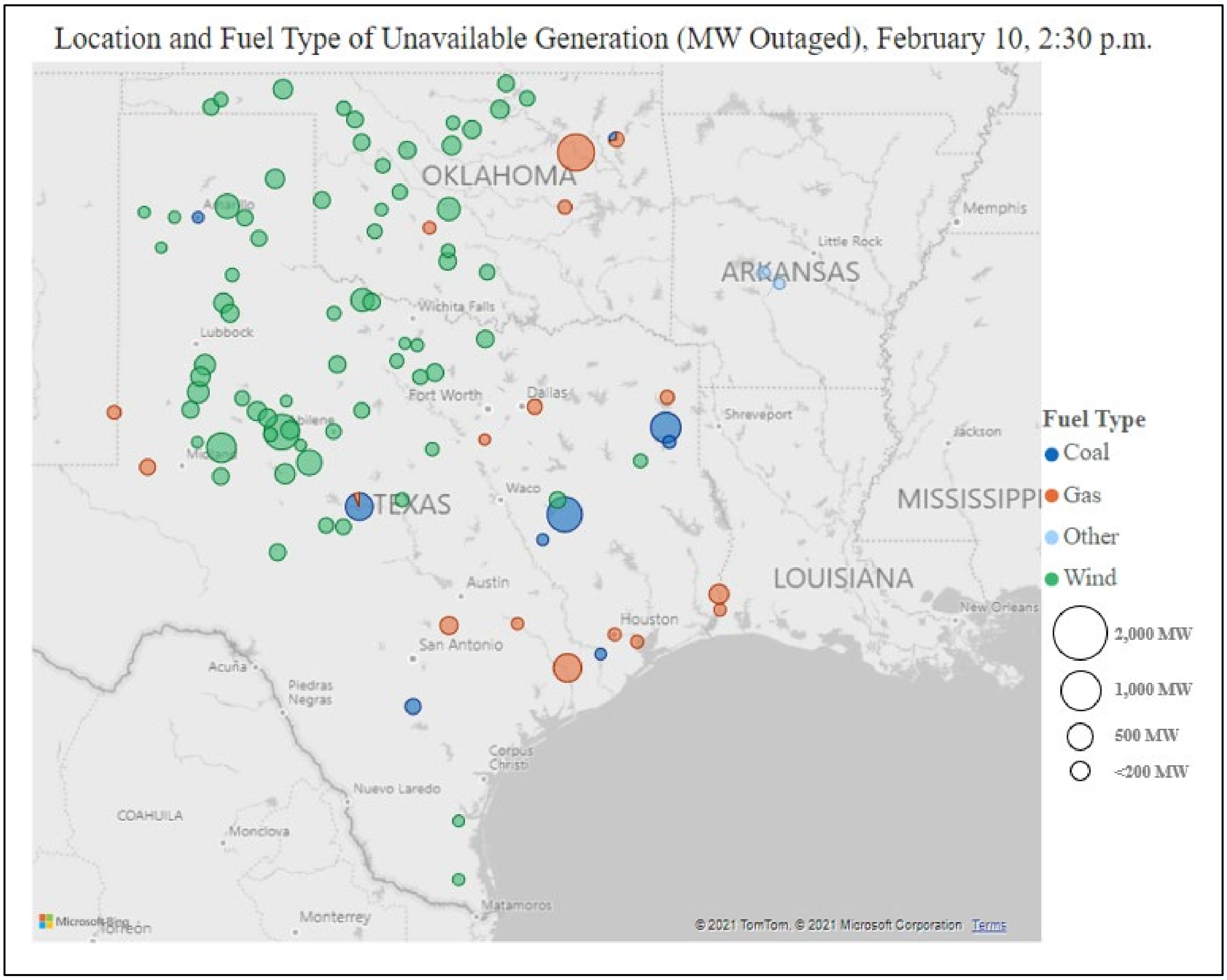


Figure 34: Location of Unplanned Generation Outages and Derates, (MW Outaged), by Fuel Type, Total Event Area, February 10, 2:30 p.m.



In ERCOT, the outaged wind generation remained offline until the ambient temperatures rose above freezing, allowing ice on the turbine blades to melt, which did not occur until late in the week of February 14.

ii. Other Types of Generator Freezing Issues

To a lesser degree, other types of generating units were also affected by freezing issues during the week of February 7. In SPP, primarily in the southern parts of Oklahoma, Kansas and Texas, natural gas, coal/lignite, and oil/distillate generating units experienced outages, derates, and failures to start. Frozen equipment, transmitters, sensing lines, valves, and inlet air systems all contributed to the freeze-related events. Outages due to freezing issues in natural gas, coal/lignite and oil/distillate generating units in SPP totaled 3,425 MW during the week of February 7. In addition to the generating unit outages directly attributed to freezing in SPP, all unplanned generating unit outages increased as temperatures decreased. In addition to the 3,425 MW, there were 3,680 MW of additional mechanical/electrical outages by the end the week of February 7. In ERCOT, during the week of February 7, natural gas-fired generators experienced outages, derates and failures to start due to freezing issues, with losses totaling approximately 4,722 MW, and mechanical/electrical outages increased by 4,675 MW by the end the week of February 7.

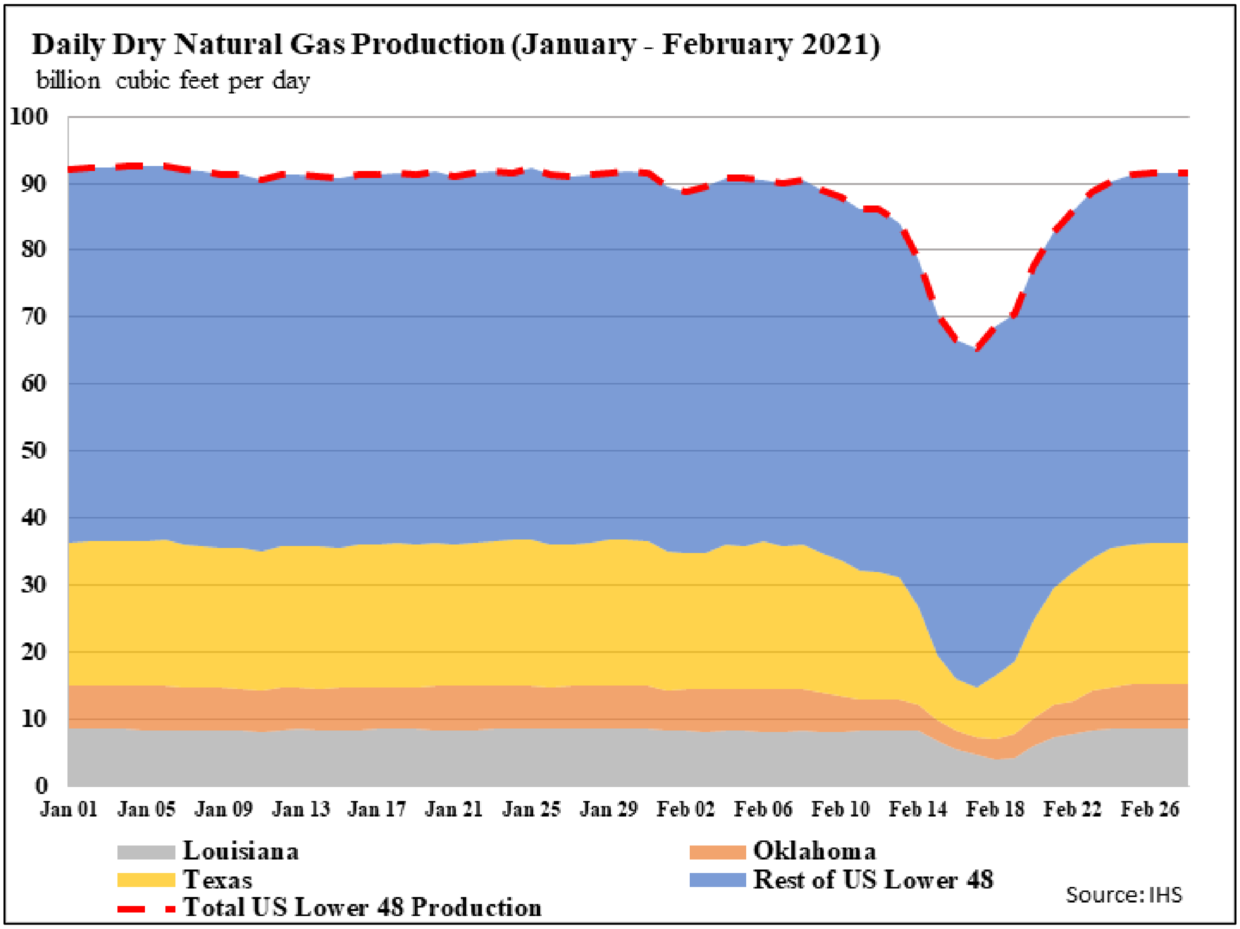
b. Natural Gas Production Cold Weather Issues - February 8 - 13

i. Natural Gas Production Declines Begin at Wellheads

Natural gas production in Texas, Oklahoma, and Louisiana was relatively flat or level from January 1, 2021 through February 7, 2021. During the Event, unplanned outages of natural gas wellheads due to freeze-related issues, loss of power and facility shut-ins to prevent imminent freezing issues, as well as unplanned outages of gathering and processing facilities, resulted in a decline of natural gas production. As shown in Figure 35, below,[163] production began to decline first in Oklahoma and Texas beginning on approximately February 7 and continued to decline as the week progressed.

[163] Figure 35 is based on raw data provided by IHS, from which the Team prepared the Figure.

Figure 35: Daily Dry Natural Gas Production (January - February 2021)



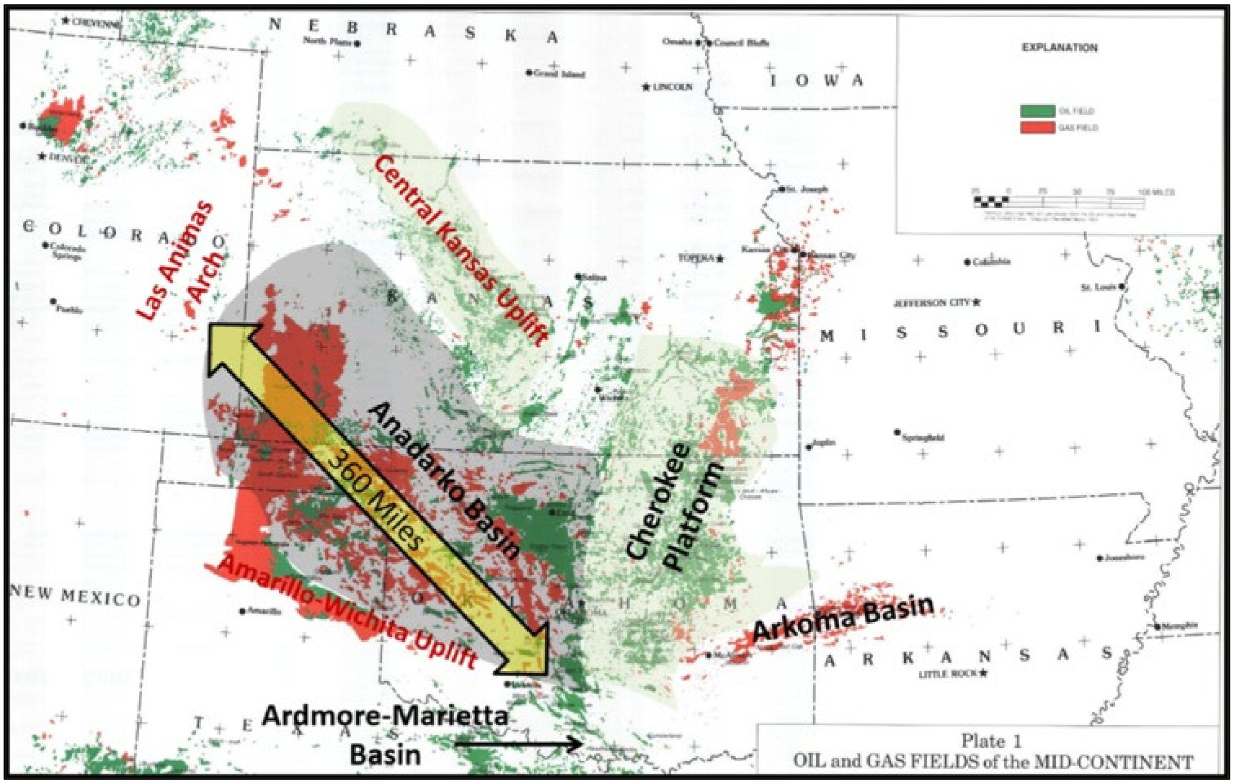
Before the severe cold weather began, available natural gas supply was sufficient to meet firm supply and transportation commitments. Some natural gas production facilities were out of service primarily due to mechanical/electrical problems. Most of these pre-existing (i.e., prior to February 8) natural gas production facility outages continued throughout the Event.

Any increased demands for natural gas, such as from residential heating needs or BES natural gas-fired generators, would need to be met by:

- increasing withdrawals from natural gas in storage during the Event,
- importing natural gas into the Event Area, or
- curtailing non-firm contract customers (e.g., generating units with non-firm transportation, interruptible industrial customers).

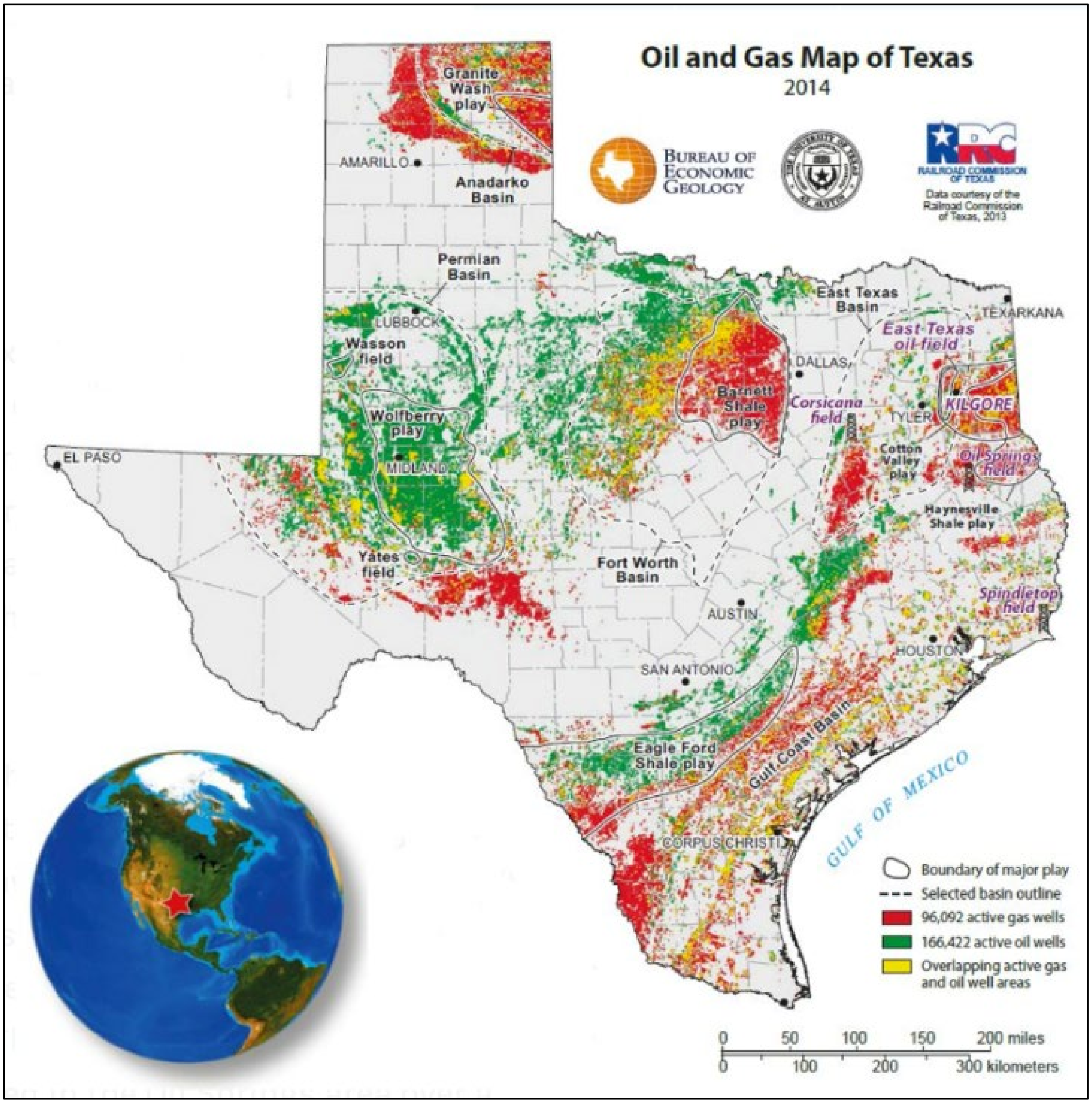
As shown in Figure 35, above, beginning on approximately February 7, as sub-freezing temperatures hit Oklahoma and Texas, home of the Anadarko, Permian and other important natural gas production basins (depicted in the following Figures 36 and 37), total natural gas production in the Event Area began to decline due to increased natural gas production facility impairments.

Figure 36: Anadarko and Arkoma Basins[164] Geographic Location



[164] Anadarko Basin, Rascoe & Hyne, 1988

Figure 37: Texas Basins[165] Geographic Location

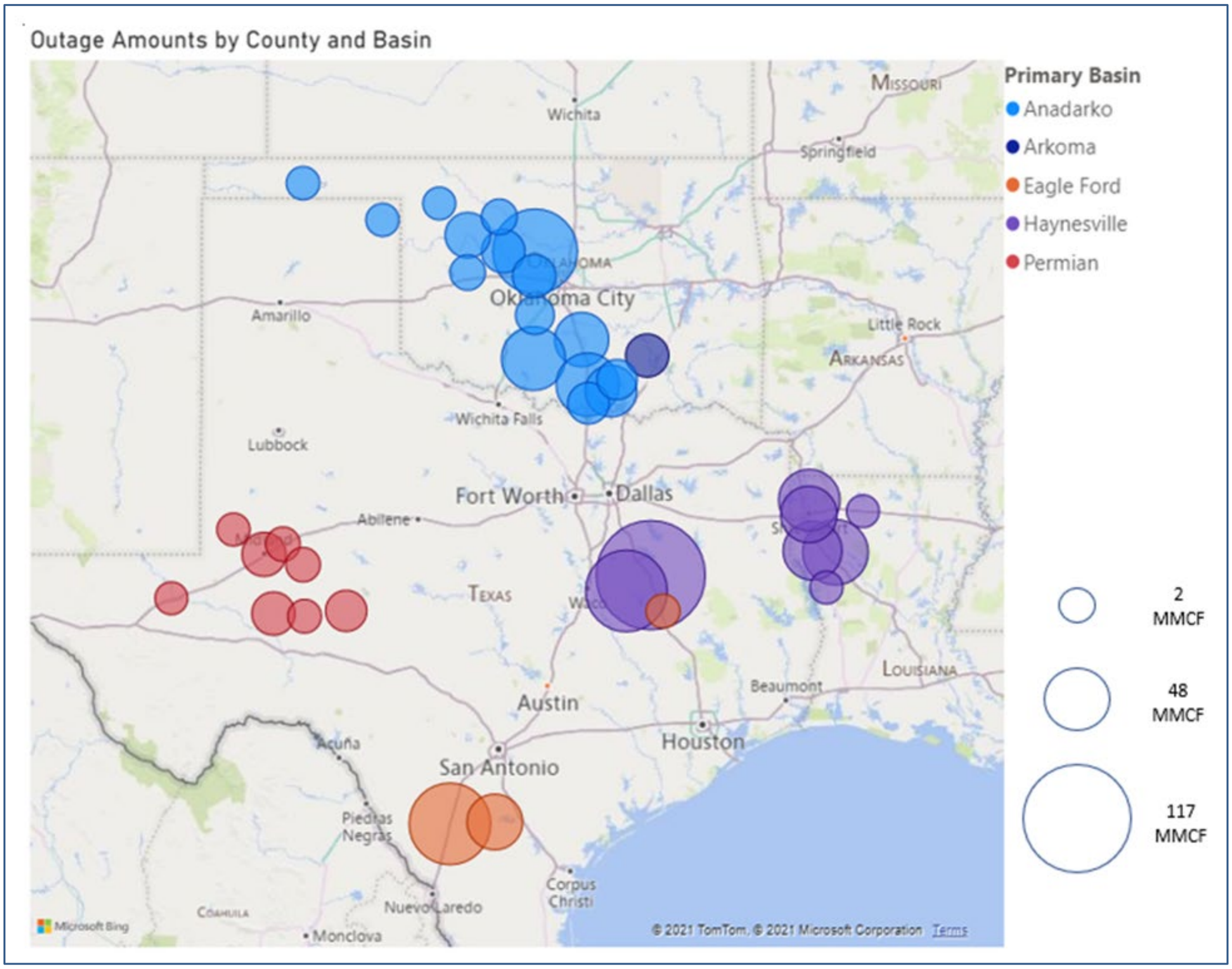


After February 7, natural gas pipeline data showed an increasing discrepancy between the amount of gas nominated and shipped, which resulted in increased pipeline critical notices to maintain pipeline system integrity. Figures 38a and 38b through 39a and 39b below show the locations and causes for producer outages on February 11 and 12 (again, the top figure in each pair shows the outages by

165 Anadarko Basin, Rascoe & Hyne, 1988.

basin, while the bottom figure shows the causes as provided by the sampled producers), which can be compared with the baseline of February 5 in Figure 25a and 25b, above.

Figure 38a: Natural Gas Production Volumetric Outages by Primary Basin, February 11, 2021[166]



[166] All outage events smaller than 1 MMCF are excluded from figure.

Figure 38b: Natural Gas Production Volumetric Outages by Primary Cause, February 11

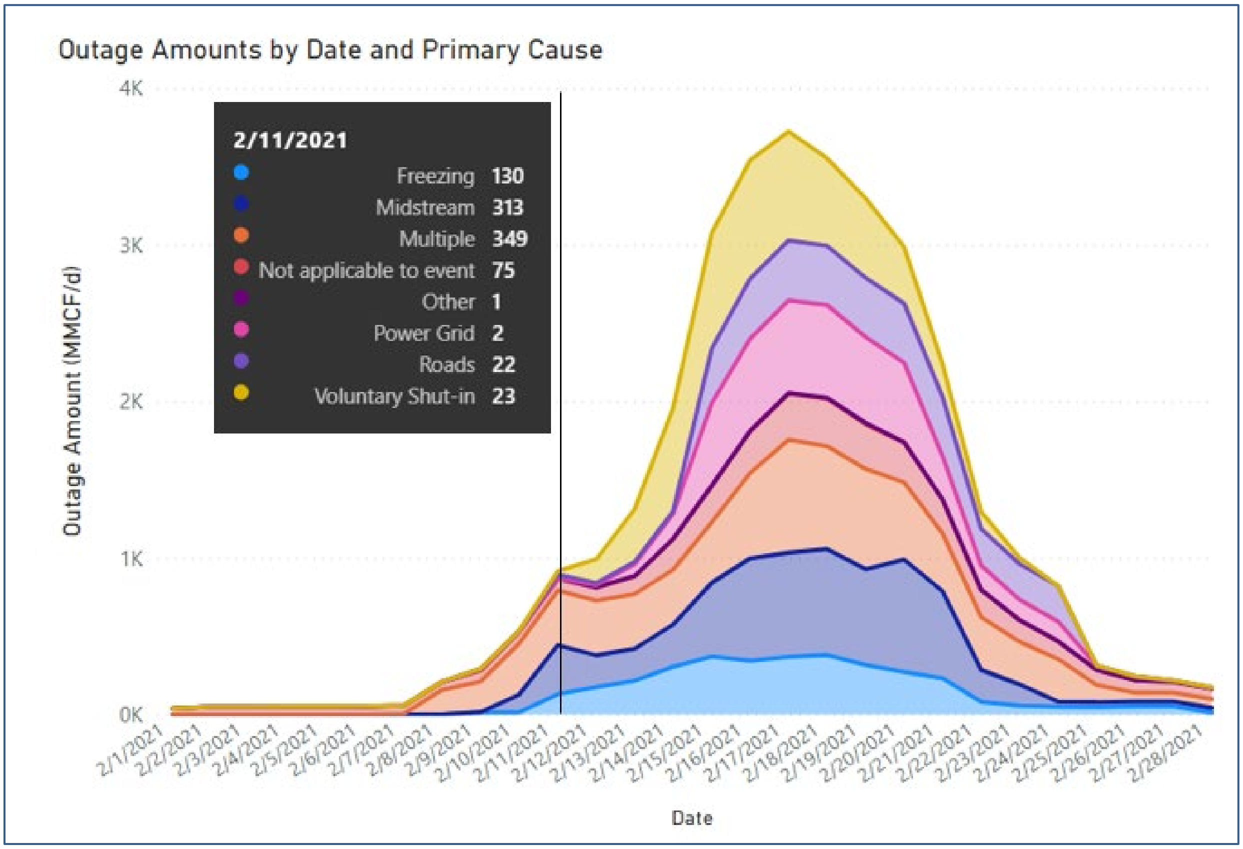
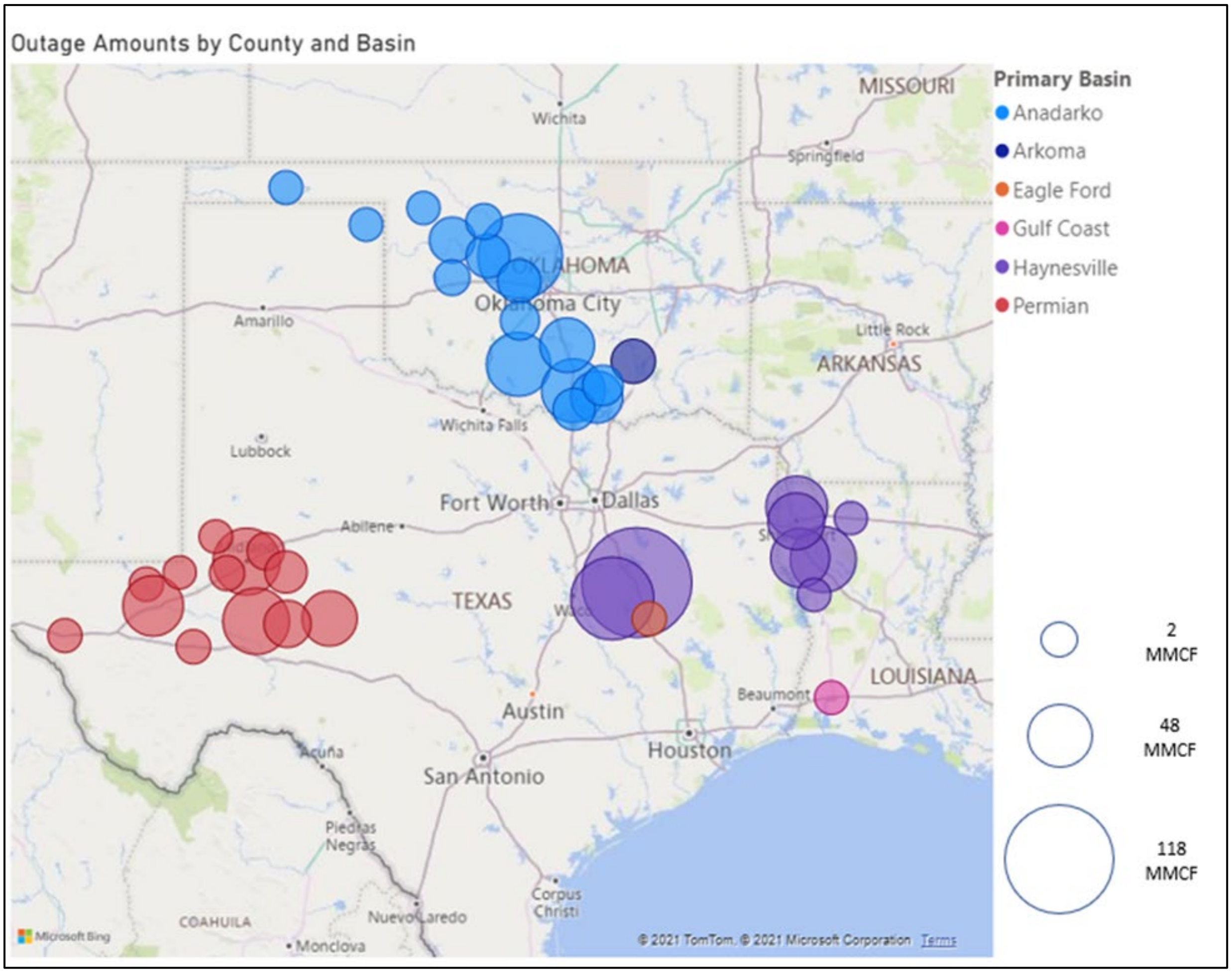
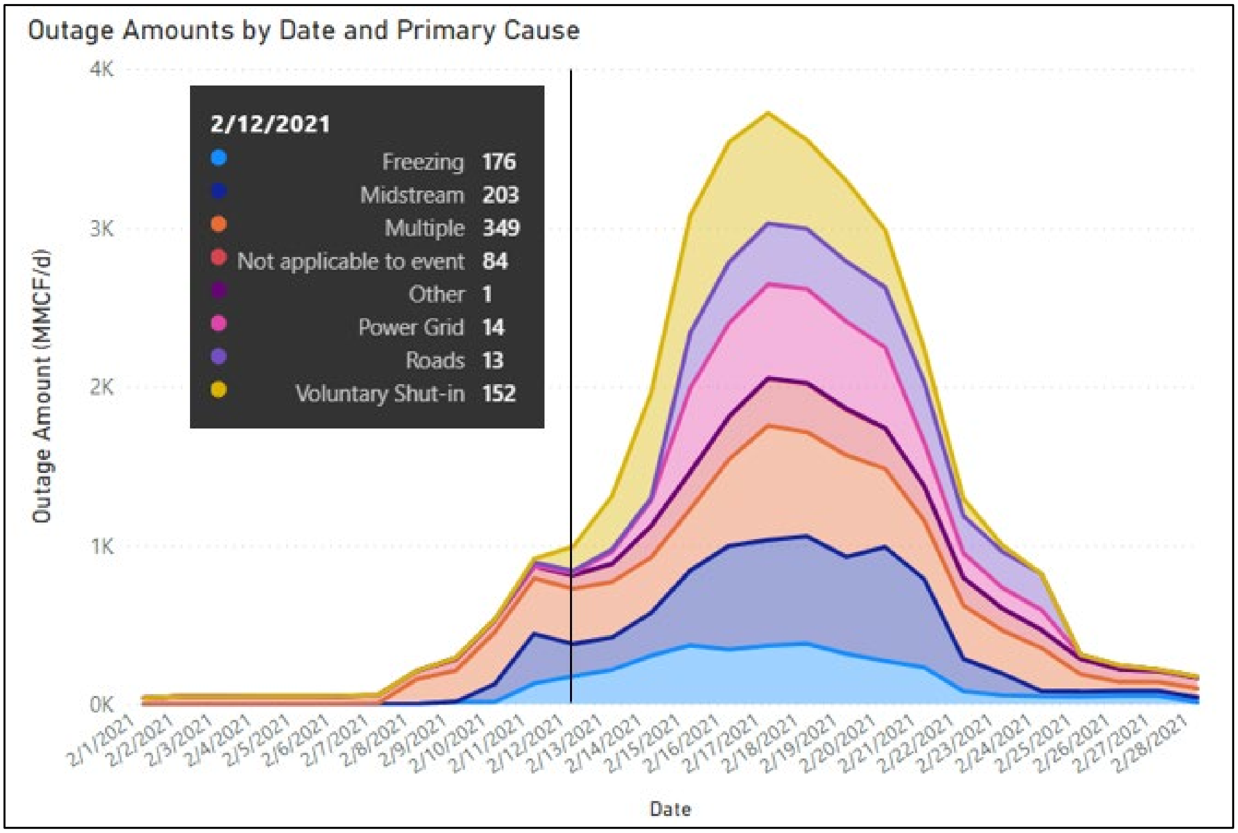


Figure 39a: Natural Gas Production Volumetric Outages by Primary Basin, February 12[167]



[167] All outage events smaller than 1 MMCF are excluded from figure.

Figure 39b: Natural Gas Production Volumetric Outages by Primary Cause, February 12



ii. Effect on natural gas processing - February 8 - 13

Natural gas processing facilities also incurred outages and reductions in output the week of February 7, due in large part to reduced production and gathering as shown in Figure 40, below.

Figure 40: Natural Gas Processing Outages and Causes, February 12-14, 2021

Processing Facility Event Causes on February 12

		Natural Gas Infrastructure Condition	Result	Facility Event Causes
	Freezing Temperature and Weather Conditions (100% of Plant Disruptions)	Reduced Gas Receipts from Production / Gathering Facilities	Processing Facility Disruption	93%
100%		Freezing Issues at Processing Facilities	Processing Facility Disruption	7%
	Loss of Power (0% of Plant Disruptions)	Processing Facilities - Loss of Power Supply or curtailment	Processing Facility Disruption	0%
	Other Issues	Mechanical Failures - Non-Weather Related	Processing Facility Disruption	0%
	Total			100%

**There were a total of 14 causes of processing plants events occuring on February 12.*

Processing Facility Event Causes on February 13

		Natural Gas Infrastructure Condition	Result	Facility Event Causes
	Freezing Temperature and Weather Conditions (100% of Plant Disruptions)	Reduced Gas Receipts from Production / Gathering Facilities	Processing Facility Disruption	95%
100%		Freezing Issues at Processing Facilities	Processing Facility Disruption	5%
	Loss of Power (0% of Plant Disruptions)	Processing Facilities - Loss of Power Supply or curtailment	Processing Facility Disruption	0%
	Other Issues	Mechanical Failures - Non-Weather Related	Processing Facility Disruption	0%
	Total			100%

**There were a total of 22 causes of processing plant events occuring on February 13.*

Processing Facility Event Causes on February 14

		Natural Gas Infrastructure Condition	Result	Facility Event Causes
	Freezing Temperature and Weather Conditions (85% of Plant Disruptions)	Reduced Gas Receipts from Production / Gathering Facilities	Processing Facility Disruption	73%
100%		Freezing Issues at Processing Facilities	Processing Facility Disruption	12%
	Loss of Power (15% of Plant Disruptions)	Processing Facilities - Loss of Power Supply or curtailment	Processing Facility Disruption	15%
	Other Issues	Mechanical Failures - Non-Weather Related	Processing Facility Disruption	0%
	Total			100%

**There were a total of 34 causes of processing plants events occuring on February 14.*

iii. Status of natural gas pipelines - February 8 - 13[168]

Pipeline Communications[169]

Interstate pipelines issue a variety of communications and directives to shippers and, pursuant to FERC regulations (18 CFR §284.12 (2021)), 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

[168] *See* Appendix L, Primer on Natural Gas Production, Processing, Transportation and Storage for background on natural gas terminology and concepts.
[169] *See* Appendix C for an example of a notice issued by a natural gas pipeline entity during the Event.

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 (e.g., horsepower utilization and availability); and projected throughput versus availability, for capacity and supply.

Operational flow orders (OFOs) 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 daily, 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.

February 6 through February 10, 2021. Several days before the coldest weather hit the Event Area and the need for firm load shed began, intrastate natural gas pipelines in Texas, as well as interstate natural gas pipelines located in Texas, Oklahoma, Kansas, and Louisiana, began issuing critical notices and similar communications related to pipeline system integrity, due to expected cold weather. On February 9, intrastate pipelines in Texas began to issue OFOs to natural gas shippers, requiring them to balance their receipts and deliveries. Also, on February 9, one intrastate pipeline in Texas issued the first of what would be several critical notices, warning that there would be pipeline natural gas delivery restrictions to natural-gas fired generating units with interruptible natural gas transportation contracts in northern Texas area of ERCOT, effective for the February 10, 2021 gas day.[170] On February 10, another critical notice was issued by the same intrastate pipeline company for the February 11 gas day, notifying natural gas-fired generating units with interruptible natural gas transportation contracts in the Austin, Texas area of ERCOT that they would be subject to natural gas delivery restrictions.

Overall, the interstate and intrastate natural gas pipelines surveyed by the Team performed as expected and were largely able to fulfill their firm transportation obligations. They were not significantly affected by the cold weather and freezing conditions. They were only minimally

[170] The gas day is from 9:00 a.m. through 8:59 a.m. Central Prevailing Time for the entire United States.

affected by power outages because most have gas-fired compressors, redundant compression, and backup power.

February 11 through 13. Increasing numbers of intrastate and interstate pipelines issued critical notices and OFOs advising shippers to stay within their nominations to protect the integrity of their systems and restricting interruptible transportation service to some natural gas-fired generating units in ERCOT. Also, during this timeframe, pipelines issued notifications that placed limitations on natural gas storage withdrawals under interruptible contracts. These notices were issued in recognition of declining natural gas supply.

iv. Effect on natural gas-fired generating units - February 8 - 13

As outages of natural gas infrastructure facilities began to increase during the week of February 7, natural gas production began to decline. This led to natural gas-fired BES generating unit outages and derates in both SPP and ERCOT. From the start of the Event on February 8 to early Tuesday morning, February 9, SPP experienced unplanned outages and derates of natural gas-fired generating units totaling 450 MW caused by natural gas fuel supply issues. By Friday night, February 12, SPP had 3,200 MW of natural gas-fired generating units outaged or derated due to natural gas fuel supply issues, and by the evening of February 13, with the coldest weather conditions yet to arrive, natural gas-fired generating units outaged or derated due to natural gas fuel supply issues had jumped to 5,000 MW.

Figure 41: Natural Gas-Fired Generating Unit Production, February 8-12, 2021

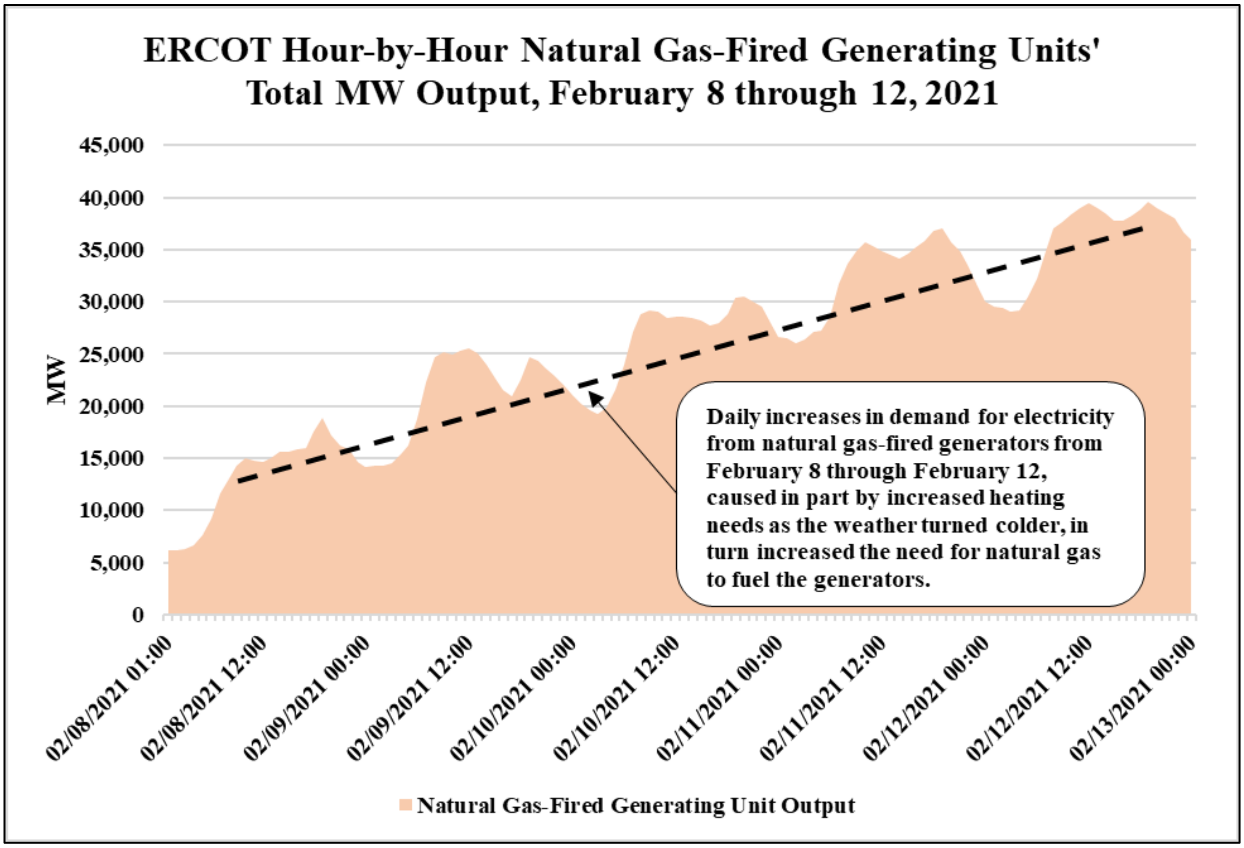


Figure 41, above illustrates the increased need for natural gas to fuel natural gas-fired generating units in ERCOT from February 8 through February 12, before increased demand from natural-gas fired generating units began to exceed available natural gas fuel supply in the Event Area. Outages and derates due to natural gas fuel supply issues began in ERCOT on February 11. By the close of the week on Saturday, February 13, with the coldest weather conditions yet to arrive in the ERCOT footprint, outages and derates of natural gas-fired generating units caused by natural gas fuel supply issues exceeded 4,000 MW. A substantial portion of these outages occurred at 9 a.m. on February 13, when nine natural gas-fired generating units in SPP supplied by Southern Star Central Gas Pipeline experienced fuel-related outages and derates, one GO/GOP in SPP derated 13 of its generating units due to natural gas fuel supply restrictions, and three units in ERCOT were outaged or derated due to a lack of fuel, causing simultaneous outages or derates of 25 natural gas-fired generating units in ERCOT and SPP, as shown on Figure 42, below.[171]

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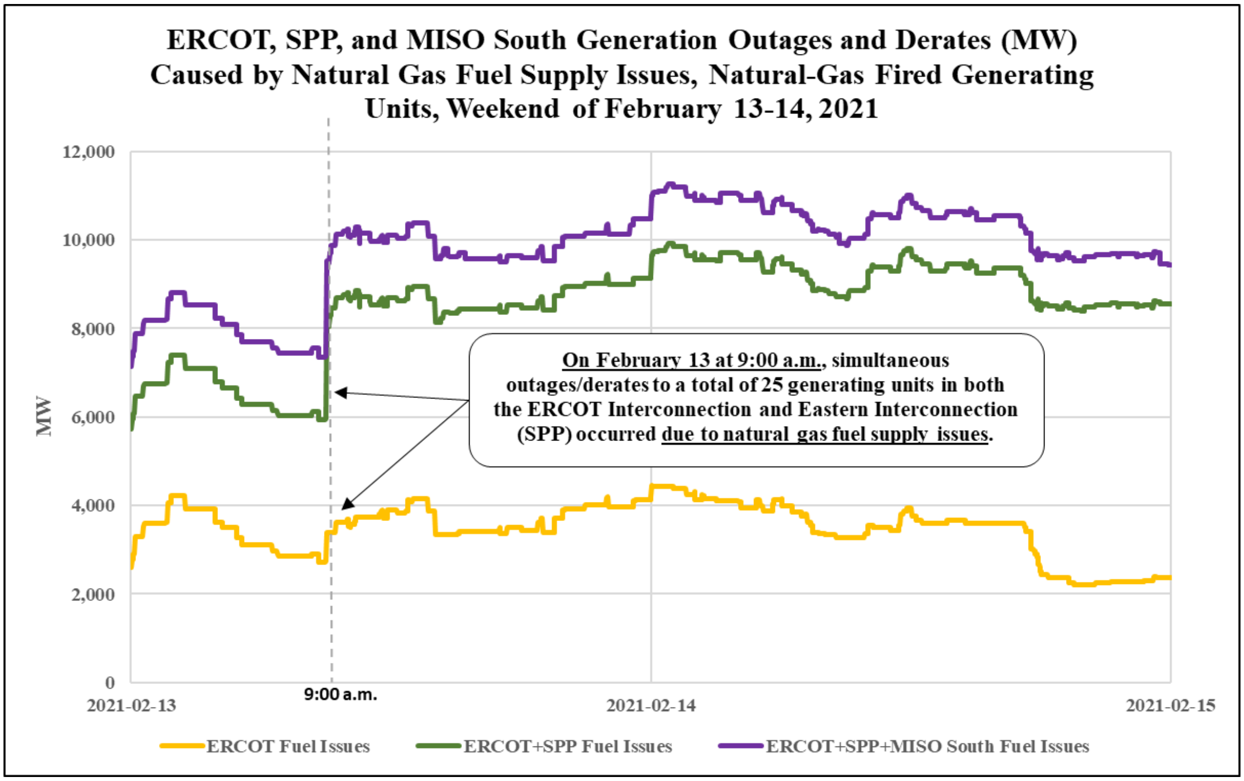
[171] The majority (17) of the 25 generating units had firm pipeline transportation and firm supply for at least some of their contracted volumes. Only nine of those generating units had their supply interrupted by the supplier. These 25 units had a combined nameplate capacity of 3,859 MW and contributed 2,791 MW of generation losses from 9:00-9:10 a.m.

Figure 42: ERCOT, SPP and MISO Generation Outages and Derates Due to Natural Gas Fuel Supply Issues – Weekend of February 13-14, 2021



4. BA/RC Real-Time Actions – February 8 – 13

a. ERCOT

ERCOT BA and RC operators were aware of the cold weather forecast and began issuing notices and advisories as shown in Figure 19 above. When the arctic air and freezing precipitation moved into northern Texas at the start of the week of February 7, ERCOT RC operators began to log reports of generating unit outages and derates and their causes. Beginning February 8, at 7:50 a.m., ERCOT saw its first reports of wind generating unit outages and derates due to turbine blade icing. ERCOT BA operators continued to receive reports of wind generating turbine blade icing around-the-clock for the remainder of the week.

On February 10, ERCOT BA learned that Atmos-Pipeline Texas was having difficulties in delivering natural gas due to the natural gas production declines and would be implementing fuel supply restrictions on February 12. The restrictions then remained in effect throughout the Event, until February 21. As the week progressed, generating unit outages in the ERCOT footprint increased, primarily due to freezing issues and natural gas fuel supply issues described in section B, above. The declining generation capacity, coupled with heating-load-driven energy demands steadily increasing throughout the week (as shown in Figure 27, above), resulted in a declining generation capacity margin to meet the demand, plus a sufficient cushion of "reserve" required above the demand, referred to in ERCOT as Responsive Reserve.[172]

By Friday February 12, even before the coldest weather had reached Texas, ERCOT's system load peaked at 63,997 MW, which was already 97 percent of its all-time historical winter peak load. On February 12 at 12:13 p.m., ERCOT BA notified the PUCT that it may need to declare an EEA during the afternoon, due to limited generation availability and high system load levels. On February 12 at 3:30 p.m. (and lasting until 5:11 pm), ERCOT BA declared a fuel supply emergency that could impact electric power system adequacy or reliability, although ERCOT did not end up declaring an EEA.[173] Cold temperatures and freezing precipitation also led to some transmission facility outages during the week of February 7, although ERCOT quickly returned most transmission facilities to service.

Normally, weekend loads are lower than weekdays; but with colder weather continuing to spread into southern Texas, electricity heating demands increased ERCOT's system load significantly during the morning hours of Saturday, February 13, peaking at 64,132 MW by 11:00 a.m. At 8:43 a.m., with higher-than-normal system loads, additional unplanned generating unit outages that occurred overnight due to natural gas fuel supply issues and wind turbine outages caused by blade icing, ERCOT's Physical Responsive Capability dropped below 3,000 MW. ERCOT issued a system Advisory, meaning that GOPs and TOPs may need to take actions in anticipation of an EEA.[174] At 8:49 a.m., ERCOT operators issued an Emergency Notice for the extreme cold weather event impacting the ERCOT footprint. ERCOT cancelled the advisory when its system load decreased somewhat on Saturday afternoon, returning its Physical Responsive Capability above 3,000 MW and avoiding the need to declare an EEA.

b. SPP

As shown earlier in Figure 19, SPP BA system operators also issued an Operating Condition Notice based on the extreme cold weather forecast for its footprint. On February 7 (two days earlier than in ERCOT), SPP BA began to receive critical notices from the interstate Gulf South gas pipeline,

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172 ERCOT Responsive Reserve is an ancillary service that provides operating reserves intended to arrest frequency decay within the first few seconds of a significant frequency deviation using Primary Frequency Response and interruptible load; after the first few seconds of a significant frequency deviation, help restore frequency to its scheduled value to return the system to normal; provide energy or continued load interruption during the implementation of the EEA; and provide backup regulation. *See* ERCOT Nodal Operating Guide http://www.ercot.com/mktrules/guides/noperating.

173 ERCOT OE-417 of February 12 at 3:30 p.m. stated, "[g]as fuel supplies are limited to generators impacting generation availability due to the extreme cold weather impacting the ERCOT region resulting in gas company curtailments."

174 Based on its emergency operations protocols, ERCOT issues an Advisory when its "Physical Responsive Capability" or PRC drops below 3,000 MW. ERCOT system operators issued an Emergency Notice for extreme cold weather system beginning to have an adverse impact on its footprint. ERCOT instructed QSEs to make resources available that can be returned to service and keep COPs and high sustained limits for generating units updated, keep ERCOT informed of known or anticipated fuel restrictions, and notify ERCOT of any changes or conditions that could affect system reliability.

warning that limited input into the pipelines from natural gas production facilities could hinder deliveries of natural gas to natural gas-fired generating units in SPP's footprint. At least two interstate and two intrastate pipelines with facilities in the South Central region issued system-wide notices on February 6 of upcoming winter weather lasting for the next week or two. On February 9, SPP began regular communications[175] with Southern Star, one of the largest interstate natural gas pipelines that delivers to natural gas-fired generating units in its footprint. SPP and Southern Star staff continued discussions throughout the Event to coordinate gas issues and pipeline reliability as part of a proactive resource commitment approach. SPP did not have a similar relationship with other natural gas pipelines serving generating units within its footprint. By the end of February 13, SPP already had over 9,700 MW of natural-gas fired generating units unavailable, before the coldest temperatures arrived. But in addition to natural gas fuel supply issues, SPP began to lose wind turbines to blade icing—beginning February 8, at approximately 3:15 a.m., which quickly rose to 123 outages and 10,700 MW of wind generation capacity unavailable by February 9.

On February 11, SPP began committing generating resources using its multiday reliability assessment process, expecting more outages from natural gas fuel supply issues due to its close coordination with Southern Star. Instead of committing generating units one day ahead, as is standard practice, SPP began sending them instructions several days in advance that they would be responsible for serving load for the period Saturday, February 13 through Tuesday, February 16.

As the week of February 7 progressed, SPP's electricity demand or load steadily increased, driven by electric heating loads (as shown in Figure 27, above, and similar to ERCOT). Lower system load on Saturday February 13, and 2,000 MW of wind generation that had returned to service from blade icing outages, helped to offset a portion of the 4,000 MW of increased outages and derates of natural gas-fired generating units due to natural gas fuel supply issues. In summary, SPP had sufficient generation capacity to meet load in its footprint during the week of February 7 and thus did not need to implement emergency measures.

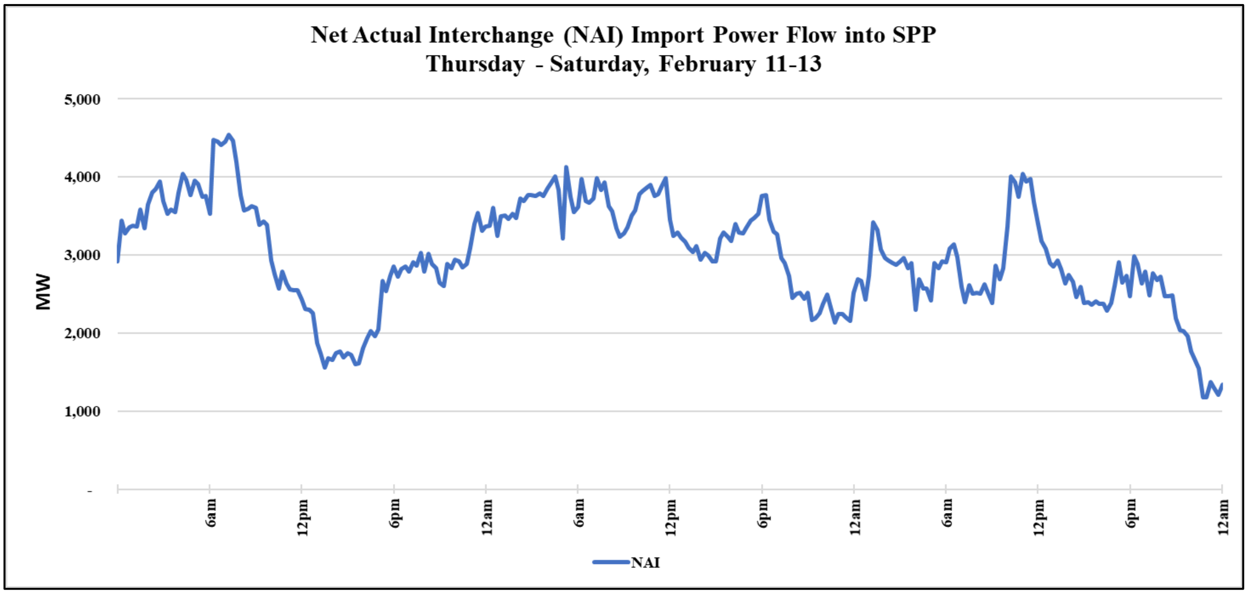
c. MISO / MISO South

Because MISO South began to experience the colder weather later than SPP and ERCOT, it did not experience any significant generation outages or derates during the week of February 7. However, the MISO BA operators knew that the severe cold weather conditions were forecast to reach deep into the South Central U.S. early in the week of February 14. See Figure 19. On February 8, SPP and MISO began management-level discussions about the forecast severe cold weather conditions and natural gas fuel restrictions expected. Discussions continued during the remainder of the week to ensure coordination as the weather worsened.

MISO transmission grid conditions during week of February 7. Overall, MISO's transmission system was normal operation during the week of February 7. Figure 43, below, shows the total actual import power which flowed on SPP's AC tie-lines (most of which are with MISO, listed in Figure 9, above) from February 11 through 13.

[175] This communication was part of an ongoing relationship between the two entities, including participation by SPP staff in the Southern Star users' group.

Figure 43: Transmission Import Power Flow into SPP, February 11-13



Even though SPP market imports reached as high as 4,600 MW on February 11 and 4,000 MW on February 13, MISO's transmission system was much less constrained during the week of February 7 than the following week, and normal (non-emergency) operations measures sufficed to manage transmission system reliability.[176] On February 11, as the expectation for the duration of extreme cold expanded, MISO extended its Cold Weather Alert through the end of the day February 16, and alerted operators to expect to be contacted about fuel restrictions. Even as MISO South's load began to increase with lower temperatures on February 11 and 12, it still had sufficient reserves and had only reached 83 percent of its all-time peak load.

> Power transfers (e.g., importing power from other Balancing Authorities) can be used to provide generation supply and reserves to areas where there may be generation shortfalls, but in addition to the specific transmission ratings on the lines over which the power is being transferred, there are other limitations to the amount of power that can be reliably transferred on the power grid. The importing BA (for example, SPP) simultaneously needs its remaining online generation to serve load (to avoid need for load shed) and to reduce transmission congestion via redispatch to accommodate import power transfers. Any remaining online generation used for one purpose is not available for the other. Attempting to transfer more power than

[176] SPP imports would similarly vary from 4,000 to nearly 6,500 MW on the morning of February 15; but on that day, SPP and MISO would be facing one of the coldest days and peak load periods of the Event, and generating unit outages would have greatly escalated in both footprints. Under those very different conditions, SPP import levels relatively similar to the week of February 7 would now need to be curtailed to alleviate transmission system emergency conditions in MISO. *See* Figure 79.

> can be supported by redispatch can create wide-area constrained grid conditions. When the grid is constrained on a wide area, the danger of violating SOLs or IROLs leads to constant contingency monitoring and redispatch or even firm load shed, as in the Event, for a transmission emergency. While east-to-west transfers played a critical role in helping MISO and SPP largely compensate for the generation outages during the Event, there eventually comes a limit to the amount of power that can be reliably transferred.[177]

As Sunday, February 14, approached, ERCOT, SPP and MISO BAs were fully aware of colder weather approaching. ERCOT and SPP had already weathered rising load and generating unit outages from natural gas fuel supply issues and blade icing, and all three BAs had ended the week of February 7 without taking emergency actions.

Everything was about to change in the coming week, in which the weather would worsen, and all three BAs would simultaneously face emergency conditions.

C. February 14 - 19: Extreme Below-Normal Cold Weather Conditions Lead to Widespread Generation Outages, Forcing Grid Operators to Make Hard Decisions

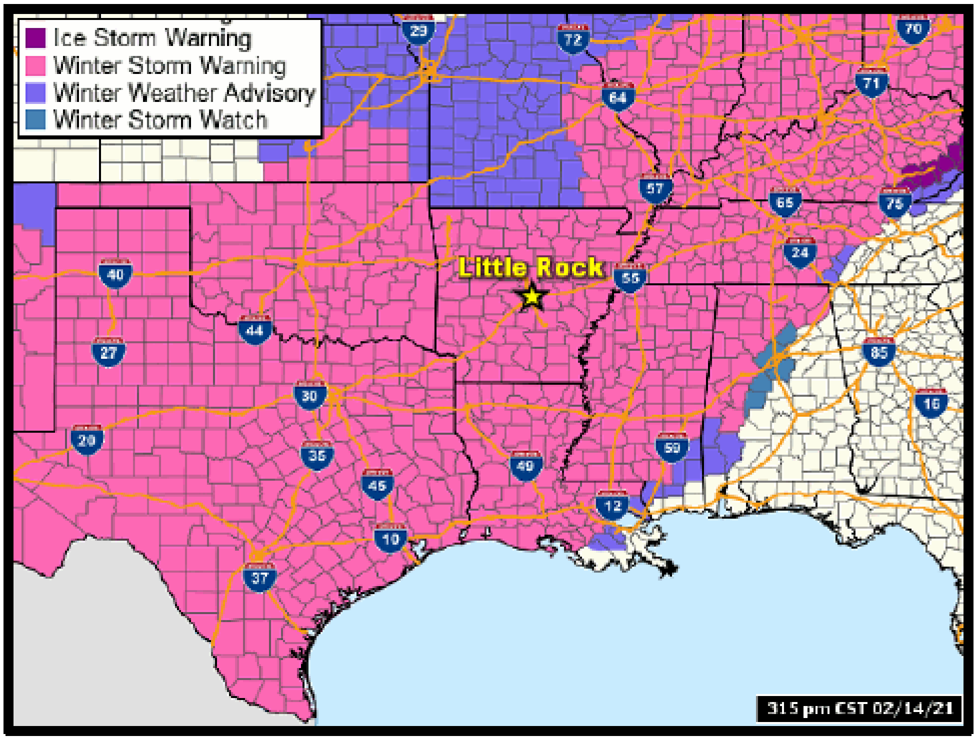
- *The Coldest Temperatures and Freezing Precipitation Begin*
- *Unplanned Generation Outages Increase*
- *Grid Operators Forced to Make Hard Decisions*

1. Overview of Worsening Weather Conditions

Beginning the weekend of February 13 and 14, and extending through Thursday, February 18, the Event Area experienced a wave of extreme cold temperatures, accompanied by snow, freezing rain and wind conditions. Precipitation began on February 13, with heavy snow occurring in Oklahoma and Arkansas, and rounds of snow, sleet and freezing rain continuing in parts of Texas, Louisiana, and Mississippi as late as Thursday, February 18. Figure 44 (below) shows the extensive area that was under a winter storm warning on February 14, while Figure 45 illustrates how low temperatures during the Event departed from normal lows on February 15.

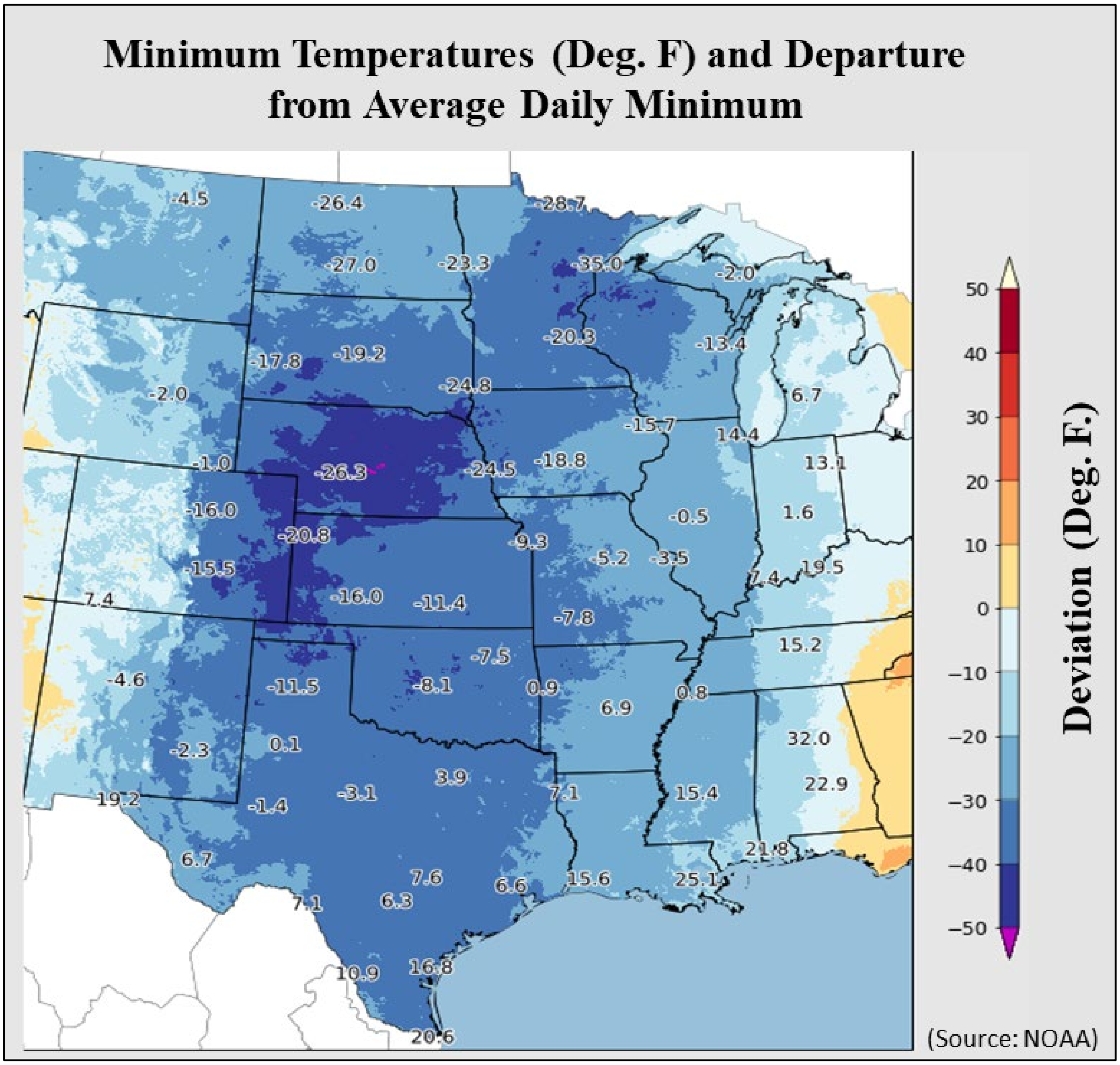
[177] *See* 2018 Report at pages 93 – 94.

Figure 44: NOAA National Weather Service – Winter Storm Warning, February 14, 2021[178]



[178] A watch is used when the risk of a hazardous weather or hydrologic event has increased significantly, but its occurrence, location, and/or timing is still uncertain. It is intended to provide enough lead time so that those who need to set their plans in motion can do so. An advisory highlights special weather conditions that are less serious than a warning. It is used for events that may cause significant inconvenience, and if caution is not exercised, could lead to situations that may threaten life and/or property. A warning is issued when a hazardous weather or hydrologic event is occurring, is imminent, or has a very high probability of occurring. A warning is used for conditions posing a threat to life or property.

Figure 45: February 15, 2021 Minimum Temperatures and Departures from Average Daily Minimum



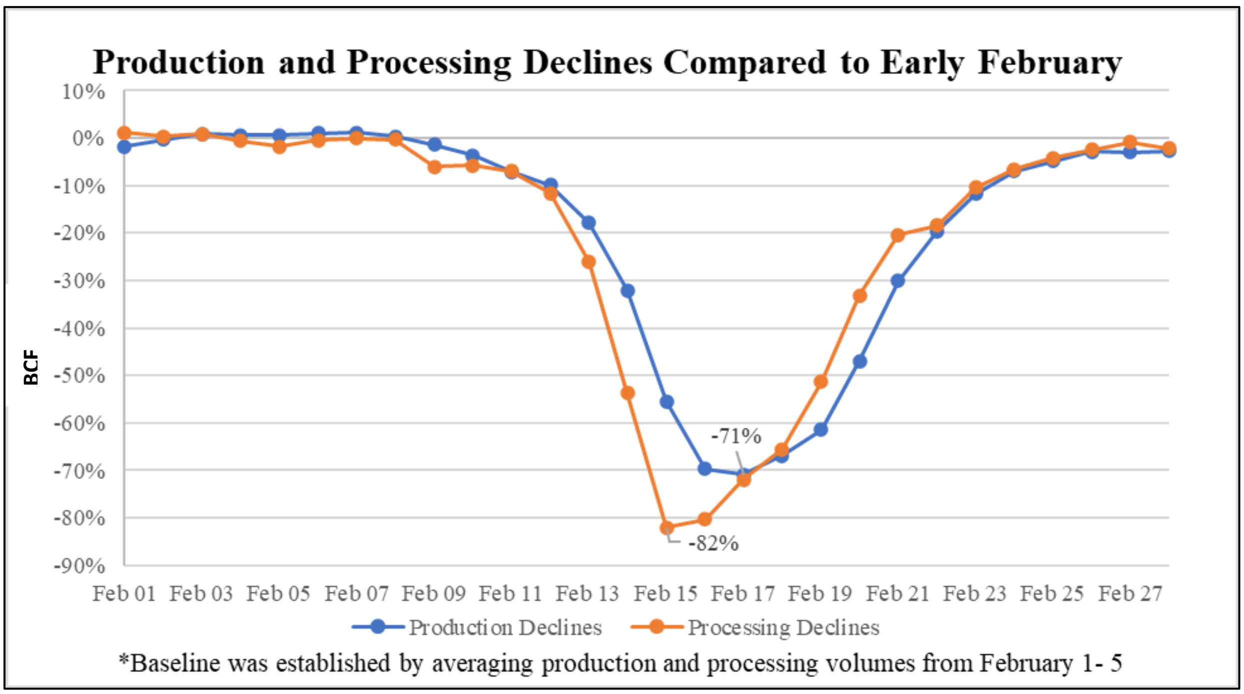
2. Effects on Natural Gas Infrastructure

a. Additional Natural Gas Production Declines in Texas and South Central U.S.

Natural gas infrastructure including wellhead, gathering, and processing facilities all suffered some degree of unplanned outages primarily due to the cold weather conditions that began on approximately February 7, resulting in a decline in natural gas supply. By February 14, natural gas wellhead and gathering facility production declined by over 30 percent, while processing declined by over 50 percent, as compared to February 1 through 5 production and processing levels, respectively. By February 15, processing had declined by over 80 percent and by February 17, production had declined by 71 percent. (See Figure 46 below).

On February 14, 88.4 percent of the volumetric contribution to the decline in natural gas production was related to the extreme cold weather. Slightly more than half of the production decline (52.2 percent) resulted from freezing issues or shut-ins to prevent freezing, while 18.1 percent resulted from loss of power (caused by a combination of ERCOT-wide firm load shed and local weather-related distribution line outages)[179] and 18.2 percent resulted from a combination of issues (for example, freezing and loss of power) (see Figure 47 below). Processing losses, analyzed by the day of maximum losses in each basin, were largely caused by reduced gas supply, as one would expect (see Figure 51). For example, the Fort Worth and Gulf Coast Basins on February 17 each had 100 percent of outages caused by reduced gas supply, the Anadarko Basin on February 16 had 81 percent, and the Permian and Eagle Ford on the February 16 and 17, respectively, each had over 50 percent of outages caused by reduced gas supply. In some basins, power outages played a larger role, with 77 percent of Haynesville Basin outages on February 19 reported to be caused by power outages/curtailments.

Figure 46: Production and Processing Declines Compared to Early February



[179] The February 14 gas day covers the 24-hour period beginning at 9 a.m. Central Prevailing Time on February 14 and ending at 9 a.m. on February 15. Between midnight February 14 and 9 a.m. February 15, ERCOT and MISO both shed firm load, and the producers did not provide data with sufficient granularity to allocate gas production data between the calendar days of February 14 and 15. *See* ERCOT Frequency Decline and Recovery: February 15, Approximately Midnight to 2 a.m., section III.C.4.(b)(i) for more information on ERCOT's orders for firm load shed, and III.C.4.(c)(i) and (iv) for more information on MISO's orders for firm load shed.

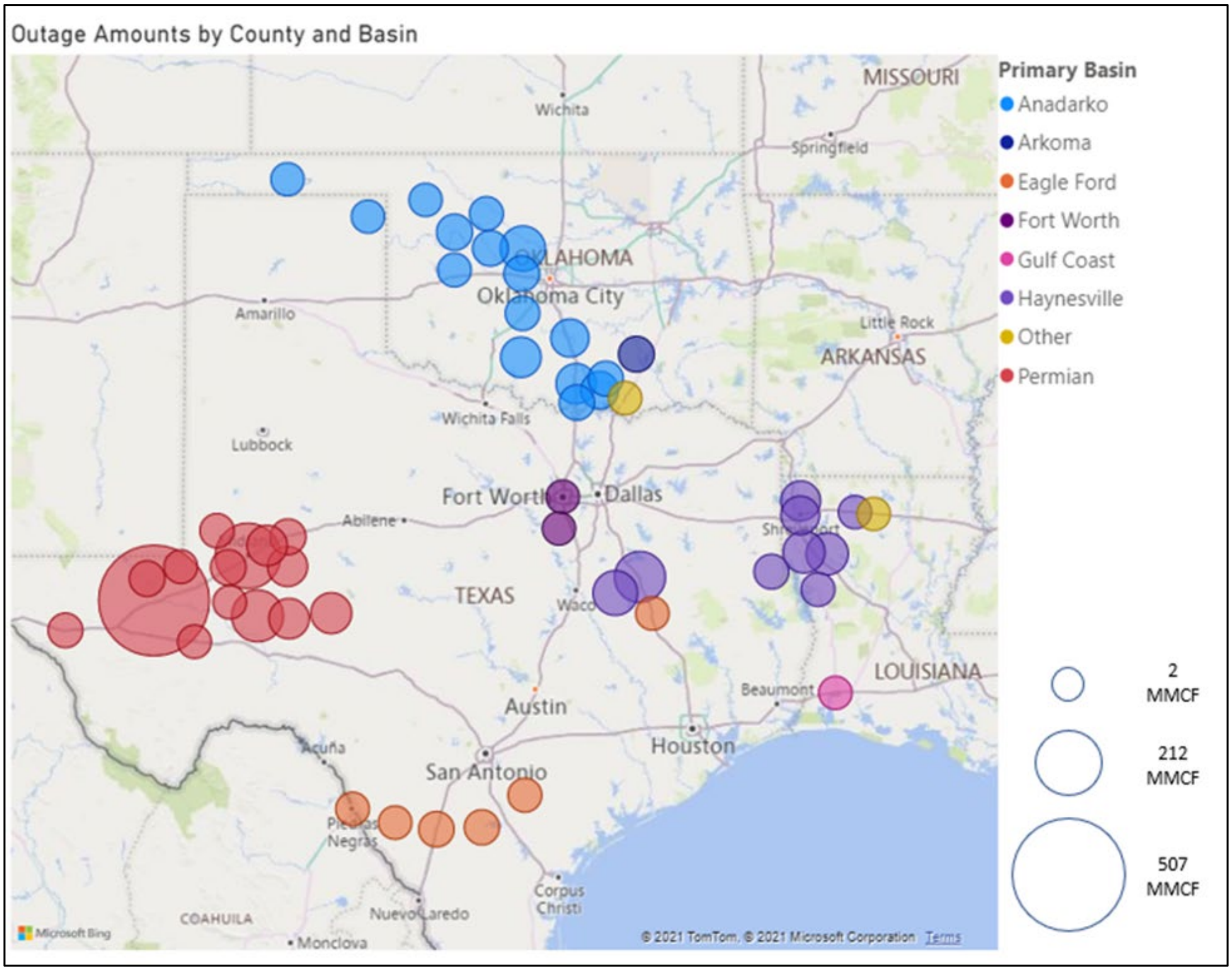
Figure 47: Volumetric Contribution of Production Outage Causes on February 14, 2021, 9:00 a.m. to February 15, 9:00 a.m. Gas Day (inclusive of ERCOT Load Shed)

Production Event Causes on February 14th (Gas Day, inclusive of a portion of ERCOT Load Shed Event)

88.4%

	Natural Gas Infrastructure Condition	Facility Event Causes
Freezing Temperature and Weather Conditions (52.1% of production disruptions)	Facility Shut-ins to Prevent Imminent Freezing Issues	33.6%
	Freezing Issues - Midstream	2.2%
	Freezing Issues at Well and Gathering Facilities	15.6%
	Freezing Issues on Roads/Access to Well and Gathering Facilities	0.8%
Loss of Power Supply (18.1% of production disruptions)	Midstream - Loss of Power Supply	10.0%
	Well/Gathering Facilities- Loss of Power Supply	8.1%
Multiple Issues (18.2% of production disruptions)	Multiple Issues (combination of two or more of above issues)	18.2%
Other Issues, Unrelated Issues (11.6% of production disruptions)	Midstream - Line Pressure	1.6%
	Midstream - Other	0.0%
	Well and Gathering Facility Issues - Not Applicable to Event	10.0%
Total		100.0%

Figure 48a: Natural Gas Production Volumetric Outages by Primary Basin, February 14[180]



180 All outage events smaller than 1 MMCF are excluded from figure.

Figure 48b: Natural Gas Production Volumetric Outages by Primary Cause, February 14

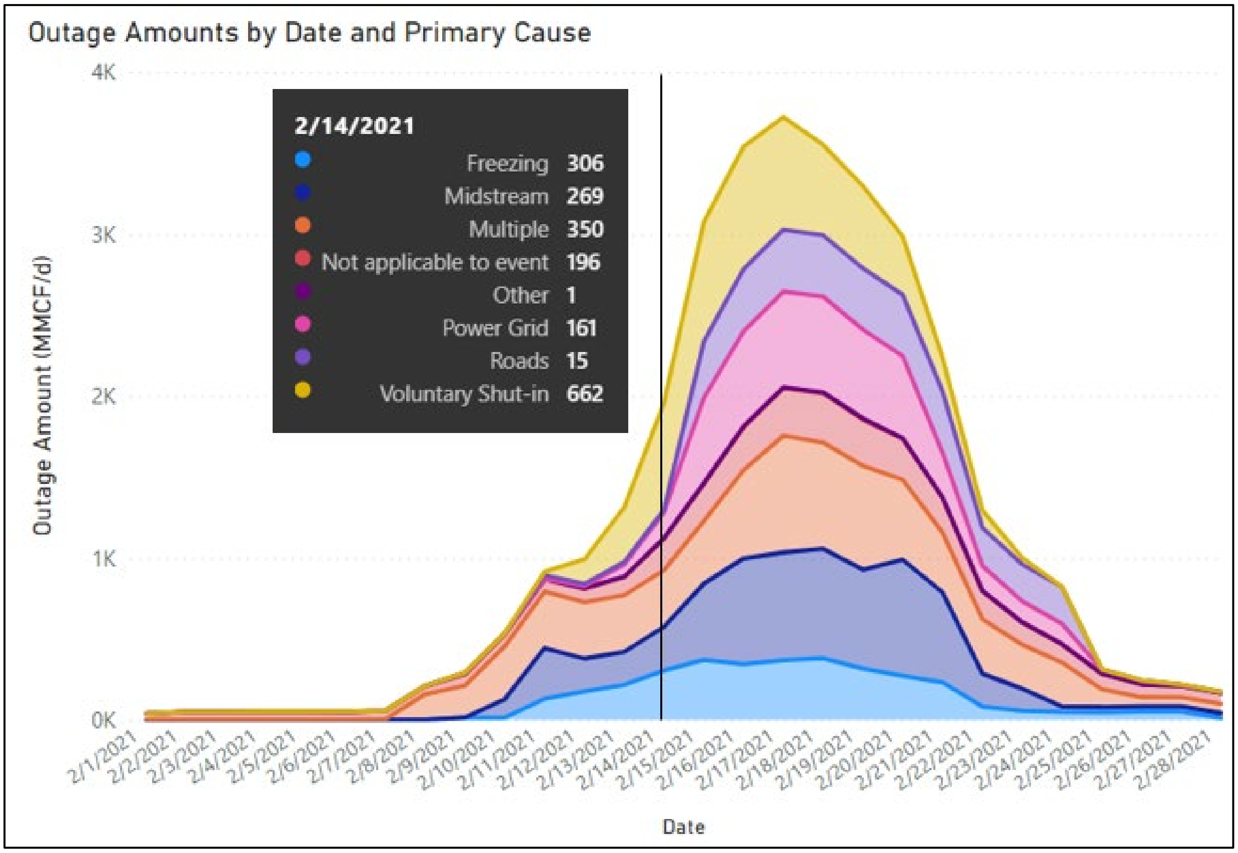
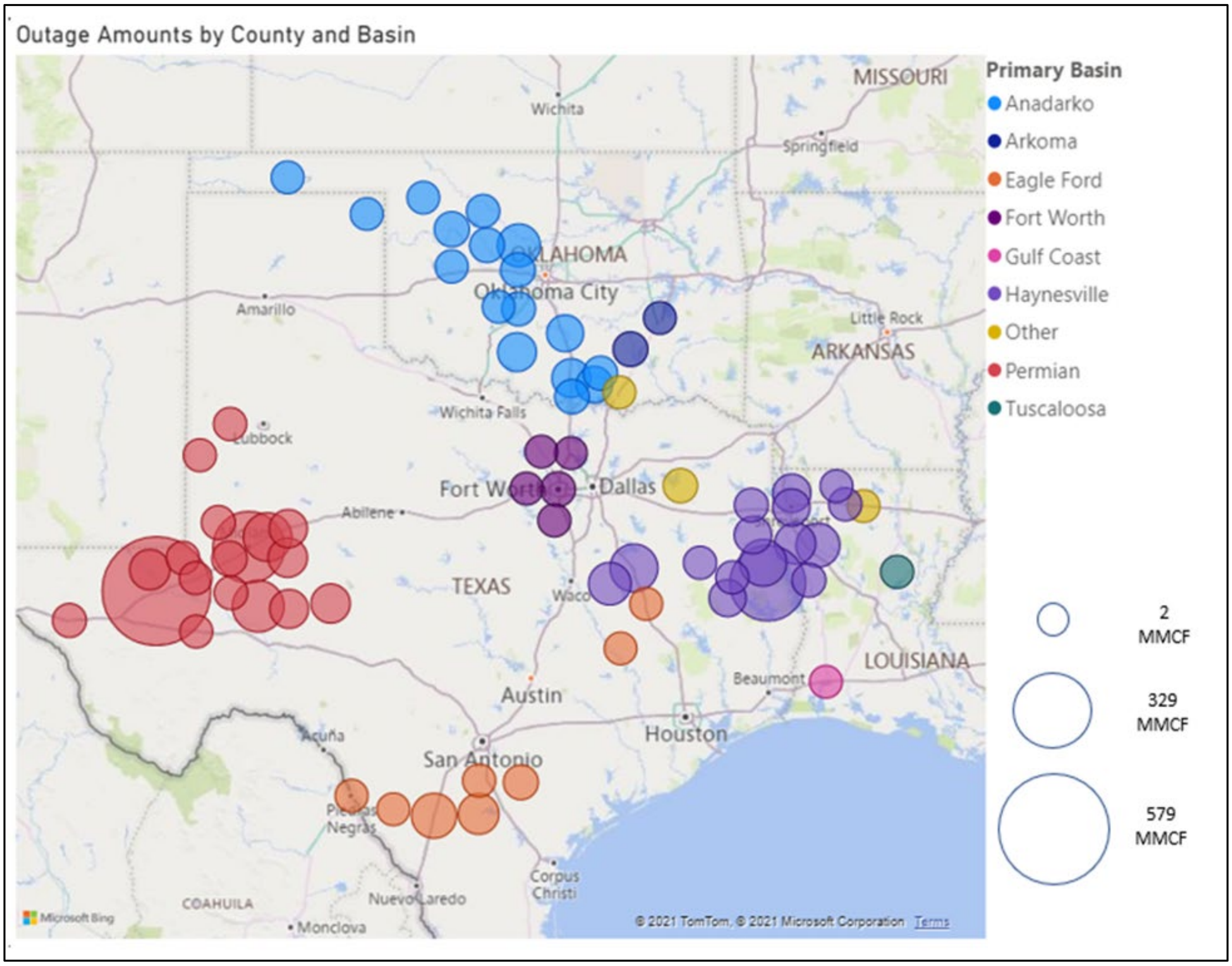


Figure 49a: Natural Gas Production Volumetric Outages by Primary Basin, February 15[181]



[181] All outage events smaller than 1 MMCF are excluded from figure.

Figure 49b: Natural Gas Production Volumetric Outages by Primary Cause, February 15

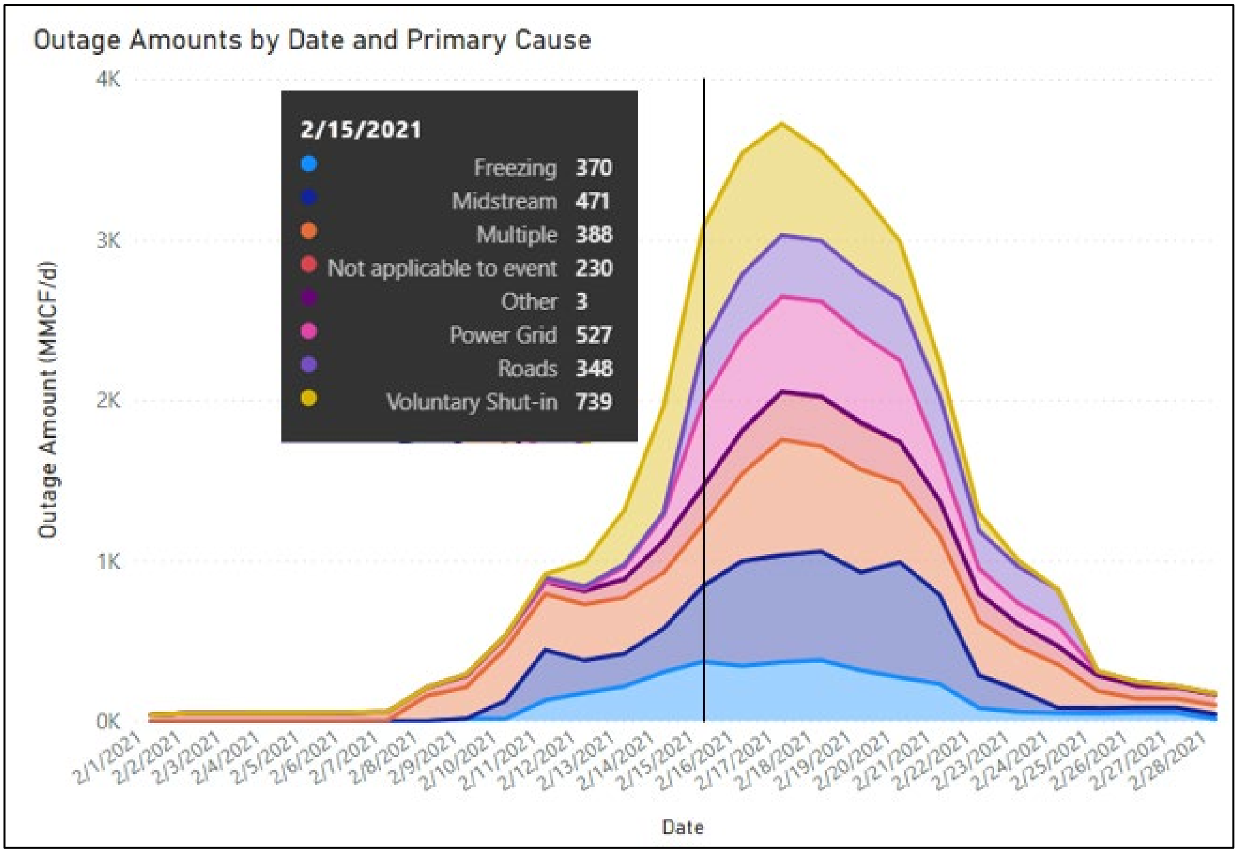
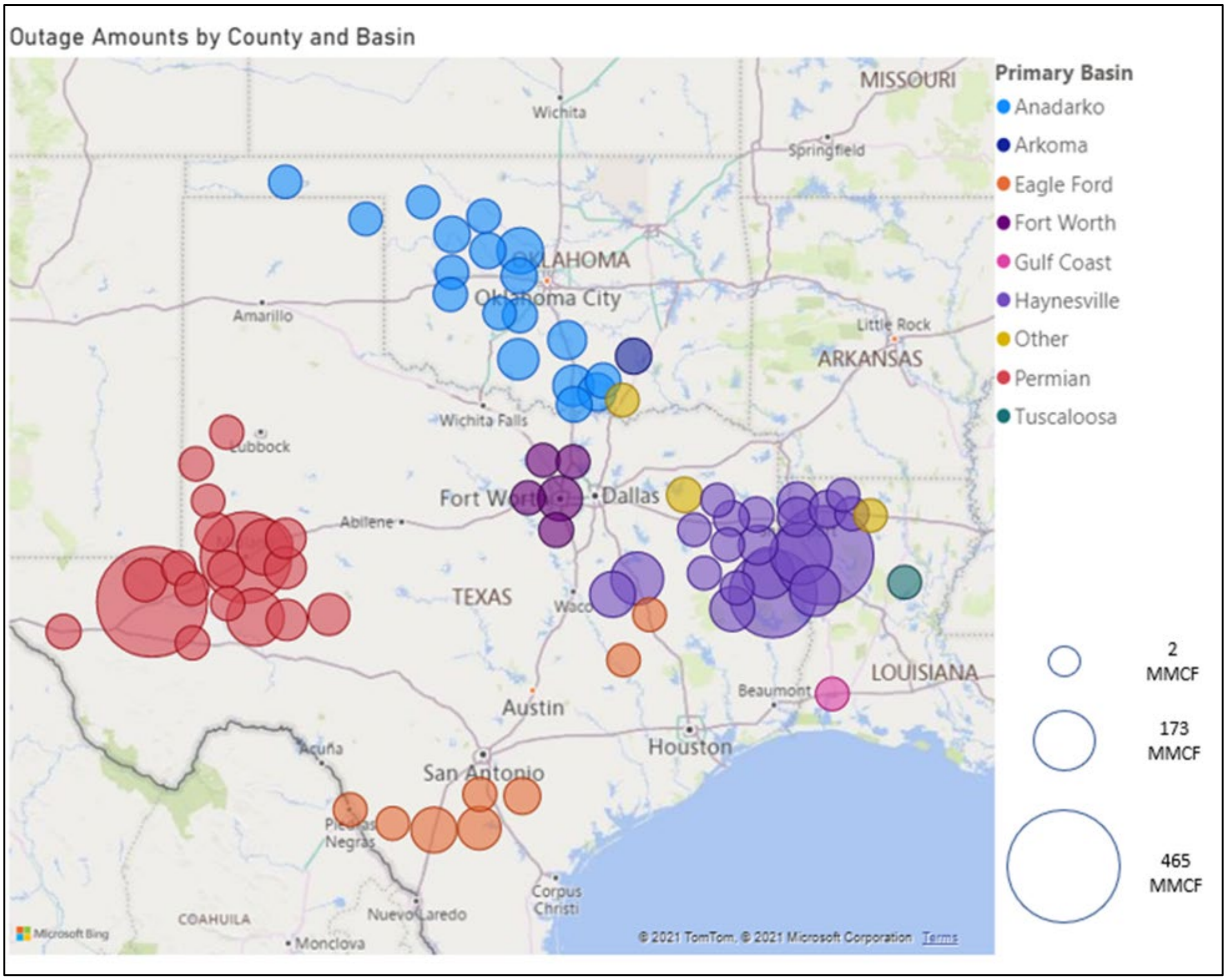


Figure 50a: Natural Gas Production Volumetric Outages by Primary Basin, February 17[182]



[182] All outage events smaller than 1 MMCF are excluded from figure.

Figure 50b: Natural Gas Production Volumetric Outages by Primary Cause, February 17

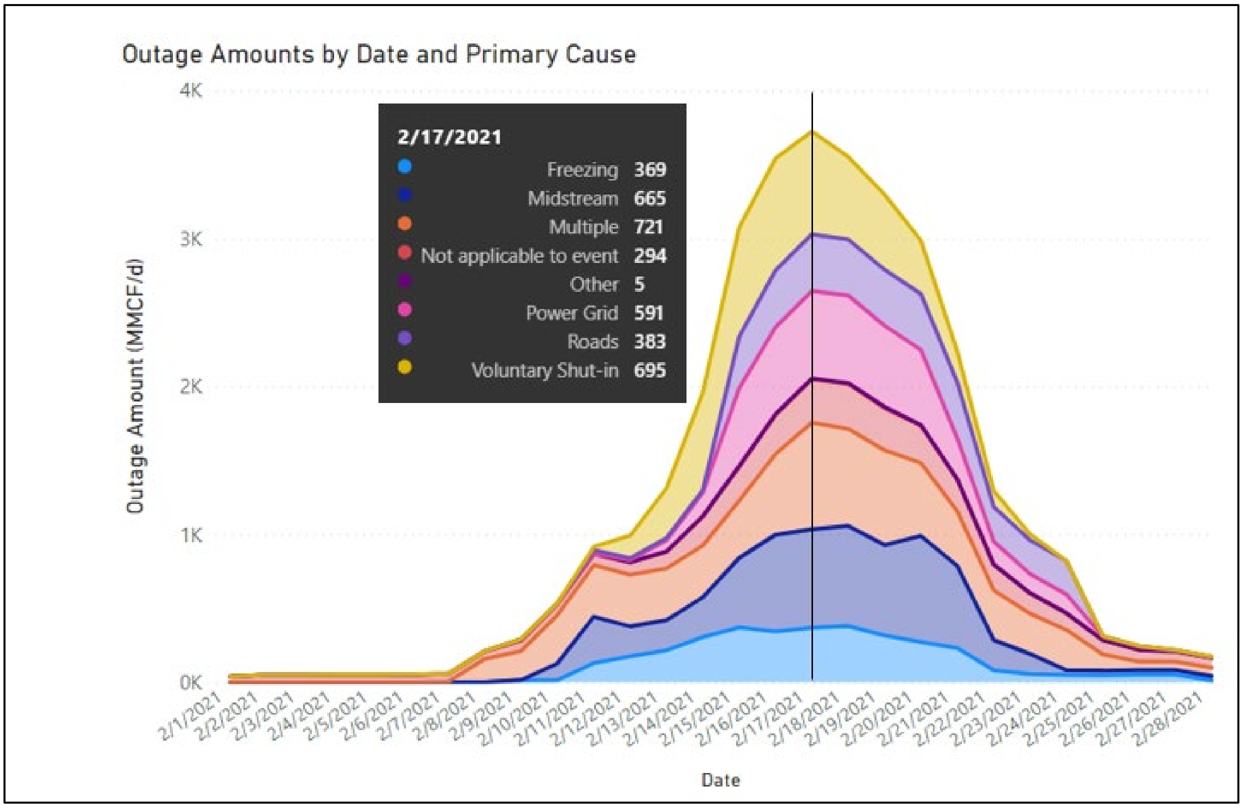


Figure 51: Volumetric Contribution Comparison of Sampled Processing Outages by Basin, February 16-19, 2021

BASIN	MAXIMUM DAILY PRODUCTION OUTAGE (Bcf)	MAXIMUM DAILY PROCESSING OUTAGE (Bcf)	CAUSES
Anadarko (Feb 16th)	1.23 Bcf	0.35 Bcf	81% Reduced Gas Supply, 6% Power Outages/Curtailments, 13% Mechanical failures not related to weather
Permian (Feb 16th)	2.01 Bcf	1.04 Bcf	58% Reduced Gas Supply, 25% Power Outages/Curtailments, 17% Mechanical failures related to weather
Fort Worth (Feb 17th)	0.6 Bcf	0.02 Bcf	100% Reduced Gas Supply
Eagle Ford (Feb 17th)	0.66 Bcf	0.09 Bcf	50% Reduced Gas Supply, 50% Power Outages/Curtailments
Gulf Coast (Feb 17th)	0.02 Bcf	0.38 Bcf	100% Reduced Gas Supply
Haynesville (Feb 19th)	2.09 Bcf	0.38 MMcf	25% Reduced Gas Supply, 75% Power Outages/Curtailments

Utility Curtailment Programs and Priority of Service in Emergencies. As compared to natural gas pipeline companies, which typically adhere to strict definitions of firm and interruptible or non-firm transportation, some states have outlined natural gas curtailment programs or priorities of service for utility customers during emergencies that prioritize human needs. These priorities of service can align with, or supersede, contractual terms and conditions. For example, the Texas RRC has rules that mandate that in emergencies, natural gas utilities provide the highest priority deliveries to residences, hospitals, schools, churches, and other human needs customers, small industrials and regular commercial loads.[183] Residential home heating load normally has firm pipeline transportation provided by its local distribution company, which also provides it with the highest level of contractual priority. In emergencies, industrial customers, including natural gas-fired generating units, would normally be interrupted or curtailed before residential and commercial customers, regardless of contractual priority. During the Event, the RRC issued an emergency order, effective February 12, which elevated "[d]eliveries of gas to electric generation facilities which serve human needs customers" as second in priority behind "deliveries of gas by natural gas utilities to residences, hospitals, schools, churches and other human needs customers, and deliveries to Local Distribution Companies which serve human needs customers."[184] This order had the effect of prioritizing deliveries of gas to generating units even if they did not have firm pipeline transportation contracts.

Natural Gas Usage by End-User Type for February 2021

Natural gas use by residential and commercial end-users:

- Home Heating/Residential Natural Gas Demand: due to the extreme cold weather, the demand for natural gas for home heating increased significantly. In February 2021, the residential sector consumption in Texas reached a monthly record high of 1.8 Bcf/d, 53 percent higher than February 2020 levels and 64 percent higher than the five-year average.[185]
- Commercial Natural Gas Demand: Commercial sector consumption of natural gas in Texas also increased in February, reaching 0.92 Bcf/d, the highest level since January 2018.[186]

Natural gas use by large industrial users: In February, industrial sector natural gas consumption in Texas fell to 4.1 Bcf/d, or 23 percent lower than February 2020 levels, the largest monthly decline on record, caused by the direct effects of the extreme cold weather, including power outages and equipment failure, and indirect effects, such as supply shortages (including natural gas liquids as raw materials) and extreme prices.[187]

Natural gas use by natural gas –fired generating units: Across the entire month of February, consumers of gas for electric power, which includes natural gas-fired generating units, increased by 4.6 percent over January 2021 use. The increased

183 *See* https://www.rrc.texas.gov/gas-services/curtailment-plan.
184 Railroad Commission of Texas, *Emergency Order* (2021), https://rrc.texas.gov/media/cw3ewubr/emergency-order-021221-final-signed.pdf.
185 Mike Kopalek & Emily Geary, *February 2021 weather triggers largest monthly decline in U.S. natural gas production*, Today In Energy (May 10, 2021) https://www.eia.gov/todayinenergy/detail.php?id=47896
186 *Id.*
187 *Id.*

consumption occurred on days in February where natural gas supply *was* available to meet the increased demand of the online natural gas-fired generating units to generate more electricity. Figure 52 below shows the changes in *monthly volume* consumptions of natural gas for end-users from January to February 2021 for Texas, Oklahoma, and Louisiana, and Figure 53, below shows natural gas demand changes from November 2020 – February 2021.

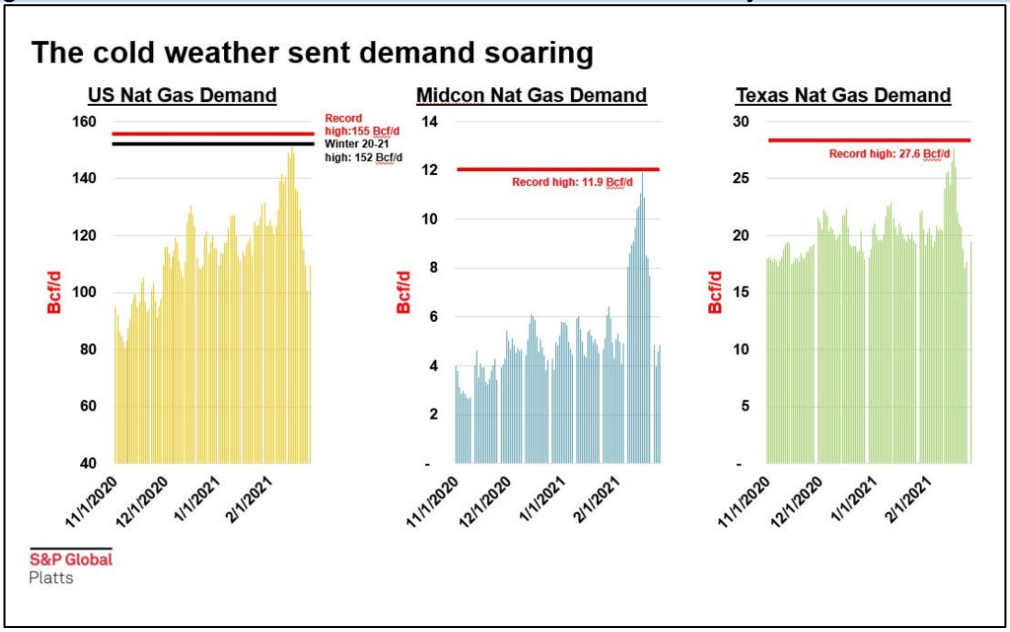
Figure 52: Natural Gas Consumption by End Use, January – February, 2021[188]

Natural Gas Consumption by End Use			
	January 2021 (Bcf)	**February 2021** (Bcf)	**Percent Change**
Residential - LA	6.9	7.4	7.3%
Residential - OK	13.0	13.9	7.0%
Residential - TX	39.0	50.6	29.9%
Commercial - LA	3.6	3.9	9.1%
Commercial - OK	7.5	8.2	9.4%
Commercial - TX	24.5	25.7	4.9%
Industrial - LA	101.9	83.7	-17.9%
Industrial - OK	20.3	13.8	-32.2%
Industrial - TX	176.7	116.1	-34.3%
Electric Power - LA	20.9	22.6	8.0%
Electric Power - OK	21.4	21.7	1.4%
Electric Power - TX	119.4	124.9	4.6%
(Source: EIA)			

The volume of natural gas consumed by natural gas-fired generating units increased on some days in February 2021, which contributed to the overall increased monthly consumption by electric power as compared to January, as shown in Figure 52, above.

[188] *See* U.S. Energy Info. Adm., *Natural Gas Consumption by End Use*, data1 (2021), https://www.eia.gov/dnav/ng/NG_CONS_SUM_DCU_STX_M.htm.

Figure 53: Natural Gas Demand November 2020 – February 2021



b. Imports of Natural Gas from Other Regions[189]

Natural gas pipelines provided operational flexibility and used reversible flows to import from areas with less demand where possible. The Midcontinent and Texas regions, traditionally suppliers of natural gas to neighboring states, continued to export gas but also imported gas from nearby regions to meet their peak demand. On balance during the Event, the Midcontinent region became a net importer of natural gas on high demand days and Texas saw drastic reductions of exports, as shown in Figure 54 below. In the Midcontinent, exports to northeast Texas experienced a significant decline, by around 1 Bcf/d during the peak days of February 15 and 16. Similarly, Texas reduced its gas exports to nearby states during the storm. The Texas portion of the Permian basin in particular experienced a significant decline in exports to the southwest region by around 0.5 to 0.6 Bcf/d from early February levels on February 15 and 16. South Texas gas flows to serve LNG export markets and Mexico declined by around 2 Bcf/d on February 16.

During the peak of the Event on February 15 and 16, Midcontinent and Texas temperatures tumbled more than 40 degrees below normal, with Midcontinent dipping below zero degrees. As a result, natural gas demand in the Midcontinent hit a new single-day high of 11.9 Bcf/d on February 15, and Texas hit a record of 27.6 Bcf/d on the same day. Figures 54-56 illustrate the change in

[189] Information in this section sourced from Luke Jackson, *What Caused Midcon/Texas Natural Gas Price Spikes and What are the Implications for US Summer 2021 Balances?* (Feb. 25, 2021, 4:42 PM), S&P Global Platts, https://benport.bentekenergy.com/spotlight/2021/02/what-caused-midcontexas-natural-gas-price-spikes-and-what-are-the-implications-for-us-summer-2021-balances/. Graphics reprinted with permission.

pipeline flows to meet increased natural gas demands in South Central U.S. and Texas during February 2021.

Figure 54: South Central U.S. Natural Gas Inflows and Outflows, February 1 – 20, 2021

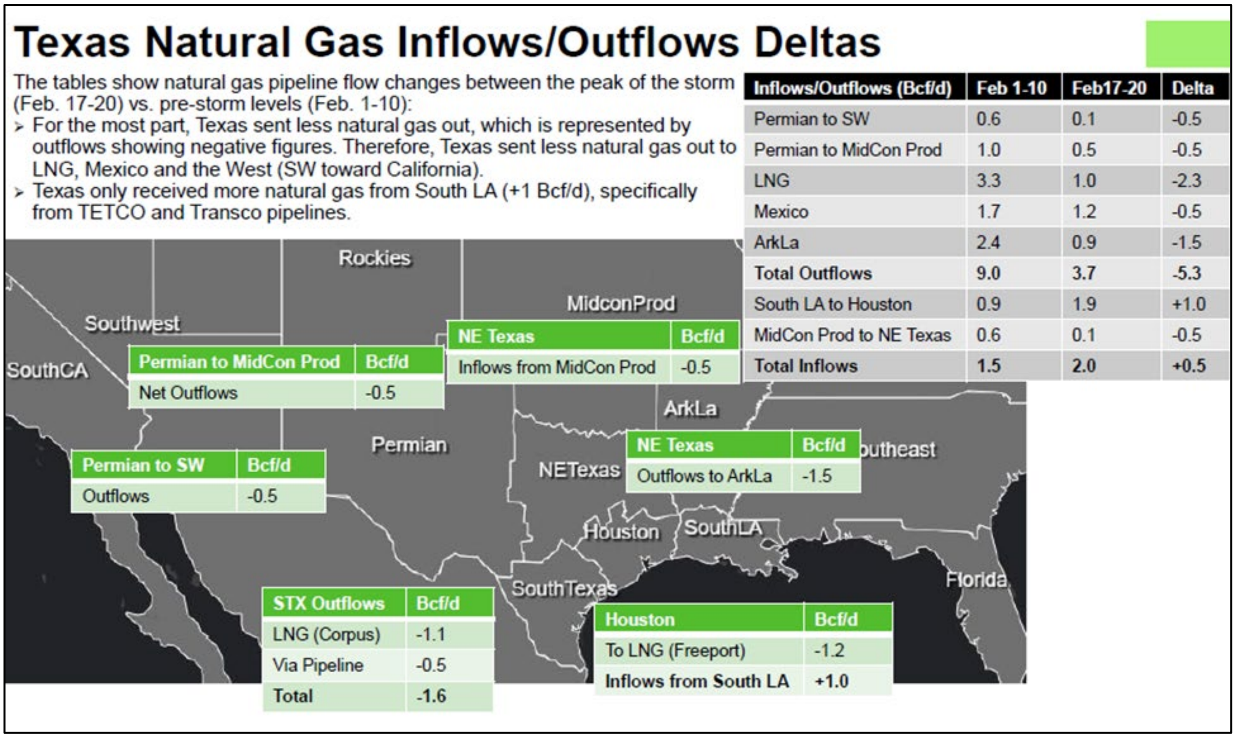


Figure 55: Texas Natural Gas Inflows and Outflows, February 1 – 20, 2021

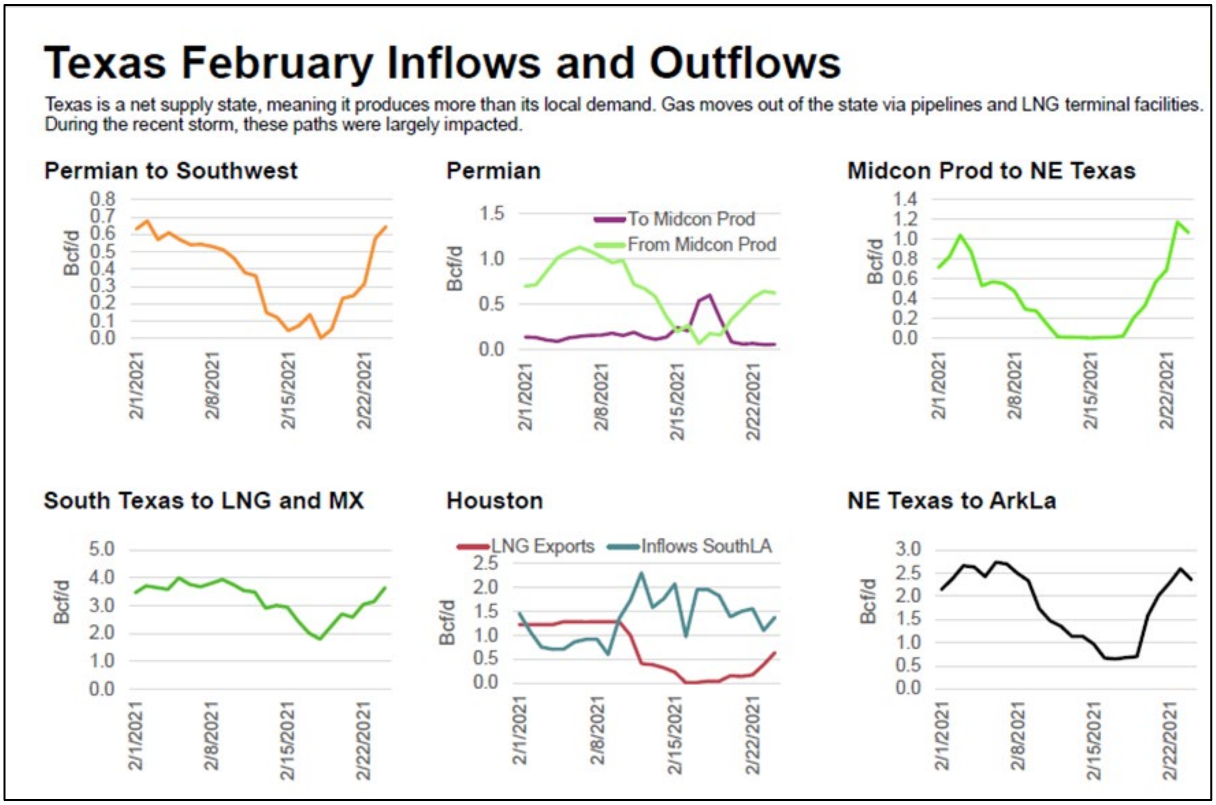
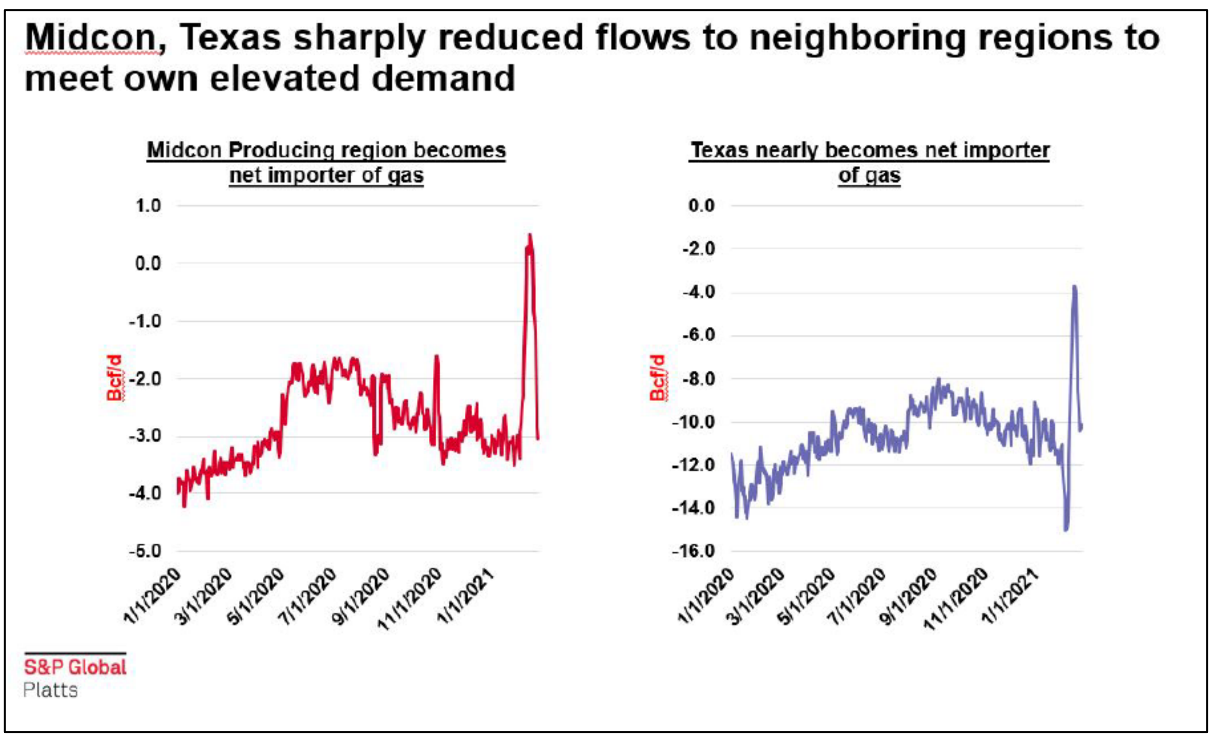


Figure 56: Texas Natural Gas Flow Changes to Neighboring Regions

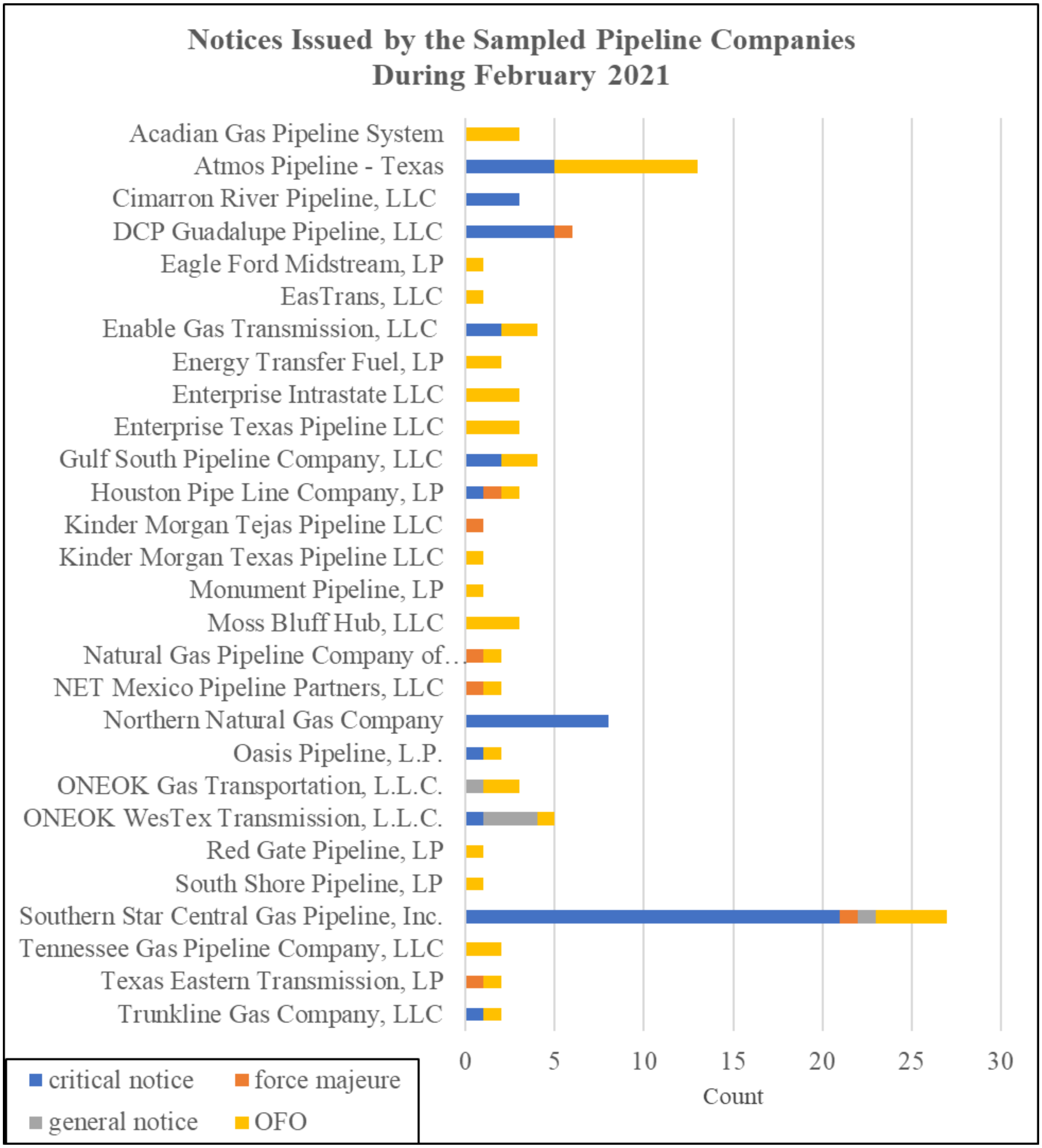


c. Natural Gas Pipeline Conditions - February 14 - 20

During the Event, interstate and intrastate natural gas pipelines throughout the Event Area were only minimally affected by power outages (because most used natural gas-fired compressors and have backup power for control systems) and were largely able to meet their firm transportation commitments. Seven pipelines issued notices of force majeure that affected 14 firm shippers, including four natural gas-fired generating units. See Figure 57, below. Intrastate Kinder Morgan pipelines issued force majeure notices to their non-human-needs industrial customers under the Texas RRC's emergency order. Pipeline communications via system-wide OFO, critical, and other notices conveyed to customers that the pipelines were in an emergency situation and would not tolerate customers shorting the pipelines[190] or going over their capacity allotment.

[190] "Shorting" a pipeline occurs when a customer shipping gas on a pipeline system takes off more gas than its commodity seller had placed onto the system. This forces the pipeline to balance the supply shortfall. In periods of high demand, multiple shippers taking more than they placed on the system can lower the pipeline's system pressure. If the pipeline's operating pressure declines significantly, it can cause service reliability problems. Understanding this, during high demand periods, pipelines often issue critical notices, OFOs or low line pack warnings and impose stricter balancing tolerance levels. During the Event, pipelines were concerned about customers taking more gas than they were entitled to, so many issued low OFO penalties tightening the tolerance levels and imposing high OFO penalties (consistent with their tariff) for violations in order to discourage this behavior.

Figure 57: Notices Issued by Pipeline Companies During February 2021



<u>February 14 through 16.</u> On February 14, as colder weather and freezing precipitation moved throughout the Event Area, more natural gas processing plants reported outages that were attributed to either lack of natural gas supply, mechanical failure due to weather, or power outages. During this timeframe, pipelines issued the greatest number of critical notices for the need to curtail deliveries, primarily due to loss of natural gas supply. For example, at 8:30 a.m. on the morning of February 14, Northern National Gas Company, the largest interstate pipeline company in the U.S., issued a critical notice effective for the gas day beginning at 9 a.m. on Monday, February 15. The notice mentioned temperatures would be "well below normal" through the weekend, and that "Northern is at imminent risk of experiencing reduced receipts at pipeline interconnects." Also, on February 14, the first force majeure notices were issued by an intrastate natural gas pipeline in ERCOT, because of lack of natural gas supply and a pipeline equipment failure. These force majeure notices resulted in a limited number of delivery curtailments to natural gas-fired generating units in ERCOT with firm natural gas transportation contracts.

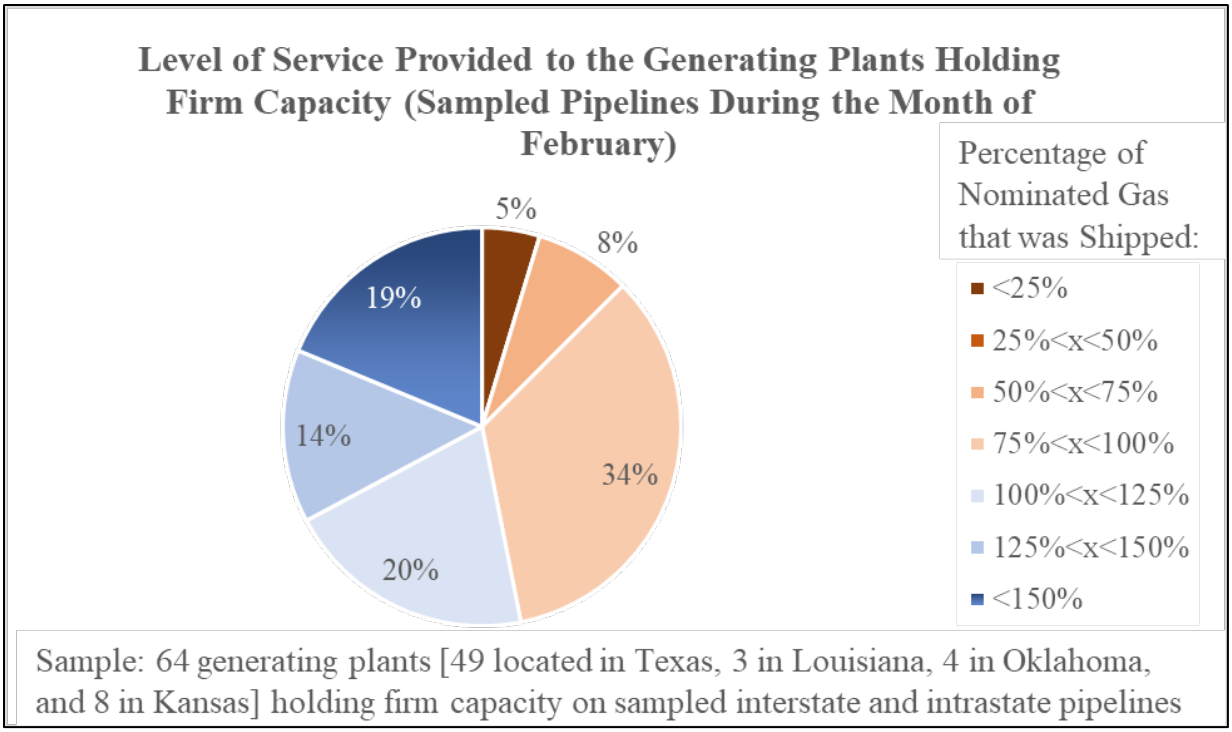
On February 15 and 16, after ERCOT had ordered firm load shed, several force majeure notices were issued which resulted in curtailment of natural gas deliveries. Causes included compressor station mechanical problems, loss of compressor electric power supply, and curtailments to industrial natural gas customers due to the RRC's emergency order for priority for human needs. Some of these force majeure conditions lasted through February 18.

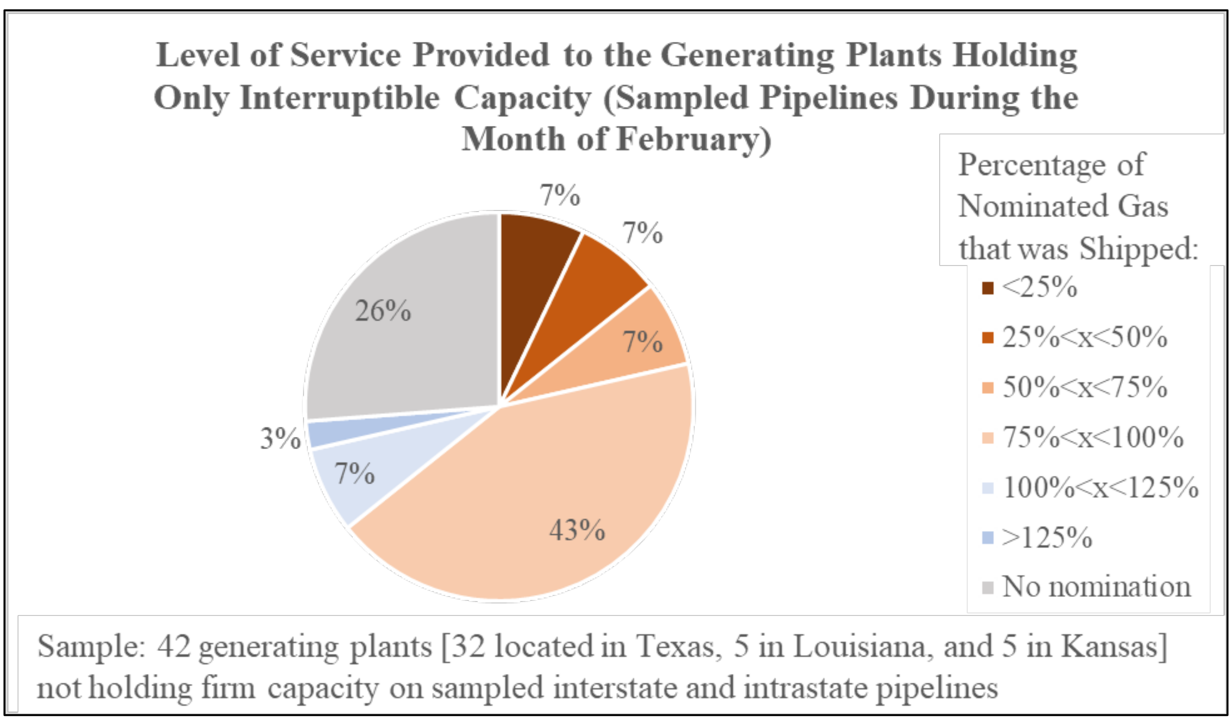
February 17 through 20. Intrastate and interstate pipelines continued to issue critical notices during this period, primarily due to natural gas supply shortfalls, but to a lesser extent, because weather conditions gradually improved. Although there were no declarations of force majeure, pipelines issued several OFOs due to declines in both natural gas supply and line pack.

Over the entire Event, despite the issuance of some force majeure notices and OFOs, interstate and intrastate pipelines were able to ship a substantial percentage of the gas nominated by firm shippers. Thirteen pipelines provided daily data which the Team used to evaluate the level of transportation service provided to natural gas-fired generating units during the month of February. Specifically, the Team examined the daily amount of gas each generating unit (referred to as "plant" by the pipeline) nominated and what percentage of that nominated gas was actually shipped. Over half of the generating plants holding firm capacity on the sampled pipelines (53 percent) had 100 to 150 percent or more of their nominated gas shipped.[191] Most generating plants that did not hold firm capacity still had some gas shipped: over fifty percent of the generating plants holding only interruptible capacity had 75 to over 125 percent of their nominated gas shipped. Marketers are not represented in this data. See Figure 58, below.

[191] As shown in Figures 59 and 60 below, the nominations were not always consistent with contracted volumes.

Figure 58: Level of Service Provided to the Generating Plants Holding Firm Capacity (Sampled Pipelines During the Month of February)





The graphs in Figures 59 and 60, below, depict interstate and intrastate volumes nominated, volumes shipped and volumes contracted throughout the Event Area, demonstrating the potential value of firm transportation during the winter months and underscoring that the peak for natural gas as a whole still occurs during the winter months, although natural gas-fired generating units often serve a summer peaking region (as in ERCOT).

Figure 59: Firm Natural Gas Pipeline Capacity Contracting and Scheduling by Natural Gas-Fired Generating Plants – Interstate Pipelines

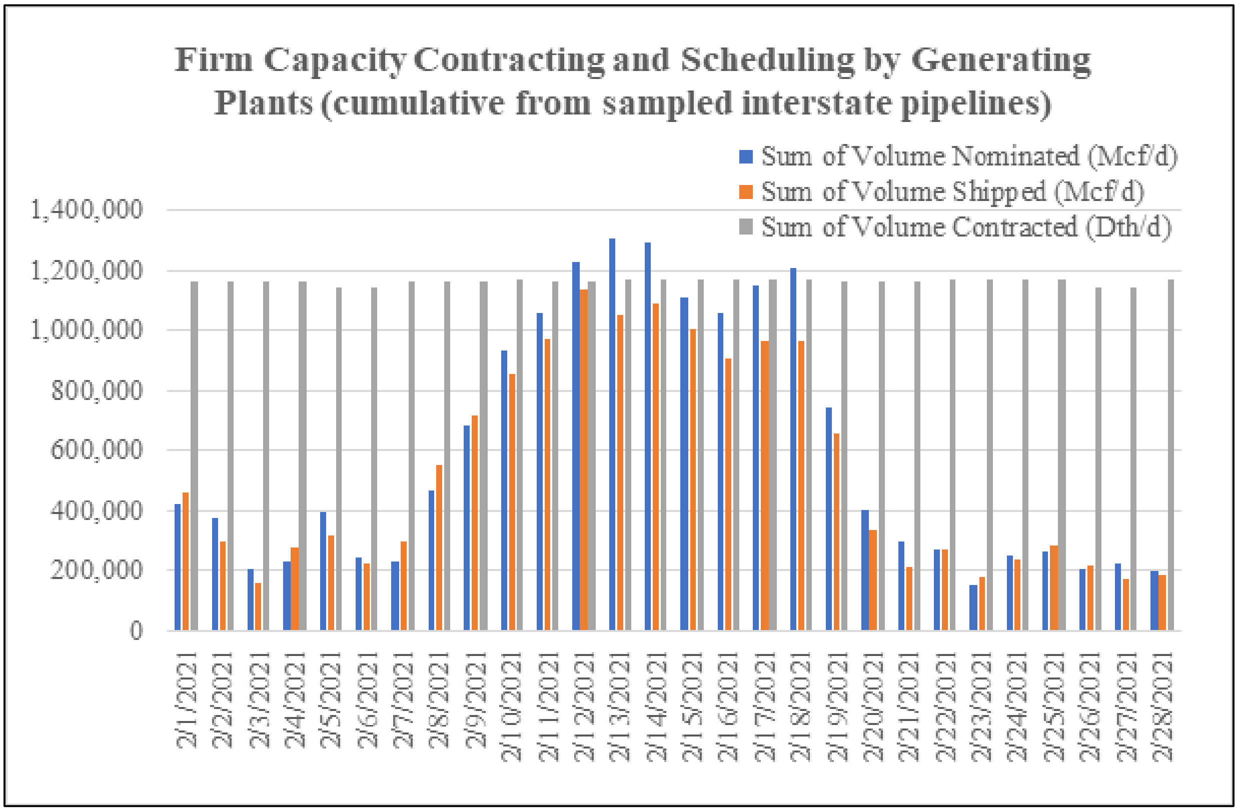
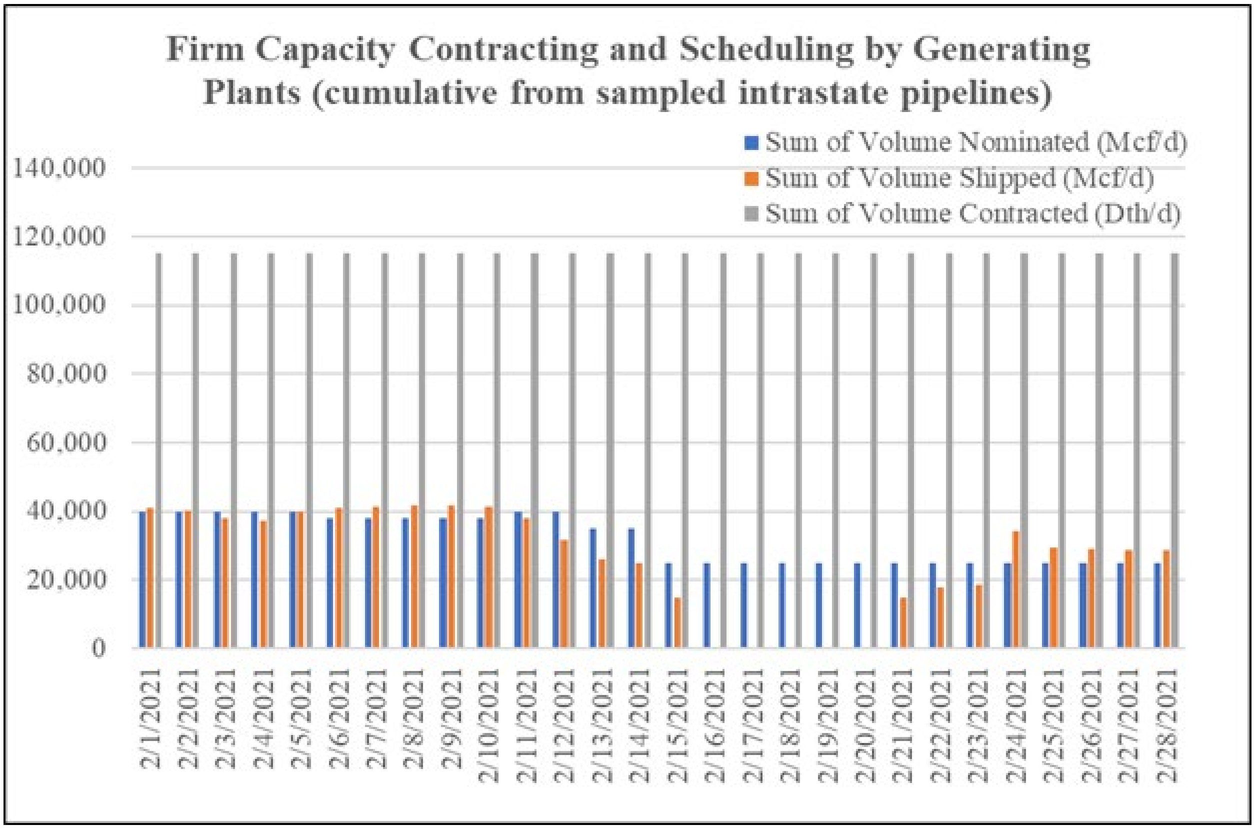


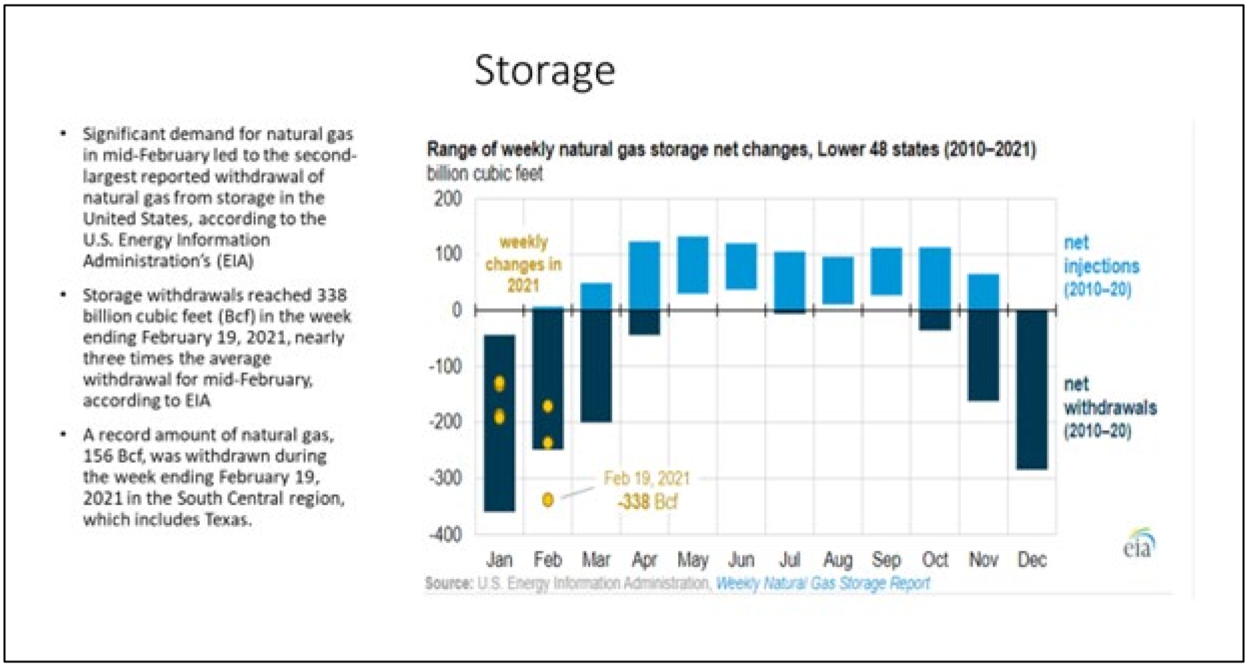
Figure 60: Firm Natural Gas Pipeline Capacity Contracting and Scheduling by Natural Gas-Fired Generating Plants – Intrastate Pipelines



d. Natural Gas storage

Natural gas pipelines and shippers were able to meet their obligations partly due to the effective use of production- and market-area storage fields. Hit with the combination of freeze-induced natural gas production declines in Texas and the South Central U.S., increased natural gas consumption from residential and commercial customers, and increased demands from natural gas-fired generating units, pipelines and shippers relied on storage facilities, making record withdrawals for February, as shown in Figure 61 below. Pipelines made storage injections prior to the Event and withdrawals during the Event to meet natural gas demand in the Event Area.

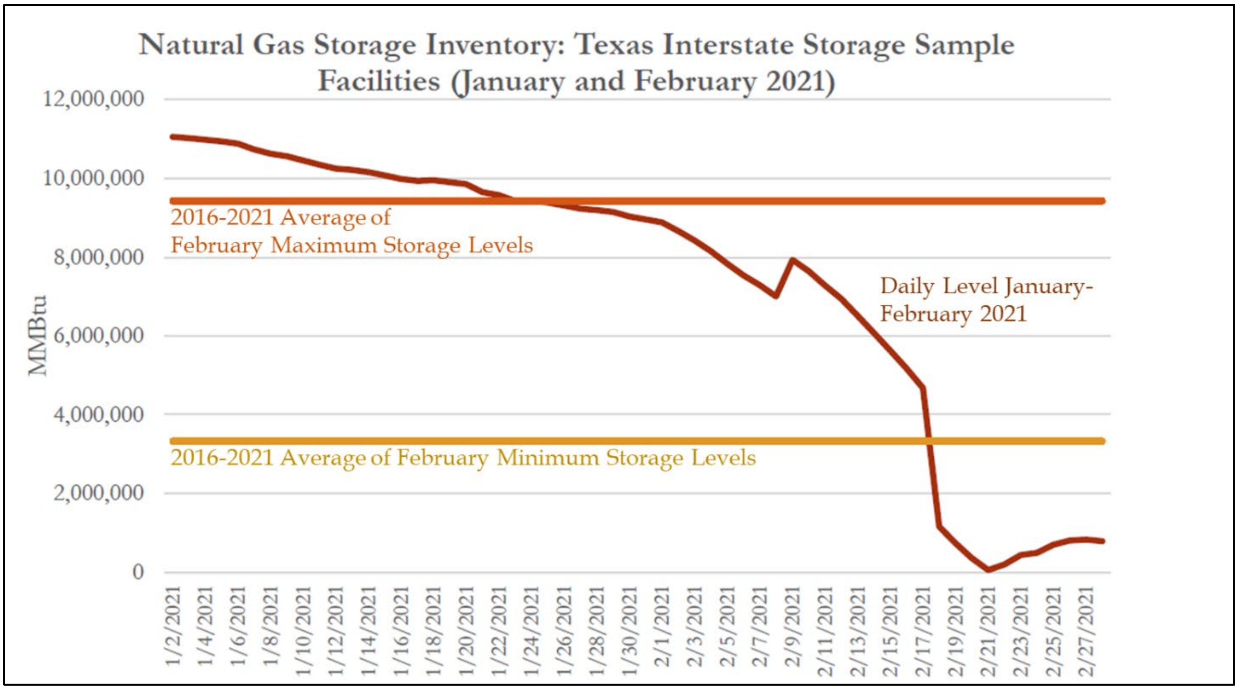
Figure 61: Natural Gas Storage Withdrawals and Injections, Lower 48 States (2010 to February 2021)[192]



Storage fields reached maximum withdrawal rates between February 17 and 18 (as shown in Figure 62 below), based on a sample of daily levels at five interstate storage facilities compared to average levels for February over the past six years. Most storage fields did not see injections restart until February 21. Storage generally performed as expected relative to its inventories, pressures, and deliverability curves throughout the Event.[193]

[192] United States Energy Information Administration (EIA), *Cold weather results in near-record withdrawals from underground natural gas storage*, Today in Energy (Feb. 26, 2021), https://www.eia.gov/todayinenergy/detail.php?id=46916.
[193] UT Report at 47.

Figure 62: Natural Gas Storage Inventory[194]



e. Natural Gas Pipeline Outages

Natural gas pipelines were largely unaffected by wide scale power outages. Notably, most compressor stations are gas-powered, and pipelines have backup generators and/or batteries at their major facilities. Isolated electrical power loss occurred at compressor stations, storage facilities, and meter stations. Figure 63, below describes reported natural gas pipeline outages due to power loss that impacted pipeline flows.

194 UT Report, Figure 2w (attributed to Wood Mackenzie).

Figure 63: Natural Gas Pipeline Power Outages that Impacted Flows

Date(s)	Facility(ies)	Cause	Effect
2/15/21	One compressor station	Loss of commercial electric power	Deliveries curtailed until backup generation became available
2/15/21	Storage facility	Loss of commercial electric power	55% reduction of maximum withdrawal capacity for about eight hours
2/15-2/16/21	Two compressor stations	Loss of commercial electric power	Issued a Force Majeure notice, impacted one commercial, non-generating-unit location
2/16-2/18/21	One compressor station	Loss of commercial electric power, failure of backup generator	Issued a Force Majeure notice
2/19/21	Meter station	Loss of commercial power	Unable to receive gas for about seven hours
2/16/21	One compressor station	Loss of commercial power	Fell short of nominated volumes
2/14-2/15/21	Storage facility	Losses of commercial power (twice)	Interrupted operation of the glycol dehydration unit, reducing operational ability
2/17/21	Meter station	Loss of power, backup generator failed	Unable to receive gas for about two hours until portable generator delivered

Approximately a third of the pipelines that provided data to the Team (10 of 32) had some facilities (meter stations, compressor stations, storage facilities) designated as protected or critical load. All pipelines had backup generators and/or batteries at their major facilities. None of the pipelines participated in demand response programs. Only approximately 16 percent of the 128 reported pipeline-related events affecting compressor stations resulted in associated flow reduction.[195] The majority of the 128 pipeline-related events were the result of mechanical issues that did not affect operations, and since the majority of pipelines deployed personnel to compressor stations around-the-clock, even compressor station events that affected operations were resolved on average within 25 hours.

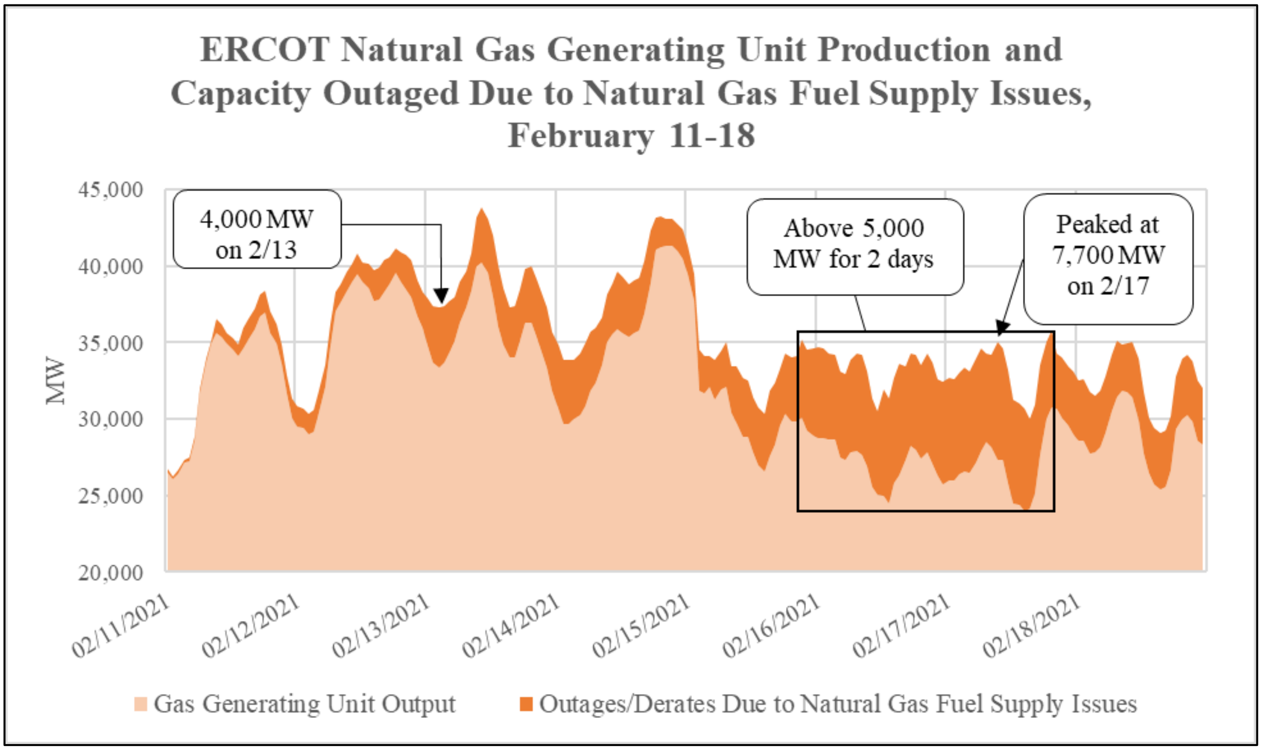
[195] Only four of these events were related to power outages (whether caused by rotating load shed or local, weather-related distribution outages). They are described in more detail in Figure 63, above.

3. Unplanned Generating Unit Outages Begin to Escalate

Increased Generating Unit Outages Due to Natural Gas Supply Issues. On February 14, the ERCOT, SPP and MISO footprints combined averaged over 10,300 MW in generating unit outages and derates due to natural gas fuel supply issues. Going into February 15, ERCOT had approximately 2,300 MW of unplanned generating unit outages and derates due to natural gas fuel supply issues, while SPP had over 6,000 MW and MISO South had 700 MW.

As natural gas fuel supply issues worsened during the week of February 14, reductions in natural gas-fired generating unit output followed, as shown in Figure 64, below.

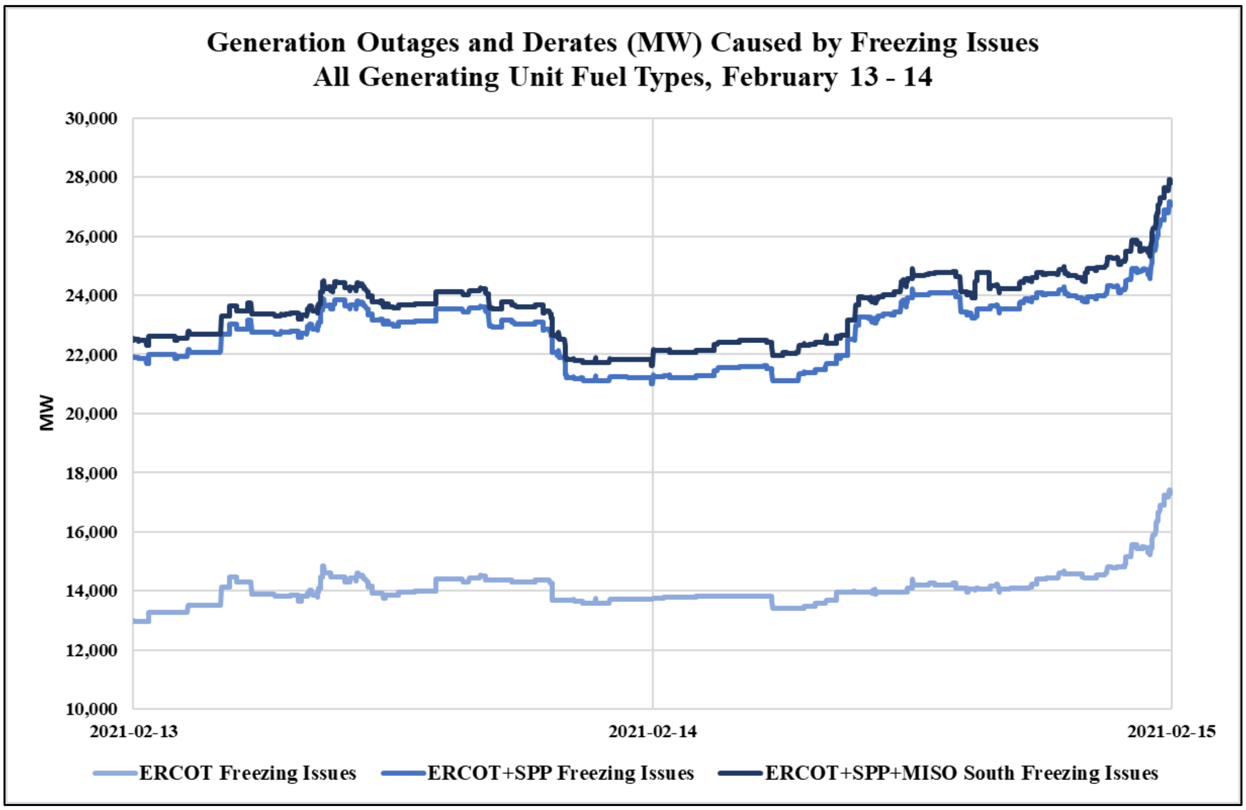
Figure 64: ERCOT Natural Gas-Fired Generating Unit Production and Capacity Outaged Due to Natural Gas Fuel Supply Issues, February 11 – 18



Additional Generating Unit Outages due to Freezing Issues. By the weekend of February 13 and 14, ERCOT unplanned generating unit outages and derates due to freezing issues averaged over 14,000 MW. ERCOT had all available units operating on February 14, in an attempt to avoid failures to start. Temperatures in Dallas fell to four degrees by the morning of February 15, compared to a normal daily minimum temperature for the same day of 39 degrees, accompanied by freezing precipitation and wind in a large portion of the Event Area. Additional generating units experienced freezing issues, resulting in a sharp upward trend in the number of generating unit outages and derates in the Event Area by the late evening hours of February 14, into the early morning of February 15. At the start of February 15, the number of freezing-related unplanned generating unit outages increased sharply to over 17,400 MW.

Over the weekend of February 13 and 14, in SPP, generating unit outages and derates due to freezing issues averaged over 8,700 MW, increasing to over 9,700 MW by the start of February 15. In MISO South, generating unit outages and derates due to freezing issues were still relatively minimal as compared to ERCOT and SPP (as seen in Figure 65, below), since the colder temperatures and freezing precipitation arrived there after reaching SPP and ERCOT. MISO South cumulative freezing-related generating unit outages and derates averaged 700 MW. ERCOT, SPP and MISO freezing-related generating unit outages and derates in total climbed from approximately 22,400 MW to 27,800 MW during the period from February 13 to the start of February 15, as shown in Figure 65, below.

Figure 65: Generation Outages and Derates Due to Freezing Issues – February 13 - 14



To gain additional insight on generation unavailable during early part of the week of February 14, Figure 66a, below, provides perspectives on total unavailable generation (including the causes of the unplanned generation outages) at different times on February 14 through 16, as compared to the onset of the cold weather (February 8) within the three BA footprints, and for the entire Event Area. Figures 66b and 66c illustrate the total unavailable generation over time, by BA footprint. Total unavailable generation exceeded 90,000 MW in the Event Area on February 16 at 5 p.m., as shown in Figures 66a and 66c below.

Figure 66a: Unavailable Generation at Different Points in Time, February 14 -16[196]

Generation Outages and Derates (Nameplate MW)	*Before Onset of Colder Weather (MW)*	Point of Time During Event: As of Sunday Feb. 14 12 a.m. (MW)	As of Monday Feb. 15 12 a.m. (MW)	As of Monday Feb. 15 12 p.m. (MW)	As of Tuesday Feb. 16 12 a.m. (MW)	As of Tuesday Feb. 16 12 p.m. (MW)	As of Tuesday Feb. 16 5 p.m. (MW)	*Non-Coincident Event Area Peak Time (MW)*
ERCOT Footprint								
Planned:	3,079	1,859	1,859	1,859	1,859	1,812	1,812	1,812
Unplanned:	10,633							
Freezing Issues:		13,712	17,308	29,680	27,548	26,143	26,918	29,704
Fuel Issues:		4,259	2,435	4,194	6,239	6,320	6,746	4,400
Mechanical/Electrical Issues:		4,675	5,659	7,432	8,237	9,037	8,038	8,211
Other Issues:		238	1,015	3,617	2,164	1,778	1,598	3,617
Incremental Unplanned:		**12,251**	**15,784**	**34,290**	**33,555**	**32,645**	**32,667**	**35,299**
Total Unavailable:	13,712	**24,743**	**28,276**	**46,782**	**46,047**	**45,090**	**45,112**	**47,744**
Percent of Installed Capacity:	11.1%	20.1%	23.0%	38.0%	37.4%	36.6%	36.7%	38.8%
SPP Footprint								
Planned:	6,238	4,999	4,569	3,996	3,811	3,811	3,811	3,811
Unplanned:	11,264							
Freezing Issues:		7,292	9,744	11,520	11,672	11,311	11,634	12,472
Fuel Issues:		5,411	6,361	6,771	8,092	9,199	9,405	9,866
Mechanical/Electrical Issues:		3,680	4,561	4,225	4,027	3,937	3,911	4,297
Other Issues:		890	1,275	792	792	792	792	792
Incremental Unplanned:		**6,009**	**10,677**	**12,044**	**13,319**	**13,975**	**14,478**	**16,163**
Total Unavailable:	17,502	**22,272**	**26,510**	**27,304**	**28,394**	**29,050**	**29,553**	**31,238**
Percent of Installed Capacity:	18.6%	23.6%	28.1%	29.0%	30.1%	30.8%	31.4%	33.2%
MISO South Footprint								
Planned:	1,793	1,500	1,500	1,455	1,280	1,280	1,280	1,280
Unplanned:	1,406							
Freezing Issues:		606	756	4,938	5,219	7,607	8,247	8,247
Fuel Issues:		1,730	1,291	1,237	1,753	2,279	3,671	3,671
Mechanical/Electrical Issues:		1,971	1,231	2,006	1,958	2,342	2,873	2,873
Other Issues:		-	-	736	736	775	775	775
Incremental Unplanned:		**2,901**	**1,872**	**7,511**	**8,260**	**11,597**	**14,160**	**14,160**
Total Unavailable:	3,199	**5,807**	**4,778**	**10,372**	**10,946**	**14,283**	**16,846**	**16,846**
Percent of Installed Capacity:	7.6%	13.9%	11.4%	24.8%	26.1%	34.1%	40.2%	40.2%
Total Event Area								
Incremental Unplanned:		**21,161**	**28,333**	**53,845**	**55,134**	**58,217**	**61,305**	**65,622**
Total Unplanned:	23,303	**44,464**	**51,636**	**77,148**	**78,437**	**81,520**	**84,608**	**88,925**
Total Unavailable:	34,413	**52,822**	**59,564**	**84,458**	**85,387**	**88,423**	**91,511**	**95,828**
Percent of Installed Capacity:	13.3%	**20.4%**	**23.0%**	**32.6%**	**32.9%**	**34.1%**	**35.3%**	**37.0%**

196 "Before Onset of Colder Weather" column refers to February 8, 12 a.m. Percent of Installed Capacity is based on 123,057 MW, 94,232 MW and 41,865 MW for ERCOT, SPP and MISO South, respectively. The "Non-Coincident Event Area Peak" of unplanned generation outages and derates was 65,622 MW, which occurred at different points in time: in ERCOT on February 15 at 1:05 p.m., MISO South on February 16 at 5:01 p.m., and SPP on February 17 at 12:17 a.m. The coincident peak of incremental unplanned generation in the Event Area was 61,305 MW which occurred on Tuesday, February 16 at 5 p.m., as shown in Figure 66a ("As of Tuesday, February 16, 5 p.m." column.).

Figure 66b: Total Unavailable Generation over Time, February 8 - 20, by BA Area

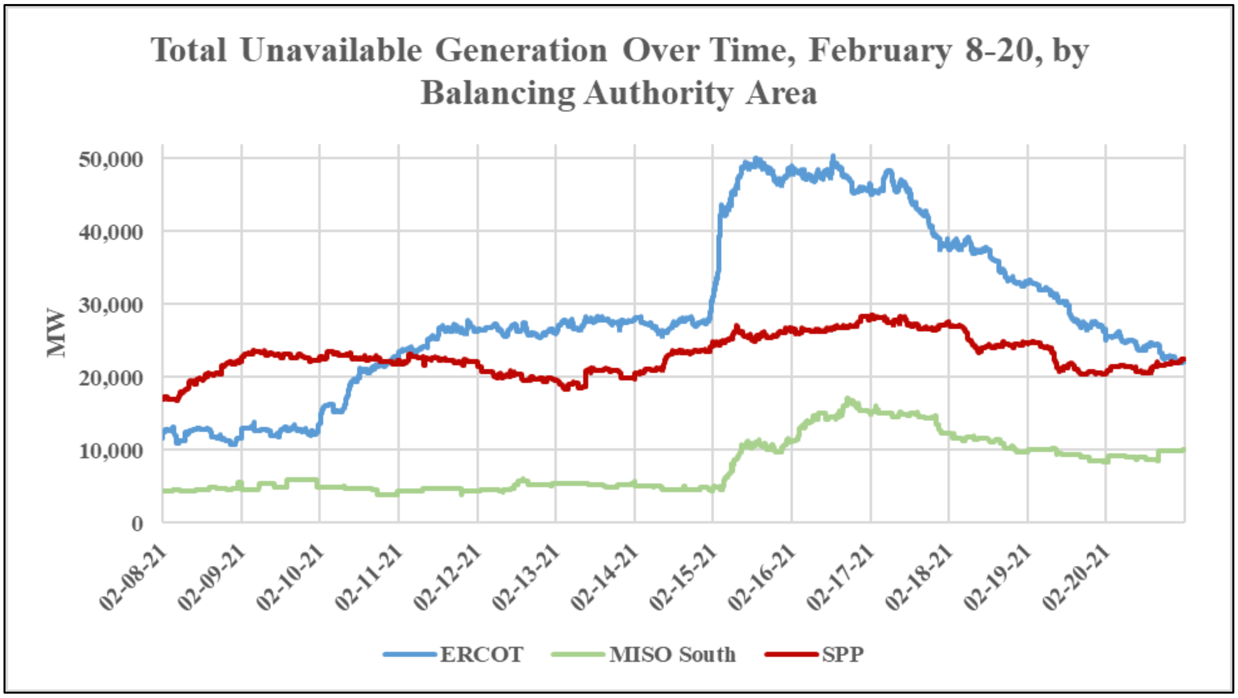
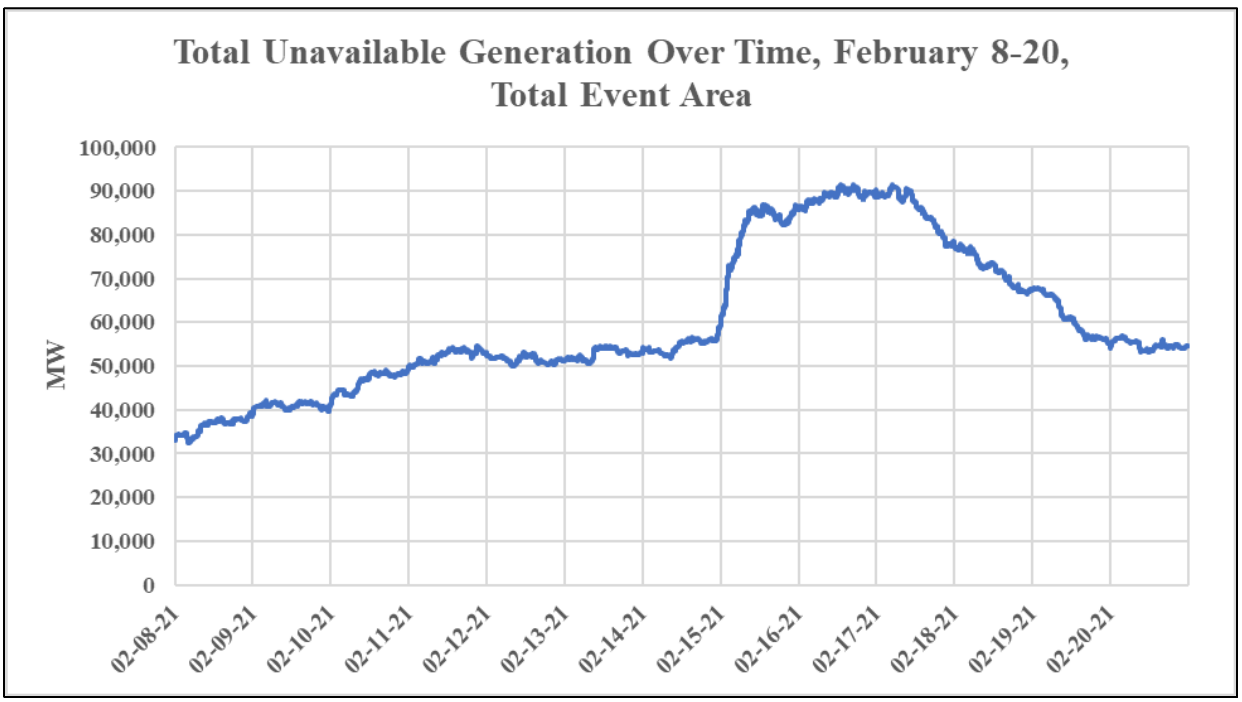


Figure 66c: Total Unavailable Generation over Time, February 8 - 20, Total Event Area

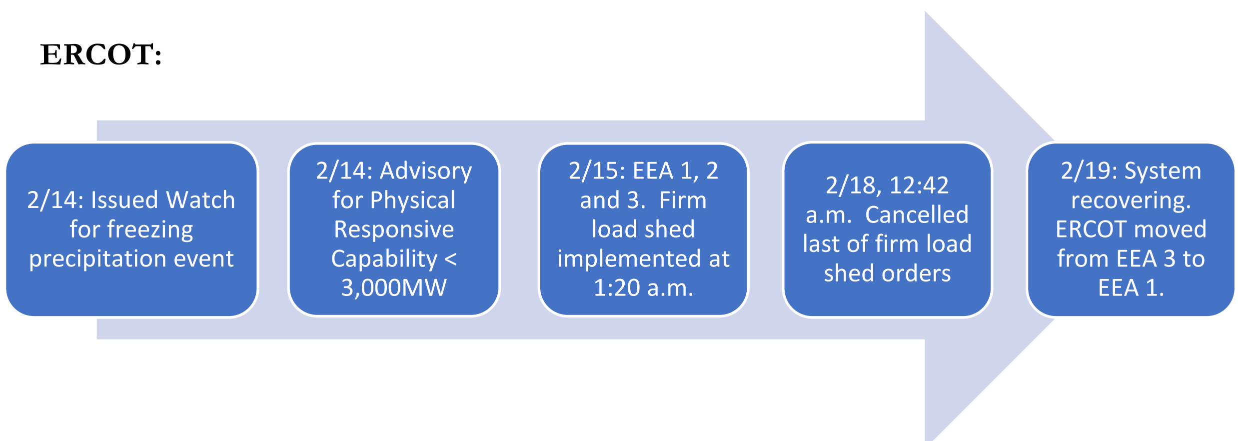


4. Grid Operators' Real-Time Actions Due to Unplanned Generating Unit Outages

a. Overview

With freezing precipitation and severe cold temperatures invading the region, ever-increasing unplanned generating unit outages, coupled with forecast record- or near-record peak electricity demands for February 15 and 16, ERCOT, SPP and the MISO BA and RC operators were faced with "the perfect storm." Increases in generating unit unavailability continued in ERCOT, MISO South and SPP, and all three declared energy emergencies during the week of February 14 for this core reason. The most prominent problem that faced ERCOT and SPP grid operators was balancing load against remaining available electric generation output. ERCOT's challenge was most severe, due to the magnitude of unplanned generating unit outages in its area, coupled with its limited ability to import power to help offset generation shortfalls.[197] While MISO and SPP had the ability to import power from the east where weather conditions were less severe to make up for a large portion of their generation shortfalls, they reached transmission limits in doing so (only so much power could be reliably imported), requiring MISO to declare transmission emergencies[198] in addition to SPP and MISO South's energy emergencies. Figure 67, below, provides a summary of the alerts declared by all three entities during the week of February 14, 2021.

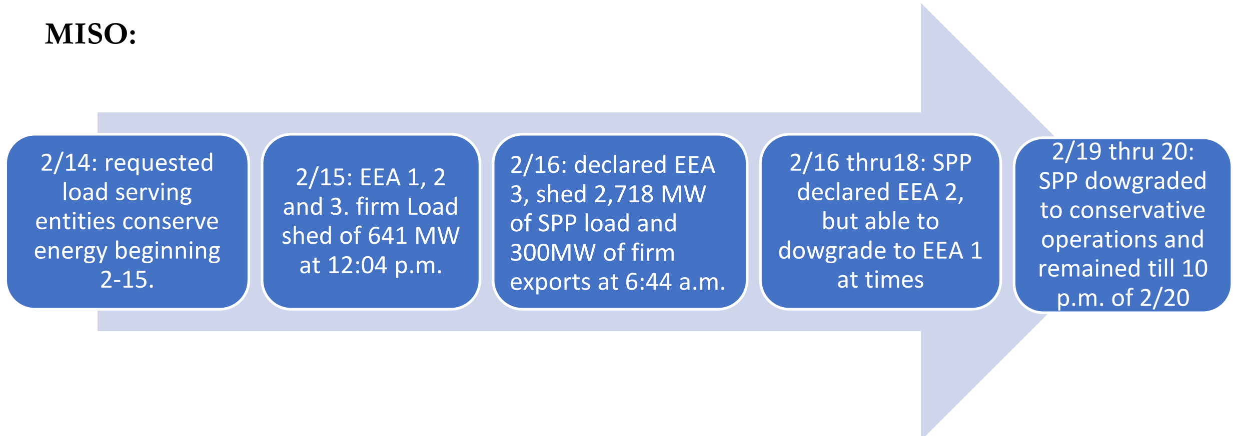
Figure 67: Alerts Issued by ERCOT, SPP and MISO, February 14-20, 2021



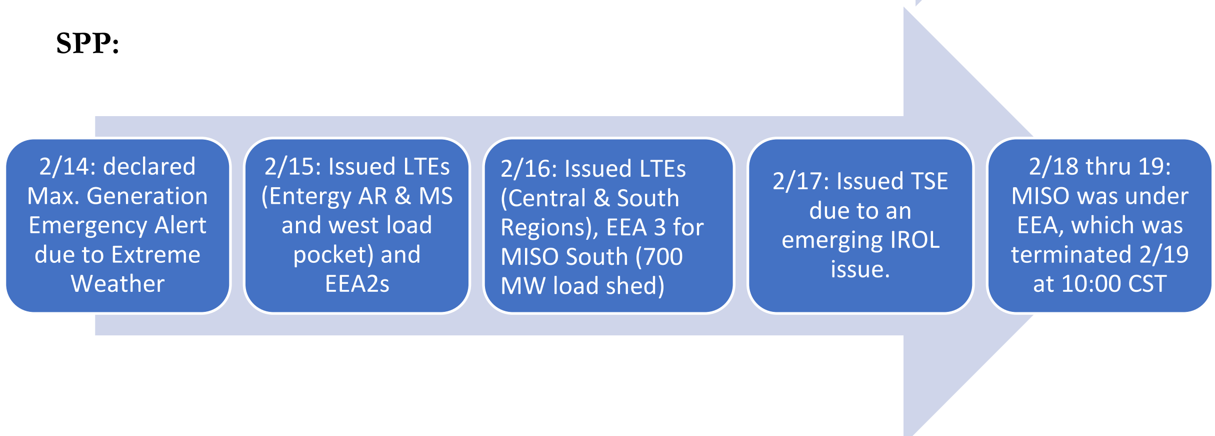
[197] The entire ERCOT Interconnection has a maximum total import limitation of only 1,220 MW over its direct current ties with SPP (Eastern Interconnection) and CENACE (Mexico). ERCOT did schedule power to be imported to the extent available from the Eastern Interconnection. ERCOT, unlike MISO and SPP (who collectively imported nearly 13,000 MW) did not have the ability to import many thousands of MW from the Eastern Interconnection. Had ERCOT been able to import more power, it likely would have decreased the amount that MISO and SPP would have been able to import.

[198] At different times and locations, MISO declared local transmission emergencies (LTEs) and transmission system emergencies (TSEs) to maintain BES reliability.

MISO:



SPP:



b. ERCOT Operator Actions: Maintaining Frequency Despite Generation Outages to Prevent Grid Collapse

While ERCOT was able to avoid energy emergency measures through Saturday February 13, on Sunday, February 14, ERCOT was faced with even colder temperatures than Saturday, with the arctic air spreading into southern Texas, and additional electricity heating demands driving system load nearly ten percent higher than the day before.[199] At 9:21 a.m., ERCOT notified the PUCT that an EEA declaration might be needed that day. ERCOT had several ongoing 345kV transmission facility outages on Sunday, which primarily resulted from by freezing precipitation.[200] At 11:33 a.m. on February 14, similar to Saturday morning, ERCOT's Physical Responsive Capability[201] dropped

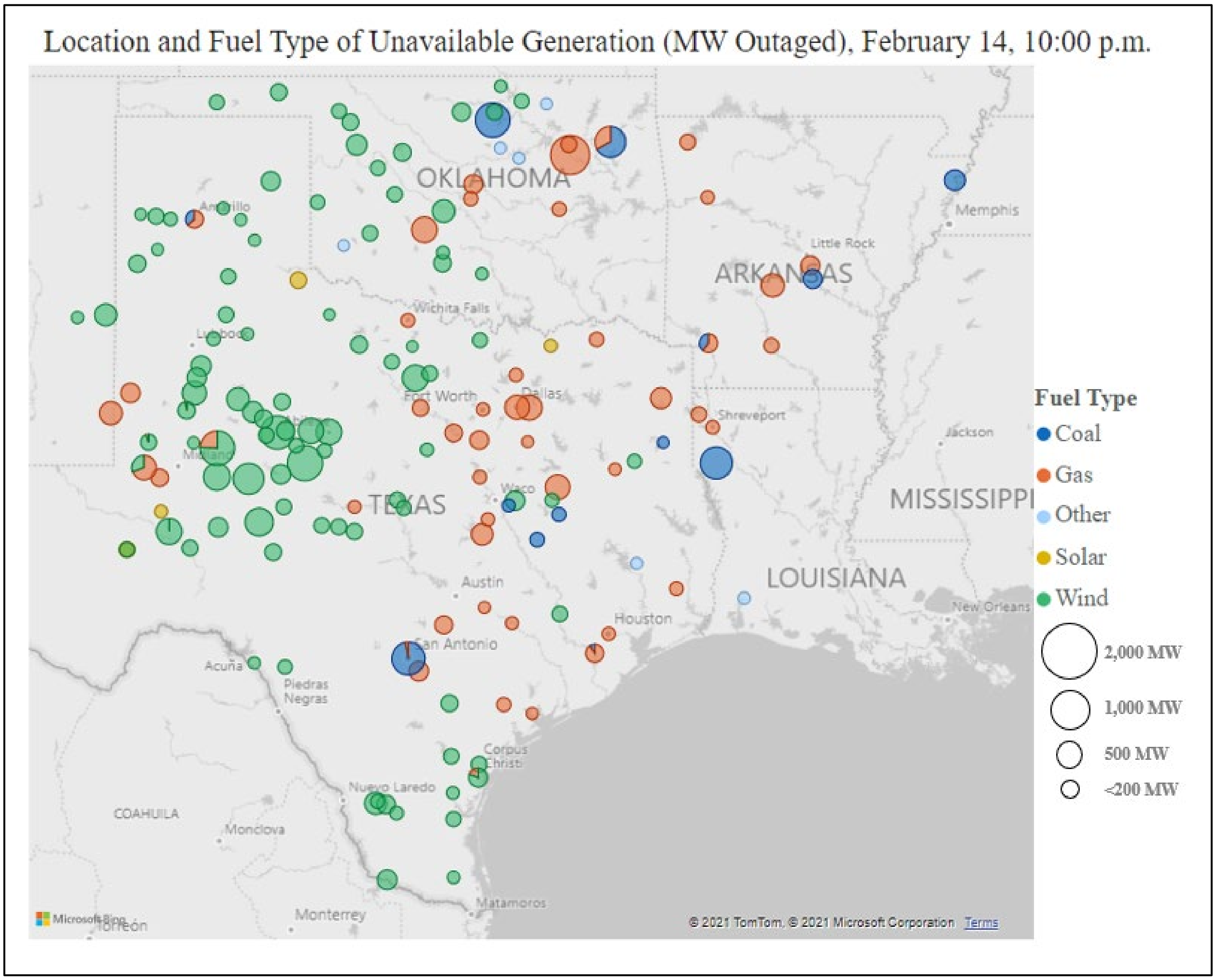
[199] On February 13, ERCOT peaked at 64,181 MW, but the next-day forecast for February 14 projected a peak of 70,327 MW (9.6 percent higher than the actual February 13 peak).

[200] Fortunately, these outages ended by Sunday evening, and the ERCOT RC/TOP implemented post-contingency mitigation measures to remain within system operating limits.

[201] Physical Responsive Capability values in this section are based on ERCOT's historical database of recorded values provided during the Event from the QSEs. ERCOT discovered after the Event that some QSEs were not updating the responsive reserve amounts for their generating units promptly during the Event. See Recommendation 23.

below 3,000 MW, which meant ERCOT BA no longer had sufficient contingency reserves above the current system load level. ERCOT issued an Advisory, meaning it recognized that conditions were developing such that GOPs and TOPs may need to take actions in anticipation of an EEA. At 3:17 p.m., ERCOT issued a Watch for a projected reserve capacity shortage, with no market solution available for hours ending 5:00 p.m. through 9:00 p.m., which translated to a high risk of an EEA event. On Sunday night, February 14, at hour-ending 8 p.m., ERCOT's system load reached an all-time winter peak of 69,871 MW, which remains ERCOT's highest recorded actual winter peak load to date, since ERCOT operators needed to shed large amounts of firm load on Monday and Tuesday. Then-committed generating units remained online during the Sunday evening peak and for about two hours more, so ERCOT BA operators did not need to declare an EEA.

Figure 68: Location of Unplanned Generation Outages and Derates, (MW Outaged), by Fuel Type, Total Event Area, February 14, 10 p.m.



System load decreased and Physical Responsive Capability recovered toward 3,000 MW after 9 p.m., and at 9:58 p.m., ERCOT cancelled its Watch for a projected reserve capacity shortage. Figure 68, above shows the generating unit outages in the Event Area as of February 14 at 10 p.m. The improved conditions in ERCOT did not last long.

At approximately 10:00 p.m. on February 14, and continuing into the early morning hours of February 15, unplanned generation outages and derates sharply increased, as shown in Figure 69, below. Over a three-hour period, approximately 6,000 MW of additional unplanned generation outages and derates occurred. These outages were primarily caused by freezing issues (52 to 60 percent of the outages during that period, as shown in Figure 70, below).

Figure 69: ERCOT Sharp Increase in Generation Outages and Derates

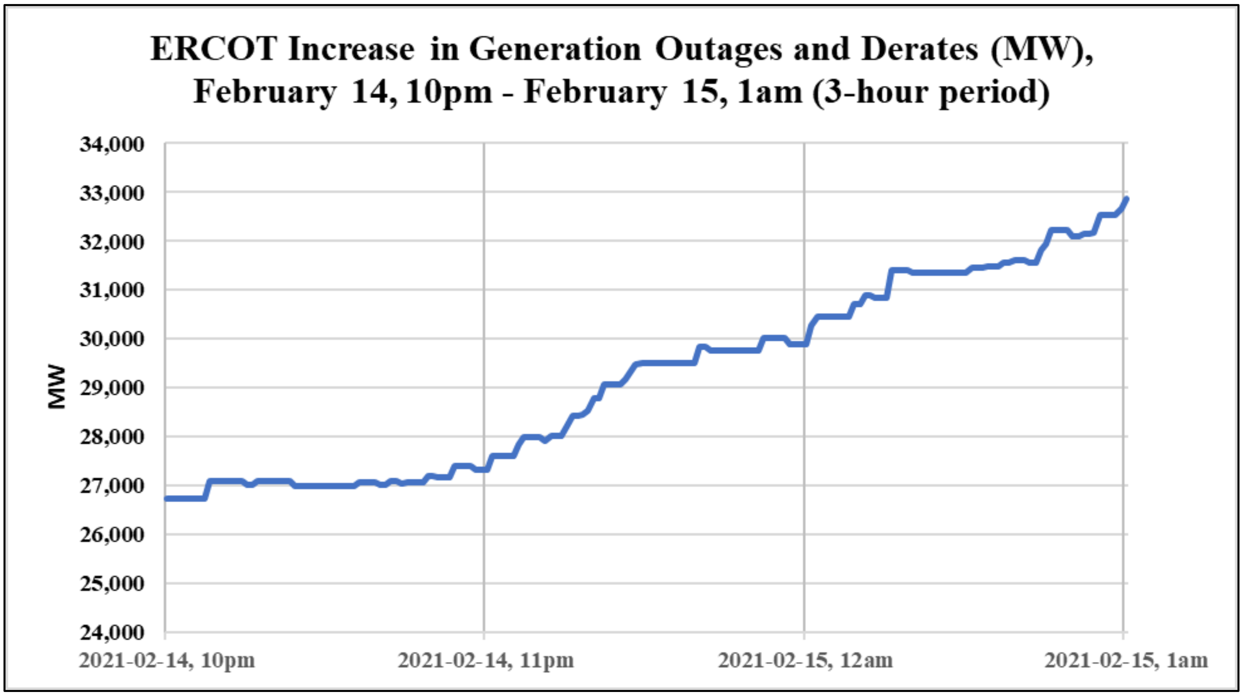
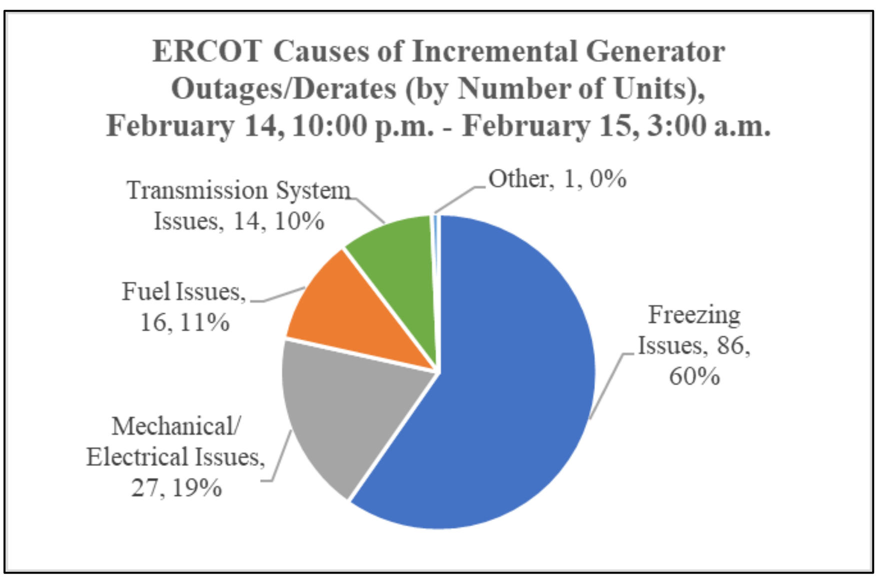
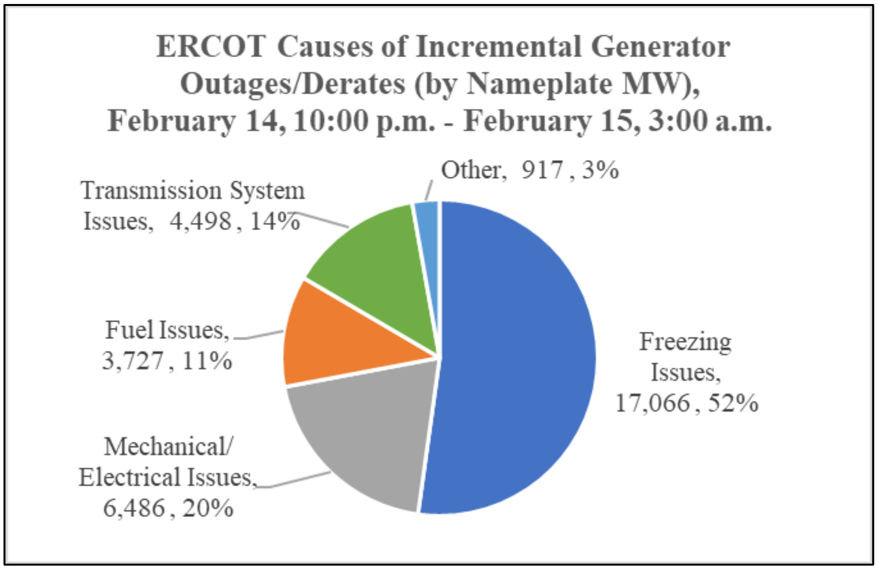


Figure 70: ERCOT Causes of Incremental Generator Outages/Derates, February 14, 10 p.m. – February 15, 3:00 a.m.





At 11:32 p.m., ERCOT issued an Advisory for Physical Responsive Capability less than 3,000 MW. ERCOT System Operators also issued two additional Advisories via hotline and ERCOT notifications due to Physical Responsive Capability falling below 3,000 MW.

Frequency Response Overview[202]

Frequency as a measure of the reliability status of a power system (in this case, ERCOT BA) can be likened to pulse or heart rate as a measure of human health. It provides a key indicator of the BA's continued ability to reliably meet demand. Maintaining frequency requires balancing a system's aggregate generation output to load moment-to-moment. It also requires having sufficient reserves of generation available at all times to withstand the sudden loss of the largest generator on the system, in order to instantaneously make up for the loss of power and reestablish balance.

Normal Frequency Control and Response

During normal operating conditions, system frequency is maintained through the automatic generation control (AGC) system, which maintains a balance between load and resources and keeps tie line flows at prescribed levels. In ERCOT, all external tie lines are DC converter stations, so the ERCOT system operates on a frequency bias only. Several generating resources automatically raise or lower their output at the direction of the AGC system to maintain frequency. This action is called secondary frequency response (SFR) and requires frequency responsive reserves to be effective for excursions in frequency.

[202] See Appendix E, Characteristics of Interconnection Frequency During the Event, for an in-depth look at the frequency and related characteristics of the ERCOT system during the Event.

A much faster-acting form of frequency control and response called primary frequency response (PFR) comes from automatic generator governor response, load response (typically from motors), and other devices that provide an immediate response (within seconds) to arrest and stabilize frequency in response to frequency deviations, based on local (device-level) control systems. Those actions are autonomous and are not directly controlled by the AGC system or the system operator. Again, the effectiveness of PFR is subject to the availability of "headroom" (unloaded "spinning reserves" on the online generation. For example, a generating unit with a maximum output limit of 500 MW and current output of 475 MW, could have 25 MW output available for PFR).

Tertiary frequency control is the next level of frequency management, in which a Balancing Authority redispatches generation, (e.g., starts additional generation), or calls on demand response to restore frequency responsive reserves for PFR and SFR following a low-frequency excursion. This action may include manual shedding of load by the system operator to restore reserves.

The need to maintain frequency to prevent a collapse of the system was the fundamental driving force behind ERCOT's decision to shed firm load. Because ERCOT is not synchronously connected to either the Eastern or Western Interconnections, all frequency response must come from resources internal to ERCOT's BA area. And because ERCOT is smaller than the other interconnections, the loss of any given generating unit results in a comparatively steeper frequency decline, necessitating a more robust frequency response. In 1988, ERCOT established a minimum responsive reserve requirement of 2,300 MW, based on an N-2 criterion—the simultaneous loss of two system elements, in ERCOT's case, covering one nuclear-powered unit and the next largest unit on the system. The purpose of the responsive reserves, both generation and load, is to ensure there is sufficient frequency response availability (i.e., Physical Responsive Capability)[203] arrest frequency declines before they reach 59.3 Hz (the trigger threshold for the first block of automatic underfrequency load shedding (UFLS. Should load resources be deployed manually by system operators, they are no longer available to provide frequency response. Should generation resources be dispatched to meet load, they would no longer be reserved to provide frequency response until recalled.

Frequency Conditions and The Decision to Shed Load

Load shedding is implemented to correct an electrical power imbalance if load exceeds supply and system operators cannot bring the system back into balance through other measures. Load shedding may be used to reduce an overload condition (such as when thermal limits on a transmission line are exceeded), to

203 Physical Responsive Capability is a representation of the total amount of frequency responsive resource capability online in real time. ERCOT Nodal Protocols Section 2.1. It is calculated based on resource telemetry (e.g. from QSEs for generating units). ERCOT Nodal Protocols Section 6.5.7.5(1)(m).

recover from an underfrequency condition, or to return voltage to a normal level. The operation can be manual (operator-initiated) or automatic (initiated by protective relays), depending on how quickly the frequency is decaying or the voltage is falling. For slowly-declining frequency or voltage issues, the manual option is usually chosen. For rapidly-declining frequency or voltage, the automatic relays will activate without operator intervention. ERCOT maintains and closely monitors its frequency responsive reserve levels (also referred to by ERCOT as its Physical Response Capability, or PRC), to comply both with its own 2,300 MW criterion and with the 1,430 MW minimum criterion required by NERC Reliability Standards.[204] ERCOT relies on demand-side load resources to provide up to 60 percent of its 2,300 MW responsive reserve requirement. These resources automatically disconnect when the frequency declines to 59.7 Hz.

i. ERCOT Frequency Decline and Recovery: February 15, Approximately Midnight to 2 a.m.

After ERCOT issued its advisory for Physical Responsive Capability dropping below 3,000 MW, at 11:32 p.m. on February 14, its frequency was 59.963 Hz, still within the normal range. Shortly after midnight heading into February 15, as generating units continued to trip or run back (also known as ramping down), ERCOT BA operators experienced the most dangerous two hours of ERCOT's existence. Due to the unrelenting generating unit losses during this period, the actions ERCOT BA operators took to restore Physical Responsive Capability and maintain normal frequency (initially, calling on demand response, then ordering small blocks of firm load shed) could not keep up, and frequency continued to drop. ERCOT BA operators were forced to shed larger blocks of firm load, and within minutes of one another, to restore frequency. Generating units failed at such a rapid pace that frequency dropped to the point of triggering a nine-minute time delay on generator underfrequency relays. Had ERCOT's frequency remained under this level for nine minutes, rather than over 4 minutes as actually happened, approximately 17,000 MW of additional generation would have tripped, potentially blacking out all of ERCOT. ERCOT BA operators were able to restore frequency to within the normal range by shortly after 2 a.m. and avoided tripping the underfrequency relays that could have caused a blackout, by shedding firm load as needed, to a cumulative total of 10,500 MW by 2 a.m. The following chronology examines the two-hour frequency decline and recovery in more detail. **All times are on February 15.**

From 12:06 a.m. through 12:11 a.m., four generating units ran back or tripped totaling 326 MW, and ERCOT's frequency declined to 59.940 Hz. At 12:10 ERCOT issued a Watch for Physical Responsive Capability less than 2,500 MW.

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[204] NERC Reliability Standard (Operating Process as part of its Operating Plan to determine its Most Severe Single Contingency and make preparations to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency available for maintaining system reliability."

At 12:15 a.m., ERCOT entered emergency operations for the first time during the Event and declared an EEA 1[205] because its reserves dropped below the minimum responsive reserve requirement of 2,300 MW at 12:09 a.m. At 12:15 a.m., frequency was 59.958 Hz and Physical Responsive Capability was 2,269 MW.

At 12:15 a.m., in response to its responsive reserves dropping below 2,300 MW, ERCOT deployed 847.15 MW of 30-minute Emergency Response Service (ERS-30).[206] However, this deployment did not resolve ERCOT's low reserves because an additional five generating units totaling 473 MW had tripped or run back in the last 10 minutes.

From 12:35 a.m. through 12:54 a.m., five more generating units ran back or tripped totaling 428 MW. Frequency declined from 59.942 Hz to 59.911 Hz. At 12:57 a.m., one unit ramped down from 325 MW to 133 MW (tripping at 01:18), and another 41 MW tripped offline. At 12:59 a.m., ERCOT frequency fell below 59.91 Hz (to 59.908 Hz).

At 1:07 a.m., ERCOT declared an EEA 2[207] when it was unable to maintain frequency above 59.91 Hz for more than 7 minutes. ERCOT also deployed 51.6 MW of ERS-10.[208] Frequency had declined from 59.912 Hz to 59.872 Hz in about 10 minutes.

At 1:07 a.m., ERCOT issued an initial Verbal Deployment Instruction (VDI) to all QSE's representing Load Resources, preparing to deploy Groups 1 and 2 of those demand response resources. Frequency was at 59.868 Hz, and Physical Responsive Capability was 1,761 MW. At 1:11 a.m., ERCOT sent resource-specific electronic instructions to deploy Group 1 and Group 2. This action reduced load from 65,000 MW to 64,577 MW (a 423 MW reduction) and reduced Physical Responsive Capability load from 907 MW to 391 MW over the next five minutes. During this time, system frequency began to decline because of unplanned generation outages, and at 1:15 a.m., reached 59.88 Hz, although it recovered quickly—by 1:16 a.m., in response to ERCOT's EEA 2 actions, frequency recovered to above 59.95 Hz, within its normal range of 59.95 – 60.05 Hz.

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At 1:18 a.m., a generating unit tripped at 133 MW, resulting in a frequency drop from 59.955 Hz to 59.924 Hz (approximately 31 mHz).[209] This was a frequency sensitivity[210] of -2.59 mHz/second/100 MW loss. Figure 71 below illustrates the second-by-second change in ERCOT system frequency caused by losing even a relatively small generating unit at that time. Frequency dropped to 59.923 Hz before stabilizing at 59.934 Hz. Primary frequency response was limited at this time due to lack

205 According to the ERCOT operations desk procedures: EEA level 1 means that Physical Responsive Capability is less than 2,300 MW and is not expected to be recovered above 2,300 MW within 30 minutes without use of EEA level 1 procedures.

206 ERS-30 is Emergency Response Service, an aggregated demand response product that must be able to deploy in 30 minutes or less.

207 According to the ERCOT operations desk procedures: EEA level 2 means that Physical Responsive Capability is less than 1,750 MW, or operators are unable to maintain frequency above 59.91 Hz, and Physical Responsive Capability is not expected to be recovered above 1,750 MW within 30 min without use of EEA level 2 procedures.

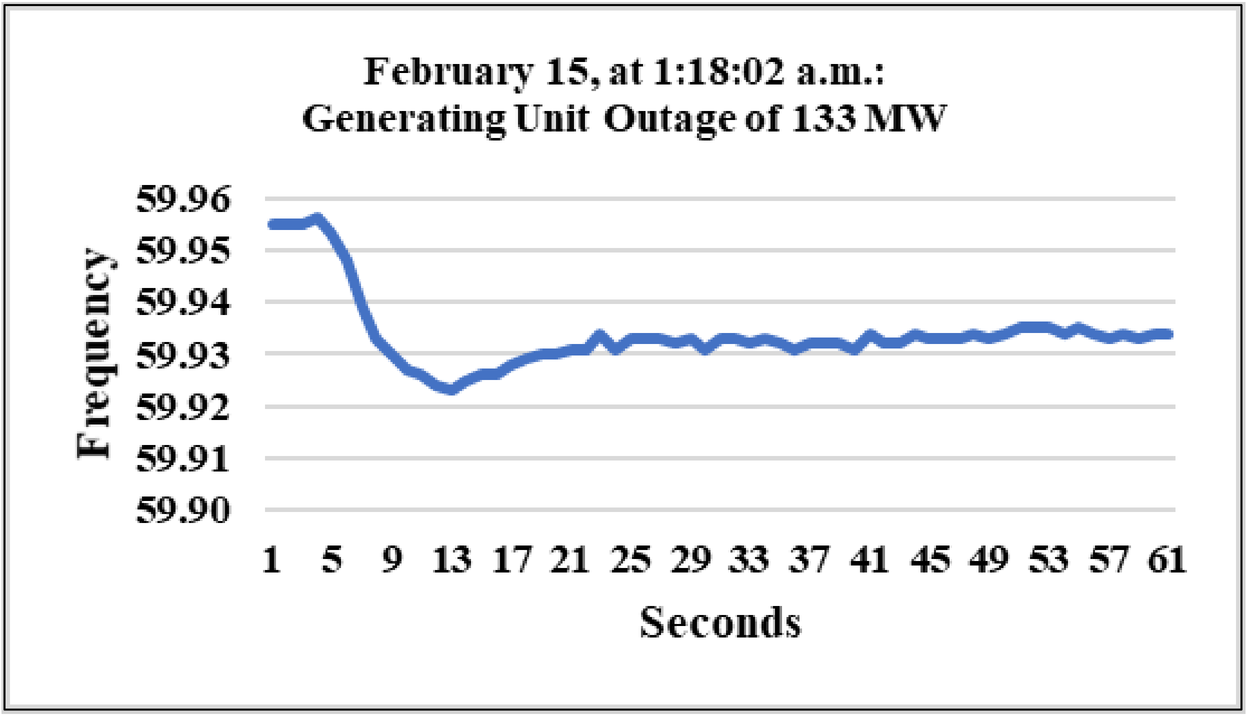
208 ERS-10 is another Emergency Response Service, similar to ERS-30, an aggregated demand response product, but must be able to deploy in 10 minutes or less.

209 Millihertz, which represents one-thousandth of a hertz.

210 The frequency sensitivity metric is described in greater detail in Appendix E.

of available headroom remaining for the generating units that were online and because turbine governors were already deployed in response to the low system frequency before the unit tripped.

Figure 71: Generation Outage and Effect on System Frequency, February 15 at 1:18:02 a.m.

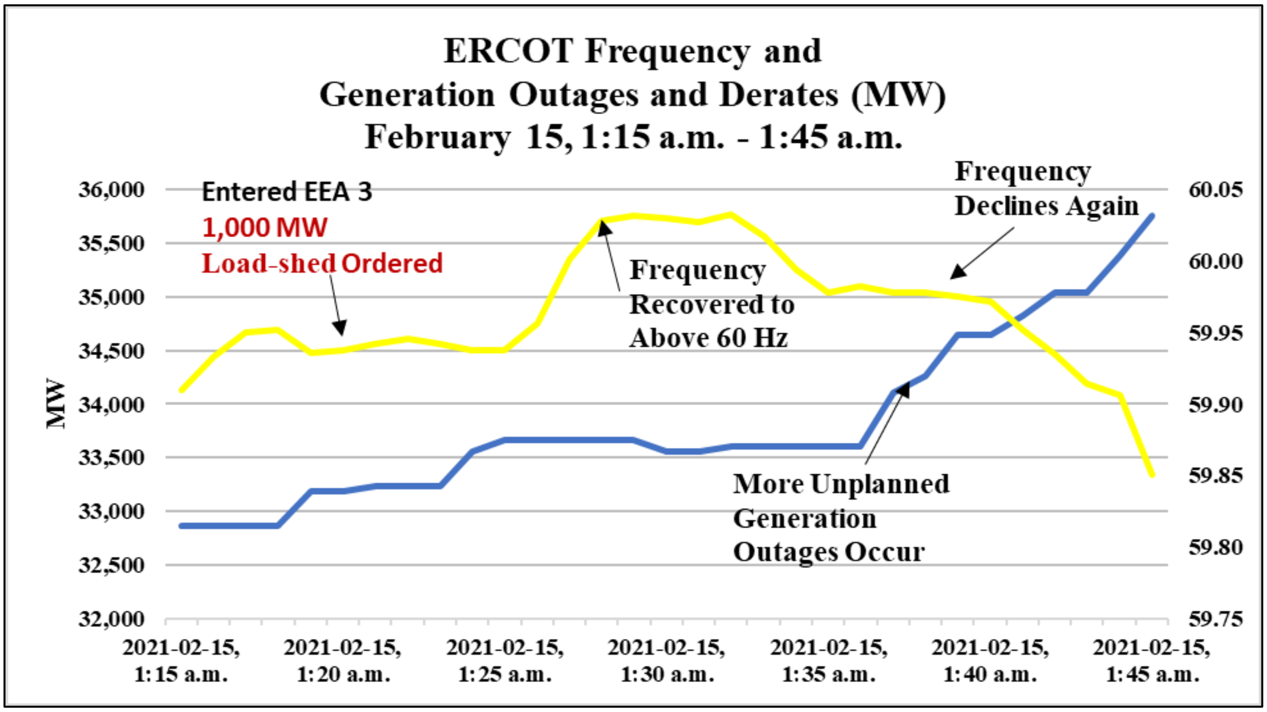


At 1:18 a.m., ERCOT Physical Responsive Capability fell below 1,430 MW (criteria for EEA 3) to 1,377 MW. Frequency was at 59.932 Hz. At 1:20 a.m., ERCOT declared EEA 3 and instructed TOPs to shed 1,000 MW of firm load. System load was 64,256 MW and frequency was 59.944 Hz.

At 1:20 a.m., a small generating unit tripped at 23 MW, resulting in a frequency drop from 59.942 Hz to 59.938 Hz in 4 seconds, a frequency sensitivity of -4.35 mHz/second/100 MW loss, showing that ERCOT BA's ability to respond was even less robust two minutes after the last frequency sensitivity calculation at 1:18 a.m. At 1:26 a.m., frequency recovered to 60.001 Hz after 1,000 MW of manual load shed, with load at 63,840 MW and Physical Responsive Capability at 1,281 MW, but soon began to decline. By 1:33 p.m., frequency declined to 59.975 Hz, a 45 mHz drop within one minute.

At 1:35 a.m. through 1:44 a.m., frequency dropped from 59.978 Hz to 59.823 Hz (a 155 mHz drop over almost 5 minutes) as over 1,500 MW more generating units in the ERCOT footprint experienced outages and run backs, causing frequency to steadily decline. Figure 72 below shows further increases in generation outages and derates and their effects on ERCOT frequency. ERCOT was about to enter the most dangerous 15 minutes of its history.

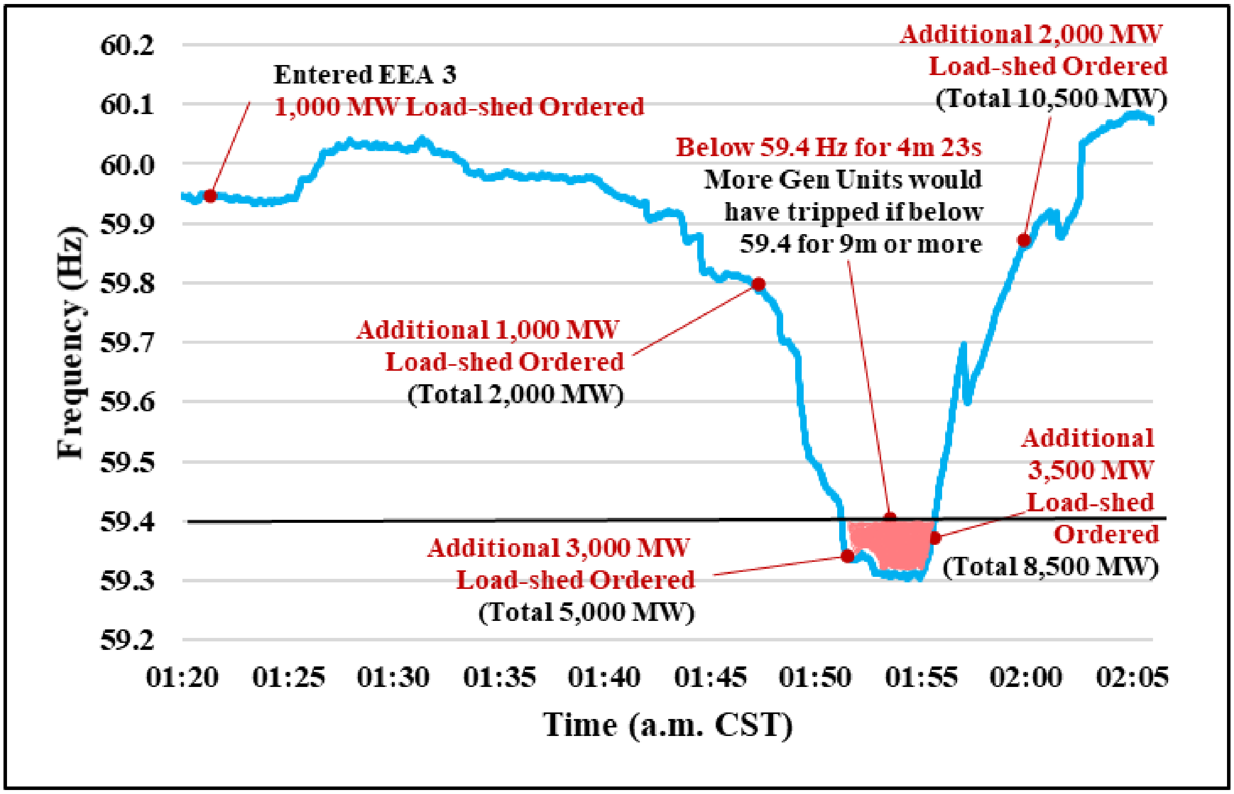
Figure 72: EEA 3 1,000 MW Firm Load Shed, Increase in Generation Outages and Derates and their Effects on ERCOT Frequency, February 15, 1:15 – 1:45 a.m.



From 1:44 a.m. through 1:49 a.m., another five generators tripped or ran back to zero output, totaling 1,712 MW within five minutes. Frequency fell from 59.817 Hz to 59.504 Hz, generation output was 61,205 MW, system load was 62,405 MW, and Physical Responsive Capability was 1,549 MW.

At 1:45 a.m., ERCOT instructed TOPs to shed an additional 1,000 MW of firm load (2,000 MW of firm load had been shed by that time), as indicated in Figure 73, below. Frequency was 59.820 Hz, generation output was 61,494 MW, system load was 62,690 MW, and Physical Responsive Capability had fallen from 1,694 MW to 1,267 MW in 10 minutes.

Figure 73: ERCOT System Frequency, February 15, 1:20 - 2:05 a.m.



At 1:51 a.m., frequency fell below the 59.4 Hz generator underfrequency relay trip level, starting the nine-minute time delay on those relays (see "Below 59.4 Hz for 4m 23s" caption and red shaded area in Figure 73, above). If the underfrequency relays had tripped, approximately 17,000 MW of generation would be outaged, potentially causing a total blackout of the ERCOT BA footprint. ERCOT ordered another 3,000 MW of load shed at 1:50 a.m., with total load shed then at 5,000 MW. Frequency was 59.496 Hz, generation output was 61,273 MW, system load was 61, 469 MW, and Physical Responsive Capability was 1,435 MW.

From 1:51 a.m. through 1:59 a.m., another three generators tripped or ran back to zero output, totaling 534 MW. At 1:54 a.m., ERCOT frequency reached its lowest level of the Event at 59.304 Hz. Generation output was 60,381 MW, system load was 61,590 MW, and Physical Responsive Capability was 1,044 MW. Approximately 276 MW of load tripped by UFLS relays at this time, although system frequency was not actually recorded as at or below 59.3 Hz, due to the close proximity of system frequency to the relay setpoints at 59.3 Hz.

At 1:55 a.m., ERCOT instructed TOPs to shed an additional 3,500 MW of firm load (total load shed was then 8,500 MW). Frequency was at 59.306 Hz, generation output was at 60,374 MW, load was at 61,583 MW, and Physical Responsive Capability was 1,403 MW.

At 1:55 a.m., frequency rose to 59.401 Hz, above the generator underfrequency relay protection trip level, after remaining below 59.400 Hz for four minutes and 23 seconds. However, ERCOT's system was not yet stable. Generation output was 60,120 MW, system load was 61,328 MW, and Physical Responsive Capability was 1,127 MW.

At 1:57 a.m., frequency rose to 59.689 Hz with system load at 60,454 MW and Physical Responsive Capability at 1,556 MW, but shortly thereafter, from 1:57 a.m. through 2:01 a.m. seven generators tripped or ran back, totaling 1,165 MW. The impact of this resource loss was offset by an additional 2,000 MW of load shedding ordered by ERCOT at 2:00 a.m., bringing the total load shed to 10,500 MW, as indicated in Figure 73, above. The combination of the 3,500 MW load shedding ordered at 1:55 a.m. and the 2,000 MW shedding ordered at 2:00 a.m. caused the frequency to continue to rise despite the loss of 1,165 MW of resources from 1:57 through 2:01 a.m.

At 2:02 a.m., system frequency rose above 60.0 Hz, with generation output at 57,002 MW, system load at 58,197 MW, and Physical Responsive Capability improved at 1,636 MW. The last 5,500 MW of load shed ordered was still taking effect. At 2:09 a.m., system frequency improved to 60.094 Hz as the effects of load shedding and resources losses balanced out. Generation output was at 53,578 MW, system load was 54,775 MW, and Physical Responsive Capability was a greatly-improved 2,952 MW.

By 2:30 a.m., ERCOT had ordered TOPs to restore 1,500 MW of load that had been shed, leaving 9,000 MW still disconnected, and had recalled other load resources that had been deployed. With frequency at 60.062 Hz and Physical Responsive Capability at 3,017 MW, the ERCOT system was considered stable.

Ultimately over the course of the Event, responsive reserves were less than 1,430 MW for approximately 4.5 hours on February 15, 1.9 hours on February 16, and 0.7 hours on February 17, and ERCOT shed a maximum of 20,000 MW of firm load by 7:00 p.m. on February 15. Throughout the low frequency event, ERCOT operators maintained system inertia.[211] Currently, ERCOT uses a critical inertia value of 94 GW-seconds, with 100 GW-seconds used as a minimum value for operations purposes. At 120 GW-seconds, ERCOT operators begin committing additional synchronous reserves and at 105 GW-seconds, they deploy non-spinning reserves. Inspection of the 1-second inertia data for the Event showed that system inertia during the period ranged from 254 GW-seconds to 349 GW-seconds, well above ERCOT's critical inertia level.

"What-if" Considerations

Had ERCOT lost a large contingency during the time that its Physical Responsive Capability was low, its reserves may have been insufficient to arrest the frequency decline above the first stage of underfrequency load shedding. The result may have been a sharp frequency decline which, when it crossed 59.3 Hz, would have triggered the first block of underfrequency load shedding, tripping five percent of ERCOT's system load. Even though the underfrequency load shedding would have tripped automatically, it would have taken out firm load and would be in addition to any firm load that operators may have already shed. Depending on the circumstances

[211] Kinetic energy stored in spinning generators. "Inertial response provides an important contribution to reliability of the system in the initial moments following a generation trip event and determines the initial Rate of Change of Frequency [how quickly frequency initially declines]." Danya Pysh, *Inertia: Basic Concepts and Impacts on the ERCOT Grid*, ERCOT Pub. (Apr. 4, 2018), https://www.ferc.gov/media/inertia-basic-concepts-and-impacts-ercot-grid.

> surrounding the moment of activation of the automatic underfrequency load shedding, it is possible that an overvoltage condition could have occurred in one or more localized areas, that frequency could have significantly overshot the 60 Hz nominal frequency, or that other electrical perturbations could have developed that would have resulted in the tripping of even more generation. Only a detailed dynamic simulation could answer the question as to how widespread the February 2021 blackout would have been had the automatic underfrequency load shedding been triggered.

By 2:15 a.m., after beginning EEA 3 at 1:15 a.m. with 1,000 MW firm load shed, and having ordered a total of 10,500 MW of firm load shed, ERCOT system load had decreased by 10,745 MW (as shown in Figure 75, below). Although ERCOT would be required to shed additional firm load, peaking at 20,000 MW at 7:15 p.m. on February 15, ERCOT system operators had successfully faced the most dangerous challenge to the stability of the interconnection, and temporarily restored frequency to normal. ERCOT's fellow BAs MISO and SPP were facing their own emergencies caused by cold-weather-induced generating unit outages.[212] Figure 74, below shows the increase in generation outages in the Event Area, as compared to the conditions at 10 p.m. shown in Figure 68. Figure 75, below shows the trend of firm load shed in MW and change in ERCOT system load.

[212] Although both SPP and MISO South footprints experienced significant increases in generation outages and needed to declare emergencies, the Eastern Interconnection frequency remained within its normal range of 59.95 – 60.05 Hz during the morning of February 15.

Figure 74: Location of Unplanned Generation Outages and Derates, (MW Outaged), by Fuel Type, Total Event Area, February 15, 3:00 a.m.

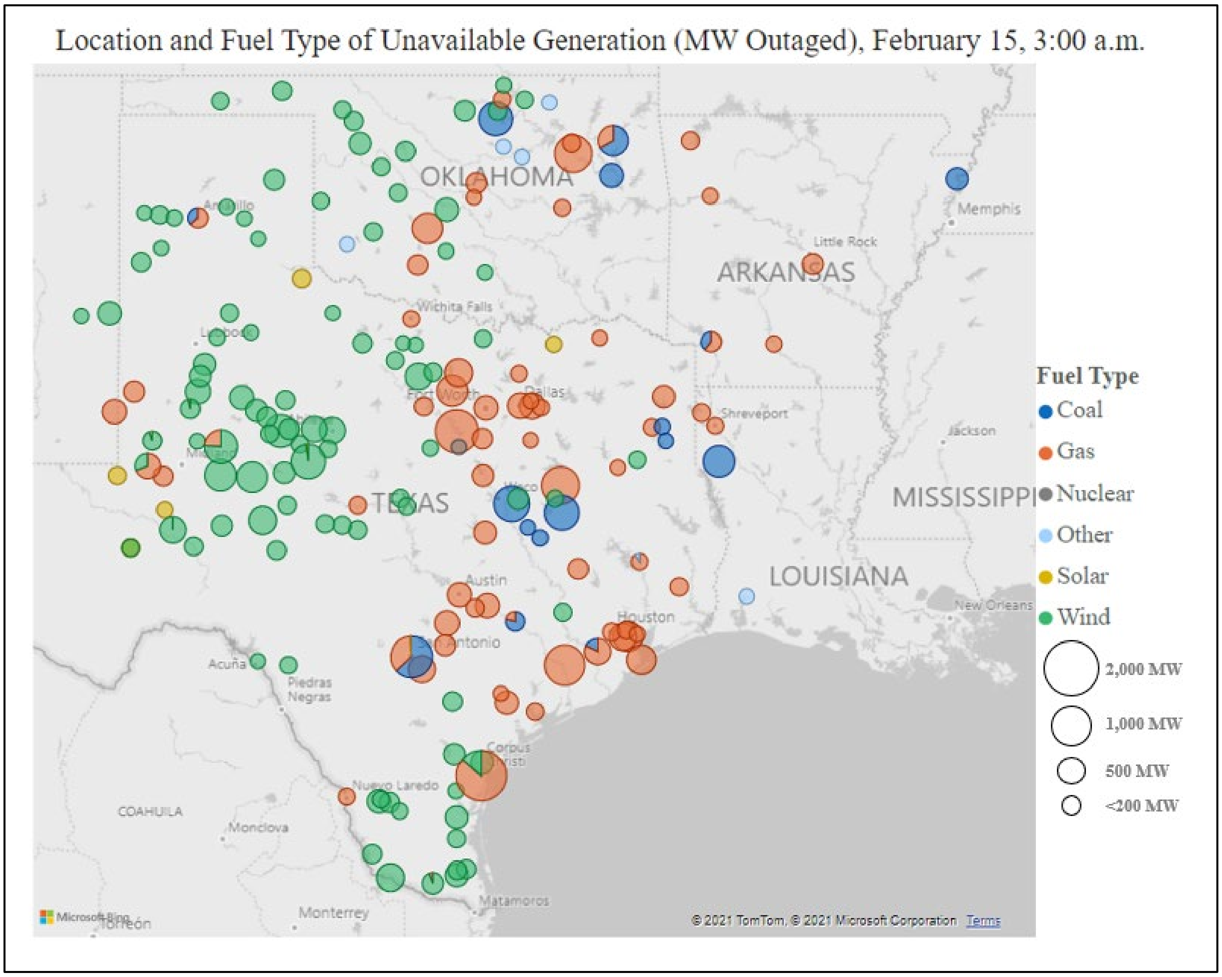
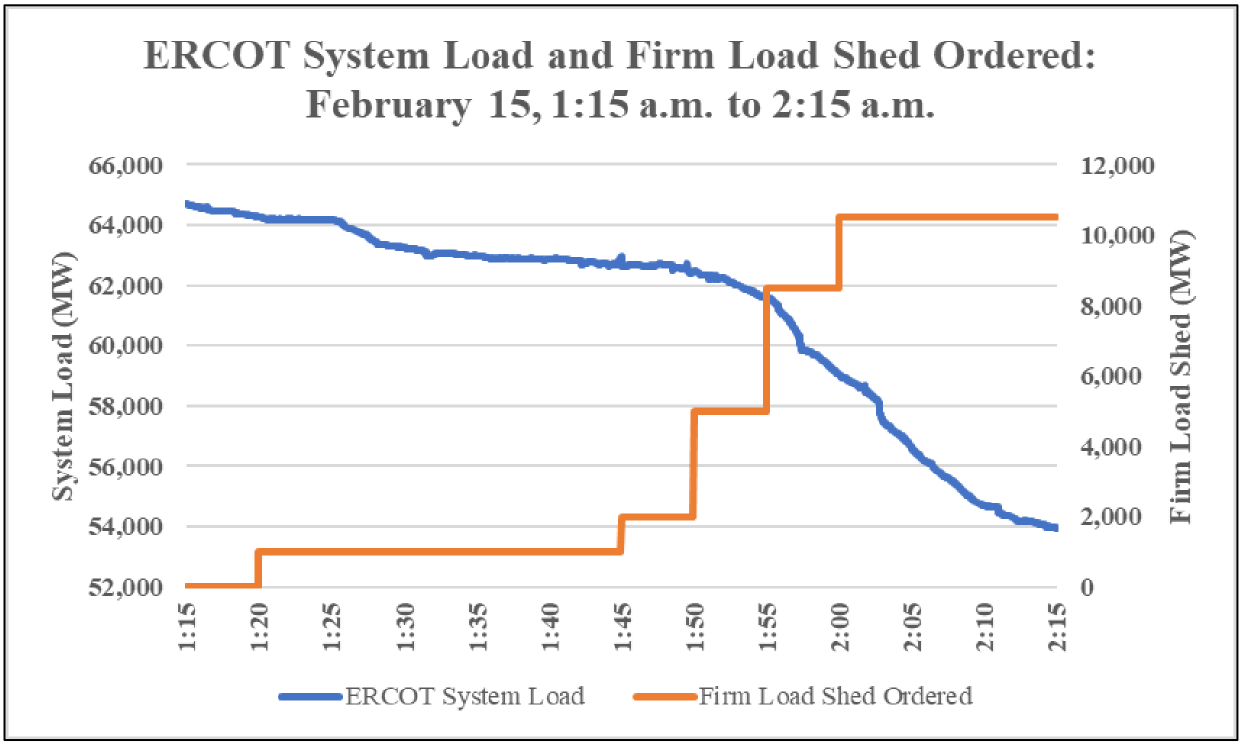


Figure 75: ERCOT Firm Load Shed and Changes in System Load, February 15, 1:15 - 2:15 a.m.



c. Transmission and Energy Emergencies in MISO and SPP

i. MISO South Transmission Emergencies

While ERCOT was experiencing energy emergency conditions early the morning of February 15, MISO South was also experiencing constrained transmission conditions due to significant increases in unplanned generation outages, as well as increasing load levels in both MISO South and southern SPP (shown in Figure 76, below). As a result, MISO system operators were required to declare a Local Transmission Emergency (LTE) for one of its load pockets in MISO South. To make up for generation shortfalls and increasing load levels, both MISO and SPP BAs scheduled power from BAs located in the eastern portion of the Eastern Interconnection that were not experiencing the extreme cold. These scheduled east-to-west imports increased east-to-west power flows into[213] and through MISO's transmission system, including through MISO South into southern SPP during the early morning hours of February 15 (shown in Figure 77, below).

[213] During the week of February 14, like SPP, MISO also needed to import power from BAs in the eastern portion of the Eastern Interconnection to alleviate generation shortfalls in its footprint.

Figure 76: MISO South and Southern Area of SPP

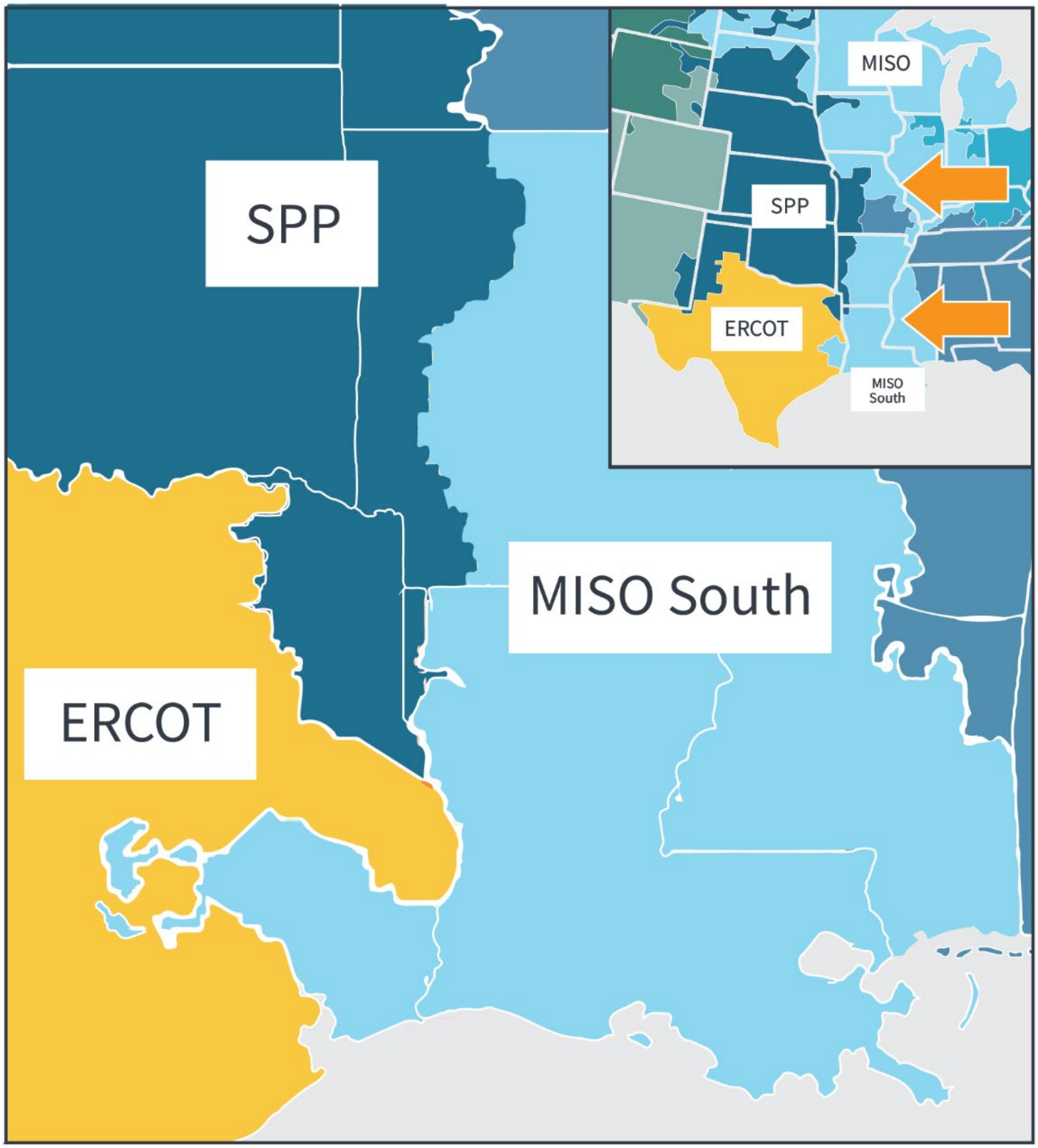
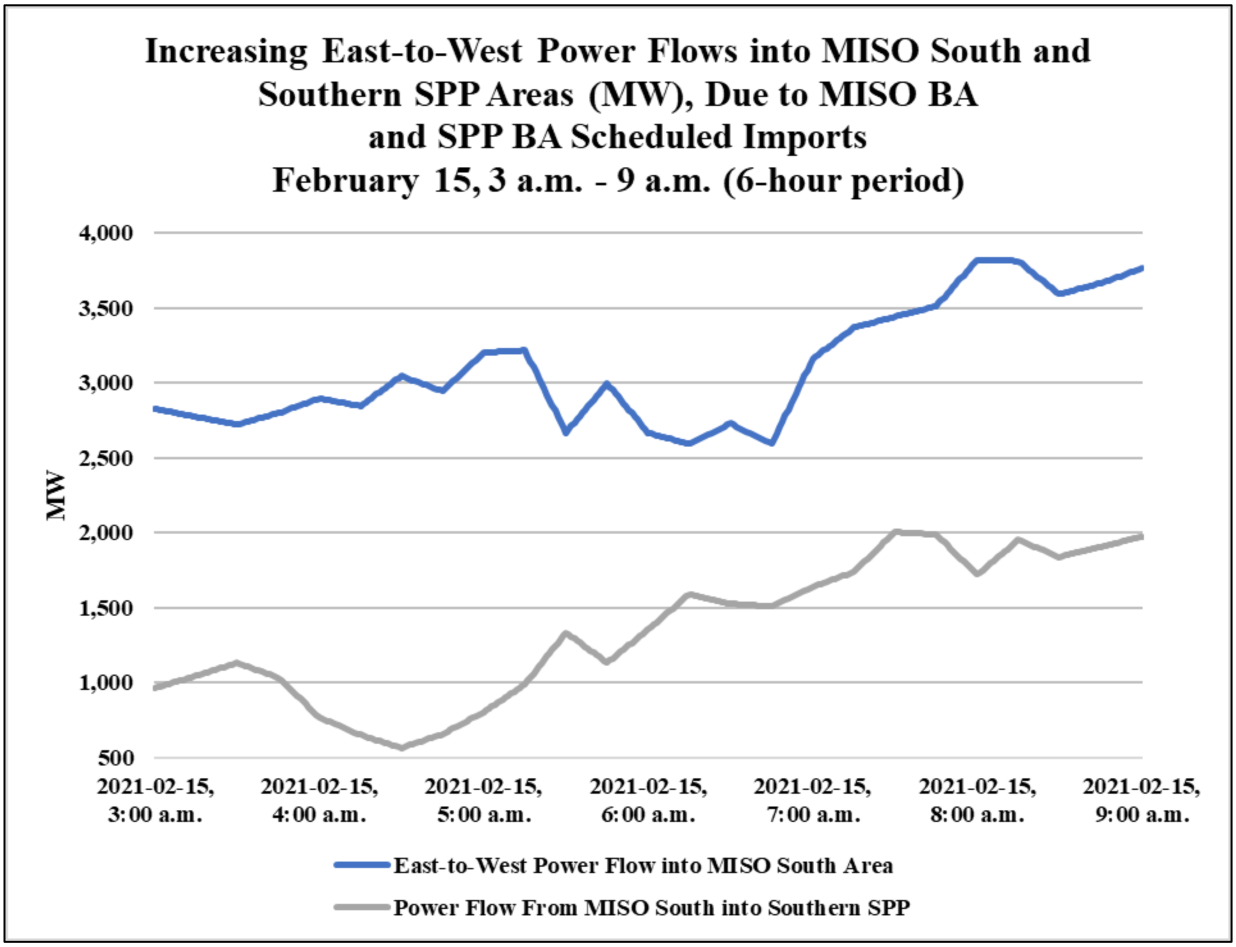


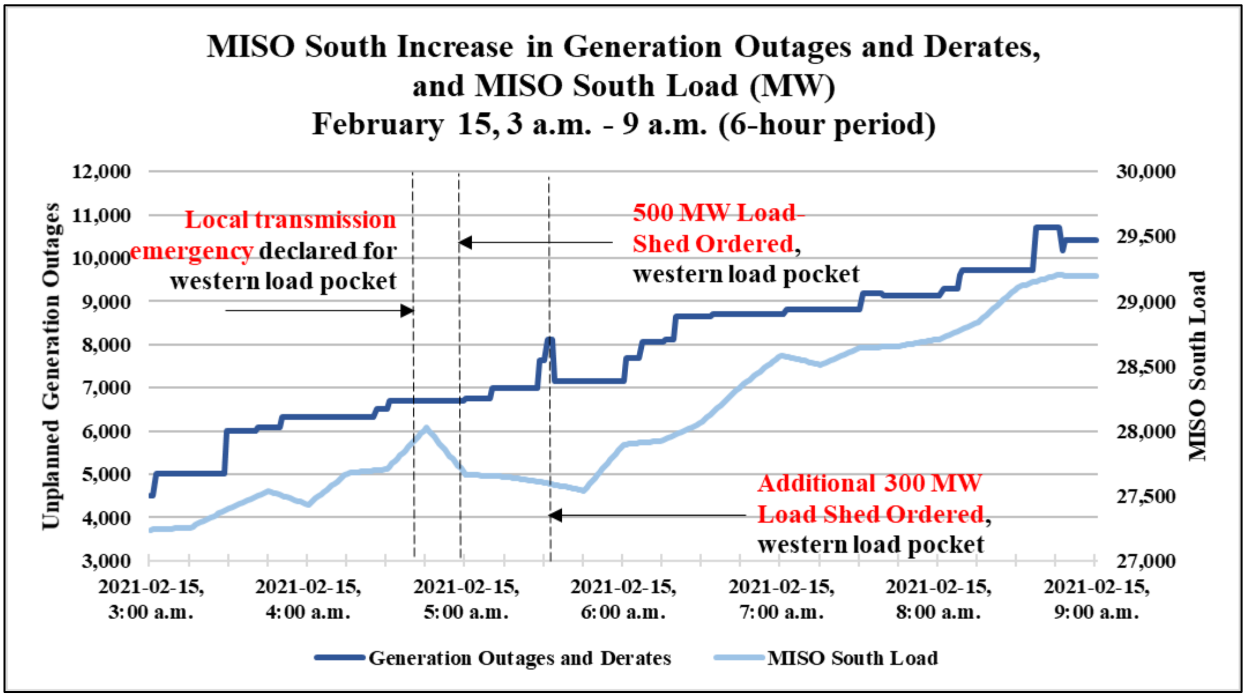
Figure 77: Increasing East-to-West Power Flows into MISO South and Southern SPP (MW), Due to MISO BA and SPP BA Scheduled Imports February 15, 3 a.m. - 9 a.m. (6-hour period)



At 5:15 a.m. on February 15, MISO issued a Local Transmission Emergency (LTE) for Entergy Arkansas to manually redispatch a nuclear unit to relieve a real-time overload of a 500 kV line, which was primarily due to key generation outages in an associated area of the SPP footprint.

In the early morning hours of February 15, conditions in the West of the Atchafalaya Basin, MISO South's western load pocket in eastern Texas, began to deteriorate. Two 230 kV transmission lines tripped due to icing conditions and MISO had over 1,400 MW of unplanned generation outages. After multiple transmission overloads (both pre- and post-contingency), at 4:40 a.m. on February 15, MISO declared an LTE and issued operating instructions to shed 500 MW of firm load in the western load pocket of MISO South at 4:55 a.m. At 5:33 a.m., as load continued to climb, MISO ordered an additional 300 MW of firm load shed (for a total of 800 MW) in the western load pocket. See Figure 78, below.

Figure 78: MISO South Increase in Generation Outages and Derates, February 15, 3 a.m. - 9 a.m. (6-hour period)



By 12:30 a.m. on February 16, most of the western load pocket load that had been shed was restored (700 of the 800 MW), based on off-peak system load levels and restoration of two transmission lines. But just a few hours later, both MISO South and SPP declared transmission emergencies. MISO had not only an LTE, but also a transmission system emergency (TSE), due to an Interconnection Reliability Operating Limit (IROL)[214] caused by additional generation outages in both MISO South and southern SPP.

At 4:30 a.m., MISO ordered an additional 300 MW of firm load shed due to a Local Transmission Emergency in the western load pocket, followed by a Transmission System Emergency in western Louisiana and the western load pocket in east Texas at 6:05 a.m., for which it ordered 500 MW of firm load shed. But because additional generating units tripped during implementation of the load shed, at 6:26 a.m., MISO ordered an additional 500 MW. MISO had ordered a total of 1,400 MW load shed in western Louisiana and the western load pocket, consisting of 1,000 MW in western Louisiana and 400 MW in the western load pocket (100 MW of which was preexisting from the

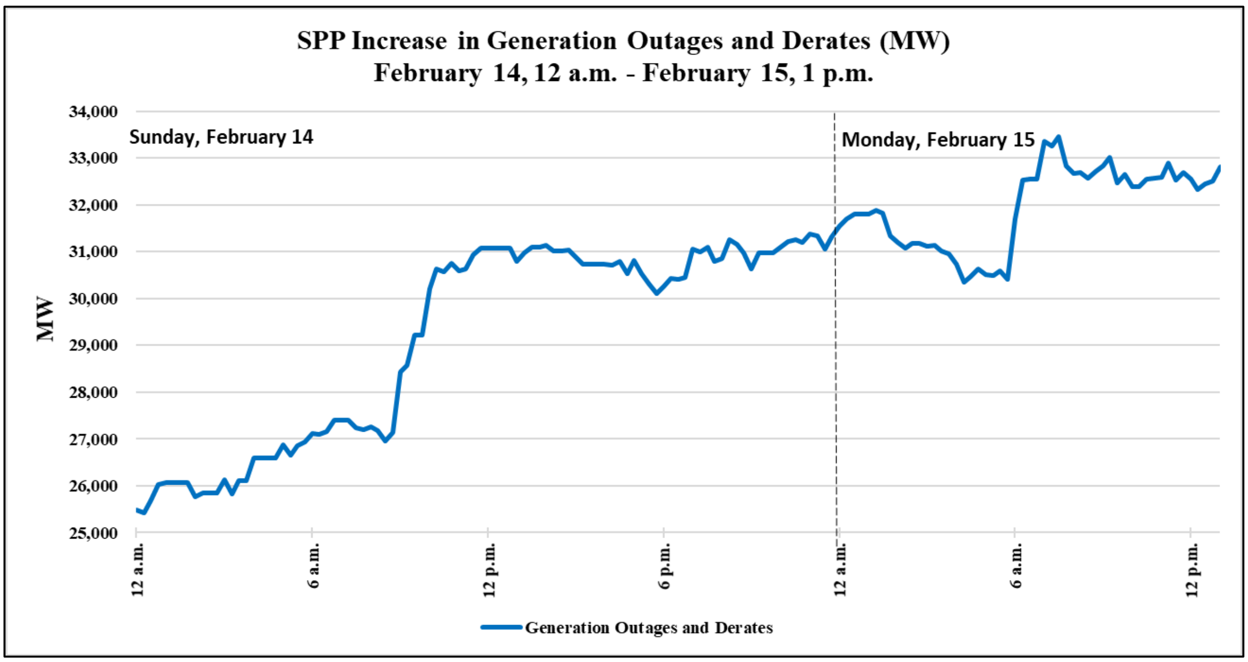
[214] An Interconnection Reliability Operating Limit is a System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk-Electric System. A System Operating Limit is the most limiting of the values (whether MW, kV, MVAr, or Hz) for a specified system configuration to ensure that established reliability criteria are satisfied.

prior day). MISO began restoring load at 7:42 a.m. on February 16, had restored it all by 10:10 a.m. and terminated the TSE at 10:41 a.m.[215]

ii. SPP Energy Emergencies

While ERCOT and MISO both were experiencing emergency conditions during the early morning of February 15, SPP also declared an energy emergency when increasing unplanned generation outages and derates over the weekend combined with forecast peak electric demands (driven by extreme cold weather) for Monday, February 15. Unplanned generation outages were already increasing on Sunday, February 14, as shown in Figure 79, below, and the trend continued into Monday morning.

Figure 79: SPP Increase in Generation Outages and Derates (MW), February 14 12:00 a.m. – February 15, 1:00 p.m.



Based on its concerns about the weather and natural gas fuel supply issues, on Sunday February 14 at 9:27 a.m., SPP emailed its TOPs, GOPs, and market operators that an EEA 1 would begin Monday, February 15, at 5:00 a.m. Later that afternoon, at 1:57 p.m., SPP asked member utilities for the first time to make public appeals for energy conservation, beginning on February 15.

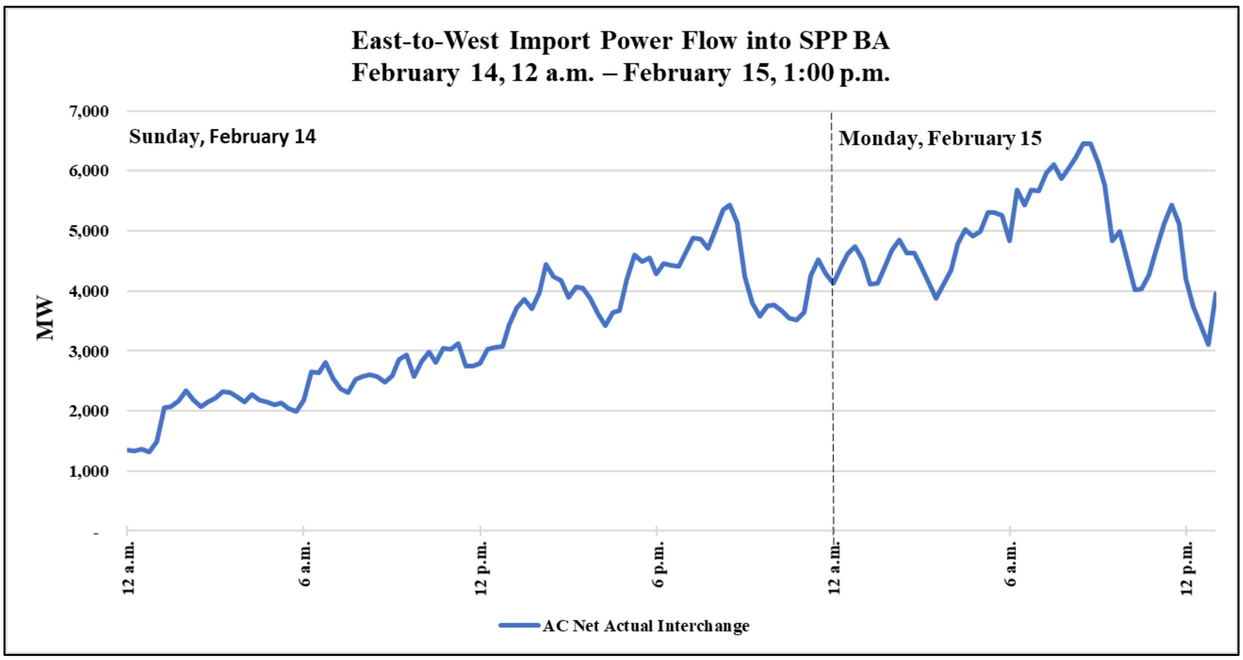
On Monday, February 15 at 5:00 a.m., SPP began its EEA 1, meaning that all available resources had been committed to meet obligations, and SPP was at risk of not meeting required operating reserves. From 6:00 a.m. to 8:00 a.m., unplanned generation outages and derates in the SPP footprint

[215] At various times on February 15 and 16, MISO also declared EEA 2 for MISO South, which triggered appeals for voluntary load reduction and demand response, but not firm load shed.

increased over 3,000 MW, as shown in Figure 79, above. At 7:22 a.m., SPP declared an EEA 2, which required SPP to ask its member companies to issue public conservation appeals and served as a maximum emergency generation notification for generating units (informing that the emergency ranges of generating units may be required).

To meet its winter peak electricity demands and mitigate the energy emergency caused by increasing unplanned generation outages and derates, SPP began importing power from the east. SPP's imported power from entities in the eastern portion of the Eastern Interconnection flowed through MISO's transmission network (including MISO South, as shown in Figure 76, above) and was subject to curtailment.[216] Figure 80 below shows SPP's increasing trend of import power flows, ranging from 4,000 to over 6,000 MW early on February 15.[217]

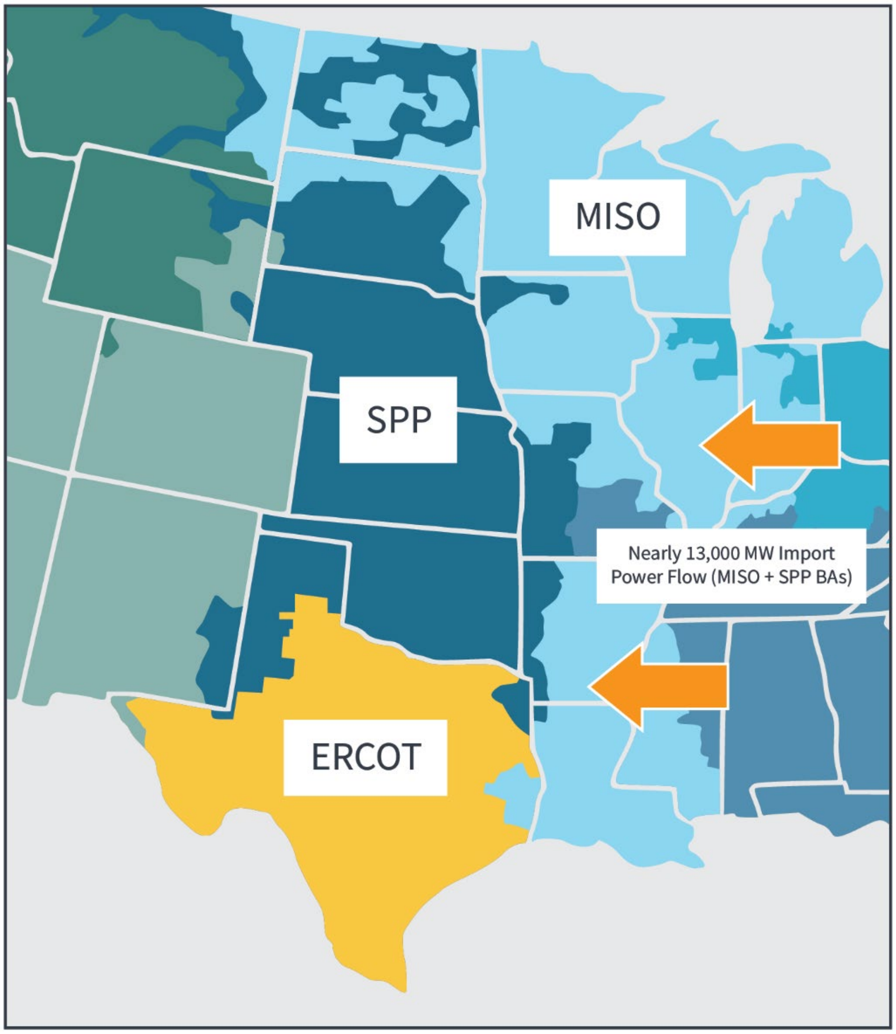
Figure 80: Increasing East-to-West Import Power Flows into SPP BA Footprint, Flowing Through MISO Transmission Network, February 14 – February 15, 1:00 p.m.



At the same time that SPP's imports from the east were increasing, MISO was also importing power from entities in the east, which, combined with SPP's imports, peaked at nearly 13,000 MW on Monday, February 15, as illustrated in Figure 81, below.

216 SPP has DC ties with the ERCOT and Western Interconnections, but with much more limited transfer capabilities than it has with the BAs in the Eastern Interconnection.
217 Compared to the east-to-west power imports SPP scheduled during the week of February 7, which generally remained below 4,000 MW (see Figure 43).

Figure 81: East-to-West Import Power Flows into MISO BA Footprint, February 15



Congestion due to the increasing imports continued building and at 4:17 a.m., MISO could have issued a TLR, however, because MISO operators knew of the emergency conditions in ERCOT and SPP, MISO RC did not immediately issue the TLR and curtail SPP's imports (which would also have curtailed ERCOT's imports). Instead, MISO RC and PJM worked in Safe Operating Mode, which allowed PJM to take some wind generating units offline to help mitigate congestion. This allowed MISO to delay issuing the TLR,[218] but at 7:30 a.m., MISO did issue a TLR 3B declaration to reduce non-firm flows into SPP, effective immediately, to relieve transmission constraints. SPP reached a maximum net import of 6,457 MW at 8:30 a.m., as seen on Figure 80, above, and still maintained

[218] This was another example of the RCs coordinating during the Event, working to prioritize the most critical emergencies among the three RCs.

DC tie exports to ERCOT during this period. Shortly thereafter, at 8:58 a.m., SPP set an all-time winter peak load of 43,661 MW.

At 9:00 a.m., an unplanned outage of an additional 500 MW of generation occurred in the SPP footprint, and at the same time, SPP suffered additional TLR curtailments of non-firm imports to alleviate transmission constraints.[219] At 10:08 a.m. on February 15, with its imports reduced and insufficient reserves, SPP declared EEA 3. At 12:04 p.m. SPP directed 610 MW of firm load shed, and curtailed exports to ERCOT by 250 MW (from 815 MW to approximately 560 MW). SPP terminated the EEA 3 by 2:00 p.m., dropping to EEA 2 and restoring ERCOT's exports. SPP remained in EEA 2 through the rest of the day and into the morning of February 16.

Many system conditions remained the same in MISO and SPP on February 16: increased generating unit outages, peak electricity demands, and the need for high non-firm east-to-west power imports. At 6:00 a.m. on February 16, the MISO RC declared a TSE for its next-worst contingency (a 345kV transmission line, which was identified as a temporary IROL). Just minutes later, at 6:10 a.m., MISO lost the next-worst contingency, verified as an IROL by 6:18 a.m., and curtailed SPP's imports, by approximately 4,300 MW, via TLR 3B and TLR 5A declarations at 6:45 a.m. and 7:15 a.m., respectively (see Figure 82, below).[220] Still short of generation, and unable to import what it needed to compensate for the generation shortfalls, SPP declared its second EEA 3 of the Event at 6:15 a.m. due to "extremely low temperatures, inadequate supplies of natural gas and wind generation." At 6:44 a.m., SPP ordered 1,359 MW of firm load shed and curtailed 150 MW of firm exports to ERCOT. At 7:18 a.m., SPP ordered a second load shed block of 1,500 MW (1,359 firm load shed plus curtailed 150 MW of firm exports to ERCOT). SPP restored all load and exports by 10:07 a.m. and returned to EEA 2 at 11:30 a.m.

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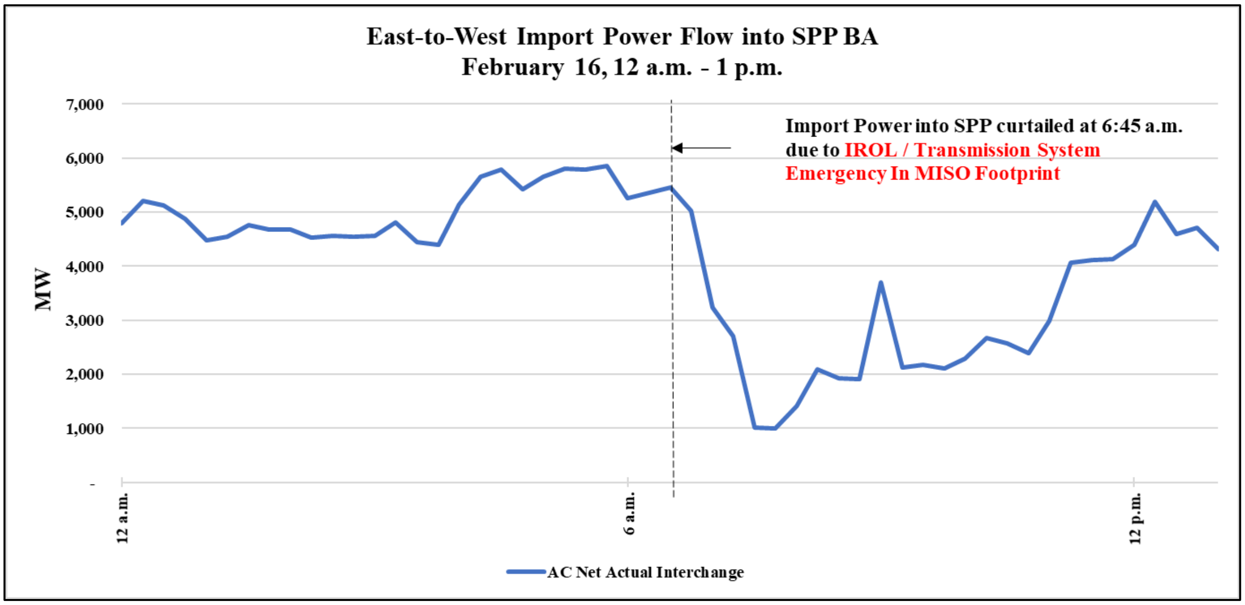
[219] TVA called a TLR Level 3 resulting in curtailments of non-firm power transfers from BAs east of MISO to SPP.
[220] Also, in addition to SPP import curtailments to help alleviate the IROL condition, at 6:52 a.m., MISO RC and a local TOP implemented 140 MW of firm load shed in MISO's own footprint to alleviate real-time and post-contingency transmission overloads.

Figure 82: East-to-West Import Power Flow into SPP BA Footprint, February 16, 12 a.m. – 1 p.m.



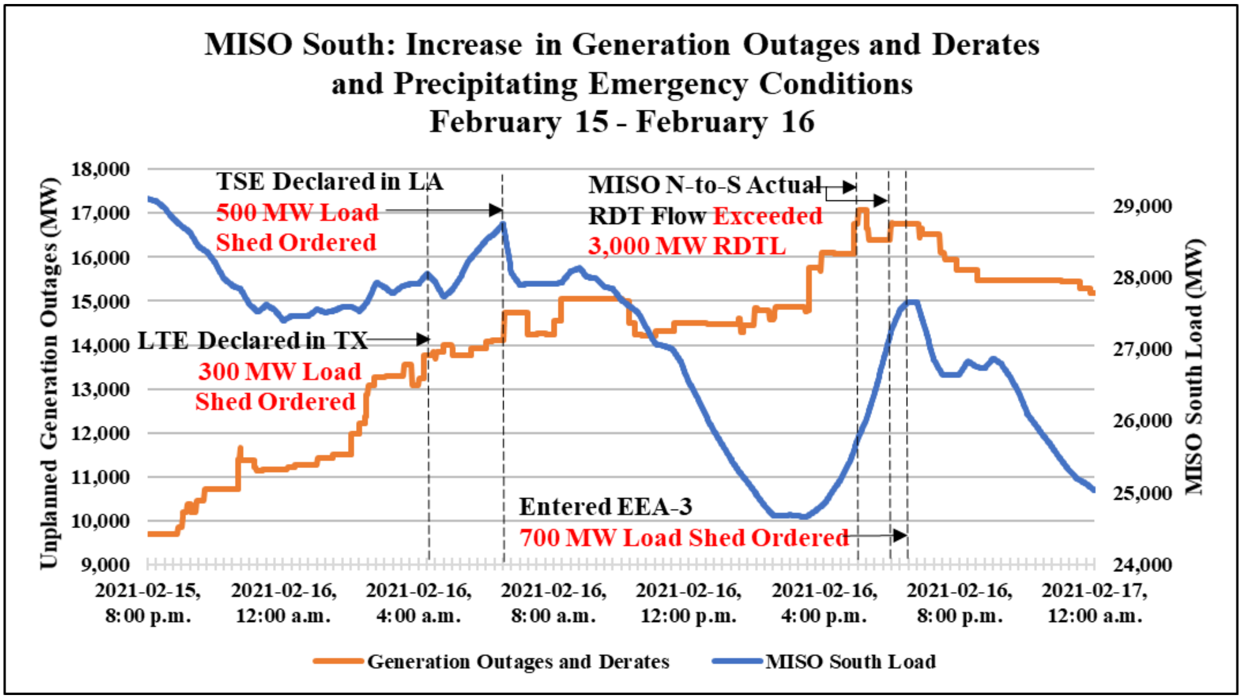
iii. SPP Transmission Emergency

On February 15 at 7:09 p.m., SPP RC declared a Transmission Emergency (which is on a system-wide level, not isolated to a single area, contingency, or event) due to multiple N-1 constraints across its system and abnormally high congestion throughout the SPP RC footprint. The Emergency lasted until February 16 at 4:22 p.m. SPP RC used market dispatch through Congestion Management Events, Out-of-Merit Energy dispatch instructions, reconfiguration plans and post-contingent load shed plans to mitigate the congestion across its footprint. SPP RC did not direct any load shed because of its transmission system emergency; however, one TOP did initiate load shed to help mitigate a local area pre-contingent facility rating exceedance on a 115 kV circuit. SPP RC posted its Transmission Emergency declaration on the RCIS, along with updates and notice of the transmission emergency declaration ending.

iv. MISO South Energy Emergency

During the early morning hours of February 15, the MISO South footprint experienced an increase of nearly 6,000 MW of generation outages, derates and failures to start from 3:00 a.m. to 9:00 a.m. Unfortunately, this pattern repeated beginning at approximately 8:00 p.m. on February 15 and continued until about 5:00 p.m. on February 16, as shown in Figure 83, below. During this time, MISO South lost an additional 7,300 MW of generation to outages, derates and failures to start. At its worst point, MISO South had over 16,800 MW of nameplate generation outaged (over 50 percent of MISO South's all-time actual winter peak load[221] and over 40 percent of its installed generation capacity).[222]

Figure 83: MISO South Continuing Unplanned Generation Outages and Precipitating Grid Emergency Conditions



Even though the cold temperatures across MISO South on February 16 were, on average, slightly less severe than on February 15, resulting in slightly lower electricity demands, MISO needed to declare transmission emergencies[223] and an energy emergency for MISO South due to the excessive unplanned generation outages, derates and failures to start. On February 16 at 4:59 a.m., MISO declared an EEA 2 for MISO South for the morning and afternoon, which would later be extended through the remainder of the day.

At 4:50 p.m. on February 16, the MISO South footprint suffered the additional outages of two large generating units, continuing the pattern of escalating unplanned generation outages. These events caused MISO's north-to-south actual (raw) RDT flow to exceed its RDTL of 3,000 MW, indicated in Figure 83, above. When MISO exceeded the RDTL, its operators contacted SPP and the other BAs that are parties to their joint operating agreement to discuss the conditions. While MISO's RDT flow returned within normal limits for a short time, at 5:50 p.m. MISO initiated a call to the

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[221] 32.1 GW, January 17, 2018.
[222] 41.3 GW.
[223] The LTE and TSE shown in Figure 83 above were previously described in sub-section (i) above.

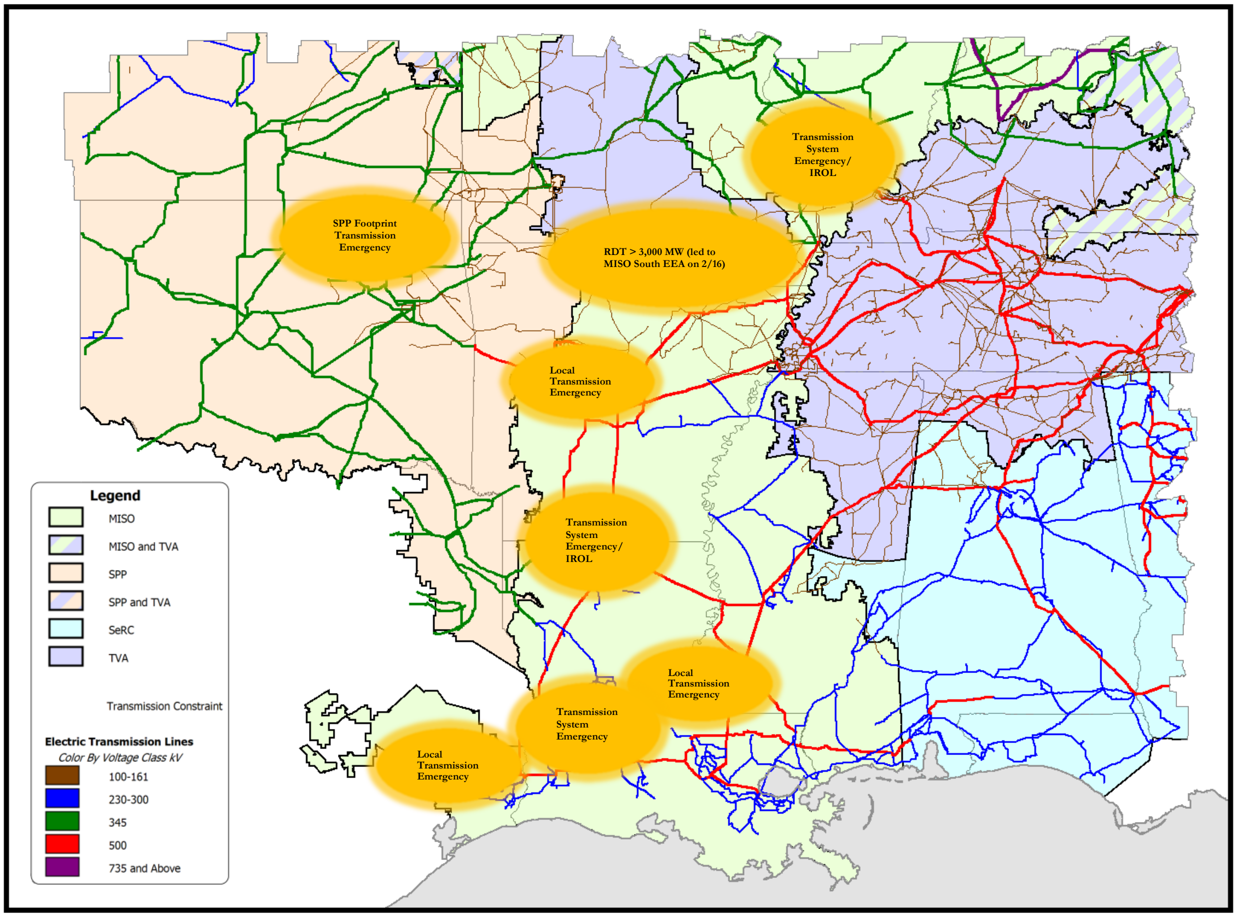
other BAs asking permission to raise the north-to-south RDTL to 3,700 MW.[224] The joint BA parties studied the potential, but with a portion of east-to-west import power transfers into MISO South already curtailed at 5:15 p.m., multiple 500 and 345kV post-contingency constraints developing on neighboring transmission systems, and the fact that granting the request would require additional curtailments to east-to-west import power transfers to MISO South, the BAs informed MISO at 6:10 p.m. that they were unable to facilitate the RDTL increase above 3,000 MW.

At 6:20 p.m. on February 16, MISO's actual north-to-south RDT flow again exceeded 3,000 MW due to both increasing generation outages and system demand, as shown in Figure 83, above. MISO had exhausted its ability to import power east-to-west into MISO South, its actual RDT flow north-to-south exceeded the RDTL, and it had no ability to raise the RDT limit without overloading neighboring transmission systems. Given all system conditions, including the inability to import the energy it needed to meet the MISO South demand, and realizing the grid's stability was in danger, at 6:40 p.m., MISO declared an EEA 3 and ordered 700 MW of firm load shed in MISO South to avoid widespread cascading outages.

At 7:00 p.m., the actual RDT flow dropped below the 3,000 MW RDTL. At 7:50, MISO ordered 300 MW of load that was shed to be restored, and at 8:41 p.m. ordered restoration of the remaining load, due to over 1,000 MW of generation returning to service and MISO South system demand decreasing following the evening peak. Figure 84, below, illustrates how constrained the Eastern Interconnection was in the MISO and SPP footprints, February 15-17, 2021.

[224] Under the version of MISO/SPP Regional Transfer Operations Procedure in effect during the Event, a party could request a temporary increase or decrease in the RDT limit to avoid a system emergency, or address emergent or actual system emergencies.

Figure 84: Summary: MISO and SPP Transmission Emergencies View – February 15 – February 17



d. Managing Firm Load Shed

From February 15 to 18, when winter electricity demands and unavailable generation were at their highest levels, to maintain electric grid reliability (including avoiding instability, uncontrolled separation or cascading failures of the BES), system operators for ERCOT, MISO and SPP BAs correctly implemented energy emergency measures including ordering firm load shed within their respective footprints as follows:

- ERCOT BA: starting on February 15, 2021 and lasting nearly three consecutive days and at its worst point, 20,000 MW;
- SPP BA: on February 15 and 16, four hours and twenty minutes total and at its worst point, 2,718 MW. SPP declared system-wide emergencies on February 15 and 16 due to capacity shortages within its BA. Most of SPP's unavailable generation was in the southern portion of its system. SPP shed 610 MW for one hour on February 15 when its imports were curtailed. On February 16, SPP shed load in two separate steps of 1,359 MW each (33 minutes apart), totaling 2,718 MW, for three hours (again the load shed coincided with imports being

curtailed to SPP). In both instances, SPP restored the lost load once curtailed imports were restored; and

- MISO BA (MISO South): on February 16 for two hours and forty-one minutes and at its worst point, 700 MW.

The following Figures 85 – 87 show the patterns of EEA 3 firm load shed ordered for energy emergencies from February 15 through February 18 in ERCOT, SPP and MISO, respectively.

Figure 85: ERCOT EEA 3 Energy Emergency Firm Load Shed Ordered (MW)

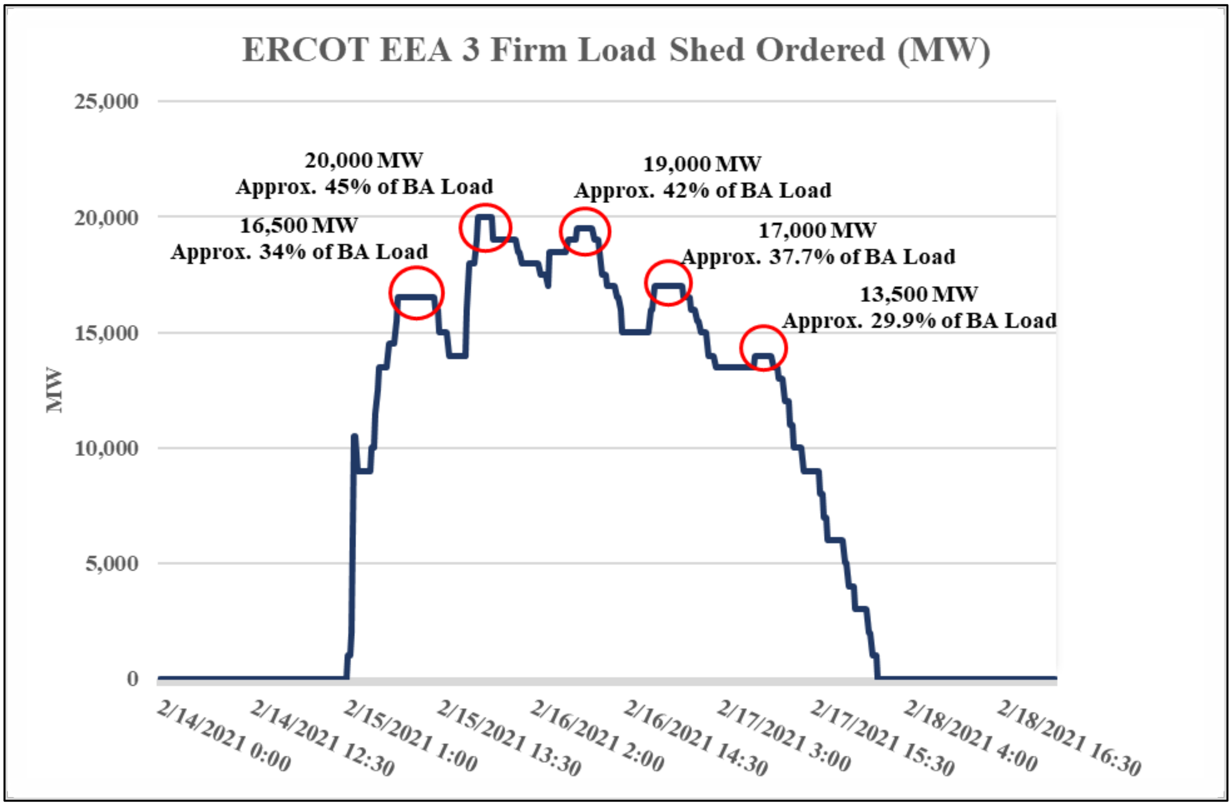


Figure 86: SPP EEA 3 Energy Emergency Firm Load Shed Ordered (MW)

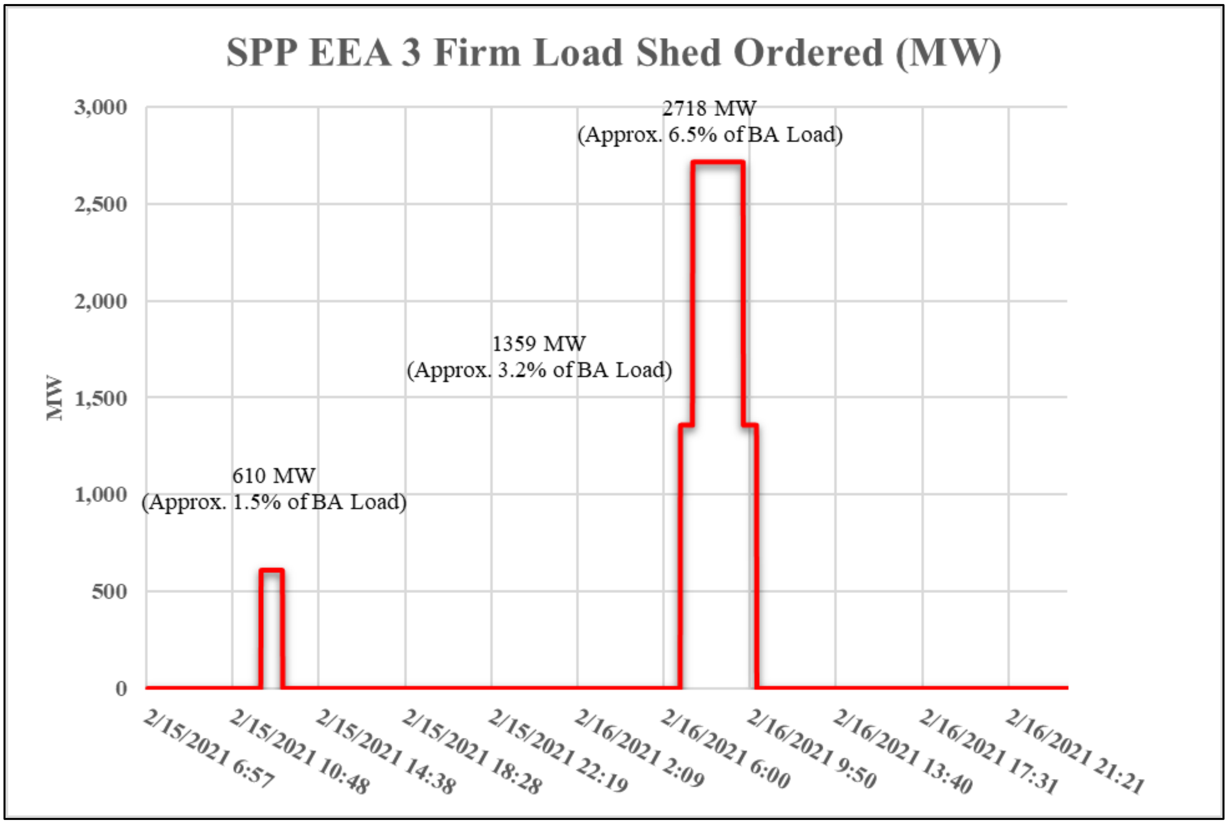
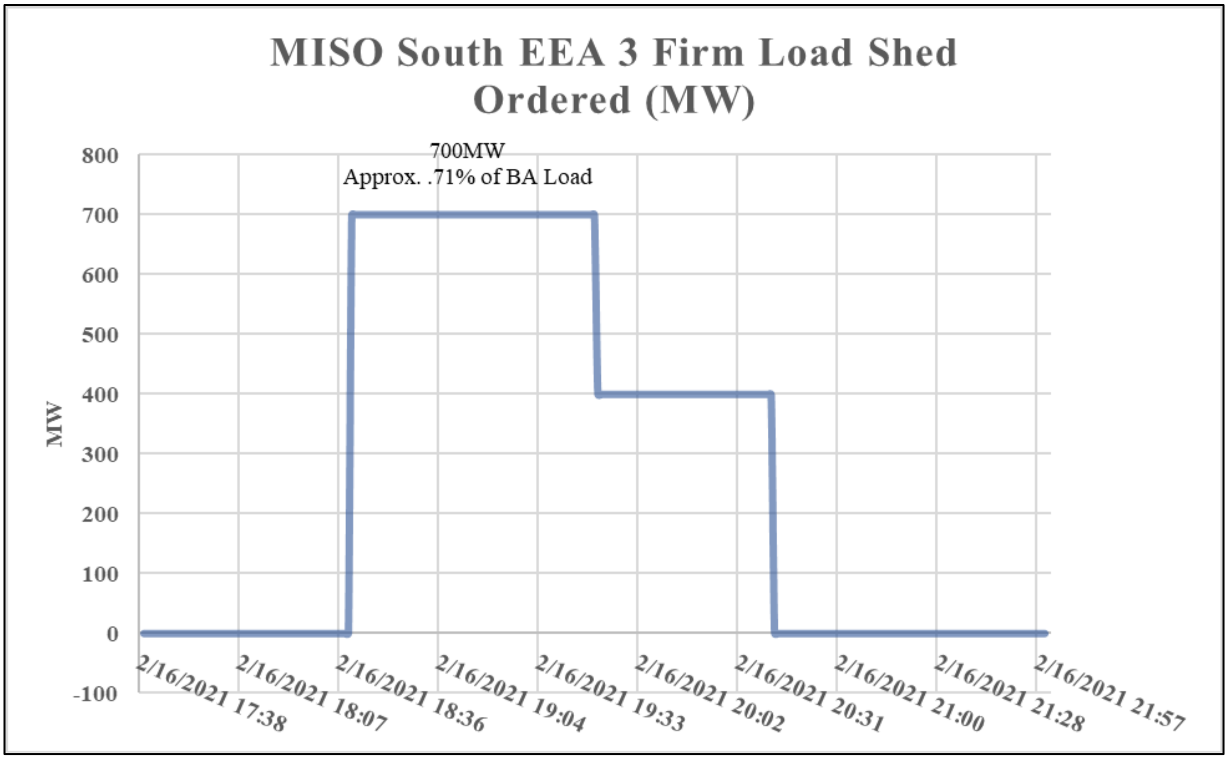


Figure 87: MISO South EEA 3 Energy Emergency Firm Load Shed Ordered (MW)



i. Natural Gas – Electric Interdependency: Firm Load Shed Caused Outages to Natural Gas Facilities Critical to Providing Natural Gas Fuel Supply to BES Generating Units

The manual load shed plans (of TOPs) and automatic underfrequency load shed plans (of TOs and DPs) within the ERCOT footprint were designed to avoid controlled power outages to priority or critical electric loads if the need to shed firm load arose. However, most of the natural gas production and processing facilities the Team surveyed were not identified as critical load or otherwise protected from manual load shedding. Because it is not the entity that implements load shedding, ERCOT did not anticipate that firm load shed would contribute to power outages of natural gas production and processing facilities, that would in turn, contribute to the decline in natural gas supply and delivery to natural gas-fired generating units. Thus, from early February 15 through February 18, the implementation of manual firm load shed by ERCOT, SPP and MISO[225] operators to preserve BES reliability partially contributed to the decline in the production of natural

[225] Even though SPP's orders for firm load shed were on a much smaller scale than ERCOT's, circuits providing natural gas fuel supply to generating units, including facilities in Texas, were known to be interrupted. Some TOPs within MISO did not exclude natural gas infrastructure from their manual load shed plans; therefore, MISO South manual load shed could also have partially contributed to the decline in the production of natural gas.

gas. Because many critical natural gas infrastructure loads had not been identified during the Event, and both power outages caused by both weather and firm load shed were coincident during this timeframe, the extent of power outages to critical natural gas infrastructure loads due to firm load shed is unknown.

Within the SPP footprint, some natural gas infrastructure was identified as critical and protected from load shed, while other circuits supplying natural gas infrastructure were not protected from manual load shed. One TOP with rural load that includes a significant amount of oil and natural gas wells stated that some wells were impacted by its load shed, but it did not receive any inquiries or concerns about load shed affecting natural gas infrastructure. Two TOPs within SPP's footprint reported they reached out to natural gas infrastructure entities during the Event and either did not shed their load or ensured that load shed would not impact their operations by verifying that the natural gas infrastructure entities had onsite generation. Another TOP reported that while natural gas infrastructure was not designated as critical at the time of the Event, it was now working with natural gas infrastructure entities to identify natural gas infrastructure necessary to support generating units.

ii. Difficulties in Rotating Firm Load Shed and Avoiding Overlap of Automatic Load Shed/UFLS

As February 15 wore on, due to increasing levels of unplanned generating unit outages and derates and increasing electricity demands, ERCOT needed to shed larger quantities of firm load to keep the power grid stable. The combined magnitude and duration of manual firm load shed needed to maintain BES reliability in ERCOT caused electric service providers (TOPs, TOs and DPs) to have difficulties in rotating the manual load shed and required operators to implement controlled outages of electric circuits normally reserved for automatic load shed (e.g., underfrequency load shed/UFLS). In ERCOT, at least 25 percent of the load is to be reserved for automatic load shedding (and this does not include critical loads protected from manual load shedding, such as hospitals, police stations, etc.). System operators are required to minimize overlap between manual load shed and UFLS.[226] ERCOT operators needed to protect at least 25 percent of load beyond the 14-28 percent of manual load shed ordered on February 15-16 and the identified critical loads from manual load shed. These protective actions made it difficult for ERCOT operators to avoid use of some UFLS circuits for manual load shed and hampered their ability to use additional circuits to perform rotational load shed. The use of the UFLS circuits for manual load shed would render them unavailable if the frequency in ERCOT dropped and UFLS was needed to preserve BES reliability.

[226] See Reliability Standard EOP-011-1 - Emergency Operations, Requirement R1.

e. Conditions Gradually Improve

i. MISO South and SPP

The last of SPP's and MISO's energy emergency EEA 3 firm load shed events occurred on February 16. While Wednesday through Friday, February 17 to 19 brought less severe cold weather conditions as compared to February 15 to 16, below-freezing temperatures still prevailed in southern SPP and MISO South locations for many hours. Both still had significant unplanned generating unit outages in their respective footprints, due to ongoing freezing and natural gas fuel supply issues.

MISO South. At the start of February 17, MISO's north-to-south actual RDT flow again exceeded its RDTL of 3,000 MW, due to MISO South's increased unplanned generation outages, electricity demands and east-west import constraints. At 12:54 a.m. on February 17, MISO declared a TSE due to an emerging next-contingency IROL condition. Under the emergency, MISO was able to manage generation resources to reduce actual RDT flows to be within limits, and the TSE was converted to an LTE, which was subsequently terminated at 8:40 a.m. For its evening peak load timeframe on Wednesday, February 17, MISO declared another energy emergency (EEA 2) for MISO South and called on voluntary load management measures. MISO terminated the EEA 2 at 8:30 p.m. and did not need to implement energy emergency load reduction measures for the remainder of the week. MISO's last LTE for Louisiana was terminated on February 18 at 12:00 p.m. On Saturday, February 20, MISO ceased conservative operations and returned to normal operations at 3:00 pm.

SPP. By Wednesday, February 17 at 1:15 p.m., SPP was able to downgrade its energy emergency to EEA 1. Like MISO for MISO South, for its evening peak load timeframe on February 17, SPP escalated its energy emergency to EEA 2 for its footprint, and instructed voluntary load management measures again to be implemented until 10:59 p.m., when it downgraded its energy emergency level to EEA 1. On February 19 at 9:20 a.m., SPP was able to cease energy emergency operating conditions. SPP remained in conservative operations until Saturday, February 20, when it returned to normal operations at 10:00 pm.

ii. ERCOT

With ERCOT's generation shortfalls much more severe than MISO South and SPP footprints, it remained in EEA 3 on February 17. Moderating temperatures allowed gradual reductions in firm load shed, even though only a small number of generating units had returned to service at that point. As evening approached, additional generation that returned to service was sufficient to reduce load shed directives through the evening of February 17, and by 11:55 p.m., ERCOT issued instructions to restore all remaining load, for the first time since Monday, February 15.

On Thursday, February 18, unplanned generation outages in the ERCOT footprint continued to return to service as temperatures continued to increase. Some customer outages remained, due to ice storm damage or need for manual restoration and return of large industrial facilities. On Friday, February 19, at 9:00 a.m., ERCOT downgraded its energy emergency to EEA 2, and by 10:35 a.m., ERCOT returned to normal operations, concluding the Event.

D. Post-Event Actions by Entities & Government

1. By Involved Entities

On July 13, 2021, ERCOT delivered its "Roadmap to Improving Grid Reliability," a list of sixty actions, each of which is marked "complete," "on track," or "limited progress."[227] Approximately half of the actions related directly to reliability, while others involved communications, governance, or market issues. Some of the completed actions addressed inquiry recommendations areas, such as generators providing more frequent market updates or reporting all forced outages, and improving the assessment of extreme weather scenarios.[228] Among the actions that are on track include identifying when ERCOT load forecasts have high uncertainty, considering whether additional reserves are necessary, improving the reliability of black start, improving fuel security via market incentives, and considering on-site fuel supply for generating units.[229] ERCOT [230] is developing new load forecast metrics that will be completed in 2021.

MISO and SPP released public reports on the Event.[231] In addition to analyzing the grid operations, markets, communications, and other key aspects of the events experienced in their respective footprints, both made recommendations. MISO identified 20 lessons learned, joining each lesson with one or more "actions to address." SPP made 22 recommendations (for new actions, policies, or assessments) organized into 3 tiers by urgency.

As with ERCOT's Roadmap, some of the recommendations involved communications, markets, and other non-reliability topics. Other recommendations covered important reliability topics including resource adequacy, fuel assurance, planning for extreme event scenarios and load reduction, emergency drills, situational analysis, system operator training, and protection of critical infrastructure.[232]

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227 Electric Reliability Council of Texas (ERCOT), *Roadmap to Improving Grid Reliability*, (July 13, 2021), http://www.ercot.com/content/wcm/lists/219694/ERCOT_Roadmap_Final_July_13_2021.pdf.
228 See Actions 3, 4, and 9.
229 See Actions 22, 37, 56, and 57.
230 ERCOT Nodal Protocol Revision Request Number 1089 (July 28, 2021) Nodal Protocol Revision Request (NPRR) 1089 (previously, ERCOT only required an official with binding authority to submit the information, not the highest-ranking official).
231 Midcontinent Independent System Operator (MISO), *The February Artic Event: Event Details, Lessons Learned and Implications for MISO's Reliability Imperative*, (Feb. 14-18, 2021), https://cdn.misoenergy.org/2021%20Arctic%20Event%20Report554429.pdf; A Comprehensive Review of Southwest Power Pool's Response to the February 2021 Winter Storm: Analysis and Recommendations (July 19, 2021) https://www.spp.org/documents/65037/comprehensive%20review%20of%20spp's%20response%20to%20the%20feb.%202021%20winter%20storm%202021%2007%2019.pdf.
232 See Appendix H for a comparison of recommendations from several reports on the Event, including the ERCOT, MISO and SPP reports.

2. By Government

Texas Senate Bill 3 (SB3) was the most significant legislation that arose out of the Event. Effective on signing on June 8, 2021, SB3 combined provisions regarding public communication during emergencies, gas-electric coordination, protecting critical gas infrastructure, additional inspections of, and reports regarding, winter preparedness, and load shedding. Among the provisions most relevant to the Event are:

- Development of a new "power outage alert" (with coordination among several agencies including the PUCT and Department of Transportation (to use its highway messaging signs).
- Creation of a new "Texas Energy Reliability Council," with the purpose of fostering better communication between the natural gas and electric industries. Its members include the Chairs of the Texas Railroad Commission and PUCT, ERCOT, and members from the natural gas and electric industries, as well as other energy and industrial sectors.
- Creation of a committee to map the electricity supply chain "in order to designate priority electricity service needs during extreme weather events" (and update that map yearly). The committee is also required to file reports with the Legislature on the "reliability and stability of the electricity supply chain," and "include recommendations to . . . decrease the frequency of extended power outages caused by a disaster." The committee, composed of Executive Directors of the PUCT and the RRC and the President and CEO of ERCOT, is tasked with mapping Texas's electricity supply chain, identifying critical infrastructure sources, and establishing best practices to prepare facilities in the supply chain to maintain service in an extreme weather event, among other responsibilities.
- Requiring gas supply chain facilities identified on the electricity supply chain map and directly serving natural gas-fired generating units to "implement measures to prepare to operate during a weather emergency," be subject to inspections (prioritized based on risk level), and if repeatedly experiencing weather-related interruptions, to obtain an independent assessment of their weatherization plans, procedures and operations and submit the assessment to the RRC. The RRC can require a gas supply chain facility to implement recommendations from the independent assessment.
- Development of a communication system between critical infrastructure sources, the PUCT and ERCOT to ensure that electricity and natural gas supplies in the electricity supply chain are prioritized to those sources during an extreme weather event.
- Requiring the PUCT and RRC to collaborate on rules for designating natural gas facilities and entities as critical electric customers or critical gas suppliers, which could include natural gas production, processing, and transportation, related water disposal facilities, and delivery

of natural gas to generating units[233], and requiring that only facilities prepared to operate during a weather emergency may be designated as critical.

- Requiring municipal utilities, cooperatives, power generation companies or exempt wholesale generators to implement measures to prepare their generating units to provide "adequate electric generation service during a weather emergency," be subject to inspections, and if repeatedly experiencing weather-related interruptions, to obtain independent assessment of their weatherization plans, procedures and operations, and submit the assessment to the PUCT. The PUCT can require the generation provider to implement recommendations from the assessment.
- Requiring that utilities provide retail customers with information about involuntary load shedding, and how to apply to become a critical care retail customer or other protected class of retail customer.
- Adding new rules regarding how to conduct firm load shedding, including that the PUCT examine whether entities complied with their load shed plans, and providing for at least one load shed drill each in the summer and winter.
- Requiring procurement of competitive "ancillary or reliability services" to ensure reliability during extreme heat and extreme cold weather and during times of low wind or solar; winter resources required to include on-site fuel storage, dual-fuel capability or "fuel supply arrangements to ensure winter performance for several days."

On October 21, 2021, the PUCT issued a final rule requiring generating units in ERCOT to take certain winter preparation actions by December 1, 2021, including:

- Using best efforts to implement measures intended to ensure sustained operation of "cold weather critical components[234] during winter weather conditions, including weatherization, onsite fuel security, staffing plans, operational readiness, and structural preparations . . .;"
- Take specific preparation measures including installing adequate wind breaks, enclosing sensors for cold weather critical components, inspecting/repairing thermal insulation, confirming the operability of instrument air moisture prevention systems, maintaining and testing (on a monthly basis, November through March) freeze protection components, and installing monitoring systems for cold weather critical components (e.g., heat tracing or instrument air moisture prevention systems);

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233 The RRC also revised the form for "Application for Critical Load Serving Electric Generation and Cogeneration," revised as of March 2021. Instead of stating that it does not apply to "field services," which could have deterred production facilities from seeking protection, no matter how large or critical the facility, the form now more broadly covers production, processing and pipeline facilities: "[t]he designation shall only be requested for individual premises (meters) that provide electricity to natural gas production, saltwater disposal wells, processing, storage, or transportation such as a natural gas compressor station, gas control center, or other pipeline transportation infrastructure."

234 Similar to the Report, the PUCT defines cold weather critical component as "any component that is susceptible to freezing or icing, the occurrence of which is likely to significantly hinder the ability of a resource or transmission system to function as intended and, for a generation entity, to lead to a trip, derate or failure to start . . .." *Rulemaking to Establish Electric Weatherization Standards*, Project No. 51840, Order Approving Rule, at p. 86, definition 1 (Oct. 21, 2021); 51840_101_1160359.PDF (texas.gov).

- Use best efforts to address cold weather critical component failures that occurred "because of winter weather conditions in the period between November 30, 2020 and March 1, 2021;"
- Provide training on winter weather preparations and operations; and
- "Determine minimum design temperature or minimum experienced operating temperature, and other operating limitations based on temperature, precipitation, humidity, wind speed, and wind direction."[235]

[235] *Id.* at 86-89.

IV. Analysis

A. Overview

The Event began with extreme cold temperatures and freezing precipitation. Both open-frame generating units, common throughout Texas and the South Central U.S., 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. The extent to which the Event was caused by the failure of all types of generating units to prepare for extreme cold weather or associated freezing precipitation, cannot be overstated. Figure 88, below, illustrates the generating unit outages by fuel type over time over the course of the Event. Outages of wind generating units rose early in the Event, starting February 10, and reached a plateau of 20 to 25 GW that sustained through February 18. Natural gas and coal generating unit outages rose on February 15, with natural gas-fired generating unit outages nearly doubling in two days, from 25 GW to 50 GW by February 17. Figures 89 through 91 show the relative proportions of the fuel types of the generating units that experienced unplanned outages, derates and failures to start during the Event, analyzed by total MW loss during the Event, number of outages, or number of units.

Figure 88: Generation Outages, Derates, and Failures to Start (MW) by Fuel Type, February 8-20, Total Event Area

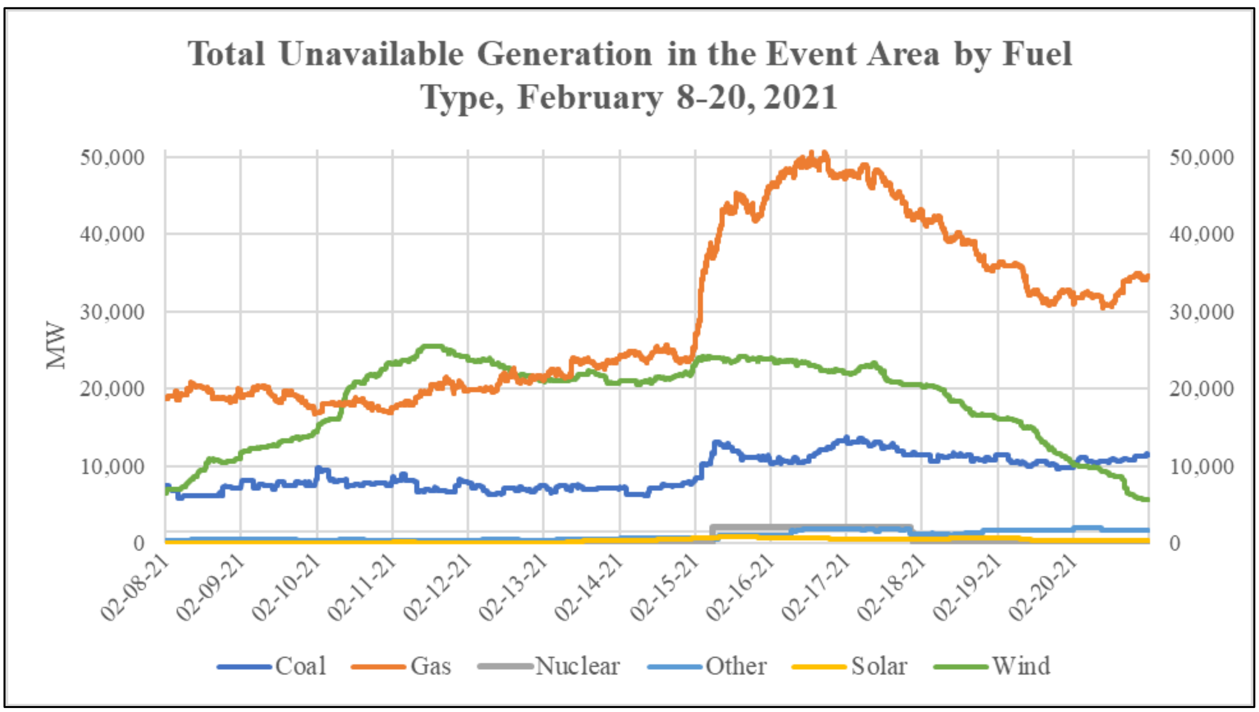


Figure 89: Number of Incremental Unplanned Generation Outages, Derates, and Failures to Start by Fuel Type, February 8-20, Total Event Area

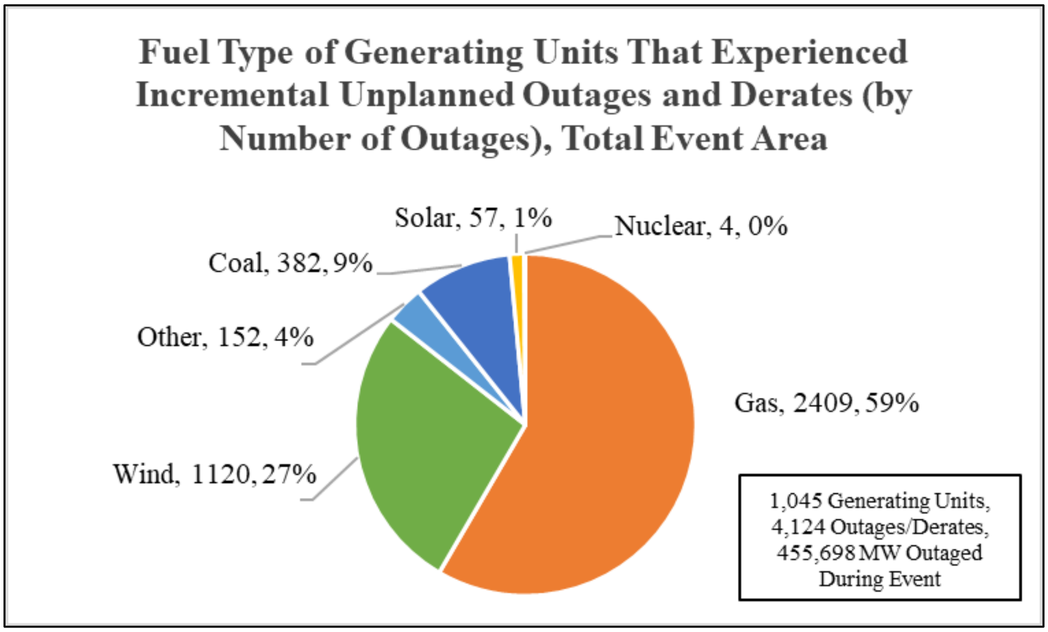


Figure 90: Generation Outages, Derates, and Failures to Start (Outaged MW) by Fuel Type, February 8-20, Total Event Area

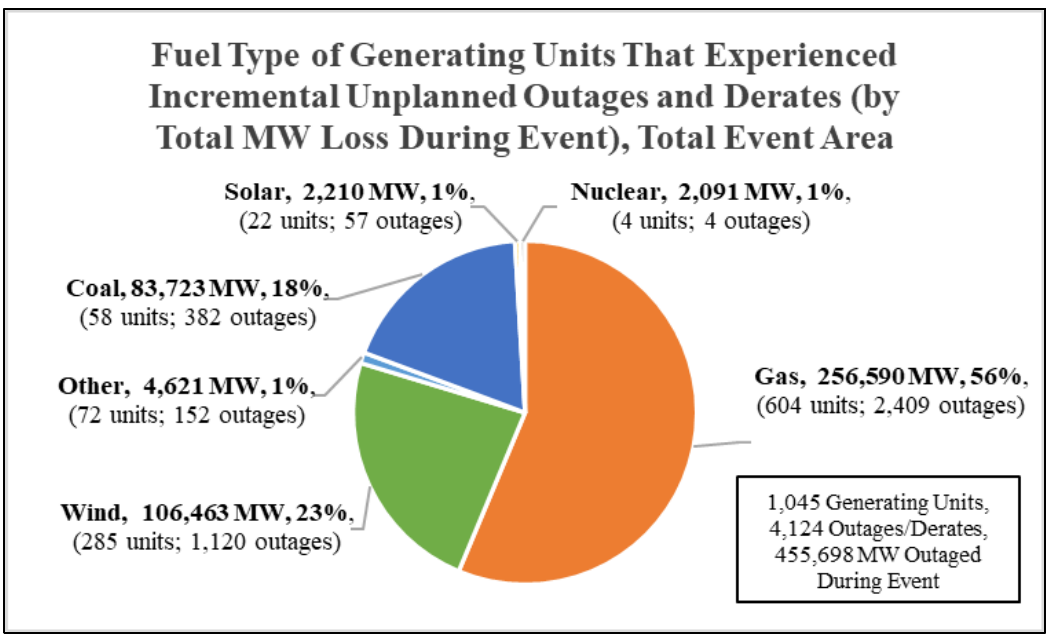
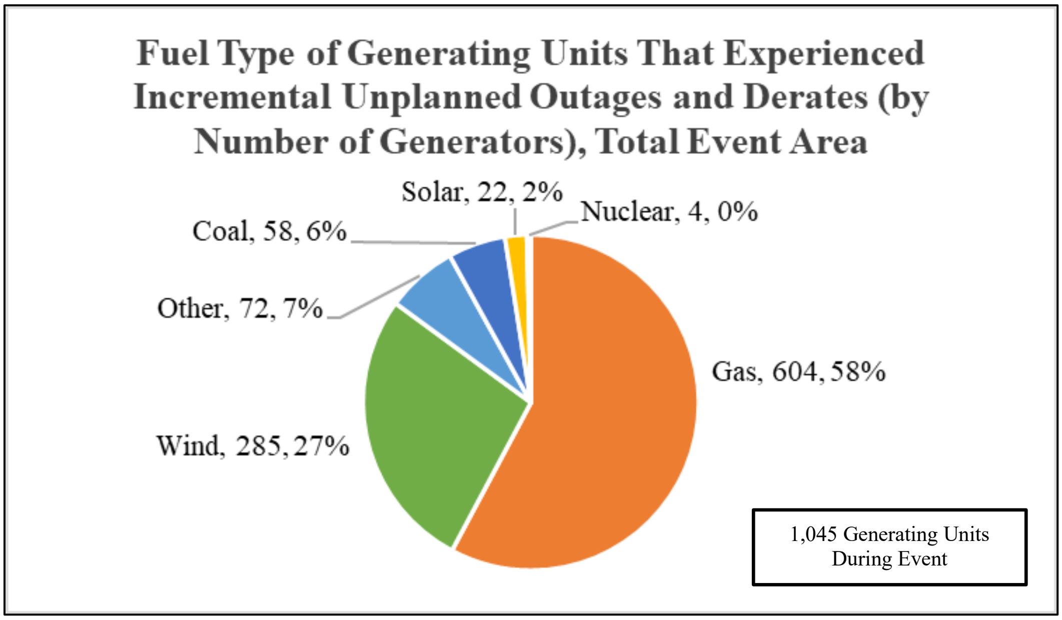


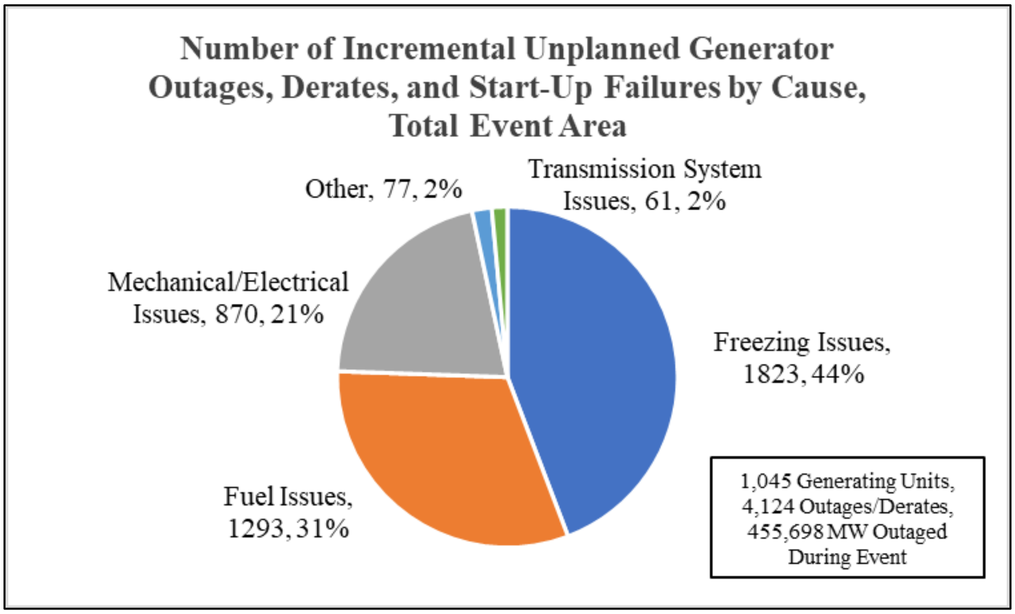
Figure 91: Number of Unique Generating Units that Experienced an Outage or Derate by Fuel Type, February 8-20, Total Event Area



Numbers of outages, rather than some other measure such as numbers of individual generating units, proved to be the most accurate way to divide the causes of generating unit failures, as well as the fuel types of the generating units. A single generating unit's outages, during an Event lasting nearly two weeks, may have stemmed from multiple causes. For example, a freezing-related outage may have been preceded or followed by a derate caused by natural gas fuel supply issues. Figures 92 and 93 below reflect, for the total Event Area and total Event duration of February 8 through 20, the combined total of all individual generating units outaged and all MW associated with each generating unit outage or derate. So for example, if an (imaginary) generating unit named "ERCOT 1" was a gas unit with a nameplate capacity of 300 MW, and during the Event it experienced an outage, followed by a derate of 100 MW and another derate of 50 MW, it would be reflected in Figures 92 and 93 as one unit, and a total of 450 MW outaged during the Event. The Team acknowledges that the total of 455,698 MW "outaged during Event" may at first glance appear to be an astronomical number and does not mean to convey or imply that this amount of MW was ever outaged simultaneously during the Event. But on the other hand, the number does represent real losses. Every MW of that 455,698 MW was being counted upon by ERCOT, SPP or MISO to serve load at some point during the Event. If the causes of the outages are not addressed, extreme generation failures resulting in firm load shed can continue to reoccur during freezing temperatures.

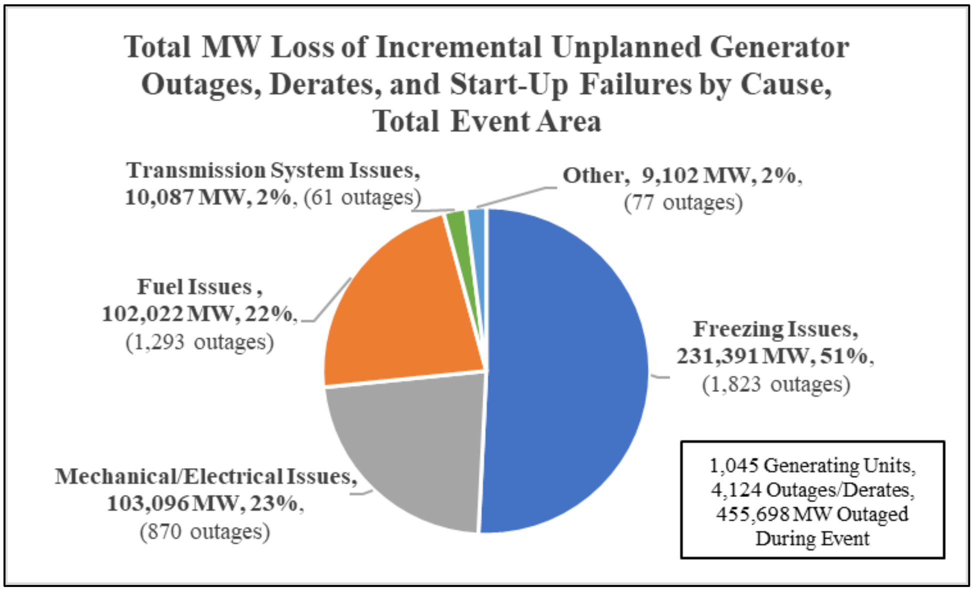
The principal cause of generating unit outages was freezing components and systems resulting from the cold temperatures and precipitation. **Freezing issues and fuel issues combined to cause 75 percent of all unplanned generating unit outages, derates and failures to start during the Event**, as shown in Figure 92 below (as measured by number of outages). Fuel issues included 87 percent natural gas fuel supply issues (decreased natural gas production, terms and conditions of natural gas commodity and transportation contracts, low pipeline pressure and other issues)[236] and 13 percent other fuel issues. Natural gas fuel supply issues alone caused 27.3 percent of all unplanned generating unit outages, derates and failures to start during the Event. Mechanical/electrical issues, responsible for an additional 21 percent of outages, derates and failures to 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 92: Number of Incremental Unplanned Generation Outages, Derates, and Failures to Start by Cause, February 8-20, Total Event Area



[236] See section IV.C. for more discussion of natural gas fuel supply issues.

Figure 93: Total MW Loss of Incremental Generation Outages, Derates, and Failures to Start (Outaged MW) by Cause, February 8-20, Total Event Area



Despite multiple recommendations since 2011 that generating units should take actions to prepare for the winter (including detailed recommendations for winterization plans),[237] 49 generating units in SPP (15 percent), 26 in ERCOT (7 percent), and 3 units in MISO South (4 percent), did not prepare any winterization plans. As further evidence that generating units could be better prepared for winter, **81 percent of the generating unit outages**, derates or failures to start **occurred at temperatures above the unit's ambient design temperature**.

The extreme weather spanned two weeks—the weeks of February 7 and 14—with both load and generating unit outages increasing from one week to the next. During the week of February 14, especially in the early morning hours of February 15, generating unit outages and increasing load intersected at the point where ERCOT BA operators no longer had sufficient reserves, and then could no longer balance load and available generation. At its worst point, ERCOT averaged 34,000 MW of generating unit outages and derates based on "expected" capacity[238] (nearly half the amount of ERCOT's actual all-time winter peak load). These outages were sustained for two consecutive days, with the largest proportion being gas-fueled generating units. As a direct result of the massive

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[237] https://www.ferc.gov/sites/default/files/2020-07/OutagesandCurtailmentsDuringtheSouthwestColdWeatherEventofFebruary1-5-2011.pdf (Recommendations 11, 14-19), https://www.ferc.gov/sites/default/files/2020-07/SouthCentralUnitedStatesColdWeatherBulkElectricSystemEventofJanuary17-2018.pdf (Recommendation 1). See also discussion of Recommendation 1 in the 2018 Report (at pp. 88-89) for additional generating unit winterization resources predating the Event.
[238] Expected capacity is less than nameplate capacity and may include adjustments for percentages of wind and solar depending on weather forecasts, and possibly seasonal adjustments to thermal units (for example, a gas turbine could be derated slightly on a hot summer day).

generating unit losses, ERCOT was forced to order an unprecedented 20,000 MW of firm load shed, more than twice the amount of load shed during the 2011 event, and to maintain firm load shed for nearly three days. The magnitude and duration of the manual load shed required during the Event made it difficult to rotate the outages and required system operators to use automatic/UFLS load shed circuits for manual load shed instead.

MISO and SPP also experienced unplanned generating unit outages (included within the Event Area statistics) and needed to shed firm load for energy and/or transmission emergencies. However, their strong connections within the Eastern Interconnection allowed them to import large quantities of MW (reaching a maximum of nearly 13,000 MW on February 15) to mitigate generation shortfalls and meet winter peak energy demands.

B. Causes of Generating Unit Outages

Freezing issues (44.2 percent) and fuel issues (31.4 percent) together caused 75.6 percent of the 4,124 total unplanned generating unit outages, derates, and failures to start during the Event. An additional 21.1 percent of outages, derates, and failures to start were caused by "mechanical/electrical issues," but these issues too were related to the cold temperatures—as temperatures decreased, the number of generating units outaged or derated due to mechanical/electrical issues increased. In total, about 48 percent of ERCOT's, 45 percent of MISO's and 36 percent of SPP's generating unit outages, derates and failures to start during the Event were caused by freezing issues. Sixty percent of all generating units that reported an outage, derate or failure to start during the Event experienced at least one caused by freezing issues (multiple generating units had multiple outages, some from different causes).

Approximately 82 percent of the ERCOT entities that submitted a declaration of preparation for winter had at least one generating unit outaged or derated due to freezing issues, which raises questions about the efficacy of the ERCOT protocols and how the implementation of these protocols is evaluated by ERCOT and enforced by the PUCT.

Freezing issues arise because the generating units are not prepared for the cold temperatures, wind, or freezing precipitation to which they are exposed. Within the freezing issues, certain components and systems of the generating units freeze most often, as shown by the tables and representative generating units below. The top categories, such as frozen transmitters, sensing lines and instrumentation, frozen valves and inlet air systems, and wind turbine blade icing, have repeatedly caused unplanned outages in multiple events. If these most vulnerable elements, deemed "cold-weather-critical components," are better protected before future cold weather events, GOs/GOPs could prevent outages, derates and failures to start. As Figure 94 below shows, a GO need not guess where to focus in preparing for the winter. **Protecting transmitters, sensing lines and instrumentation, as well as wind turbine blades, against icing and freezing could have cut the MW of generating units experiencing an outage by 67 percent in ERCOT, 47 percent in SPP and 55 percent in MISO South**.

Figure 94: ERCOT, SPP and MISO South Generating Unit Freezing Issues Sub-Causes

ERCOT

	Equipment Category	Components and Systems	Generating Units	MW Outaged or Derated[1]	Percent of MW Outaged or Derated
	Turbine Blades (33% of MW Outaged/Derated)	Icing on blades	190	22,231	32.5%
67%	**Instrumentation** (35% of MW Outaged/Derated)	Frozen transmitter	61	10,757	15.7%
		Frozen sensing lines	37	8,791	12.9%
		Frozen instrumentation	27	4,203	6.2%
	Other Equipment Freezing Problems	Frozen equipment	73	6,941	10.2%
		Frozen valve	31	4,941	7.2%
		Equipment failure	41	4,734	6.9%
		Other freeze-related issue[2]	29	5,705	8.4%

[1] Units with multiple freeze-related outages are counted once per subcause using the maximum MW outaged.
[2] Includes freeze-related subcauses external to the generating unit such as frozen coal or ice on transmission lines.

SPP

	Equipment Category	Components and Systems	Generating Units	MW Outaged or Derated[1]	Percent of MW Outaged or Derated
	Turbine Blades (32% of MW Outaged/Derated)	Icing on blades	63	8,703	32.3%
47%	**Instrumentation** (15% of MW Outaged/Derated)	Frozen sensing lines	10	1,820	6.8%
		Frozen instrumentation	4	1,236	4.6%
		Frozen transmitter	8	991	3.7%
	Other Equipment Freezing Problems	Frozen equipment	59	6,913	25.7%
		Equipment failure	12	1,476	5.5%
		Frozen valve	11	1,227	4.6%
		Other freeze-related issue[2]	19	4,552	16.9%

[1] Units with multiple freeze-related outages are counted once per subcause using the maximum MW outaged.
[2] Includes freeze-related subcauses external to the generating unit such as frozen coal or ice on transmission lines.

MISO South

	Equipment Category	Components and Systems	Generating Units	MW Outaged or Derated[1]	Percent of MW Outaged or Derated
55%	**Instrumentation** (55% of MW Outaged/Derated)	Frozen transmitter	23	8,384	39.7%
		Frozen instrumentation	6	1,847	8.7%
		Frozen sensing lines	7	1,440	6.8%
	Other Equipment Freezing Problems	Frozen equipment	16	3,847	18.2%
		Frozen valve	5	1,276	6.0%
		Equipment failure	2	540	2.6%
		Other freeze-related issue[2]	6	3,792	17.9%

[1] Units with multiple freeze-related outages are counted once per subcause using the maximum MW outaged.
[2] Includes freeze-related subcauses external to the generating unit such as frozen coal or ice on transmission lines.

Frozen Sensing Lines and Transmitters: Power plant instrumentation, including transmitters and sensing lines, provides data necessary to monitor various operational parameters and control the generating unit's systems. Typically, sensing lines containing a standing water column are used to sense changes in pressure and a transducer produces an electronic signal that transmits the information to the plant's control systems. In sub-freezing temperatures, if freeze protection is not employed on critical unit systems and instrumentation, the water in the sensing lines can freeze, causing faulty signals and subsequent unit trips or derates.

Other than icing blades on wind turbines, frozen transmitters and sensing lines made up the majority of freeze-related outages and derates during the Event, across all unit types. Frozen sensing lines and transmitters caused outages or derates of dozens of units in all three BA footprints. For example, in ERCOT, a frozen sensing line caused a 932 MW coal generating unit to be derated to 360 MW when a pressure transmitter failed. In MISO, frozen level transmitter sensing lines and chemical feed lines caused two outages of a 511 MW natural gas-fired generating unit. And in SPP, a frozen limestone slurry line caused a 190 MW derate to a coal unit. Other representative outages caused by cold-weather-critical components include:

ERCOT Units:

- Frozen feedwater flow sensing lines caused the outage of a 568 MW natural gas-fired generating unit.
- Frozen steam drum level transmitter sensing lines caused a coal unit to trip at 577 MW due to a false high drum level indication.

MISO Units:

- Erratic drum level transmitters readings related to cold weather caused a 1,000 MW natural gas-fired generating unit to be derated by 130 MW.
- A 6-inch section of sensing line tubing without insulation and heat trace caused a frozen boiler feed pump to trip, thereby causing an 899 MW natural gas-fired generating unit to be derated by 238 MW and later outaged.

SPP Units:

- Freezing of two out of three furnace flow instruments caused a 650 MW coal unit to trip.
- A frozen transmitter led to a false steam drum level indication, shutting down boiler feed pump(s), causing low pressure, and tripping a 165 MW natural gas-fired unit.

Blade Icing: Blade icing caused multiple operational issues for wind generating units during the Event. Precipitation and condensation during cold weather can cause layers of ice to form on turbine blades, causing potential balancing, bearing, and other equipment problems, as well as safety problems when accumulated ice falls from the wind blades, known as “ice throws.” The examples below are characteristic of the operational issues experienced by wind generating units during the Event.

ERCOT Units:

- Blade icing on several turbines resulted in automatic shutdown by turbine controllers to prevent equipment damage, derating a 94 MW wind generating unit by about 50 MW.

- Ice buildup on turbine blades caused aerodynamic degradation of the blades, reducing the ability of the affected wind turbines to produce power, thereby derating a 230 MW wind generating facility to 130 MW.

SPP Unit:

- Icing on blades caused a forced outage of a 400 MW wind generating facility.

Low Temperature Limits: Wind turbines are typically designed to operate within a designated range of ambient temperatures and have an automatic shutdown feature to protect their components in the event the designated range is exceeded. Although manufacturers offer an "extreme cold weather package,"[239] which allows a turbine to continue operating in colder temperatures, GOs surveyed in ERCOT did not typically purchase this option.[240] For example, one 230 MW wind farm was derated by 25 MW and later suffered outages when the turbines, designed to shut down when the temperature drops below five degrees, performed as expected and shut down. Turbine operations, maintenance, and availability are all based on this ambient temperature limitation. In SPP, 32 wind generating units experienced automatic cutoffs once they reached their ambient design temperature limits.

Frozen Equipment (General): Many critical systems besides sensing lines experienced freezing problems caused by the low temperatures. These included emissions systems, feedwater systems, control air systems, lubricating oil systems, and the like. Emissions systems sometimes rely on water, which is susceptible to freezing. Similarly, control air systems contain moisture-laden air which can lead to freezing if the moisture is not removed. Equipment lubricants that are not kept at specified temperatures can also adversely affect the operation of equipment. The following examples illustrate critical system malfunctions due to freezing beyond sensing lines:

ERCOT Units:

- Chunks of ice entered a fan and contacted the rotor, causing a forced draft fan failure, which tripped a 325 MW natural gas-fired generating unit.
- The radiator on the intake of a compressor completely iced over, preventing the compressor from intaking air or compressing air, resulting in a loss of 46 MW at a natural gas-fired generating unit.

SPP Units:

- Inlet filters plugged with snow led to high differential pressure across the filters, forcing a 268 MW gas-fired turbine offline.
- Boiler heat trace and insulation failed on part of the reheat attemperation system,[241] causing a 500 MW coal unit to be outaged.

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[239] *General Electric, GE Energy's 2.5xl Wind Turbine Now Offers Extreme Cold Weather Capabilities for Challenging Applications in North America and Europe,* Press Release (Sept. 21, 2009), https://www.renewableenergyworld.com/om/ge-inks-1-gw-in-service-deals-offers-extreme-cold-weather-capabilities-for-2-5xl-turbine/

[240] One large owner of wind turbines in ERCOT confirmed that winterization packages are not typically applied in that region.

[241] A coil of pipe through which hot or cold water may be run, used to control steam temperature in a steam turbine.

Frozen Valves: When exposed to extreme cold weather conditions, the operation of valves can become sluggish. Depending on the particular application of these components, sluggish valves can cause instability in the boiler or turbine controls, which can eventually lead to a unit trip. Below are examples of generating units that experienced valve issues due to cold weather during the Event.

ERCOT Units:

- High-pressure steam water control valves froze, cutting off steam to the turbine and tripping a 262 MW natural gas-fired generating unit.
- Frozen valves and drain lines on auxiliary boilers prevented a 749 MW natural gas-fired generating unit from starting.

MISO Unit: Frozen fuel gas positioners on two heat recovery steam generator units caused a 22 MW derate of a natural gas-fired generating unit.

Frozen Water Lines: The condensate and boiler feedwater systems of steam-cycle generating units (coal, conventional gas, and combined cycle) use water from the condenser and add heat (through a series of feedwater heaters) and pressure (through condensate and boiler feedwater pumps) to increase cycle efficiency before the water enters the boilers. Piping, pressure vessels, and valves within these boiler feeder systems are susceptible to freezing, absent freeze protection measures, especially if the unit is offline at the onset of freezing temperatures. The following examples demonstrate typical operational issues during the Event:

ERCOT Unit:

- The air-cooled condenser at a natural gas-fired unit froze, resulting in elevated backpressure, which caused the unit to trip at 474 MW.

MISO Units:

- A frozen pipe ruptured in the makeup water micro-filtration system, causing a 551 MW natural gas-fired generating unit to be derated by 264 MW.
- Freezing issues on a circulating water system led to a coal plant being derated by 265 MW.

SPP Unit:

- A frozen condensate supply line eliminated all water flow to the heat recovery steam generator boiler piping system, forcing a 350 MW natural gas-fired generating unit offline.

These failures occurred despite the fact that the Event was the fourth cold weather event in the U.S. in the past 10 years which jeopardized BES reliability, and several of those events resulted in published reports and recommendations. The Team questioned GOs and GOPs involved in the Event about whether they incorporated voluntary recommendations available to industry from either of two sets of past recommendations: the 2011 Report recommendations, and NERC's Reliability Guideline on Generating Unit Winter Readiness, which originally dates to 2012 (but is frequently updated). Over 40 percent of the GOs/GOPs in the south central U.S. regions where "freezing issues" were identified as the predominant cause of unplanned generation outages, derates or failures to start (ERCOT and MISO South) stated that they did not incorporate specific generator-related recommendations from the 2011 Report or specific recommendations from the Guideline.[242]

C. Natural Gas Supply and Delivery[243]

Generating unit outages and natural gas fuel supply and delivery were inextricably linked in the Event. Fuel issues, at 31.4 percent, were the second largest cause of unplanned outages, derates and failures to start during the Event. Eighty-seven percent of the fuel issues involved natural gas fuel supply issues and 13 percent involved issues with other fuels (such as coal or fuel oil), as shown in Figure 95, below. Natural gas fuel supply issues alone caused 27.3 percent of the generating unit outages. Natural gas fuel supply issues include declines in natural gas production, the terms and conditions of natural gas commodity and transportation contracts, low pipeline pressure and other issues. During the Event, unplanned outages of natural gas wellheads due to freeze-related issues, loss of power and facility shut-ins to prevent imminent freezing issues, and unplanned outages of gathering[244] and processing[245] facilities decreased the natural gas available for supply and transportation to many natural gas-fired generating units in Texas and the South Central U.S.

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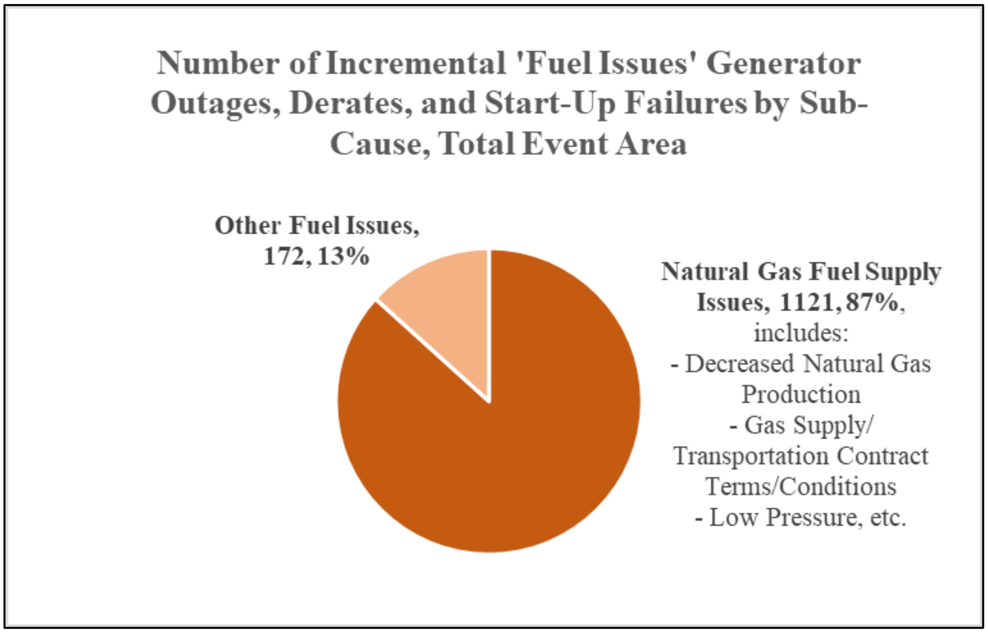
242 The Team requested data from GOs/GOPs in ERCOT, MISO South and all of SPP, based on where energy emergencies occurred. SPP's largest cause of unplanned outages, derates, or failures to start of accredited BES generation across its entire footprint during the Event was natural gas fuel supply issues, not freezing issues. Unlike ERCOT and MISO South, which have their entire footprints in warmer climates and have open-frame generating units, SPP's footprint includes some of the northernmost regions of the U.S. (e.g. North Dakota), where large numbers of enclosed generating units are designed to withstand extremely low temperatures.

243 Unless otherwise stated, the source of data for this section is the sample of producers, processors and pipelines that responded to the Team's data requests. *See* Appendix I.

244 Gathering facilities include extensive low-pressure natural gas lines which aggregate the production of several separate natural gas wells into one larger receipt point. *See* AGA Natural Gas Glossary, "Gathering" definition.

245 Processing involves extracting or removing initial components (liquefiable hydrocarbons, such as propane, butane, ethane, or natural gasoline) from the natural gas stream. *See* AGA Natural Gas Glossary, "Processing Plant" definition.

Figure 95: Fuel Issues – All Generation Types

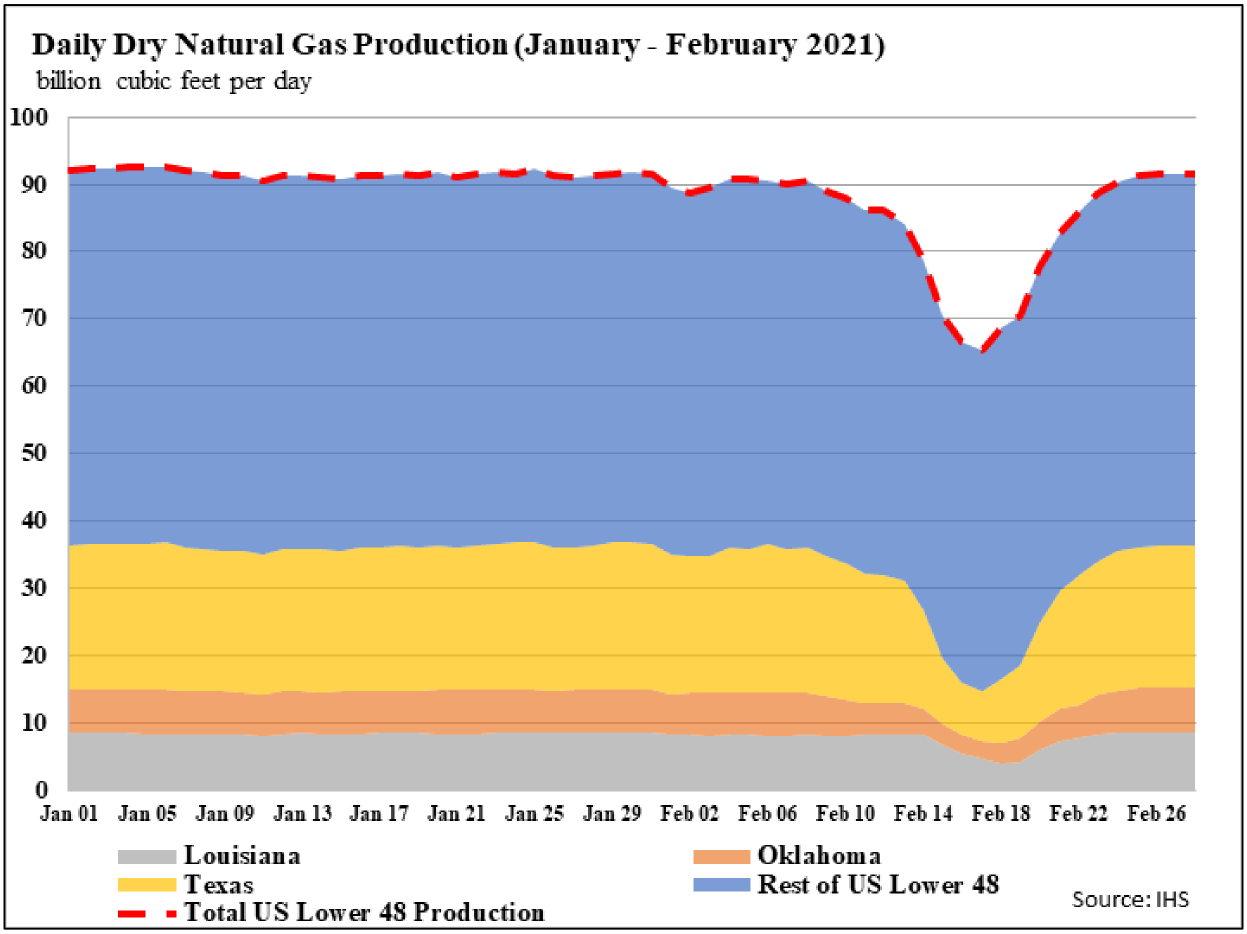


Natural gas-fired units also represented the largest percentage of generating units that experienced unplanned outages, derates, or failures to start, whether examining the fuel type of generating units by number of units, outages, or nameplate MW capacity, as shown in Figure 3, above.

Natural gas fuel supply issues overview. From February 8 through February 20, the combined effects of decreased natural gas production, the specific terms and conditions of natural gas commodity and pipeline transportation contracts, and other issues like low pipeline pressure, resulted in a total of 357 individual natural gas-fired generating units within ERCOT (185 units), SPP (141 units) and MISO South, (31 units) experiencing 1,121 outages, derates or failures to start.[246] Although having firm supply or transportation contracts did not guarantee a generating unit remained online, only 29 percent (109 units) of the natural gas-fired generating units with unplanned outages had <u>both</u> firm natural gas supply and firm natural gas pipeline transportation contracts.[247]

[246] The impact of production declines on natural gas-fired generating units is not always immediate, due to the pipelines' preparations for the storm (e.g., line packing, use of storage, etc.).
[247] *See* Figure 103 for more information on the contractual arrangements held by the GOs/GOPs involved in the Event.

Figure 96: Daily Dry Natural Gas Production (January - February 2021)



Wellhead Effects on Production. A significant level of wellhead freeze-offs during the Event lowered natural gas production. As a result, total U.S. Lower 48 natural gas production fell to 65.4 Bcf/d on February 17, a 28 percent decline from the 90.8 Bcf/d production level seen on February 8 (as seen on Figure 96 above). Most producing regions of the U.S. saw a sharp weather-related decline and recovery as illustrated in Figure 96, above: when temperatures fell, regional production dropped, and as temperatures rose after the Event, regional production recovered, eventually to pre-Event levels. The largest Event-related impacts on natural gas production were in Texas, Oklahoma, and Louisiana. Texas production declined by 70.1 percent, Oklahoma production by 56.8 percent and Louisiana production, by 53.5 percent, as compared to January 2021 average production.[248] Average production declines in these states constituted over 80 percent of the total

[248] In its Preliminary Findings and Recommendations, the Team had calculated 2021 natural gas production declines against the average for early February, however, to compare the 2011 and 2021 events, the Team needed to switch to the average for the month of January because the 2011 event occurred from February 1 to 5. The source for all figures in this paragraph is IHS data shared with the Team.

declines across the entire lower 48 States during the period from February 15-20 when compared to average production in January 2021.

Weather/Freeze-Related Effects on Production. The majority (58 percent) of the decline in natural gas production during the Event was weather/freeze-related, as shown in Figure 97 below. This category includes production declines directly caused by freezing, preemptive shut-ins to protect natural gas facilities from freeze-related impacts, and poor road conditions (due to precipitation) that prevented the removal of fluids from production sites or access to facilities to make necessary repairs.

Loss of Power Supply to Natural Gas Infrastructure. For the Event overall, loss of power supply to natural gas infrastructure caused 23.5 percent of the decline in natural gas production. Power outages at natural gas infrastructure facilities were caused by both weather and manual firm load shedding. Because many natural gas infrastructure loads had not been identified as critical loads to be protected from manual firm load shedding, and power outages caused by weather and firm load shed were coincident, the exact extent of firm load shed-caused power outages to critical natural gas infrastructure loads is unknown. However, the firm load shed did not begin until the early morning of February 15, so natural gas production declines caused by power outages and occurring before that time would necessarily have been caused by weather-caused power outages.

Calculating the exact percentage of production declines caused by power outages daily during the Event posed challenges. One complicating factor is that producer data uses the gas day (9 a.m. Central to 9 a.m. Central), while grid and generating unit data is based on the calendar day. The natural gas production and processing entities did not provide data in sufficient granularity for the Team to split their data between calendar days February 14 and 15. However, the percentage of production declines caused by power outages varied little between the overall Event (21.5 percent), February 14 (18.1 percent), and February 17, the day of maximum production losses (21.6 percent). See Figures 97 - 99, below, which attribute production losses to various causes, including “midstream-loss of power supply” and “well/gathering facilities-loss of power supply,” based on each cause’s proportionate volumetric share.

Figure 97: Natural Gas Production Event Causes, February 8-20, 2021[249]

Production Event Causes on February 8th - 20th

86%

	Natural Gas Infrastructure Condition	Facility Event Causes
Freezing Temperature and Weather Conditions (43.2% of production disruptions)	Facility Shut-ins to Prevent Imminent Freezing Issues	18.0%
	Freezing Issues - Midstream	5.1%
	Freezing Issues at Well and Gathering Facilities	11.1%
	Freezing Issues on Roads/Access to Well and Gathering Facilities	9.1%
Loss of Power Supply (21.4% of production distruptions)	Midstream - Loss of Power Supply	10.4%
	Well/Gathering Facilities- Loss of Power Supply	11.1%
Multiple Issues (21.3% of production disruptions)	Multiple Issues (combination of two or more of above issues)	21.3%
Other Issues, Unrelated Issues (14% of production disruptions)	Midstream - Line Pressure	4.9%
	Midstream - Other	0.4%
	Well and Gathering Facility Issues - Not Applicable to Event	8.8%
Total		100.0%

Figure 98: Natural Gas Production Event Causes for February 14, 9:00 a.m. to February 15, 9:00 a.m. Gas Day (inclusive of a portion of ERCOT Load Shed Event)

Production Event Causes on February 14th (Gas Day, inclusive of a portion of ERCOT Load Shed Event)

88.4%

	Natural Gas Infrastructure Condition	Facility Event Causes
Freezing Temperature and Weather Conditions (52.1% of production disruptions)	Facility Shut-ins to Prevent Imminent Freezing Issues	33.6%
	Freezing Issues - Midstream	2.2%
	Freezing Issues at Well and Gathering Facilities	15.6%
	Freezing Issues on Roads/Access to Well and Gathering Facilities	0.8%
Loss of Power Supply (18.1% of production disruptions)	Midstream - Loss of Power Supply	10.0%
	Well/Gathering Facilities- Loss of Power Supply	8.1%
Multiple Issues (18.2% of production disruptions)	Multiple Issues (combination of two or more of above issues)	18.2%
Other Issues, Unrelated Issues (11.6% of production disruptions)	Midstream - Line Pressure	1.6%
	Midstream - Other	0.0%
	Well and Gathering Facility Issues - Not Applicable to Event	10.0%
Total		100.0%

249 Percentages shown in yellow and orange columns may not equal the combined total of percentages shown in "facility event causes" column due to rounding.

Figure 99, below examines the peak day for natural gas production loss, which occurred on the February 17 gas day (9 a.m. February 17, to 9 a.m. February 18). Even during this period, loss of power supply only caused 21 percent of production declines, while 44.5 percent were caused by freezing/weather-related issues.

Figure 99: Natural Gas Production Event Causes – February 17, 9:00 a.m. to February 18, 9:00 a.m. Gas Day of Maximum Production Losses

Production Event Causes on February 17th (Day of Maximum Production Losses)

85.7%

	Natural Gas Infrastructure Condition	Facility Event Causes
Freezing Temperature and Weather Conditions (44.5% of production disruptions)	Facility Shut-ins to Prevent Imminent Freezing Issues	18.5%
	Freezing Issues - Midstream	5.3%
	Freezing Issues at Well and Gathering Facilities	10.0%
	Freezing Issues on Roads/Access to Well and Gathering Facilities	10.7%
Loss of Power Supply (21.6% of production disruptions)	Midstream - Loss of Power Supply	8.8%
	Well/Gathering Facilities- Loss of Power Supply	12.7%
Multiple Issues (19.6% of production disruptions)	Multiple Issues (combination of two or more of above issues)	19.6%
Other Issues, Unrelated Issues (14.3% of production distruptions)	Midstream - Line Pressure	5.9%
	Midstream - Other	0.5%
	Well and Gathering Facility Issues - Not Applicable to Event	7.9%
Total		100.0%

Figure 100, below examines the issue from the perspective of the natural gas-fired generating units that experienced outages, derates or failures to start due to natural gas fuel supply reductions, and compares whether the outages happened before or after the firm load shed began early on February 15. The majority of natural gas production/supply declines in Oklahoma, northern and western Texas occurred before February 15, the first day on which firm load shed occurred, while the majority of the production declines in central, eastern, and southern Texas and Louisiana occurred on and after February 15. Sixty percent of all natural gas-fired units affected by natural gas fuel supply issues had already experienced outages, derates, or failures to start by February 14, before any firm load had been shed, while 32 percent had fuel supply issues both before and after the firm load shed began. The data in Figure 100, below, unlike data from natural gas infrastructure entities, is directly from the GOs/GOPs, which use the 24-hour day. All outages shown as occurring on February 14 are the result of natural gas fuel supply issues that happened before any firm load had been shed.

Figure 100: Natural Gas-Fired Generating Unit Outages, Derates or Failures to Start due to Natural Gas Fuel Supply Issues - Before and After ERCOT Firm Load Shed

Natural gas fuel supply Issues caused outages/derates/failures to start:	2/8 - 2/14 (Prior to Firm Load Shed)	2/15 - 2/20 (During and After Firm Load Shed)
Total Individual Generating Units	**213**	**258**
ERCOT BA Footprint	111	134
SPP BA Footprint	91	103
MISO South Footprint	11	21

Effects on Natural Gas Processing Facilities. Natural gas processing facilities necessarily are dependent on natural gas production, and thus reduced receipts from production caused the majority (61 percent) of processing declines experienced during the Event, as shown in Figure 101, below. Loss of power (18 percent) and freezing issues at processing facilities (13 percent) were the next two largest causes of the decline in processing. The share of processing declines caused by power outages increased by six percentage points between February 14, before any firm load shed had occurred (15 percent of processing declines), and February 17, when processing facility losses were the greatest (21 percent of processing declines).

Figure 101: Natural Gas Processing Facility Event Causes for Specific Timeframes

Processing Facility Event Causes on February 8 - 20

		Natural Gas Infrastructure Condition	Result	Facility Event Causes
92%	Freezing Temperature and Weather Conditions (74% of Plant Disruptions)	Reduced Gas Receipts from Production / Gathering Facilities	Processing Facility Disruption	61%
		Freezing Issues at Processing Facilities	Processing Facility Disruption	13%
	Loss of Power (18% of Plant Disruptions)	Processing Facilities - Loss of Power Supply or curtailment	Processing Facility Disruption	18%
	Other Issues	Mechanical Failures - Non-Weather Related	Processing Facility Disruption	8%
	Total			100%

**There were a total of 67 causes of processing plant events occuring from February 8 to February 20.*

Processing Facility Event Causes on February 14

		Natural Gas Infrastructure Condition	Result	Facility Event Causes
100%	Freezing Temperature and Weather Conditions (85% of Plant Disruptions)	Reduced Gas Receipts from Production / Gathering Facilities	Processing Facility Disruption	73%
		Freezing Issues at Processing Facilities	Processing Facility Disruption	12%
	Loss of Power (15% of Plant Disruptions)	Processing Facilities - Loss of Power Supply or curtailment	Processing Facility Disruption	15%
	Other Issues	Mechanical Failures - Non-Weather Related	Processing Facility Disruption	0%
	Total			100%

**There were a total of 34 causes of processing plants events occuring on February 14.*

Processing Facility Event Causes on February 17

		Natural Gas Infrastructure Condition	Result	Facility Event Causes
100%	Freezing Temperature and Weather Conditions (79% of Plant Disruptions)	Reduced Gas Receipts from Production / Gathering Facilities	Processing Facility Disruption	76%
		Freezing Issues at Processing Facilities	Processing Facility Disruption	3%
	Loss of Power (21% of Plant Disruptions)	Processing Facilities - Loss of Power Supply or curtailment	Processing Facility Disruption	21%
	Other Issues	Mechanical Failures - Non-Weather Related	Processing Facility Disruption	0%
	Total			100%

**There were a total of 33 causes of processing plant events occuring on February 17.*

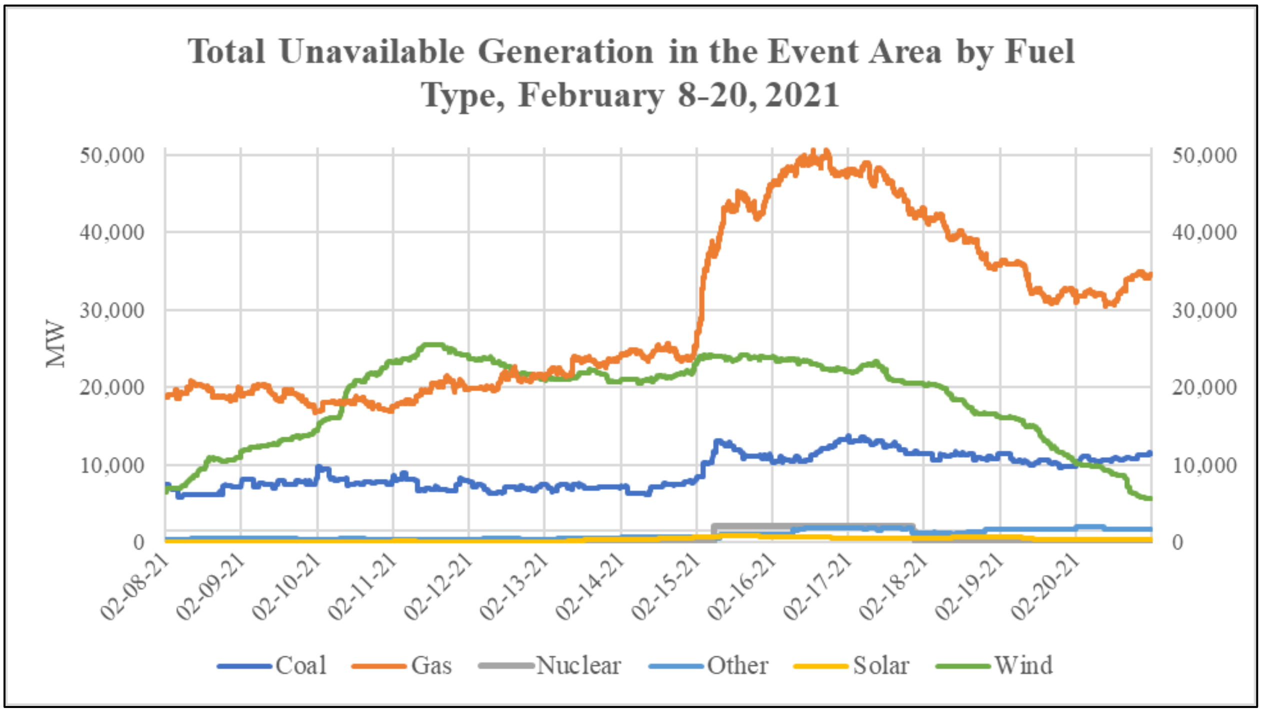
While some pipelines declared force majeure[250] and others had low pressure issues, many pipelines pointed out that they were able to meet all firm commitments. Only 29 percent of the generating units with unplanned outages due to fuel supply issues had both firm transportation and firm commodity contracts. The effect on pipelines during the Event differed from the previous worst event, 2011, due to the record reductions in production of natural gas as well as the unprecedented numbers of natural gas-fired generating units that failed to perform.[251] Both natural gas production decline percentages and natural gas-fired generating unit outages dramatically increased in 2021 as

[250] *See* Figure 57.

[251] The 2011 arctic cold front caused estimated production declines of 5.5 Bcf/d on February 1 to 4, with an estimated total production decline of 14.8 Bcf. The San Juan and Permian Basins were especially hard hit. 2011 Report at 113-115. These declines propagated downstream and ultimately resulted in natural gas curtailments to more than 50,000 customers in New Mexico, Arizona, and Texas, including the cities of El Paso, Texas, and Tucson, Arizona. The production losses "stemmed principally from three cause: freeze-offs, icy roads, and [firm load shed]." 2011 Report at 2, 9. As in the Event, icy roads also prevented maintenance crews from reaching the wellheads to remove produced water, which, if not removed, causes the wellheads to shut down automatically once tanks are full.

compared to 2011. For example, Texas peak natural gas production during the January 1 to 5, 2011 event declined by 22 percent as compared to the January average in 2011, but Texas peak natural gas production during the Event declined by 70.1 percent as compared to January production in 2021. The Oklahoma peak natural gas production decline was also 22 percent in the 2011 event, but was 56.8 percent in 2021, while Louisiana production appeared unaffected in the 2011 event, but peak natural gas production declined 53.5 percent in 2021, as compared to January. From the onset of the Event, unplanned natural gas-fired generating unit outages and derates for the total Event Area increased by approximately 30,000 MW (primarily due to freezing issues and natural gas fuel supply issues) as of February 16, 2021, compared to 14,702 MW of generating unit outages, derates and failures to start for all fuel types of generation in 2011 in ERCOT.[252] See Figure 102, below.

Figure 102: Total Unavailable Generation in the Event Area by Fuel Type, February 8-20, 2021



D. Grid Preparedness and Emergency Operations

1. Peak Load Forecasts and Reserve Margin Calculations

50/50, 90/10 winter peak load forecasts for southern U.S. areas. The winter season peak load forecasts used in calculating winter season reserve margin projections for the ERCOT, MISO South and SPP footprints were substantially lower than the actual peak load demand during the Event (including the firm load shed). While neither the 50/50 nor the 90/10 case is expected to predict

[252] 2011 Report, page 78. The natural gas-fired generating outages for the 2011 event area are not available, however, as in the Event, ERCOT had the largest generation outages and firm load shed in 2011.

any given day's load exactly, the 90/10 case has typically in the past served as a proxy for the more extreme load results that could be expected in a season. But given the occurrence of extreme cold weather events in the U.S., as well as the potential for significant resistive heating load during those events in southern states, which can quickly escalate load, other extreme scenarios beyond the 90/10 case should be included when planning for winter loads, especially in the South/South Central/Southwest.

The expected, or 50/50, seasonal peak load forecast methodologies are typically based on multiple years of actual winter peaks. Because the 50/50 and 90/10 use the same historical sampling, which in southern climates includes multiple years of mild-weather peak loads and very few cold-weather peak loads, the 90/10 cases for the BAs involved in the Event did not adequately predict extreme load days on which resistive heating might activate. The 90/10 winter season peak load forecasts for each BA footprint were lower than actual peak loads during the Event as follows: ERCOT, 14.3 percent lower; SPP, 4.8 percent lower; MISO South; 5.7 percent lower.[253] Historical samplings limited to winters where extreme cold weather occurred (i.e. when auxiliary resistive heating load[254] would have been prevalent) can provide a data source for developing extreme scenario winter peak load forecasts that could yield improved accuracy of forecast winter peak reserve margins.

Available generation capacity during winter peak conditions. The generation capacity component used in the NERC winter reliability assessment to calculate reserve margins assumes that natural gas-fired generating units without firm natural gas contracts and/or firm pipeline transportation will be able to produce their full capacity when called upon. For example, for winter 2020-2021, SPP expected to have 29,965 MW[255] of natural gas-fired generation capacity. However, during the Event, natural gas fuel supply issues resulted in over 15,000 MW of this capacity (over half of its natural gas-fired generation capacity) being outaged or derated at SPP's highest period[256] of generation unavailability. During the Event, ERCOT, SPP and MISO South had 357 natural gas-fired generators outaged or derated due to natural gas fuel supply issues (commodity and transportation). Natural gas fuel supply issues were the second-largest cause of unplanned outages, derates and failures to start during the Event.[257] During winter peak conditions, when non-firm natural gas supply and transportation are at a higher risk of being unavailable, using the full capacity of such generators in anticipated reserve margin calculations does not adequately capture natural gas

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253 Likewise, the expected or "50/50" winter season peak load forecasts were also low: ERCOT, 33.1 percent too low; SPP, 11.7 percent too low; MISO South, 8.9 percent too low.

254 *See* Figure 108 for a graph of how demand rises as ambient temperature falls when auxiliary heating is employed.

255 Accredited Capacity Winter 2020-2021, for gas fueled generation. *See* also Figure 103 and related discussion regarding the generating units' natural gas fuel supply arrangements.

256 February 17 at 12:17 AM

257 Similarly, in early January 2014 during the east coast polar vortex event, the cold weather also increased demand for natural gas, which resulted in a significant amount of gas-fired generation being unavailable due to natural gas fuel supply issues. Polar Vortex Review at page iii. Gas-fired generation was also a significant source of unplanned outages and derates in the 2011 and 2018 events. 2011 Report at 153 (natural gas fuel supply issues contributed a little less than ten percent of the total MW that were out at the worst point during the 2011 event); 2018 Report at 10 (16 percent of unplanned generating unit outages caused by natural gas fuel supply issues). The Team acknowledges that some of the ISOs/RTOs involved in these events have taken steps in response, some of which required, and received, Commission approval. For freezing issues causing unplanned solar resource outages and derates, see Appendix D.

fuel supply uncertainties, which resulted in overstating available capacity values used in calculating winter peak reserve margins for the NERC winter seasonal assessment.

Expected capacity of intermittent resources.[258] The percentages of nameplate wind generation presently included as capacity in winter reserve margins similarly may not be representative of those generating units' actual availability during an actual event. For example, ERCOT included 8,100 MW of wind generation as capacity in its internal 2021 annual reserve margin. For the 2020/2021 ERCOT Winter SARA, ERCOT estimated 7,070 MW[259] to be available during winter peak (with a low wind output scenario dropping to 1,791 MW). But for the 72-hour period during February 15-17 during which ERCOT shed firm load, ERCOT wind output averaged only 3,100 MW per hour, dropping as low as approximately 500 MW at one point. Wind generation was unavailable due to both icing conditions and low wind speeds. Winter season reliability assessments should provide more specifics and quantification of risks, including scenarios where there is a likelihood of conditions occurring simultaneously (e.g., both low wind and freezing precipitation scenarios).

MISO South 90/10 Load Forecast*:* MISO determines its Load Forecast Uncertainty percentage based on the actual highest summer peak load day for each of the past 30 years. Because MISO then multiplies the ten local/zonal 50/50 *winter* peak forecasts by this *summer* Load Forecast Uncertainty percentage, MISO South's winter 90/10 load forecast was only 3.9 percent higher than the 50/50 winter forecast for the whole MISO BA. The Load Forecast Uncertainty percentages of local resource zones 8, 9, and 10 (which make up MISO South) are small (4.1 percent, 2.3 percent, and 4.4 percent, respectively) for summer, because hot, humid temperatures occur every single year in MISO South. However, MISO South/zones 8, 9 and 10 could have significantly higher Load Forecast Uncertainty percentages during winter peaks, due to the volatility of winter load spikes from electric heat.

SPP 90/10 Load Forecast: SPP provides a "90/10" load forecast value to NERC for its Winter Reliability Assessment, but the number that SPP provides is based on its 50/50 load forecast increased by five percent. SPP does not currently develop a statistically-based 90/10 load forecast; other BAs like ERCOT and MISO do.

2. Emergency Operations Analysis

Managing Transmission Congestion. ERCOT, MISO and SPP maintained effective situational awareness of the real-time conditions of the BES during the Event, and promptly responded to maintain BES reliability throughout the Event. MISO's and SPP's ability to transfer nearly 13,000 MW of power through their numerous ties with adjacent BAs in the Eastern Interconnection helped to alleviate portions of their generation shortfalls with imports from BAs that were not experiencing

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[258] The expected capacity of solar in each footprint was negligible, representing only 0.2 to 0.4 percent of expected capacity, so it did not have as great an effect on the reserves of these BAs as wind. If a BA relied on solar for a greater share of its expected capacity, the same caveat could apply to solar. While wind turbines are vulnerable to icing, a recent machine-learning study of maintenance records by Sandia National Labs identified snow events as causing the largest performance reductions at solar facilities. Nicole D. Jackson & Thushara Gunda, *Evaluation of extreme weather impacts on utility-scale photovoltaic plant performance in the United States*, 302, Applied Energy, 1:7 (2021).

[259] *See* footnote 66 for details on how ERCOT estimated this value.

the extreme cold weather. These transfers were not without consequences. The most threatening to BES reliability was the potential IROL identified by MISO RC for the loss of its next-worst contingency, a 345 kV transmission line. Minutes later, at 6:10, the next-worst contingency actually occurred, and after MISO verified it was an IROL at 6:18 a.m., MISO curtailed SPP's imports, which resolved the IROL.

Load Shed. ERCOT, unlike MISO and SPP (who collectively imported nearly 13,000 MW), did not have the ability to import many thousands of MW from the Eastern Interconnection, and thus needed to shed the greatest quantity of firm load to balance electricity demands with the generating units that were able to remain online. By 7:00 p.m. on February 15, ERCOT had ordered 20,000 MW of manual firm load shed, which it sustained for nearly three days. The combined magnitude and duration of manual firm load shed needed to maintain BES reliability in ERCOT, ranging from 14-28 percent of ERCOT's peak load caused electric service providers (TOPs, TOs and DPs) to have difficulties in rotating the controlled outages to customers. Operators needed to use electric circuits configured for automatic load shed (e.g., underfrequency load shed/UFLS) for manual firm load shed. In ERCOT, at least 25 percent of the load is required to be reserved for automatic load shedding (and this does not include critical loads protected from manual load shedding, such as hospitals, police stations, etc.).

Because it is not the entity that implements load shedding, ERCOT did not anticipate that its use of firm load shedding to preserve system stability would contribute to power outages of natural gas production and processing facilities, that would in turn, contribute to the decline in natural gas supply and delivery to natural gas-fired generating units. The manual load shed plans (of TOPs) and automatic underfrequency load shed plans (of TOs and DPs) within the ERCOT footprint were designed to avoid controlled power outages to priority or critical electric loads if the need to shed firm load arose. However, most of the natural gas production and processing facilities surveyed were not identified as critical load or otherwise protected from manual load shedding.

V. Key Recommendations[260]

The magnitude of the Event, and the seriousness of the consequences that resulted from the firm load shed in ERCOT, warrant prompt implementation of the Recommendations. To create a sense of urgency, each Recommendation is assigned to one of four timeframes within which it can and should be implemented.[261] Recommendations assigned to the first timeframe can and should be implemented before winter 2021-2022 (the Team suggests November 1 as the beginning of "winter"). Recommendations assigned to the second timeframe can and should be implemented before winter 2022-2023. Recommendations assigned to the third timeframe can and should be implemented before winter 2023-2024, and the fourth timeframe (Implementation Timeframe D) includes recommendations which could extend beyond winter 2023-2024, but should be completed as soon as possible. See Figure 114 at the conclusion of the Recommendations for a full list of the Recommendations and their assigned timeframes.

A. Electric Generation Cold Weather Reliability

Key Recommendation 1 (a through g): The NERC Reliability Standards should be revised as follows:

Key Recommendation 1a: To require Generator Owners to identify cold-weather-critical components and systems for each generating unit. Cold-weather-critical components and systems[262] are those which are susceptible to freezing or otherwise failing due to cold weather, and which could cause the unit to trip, derate, or fail to start. (Winter 2023-2024)

Key Recommendation 1b: To require Generator Owners to identify and implement freeze protection measures for the cold-weather-critical components and systems (see Key Recommendation 1f., below, for guidance on ambient temperature and weather conditions to be considered). The Generator Owner should consider previous freeze-related issues experienced by the generating unit, and any corrective or mitigation actions taken in response. At an interval of time to be determined by the Balancing Authority, the Generator Owner should analyze whether the list of identified cold-weather-critical components and systems remains accurate, and whether any additional freeze protection measures are necessary. (Winter 2023-2024)

[260] While all Recommendations are important to preventing recurrence of the Event, Key Recommendations focus on revisions to the Reliability Standards, actions to prevent electric generating unit and natural gas infrastructure freezing issues, grid operations and gas-electric coordination measures for cold weather preparedness.
[261] For mandatory Reliability Standards, implementation means that new and/or revised Standards that address the Recommendation are proposed to the Commission for approval within the timeframes listed with the Recommendations below. In the FERC-approved NERC Rules of Procedure, Appendix 3A Standard Processes Manual, NERC can deviate from its normal process when necessary to meet an urgent reliability issue. *See* https://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx.
[262] Examples include instrumentation, transmitters, sensing lines and wind turbine blades. *See* Figure 94 and related discussion in IV.B, above.

Since 2011,[263] staff from the Commission, NERC and the Regional Entities have periodically alerted industry to the need for generating units to prepare for cold weather, especially the non-enclosed units found in southern and other warm-weather regions of the U.S. Together, they have issued two prior inquiry reports regarding cold weather events in which multiple generating units experienced outages, derates and failures to start, jeopardizing BES performance.[264] The 2018 Report found that the event was "caused by failure to properly prepare or 'winterize' the generation facilities for cold temperatures."[265] In 2011, the report found "many generators failed to adequately apply and institutionalize knowledge and recommendations from previous severe winter weather events, especially as to winterization of generation and plant auxiliary equipment."[266] Both the 2011 and 2018 Reports identified certain equipment that more frequently contributed to generating unit outages, including frozen sensing lines, frozen transmitters, frozen valves, frozen water lines, and wind turbine icing.[267,268] The Event was no different—generation freezing issues were the number one cause of the Event, and the same frequently-seen frozen components reappear. Given the repeated appearance of certain equipment in causing generating unit outages during cold weather events, NERC recommends in its Reliability Guideline that entities responsible for generating units "identify and prioritize critical components, systems and other areas of vulnerability." NERC further explains in its Reliability Guideline that "this includes critical instrumentation or equipment that has the potential to . . . initiate an automatic unit trip . . . impact unit start-up[,]. . . initiate automatic unit runback schemes or cause partial outages."[269]

In response to the finding in the 2018 Report that one third of the GOs/GOPs surveyed still had no winterization provisions after multiple recommendations on winter preparedness for generating units,[270] the 2018 Report recommended potential new or revised Reliability Standards to address the need for generating units to prepare for cold weather and the need for BAs and RCs to be aware of specific generating unit limitations, such as ambient temperatures or fuel supply. That recommendation led to the Reliability Standards being revised (effective April 1, 2023)[271] to require, in part, that "[e]ach Generator Owner shall implement and maintain one or more cold weather preparedness plan(s) for its generating units. The cold weather preparedness plan(s) shall include the following, at a minimum: . . . Generating unit(s) freeze protection measures based on geographical location and plant configuration; . . . Annual inspection and maintenance of generating unit(s) freeze protection measures . . .." Although the revised EOP-0011-2 requires GOs to have a

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263 *See* section II.D.1., above, for a discussion of the 2011 event.

264 https://www.ferc.gov/sites/default/files/2020-07/OutagesandCurtailmentsDuringtheSouthwestColdWeatherEventofFebruary1-5-2011.pdf; https://www.ferc.gov/sites/default/files/2020-07/SouthCentralUnitedStatesColdWeatherBulkElectricSystemEventofJanuary17-2018.pdf.

265 2018 Report at 80-81.

266 2011 Report at 195.

267 2011 Report at 142.

268 2018 Report at 82.

269 Reliability Guideline at 3.

270 Despite multiple recommendations that generating units take actions to prepare for the winter (and providing detailed suggestions for winterization), 40 generating units in SPP (10.5 percent), 35 in ERCOT (8 percent), and one unit in MISO (one percent), still did not have winterization plans.

271 Approved by the Commission in *Order Approving Cold Weather Reliability Standards*, 176 FERC ¶ 61,119 (2021).

plan which includes freeze protection measures, it does not require them to actually implement any specific freeze protection measures on their equipment.

Key Recommendations 1a and 1b take the next logical step by requiring GOs to (i) identify the cold-weather-critical components and systems and (ii) identify and implement freeze protection measures for those components and systems. Cold-weather-critical components and systems are the components and systems most responsible for the generating unit outages, derates and failures to start which have plagued grid operators in the four studied cold weather events in the last 10 years. Those components and systems (including wind turbine blades, transmitters, sensing lines and instrumentation) froze, caused trips, derates or failures to start, and, during the Event, were responsible for over 68,000 MW of generating unit outages in ERCOT, nearly 27,000 MW in SPP and over 21,000 MW in MISO South.[272] With implementation of this Key Recommendation, BAs and RCs would no longer have to struggle to recover from preventable outages of generating units.

GADS' extensive cause codes currently provide information about each component's role in causing generating unit outages. NERC should make changes to GADS reporting that will allow for identification of the specific operating conditions that contribute to equipment failures (e.g. freezing conditions, frozen precipitation, etc.) to better allow for tracking of trends related to performance of cold-weather-critical components and systems.

<u>Key Recommendation 1c</u>: To revise EOP-011-2, R7.3.2[273] to require Generator Owners to account for the effects of precipitation and the accelerated cooling effect of wind when providing temperature data. (Winter 2023-2024)

EOP-011-2, R7.3.2 (effective April 1, 2023) requires a GO to include in its cold weather preparedness plan, at a minimum, the generating unit's minimum design temperature, historical operating temperature or current cold weather performance temperature determined by an engineering analysis. This Key Recommendation would also require GOs to understand how precipitation and the accelerated cooling effect of wind limit their generating unit's performance. Frozen precipitation can lead to icing issues that affect equipment necessary for the operation of the generating unit, for example ice accumulation on wind turbine blades, air inlet filters, and vents necessary for cooling equipment.

The unit's ambient temperature design may not have factored in the accelerated cooling effect of wind. The 2011 Report identified the accelerated rate of heat loss caused by wind as a factor in that event's generating unit outages, derates and failures to start. The Report explained that "sustained high winds can quickly and continuously remove the heat radiating from boiler walls, steam drums, steam lines, and other equipment in an electric generating station, causing ambient temperatures to

[272] *See* Figure 94 above.
[273] EOP-011-2 (Emergency Preparedness and Operations) is part of the Reliability Standards recently approved by the Commission in *Order Approving Cold Weather Reliability Standards*, 176 FERC ¶ 61,119 (2021). Among other things, this Reliability Standard requires GOs/GOPs to have cold weather preparedness plans which include minimum design, historical operating, or cold weather performance temperature data for the GO's generating units.

drop below freezing in spite of the heat being produced by the facility."[274] In other words, the temperature may be within the generating unit's ambient temperature design limitations, but precipitation or the cooling effect of wind can result in the generating unit being inoperable. Knowing the ambient temperature design and the effects of wind or precipitation allows GOs to prepare when the temperature is forecasted to reach their generating units' ambient design limitations. Preparing a generating unit for all potential effects of a cold weather event, whether induced by cold ambient temperatures alone, or cold ambient temperatures plus wind, and ice, can increase the likelihood that the generator will remain operational throughout the event.

The Event demonstrated that ambient temperatures alone do not serve as a basis to predict whether a generating unit can perform during predicted cold weather. For **81 percent of the generating units outaged, at the time the outage occurred, ambient temperatures were above the generating unit's stated design criteria**. While half of the generating units that experienced an outage, derate or failure to start due to freezing experienced a minimum temperature below their design criteria at some point during the Event, the other half experienced an outage or derate due to freezing issues without ever experiencing temperatures below their ambient temperature design criteria. This Key Recommendation would revise EOP-011-2, R7.3.2 to require consideration of the effect of wind and precipitation on the generating unit.

<u>Key Recommendation 1d</u>: To require Generator Owners that experience outages, failures to start, or derates due to freezing to review the generating unit's outage, failure to start, or derate and develop and implement a corrective action plan (CAP) for the identified equipment, and evaluate whether the CAP applies to similar equipment for its other generating units. Based on the evaluation, the Generator Owner will either revise its cold weather preparedness plan to apply the CAP to the similar equipment, or explain in a declaration (a) why no revisions to the cold weather preparedness plan are appropriate, and (b) that no further corrective actions will be taken. The Standards Drafting Team should specify the specific timing for the CAP to be developed and implemented after the outage, derate or failure to start, but the CAP should be developed as quickly as possible, and be completed by no later than the beginning of the next winter season. (Winter 2022-2023)

FERC-NERC-Regional Entity joint staff reports and NERC's Reliability Guideline have recommended various voluntary evaluations of generating unit cold weather performance. The 2011 Report recommended that "at the end of winter, an additional round of inspections and testing should be performed and an evaluation made of freeze protection performance in order to identify potential improvements, required maintenance, and freeze protection component replacement for the following winter season."[275] NERC's Reliability Guideline recommends that "after a severe winter weather event, entities should use a formal review process to determine what program elements went well and what needs improvement. Identify and incorporate lessons learned . . ."[276]

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[274] 2011 Report, Appendix: Impact of Wind Chill, p. 2 of 2.
[275] 2011 report at 205 (Recommendation 14).
[276] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_Generating_Unit_Winter_Weather_Readiness_v3_Final.pdf#search=reliability%20guidelines at 3.

NERC's 2014 Polar Vortex Review recommended that entities "continue to follow the Reliability Guideline."[277]

The newly-revised Reliability Standard EOP-011-2 (effective April 1, 2023) lacks any corrective action process requirement for freeze-related issues, but PRC-004-6 R5 provides a model by requiring a corrective action plan (CAP) in response to protection system failures. The PRC-004-6 R5 model could be adapted to freeze-related issues associated with generating unit outages, derates or failure to start. This Key Recommendation does not go as far as requiring evaluation of all generating units' performance at the end of winter or at the end of a severe winter event. Rather, it focuses only on the generating units that <u>actually experienced</u> an outage, derate or failure to start due to freezing. This focus is justified as freezing components have been one of the top causes in three grid events involving firm load shed (including the Event) and one near-miss (the 2018 event) in the past ten years.

<u>Key Recommendation 1e</u>: To revise EOP-011-2, R8, to require Generator Owners and Generator Operators to conduct annual unit-specific cold weather preparedness plan training. (Winter 2022-2023)

Since 2011, FERC, NERC and Regional Entities have recognized the importance of training for winterization/winter preparedness. The 2011 Report recommended that "each [GO/GOP] should develop and annually conduct winter-specific and plant-specific operator awareness and maintenance training,"[278] while the Reliability Guideline similarly recommends "annual training in winter specific and plant specific awareness and maintenance . . .."[279] Newly-revised EOP-011-2, R8 (effective April 1, 2023) added a requirement that GOs and GOPs "identify the entity responsible for providing generating unit-specific training, and that identified entity shall provide the training to its maintenance or operations personnel responsible for implementing cold weather preparedness plan(s) developed pursuant to Requirement R7." However, it does not require that the training occur annually. This Key Recommendation simply repeats the prior recommendations for <u>annual</u> training, recognizing the importance of regular training, and would revise EOP-011-2, R8 to require annual training.

Responses from the GOs/GOPs involved in the Event show that annual training is not yet universal in the Event Area. In ERCOT, despite two prior cold weather events leading to firm load shedding (1989 and 2011), 14 percent of generating units still did not provide any information about operator training programs. Seven percent of the generating units reporting outages in MISO South and 24 percent of the generating units reporting outages in SPP did not provide any evidence of a training program upon request.

<u>Key Recommendation 1f</u>: To require Generator Owners to retrofit existing generating units, and when building new generating units, to design them, to operate to a specified ambient temperature and weather conditions (e.g., wind, freezing precipitation). The specified

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[277] Polar Vortex Review at 19.
[278] Recommendation 18, at 208.
[279] Reliability Guideline at 5.

ambient temperature and weather conditions should be based on available extreme temperature and weather data for the generating unit's location.[280] (Winter 2022-2023)

Recommendation 12 of the 2011 report suggested that "[c]onsideration should be given to designing all new generation plants and designing modifications to existing plants (unless committed solely for summer peaking purposes) to be able to perform at the lowest recorded ambient temperature for the nearest city for which historical weather data is available, factoring in accelerated heat loss due to wind speed."[281] In a similar vein, the Reliability Guideline recommends that "entities review the winter cold weather temperature design basis for their generating units to determine if improvements are needed."[282] Those voluntary recommendations do not appear to have been implemented. Not only did generating units fail to perform at the lowest recorded ambient temperature for the nearest city, but many failed to perform at their own ambient design temperatures.[283]

The simple fact is that the BES cannot operate reliably without adequate generation. When, as during the Event, massive numbers of generating units fail during cold temperatures, eventually grid operators must shed firm customer load to prevent uncontrolled load shedding and cascading outages. These firm load shedding events during cold temperatures are not just another transmission system mitigation technique—they have very real human consequences. Millions went without heat, lights, refrigeration, and water for days during the Event. Hundreds died from hypothermia or trying to keep warm, in their homes, in their beds. Preventing another event like this begins with ensuring enough generating units will be available during the next cold weather event, and that means generating units need to be modified/retrofitted to perform under the adverse winter weather conditions that have been experienced at its location. While not seeking to require any new generation, this Key Recommendation also means that any future generating units that are built should be designed to perform under the same adverse weather conditions. *See also* Key Recommendation 2 regarding compensation for these investments.

280 The Standards Drafting Team can decide what additional specificity is desirable for this requirement, for example, specifying the number of years of weather data to be considered in establishing the required ambient temperature and weather conditions, and the source of the extreme temperature and weather data.
281 2011 Report at 204.
282 Reliability Guideline, Recommendation #9, at 20.
283 *See* Recommendation 1c. Many outages in the Polar Vortex event, including a number of those in the southeastern United States, were also the result of temperatures that fell below the plant's design basis for cold weather. Polar Vortex Review at 2.

<u>Key Recommendation 1g</u>: To provide greater specificity about the relative roles of the Generator Owner, Generator Operator, and Balancing Authority in determining the generating unit capacity that can be relied upon during "local forecasted cold weather" in TOP-003-5: [284]

- **Based on its understanding of the "full reliability risks related to the contracts and other arrangements [Generator Owners/Generator Operators] have made to obtain natural gas commodity and transportation for generating units,"**[285] **each Generator Owner/Generator Operator should be required to provide the Balancing Authority with data on the total percentage of the generating unit's capacity that the Generator Owner/Generator Operator reasonably believes the Balancing Authority can rely upon during the "local forecasted cold weather."**
- **Each Balancing Authority should be required to use the data provided by the Generator Owner/Generator Operator, combined with its evaluation, based on experience, to calculate the percentage of total generating capacity that it can rely upon during the "local forecasted cold weather," and share its evaluation with the RC.**
- **Each Balancing Authority should be required to use its calculation of the percentage of total generating capacity that it can rely upon to "prepare its analysis functions and Real-time monitoring,"**[286] **and to "manag[e] generating resources in its Balancing Authority Area to address . . . fuel supply and inventory concerns" as part of its Capacity and Energy Emergency Operating Plans.**[287] **(Winter 2023-2024)**

TOP-003-5 R1 and R2 (effective April 1, 2023) will require TOPs and BAs, respectively, to include in their data specifications to the GO requests for information "during local forecasted cold weather" about generating units' operating limits, including "capability and availability; fuel supply and inventory concerns; fuel switching capabilities; and environmental constraints," as well as minimum temperature, based on one of three options.[288] A related requirement, EOP-011-2 R7.3 (also effective April 1, 2023), will require GOs to develop cold weather preparedness plans which include, at a minimum, their generating unit(s)' cold weather data such as the aforesaid capability, fuel supply concerns, environmental constraints, etc. The intent behind requiring GOs to identify and share with the BAs and TOPs the expected limitations of their generating units "during local

[284] TOP-003-5, R2.3 (Operational Reliability Data) is part of the Reliability Standards approved by the Commission in *Order Approving Cold Weather Reliability Standards*, 176 FERC ¶ 61,119 (2021). Under TOP-003-5, the Balancing Authority maintains a data specification, which is a list of data it requires from other entities, such as the Generator Owners and Generator Operators, to perform its analysis and real-time monitoring. As part of its data specification directed to Generator Owners and Generator Operators, the Balancing Authority is required to include "provisions for notification of [the generating unit's] status during local forecasted cold weather," including operating limits based on several factors and the unit's minimum temperature.
[285] Recommendation 8, below. Recommendation 8, while not a Reliability Standards revision, is a necessary complement to Key Recommendation 1g.
[286] TOP-003-5, R2.
[287] EOP-011-2, R2.2.3.2.
[288] TOP-003-5 R1.3.1, internal numbering omitted, and 1.3.2 paraphrased (the three options are design temperature, historical operating temperature, or temperature determined by an engineering analysis).

forecasted cold weather," is to prevent grid operators from being surprised when large numbers of generating units that had committed to run are unable to do so during cold weather events.

This Key Recommendation takes the next logical step and attempts to eliminate doubt about which entity is responsible to provide information or act on information. In the Event and other past cold weather events, GOs/GOPs/(QSEs in ERCOT) provided overly-ambitious projections about the ability of generating units to perform during cold weather events. As a result, the BAs and RCs were at times left with the responsibilities to serve load and manage the transmission system, respectively, without sufficient generation to serve load or support grid transfers, voltage, etc. To prevent recurrence of those scenarios, this Key Recommendation aims to assign each grid actor specific roles to avoid surprises as much as possible.

Key Recommendation 8, below, which is not a Reliability Standards change, recommends that GOs/GOPs understand the "full reliability risks related to the contracts and other arrangements they have made to obtain natural gas commodity and transportation for generating units." Using that understanding, the GO/GOP would then calculate the percentage of the generating unit's total capacity that the GO/GOP reasonably believes it can provide to the BA so that the BA can rely upon it, taking into account the "local forecasted cold weather" as well as the "full reliability risks related to their [fuel] contracts and other arrangements." So, for example, if a GOP knows that it has non-firm natural gas commodity and transportation, and that its generating units are almost always interrupted in favor of local heating load during cold weather events, the percentage of its capacity that the GO/GOP would provide the BA may be close to zero. Another GO/GOP with a dual-fuel unit that has seldom failed during a cold weather event may appropriately provide a much higher percentage of its capacity to the BA. The purpose of this Key Recommendation is not to provide a strict liability number, whereby the GO/GOP has violated the Standard unless it operates at the exact percentage predicted, but rather to transmit a good-faith, reasonable estimate, based on the information GOs/GOPs have about their historical temperature capability, fuel limitations, environmental limitations, and contractual provisions for fuel.

The BA would then consider the GOs'/GOPs' projections for their generating units, combined with the BA's experience with those generating units, the natural gas pipelines serving those generating units, and the weather predictions it is relying on for its load forecasting—to calculate the percentage of total generating capacity that it can rely upon during the "local forecasted cold weather." The BA would then share the percentage of total generating capacity that it believes it can rely upon with the RC. As with the GOs/GOPs, the goal of this Key Recommendation is not for the BA to provide a number for which it is held strictly liable, but rather a reasonable, good-faith number based on its historical experience as well as the data provided by the GOs/GOPs. While these projections will surely not be perfect, they will be better than the day-ahead commitments relied upon during the Event and in 2011. The BA and RC can then use these tempered expectations for generating units to perform their respective grid operations, including the important BA responsibilities highlighted in the last bullet above—real-time monitoring and managing generating resources as part of its capacity and energy emergency operating plans.

<u>Key Recommendation 2</u>: **Generator Owners should have the opportunity to be compensated for the costs of retrofitting their units to operate to a specified ambient temperature and weather conditions (or designing any new units they may build) through markets or through cost recovery approved by state public utility commissions (e.g., as a reliability surcharge) to be included in end users' service rates. The applicable ISOs/RTOs (market operators)**

and/or public utility commissions should identify how best to ensure Generator Owners have the opportunity to be compensated for making these infrastructure investments. (Winter 2022-2023)[289]

The 2011 Report recommended that when GOs build new generating units, they should be designed to operate to the lowest ambient temperature. The Report also recommended that existing generating units be retrofitted to operate to the lowest ambient temperature. At the time, GOs resisted implementing those and other recommendations, questioning how they would recover the costs of those improvements, and at least one market operator recognized that generators might need to be compensated for the additional costs of preparing for extreme cold events.[290]

In April 2021, analysts from the Dallas Federal Reserve Bank considered a Value of Lost Load (VOLL) analysis as a proxy for the damages caused by the Event. Using 2019 data for gross domestic product, electricity consumption and retail prices, they reached an average VOLL of $6,733 per megawatt hour (MWh) for firms and $117.60 per MWh for households. Using an average MW outage of 14,000 and a duration of 70.5 hours, they estimated the total VOLL for the Event at $4.3 billion (conservative compared to some of the other estimates of Event damages mentioned by the Dallas Fed—e.g., $10 to $20 billion of insurance costs, $80 to $130 billion of direct and indirect costs). But even using only the VOLL figure, the analysts argued that prevention measures costing up to $430 million per year are cost effective (assuming that severe cold weather events happen once every ten years).[291] These calculations do not, and cannot, accurately place a value on the lives lost. It is time to consider whether the markets or public utility commissions can encourage the GOs to prepare their units to perform at the temperatures experienced during the Event and in 2011. This Key Recommendation does not ask market operators and public utility commissions to make market design changes or add surcharges to end-use-customers' utility bills without obtaining data, testimony or other support for the arguments made in 2011. It only recommends that the market operators and public utility commissions consider the issue and if the GOs convince them that they cannot make these infrastructure investments otherwise, that they provide opportunities for the GOs to be compensated.

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289 Implementation for Key Recommendation 2 means that the applicable ISOs/RTOs and/or public utility commissions have begun the appropriate proceedings to consider how best to ensure Generator Owners have the opportunity to be compensated for the costs of retrofitting existing units, or designing any new units they may build to operate to specified ambient temperatures and weather conditions.

290 (*See*, *e.g.,* Comments filed in response to Project 2013-01 Cold Weather Comments_Received_2013-01_102412.pdf (nerc.com), ("market operators may be better equipped to address the cost of winterization into their market rules"); ("the cost impact for this project will not be insignificant. Even though it may be another 30 years before a winter event of this magnitude takes place. . . . the goal would be to quantify the reliability benefits so that they always outweigh the cost – so that we may apply our scarce dollars to other programs just as important); ("market operators should address the cost of winterization into their market rules, based on the expectations the state utilities commission has of the market operator for serving firm load," "reasonably, the market operator would develop a compensation mechanism for assuring that generators would be available under certain stressful climatic conditions," "there may need to be a compensation mechanism developed for generators that are expected to operate without failure in an extreme cold weather event.")

291 Cost of Texas' 2021 Deep Freeze Justifies Weatherization - Dallasfed.org

Key Recommendation 3:[292] **In the interim before the Reliability Standards revisions approved by the Commission in *Order Approving Cold Weather Reliability Standards*, 176 FERC ¶ 61,119 (2021), become effective, FERC, NERC and the Regional Entities should host a joint technical conference to discuss how to improve the winter-readiness of generating units (including best practices, lessons learned and increased use of the NERC Guidelines). Participants could include entities from cold weather regions throughout the ERO, Generator Owners/Generator Operators that operated during the entire Event or performed well in other cold weather events, Regional Entity staff who perform winterization audits, wind turbine manufacturers (to discuss winterization packages), and manufacturers of winterization equipment for other types of generation. (Winter 2022-2023)**

The Reliability Standards revisions to EOP-011, IRO-010 and TOP-003 (versions -2, -4 and -5, respectively) (effective April 1, 2023) will, for the first time, require GOs to implement and maintain cold weather preparedness plans for their generating units, which plans must include, among other things, freeze protection measures, annual inspection and maintenance of freeze protection, and cold weather capability information about the generating unit. GOs and GOPs are also required to identify the responsible party for training operations or maintenance staff on the cold weather preparedness plan. However, these improvements will not take effect until the winter of 2023/2024. In the two winters before they take effect, the danger of another severe cold weather event that could again hobble generating unit capacity remains. A recent study connected the Event to global-warming-induced weather anomalies that are likely to continue to produce severe winter storm events.[293] This Key Recommendation urges Commission staff, NERC and the Regional Entities to educate GOs and GOPs about changes they can make now to better perform during extreme cold weather events. The Team also strongly encourages GOs and GOPs to voluntarily implement the Reliability Standards revisions in advance of their effective date.

Key Recommendation 4:[294] **In following EOP-011-2, R7,[295] Generator Owners' plans should specify times for performing inspection and maintenance of freeze protection measures, including at a minimum, the following times: (1) prior to the winter season, (2) during the winter season, and (3) pre-event readiness reviews, to be activated when specific cold weather events are forecast. (Winter 2022-2023)**

The Texas PUC's regulations and ERCOT's Nodal Protocols contain requirements for generating units to have and adhere to winterization plans. Despite these requirements, about 82 percent of GOs/GOPs that submitted a declaration of preparation for winter to ERCOT had at least one generating unit with an unplanned outage or derated due to freezing issues during the Event. A weakness of the ERCOT approach is that there are neither minimum requirements for winterization

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292 Recommendation 7 in the September 23 Presentation.
293 Judah Cohen et al., *Linking Arctic variability and change with extreme winter weather in the United States,* 373 Sci. 1116, 1120 (2021); [Linking Arctic variability and change with extreme winter weather in the United States (science.org)]
294 Formerly Key Preliminary Recommendation 8 in the September 23 Presentation.
295 Part of the Reliability Standards revisions approved by the Commission in *Order Approving Cold Weather Reliability Standards*, 176 FERC ¶ 61,119 (2021), requires GOs' cold weather preparedness plans to address inspection and maintenance of freeze protection measures.

plans nor any deadline by which all winter preparations should be completed. Key Recommendations 1a and 1b covered the identification and protection of critical components. Key Recommendation 4 recognizes an element frequently seen in strong winterization plans: multiple inspections and frequent maintenance of freeze protection measures once they have been installed. At a minimum, Key Recommendation 4 would require inspection of freeze protection measures such as heat tracing prior to the winter season, during the winter season (the Standards Drafting Team should consider how often—perhaps monthly), and prior to a cold weather event, at a time when the weather forecast has narrowed enough to take concrete actions such as erecting temporary windbreaks or shelters, positioning heaters or draining equipment prone to freezing.

B. Natural Gas Infrastructure Cold Weather Reliability and Joint Preparedness with Bulk Electric System for Winter Peak Operations

Key Recommendation 5:[296] 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, including measures to prepare to operate when specific cold weather events are forecast. (Winter 2022-2023)

Key Recommendation 6:[297] In preparing for winter weather conditions, natural gas infrastructure facilities should implement measures to protect against freezing and other cold-related limitations which can affect the production, gathering and processing of natural gas. Those measures could include, but are not limited to:

- **implementing specific measures to directly protect vulnerable components against freezing, including**
    - **hydrate suppression chemicals/methanol injections,**
    - **burial of flow lines,**
    - **covering/sheltering sensitive facilities,**
    - **heat tracing, and/or**
    - **temporary/permanent heating equipment;**
- **ensuring necessary emergency staffing (may be known as surge capacity), including**
    - **manning key facilities 24/7 during extreme conditions,**
    - **reallocating staff to key facilities, and/or**
    - **increasing staff in the field as well as at the control center;**
- **developing mutual assistance programs, whereby fellow natural gas infrastructure entities that are not affected by the same storm could supply equipment, supplies or staff, to natural gas infrastructure entities affected by a cold weather emergency;**
- **addressing issues related to reliability of electric power, including:**

[296] Formerly Key Preliminary Recommendation 3 in the September 23 Presentation.
[297] Formerly Key Preliminary Recommendation 4 in the September 23 Presentation.

- **reviewing electric power supply contracts to understand whether the natural gas infrastructure facility has firm or interruptible electrical power (critical natural gas infrastructure loads should not purchase interruptible electric power),**
- **reviewing whether all electrical equipment has been designated as critical load, and/or**
- **installing backup generation (of adequate size) at critical sites, and/or**
- **taking proactive steps to procure quick turnaround on requests for environmental waivers for backup generators;**

- **ensuring sufficient inventory of critical spare parts, consumables, equipment, and supplies**;
- **establishing lines of communication with downstream entities, power providers, customers, and state regulators so that contact information and relationships are already established when needed during emergencies;**
- **enhancing emergency operations plans to incorporate specific extreme cold weather response elements;**
- **conducting training and drills about emergency operations plans, including coordinated drills/exercises with other natural gas infrastructure entities;**
- **ensuring physical access to key facilities, including:**
  - **coordination with state/local authorities, law enforcement or third-party contractors to prioritize organizations' activities for ensuring physical access,**
  - **road clearing/plowing and salting/deicing,**
  - **awareness of/updating easements to ensure access to leased facilities in emergencies, and/or**
  - **winterizing some or all of the vehicle fleet used for servicing critical natural gas infrastructure;**
- **managing fluids during extended cold weather events, including pre-draining storage tanks prior to an event, adding additional storage/frac tanks, storage pools, and production water gathering systems; and/or**
- **increasing capacity and resilience of saltwater disposal systems to avoid production shut-ins. (Winter 2022-2023)**

Key Recommendations 5 and 6 respond to the many natural gas production (including gathering), processing, and, to a lesser extent, pipeline, facilities adversely affected during the Event. While ideally, as in Key Recommendation 5, natural gas infrastructure entities would be legally obligated to prepare for cold weather, Key Recommendation 6 includes multiple practices that natural gas infrastructure entities can voluntarily implement. Some are long-term solutions, such as burying flow lines or adding production water systems, while others can be implemented relatively quickly, in the time between when a cold weather event is predicted and when it begins. Measures that can be quickly implemented include obtaining a backup emergency generator, pre-draining storage tanks, or manning key facilities around-the-clock. Taken together, they provide a good checklist for natural gas infrastructure owners interested in improving their performance when a similar cold weather event occurs. The Team includes some pipeline-related measures because, although natural gas pipelines were not tested in the Event as severely as in 2011, due to the record reductions in production of natural gas as well as the unprecedented numbers of natural gas-fired generating units that failed to perform, in another cold-weather event, they could again face conditions more similar to 2011, in which several LDCs curtailed gas service to retail customers.[298]

Key Recommendation 7:[299] **FERC should consider establishing a forum in which representatives of state legislatures and/or regulators with jurisdiction over natural gas infrastructure, in cooperation with FERC, NERC and the Regional Entities (which collectively oversee the reliability of the Bulk Electric System), and with input from the Balancing Authorities (which are responsible for balancing load and available generation) and natural gas infrastructure entities, identify concrete actions (consistent with the forum participants' jurisdiction) to improve the reliability of the natural gas infrastructure system necessary to support the Bulk Electric System. Options for establishing the forum could include a joint task force with NARUC, a Federal Advisory Committee, or FERC-led technical conferences. Ideally, the forum participants will produce one or more plans for implementing the concrete actions, with deadlines, which identify the applicable entities with responsibility for each action. At such a forum, topics could include:**[300]

- **Whether and how natural gas information could be aggregated on a regional basis for sharing with Bulk Electric System operators in preparation for and during events in which demand is expected to rise sharply for both electricity and natural gas, including whether creation of a voluntary natural gas coordinator would be feasible;**
- **Whether Congress should consider placing additional or exclusive authority for natural gas pipeline reliability within a single federal agency, as it appears that no one agency has responsibility to ensure the systemic reliability of the interstate natural gas pipeline system;**
- **Additional state actions (including possibly establishing an organization to set standards, as NERC does for Bulk Electric System entities) to enhance the reliability of intrastate natural gas pipelines and other intrastate natural gas facilities;**
- **Programs to encourage and provide compensation opportunities for natural gas infrastructure facility winterization;**
- **Which entity has authority, and under what circumstances, to take emergency actions to give critical electric generating units pipeline transportation priority second only to residential heating load, during cold weather events in which natural gas supply and transportation is limited but demand is high;**

[298] 2011 Report at 126-135.
[299] Formerly Key Preliminary Recommendation 5 in the September 23 Presentation.
[300] The Team is not advocating for the specific implementation of any specific action on any of these topics; rather, this Recommendation envisions that the entities with the most control over, and those most affected by, the natural gas reliability issues that have repeatedly arisen during cold weather events will convene and identify potential solutions. For example, the Team is not advocating that all generating units need to obtain firm natural gas supply or transportation contracts, but that entities convene to identify possible solutions to issues surrounding natural gas-fired generating units that do not have firm natural gas supply or transportation contracts.

- **Which entity has authority to require certain natural gas-fired generating units to obtain either firm supply and/or transportation or duel fuel capability, under what circumstances such requirements would be cost-effective, and how such requirements could be structured, including associated compensation mechanisms, whether additional infrastructure buildout would be needed, and the consumer cost impacts of such a buildout;**
- **Expanding/revising natural gas demand response/interruptible customer programs to better coordinate the increasing frequency of coinciding electric and natural gas peak load demands and better inform natural gas consumers about real-time pricing;**
- **Methods to streamline the process for, and eliminate barriers to, identifying, protecting, and prioritizing critical natural gas infrastructure load;**
- **Whether resource accreditation requirements for certain natural gas-fired generating units should factor in the firmness of a generating unit's gas commodity and transportation arrangements and the potential for correlated outages for units served by the same pipeline(s);**
- **Whether there are barriers to the use of dual-fuel capability that could be addressed by changes in state or federal rules or regulations. Dual-fuel capability can help mitigate the risk of loss of natural gas fuel supply, and issues to consider include facilitating testing to run on the alternate fuel, ensuring an adequate supply of the alternate fuel and obtaining the necessary air permits and air permit waivers. The forum could also consider the use of other resources which could mitigate the risk of loss of natural gas fuel supply;**
- **Electric and natural gas industry interdependencies (communications, contracts, constraints, scheduling);**
- **Increasing the amount or use of market-area and behind-the-city-gate natural gas storage; and**
- **Whether or how to increase the number of "peak-shaver" natural gas-fired generating units that have on-site liquid natural gas storage. (Winter 2022-2023)**

This Key Recommendation proposes a forum to address the problem 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. In February 2021, millions of Americans were dependent upon natural gas not only to heat their homes, but also to provide the fuel for the generating units that would provide the energy to light their homes and energize their furnaces (so they could use the natural gas that heats their homes). During the Event, natural gas fuel supply 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.

The idea of a forum in which "representatives of the electric and natural gas industries operating in the region, as well as the regulatory bodies overseeing them," can meet to discuss and cooperate on gas-electric interdependence, is not new. That language, while not from a recommendation, is taken directly from a discussion in the 2011 Report of how to address fuel switching issues.[301] The 2011 Report devoted an entire section to electric and natural gas interdependencies. The 2011 Report recognized that falling natural gas prices as a result of shale gas technological advances led to natural gas becoming an increasingly popular fuel choice for generating units, while compressors used in the production and transportation of natural gas increasingly relied on electricity instead of natural gas.[302]

Despite the actions taken before and after the 2011 event (discussed in more detail below), natural gas-electric infrastructure interdependencies remain unsolved.[303] The Event showed that natural gas-fired generating units were, in many cases, dependent on natural gas production facilities for natural gas supply, but many of them were unable to produce, leaving many units without natural gas even when natural gas pipeline facilities performed as well as could be expected. Natural gas production facilities are almost entirely intrastate and unregulated. NERC's 2021 Reliability Risk Priorities Report,[304] intended to identify the key risks to the BES,[305] identifies "critical infrastructure interdependencies, such as the ability to deliver natural gas to generating units supporting reliability" as one of the top four risks.[306]

The Team believes that the time has come for a concerted effort among those who can address the natural gas-electric infrastructure interdependency problem to consider the topics set forth above, or other topics of their own choosing.[307] With severe cold weather events forecasted to increase,[308] society can no longer afford to view occurrences like the Event and the 2011 event as "black swan events"[309] that are unlikely to reoccur. BAs and RCs should no longer be forced to serve load and

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301 2011 Report at 194.
302 2011 Report at 189.
303 A few ISOs/RTOs have implemented "pay for performance" constructs. For example, PJM has a "Capacity Performance" program, in which "generators may receive higher capacity payments and *are expected in return to invest* in modernizing equipment, firming up fuel supplies and adapting to use different fuels." https://pjm.com/-/media/markets-ops/rpm/review-of-october-2019-performance-assessment-event.ashx at 2 (emphasis added). Generators receiving the higher capacity payments that do not perform during one of the Performance Assessment Intervals, can be penalized. While intended to encourage such investments, Generator Owners are not required by pay-for-performance rules to obtain firm gas commodity or transportation contracts.
304 *See* https://www.nerc.com/comm/RISC/Documents/RISC%20ERO%20Priorities%20Report_Final_RISC_Approved_July_8_2021_Board_Submitted_Copy.pdf
305 *Id.* at 5.
306 *Id.* at 32-33.
307 This Recommendation is related to Recommendation 24, which suggests that the same entities involved in the forum study and enact measures "to address natural gas supply shortfalls during extreme cold weather events." The topics included in Recommendation 24 were those the Team viewed as requiring additional study before they might be ready for discussion in the forum, however, forum participants should feel free to consider any topic from Recommendation 24 in addition to those included in this Recommendation, or to refer any topic from this Recommendation for further study.
308 Judah Cohen et al., *Linking Arctic variability and change with extreme winter weather in the United States,* 373 Sci. 1116, 1120-1121 (2021); https://www.science.org/doi/10.1126/science.abi9167. The authors also identify a precursor condition that, if identified by forecasters, could provide more warning before future extreme cold weather events in warm-weather areas like the Event. 373 Sci. at 1122 and Figure 2.
309 From the book of the same name by Nicholas Taleb, black swan events refer to rare and unpredictable outlier events. https://en.wikipedia.org/wiki/The_Black_Swan:_The_Impact_of_the_Highly_Improbable

operate the grid during these events under conditions beyond anything ever intended, studied, or trained for.

The Team has proposed several options for how the natural gas infrastructure entities, grid entities and those with power to regulate these entities, as well as NERC and its Regional Entities, can convene to tackle the natural gas-electric infrastructure interdependency puzzle. Each option has its benefits and potential drawbacks, which are set out in the table below. On balance, while the Federal Advisory Committee would require more effort to convene, it best fits the need to allow a group of disparate representatives from multiple industries, and multiple state and federal regulators (or those who have authority to regulate but have not exercised it, such as Congress and some state legislatures), to address a thorny problem over time, with the assistance of experts as needed. This Key Recommendation is not meant to be prescriptive as to the method used or topics addressed--if the affected sectors, entities, regulatory agencies, and other regulators can find another forum to accomplish the same objectives, the Team would welcome that approach.

Forum	Description	Benefits	Potential Drawbacks
Federal Advisory Committee[310]	Chairman of the Commission can create a committee which can include non-Federal employees (such as state regulators, industry representatives, NERC, Regional Entity and NARUC, etc.)	-allows for committee to continue to meet until purpose is accomplished, then committee will end -committee can hire experts if needed -allows public participation at most meetings -committee members can be compensated for their time if needed -federal employees can be assigned to work for the committee without losing pay or benefits	-requires consultation with Secretariat of the General Services Administration and public notice in the Federal Register before establishing committee -recordkeeping requirements for Commission, including drafting a charter - the committee is legally required to provide advice to the Commission, not other entities, although scope of issues to be addressed is broader than Commission's jurisdiction.

[310] Federal Advisory Committee Act, §7(c), 5 U.S.C.A. App. 2 (2018); regulations found at GSA Regulations, Part 102-3, [§102-3.5](#) *et. al.* (2021) (Federal Advisory Committee Management), https://www.gsa.gov/policy-regulations/regulations/federal-management-regulation-fmr/idtopicx2x1678#idtopicx2tex1688.

FERC-led Technical Conferences	One or more technical conferences similar to the ones conducted in 2012 as described above—would include filed written testimony, public hearings with testimony; technical conference testimony is often used as the factual basis to support later Commission action such as Notice of Proposed Rulemaking.	-fully within FERC's jurisdiction without any additional permission or recordkeeping -long-established procedures, familiar to electric and interstate gas pipeline sectors -allows for public participation	-FERC may have reached the limits of what can be accomplished via this method for the gas-electric coordination issue—see past history below. -limited duration—normally a day or series of days of testimony plus written filed testimony -not ideally-suited for a series of ongoing meetings among representatives from natural gas and electric sectors as well as their regulators or potential regulators -regulations do not specifically allow for compensating participants or experts -does not allow for members of other federal agencies to work on the project, as does the forum, while maintaining salary and benefits
Joint FERC-NARUC Technical Conference(s)	Similar to FERC-led Technical Conference, but with cooperation between FERC and NARUC[311] in	-same procedural benefits as FERC-led Technical Conference(s)	-same potential drawbacks as FERC-led Technical Conferences

[311] National Association of Regulatory Utility Commissioners. [Home - NARUC]

	planning and execution	-NARUC leadership and staff participation -NARUC expertise with state regulatory issues and intrastate gas and electric infrastructure -access to NARUC's contacts and relationships with state regulators and industry participants	

The Commission and NERC have already taken actions within their respective areas of authority to address gas-electric interdependency issues, but some aspects of the problem are either outside their authority or require cooperation among jurisdictions. After the 2011 event,[312] the Commission initiated a proceeding (Docket No. AD12-12-000) in early 2012, requesting comments on questions about topics including market structure and rules, scheduling, communications, infrastructure, and reliability.[313]

The Commission received comments from 79 entities and convened five regional conferences in Docket No. AD12-12-000[314] for the Central, Northeast, Southeast, West and Mid-Atlantic regions throughout the month of August 2012, in advance of the winter heating season, to solicit input from both industries regarding the coordination of natural gas and electricity markets. A cross-section of industry representatives participated in the docket and/or attended the conferences, which were structured around three sets of issues: scheduling and market structures/rules; communications, coordination, and information-sharing; and reliability concerns.

[312] Even before the 2011 event, NERC had a Gas-Electric Interdependency Task Force, which released a 2004 report titled "Gas/Electricity Interdependencies and Recommendations." 2011 Report at 194; https://www.naesb.org//misc/nerc_gas_electricity_interdependencies_2004.pdf (focused on "gas pipeline operations and planning and electric generation operations and planning," not natural gas processing or production).

[313] *Coordination between Natural Gas and Electricity Markets*, Docket No. AD12- 12-000 (Feb. 15, 2012) (Notice Assigning Docket No. and Requesting Comments) (available at https://elibrary.ferc.gov/eLibrary/filedownload?fileid=01CF0351-66E2-5005-8110-C31FAFC91712). The topics were based on questions raised by then-Commissioner Moeller in a statement. Commissioner Philip D. Moeller, Request for Comments of Commissioner Moeller on Coordination between the Natural Gas and Electricity Markets (Feb. 28, 2012), available at https://elibrary.ferc.gov/eLibrary/filelist?accession_Number=20120228-4005.

[314] *Coordination between Natural Gas and Electricity Markets*, Docket No. AD12- 12-000 (July 5, 2012) (Notice of Technical Conferences) (available at http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13023450); 77 Fed. Reg. 41,184 (July 12, 2012) (available at http://www.gpo.gov/fdsys/pkg/FR-2012-07- 12/pdf/2012-16997.pdf).

As a result of the conferences, the Commission received valuable feedback which resulted in two orders that removed roadblocks to gas-electric cooperation. First, in Order No. 787,[315] the Commission addressed fears that the Standards of Conduct prohibited communication between electric utilities and pipelines. The order revised Commission regulations to explicitly authorize interstate natural gas pipelines and public utilities to share nonpublic operational information for the purpose of promoting reliable service or operational planning on either the public utility's or pipeline's system. While authorizing certain beneficial information sharing, FERC also established a "no conduit rule," which prohibits public utilities and pipelines—as well as their employees, contractors, consultants, and agents—from disclosing—or using anyone as a conduit for disclosure of—nonpublic, operational information that they receive under this rule to a third-party or to its marketing function employees. Finally, the order included additional protections to ensure that shared information remains confidential.

Second, in Order No. 809,[316] the Commission helped harmonize natural gas interstate pipeline transportation and the gas day with the needs of natural gas-fired generating units by extending the first, and most commonly-used, day-ahead deadline for scheduling interstate transportation, and adding another scheduling opportunity during the gas day. These changes helped better align the natural gas and electric daily schedules, although differences remained, and allowed natural gas shippers to adjust their contracts to reflect changes in demand. The Final Rule provided additional contracting flexibility to firm natural gas transportation customers by allowing multi-party transportation contracts, but declined to move the start of the gas day from 9 a.m. to 4 a.m. as initially proposed. The Commission also instituted proceedings under section 206 of the Federal Power Act (FPA) to ensure that the ISOs'/ RTOs' day-ahead scheduling practices harmonized with the revisions to the natural gas scheduling practices adopted by the Commission.

Although the Commission took actions within its jurisdiction to address the issues raised during the 2012 technical conferences, some debates from 2012 continue today. For example, natural gas-fired GOs participating in the RTO/ISO markets claimed in 2012 that managing fuel procurement risk was challenging because the timeframe for nominating natural gas transportation service, including pursuant to capacity release,[317] was not synchronized with the timeframe during which generators receive confirmation of their bids in the day-ahead electric markets. On the other hand, natural gas pipelines argued that the problem was not the gas-electric day mismatch but rather the failure of the GOs/GOPs to sign up for firm capacity or firm pipeline transportation. Similar discussions continue today about why GOs/GOPs do not sign up for firm capacity or firm pipeline transportation, and what, if anything, can be done to influence that behavior. In 2012, natural gas-fired generating units told the Commission that they were not subscribing to firm transportation contracts on pipelines because their capacity use was not high enough to make the decision economic, stressing that they would not be able to recover the cost of firm pipeline transportation capacity in their dispatch prices in the competitive ISO/RTO markets. To address this concern, some natural gas pipelines told the Commission they were offering enhanced flexible firm transportation and storage services, such as no-notice service or the ability to take at a non-uniform

[315] 145 FERC ¶ 61,134 (2013).
[316] 151 FERC ¶ 61,049 (2015).
[317] Capacity release refers to holders of firm transportation or storage rights reselling a portion of that capacity. Interstate capacity release occurs pursuant to pipeline or storage facility tariffs approved by FERC.

hourly flow rate or to allow contracts for firm rights to exceed daily scheduling limits without penalty. Still, the Commission learned that many generators were not subscribing to these services, mainly due to cost concerns.

NERC also issued two Reliability Guidelines after the 2011 event intended to increase coordination between the natural gas and electric sectors and reduce the risks associated with fuel unavailability. The first guideline, Gas and Electrical Operational Coordination Considerations,[318] provided guidance in areas including:

- establishing natural gas and electric industry coordination mechanisms,
- understanding how the gas and electric systems interface with each other and their interdependencies,
- training (which included a recommendation about joint training related to load shedding) and testing,
- establishing and maintaining open communication channels, and
- gathering and sharing information/situational awareness.

The second guideline, Fuel Assurance and Fuel-Related Reliability Risk Analysis for the BES,[319] focused on fuel supply risk analysis for all generating unit fuel sources (not just natural gas).

Fuel Switching: A Missed Opportunity?

Units 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 ERCOT, approximately 392 generating units reported an unplanned outage, derate or failure to start and use coal, gas, oil, waste heat or other non-renewable fuels as their primary or only fuel. About 41 of those generating units are capable of fuel switching, yet only roughly a third (14 of 41) attempted to switch from their primary fuel to their secondary fuel during the Event. Of the 14, 11 generating units were initially successful in switching fuel types (gas to distillate oil or oil), but 12 units either failed to switch (three units) or subsequently experienced outages related to their use of alternate fuels (nine units). Twenty-four generating units were capable of fuel switching but were not requested or required to switch during the Event, and the remaining three units capable of fuel switching were on planned or maintenance outages.

Approximately 86 percent (12 out of 14) generation units that attempted to switch fuel types in ERCOT failed or were subsequently outaged or derated. The majority of the units that attempted switching were gas generators switching to distillate oil or oil. Failures in fuel switching were due to problems including the blade path temperature spread from uneven burning of oil, fuel oil pump fouling, fuel oil system trip, fire in turbine enclosure due to fuel oil leak, valve failure, never operated on

[318] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Gas_Electric_Guideline.pdf
[319] *See* https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Fuel_Assurance_and_Fuel-Related_Reliability_Risk_Analysis_for_the_Bulk_Power_System.pdf

alternate fuel, inability to synchronize on alternate fuel source due to loss of flame issues during startup, and inability to synchronize on alternate fuel source due to failure to accelerate fault during startup.

In MISO South, four entities reported owning a total of nine dual-fuel units, and one unit was asked to operate on fuel oil due to natural gas fuel restrictions. The unit used a propane system for starting and contributed up to 120 MW of generation from February 15 through February 17. In SPP, nine entities reported owning 46 units capable of fuel switching. In total, 38 units attempted to switch fuels during the Event, and 37 of 38 units successfully switched fuels. One unit failed to start on the secondary source, and one unit was asked three times, failed in one attempt to switch, and did eventually switch. Most units switched from natural gas to oil, and two units supplemented coal with natural gas. Generating units in SPP that switched fuels contributed an average of 1,300 MW of generation during the height of the Event from February 15 through February 18.

Key Recommendation 8:[320] **To better provide Balancing Authorities with accurate information under TOP-003-5, R2.3.1.2 ("fuel supply and inventory concerns"), Generator Owners/Generator Operators should identify the full reliability risks related to the contracts and other arrangements they (individually or collectively)**[321] **have made to obtain natural gas commodity and pipeline transportation for generating units, including but not limited to volumetric terms, transportation service types, and impacts from potential force majeure clauses. (Winter 2021-2022)**

This Key Recommendation seeks to ensure that natural gas-fired generating units convey to BAs the reliability of their natural gas commodity and transportation contracts, especially whether those contracts are firm or non-firm (and any volumetric limits). Such information would give a BA a better sense of the generation capacity available in its footprint during emergencies like the Event, and improve the BA's operational planning. This Key Recommendation is a necessary predecessor to Key Recommendation 1h, which apportions responsibility for estimating the likelihood of generating units being able to perform during "local forecasted cold weather" between generating units and BAs.

This Key Recommendation also will also help GOs/GOPs comply with TOP-003-5, R2.3.1.2 (effective April 1, 2023), which adds to the BA's data specification "provisions for notification of BES generating unit(s) status during local forecasted cold weather to include . . . operating limitations based on . . . fuel supply and inventory concerns." Requirement 2.3.1.2 will require BAs to ask for information about limitations based on fuel supply and inventory concerns. To prepare to respond to the BA's data specification, this Key Recommendation encourages GOs/GOPs to identify the reliability risks related to their natural gas commodity and pipeline transportation arrangements. Although TOP-003-5, R2.3.1.2 will not be effective until April 1, 2023, the Team has

[320] Formerly Key Preliminary Recommendation 6 in the September 23 Presentation.
[321] Arrangements to obtain natural gas commodity and pipeline transportation for generating units may vary between generator owners and generator operators. The GOs should identify the party(s) to their BAs who will be providing the information that is specified by the BA.

designated this Key Recommendation to be implemented before winter 2021-2022, and encourages GOs/GOPs to share this information voluntarily with their BAs in advance of TOP-003-5, R2.3.1.2's effective date.

During the Event, natural gas fuel supply issues impacted 357 natural gas-fired generators across the three areas; 55 percent, or 185 of 336 natural gas-fired generating units in the ERCOT footprint; 40 percent, or 31 of 77 units in MISO South; and 74 percent, or 141 of 191 units in the SPP footprint, as shown in Figure 103, below.

Figure 103: Contractual Arrangements of Natural Gas-Fired Generating Units that Experienced Outages and Derates in the Event Area

Generating Unit Natural Gas Commodity and Transportation Contracts						
	ERCOT		MISO		SPP	
	Generators	Percent	Generators	Percent	Generators	Percent
Firm Commodity/Firm Transportation	45	24%	10	32%	47	33%
Firm Commodity/Mixed Transportation	14	8%	7	23%	19	13%
Firm Commodity/Non-Firm Transportation	0	0%	0	0%	4	3%
Non-Firm Commodity/Non-Firm Transportation	26	14%	1	3%	24	17%
Non-Firm Commodity/Mixed Transportation	9	5%	0	0%	13	9%
Non-Firm Commodity/Firm Transportation	1	1%	3	10%	14	10%
Mixed Commodity/Mixed Transportation	34	18%	5	16%	0	0%
Mixed Commodity/Firm Transportation	35	19%	0	0%	0	0%
Mixed Commodity/Non-Firm Transportation	0	0%	0	0%	0	0%
Did not provide information re: commodity contract type	10	5%	0	0%	11	8%
No contract or did not provide information about transportation contract type	11	6%	5	16%	9	6%
Total	**185**	**100%**	**31**	**100%**	**141**	**100%**

As shown in Figure 103, above, the *majority* of natural gas-fired generating units experiencing outages and derates had a mixture of firm and non-firm commodity and pipeline transportation contracts or had interruptible transportation contracts for their contracted volumes. A minority of natural gas-fired generating units had both firm commodity and firm transportation contracts for all their contracted volumes. Generally natural gas-fired generating units do not contract for the full volumes of natural gas needed to run at maximum capacity. Typically, they use short-term sales or storage capacity to procure additional natural gas as needed. During the Event, some natural gas-fired generating units attempted to procure their gas commodity from alternative sources, but due to natural gas supply shortages, the majority were unable to secure additional volumes above their contracted volumes to operate at their expected capacity.

Although generating units with firm natural gas commodity and transportation contracts were not immune from outages and derates due to natural gas fuel supply issues, of the 357 natural gas-fired generating units across the three footprints that had an outage or derate due to natural gas fuel supply issues, only 29 percent had both firm natural gas commodity and firm natural gas pipeline transportation contracts for any volume, as Figure 103 shows (ERCOT, 45; MISO, 10; SPP, 47). Figure 104a, below, shows firm natural gas pipeline transportation capacity contracted, daily volumes of natural gas nominated and daily volumes of natural gas ultimately shipped. Even though the figure indicates that natural gas shipped to natural gas-fired generating units with firm interstate pipeline capacity was less than contracted volumes beginning February 10 and continuing through the Event period (outages due to natural gas fuel supply issues began in the SPP footprint on February 8, 2021), the majority of nominated natural gas was delivered to natural gas-fired generating units. Natural gas-fired generating units with interruptible transportation contracts were still able to nominate and ship some gas under those contracts, but at smaller volumes than gas shipped under firm transportation contracts. Natural gas-fired generating units that were unable to procure natural gas commodity would not have submitted a nomination for transportation. See Figure 104b for volumes nominated and shipped by natural gas-fired generating units with interruptible transportation contracts.

Figure 104a: Firm Pipeline Capacity that was Nominated, Shipped, and contracted by Natural Gas-Fired Electric Generation, February 1-28, 2021 From Sampled Pipelines in Oklahoma, Texas, Louisiana, and Kansas (Units: Dth/d)

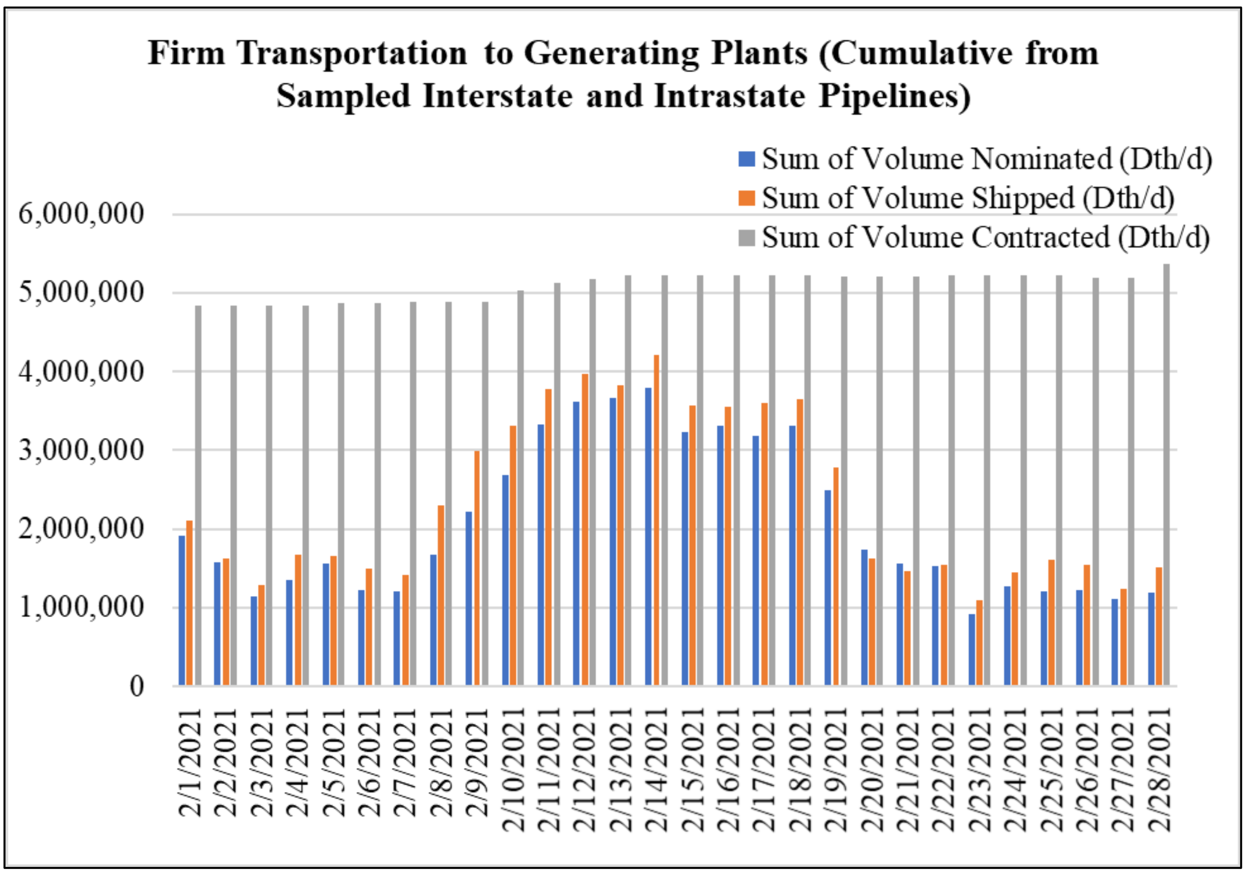
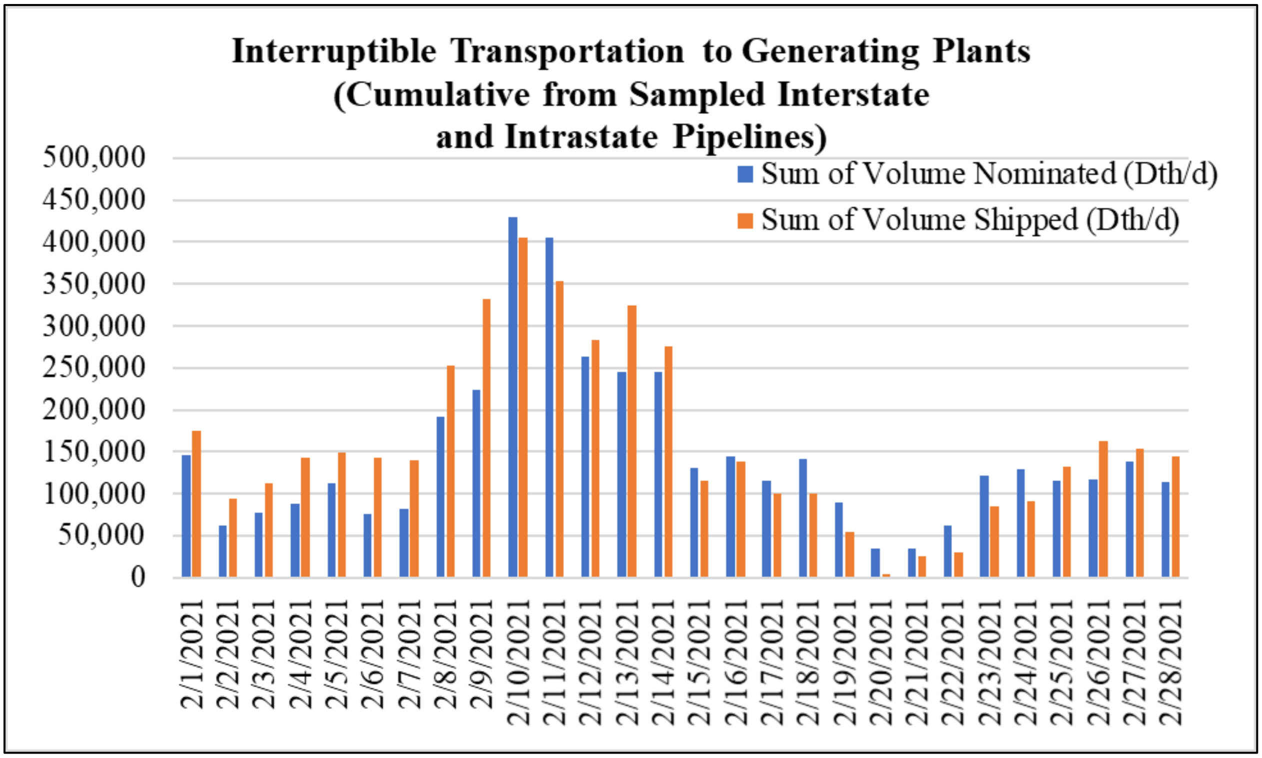


Figure 104b: Interruptible Pipeline Capacity that was Nominated by and Delivered to Natural Gas-Fired Electric Generation, February 1-28, 2021, on the Sampled Pipelines in Oklahoma, Texas, Louisiana, and Kansas (Units: Dth/d)



By assessing the terms and conditions of the commodity and transportation contracts that will be in effect during winter peak conditions for their natural gas-fired generating units, GOs/GOPs can achieve a greater understanding of the risks of natural gas fuel interruption across their fleet. GOs/GOPs can then include this information when providing their operating limitations based on fuel supply and inventory concerns to the BA, for the BA's incorporation into operational planning analyses for winter peak conditions.

C. Grid Emergency Operations Preparedness

<u>Key Recommendation 1 (h through j):</u> The Reliability Standards should be revised as follows:

<u>Key Recommendation 1h</u>: To require Balancing Authorities' operating plans (for contingency reserves and to mitigate capacity and energy emergencies) to prohibit use for demand response of critical natural gas infrastructure loads.[322] (Winter 2023-2024)

In the Event, at least one natural gas infrastructure entity (a producer) registered what it called its "high-electric demand, low-production facilities" in ERCOT's Load Resource demand response program, which would result in its facilities being de-energized during the Event. This sampling of natural gas producers in the ERCOT area[323] led the Team to conclude that other natural gas production entities could have participated in demand response programs and been called upon to de-energize, thereby becoming unavailable and contributing to natural gas fuel supply issues during the Event. Under the Reliability Standards, a Balancing Authority has operating plans to plan for contingency reserves and to mitigate emergencies in its area, including energy emergencies.[324] These plans can rely in part on demand response programs. If the resources the BA relies upon to reduce load (in this case, ERCOT relying on Load Resources that included gas production entities) instead reduce the availability of the BAs' natural gas-fired generation, BES reliability would be harmed, and the purpose of the plan would be defeated. This Key Recommendation does not advocate for an absolute prohibition on BAs' operating plans allowing natural gas infrastructure loads to participate in demand response; rather, it limits the operating plans' prohibition to *critical* natural gas infrastructure loads which, if de-energized, would adversely affect BES natural gas-fired generation.[325] *See also* Recommendation 28, below, regarding further study of how to identify critical natural gas infrastructure loads.

<u>Key Recommendation 1i</u>: To protect critical natural gas infrastructure loads from manual and automatic load shedding (to avoid adversely affecting Bulk Electric System reliability):

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[322] Critical natural gas infrastructure loads are natural gas infrastructure (see definition in footnote 29) loads which, if de-energized, could adversely affect provision of natural gas to BES natural gas-fired generating units, thereby adversely affecting BES reliability. *See* further study Recommendation 28 below, regarding criteria for identification of critical natural gas infrastructure loads.

[323] *See* Appendix I for a discussion of the scope of the Team's natural gas production data.

[324] Reliability Standard BAL-002-3 - Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event requires BAs to have an operating process as part of its operating plan to make preparations to have contingency reserves equal to or greater than the BA's most severe single contingency available for maintaining system reliability. Reliability Standard EOP-011-1 – Emergency Operations requires each BA to develop, maintain, and implement one or more Reliability Coordinator-reviewed operating plan(s) to mitigate capacity emergencies and energy emergencies within its Balancing Authority Area.

[325] If a natural gas infrastructure entity owns or operates a natural gas facility that has electric loads that are *not* determined to be critical, those loads could be used as demand response and interrupted via instructions issued by the BA, to provide contingency reserves (as part of the BA's Operating Plan).

- **To require Balancing Authorities' and Transmission Operators' provisions for operator-controlled manual load shedding to include processes for identifying and protecting critical natural gas infrastructure loads in their respective areas;**
- **To require Balancing Authorities', Transmission Operators', Planning Coordinators', and Transmission Planners' respective provisions and programs for manual and automatic (e.g., underfrequency load shedding, undervoltage load shedding) load shedding to protect identified critical natural gas infrastructure loads from manual and automatic load shedding by manual and automatic load shed entities[326] within their footprints;**
- **To require manual and automatic load shed entities to distribute criteria to natural gas infrastructure entities that they serve and request the natural gas infrastructure entities to identify their critical natural gas infrastructure loads; and**
- **To require manual and automatic load shed entities to incorporate the identified critical natural gas infrastructure loads into their plans and procedures for protection against manual and automatic load shedding. (Winter 2023-2024)**

The manual load shed plans (of TOPs) and automatic underfrequency load shed plans (of TOs and DPs) within the ERCOT footprint were designed to avoid controlled power outages to priority or critical electric loads if the need to shed firm load arose. However, most of the natural gas production and processing facilities surveyed were not identified as critical load or otherwise protected from manual load shedding.[327] Thus, from early February 15 through February 18, the implementation of manual firm load shedding by ERCOT operators to preserve BES reliability partially contributed to the decline in the production of natural gas. Protecting these facilities from manual load shedding would have helped to provide natural gas supply and transportation to natural gas-fired generating units –potentially reducing the total magnitude of manual firm load shed needed by the ERCOT BA to maintain BES reliability.

<u>Key Recommendation 1j</u>: In minimizing the overlap of manual and automatic load shed, the load shed procedures of Transmission Operators, Transmission Owners and Distribution Providers should separate circuits that will be used for manual load shed from circuits used for underfrequency load shedding/undervoltage load shedding or serving critical load. Underfrequency load shedding/undervoltage load shedding circuits should only be used for manual load shed as a last resort and should start with the final stage (lowest frequency). (Winter 2022-2023)

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[326] Manual and automatic load shed entities include applicable TOPS, TOs, and DPs.
[327] According to the RRC, one reason that production facilities in Texas may have not self-identified as critical load is that a form in use prior to the Event (to apply for the status of "Load Serving Natural Gas-Fired Generation," which included gas infrastructure serving generation) stated that it was not to be used by "field services," and typically producers are considered to be "field services." Of the 32 pipelines (both interstate and intrastate) that provide data, 10 pipelines had some facilities (which included metering stations, compressor stations, and storage facilities) designated as protected or critical load. To protect pipelines from load shedding, all pipelines had backup generators/batteries at their major facilities. Thus, only a very small number of pipeline facilities were affected by the firm load shed.

Reliability Standard EOP-011-1, Requirement R2.2.8 requires provisions for operator-controlled manual load shedding that minimize the overlap with automatic load shedding and are capable of being implemented in a timeframe adequate for mitigating the emergency. ERCOT requires a minimum of 25 percent of load to be connected to UFLS circuits in three steps. Five percent of load should automatically shed at 59.3 Hz (block one), 10 percent should automatically shed at 58.9 Hz (block two), and 10 percent should automatically shed at 58.5 Hz (block three).

At times during the Event, ERCOT manual and automatic load shedding entities were forced to manually shed circuits normally reserved for automatic UFLS, due to the large amounts of load shedding ordered, the duration of the load shedding, and the circuits protected from load shedding as critical. ERCOT operators on several occasions advised TOP operators to manually shed block two of their UFLS circuits to maintain their obligation of total pro rata load shed.

There was a significant risk in ERCOT of the UFLS activating during the four minutes on February 15 when its frequency was below 59.4 Hz, and in fact, approximately 276 MW of UFLS circuits did activate. Even when a system is not as close to the edge as ERCOT was on February 15, there is always the risk that during cascading or uncontrolled load shed, every MW of UFLS will be needed, and especially the first block of UFLS, where operators have the best chance of arresting the frequency decline.

At the same time, this Key Recommendation recognizes that during dire situations like the Event in ERCOT, TOPs, TOs and DPs may not have enough non-UFLS and non-critical circuits to implement the amount of load shed directed by the BA. In such a situation, protecting system reliability requires the lesser evil of using some UFLS circuits to implement the required load shedding. However, under this Key Recommendation, the Team prefers that the TOPs, TOs and DPs start with the lowest frequency (which in ERCOT would be block three, not block two), to minimize system impacts if UFLS does activate. The Key Recommendation to draw from the third block, or last stage, of UFLS—the least likely to be needed—balances the risk of the immediate emergency need to balance generation and load to maintain reliability, with the potential for frequency disturbances in the future.

D. Grid Seasonal Preparedness for Cold Weather

Key Recommendation 9: Planning Coordinators should reconsider some of the inputs to their publicly-reported winter season anticipated reserve margin calculations[328] for their respective Balancing Authority footprints so that the reported reserve margins will better predict the reserve levels that the Balancing Authorities could experience during winter peak conditions. MISO and SPP should also improve their internal winter peak load forecasts. The suggested improvements should result in seasonal reserve margin projections which better account for resource and demand uncertainties and align better with each Balancing Authority footprint's near-term planning during forecast cold weather events. Planning Coordinators should reconsider the following components of winter reserve margins:

[328] *See* https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2020_2021.pdf.

a. **ERCOT, SPP, MISO (for MISO South) and other Planning Coordinators that forecast load within southern states should adjust their 50/50 forecasts to reflect actual historic peak loads that occurred during severe cold weather events in their footprints, and reflect the potential for exponential load increase due to the resistive heating used in southern states;**
b. **Planning Coordinators should revisit how much natural gas-fired generation should be considered as capacity to be included in winter season anticipated reserve margin calculations and projections;**
c. **Planning Coordinators should revisit how much wind[329] generation should be considered as capacity and included in winter reserve margin calculations and projections;**
d. **MISO should perform a winter peak analysis for each MISO sub-zone (focusing on MISO South) to improve its winter peak load forecast. MISO should use actual prior winter peak loads in the analysis, rather than summer peak load data modified by uncertainty factors; and**
e. **SPP should develop a 90/10 seasonal forecast procedure, like those employed by other regions, including MISO and ERCOT. As part of that procedure, SPP should consider breaking the SPP footprint into northern and southern sub-regions, given the potential for exponential load increase due to the resistive heating used in southern states. (Winter 2023-2024)**

ERCOT, MISO, and SPP anticipated winter reserve margins of 50 percent, 49 percent, and 59 percent, respectively, in the NERC seasonal assessment,[330] but all needed to shed firm load in February 2021. The combination of winter seasonal load forecasts that were substantially lower than actual peak load, and failure to consider the extent to which generation might be unavailable during winter peak weather in the anticipated winter reserve margins,[331] led to publicly-reported[332] reserve margin projections for the 2020/2021 winter season that could have led policy makers to make incorrect assumptions about the actual level of reserves that would be available during winter peak conditions. While planning reserve margins are designed to assess the overall capacity supply of the system, and not necessarily to predict energy requirements and operational scenarios, even the extreme-case assessments did not consider the extent to which the BAs' reserves were actually depleted during the Event. The extreme, or "90/10," scenarios conducted as part of the seasonal assessments should be designed to test a variety of extreme expected system conditions, such as

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329 *See* note 28 regarding the role of solar units in the Event. If an entity is relying on a substantial amount of solar generation, this Recommendation could apply to solar generation as well.
330 *See* NERC 2020-2021 Winter Reliability Assessment (November 2020), Data Concepts and Assumptions page 31, available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2020_2021.pdf.
331 The NERC 2020-2021 Winter Reliability Assessment did contain "seasonal risk scenarios" which included generator forced outages and higher loads; however, not at the magnitude experienced in the Event. These generator forced outages and higher loads are not included in the anticipated reserve margin projections.
332 Entities such as ERCOT, MISO and SPP also perform winter seasonal assessments for their own internal use prior to each winter season. These assessments typically include a range of scenarios, with some that take into account lower generation availability and extreme peak load conditions in calculating less-optimistic winter reserve margins.

those that may be experienced during severe and prolonged cold weather. SPP should develop a statistically-based 90/10 load forecast.

During winter peak conditions, fuel for natural gas-fired generating units may be in competition with natural gas for residential heating needs. While the local distribution companies that supply natural gas for residential heating normally have firm commodity and transportation contracts, natural gas-fired generating units often have non-firm or interruptible contracts. When natural gas commodity or transportation availability is limited, natural gas-fired generating units without firm commodity and transportation contracts often cannot perform (or perform to their full expected capacity). This Key Recommendation encourages Planning Coordinators to recognize that they may not be able to count on the generating units' full capacity during winter peak conditions.

The variability in expected intermittent generating unit winter peak capacity may be affected by more than wind and irradiance. Factors that should be taken into account include the effects of cold weather precipitation conditions (ice and snow build-up).

For MISO, winter season Load Forecast Uncertainty percentages (LFU) should be based on the actual highest winter peak load day for each of the past 30 years. Zones 8, 9 and 10 (MISO South zones) could have significantly higher LFUs during winter peaks due to the volatility of winter load spikes due to electric heat.

VI. Additional Recommendations

<u>Recommendation 10</u>: **Transmission Owners/Transmission Operators, in coordination with Distribution Providers and Reliability Coordinators, should evaluate load shedding plans for opportunities to improve their capacity for rotating manual load shedding, especially when load shedding is required for extended periods during stressed system conditions. These evaluations should consider:**

- **a. under what circumstances underfrequency load shedding circuits may be used for rotating load during longer duration events;**
- **b. use of remote-controlled distribution circuit load interrupting devices (e.g., distribution line load break devices) to enable operators to deenergize and reenergize smaller portions of large distribution circuits to improve rotational load shedding; and**
- **c. whether advanced metering infrastructure could be leveraged to achieve greater real-time distribution situational awareness (instead of being limited to distribution substation circuit-level) to more strategically deploy or better rotate manual load shedding, such as to shed non-critical large loads (e.g., a factory that is not operating during the cold weather event). (Winter 2023-2024)**

When the ERCOT BA system operators give an order to manually shed 1,000 MW firm load, that 1,000 MW is then automatically divided into pro rata shares among the ERCOT TOPs, with Oncor and CenterPoint having the largest shares at 36 and 25 percent, respectively. The TOPs' load-shedding provisions must be capable of taking the necessary actions to shed their pro rata shares of load in a timeframe adequate for mitigating the emergency.[333] The actual amount of load shed by each TOP, and for the entire ERCOT footprint, is usually larger than the amount ordered, because TOP system operators ensure that, at a minimum, their pro rata share of load shed is sufficient to address the emergency condition. Ideally, the TOP can shed the load automatically via SCADA—which permits operators in a control room to implement the load shed immediately. But in some cases, a TOP may have to dispatch field personnel to disconnect a circuit to accomplish a portion of the load shed, which is very time-consuming. The unprecedented amount of load shed that ERCOT BA operators needed to order at the peak of the Event to prevent system failure (20,000 MW), the duration of the maximum load shed, and the number of circuits that were off-limits, (whether due to critical load like hospitals and first responders, or UFLS/UVLS) meant that some TOPs could not rotate their outages. Instead the same customers remained out of service for many hours or even days. For example, during the Event, Austin Energy's general manager said, "[t]here

[333] The NERC Standards do not specify a required timeframe. ERCOT specifies that measures including manual load shed must be implemented to restore reserves (recovery of Physical Responsive Capability to 1,000 MW) within 30 minutes. *ERCOT Nodal Operating Guides (Feb. 1, 2021) Section 4: Emergency Operations.*

is no more energy we can shut off at this time so we can bring those customers back on," as all available circuits were serving critical load such as hospitals and water treatment centers.[334]

During the Event, the amount of load connected to UFLS circuits substantially exceeded the ERCOT-required levels at times for certain TOPs, due to high system loading and the reduction in demand from manual load shedding that had already occurred. One TOP noted that the load on its UFLS circuits exceeded 60 percent of its load at times during the Event, primarily due to manual load shedding. This is substantially higher than ERCOT's UFLS requirements and prevented the TOP from rotating much of its load. If a TOP has sufficient monitoring capability during an extreme load shed scenario to calculate the difference between the UFLS margin required versus the actual load on its UFLS circuits, the TOP may be able to use this "margin" from circuits normally reserved for UFLS to shed load and rotate outages, while still meeting its UFLS obligations. Such an approach could increase the amount of load available for rotating outages, spreading the burden of those outages to a larger and more diverse pool of load, and provide flexibility. It could also reduce the risk of an overshoot in frequency if UFLS were to operate while actual UFLS-connected loads substantially exceeded the required obligation.

The affected BAs' load shed plans in effect before the Event contemplated much smaller and shorter manual load shedding events than the Event. The plans did not consider an extended load shed scenario the size and duration of ERCOT's during the Event, or generating unit outages of the magnitude faced by ERCOT during the Event.

To increase the capabilities of their load shedding plans, TOPS and DPs should perform studies to identify circuits available for rolling blackouts that could decrease the duration and frequency of rolling blackout outages (e.g., review all critical load distribution circuits and identify non-critical load branch circuits connected) and identify additional methods of performing operator-controlled manual load shedding of the non-critical circuits while protecting the critical loads from de-energization.

TOPs and DPs should investigate using technology to enhance their ability to rotate load shedding, including use of remote-controlled distribution branch circuit load interrupting devices (e.g., SCADA-controlled distribution line load break devices) that can allow system operators to deenergize and reenergize the branch into smaller non-critical load segments of large distribution circuits. For locations where electric customer advanced metering infrastructure (i.e. "smart meters") has been deployed, this technology may be leveraged to provide real-time customer load information, which in turn can provide real-time monitoring of branch circuit loads to enable system operators to make more strategic decisions when implementing manual, rotational load shed.[335]

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[334] Katherine Blunt, Charles Passy, *In Texas, Winter Storm Forces Rolling Power Outages as Millions are Without Power*, Wall Street Journal (February 16, 2021), https://www.wsj.com/articles/winter-storm-forces-rolling-power-outages-in-texas-11613407767

[335] *See* U.S. Department of Energy - Office of Scientific and Technical Information, "Leveraging AMI Data for Distribution System Model Calibration and Situational Awareness" (2015), at https://www.osti.gov/servlets/purl/1237701 ("real-time monitoring, network restoration, outage management. . . energy loss optimization, and . . . and load control" are among the benefits of distribution system state estimation enabled by advanced metering infrastructure or "smart meters").

System operators need tools and EMS[336]/SCADA displays that track load shed outage locations, quantities, and their durations. Automated load shedding applications that rotate load circuits on a timed basis using the EMS/SCADA system and protect critical load can relieve operators of some of the burden during extended load shedding events, as compared to using manual tools and manual recordkeeping methods.[337]

For those circuits identified as requiring extended outages, TOPs and DPs should perform further simulation studies to identify any issues with reenergizing circuits due to high cold load pickup inrush currents.[338] TOPs and DPs should periodically review and update circuit data and disseminate maps showing the areas outaged by each circuit, and the areas protected due to critical load or UFLS/UVLS, to management and operators. DPs also should consider sharing some information about protected circuits with residential and commercial customers, so that they could understand why they see lights on nearby when their home or business has been without power for many hours.

And finally, TOPs need to regularly perform manual load shed training and drills to exercise use of their expanded manual load shedding plans, and ensure that the training covers their computer-automated load shed monitoring and control tools and applications.

Recommendation 11: Generator Owners should analyze mechanical and electrical systems not directly susceptible to freezing but which suffered failure during cold weather events, to assess the impact of extreme cold weather on mechanical stress, thermal cycling fatigue and thermal stress on plant equipment, as well as other effects of cold weather such as embrittlement of mechanical and electrical components. Generator Owners should use this analysis to take appropriate actions to prevent mechanical and electrical failure during cold weather events. Components and systems for analysis may include:

- **components dependent on lubrication for proper operation,**
- **fuel, air, and hydraulic filters,**
- **piping and wiring,**
- **superheaters and reheaters,**
- **boiler components, and**
- **insulation. (Winter 2023-2024)**

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336 Energy management system.

337 Not everything is better with a human touch. You need automation. - Survalent | Advanced Distribution Management Systems (ADMS) | SCADA, OMS & DMS (fully automated rolling load shed program that protects critical load).

338 Cold load pickup is the phenomenon that takes place when a distribution circuit is reenergized following an extended outage of that circuit. Cold load pickup is a composite of two conditions: inrush and loss of load diversity. Cold load pickup includes a combination of non-diverse cyclic load, continuously operating load, transformer magnetizing current, capacitor inrush current and motor starting current. The combination can result in load levels that are significantly higher than the circuit's normal peak load levels.

The majority of generating units in ERCOT and MISO South are exposed to the elements, compared to many in SPP and those in MISO North, where generating units are typically enclosed. The open configuration of generating units in ERCOT and MISO South makes them more susceptible to cold-weather-related failures. Although most GOs/GOPs attested to ERCOT that they completed winter readiness actions prior to the Event, failures of systems directly or indirectly tied to cold weather occurred. Non-freezing-related mechanical/electrical failures of systems and components reported by GOs/GOPs included:

- Oil lube systems including lube oil pumps. Pump bearing or seal-wear-related failure is not uncommon. Pump motors and gears may also fail. If the lubricant is not rated for low temperatures, failures that look like inadequate lubrication or sticky lubricant may occur. (e.g., lube oil pressure switch in boiler feed pump failed to turn on the lube oil pump).
- Elastomeric seal materials are subject to low temperature embrittlement failure.[339]
- Wiring issues (e.g., solenoid failure). Accumulated damage from heating (current flow), voltage stress, vibration, or corrosion will eventually cause coil failure which is usually marked up to "aging." Sometimes changing plant output adds the final stress needed for a solenoid failure, so these issues are often discovered while starting up a unit, ramping, or in a sudden load change. Many solenoids require lubrication – cold gelling of lubricant can make solenoids stick (e.g., when attempting to restart a unit, a stuck solenoid prevented restart, or a purge vent valve solenoid failed to modulate during the startup sequence and prevented the unit from synchronizing).
- Condensate and feedwater heating system issues. These generally have steam traps and small-diameter drains that, if unprotected from freezing, can cause problems with water flows and levels, so some of these outages could be cold-weather-related (e.g., a unit was available to start but was kept offline due to limited condensate water from the steam host).[340]
- Boiler issues (e.g., water wall tube leaks). Although some amount of boiler issues is to be expected in a facility with steam boilers, and some failure tolerance is normally built into the unit design, too much tube leakage will require a unit shutdown. Among the factors that will tend to increase failures of steam equipment are thermal stresses related to rapid startups, load changes, water chemistry problems, and uneven heating (firebox/fuel side issues).
- Vent and control valves are subject to internal and external failure mechanisms. Internally, mechanical wear, erosion, fatigue, chemistry, and maintenance issues tend to dominate as failure causes. These internal failures are usually revealed by leakage or changes in flow characteristics over time. External failures can be initiated by actuator or control failures – these may be influenced by cold issues such as freezing of a sensing line, differential thermal expansion of supports and restraints, or hydraulic control system failures which may lead to

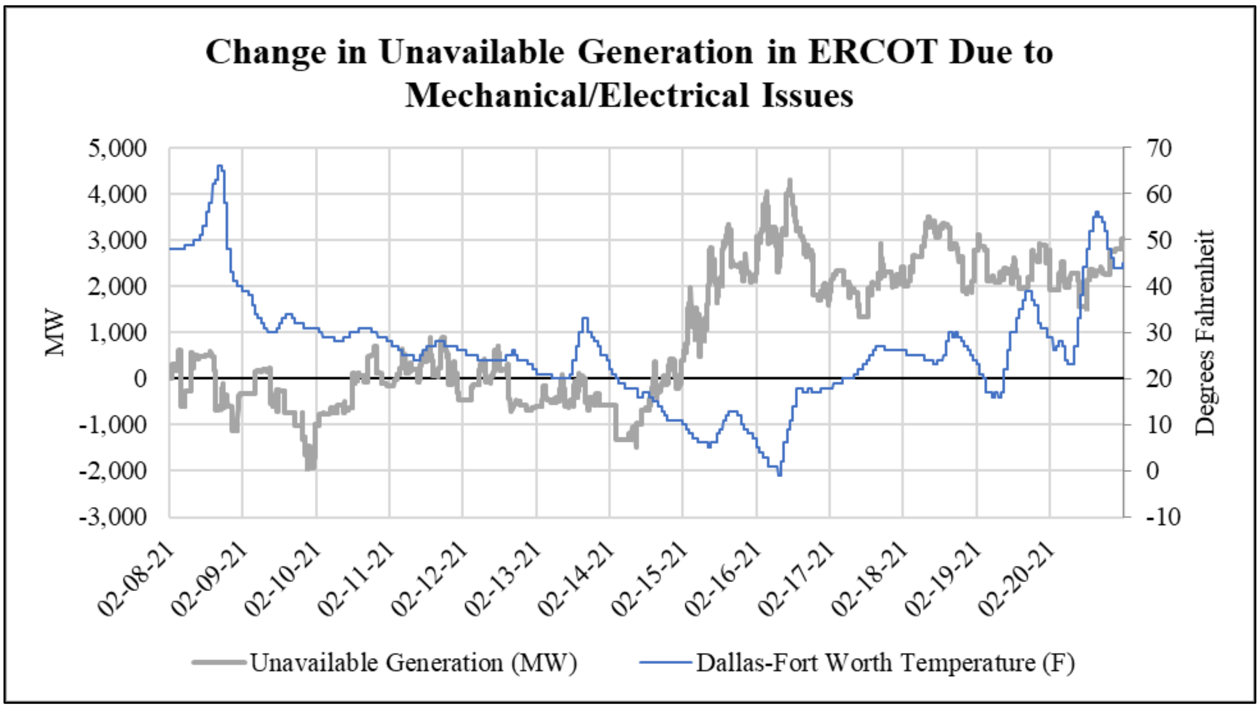
[339] Elastomeric means flexible or stretchy, such as plastic, rubber, or silicone materials. Thin metal bellows may also succumb to low temperature embrittlement. All flexible seal materials have operating temperature range limits.
[340] Some of these items may also use elastomer seals and boots that have minimum temperature limits to avoid embrittlement, but they were not identified in outage data.

limited or improper movement (e.g., a control valve or manual bypass valve leak resulted in high fuel gas pressure trip of two engines).

- Tuning for combustion turbine generating units is fuel- and temperature-sensitive. Derates have been reported due to intake low air temperature (e.g., an engine running at a much lower inlet temperature than it was tuned for caused unit to be derated, due to unstable combustion and acoustic vibrations that could damage turbine components).

Unplanned incremental generating unit outages, derates and failures to start attributed to mechanical/electrical issues during the Event caused a total of 103,096 MW of non-coincident outaged generation during the Event.[341] Although they were not directly caused by freezing, these outages are associated with the cold weather—as temperatures fell, the incidence of mechanical/electrical issues increased. See Figure 105, below.

Figure 105: Change in Unavailable Generation in ERCOT Due to Mechanical/Electrical Issues



In 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.[342]

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[341] *See* discussion in Analysis, sections IV.A and B, and Figure 93.
[342] 2018 Report at 80 (three cities had correlation coefficients of -0.7 or greater, and the majority of cities had coefficients of -0.5 to -0.7).

Some of these mechanical/electrical failures may be indirectly related to freezing issues, such as stress caused by freeze-thaw cycles. Unlike direct freezing issues, these failures are not necessarily prevented by heat tracing and insulation. At temperatures outside of the design operating temperatures, differential thermal expansion may cause mechanical overload of restraints, supports, structures or add to other existing loads (look for bowing, cracked welds, failed bolts, tighter- or looser-than-expected fittings or joints).

GOs should consider the following (and related or similar) systems, components and potential mechanisms leading to failure:

- Components dependent on lubrication for proper operation (e.g., lubricated gearbox), or which seem to have failed due to being improperly lubricated, may be due to operation at colder temperatures for which the lubricant was rated. Lower temperatures increase lubricant viscosity, which restricts lubricant flow and can alter its efficiency.
- Fuel, air, and hydraulic filters can be affected by cold air. Moisture in the air or collected by the fuel filter, or contaminating hydraulic fluid, may freeze and block filters.
- Temperatures below the material's rating can cause pipes and plastic wiring insulation to become brittle. Material near welds may have different properties from the general metal piping or structure that could cause the welds to weaken.
- Superheaters and reheaters can experience additional thermal stress and fatigue[343] from temperature changes.
- Extreme temperature changes can also impact other types of aging equipment. For instance, aging insulation can become brittle during cold weather, making failure more likely.
- Low temperature fatigue cracking (e.g., economizer inlet tubes, furnace wall tubes, steam drum internals) can occur when relatively cold water enters hot boiler components.

While the magnitude of these generating unit outages cannot be ignored, without more evidence as to the actual causes of the association between unplanned mechanical/electrical outages and cold temperatures, it will be difficult to craft the appropriate remedies, whether it be a potential Reliability Standards revision or some other action. The Team recommends further analysis by GOs 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.

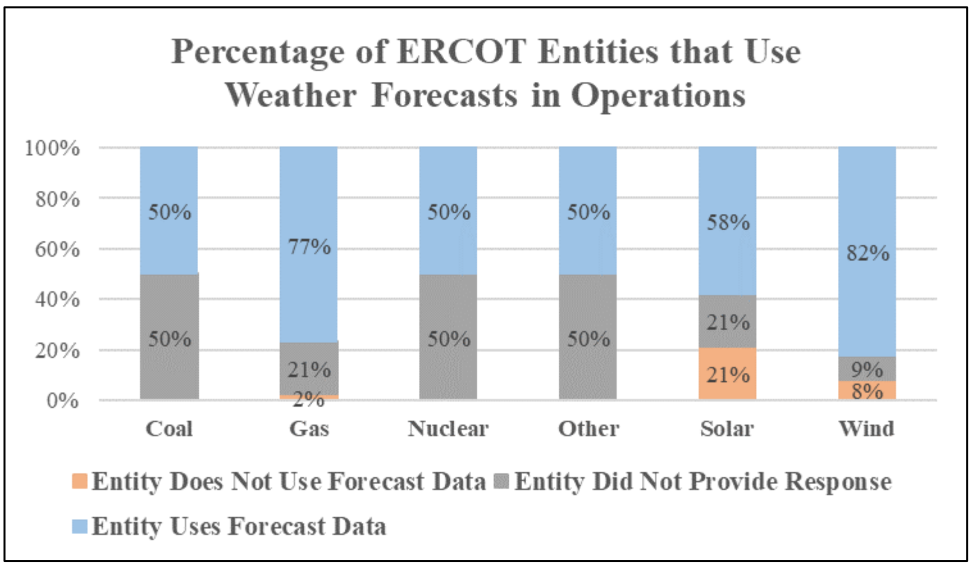
<u>Recommendation 12</u>: Generator Owners and Generator Operators should incorporate weather forecasts into planning the operation of their generating units prior to cold weather to lessen the impact of cold weather events on the performance and availability of the units. For example, adding a temporary wind break can protect exposed equipment that could potentially freeze (based on the forecasted wind and/or precipitation). (Winter 2021-2022)

343 Fatigue is defined as a process of progressive localized plastic deformation occurring in a material subjected to cyclic stresses and strains at high stress concentration locations that may culminate in cracks or complete fracture after a sufficient number of fluctuations.

Having accurate weather forecasts allows GOs/GOPs to plan and better prepare for extreme cold weather events. Cold weather preparations that can occur shortly before a forecasted cold weather event include checking insulation for gaps, checking heat tracing to make sure all circuits are fully operational, adding wind breaks and heaters to protect critical components and systems, adding temporary shelters to protect critical components and systems from freezing precipitation, and adding heaters to uninsulated rooms. When evaluating actions to take in response to the weather forecast, GOs/GOPs should be mindful of the accelerated heat loss due to wind, and its effect on a generating unit's operations.[344] Critical components and systems that are exposed may freeze more quickly due to the accelerated heat loss caused by wind.

Of the 132 GOs/GOPs surveyed in ERCOT, 114 (86 percent) provided information related to their weather forecasts and associated actions. As shown in Figure 106 below, the majority of wind and gas generators within ERCOT reported incorporating temperature forecasts in their planning or operations.[345]

Figure 106: ERCOT Generator Owners/Operators that Incorporated Weather Forecasts in Operations



Some GOs/GOPs surveyed did not use weather forecast data for operational planning. For example, some wind and solar GOs/GOPs explained that expected temperature is not a metric they considered in output forecasting (but could be relevant to preparing for a severe cold weather event). A few GOs/GOPs that did use weather forecast data during the Event reported actual temperatures substantially lower than forecasted temperatures. One GO/GOP reported that the low temperature on February 9 was 18 degrees lower than the next-day temperature forecasted and the low temperature on February 15 was 13 degrees lower than the next-day temperature forecasted.

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344 *See* 2011 Report Appendix "Impact of Wind Chill."

345 Note: Entities that reported multiple fuel types are counted separately for each fuel type in the chart.

Another GO/GOP reported that the temperatures for Austin, Texas were up to 18 degrees lower than the hourly day-ahead forecasted temperatures from February 9 to 10 and eight degrees lower than the forecasted temperatures on the night of February 14 to 15.

The 14 GOs/GOPs surveyed in MISO South own a total of 71 generating units, and all surveyed entities used weather forecasts. However, only six percent (4 of 71) provided forecasts that accounted for the cooling effect of wind.

Thirty-two SPP GOs/GOPs provided data for 318 generating units, and nearly all surveyed entities used weather forecasts. However, only 27 percent (87 of 318) provided weather forecasts that accounted for the cooling effect of wind. Three percent of GOs/GOPs who did not use weather forecasts for planning and operations justified it by stating that their resources are designed to operate in cold weather temperatures.

Those GOs/GOPs that did use weather forecasting for planning and operations used a variety of available weather forecast sources, ranging from NOAA data and subscription forecast services. Some GO/GOPs used a combination of sources, while others had meteorologist on staff to support their weather forecast needs. Additional forecast sources include TV and radio news, ERCOT Senior Meteorologist daily report, Weather Services International, Meteologica, Weather Underground, Global Forecast System, StormGeo.com, and weather.gov, among others.

Recommendation 13: Generator Owners within the ERCOT Interconnection should review the coordination of protective relay settings associated with generator underfrequency relays, balance of plant relays, and tuning parameters associated with control systems, which could trip generating units during low frequency or high rate-of-change of frequency conditions. Also, to evaluate how often generating units trip due to these causes, NERC should consider adding a Generating Availability Data Source Cause Code Amplification Code[346] for outages related to frequency deviation. (Winter 2022-2023)

The condition that most threatened BES reliability during the Event was ERCOT's low frequency excursion on February 15, which was caused by unplanned generation outages and derates in the ERCOT footprint. Due to the loss of Physical Responsive Capability of the generators that were online, the frequency began to steadily decline. As the frequency declined, several generators tripped offline due to the lower frequency level or rapid rate of frequency change: approximately 1,769 MW of coal generation and 2,190 MW of gas generation experienced unplanned outages from this cause. For instance, a 933 MW coal unit tripped due to the rapidly-changing frequency, which affected the boiler controls, caused a high boiler pressure condition, and tripped the unit. Another unit reported that the low frequency condition caused the turbine speed and air flow to decrease, which led to a temperature increase that tripped the unit. Additional examples are shown below in Table 107b. ERCOT should implement an expedited review of all BES generators within its footprint to identify the extent of this condition, and identify steps for mitigation. The results from

[346] According to NERC, "the purpose of the amplification code is to further identify the cause of an outage by describing the failure mode. The amplification code is two alpha-numeric characters following the cause code . . . Failure modes are leaks, corrosion, personnel error, fire, etc." [Appendix J: Cause Code Amplification Codes (nerc.com)](https://www.nerc.com)

implementing this Recommendation should considered as part of the study recommended by Recommendation 27, regarding low frequency or high rate-of-change of frequency conditions in the other interconnections.

Events related to grid frequency disturbances are not typically separately-captured when entities report their generator outages to NERC. This is partially due to the lack of a cause code amplification code for grid frequency events occurring on the BES in the GADS[347] cause codes. The lack of a GADS cause code amplification code means that generating unit outages caused by frequency disturbances are instead attributed to another cause, preventing accurate assessment of the magnitude of the problem. Unlike GADS, the Team did not rely on cause codes but collected multiple descriptions of the reasons for the outages from the GOs/GOPs, which allowed it to collect the data summarized in Figure 107a and 107b, below:

Figure 107a: ERCOT Generating Units (by Fuel Type) that Experienced Outages due to Low Frequency or High Rate-of-Change of Frequency Conditions During February 15 Frequency Decline/Recovery Condition

Fuel Type	Number of Outages Reported	Grid Disturbance (Frequency) (MW)
Gas	11	2,190
Coal	2	1,769
Total	13	3,959

347 NERC's Generating Availability Data System (GADS) is a mandatory industry program for conventional generating units that are 20 MW and larger. Generating Availability Data System (GADS) (nerc.com))The reporting requirements are specified in the GADS Data Reporting Instructions (DRI). GADS maintains operating histories on more than 5,000 generating units in North America. Through GADS, NERC collects information about the performance of electric generating equipment and provides assistance to those researching information on power plant outages. GADS data also supports equipment availability analyses, is used to conduct assessments of generation resources, and to improve generator performance. GOPs enter GADS cause codes when reporting generating unit outages or derates and data can then be compiled by that cause code. For example, there is a specific cause code (5009) for "other inlet air problems."

Figure 107b: Causes of ERCOT Generating Units (by Fuel Type) that Experienced Outages due to Low Frequency or High Rate-of-Change of Frequency Conditions During February 15 Frequency Decline/Recovery Condition

Fuel Type	MW	Cause
Coal	933	At 01:55 grid frequency began to quickly increase from a low of 59.3 Hz. Boiler demand began to decrease, turbine valves began to close, and boiler pressure began to rise. The energy from the boiler could not be removed fast enough and boiler pressure increased to a point where the unit is tripped on high boiler pressure.
Combined Cycle	594	Frequency drop caused mass air flow reduction, which caused high pressure superheat tubes' temperature to increase, tripping the unit.
Gas	213	Combustion turbine tripped by automatic voltage regulator on excessive MWs during frequency disturbance.
Gas	105	Gas turbine inlet guide vanes stuck during a low frequency event.
Coal	836	Frequency disturbance caused low boiler circulating water inlet pressure, tripping unit.
Combined Cycle	572	2x1 combined cycle unit tripped due to loss of auxiliary bus during grid frequency disturbance

Recommendation 14: Owners and operators of natural gas production facilities should consider upgrading SCADA controls to improve real-time local monitoring of wellhead sites, which could allow them to incrementally increase or decrease production in response to real-time events. (Winter 2023-2024)

Natural gas production facilities that used updated technology to monitor and control their facilities during the Event were able to manage and assess operational data and develop plans for managing production issues in a more efficient and timely manner. Discussions with production entities revealed that nearly all producers have some basic level of remote monitoring capability, and most producers have some SCADA control capability (e.g., remote shutoff), with some implementing more advanced systems capable of managing flow (both through local and remote flow automation technology) and remote startup. SCADA systems are used in both electric and natural gas infrastructure to communicate between facilities. Advanced SCADA systems[348] exist that can enhance situational awareness by providing infrastructure operators with access to production facilities' real-time, accurate data, and allowing operators to remotely monitor, control and optimize their processes. Among other things, advanced SCADA can:

- maintain and adjust production operations in coordination with downstream processes and systems, including the ability to remotely shut-in and restart production wells;
- provide operational data from the field needed to perform equipment maintenance;
- provide data to ensure personnel, environmental and equipment safety; and
- provide information for third-party logistics necessary to maintain product flow (e.g., water hauling can be scheduled and implemented based on the actual, real-time data –such as when tanks are approaching levels requiring fluid removal from the site –as opposed to pre-determined, static schedules).

With more advanced SCADA capabilities, production facility operators gain more efficient control, including more efficient management of operational issues, as well as more orderly and expedited return of production facilities to operation as system conditions improve. One entity that has implemented an advanced SCADA system across its production operations was able to (1) monitor water levels, which enabled it to prioritize low-water-producing wells and shut in higher-water-producing wells; (2) restart wells remotely during the Event, if a well shut down due to certain non-freeze-related causes; (3) control volume/flow from the wells to maintain proper line pressure for the downstream facilities to mitigate production equipment freeze-offs; and (4) more effectively return production to normal by using remote startup.

As entities implement advanced SCADA technologies, they need to develop mitigation plans to respond to weather-related issues that could impair access to SCADA systems, including such considerations as ensuring availability of power for the instrumentation and controls/electronics equipment (e.g., securing additional/spare batteries) and ramping up the capacity of maintenance, field operations and control room personnel to respond in advance of emergency situations.

<u>Recommendation 15</u>: State, federal and local authorities should consider developing and/or enhancing existing emergency centers, using gas and electric coordination/information sharing (see Key Recommendation 7), in preparation for and during extreme weather events, similar to the Department of Homeland Security's Fusion Centers.[349] These centers

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348 The Team does not advocate for any particular products but notes that cloud-based, scalable SCADA systems exist that promise to allow the collection of remote data in real time and allow operators to run less-efficient wells only a few times a year, among other functions https://www.automationworld.com/products/control/news/13319708/cloudbased-scada-drills-in-on-oil-wells

349 https://www.dhs.gov/fusion-centers/. Also, the Department of Energy's Office of Cybersecurity, Energy Security and Emergency Response, the mission of which is to "respond to and facilitate recovery from energy disruptions in collaboration with other Federal agencies, the private sector, and State, local, tribal, and territory governments," would likely participate in this effort. *See* https://www.energy.gov/ceser/office-cybersecurity-energy-security-and-emergency-response ; State, Local, Tribal, and Territorial (SLTT) Program | Department of Energy.

could facilitate federal, state and local coordination to enhance the reliability of the Bulk Electric System and natural gas infrastructure in areas including, but not limited to:

- **communication and coordination with, and mutual assistance to, natural gas and electric infrastructure entities;**
- **waiving state or federal laws such as the Clean Air Act (to help backup/dual-fuel units run for longer times) or Jones Act (to allow transportation of U.S.-sourced liquefied natural gas between U.S. ports and enable domestic use);**
- **issuance of Motor Carrier Safety Administration – Regional Emergency Declarations,**
- **Department of Energy Federal Power Act Section 202(c) use for Emergency Waivers ("Secretary of Energy may require by order temporary connections of facilities, and generation, delivery, interchange, or transmission of electricity as the Secretary determines will best meet the emergency and serve the public interest");**[350]
- **highway/road access to natural gas infrastructure (e.g., for removing water or other liquids from wellheads or mitigating damage from freezing); and**
- **Reliability Coordinators, Balancing Authorities, Transmission Operators, Generator Operators, and natural gas infrastructure entities jointly developing, facilitating, and participating in regional-based natural gas-electric extreme weather scenario operations training drills (factoring in the above-listed areas) in preparation for extreme weather events and using the results of those drills to improve emergency operations. For example, the results of the drills could help to establish clear roles and responsibilities, identify and prioritize tasks, improve emergency communication, and improve implementation of emergency operations plans. (Winter 2022-2023)**

This Recommendation builds on Key Recommendation 7, which seeks to establish a forum to build greater cooperation and communication between natural gas infrastructure and BES entities. The reliability of the BES is of critical importance to all sectors of society—commercial, industrial, retail, public safety, communications, etc. This Recommendation recognizes that maintaining the reliability of the BES during extreme cold weather and freezing precipitation like that experienced during the Event can require action by Federal, state, and local entities. DOE activated its emergency response team at the onset of the Event and coordinated with industry, interagency, and state entities to provide situational awareness and support restoration efforts.[351]

Recognizing that emergency response resources are finite, setting priorities is critical. For example, a state or county may want to forego clearing roads in certain areas to prioritize sending crews to clear and treat roads that allow access to natural gas and electric infrastructure facilities. Truly effective emergency response is more than just bringing the right people together. An overall regional

[350] *See* DOE's Use of Federal Power Act Emergency Authority | Department of Energy, *see also* Federal Power Act Section 202(c) – ERCOT, February 2021 | Department of Energy – list (and links) of emergency order issued to ERCOT in February 2021 along with subsequent compliance filings and lists of generators.

[351] *See* DOE Office of Cybersecurity, Energy Security, and Emergency Response, at https://www.energy.gov/ceser/february-2021-extreme-weather-incident.

emergency coordinator, tasked with quickly developing a response strategy across federal, state, and local agencies and response teams for the emergency condition, would greatly enhance the chances of success during a future event. An important first step would be identifying responsibility for establishing the control center, which would have the ability to share real-time information across sectors. A successful strategy would identify priorities for restoring electric and natural gas infrastructure. The existing emergency center constructs could be enhanced to include the areas that are listed above in the Recommendation. Once the agencies and entities have established their coordination relationships, the Team recommends that the appropriate entities, including RCs, BAs, TOPs, GOPs, and natural gas infrastructure entities, perform regional-based natural gas-electric extreme scenario operations training drills to assist in identifying priorities and restoration steps and practicing their execution.

Recommendation 16: Balancing Authorities should have staff with specialized knowledge of how weather impacts load, including the effects of heat pump backup heating and other supplemental electric heating. Balancing Authorities should also broaden the scope of their near-term (seven-days prior to real-time) load forecast to include multiple models and sources of meteorological information to increase accuracy and should consider regional differences within their footprints. (Winter 2022-2023)

Electric heat pumps provide a significant portion of the residential heating load in the southern U.S. Heat pumps have a rated outdoor operating temperature, which is the minimum temperature at which the unit will efficiently operate. As temperatures drop, the heat pump is able to extract less heat from the ambient air, requiring more electricity to generate the quantity of heat (BTUs) it would at warmer temperatures. During severe cold weather, heat pumps become ineffective and those homes must rely on auxiliary (aux.) electric resistance heating instead. Figure 108, below illustrates standard behavior for air electric heat pump and auxiliary heat for an example older residential home.[352] As seen in the figure, as temperatures decline below zero degrees Celsius (32 degrees Fahrenheit), "Aux. Heating" is triggered to provide home heating needs. The hourly electric demand in kilowatts increases sharply as temperatures decline. Below -10 degrees Celsius (14 degrees Fahrenheit), the home heating demand due to auxiliary heating as seen in Figure 108 ranges from two to nearly four times the demand that it was at 32 degrees Fahrenheit.

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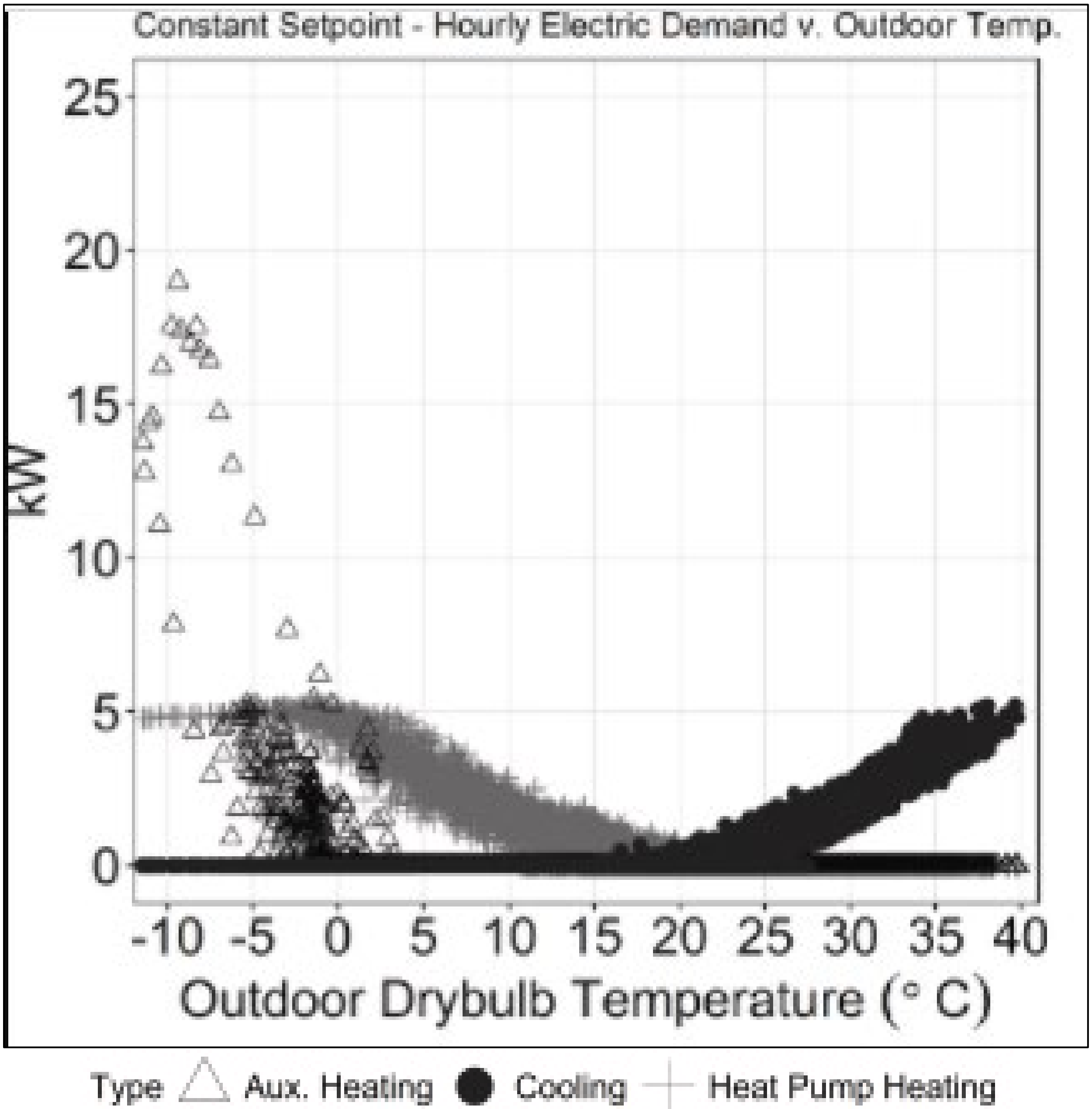
[352] Philip White et al., *Quantifying the impact of residential space heating electrification on the Texas electric grid,* 298 Applied Energy 1, 1-11 (2021); https://www.sciencedirect.com/science/article/pii/S0306261921005559?via%3Dihub

Figure 108: Air-Source Residential Heat Pump Hourly Electric Demand Versus Outdoor Temperature, with Auxiliary Heating Demand



BA staff, especially those in southern areas with substantial electric heat pump load, need to understand how changes in weather can be reflected in the above-illustrated auxiliary heating demand characteristics as supplemental heating sources are used during cold weather.

Selecting multiple weather sources for information is critical to the accuracy of load forecasting, given the sensitivity to substantial increases in heating load for every degree drop in temperature, as seen in Figure 108, above. Accurate near-term load forecasts allow for the proper scheduling of fuel supplies, commitment of generation, scheduling of interchange and scheduling of maintenance activities. BAs should use multiple sources of meteorological data and ensure that the data they receive reflects the regional differences within their footprints (e.g., MISO South, southern SPP). BAs should input this data into multiple models to provide the most accurate near-term load forecasting and cross-check the results.

Recommendation 17: In performing their near-term load forecasts, Balancing Authorities should analyze how intermittent generation affects their ability to meet the peak load (including the effects of behind-the-meter intermittent generation) (for the entire footprint as well as sub-regions, such as MISO South and SPP's southern region), especially if peak load cannot be met without variable resources. Balancing Authorities should consider performing a 50/50 or 90/10 forecast for renewable resources three-to-five days before real time. (Winter 2022-2023)

The near-term weather forecast inputs for all three BAs in the Event Area differed from actual weather forecasts, especially for longer-lead times (i.e., three-to-five days ahead of the operating day). Their common short-term weather forecast inputs (dry or wet bulb temperature), dew point and humidity, wind speed and chill, cloud cover, solar irradiance or sunshine minutes, and precipitation) were found to possess larger uncertainty for the longer lead-time forecasts. By introducing probabilistic methods for these weather inputs, entities will better be able to take into account weather forecast risk. BAs should analyze a range of forecast scenarios for each of the winter weather inputs for forecasting both the total load and net load (effects of behind the meter intermittent generation) forecasts, as well as for their intermittent resource forecasts. Examples of winter weather forecast uncertainty scenarios for analysis three to five days ahead may include:

- for total load forecasts:
    - High wind, lower-than-forecast temperature scenario, and
    - Low wind, higher-than-forecast temperature scenario;
- For net load and resource intermittent generation/resource capability uncertainties:
    - High wind, high solar, higher-than-forecast temperature scenario, and
    - Low wind, low solar, lower-than-forecast temperature scenario.

Probability distributions for each of the weather inputs can be selected based on historical winter weather conditions, including extreme winter weather conditions (e.g., develop 50/50 and 90/10 uncertainty forecasts). Using a probabilistic approach to the three-to-five day before real time winter weather forecasts for load and intermittent resources will enable BAs to quantify risk and develop operating plans that better plan for uncertainty.

Recommendation 18: Independent System Operators/Regional Transmission Organizations and/or state public utility commissions should consider providing incentives for additional demand-side management resources that could be deployed in a short period of time (i.e., 30 minutes or less), especially to replace unplanned outages or derates of generating units, and where resources are most likely to be needed during times of short supply (e.g., the southern portions of MISO and SPP footprints, other southern areas that could lose generating units during extreme cold). They should also consider how to better educate retail customers on steps they can take to help alleviate the need for load shed during extreme weather events, and how to effectively alert customers during emergencies. (Beyond winter 2023-2024 but as soon as possible)

Demand-side management or "demand response" is not a new approach to reducing load during events where electricity supply margins are narrow. The consequences of the extended and widespread firm load shed in ERCOT showed the limits of relying entirely on mandatory firm load shed in such an emergency. To prepare for the possibility of a similar event requiring large amounts of firm load shed, this Recommendation suggests that ISOs/RTOs and/or state public utility commissions pursue additional voluntary demand response programs/resources that would enable grid system operators to quickly respond during grid emergencies, as well as potentially lessen the amount of firm load shed and the durations of the outages. One possibility would be a program that could cycle outages only to certain home appliances, instead of taking out entire circuits, as happened during the Event. ISOs/RTOs would need to coordinate with electric service providers (TOPs and DPs) for program development and implementation. Public utility commissions play a role, not only in structuring incentives for demand response products, but also in educating retail electricity customers about the risks and rewards of participating in demand-side management programs, and how to minimize the need for firm load shed.

<u>Recommendation 19</u>: State public service/utility commissions or legislatures should consider retail-level incentives for energy efficiency improvements. Such incentives could include energy efficiency audits and subsidizing energy efficiency measures with public funds. (Beyond winter 2023-2024 but as soon as possible)

One way to reduce load during extreme cold weather is to increase the ability of the housing stock to withstand the ambient temperatures through energy efficiency measures such as increased insulation, weather-stripping, energy-efficient windows and doors, etc. Another report on the Event recommended increasing energy efficiency retrofits for low-income and multi-family housing across Texas.[353] A similar pre-existing program is EmPower Maryland, a legislatively-mandated program which began in 2008 and met its goal of reducing per capita electricity usage and peak demand by 15 percent by 2015. "Programs include lighting and appliance rebates, HVAC, Home Performance with Energy Star, Energy Star New Homes, combined heat and power, and other efficiency services and/or measures for homes, businesses and industrial facilities. Natural gas offerings are [also] available to eligible . . . customers." Finally, low-income customers in Maryland can participate in the Low Income Energy Efficiency Program, which "assists low-income households with installation of energy conservation measures in their homes with zero out-of-pocket expenses."[354] Each state can assess how efficiently its housing stock is using the energy it consumes during an emergency like the Event and can decide whether investments like those envisioned by the Wood report or implemented in Maryland to reduce its peak demand are a worthwhile use of incentives.

<u>Recommendation 20</u>: Adjacent Reliability Coordinators, Balancing Authorities and Transmission Operators should perform bi-directional seasonal transfer studies, and sensitivity analyses that vary dispatch of modeled generation to load power transfers to reveal constraints that may occur, to prepare for extreme weather events spanning multiple

[353] Recommendation 2-3 in the June 3, 2021 report by former FERC Chair Pat Wood III and several former PUCT members, https://www.cgmf.org/blog-entry/435/REPORT-%7C-Never-Again-How-to-prevent-another-major-Texas-electricity-failure.html
[354] https://www.psc.state.md.us/electricity/empower-maryland/

Reliability Coordinator/Balancing Authority areas like the Event. Such studies should include transmission limits on exports/imports from neighboring areas during stressed conditions, and unusual flow patterns similar to the patterns documented during the Event (east-to-west flows versus normal west-to-east, import flows into and through MISO of well over 10,000 MW) (or other unusual flows seen during extreme winter weather events for the entities performing the studies). The studies should also consider sub-areas or load pockets which may become constrained. The study results can be used to create operator training simulator (OTS) training scenarios. (Winter 2022-2023)

During the Event, RCs, BAs, and TOPs in the Eastern Interconnection reported observing greater-than-normal and abnormal export/import transfers between RC Areas and across their internal transmission systems. Throughout the Event, as each entity continued to maintain stability and reliable operations of its respective system, entities also provided as much assistance to their neighboring systems as possible without sacrificing system reliability. MISO reported a particular moment during the Event when it recorded approximately 13,000 MW of total power flowing into its footprint from adjacent BAs east of its footprint (east-to-west power flows) to aid in meeting winter peak load conditions and alleviating generation shortfalls. This pattern differed from what MISO typically experiences, which is west-to-east power flows due to exports from MISO to BAs east of their footprint (e.g., PJM[355]). The recommended transfer studies and analyses should model high transfers at high seasonal load conditions, to levels at which constraints cannot be fully alleviated without emergency measures (e.g., greater than 10,000 MW for MISO and SPP).[356] The results of these studies should be used for operations preparedness, including to develop new operating procedures for the abnormal flows and conditions modeled, as well as incorporated into system operator drills.[357]

<u>Recommendation 21</u>: Reliability Coordinators, Transmission Operators[358] and Distribution Providers, should regularly, at least once annually, perform Operator Training Simulator simulations, if available, of firm load shed scenarios, to train system operators to administer rotating load shed, avoid cascading outages and system collapse, and protect critical natural gas infrastructure customers. Scenarios should include extreme scenarios similar to the Event, which require rotating load shed and system restoration. (Winter 2022-2023)

Manual load shed is not a task which system operators perform daily, but it is critical to perform well when needed. As the Event demonstrated, system operators may be faced with situations beyond anything they ever expected. Frequent training in the basics as well as extreme scenarios like the

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355 While PJM was providing assistance to MISO and other adjacent BAs, it observed an all-time record net export transfer across connecting tie lines of approximately 15,700 MW.

356 This Recommendation is similar to Recommendation 8 from the 2018 Report (at page 95) and the Team recommends that BAs and RCs with seams/adjacent BAs and RCs review the two Recommendations together.

357 The models, studies and operations should incorporate established facility ratings and associated System Operating Limits based on ambient temperature conditions that would be expected during high seasonal load conditions. *Id.,* Recommendation 9, page 96.

358 In some areas, Transmission Owners are involved in manual load shedding, and should be included in this Recommendation.

Event will help operators be as prepared as possible for the unexpected. System operators need to practice shedding load, rotating the load shed, restoring load, and protecting critical natural gas infrastructure customers from being deenergized. Once the development of the firm load shed scenarios is complete, system operators should test these scenarios in a training environment through use of simulation tools, incorporating control room applications which assist operators in performing automatic rotation of load. Including scenarios similar to the Event in training and simulation tools would allow larger load shed scenarios to be better coordinated and minimize potential impacts in future events.

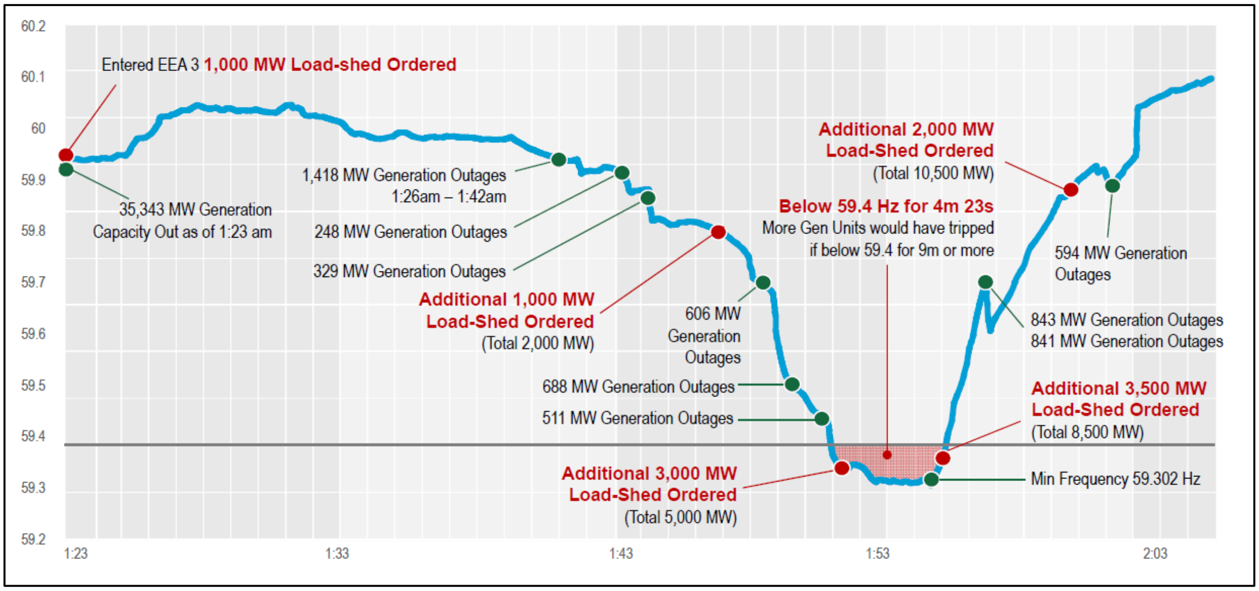
Recommendation 22: Planning Coordinators, Transmission Owners and Transmission Operators should coordinate with Generator Owners/Generator Operators to ensure that generating units are not tripped by time-delay protection systems before the first step of underfrequency load shedding is deployed. This coordination may require an underfrequency load shedding settings change to increase the first-step frequency, as well as notification to Balancing Authorities. The Regional Entity should review any changes proposed by the Planning Coordinator for (1) consistency with Standard PRC-006-5 - Automatic Underfrequency Load Shedding, and (2) whether a revision of, or regional variance from, Standard PRC-006-5 is warranted. (Winter 2023-2024)

ERCOT Nodal Protocols and NERC Reliability Standards[359] allow generators to automatically trip offline, or automatically shut down and disconnect from the grid, if the grid frequency drops to 59.4 Hz or below for more than 9 minutes. During the early morning hours on February 15, ERCOT's system frequency was less than 59.4 Hz for over four minutes, but remained above the first step of underfrequency load shedding (59.3 Hz).

If ERCOT's system frequency had remained below 59.4 Hz, but above 59.3 Hz for another four and a half minutes, a potentially large block of generation could have tripped by underfrequency relays. Consequently, the grid was within minutes of a much more serious and potentially complete blackout on the morning of February 15. See Figure 109, below.

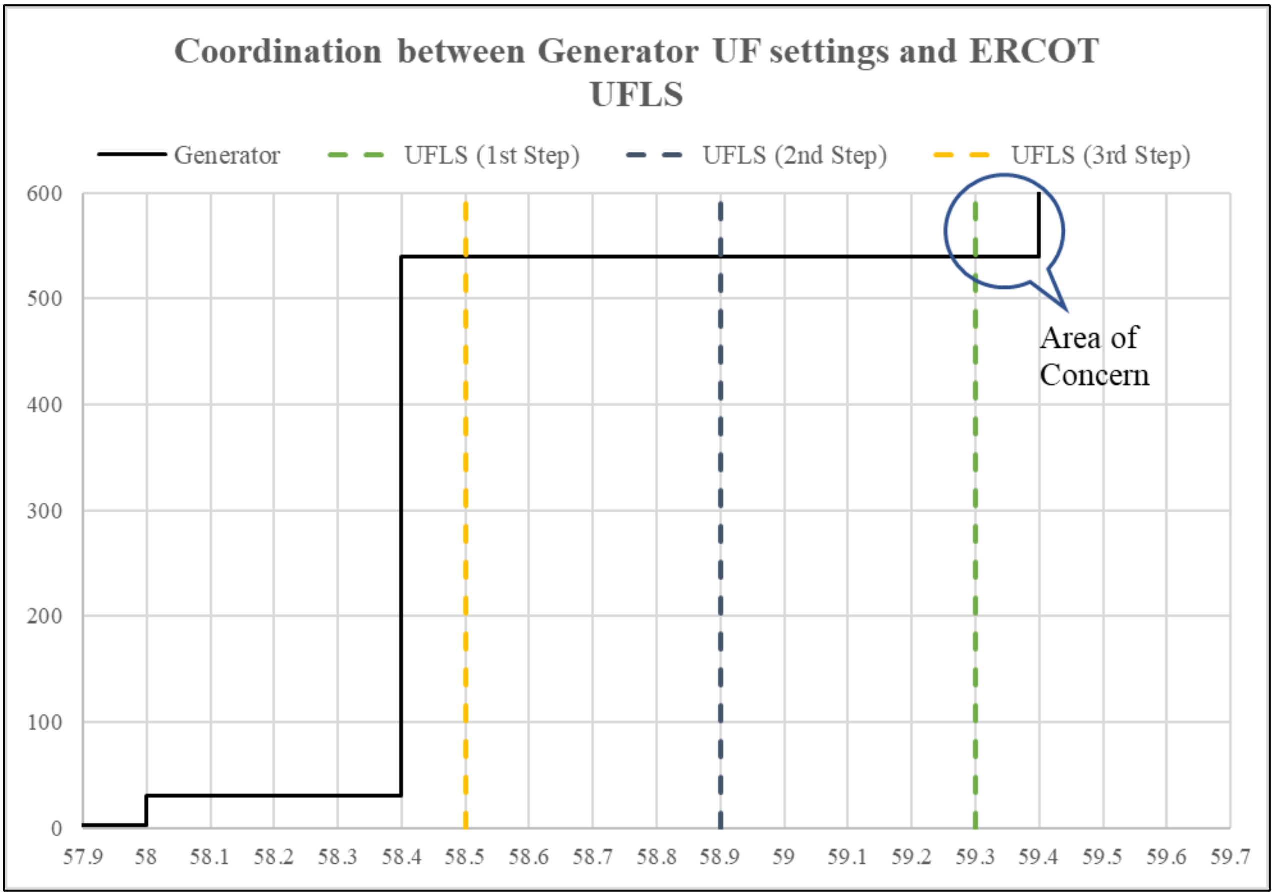
[359] PRC-024-2 – Generator Frequency and Voltage Protective Relay Settings.

Figure 109: ERCOT System Frequency, February 15, 1:20 - 2:05 a.m.



As shown in Figure 110 below, load is typically tripped by underfrequency relays at setpoints higher than the prescribed generator underfrequency relay settings required by NERC Reliability Standard PRC-024. This practice is necessary to protect generators from low frequency condition and to minimize the risk of exposure of generating units to harmful vibrations and heat that can damage generation equipment if operating at low frequency for too long. The exception to this practice is the range between 59.3 Hz and 59.4 Hz in ERCOT, as shown in Figure 110. The coordination between generator and load underfrequency tripping in the 59.3-59.4 Hz range may exacerbate a declining frequency condition within ERCOT during BES disturbances. Therefore, a review of the coordination between current UFLS and generator frequency protection settings in ERCOT may be warranted.

Figure 110: Coordination between Generator Frequency Relays and ERCOT UFLS



<u>Recommendation 23</u>: **Balancing Authorities, Reliability Coordinators and Transmission Operators should amend their outage and/or emergency operations procedures to reduce the time that Generation Owners/Generation Operators and Transmission Owners have to report generation and transmission derates and outages during declared emergency situations. This will better allow Balancing Authorities and Reliability Coordinators to identify trends (e.g., trends in facility outage or derate causes and magnitudes) during events where grid conditions are rapidly changing, to forecast future conditions and to prepare for potential system operator actions. The Balancing Authorities and Reliability Coordinators should also specify the mechanism by which the outages should be updated (e.g., phone call, system updates and outage tools). (Winter 2022-2023)**

Transmission and BA and RC system operators rely on timely and accurate data for continued situational awareness and to support real-time operating decisions to maintain the stability and reliability of the BES. This exchange of data becomes more critical during extreme or abnormal operating conditions when it is necessary to implement emergency operating procedures.

For example, during the Event, as generating units within the ERCOT, SPP and MISO South were rapidly tripping or experiencing derates (e.g., section III.C.4.b - ERCOT Operator Actions: Maintaining Frequency Despite Generation Outages to Prevent Grid Collapse), owners and operators of generating units (e.g., QSEs in ERCOT, GOs/GOPs in SPP and MISO South) needed to provide up-to-date information to assist the BA system operators in determining the need for operator actions. While much of the BA system operators' data is continually updated automatically in real time/every few seconds (e.g., system frequency, actual generating units' MW outputs, tie-line MW flows) to provide situational awareness, data that was manually-updated, including changes in Physical Responsive Capability of generating units and additional information about outages (e.g., reason for outage, expected length of outage), was not manually updated by the GOs/GOPs frequently enough.

Along with the need for BAs to have an accurate status and forecast of available generating units' capabilities and availabilities,[360] RCs and TOPs need to have an accurate status and forecast of transmission facilities' capabilities and availabilities. The Event triggered numerous transmission facility outages, causing TOs to submit a large volume of manually-updated information (as with GOs/GOPs, this information included causes of outages and estimates of restoration time).

While requiring decreased turnaround times for providing manually-updated information makes sense, BAs and RCs, in conjunction with GOs/GOPs and TOs, should also implement automation to eliminate manual updates where possible. For example, ERCOT could implement a method to automatically reassign a tripped or derated generating unit's share of Physical Responsive Capability to other online generating units, so that the total Physical Responsive Capability would remain accurate.

[360] "It is critical for ERCOT [BA operators] . . . to have an accurate value of PRC at all times as well as an accurate forecast of available generation capability and availability." ERCOT Nodal Protocol Revision Request, Number 1085 (June 30, 2021) Nodal Protocol Revision Request (NPRR) 1085 (proposing to require resources including generating units to update their status within five minutes at the latest).

VII. Recommendations for Further Study

<u>Recommendation 24</u>: Federal and state entities with jurisdiction over natural gas infrastructure should cooperate to further study and enact measures to address natural gas supply shortfalls during extreme cold weather events,[361] including:

- **possible investments in strategic natural gas storage facilities, which could be located to serve the majority of pipelines supplying natural gas-fired generating units, and preserved for use during extreme cold weather events;**
- **possible financial incentives for the natural gas infrastructure system necessary to support the Bulk Electric System to winterize or otherwise prepare to perform during extreme cold weather events;**
- **possible options for increased regasification of Liquid Natural Gas (including possible Jones Act waivers); and**
- **market/public funding for Generator Owners/Generator Operators to have firm transportation and supply and invest in storage contracts. Such funding may need to finance the infrastructure (e.g., pipeline or storage expansion) necessary to provide additional firm transportation capacity, because many existing pipelines were financed and constructed to serve Local Distribution Companies and may not have sufficient additional firm capacity. Because many pipelines were financed and constructed to serve Local Distribution Companies and may not have sufficient existing firm capacity to support an increase in demand from Generator Owners/Generator Operators, studies could also examine whether additional infrastructure would be needed to meet that demand.[362] (Winter 2023-2024)**

The Event demonstrated the significant impacts a natural gas supply shortage can have, contributing to billions of dollars in damages and over 200 deaths. This Recommendation suggests further study, followed by state and/or federal entities with jurisdiction over natural gas infrastructure determining whether it might be cost-effective to invest in preventive measures to address some of the issues that played a central role in the Event, such as natural gas production declines or the contractual limits that resulted in some natural gas-fired generating units being outaged or derated. The Team suggests a few topics for consideration by the policymakers, but does not intend to limit the topics for consideration by those studying the natural gas supply shortfalls during cold weather events. Regulations or incentives could be used to encourage more natural gas producers to operate during freezing weather rather than performing preventive shut-ins. Incentives could be used for long-term improvements in natural gas infrastructure facility winterization, or in the short term to prepare for a storm by procuring needed supplies or supporting additional staffing. Policymakers could also consider how to encourage long-term investment into more natural gas storage facilities that are

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[361] These ideas are in addition to the possible topics in Recommendation 7. If the forum from Recommendation 7 determines that a topic needs additional study, it can be moved to this Recommendation.

[362] The Team acknowledges that promoting additional pipeline infrastructure may be contrary to certain federal and state policy goals.

strategically located, and their capacity reserved, to support natural gas-fired generation. Increased storage volumes could help to stabilize the natural gas market during supply shortfalls. Market or government incentives may also help encourage or support efforts by generating units to procure firm natural gas commodity and transportation contracts.

Recommendation 25: ERCOT should conduct a study to evaluate the benefits of additional links between the ERCOT Interconnection and other interconnections (Eastern Interconnection, Western Interconnection, and/or Mexico) that could provide additional reliability benefits including:

- **increased ability to import power when its system is stressed during emergencies, and**
- **improved black start capabilities. (Winter 2023-2024)**

Recommendations 25 and 26, below, both arose from observations about the performance of ERCOT's black start units during the Event. "Black start" refers to restarting the system after a major portion of the electrical network has been de-energized, and generators that have black start capability are those that can be started independently and without external power. ERCOT does not have any synchronous connections to the Eastern Interconnection, Western Interconnection, or Mexican grid. ERCOT's Interconnection has approximately 1,220 MW of asynchronous direct current ties to SPP (820 MW) and Mexico (400 MW). Recommendation 25 suggests the possibility that, in a similar event, ERCOT may not be able to facilitate a re-start of the grid given the combined unavailability of black start and natural gas-fired generating units. Thus, it recommends that ERCOT study the benefits of additional links between ERCOT and the other Interconnections.

ERCOT's study of additional links should take into account simultaneous extreme system conditions on adjacent systems to determine the feasibility of transferring imports over the transmission systems in the adjacent interconnections, and should identify any system enhancements needed to support the potential new links.[363] This study could potentially incorporate data or findings from the studies prepared in response to Recommendation 20 (perform bi-directional seasonal transfer studies).

Additional connections to the Eastern and Western Interconnections would enable ERCOT to increase its ability to import power when its system is stressed during emergencies, such as unexpected generating unit outages during extreme weather. Connections to the Eastern and Western Interconnections would also enable ERCOT to facilitate a restart of its interconnection using external transmission sources, in addition to its existing black start restoration process. Having access to additional imports could prove crucial if ERCOT experienced a blackout and had multiple black start generating units outaged, as was the case during the Event (see Recommendation 26, below). As part of its Roadmap to Improving Grid Reliability, ERCOT has a university research agreement to "assess the potential costs and benefits of increased transmission

[363] See 2018 Report, Recommendation 8.

both internal and external to ERCOT and increase coordination with other power regions," with initial results expected in first quarter 2022.

<u>Recommendation 26</u>: A joint FERC-NERC-Regional Entity team should study black start unit availability in the ERCOT footprint during cold weather conditions. The scope of the study should include:

- **an evaluation of ERCOT's existing black start restoration plan, including a review of potential single points of failure related to natural gas system dependence;**
- **the need for ensuring that generating units with dual-fuel capability providing black start service have appropriate fuel storage (as determined by the Balancing Authority);**
- **the need for requiring additional fuel storage due to import constraints;**
- **the need for Balancing Authorities to incorporate generating units' cold weather preparations into the qualification process for certifying generators as black start units; and**
- **the need for including a requirement for black start generators to test their fuel-switching capabilities seasonally. (Winter 2023-2024)**

Recommendations 25 and 26 both arose from observations about the performance of ERCOT's black start units during the Event. ERCOT procures black start resources every two years. ERCOT currently has a total of 28 (primary and alternate) black start resources within its footprint (100 percent use natural gas as their primary fuel, while some have an alternate fuel as well). At approximately 1:45 a.m. on February 15, six of the 28 black start capable units representing 14 percent of black start capacity were unavailable (four units totaling 169 MW of capacity were either forced outaged or failed to start and two units totaling 227 MW of capacity were derated by 73 MW). The greatest risk of a blackout was during this period, when ERCOT's system frequency was rapidly declining. Had a total blackout of the ERCOT system occurred during that time, the unavailability of black start resources would have hampered ERCOT's ability to promptly restore the system.

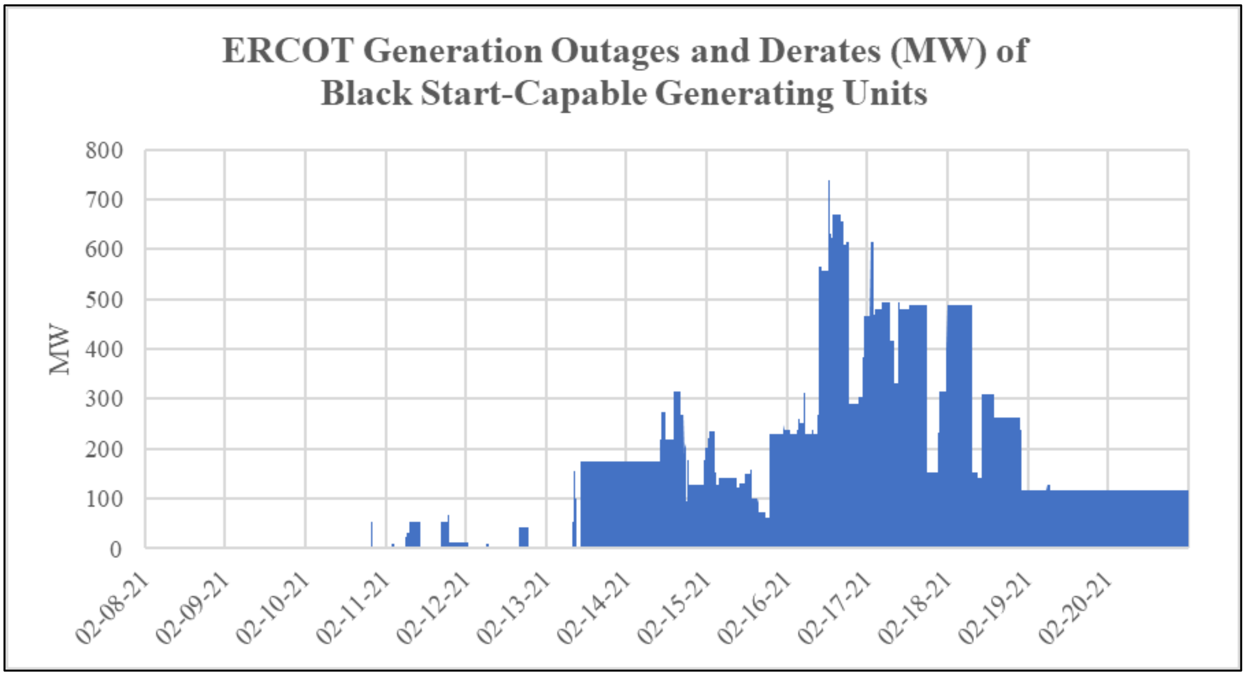
Over the course of the Event, 82 percent of ERCOT's 28 (primary and alternate) black start resources, comprising 1,418 MW out of a total 1,711 MW of black start capacity, experienced an outage, derate, or failure to start at some point. Forty-six percent of ERCOT's primary and alternate black start resources were either outaged, derated or failed to start due to freezing equipment issues (18 percent) or fuel limitations (39 percent) (see Figures 111 – 112, below). While prevention of recurrence of the Event is paramount, the Team also recognizes that ERCOT as a TOP is required to have a feasible system restoration plan, which depends on available and reliable black start resources to accomplish system restoration.[364] The high percentage of ERCOT black start units unavailable during the Event is cause for concern, even more so because ERCOT cannot rely on imports to restore its system in the event of a blackout. A study including the topics suggested by Recommendation 26 would enable ERCOT to improve the reliability of its restoration plan.

[364] *See* Reliability Standard EOP-005-3 – System Restoration from Black Start Resources.

Figure 111: ERCOT Black Start Unit MW Unavailability by Cause

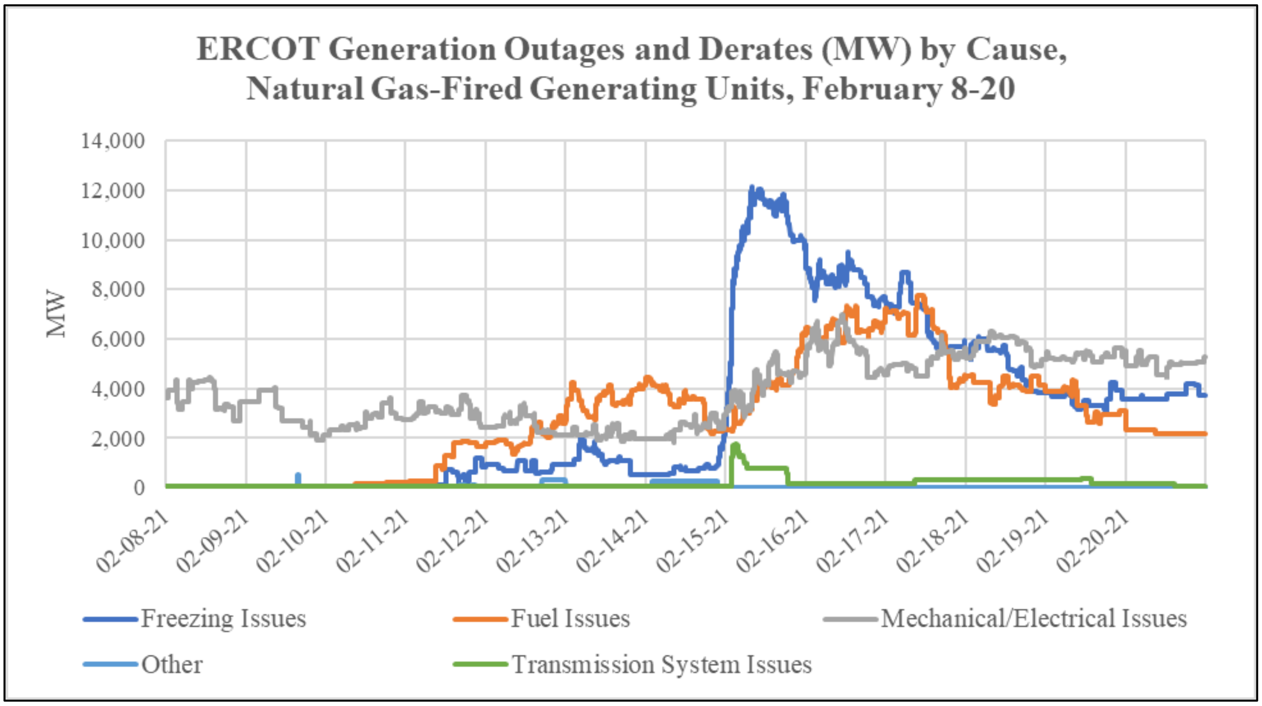
Black Start Unit Type	Freezing Issues	Fuel Issues	Mechanical/ Electrical Issues	Personnel Issues	Transmission System Issues
Gas Only	263	344	1,039	17	34
Gas/Oil	62	1,134	760		
Total	325	1,478	1,799	17	34

Figure 112: ERCOT Black Start Unit MW Unavailability by Date



During the Event, 58 percent of the generating units that experienced unplanned outages, derates or failures to start in ERCOT were natural gas-fired. These 336 units represented 57,780 MW of nameplate generation, and were responsible for 157,244 MW of the total MW outaged during the Event. Figure 113, below, shows how the causes of natural gas-fired generating unit outages and derates in ERCOT changed over time during the Event. Natural gas-fired generating unit outages and derates in ERCOT began with fuel issues starting February 11, and on February 15, when the coldest temperatures began, freezing issues increased especially sharply, but mechanical/electrical and fuel issues also escalated.

Figure 113: ERCOT Generator Outages, Derates, and Failures to Start (MW) by Cause, Natural Gas-Fired Generating Units, February 8-20, 2021



<u>Recommendation 27</u>: Beyond Recommendation 13 (Generator Owners within ERCOT review potential for units to trip due to low frequency or high rate-of-change of frequency conditions), the team recognizes that generating units tripping due to low frequency or high rate-of-change of frequency conditions could occur in the Eastern and Western Interconnections as well. Therefore, the team recommends that FERC, NERC, and the Regional Entities, in cooperation with Generator Owners, study the ERCOT low frequency event and past significant frequency disturbances. The study should consider the potential for protective relay settings associated with generator underfrequency relays, balance of plant relays, and tuning parameters associated with control systems on generating units to trip generating units during low frequency or high rate-of-change of frequency conditions in the other Interconnections, and determine the whether a new Reliability Standard is warranted, or whether other actions can best protect the reliability of the Bulk Electric System. (Winter 2022-2023)

One of the major issues associated with the Event was the low frequency disturbance on the ERCOT system on February 15 shortly before 2 a.m. Although low frequency is a threat to the reliability of the BES by itself, low frequency, or the rate of frequency change, also caused approximately 1,769 MW of coal generation and 2,190 MW of gas generation to trip or derate. For instance, a 933 MW coal unit tripped due to the rapidly-changing frequency on the grid, which affected the boiler controls and caused a high boiler pressure condition. As a result of the outages seen during the Event, the Team became concerned about the coordination of generator frequency protection with UFLS protection. NERC Reliability Standard PRC-024-2 requires generator owners to set protective relays so that generating units remain connected during defined frequency and voltage excursions. For ERCOT, PRC-024-2 requires a first step of generator underfrequency protection of not more than 59.4 Hz for not less than nine minutes. ERCOT experienced approximately four and a half minutes of operations below 59.4 Hz, but above the first step of UFLS protection set at 59.3 Hz. Given the nine-minute time requirement in the PRC-024-2 standard for a setpoint of 59.4 Hz, if ERCOT had remained below 59.4 Hz for an additional four and a half minutes it would have lost approximately 17,000 MW of generation due to UFLS and risked a potential blackout of the entire ERCOT Interconnection.

Generator model validation requirements in the NERC Standard MOD-027-1 require submission of verified turbine/governor models and load control or active power/frequency control models. The minimum frequency excursion criteria in MOD-027-1 is 0.10 Hz (at or below 59.90 Hz) for ERCOT and the Western Interconnection, and 0.05 Hz (at or below 59.95 Hz) for the Eastern Interconnection. Generator models at 59.90 Hz may not necessarily represent a unit's performance at the low frequencies near 59.30 Hz experienced during the Event. More data on generating unit behavior during past frequency disturbances, including the Event, and perhaps a period of additional data collection using a dedicated GADS code as recommended in Recommendation 13, will help to determine the whether a new Reliability Standard is warranted, or whether other actions can best protect the reliability of the BES.

<u>Recommendation 28</u>: Reliability Coordinators, Balancing Authorities, Regional Entities, Transmission Operators, Transmission Owners, Distribution Providers and one or more entities representing U.S. natural gas infrastructure[365] entities should jointly conduct a study to establish guidelines to assist natural gas infrastructure entities in identifying critical natural gas infrastructure loads[366] to manual and automatic load shedding entities, in order for the critical natural gas infrastructure loads to be protected from manual and automatic load shedding. The guidelines should establish identification criteria in a format which manual and automatic load shed entities can readily distribute to natural gas infrastructure entities they serve. Development of the guideline should include determining:

- **whether there is a need to rank the types of critical natural gas infrastructure loads that are protected from manual and underfrequency load shedding for those situations in which the amount of load required to be shed does not allow for rotating load shed; and**
- **a means for periodic review and update of the guideline, to include considering whether the current criteria for identifying critical natural gas infrastructure loads are sufficient to avoid adversely affecting BES natural gas-fired generation. (Winter 2022-2023)**

This Recommendation is necessary to support Key Recommendation 1i, regarding the protection of critical natural gas infrastructure loads. Recommendation 1i would amend the Reliability Standards to require manual and automatic load shed entities, including TOPs, TOs, and DPs, to create and

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365 *See* footnote 29 for the definition of natural gas infrastructure.

366 *See* footnote 278 for the definition of critical natural gas infrastructure loads.

distribute criteria to natural gas infrastructure entities for identifying critical natural gas infrastructure loads.

Although natural gas infrastructure loads that will actually have an adverse effect on BES natural gas-fired generating units if de-energized need protection from manual load shedding, it is equally important not to designate too many natural gas infrastructure loads as critical. Every load that is designated as critical results in a distribution circuit that cannot be used for manual load shedding, increasing the burden on the remaining circuits. Creating effective criteria will require cooperation among entities with knowledge of the grid and entities with knowledge of natural gas infrastructure. Grid entities such as TOPs, TOs and DPs should collectively know which electric circuits serve natural gas infrastructure entities' facilities, which of those circuits are already protected due to other critical loads or automatic load shedding/UFLS, their current critical load identification processes and any current associated criteria for identification within their respective service areas. Natural gas infrastructure entities can obtain information to identify which of their facilities and equipment are most critical to producing, processing, and delivering natural gas to specific BES generating units (identified by the RCs/BAs), and can also assist in translating what could start as highly technical information into criteria that can be easily understood by the target audiences. And, in addition to identifying the BES natural gas-fired generating units within the BAs' respective footprints for the natural gas infrastructure entities, the RCs /BAs can help natural gas infrastructure entities understand how natural gas-fired generating units are committed and dispatched to provide for BES reliability, especially during constrained winter peak conditions.

Figure 114: Table of Recommendations with Assigned Timeframes for Implementation

Recommendation Topic	#	Timeframe for Implementation[367]
Key Recommendations		
Cold Weather Critical Components	1a,b	2023-2024
Account for Effects of Precipitation and Wind	1c	2023-2024
Corrective Action Plans for Freeze-Related Causes	1d	2022-2023
Annual Training on Cold Weather Plans	1e	2022-2023
Operate to Specified Ambient Temperature, Weather	1f	2022-2023
Generator Capacity to Rely Upon during Cold Weather	1g	2023-2024
Generator Compensation Opportunities for Investments	2	2022-2023
Generator Winter Readiness Technical Conference	3	2022-2023
Freeze Protection Inspection and Maintenance Timing	4	2022-2023
Natural Gas Facility Cold Weather Preparedness Plans	5	2022-2023

[367] For mandatory Reliability Standards, implementation means that new and/or revised Standards that address the recommendation are proposed to the Commission for approval within the timeframes listed with the recommendations. In the FERC-approved NERC Rules of Procedure, Appendix 3A Standard Processes Manual, NERC can deviate from its normal process when necessary to meet an urgent reliability issue. *See* https://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx.

Natural Gas Facility Freeze Protection Measures	6	2022-2023
Establish Natural Gas -Electric Reliability Forum	7	2022-2023[368]
Understanding Generator Natural Gas Contract Risks	8	2021-2022[369]
Use of Demand Response - Natural Gas Infrastructure	1h	2023-2024
Protect Identified Critical Natural Gas Infrastructure	1i	2023-2024
Overlap of Manual and Automatic Load Shed/UFLS	1j	2022-2023
Peak Load Forecasts and Reserve Margin Calculations	9	2023-2024
Other Recommendations		
Improve Rotational Load Shed Plans	10	2023-2024
Cold Weather Effects-Mechanical, Electrical Systems	11	2023-2024
Generator Use of Weather Forecasts for Operating Plans	12	2021-2022
ERCOT Generators to Review Low-Frequency Effects	13	2022-2023
Natural Gas Production Facilities SCADA Control	14	2023-2024
Develop or Enhance Emergency Response Centers	15	2022-2023
Improve Near-term Load Forecasts	16	2022-2023
Analyze Intermittent Generation to improve Load Forecast	17	2022-2023
Additional Rapidly-Deployable Demand Response	18	Beyond 2023-2024 but ASAP
Retail Incentives for Energy Efficiency Improvements	19	Beyond 2023-2024 but ASAP
Perform Bi-Directional Seasonal Transfer Studies	20	2022-2023
Operator-Training Rotational Firm Load Shed Simulations	21	2022-2023
Generator Protection Settings/ UFLS Coordination	22	2023-2024
Report Times for Generation and Transmission Outages	23	2022-2023
Recommendations for Further Study		
Measures to Address Natural Gas Supply Shortfalls	24	2023-2024
Additional ERCOT Interconnection Links	25	2023-2024
ERCOT Black Start Unit Reliability	26	2023-2024
Low-Frequency Effects in Eastern, Western Interconnects	27	2023-2024
Guidelines to Identify Critical Natural Gas Facility Loads	28	2022-2023

[368] Implementation for this Recommendation means that the forum has been identified, and the participants and dates for the technical conferences or meetings have been scheduled.
[369] Although the related Reliability Standard is not proposed to be in effect for winter 2021-2022, the Team recommends that GOs voluntarily implement this Recommendation before winter 2021-2022.

APPENDICES

Appendix A: February 2021 Cold Weather Grid Operations Inquiry Joint Team Members

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Appendix B: Comparison of Similar Severe Weather Events[370]

This section compares select extreme cold weather events that have occurred in the U.S. over the past 40 years, to gain understanding of the characteristics of these weather systems and how they can vary, including their temperature variations, their durations, and other weather conditions including precipitation and wind. Five severe cold weather events that impacted south central U.S. and Texas are compared: December 1983, December 1989, February 2011, January 2018, and February 2021. Understanding the characteristics of these weather events are necessary for aiding in the development of cold weather preparedness plans and cold weather protection measures needed for electric and natural gas infrastructure facilities that are critical in supporting bulk-power system reliability - i.e. determining the levels/measures of protection in order to keep facilities operable, maintain their operation throughout the extreme cold weather.

A. Seasonal Timing of Cold Weather Events

In the continental U.S., we commonly think of the winter cold weather months as being December, January, and February. It is also commonly thought that January is the coldest month of those three, and indeed cold weather periods in parts of the U.S. during January are typical. From review of the five extreme cold weather events:

- two events occurred in December,
- one event occurred in January, and
- two events occurred in February.

Two of the five that were the coldest for the longest durations in south central U.S. and Texas occurred the at the earliest and latest times during the winter season as compared to the other events. The earliest that occurred was the December 1983 cold weather event (December 15-30) and the latest was the February 2021 cold weather event (February 8-20). The timing of *when* these extreme cold weather events occurred indicate that being prepared (implementation of infrastructure cold weather preparedness plans and freeze protection measures) for extreme cold weather needs to take place *before* cold weather has been known to occur for the infrastructure/facility locations, and likewise the measures need to remain in place and functional for the entire timeframe that extreme cold weather has been known to occur.

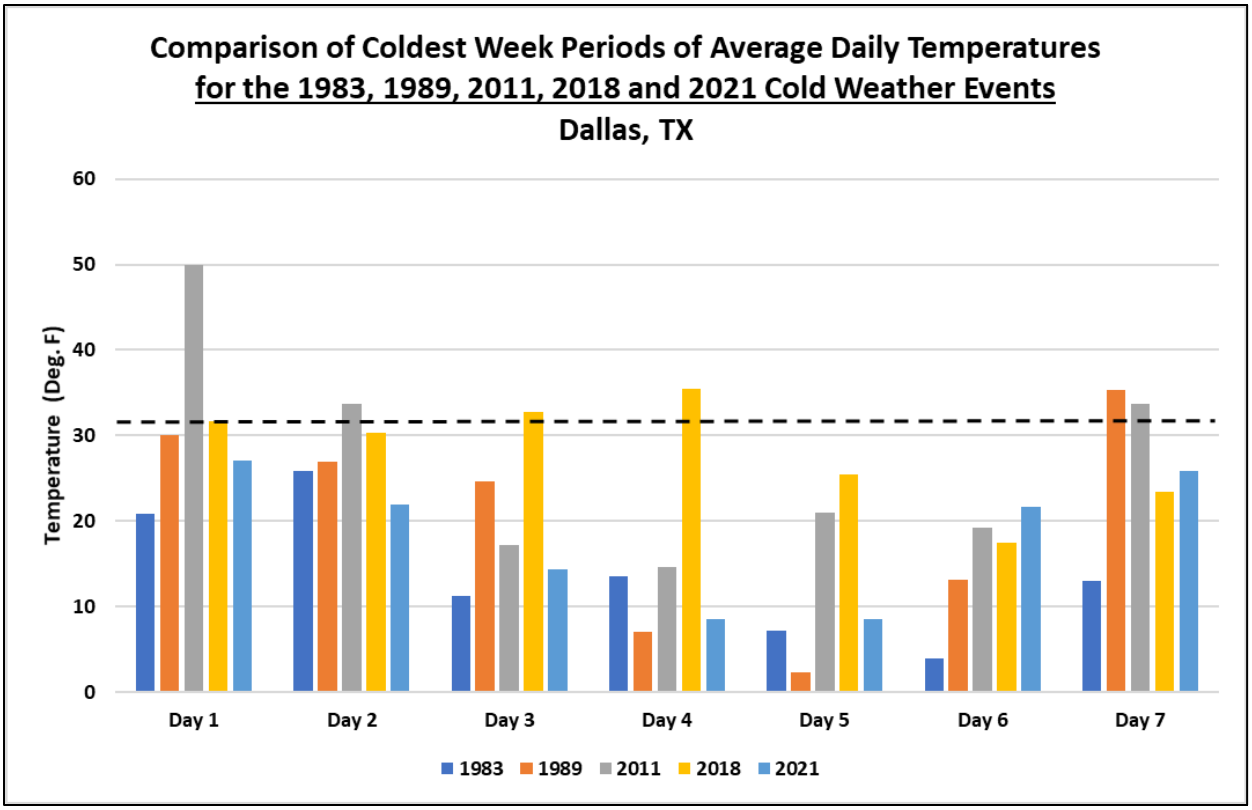
[370] The Team thanks NOAA's National Weather Service – Weather Prediction Center for weather analysis support it provided.

B. Temperature and Duration Comparison

The following charts (Figures 90 – 92) compare average daily temperatures[371] for one-week periods which occurred during each cold weather event for select locations in south central U.S.:

- 1983 cold weather event, week of December 20 – 26
- 1989 cold weather event, week of December 19 – 25
- 2011 cold weather event, week of January 31 – February 6
- Both the cold weather event, week of January 12 – 18
- 2021 cold weather event, week of February 12 – 18

Figure 115: Temperature Comparison – Dallas, TX



371 It is important to recognize that for a given average daily temperature, that there temperatures typically during the nighttime and early morning hours that may be below, and during the daytime that may be above the average daily temperature value. The team recommends extreme cold ambient temperature analysis by infrastructure entities include review of historic minimum temperatures for aiding in determining levels of freeze protection measures.

Figure 116: Temperature Comparison – Houston, TX

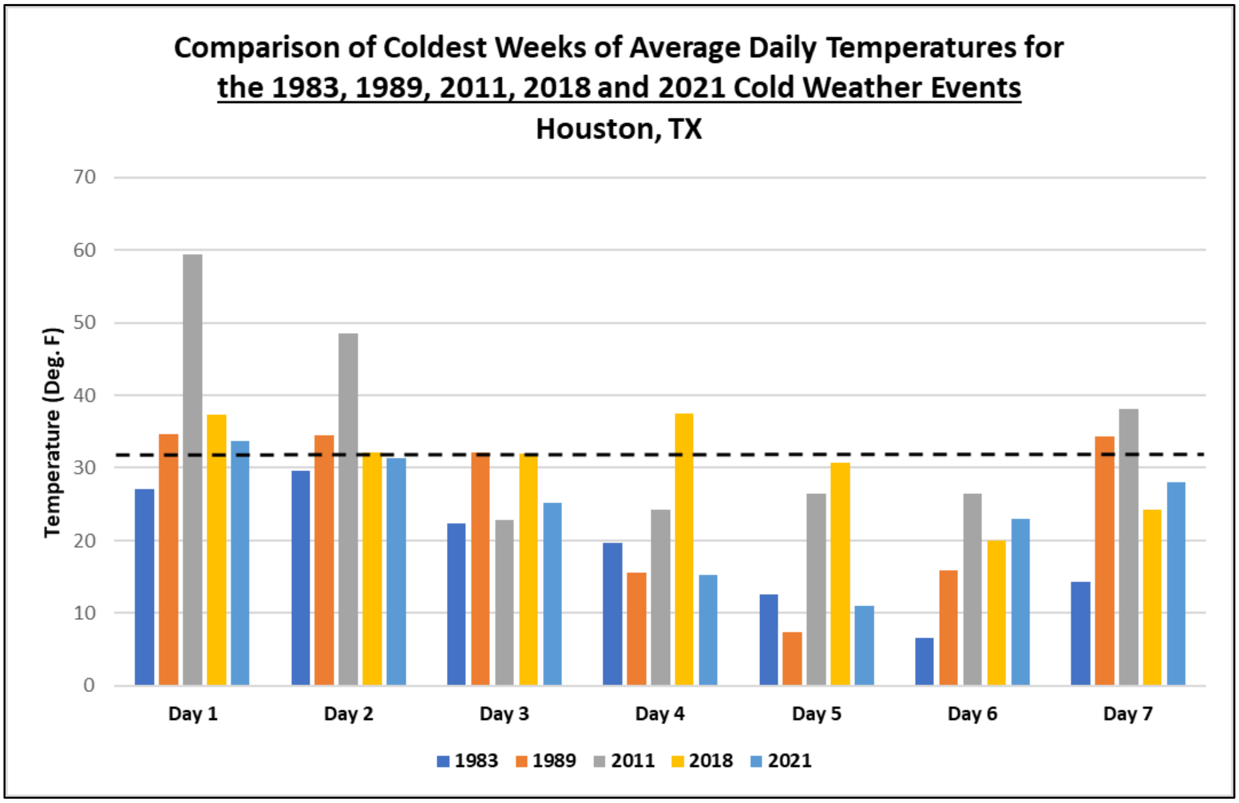
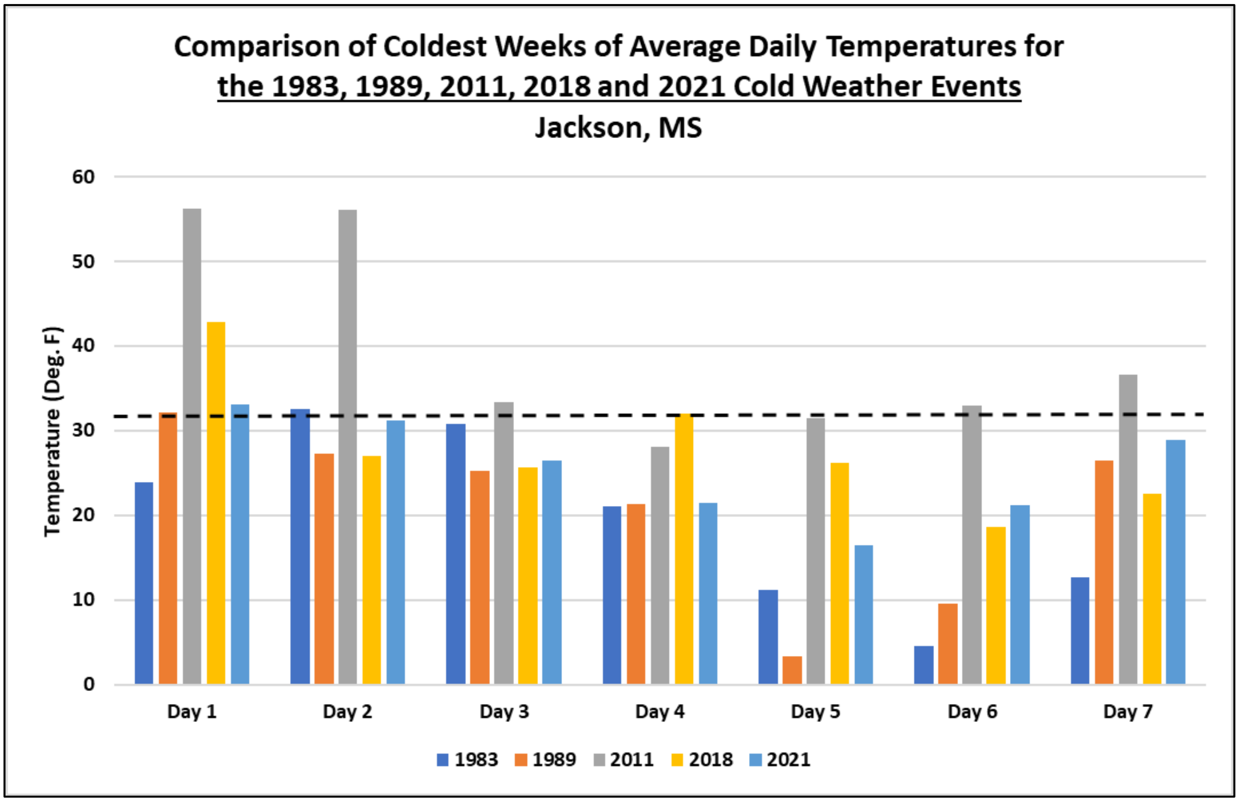


Figure 117: Temperature Comparison – Jackson, MS



The charts above provide the following insights regarding temperatures and durations.

Cold Temperatures

- Dallas, Houston, and Jackson, for at least one of the five events, each experienced at least one day where the **average daily temperature was below 10 Deg. F**, and
- Dallas, for three of the five events, experienced at least one day for each of the week-long periods where the **average daily temperature was below 10 Deg. F.**
- Houston and Jackson, for two of the five events, experienced at least one day for each of the week-long periods where the **average daily temperature was below 10 Deg. F.**
- Dallas and Jackson, for two of the five events, experience at least one day for each of the week-long periods where the **average daily temperature was below 5 Deg. F.**

Duration

- For Dallas, Houston, and Jackson, for all five events, **average daily temperatures were at or below 32 Deg. F for at least three days** out of the week-long periods,
- For Dallas, for three of the five events, **average daily temperatures were at or below 20 Deg. F for three consecutive days**, and
- For Houston and Jackson, for two of the five events, **average daily temperatures were at or below 20 Deg. F for two consecutive days**.

- In comparing below-freezing temperatures and durations, the following table contains other noteworthy statistics and observations about the cold weather events.

Figure 118: Temperature Comparison Statistics and Observations

Cold Weather Event	Duration of event	Low temp.	Noteworthy observations
1983	12.3 days below freezing DFW 6.2 days below freezing Waco, TX 5 days below freezing Houston	5 F at DFW 7 F at Waco Airport -2 F at Glen Rose 2W	7 separate cold fronts during this event
1989	14 nights below freezing over 2-3 weeks in Houston	2 F at College Station 7 F in Houston 14 F in Galveston	Coldest recorded winter for the Galveston/Houston area.
2011	5 days below freezing 12 nights below freezing over 2 weeks in Houston	17 F in Dallas 20 F in Houston	
2018	3 nights below freezing in TX and LA 7 nights below freezing in MS, AR, TN		This event was most severe east of Texas.
2021	6 days, 20 consecutive hours below freezing	6 F in Austin 8 F in Dallas 10 F in Houston	Most similar to 1983 event in long period of cold with multiple fronts affecting a wide swath of the U.S.

C. Precipitation Comparison

This section compares the level of and types of precipitation which occurred during each cold weather event in south central U.S. and Texas. It is noteworthy that for most of the events, freezing precipitation (in form of freezing rain, sleet, and/snow) conditions occurred during the leading edge of each extreme cold weather front, where the colder temperatures followed the freezing precipitation timeframe. Therefore, the precipitation timeframes for the five events below may include days ahead of or may be within the cold temperature week periods in Section B, above:

- 1983 cold weather event (December 15 – 30)
- 1989 cold weather event (December 21 – 24)
- 2011 cold weather event (February 1 – 3)
- 2018 cold weather event (January 14 – 17)
- 2021 cold weather event (February 11 – 19)

Figure 119: Precipitation Comparison

Cold Weather Event	Precipitation Summary
1983	December 15-16: Severe cold and snow storm (8+ inches) in northern Texas; multiple cold fronts occurred in north Texas through the end of December, with sub-freezing temps and snow lasting throughout the month.
1989	December 21-24: Three severe cold fronts move into Texas; precipitation was minimal with a narrow band of snow north of Austin, Texas. Overall, precipitation was not much of a factor in the southern plains during this cold weather event of 1989
2011	February 1-3: Widespread heavy snow with blizzard conditions, combined with significant freezing rain and sleet ranging from northern Texas through the upper Midwest and into New England; snowfall amounts of 10-20 inches were recorded from the Midwest to New England along with high winds; Snowfall in northern Texas was 1-4 inches, with a few smaller areas in north Texas having up to 8 inches.
2018	January 14-17: Winter Storm Inga brought snow and ice to parts of the Midwest, South and Eastern U.S. on January 14-17. The upper Midwest experienced 2-5 inches of snow and the Gulf States from Texas to Alabama experienced 1-2 inches of snow accumulation and icy conditions.
2021	February 11-19: The southern plains experienced three waves of precipitation during a 7 day period; February 11-12: Freezing rain and snow in Texas and severe heavy rain in Louisiana and Mississippi; February 14-16: Heavy freezing rain and snow hits the southern plain states combined with severe cold temps; February 17-19: Addition snow and freezing rain occur across the southern plain states with Oklahoma and Arkansas receiving significant accumulations of snow and ice.

In summary:

- the majority (four out the five) severe cold weather events' characteristics included some form of freezing precipitation (freezing rain and/or snow),
- three of those four cold weather events also included freezing rain precipitation, and
- three of those four cold weather events included significant snowfall for the region.
- Based on the fact that freezing precipitation is likely to occur during extreme cold weather events warrants that freeze protection measures should be weather or water-proofed to mitigate the risks caused by frozen precipitation.

D. Wind Comparison

This section describes the commonalities across some outbreaks of Arctic air across the Southern United States. The graphics show the composite mean wind speeds for a 7-day period, and the tables are a snapshot at designated metropolitan locations. With respect to wind conditions, the February 2021 cold weather event was not as extreme of a weather event when compared to other cold weather events at similar locations, although along the gulf coast, there were stronger wind conditions than at other locations.

Wind conditions during the 1983 cold weather event. During the week of December 20 – 26, there were northerly, north westerly, and north easterly winds at average speeds of 0 – 9 mph in the Southern United States ranging from Texas to the East Coast. On the coldest day of that week, the average wind speeds ranged from 9 – 19 mph with peak wind gusts of 34 mph.

Wind conditions during the 1989 cold weather event. During the week of December 19 – 25, there were northerly winds at average speeds of 0 – 9 mph in the southern United States. In addition, East Texas and Louisiana had average wind speeds that reached up to 9 – 13 mph and over half of the state of Louisiana had average wind speeds that reached up to 13 – 18 mph. On the coldest day of that week, the average wind speeds ranged from 5 – 17 mph with peak wind gusts of 34 mph.

Wind conditions during the 2011 cold weather event. During the week of January 31 – Feb 6, most of the Southern United States had northerly and north westerly winds at speeds of 0 – 9 mph. North and north central Texas had winds at speeds of 9 – 18 mph. On the coldest day of that week, the average wind speeds ranged from 10 – 18 mph with peak wind gusts of 31 mph.

Wind conditions during the 2018 cold weather event. During the week of January 12 – 18, most of the Southern United States had northerly and north westerly winds at speeds of 0 – 9 mph. In addition, there were northerly, north easterly, and north westerly winds at speeds of 9 – 13 mph in East Texas, Arkansas, Louisiana, Mississippi, and most of Oklahoma. Central and West Louisiana had northerly winds at speeds of 13 – 18 mph. On the coldest day of that week, the average wind speeds ranged from 5 – 17 mph with peak wind gusts of 32 mph.

Wind conditions during the 2021 cold weather event. During the week of February 12 – 18, there were north easterly winds at speeds of 9 – 22 mph in Oklahoma, Arkansas, Texas, half of Louisiana, and half of Mississippi. On the coldest day of that week, the average wind speeds ranged from 6 – 19 mph with peak wind gusts of 41 mph. In Dallas, the wind direction shifted throughout the day, ranging from the northwest to the southeast.

Figure 120: Cold Weather Event Wind Speeds (mph) for the Coldest Average Temperature Day for Each Location

Cold Weather Event ->	1983		1989		2011		2018		2021	
	Avg.	Gust	Avg.	Gust	Avg.	Gust	Avg.	Gust	Avg.	Gust
Dallas	19	34	16	34	18	31	17	32	7	21
Houston	13	25	13	28	16	29	10	25	19	38
Lake Charles	12	20	15	28	14	29	5	18	16	41
Little Rock	14	34	7	15	13	24	13	25	6	16
Jackson	12	23	17	22	10	23	10	25	6	19

In summary:

- All five severe cold weather events' possessed moderate[372] wind conditions for the majority of the above locations in south central U.S. and Texas,
- Average wind speeds for each of the five locations across all five events ranged from 10 to 15 mph.
- Average wind gusts for each of the five locations across all five events ranged from 22 to 30 mph.
- Based on the above analysis, substantial wind conditions are likely to occur during extreme cold weather events. This condition warrants that infrastructure/facility freeze protection measures should also be protected to mitigate the risks caused by accelerated heat loss due to wind.

[372] *See* https://www.weather.gov/pqr/wind.

Appendix C: Examples of Alerts and Notices Issued by Electric and Natural Gas Entities During Event

Figure 121: Example Reliability Coordinator (RC) Notice Issued February 12, 3:53 p.m.

Notification

[MISO] MISO declares Conservative Operations for Reliability Coordinator Footprint effective 02/14/2021 12:00 EST

***Declaring Conservative Operations due to extremely cold temperatures and generator fuel supply risks.

The MISO Reliability Coordinator (RC) is declaring Conservative Operations, effective from 02/14/2021 12:00 EST to 02/16/2021 23:59 EST for the following entities: Reliability Coordinator Footprint and instructs that:

- All transmission and Generation maintenance is suspended in the affected area for the duration of the Conservative Operations period, unless such maintenance will result in improved Bulk Electric System (BES) monitoring, control and security. Such maintenance will be coordinated between MISO and the applicable entity. The return to service of equipment on outage should be coordinated between MISO and the applicable entity. MISO Outage Coordination may permit on a case-by-case basis specific transmission maintenance that does not impact the Bulk Electric System.
- Transmission Operators (TOPs) and Generation Operators (GOPs) in the affected area, in coordination with the MISO and their Local Balancing Authority (LBA), are to review outage plans to determine whether any maintenance or testing, scheduled or being performed on any monitoring, control, transmission or generating equipment can be deferred or cancelled.

Figure 122: Example Natural Gas Pipeline Notice Posted February 14, 8:30 a.m.

Northern Natural Gas
A BERKSHIRE HATHAWAY ENERGY COMPANY

Printable Version

TSP Name: Northern Natural Gas Company	**SMS %:** Field 0%, Zone ABC 0%, Zone D 0%, Zone EF 0%
TSP: 784158214	**Post Date/Time:** 02/14/2021 08:30 AM
Notice ID: 058558	**Notice Effective Date/Time:** 02/15/2021 09:00 AM
Notice Type: Operational Alert/Critical Day	**Notice End Date/Time:** 02/16/2021 08:59 AM
Subject: CRITICAL DAY FOR GAS DAY FEBRUARY 15, 2021 – ENTIRE SYSTEM	**For Gas Day(s):** 02/15/2021
Critical: Y	**Notice Status:** Initiate
Location: ALL MARKET AND FIELD AREAS	**Required Response Indicator Description:** 5-No response required
MID / Zone: 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16A, 16B, 17, ABC, D, EF	

Notice Text:

Due to the severe weather conditions experienced in Northern's Market and Field Areas and significant natural gas price volatility, Northern is calling a Critical Day applicable to delivery points located in all Market Area zones and Field Area MIDs effective for the Gas Day beginning at 9 a.m. on Monday, February 15, 2021. The significance of a Critical Day being called is if a shipper takes deliveries from the pipeline in excess of scheduled quantities, such shipper may incur higher penalties as set forth on Tariff Sheet No. 53 and the DDVC rates page on Northern's website .

Northern's system-weighted average wind-adjusted temperature is forecast to be -10 degrees for Monday, February 15, 2021, and is forecast well below normal through the weekend. Northern's normal system-weighted temperature is 20 degrees. Northern is at imminent risk of experiencing reduced receipts at pipeline interconnects in its Market and Field Areas. It is uncertain when this situation will improve. As this situation continues, Northern's pipeline system integrity will be negatively impacted if deliveries are in excess of receipts, resulting in low line pack levels across the entire system. For the weekend trading block that extends from Gas Day Saturday, February 13 through Tuesday, February 16, 2021, the average Northern Demarc and Northern Ventura prices were $231.67/Dth and $154.905/Dth, respectively. The MIP price for February is unknown at this time. The Critical Day penalties are intended to deter any incentive for actual market deliveries to be above scheduled quantities.

Due to cold weather conditions impacting the Market and Field Areas, Northern expects to have limited operational flexibility to accommodate underperformance at receipt points. If underperformance occurs at any receipt points, Northern may be required to allocate these points to actual flowing volumes. Northern will continue to monitor points across the system in order to protect the pipeline's integrity.

Refer to Tariff Sheet No. 291 for information related to Critical Day provisions.

Please continue to monitor Northern's website for updates.

If you have any questions regarding this notice, please contact your marketing or customer service representative.

DDVC penalties are applicable to the bumped shipper's quantity.

Appendix D: Other Charts - Unplanned Generation Outages During Event by Fuel Type (Coal, Natural Gas, Nuclear, Solar, Wind, Other)

Figure 123a: Causes of Unplanned Generation Outages and Derates for Coal-Fired Units (by Number of Outages), Total Event Area, February 8-20

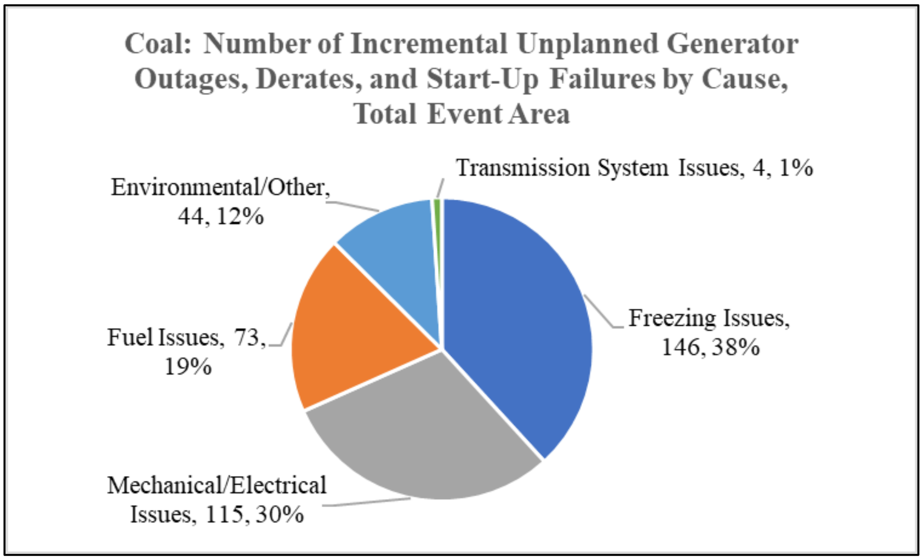


Figure 123b: Causes of Unplanned Generation Outages and Derates for Coal-Fired Units (by Outaged MW), Total Event Area, February 8-20

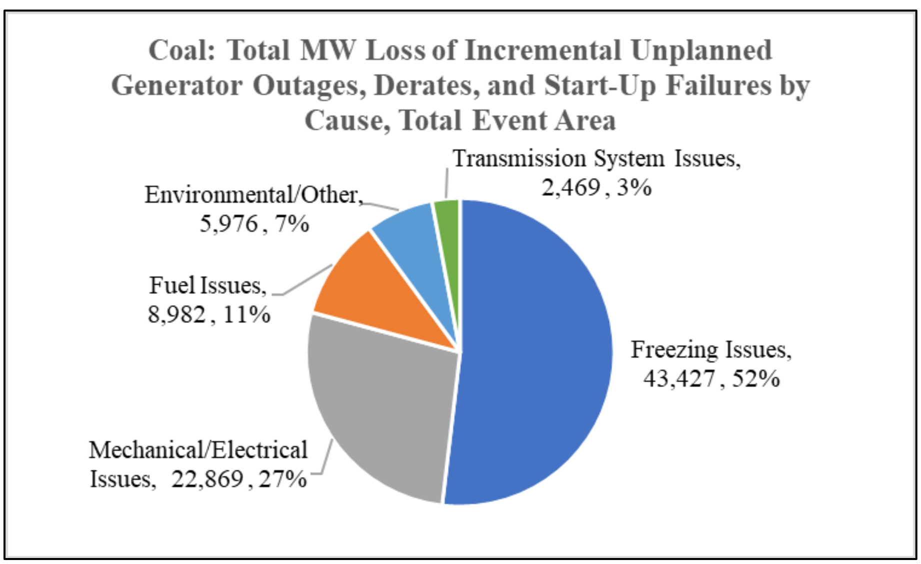


Figure 124a: Causes of Unplanned Generation Outages and Derates for Natural Gas-Fired Units (by Number of Outages), Total Event Area, February 8-20

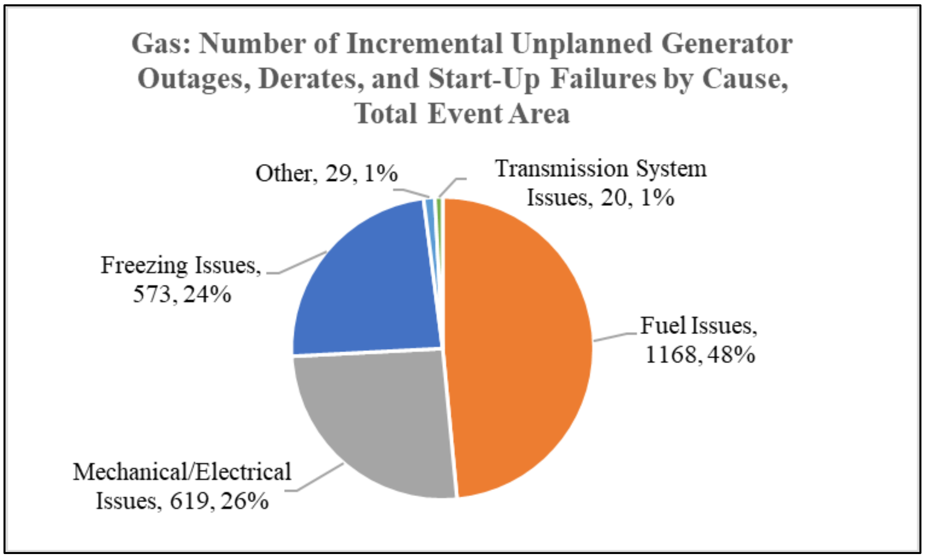


Figure 124b: Causes of Unplanned Generation Outages and Derates for Natural Gas-Fired Units (by Outaged MW), Total Event Area, February 8-20

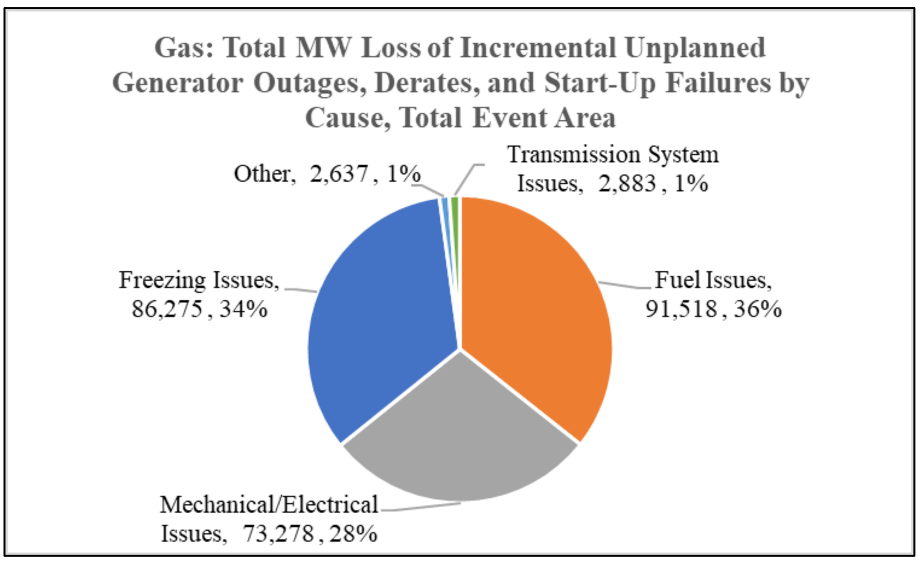


Figure 125a: Causes of Unplanned Generation Outages and Derates for Nuclear Units (by Number of Outages), Total Event Area, February 8-20

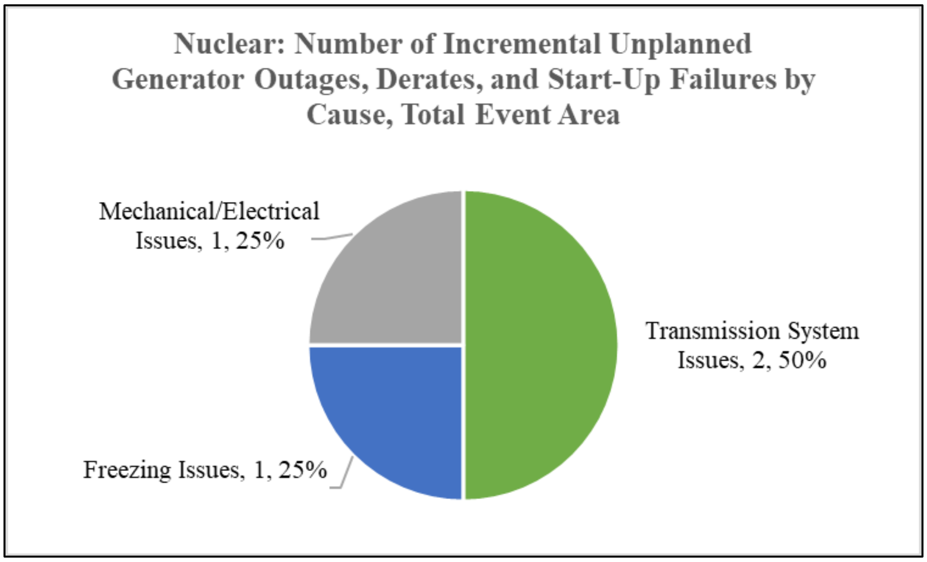


Figure 125b: Causes of Unplanned Generation Outages and Derates for Nuclear Units (by Outaged MW), Total Event Area, February 8-20

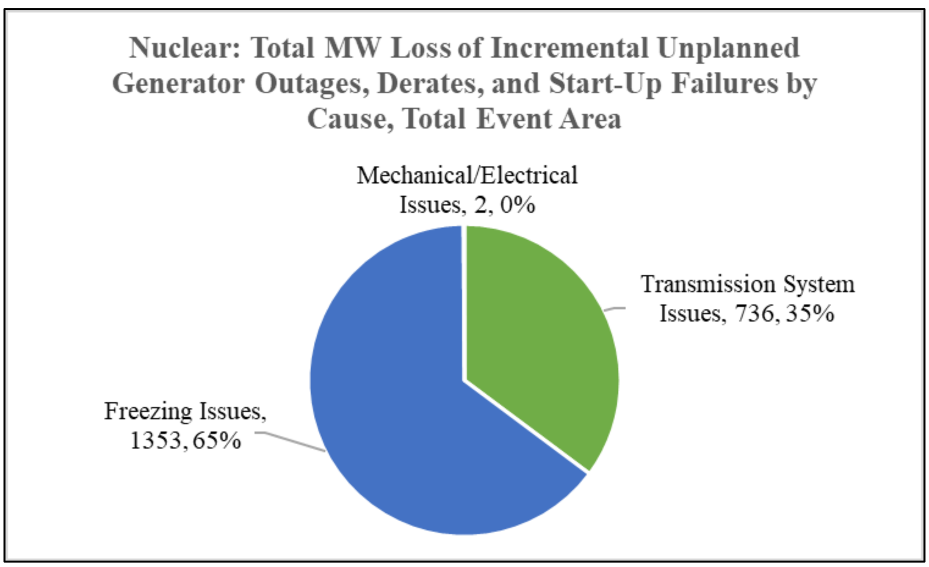


Figure 126a: Causes of Unplanned Generation Outages and Derates for Solar Resources (by Number of Outages), Total Event Area, February 8-20

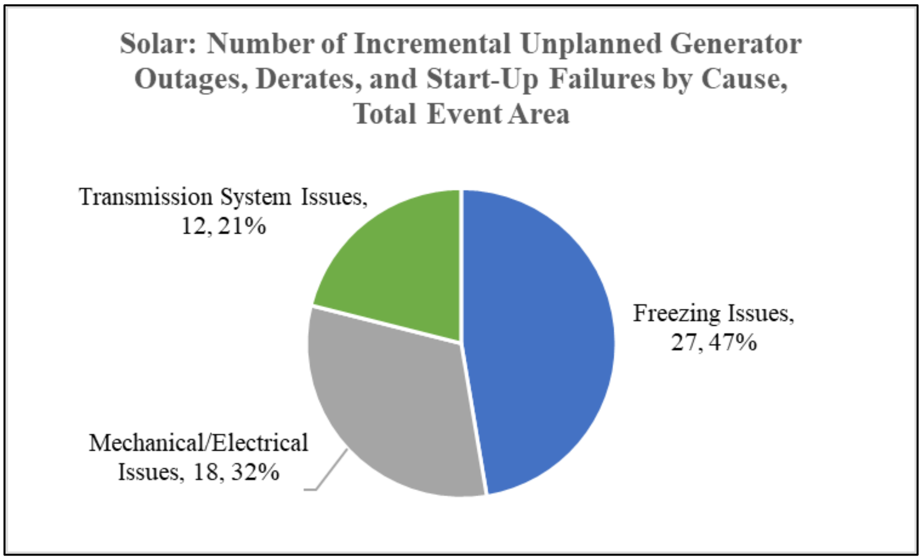


Figure 126b: Causes of Unplanned Generation Outages and Derates for Solar Resources (by Outaged MW), Total Event Area, February 8-20

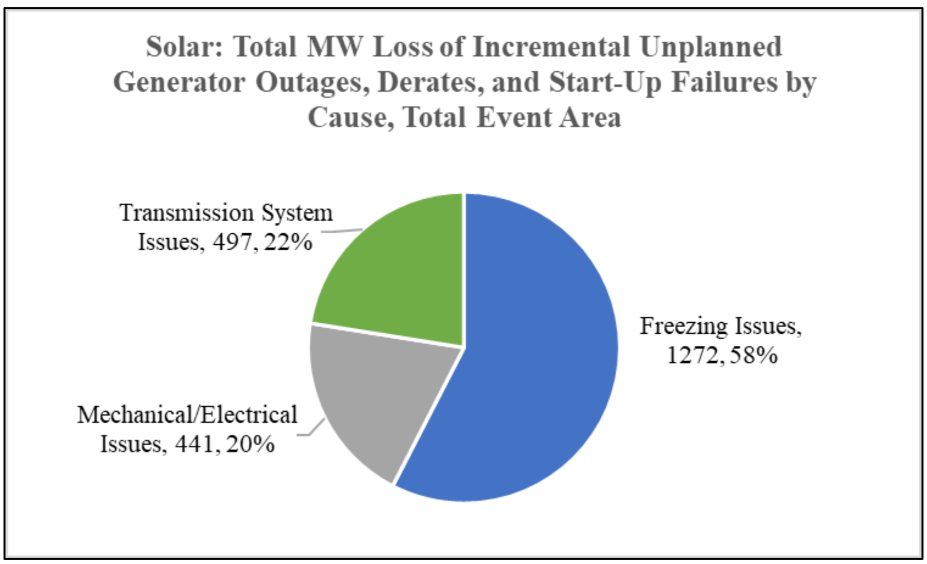


Figure 127a: Causes of Unplanned Generation Outages and Derates for Wind Resources (by Number of Outages), Total Event Area, February 8-20

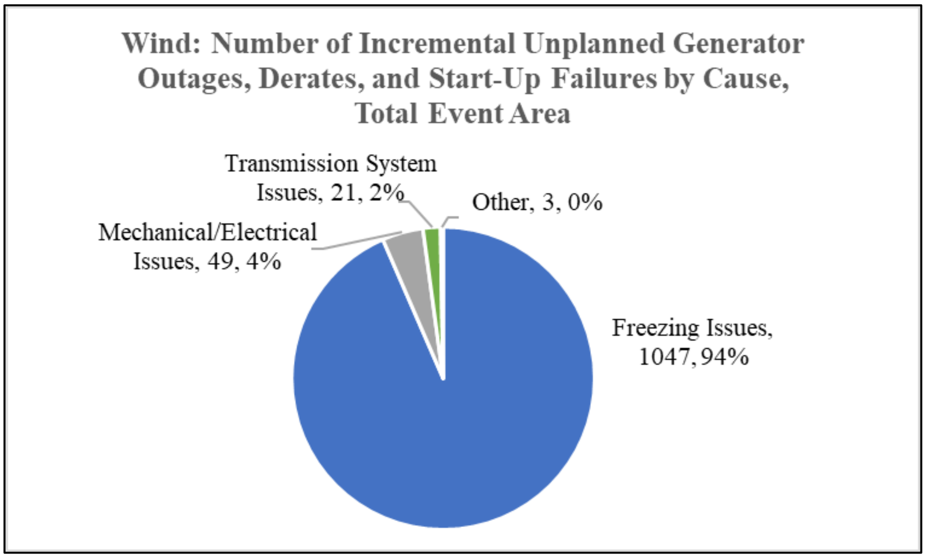


Figure 127b: Causes of Unplanned Generation Outages and Derates for Wind Resources (by Outaged MW), Total Event Area, February 8-20

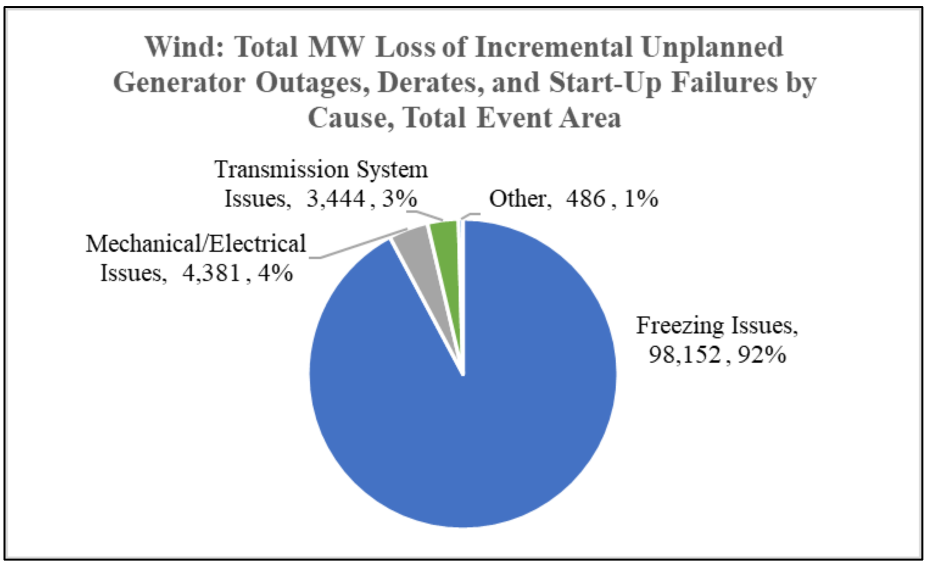


Figure 128: Causes of Unplanned Generation Outages and Derates for Other Fuel Types (by Number of Outages), Total Event Area, February 8-20

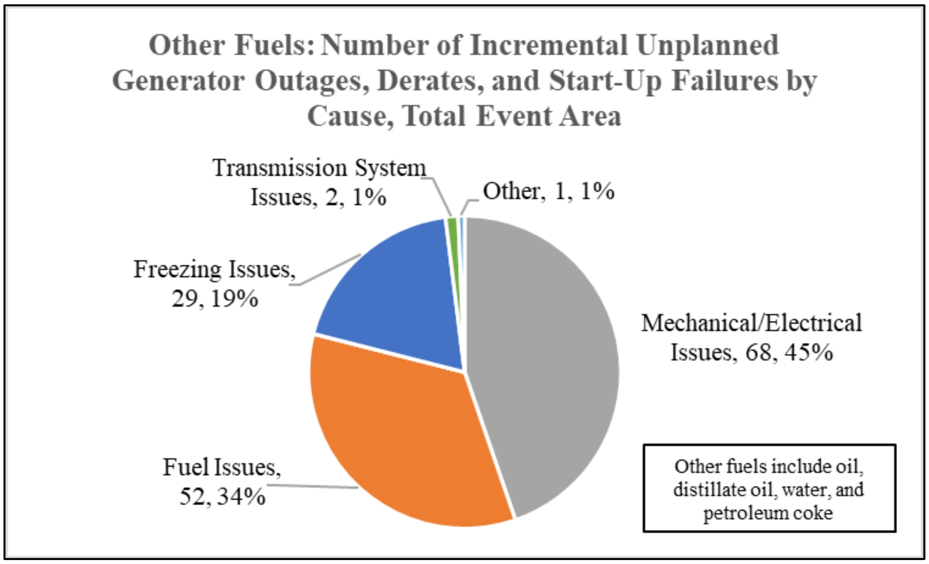
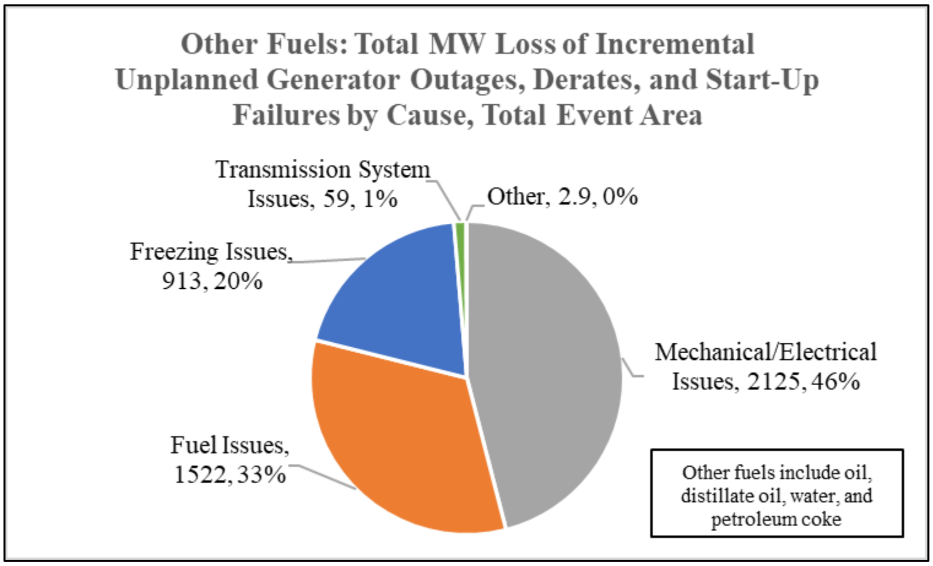
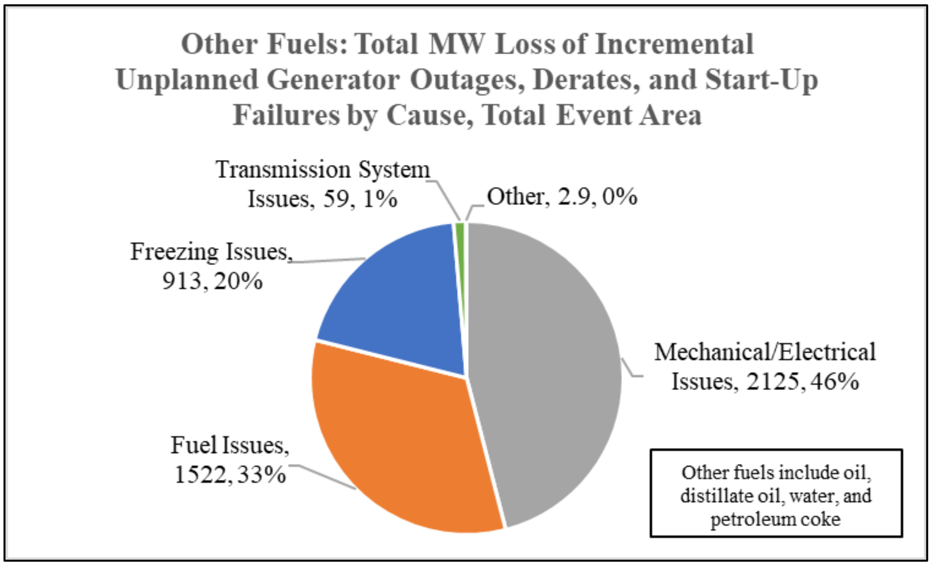


Figure 129: Causes of Unplanned Generation Outages and Derates for Other Fuel Types (by Outaged MW), Total Event Area, February 8-20





Appendix E: Interconnection Frequency Primer

Frequency Response. A key element of ERCOT's reliability performance during the 2021 cold snap was frequency response, particularly in the early morning hours of February 15. It is important to understand the severity of the frequency situation that morning, where even a relatively small loss of resources resulted in significant frequency drops in an already critical frequency situation.

Frequency Response Overview. Frequency as a measure of the reliability status of a power system can be likened to pulse or heart rate as a measure of human health. It provides a key indicator of the overall integrity of operations. Frequency control and response is the function of the "Balancing Authority." Maintaining frequency requires moment-to-moment balancing of system's aggregate generation output to its load. It also requires always having sufficient reserves available to withstand the sudden tripping of the largest generator on the system. Conversely, for loss of large amounts of load, the Balancing Authority must be able to rapidly lower generation output to reestablish the balance.

Normal Frequency Control and Response. During normal operating conditions, system frequency is maintained through the automatic generation control (AGC) system, which maintains a balance between load and resources and keeps tie line flows at prescribed levels. In ERCOT, all external tie lines are DC converter stations, so the ERCOT system operates on a frequency bias only. Several generating resources automatically raise or lower their output at the direction of the AGC system to maintain frequency. This action is called secondary frequency response (SFR) and requires frequency responsive reserves to be effective for drops in frequency.

A much faster-acting form of frequency control and response called primary frequency response (PFR) comes from automatic generator governor response, load response (typically from motors), and other devices that provide an immediate response (within seconds) to arrest and stabilize frequency in response to frequency deviations, based on local (device-level) control systems. Those actions are autonomous and are not directly controlled by the AGC system or the system operator. Again, the effectiveness of PFR is subject to the availability of headroom.

Tertiary frequency control is the next level of frequency management where a BA redispatches generation, starts more generation, or calls on demand response to restore frequency responsive reserves for PFR and SFR. This action may include manual shedding of load by the system operator to restore reserves.

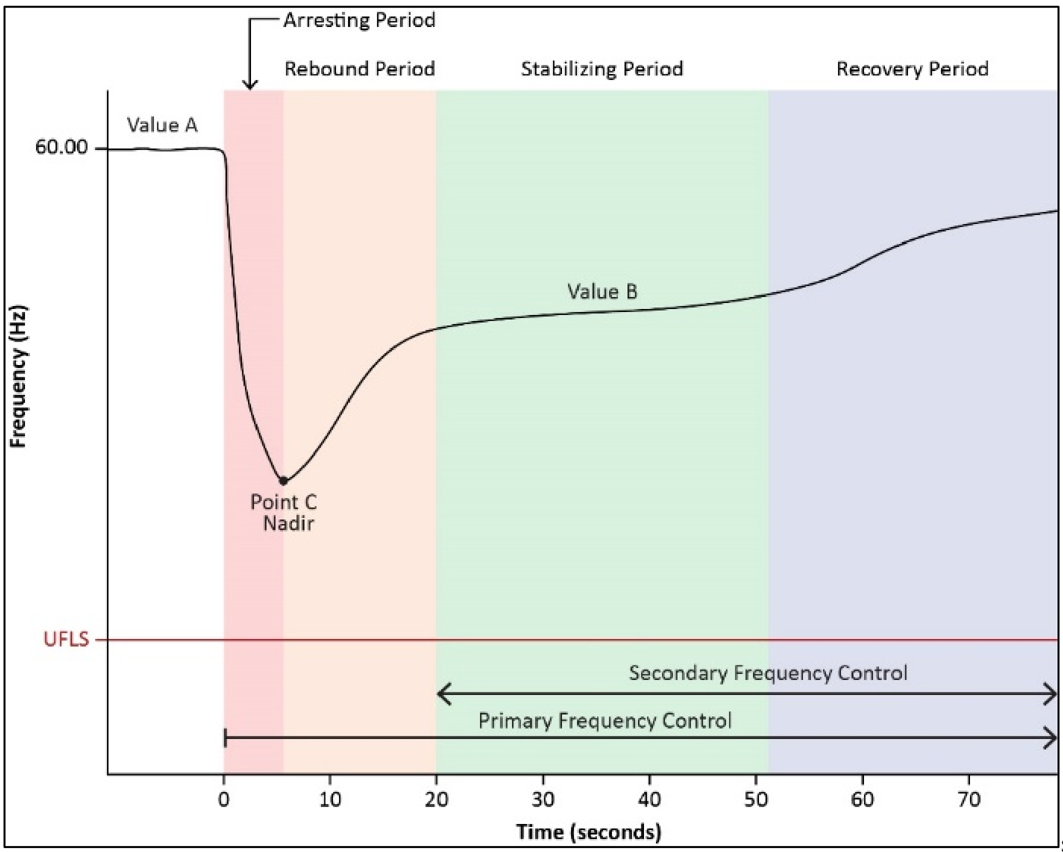
ERCOT is somewhat unique it that all generating resources in the Interconnection are subject to Regional Reliability Standard, BAL-001-TRE-2 — Primary Frequency Response in the ERCOT Region, which has been in effect since April 2015.[373] That standard requires all ERCOT resources to provide PFR for every

[373] BAL-001-TRE was implemented April 1, 2014, with compliance enforcement of the unit FRM measurements one year later in April 2015.

qualified frequency event using a frequency deadband of ±16.67 mHz.[374]. Further, the PFR performance for each generating resource is reviewed and scored for each qualifying frequency event under that standard.

New Frequency Sensitivity Metric Under Development. Both the NERC BAL-003 and ERCOT BAL-001-2-TRE standards focus of frequency response performance for significant losses of generation resources. Those standards also focus on the performance from pre-disturbance frequency Value A to the stabilized frequency Value B as defined for NERC BAL-003, as illustrated in the figure below.[375]

Figure 130: Various Stages of Interconnection Frequency Response Following Sudden Loss of Generation



Source: NERC

However, for a frequency event to be qualified for the application of those standards in ERCOT, frequency events must exceed a Value A to Point C change-in-frequency threshold of 80 mHz.

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374 Other Interconnections in North America all use a ±36 mHz deadband.
375 Pre-disturbance frequency Value A is averaged from T-16 through T+0 seconds, and the post-disturbance frequency Value B is averaged from T+20 through T+52 seconds.

A new frequency sensitivity trending metric is under development that would allow system operators to gauge how sensitive the interconnection to resource or load loss after any frequency perturbation; it works for both resource losses and load losses. It also has the benefit of not having to directly measure more complicated values like interconnection-wide inertia.

The only parameters needed are:

- Change in frequency measured in mHz,
- Time for that change to occur, and
- The amount of resource or load loss gauged in 100 MW increments.

Those measurements encompass the following indirectly

- System inertia from both rotating generation and motor loads – reflecting higher rates-of-change-of frequency for lower levels of inertia
- The dispatch mix of resources – reflecting the blend of the frequency responsiveness of the generators and other resources online – how much power and how soon can they contribute in the arresting phase of the event
- The load level reflected in the dispatch and, therefore, system inertia

Changes to Inertia and Why It Matters. As the BES transitions from conventional generators to inverter-based resources, system inertia will become lower and lower. That change will be clearly reflected in the frequency performance of the system, with a much steeper rate-of-change-of-frequency (ROCOF), indicating a lower system inertia.

By definition, inertia is the tendency for a body at rest to stay at rest, or if in motion, to stay in motion. Throughout the BES, synchronous generators are several thousand tons of mass in motion, often rotating at 3,600 revolutions per minute (at 60 Hz). The "inertial response" during a generator trip is the physics of those generators trying to maintain that 3,600 rpm speed while the system is scavenging energy from them to make up for the lost energy of the generator tripping.

The inertial tendency eventually gives way to a slowing of the rotations, dropping the system frequency until a new balance is reached, usually in less than 12 seconds. However, when inertia is lower, the fight is much quicker and the ROCOF magnitude is much higher. Since conventional generators typically begin their governor response in about 3.5 seconds, lighter inertia situations may result in a deeper and earlier nadir.

Figure 131, below shows two generating outages in ERCOT in 2009 and 2010. The red curve depicts an 890 MW generation trip at a 49,209 MW load with a relatively high inertia. The blue curve shows an 837 MW generation trip at a 23,655 MW load, with a much lower inertia. The lower inertia trip results in a ROCOF that is more than double the high inertia case.

Figure 131: Comparison of Effects on ERCOT Interconnection Frequency for Different Levels of Generator Inertia

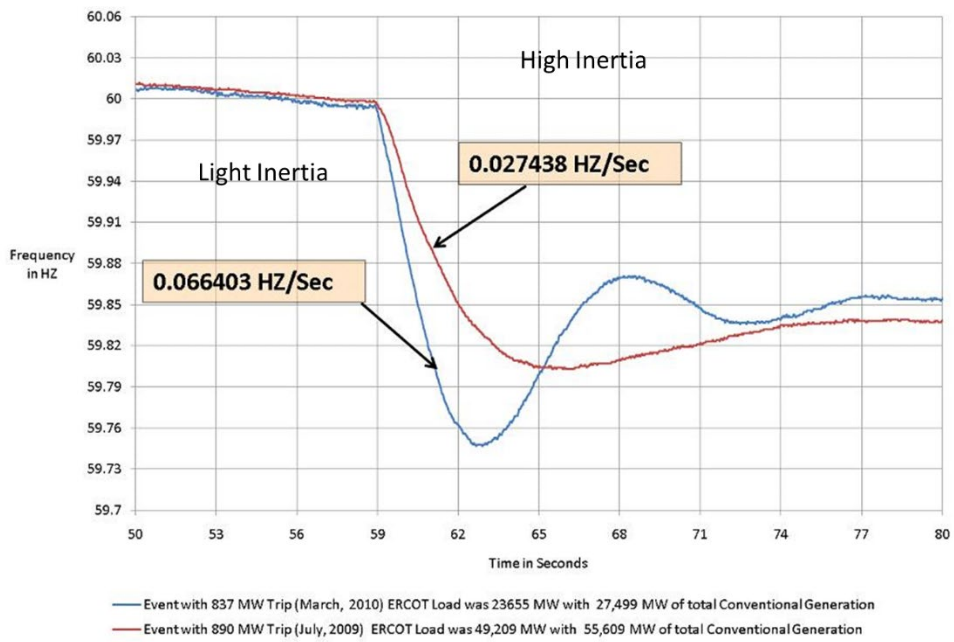
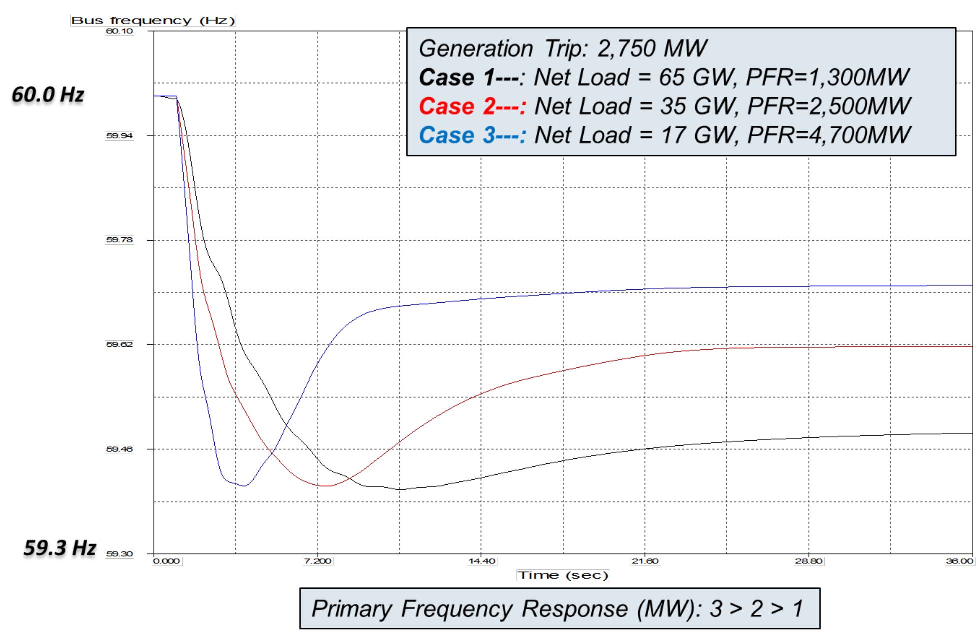


Figure 132, below shows the tradeoff between lower levels of inertia and the need for higher levels of PFR.

Figure 132: Comparison Between Lower Levels of Inertia and the Need for Higher Levels of Primary Frequency Response (PFR)



Three load/inertia cases are analyzed with PFR adjusted to maintain the frequency nadir at approximately the same frequency.[376] In all three cases, the resource loss is 2,750 MW, and the PFR is from conventional generation without any fast frequency response.

For Case 1 with the highest load and inertia, the nadir occurs at approximately 10 seconds and 1,300 MW of PFR is required for that frequency response performance.

Case 2 shows a load of 35 GW (reflecting a lower generation dispatch and inertia level). For Case 2, the ROCOF is much steeper, and the nadir occurs at about 7.2 seconds, requiring 2,500 MW of PFR for the same frequency response performance.

Case 3 shows a much lower load of 17 GW with a yet lower dispatch and inertia level. For Case 3, the ROCOF is steeper still, reflecting the lower inertia, and the nadir occurs at about 3.6 seconds. To attain the same frequency response performance as the other two cases, 4,700 MW of PFR is required.

Because lower levels of inertia require much larger PFR requirements, fast frequency response from IBRs is needed to inject energy back into the system faster during the arresting phase of the frequency event.

Frequency Sensitivity Definition – Frequency sensitivity is a rough measure of the system's trending capability to withstand losses of generation resources, calculated as the frequency change from the inflection point A to the nadir at Point C, expressed in mHz per second per 100 MW of resource loss.

EXAMPLE: If system frequency changes by -300 mHz within 15 seconds for a loss of a 1,000 MW of resource, the frequency sensitivity would be -2 mHz/second/100 MW.

In the analysis of ERCOT's frequency performance during the early morning of February 15, 2021, the Team provided frequency sensitivity for several generating unit outages to contrast how ERCOT's sensitivity to resources losses was changing.

Although this frequency sensitivity shows promise as a new metric, additional testing of its potential application is just beginning in the NERC community.

[376] The higher the load, more generation is dispatched which includes more inertia.

Appendix F: Glossary of Terms Used in the Report

Adjacent RC - A Reliability Coordinator whose Reliability Coordinator Area is interconnected with another Reliability Coordinator Area.

Alternating Current (AC) - Electric current that changes periodically in magnitude and direction with time. In power systems, the changes follow the pattern of a sine wave having a frequency of 60 cycles per second in North America. AC is also used to refer to voltage which follows a similar sine wave pattern.

Ambient Conditions - Common, prevailing, and uncontrolled atmospheric conditions at a particular location, either indoors or out. The term is often used to describe the temperature, humidity, and airflow or wind that equipment or systems are exposed to.

Asynchronous - In AC power systems, two systems are asynchronous if they are not operating at exactly the same frequency. Two systems may also be considered asynchronous if, at potential interconnection points, there is a significant difference in phase angle between their respective voltage waveforms.

Bulk Electric System - All Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy. The NERC Glossary of Terms Used in the Reliability Standards contains the list of inclusions and exclusions, and can be found at https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

Capacitor - A capacitor is a device that stores an electric charge. Although there is energy associated with the stored charge, it is negligible in terms of its capability to serve load. A capacitor bank is made of up of many individual capacitors. Its purpose is to provide reactive power to the system to help support system voltage by compensating for reactive power losses incurred in the delivery of power.

Cascading - The uncontrolled successive loss of System Elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.

Constrained System Conditions - Conditions where multiple transmission facilities (lines, transformers, breakers, etc.) are approaching, are at, or are beyond their System Operating Limits.

Conductor - In physical terms, any material, usually metallic, exhibiting a low resistance to the flow of electric current. A conductor is the opposite of an insulator. In electric power systems, the term conductor generally refers to the actual wires in overhead transmission and distribution lines, underground cables, and the metallic tubing used for busses in substations. Aluminum and copper are the predominant metals used for conductors in power systems.

Contingency - The unexpected and sudden failure or outage of a power system component, such as a generator, transmission line, transformer, or other electrical element.

Contingency Reserve - Contingency reserve is the provision of capacity deployed by a Balancing Authority to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Organization contingency requirements. Adequate generating capacity must be available at all times to maintain scheduled frequency, and avoid loss of firm load following transmission or generation contingencies. This capacity is necessary to replace capacity and energy lost due to forced outages of generation or transmission equipment.

Curtail / Curtailment - A reduction in the scheduled capacity or energy delivery of an Interchange Transaction.

Demand - 1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer.

Demand Side Management - All activities or programs undertaken by any applicable entity to achieve a reduction in Demand.

Derate - A reduction in a generating unit's net dependable capacity.

Direct Current (DC) - Electric current that is steady and does not change in either magnitude or direction with time. DC is also used to refer to voltage and, more generally, to smaller or special purpose power supply systems utilizing direct current either converted from AC, from a DC generator, from batteries, or from other sources such as solar cells.

Distribution Factor - The portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate).

Emergency - Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System.

Emergency Rating - The rating as defined by the equipment owner that specifies the level of electrical loading or output, usually expressed in megawatts (MW) or MVAr or other appropriate units, that a system, facility, or element can support, produce, or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.

Energy Emergency – A condition when a Load-Serving Entity or Balancing Authority has exhausted all other resource options and can no longer meet its expected Load obligations.

Energy Management System (EMS) - A system of computer-aided tools used by system operators to monitor, control, and optimize system performance.

Export – In electric power systems, exports refer to energy that is generated in one power system, or portion of a power system, and transmitted to, and consumed in, another.

Facility - A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)

Facility Rating - The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.

Firm Load (or Firm Demand) - That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions.

Firm Transmission Service/Capacity - The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption.

Flowgate – 1) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions. 2) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System.

Force Majeure - A superior force, "act of God" or unexpected and disruptive event, which may serve to relieve a party from a contract or obligation.

Forced Outage – 1) The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons. 2) The condition in which the equipment is unavailable due to unanticipated failure.

Generation – The process of producing electrical energy from other sources of energy such as coal, natural gas, uranium, hydro power, wind, etc. More generally, generation can also refer to the amount of electric power produced, usually expressed in kilowatts (kW) or megawatts (MW) and/or the amount of electric energy produced, expressed in kilowatt hours (kWh) or megawatt hours (MWh).

Generator - Generally, a rotating electromagnetic machine used to convert mechanical power to electrical power. The large synchronous generators common in electric power systems also serve the function of voltage support and voltage regulation by supplying or withdrawing reactive power from the transmission system, as needed.

Grid - An electrical transmission and/or distribution network. Broadly, an entire interconnection.

Heat Tracing – The application of a heat source to pipes, lines, and other equipment which, in order to function properly, must be kept from freezing. Heat tracing typically takes the form of a heating element running parallel with and in direct contact with piping.

Hour Ending - Data measured on a Clock Hour basis.

Import – In electric power systems, imports refer to energy that is transmitted to, and consumed in one power system, which is generated in another power system, or portion of another power system.

Independent System Operator (ISO) - An organization responsible for the reliable operation of the power grid in a particular region and for providing open access transmission access to all market participants on a nondiscriminatory basis.

Interchange - Electrical energy transfers that cross Balancing Authority boundaries.

Interchange Distribution Calculator (IDC) - The mechanism used by Reliability Coordinators in the Eastern Interconnection to calculate the distribution of Interchange Transactions over specific Flowgates. It includes a database of all Interchange Transactions and a matrix of the Distribution Factors for the Eastern Interconnection.

Interchange Schedule - An agreed-upon Interchange Transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the Source and Sink Balancing Authorities involved in the transaction.

Interconnection – A geographic area in which the operation of Bulk Power System components is synchronized such that the failure of one or more of such components may adversely affect the ability of the operators of other components within the system to maintain Reliable Operation of the Facilities within their control. When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.

Interconnection Reliability Operating Limit - A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System.

Interruptible Load - Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment.

Load - See Demand (Electric).

Load-serving – Serves the electrical demand and energy requirements of its end-use customers.

Load Shed – The reduction of electrical system load or demand by interrupting the load flow to major customers and/or distribution circuits, normally in response to system or area capacity shortages or voltage control considerations. In cases of capacity shortages, load shedding is often performed on a rotating basis, systematically and in a predetermined sequence.

Market Flow - The total amount of power flowing across a specified Facility or set of Facilities due to a market dispatch of generation internal to the market to serve load internal to the market.

Most Severe Single Contingency (MSSC) - The Balancing Contingency Event, due to a single contingency identified using system models maintained within the Reserve Sharing Group (RSG) or a Balancing Authority's area that is not part of a Reserve Sharing Group, that would result in the greatest loss (measured in MW) of resource output used by the RSG or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet Firm Demand and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the Sink Balancing Authority).

Near-Term – The time period that covers the next day to multiple days ahead of the operating day.

Operating Plan - A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.

Operating Process - A document that identifies general steps for achieving a generic operating goal. An Operating Process includes steps with options that may be selected depending upon Real-time conditions. A guideline for controlling high voltage is an example of an Operating Process.

Operational Planning Analysis - An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Operating Reserve - That capability above firm system demand required to provide for regulation, load forecasting error, forced and scheduled equipment outages, and local area protection. It consists of spinning and non-spinning reserve.

Outage – The period during which a generating unit, transmission line, or other facility is out of service. Outages are typically categorized as forced, due to unanticipated problems that render a facility unable to perform its function and/or pose a risk to personnel or to the system, or scheduled / planned for the sake of maintenance, repairs, or upgrades.

Peak Load (or Peak Demand) – 1. The highest hourly integrated Net Energy For Load within a Balancing Authority Area occurring within a given period (e.g., day, month, season, or year). 2. The highest instantaneous demand within the Balancing Authority Area.

Post-Contingency - The resulting power system conditions (determined by computer simulation, or by actual real-time data) following the unexpected and sudden failure or outage of a power system component, such as a generator, transmission line, transformer, or other electrical element.

Power - In physics, power is defined as the rate at which energy is expended to do work. In the electric power industry, power is measured in watts (W), kilowatts (1 kW = 1,000 watts), megawatts (1 MW = 1 million watts), or gigawatts (1 GW = 1 billion watts). For reference, 1 kW = 1.342 horsepower (hp).

Power System - The collective name given to the elements of the electrical system. The power system includes the generation, transmission, distribution, substations, etc. The term power system may refer to one section of a large interconnected system or to the entire interconnected system.

Power Transfer Distribution Factor - In the pre-contingency configuration of a system under study, a measure of the responsiveness or change in electrical loadings on transmission system Facilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100 percent) of the change in power transfer.

Rating - The operational limits of a transmission system element under a set of specified conditions. In power systems, equipment and facility power-handling ratings are usually expressed either in megawatts (MW) or in mega-volt-amperes (MVA). The term is also sometimes used to describe the output capability of generators.

Reactive Power – The portion of electricity that establishes and sustains the electric and magnetic fields of AC equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It is also needed to make up for the reactive losses incurred when power flows through transmission facilities. Reactive power is supplied primarily by generators, capacitor banks, and the natural capacitance of overhead transmission lines and underground cables (with cables contributing much more per mile than lines). It can also be supplied by static VAR converters (SVCs) and other similar equipment utilizing power electronics, as well as by synchronous condensers. Reactive power directly influences system voltage such that supplying additional reactive power increases the voltage. It is usually expressed in kilovars (KVAr) or megavars (MVAr), and is also known as "imaginary power."

Real-Time – Bulk Electric System conditions, characteristics and/or data representing what actually occurred at specific times or timeframes during the Event.

Real-Time Assessment – An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Real-Time Contingency Analysis (RTCA) – A computer application which evaluates system conditions using real-time data to assess potential (post-contingency) operating conditions.

Regional Entity - An independent, regional entity having delegated authority from NERC to propose and enforce Reliability Standards and to otherwise promote the effective and efficient administration of bulk-power system reliability.

Regional Transmission Organization (RTO) - A voluntary organization of electric Transmission Owners, transmission users and other entities approved by FERC to efficiently coordinate electric transmission planning (and expansion), operation, and use on a regional (and interregional) basis. Operation of transmission facilities by the RTO must be performed on a non-discriminatory basis.

Reliability Coordinator Area - The collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.

System Operator: An individual at a control center of a Balancing Authority, Transmission Operator, or Reliability Coordinator, who operates or directs the operation of the Bulk Electric System in real-time.

Stability – The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances.

State Estimator – A computer application which evaluates system conditions using real-time data to assess existing operating conditions.

Transformer - A type of electrical equipment in the power system that operates on electromagnetic principles to increase (step up) or decrease (step down) voltage.

Transmission – An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.

Transmission Line – A system of structures, wires, insulators, and associated hardware that carry electric energy from one point to another in an electric power system. Lines are operated at relatively high voltages varying from 69 kV up to 765 kV, and are capable of transmitting large quantities of electricity over long distances.

Trip - This refers to the automatic disconnection of a generator or transmission line by its circuit breakers.

Voltage - The force characteristic of a separation of charge that causes electric current to flow. The symbol is "V" and units are volts or kilovolts (kV).

Wide Area - The entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits.

Appendix G: Acronyms Used in the Report

AC	Alternating Current
BA	Balancing Authority
BES	Bulk Electric System
CST	Central Standard Time
DC	Direct Current
DSM	Demand-Side Management
EEA	Energy Emergency Alert
EHV	Extra-High Voltage
EMS	Energy Management System
EOP	Emergency Operations Procedure
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
FERC	Federal Energy Regulatory Commission
FRAC	Forward Reliability Assessment Commitment
GO	Generator Owner
GOP	Generator Operator
HVDC	High Voltage Direct Current
IROL	Interconnection Operating Reliability Limit
ISO	Independent System Operator
kV	Kilovolt
LBA	Local Balancing Authority

LMR	Load Modifying Resources
MSSC	Most Severe Single Contingency
MISO	Midcontinent Independent System Operator, Inc.
MRO	Midwest Reliability Organization
MVA	Megavolt-Ampere
MW	Megawatt
NERC	North American Electric Reliability Corporation
OPA	Operational Planning Analysis
PC	Planning Coordinator
PRC	Physical Responsive Capability
RC	Reliability Coordinator
RCIS	Reliability Coordinator Information System
RDT	Regional Directional Transfer
RDTL	Regional Directional Transfer Limit
RF	ReliabilityFirst Corporation
RTCA	Real-Time Contingency Analysis
RTO	Regional Transmission Organization
SCED	Security Constrained Economic Dispatch
SCRD	Security Constrained Redispatch
SERC	SERC Corporation
SeRC	Southeastern Reliability Coordinator
SOL	System Operating Limit

SPP	Southwest Power Pool, Inc.
TDU	Transmission Dependent Utility
TLR	Transmission Loading Relief
TO	Transmission Owner
TOP	Transmission Operator
TP	Transmission Planner
TRE	Texas Regional Entity
TVA	Tennessee Valley Authority
UDS	Unit Dispatch System
VSA	Voltage Stability Analysis
WECC	Western Electricity Coordinating Council

Appendix H: Table of Other Recommendations about the Event

Category Electric	Recommendation
PLANNING AND RESERVES/ Reserves Recommendations, Load Forecasting, Seasonal Studies Recommendations	• Demand forecasts for severe winter storms were too low (UT Report at 8, applies to ERCOT only) • Weather forecasts failed to appreciate the severity of the storm. Weather models were unable to accurately forecast the timing (within one to two days) and severity of extreme cold weather, including that from a polar vortex. (UT Report at 8, applies to ERCOT only) • Planned generator outages were high, but not much higher than assumed in planning scenarios. Total planned outage capacity was about 4,930 MW, or about 900 MW higher than in ERCOT's "Forecasted Season Peak Load" scenario. (UT Report at 8, applies to ERCOT only) • Perform initial and ongoing assessments of minimum reliability attributes needed from SPP's resource mix. (SPP Report at 11, Tier 1, Assessment) • Improve or develop policies, which may include required performance of seasonal resource adequacy assessments, development of accreditation criteria, incorporation of minimum reliability attribute requirements, and utilization of market-based incentives9 that ensure sufficient resources will be available during normal and extreme conditions. (SPP Report at 11, Tier 1, Policies) • Develop policies that facilitate transmission expansion needed to improve SPP's ability to more effectively utilize the transmission system during severe events. (SPP Report at 13, Tier 2, Policies) • Develop transmission planning policies that improve input data, assumptions or analysis techniques needed to better account for severe events. (SPP Report at 13, Tier 2, Policies) • MISO is moving to a sub-annual (4 season) resource adequacy construct and an accrediting methodology based in part on a resources' availability during the hours when the system is most in need (tight operating hours), thereby giving resource owners an incentive to ensure resources availability through investments in winterization, fuel

	assurance or other means. These changes are expected to be filed at the Federal Energy Regulatory Commission (FERC) in the second half of 2021. (MISO Report, at 47) • MISO will evaluate how to incorporate existing extreme cases into Seasonal Assessments and drills (MISO Report at 48). • MISO will include the impacts of high wheel through flows in the seasonal transmission assessment to better prepare for extreme weather events. (MISO Report at 49) • MISO will continue to leverage in-house and vendor meteorology expertise to inform MISO operational decisions and communication with members. MISO is continuing to assess how best to translate accurate weather forecasts into accurate forecasts of the effects of the weather (e.g., outages tied to weather). (MISO Report at 50) • In order to provide more visibility into available units, MISO is preparing an Available Resource report as part of the Capacity Sufficiency Analysis Tool (CSAT) to communicate to MISO commitment teams the resources available for commitment. The report provides a list of resources available for capacity at any given point in time and helps operations make commitment decisions during tight operating conditions by producing a dynamic list of resources, meaning that a resource will automatically drop off the available commitment list if its window for start-up has passed for any given hour. (MISO Report at 50-51) • ERCOT should improve demand forecasting capabilities. ERCOT, its market monitor, and the PUCT should all be scrutinizing ERCOT's past load forecasting and net load tools in much greater detail and sophistication. They need to identify significant biases and flaws in ERCOT's load forecasting tools and data, identify and implement better forecast tools, methods and data, and conduct on-going reassessment and improvement to assure on-going forecast accuracy with limited bias or error over time. (Recommendation 4-1, Mitchell Report) • ERCOT should broaden its use of scenario analysis with more aggressive worst-case outcomes. ERCOT should design and explore multiple climate change and extreme weather forecasts and demand scenarios in combination with multiple compound failures per event, for planning,

	resource adequacy assessments, and stress-test analyses. ERCOT's extreme stress scenarios should factor in potential communications and cyber-security failures as well as compound losses of transmission and/or generation. (Recommendation 4-2, Mitchel Report) • Acknowledge changing extreme weather threats. The Texas Legislature should require the PUCT, RRC and utilities to use forward-looking 30-year climate and extreme weather projections in combination with the worst past extreme weather and grid disaster events over a 50-year history in all planning scenarios and electricity asset reasonableness and prudence evaluations. (Recommendation 4-3, Mitchell Report) • Evaluate whether ERCOT needs different winter versus summer planning, operations and protocols. The PUCT and ERCOT should examine the distinctions between summer and winter resource needs carefully to determine whether different market products (e.g., winter-focused ancillary services) or operational protocols (e.g., limits on maintenance scheduling) are appropriate to different seasons. (Recommendation 5-1, Mitchel Report) • Greater range of extreme weather events in seasonal analysis (ERCOT Presentation, page 58) • Increase requirements for DG to provide data for planning and ops (ERCOT Presentation, page 58) • Assessment of uncertainties is critical for adequate and efficient commitment and real-time operational response (Addressed through Operations of the Future) (MISO Presentation April 27, 2021, at page 7) • Resource adequacy evaluation in constrained areas is necessary (Addressed through Market Redefinition: Resource Adequacy) (MISO Presentation April 27, 2021, at page 7) • Dispatchable Generation AND Wholesale Pricing Procedures. Provides that a generation facility is considered to be non-dispatchable if the facility's output is controlled primarily by forces outside of human control. PUCT requirements to ensure that ERCOT: Establishes reliability requirements to meet the needs of ERCOT.

	Determines the quantity and characteristics of ancillary and reliability services necessary to ensure reliability during extreme heat and extreme cold weather conditions and during times of low non-dispatchable power production. Procures ancillary or reliability services on a competitive basis to ensure reliability during extreme conditions. Develops appropriate qualification and performance requirements for services, including appropriate penalties for failure to provide the services. Sizes the services to prevent prolonged rotating outages and to minimize load variability in high demand and low supply scenarios. • The PUCT itself must ensure: Resources are dispatchable and able to meet continuous operating requirements for the season in which the service is procured; Fuel Requirements: Winter resource capability qualifications include on-site fuel storage, dual-fuel capability, or fuel supply arrangements to ensure winter performance for several days; Summer resource capability qualifications include facilities or procedures to ensure operation under drought conditions. (Texas SB3, Sec. 18) Note, this Section has another part under market development)
COORDINATION WITH GENERATOR OWNERS/OPERATORS	• MISO will investigate the feasibility of a pre-winter feedback loop, which would allow members to express their readiness for the winter weather. This feedback would include information about generator weatherization and winter checklist completion (MISO Report at 48). • MISO is combining the Winterization and Annual Gas Fuel surveys and removing all backward-looking and redundant questions, with the goal of increasing participation in the survey. MISO will consider additional ways of accessing this information, including engaging in the process to develop NERC Cold Weather standards to be reflective of the increased risks seen during the Arctic Event. (MISO Report at 49).

	• MISO will increase coordination with utilities, regulators, and others to ensure consistent messaging and to determine how and when to make emergency public appeals for conservation in the near term. MISO will schedule a communication-focused event focused on crisis communications. (MISO Report at 54) • Reinforce communications lessons learned with member companies during Hurricane Action Plan drills and Reliability Coordinator drills. Engage in identifying roles, responsibilities, dependencies, and processes for communications during winter and summer (including hurricane) readiness activities. (MISO Report at 54)
WINTERIZATION/ Generator Cold Weather Reliability ***Plant Design*** ***Maintenance/inspections generally*** ***Specific Freeze Protection Maintenance Items*** (Heat Tracing, Thermal Insulation, *Use of Wind breaks/enclosures, Training, Other Generator Owner/Operator Actions, Transmission Facilities)*	• All types of generation technologies failed. All types of power plants were impacted by the winter storm. (UT Report at 8, applies to ERCOT only) • Power plants listed a wide variety of reasons for going offline throughout the event. Some power generators were inadequately weatherized; they reported a level of winter preparedness that turned out to be inadequate to the actual conditions experienced. The outage, or derating, of several power plants occurred at temperatures above their stated minimum temperature ratings. (UT Report at 9, applies to ERCOT only) • MISO will work with states and others to identify changes that may be required in MISO processes or elsewhere, to better reflect resource availability during extreme weather events (e.g., winterization needs during extreme cold, fuel assurance). (MISO Report at 48) • MISO will focus more attention on extreme outcomes as well as expected outcomes during seasonal assessment workshops. (MISO Report at 48). • MISO will seek additional feedback from stakeholders on their learnings from past events during the Seasonal Assessment workshops. (MISO Report at 49) • Increase comprehensive drills for extreme events – including operations, outage coordination, emergency load reduction planning, communications, and regulatory coordination. MISO plans to incorporate more fuel assurance scenarios and responses into planning and drilling. (MISO Report at 49-50)

	• Reassess requirements and compensation for black-start capacity and test and drill twice/year. ERCOT and the PUCT must reassess black-start performance requirements, compensation, and penalties. ERCOT must stress-test its assumptions and generators' claims about black-start unit availability and conduct regular drills to be sure that they can rebuild the system quickly after some future grid collapse, using whatever black-start resources are available. The benefits of this readiness go beyond weather-caused events to encompass preparation for and mitigation of impacts from cyber and physical attacks on the power system. (Recommendation 5-2, Mitchell Report) • Establish active reliability compliance oversight Texas. The PUCT needs trusted, competent external entities to review and verify compliance with all weatherization and reliability requirements placed upon electric generators and utilities. Additionally, ERCOT and the PUCT need to actively review and act upon reliability review findings. Compliance with weatherization and reliability mandates is essential to move the likelihood of future supply-caused power outages toward zero. (Recommendation 6-3, Mitchell Report) • Availability is less than expected when conditions are tight, and the significant drivers (e.g., winterization, fuel assurance) are unique to seasons (Addressed through Market Redefinition: Resource Adequacy Construct and Accreditation) (MISO Presentation, April 27, 2021, at page 7) • Weather Emergency Preparedness. This section applies only to municipally owned utilities, electric cooperatives, power generation companies, or exempt wholesale generators that sell electric energy at wholesale ERCOT. Requires that ERCOT prioritize inspections based on risk level. Requires PUCT to promulgate rule for inspection by independent person when an electric generation service provider experiences repeated or major weather-related forced interruptions of service. Authorizes PUCT to require an electric generation service provider to implement appropriate recommendations included in an assessment. Requires ERCOT to review, coordinate, and approve or deny requests for planned outages. (Texas SB3, Section 13)

	• Texas PUCT Preparedness Reports. The PUCT is required to analyze emergency operations plans developed by electric utilities, power generation company, municipally owned utilities, and electric cooperatives that operate generation facilities and retail electric providers and must provide a report on preparedness. If the PUCT finds an operator's plan inadequate, the PUCT i*s required* to have the operator file an updated emergency operations plan. (Note: the PUCT was formerly "authorized" to require an updated plan). The PUCT must report its preparedness findings to the Lieutenant Governor, Speaker of the House and certain members of the legislature in every even-numbered year. (Texas, SB3, Section 24) • Sec. 25 – Railroad Commission Weather Emergency Preparedness Reports. Requires the RRC to analyze emergency operations plans developed by those natural gas facilities operators and are included on the electricity supply chain map. The RRC must prepare a preparedness report on weatherization preparedness of facilities included on the electricity supply chain map is If the RRC finds the emergency operations plans to be inadequate, it must require the operator to upgrade its emergency operations plans. The results of the RRC analysis must reported to the Lieutenant Governor, speaker of House, and certain members of the legislature. (Texas, SB3, Section 25)
COMMUNICATIONS/ RC-to-RC Communication, Situational Awareness, Seams Issues	• Develop or enhance the tools, communications and processes identified by the ORWG and needed to improve SPP and stakeholder response to extreme conditions, such as: o Enhance real-time cascading analysis studies and post results. o Develop tool(s) to increase operator awareness of Out of Merit o Energy (OOME) instructions. o Enhance and expand the use of R-Comm.10 o Create a reliability dashboard to improve situational awareness for operators. o Utilize member-maintained distribution lists for communications purposes.

	o Develop a process to update operations management during extreme conditions. (SPP Report at 12, Tier 2, Action) • Improve seams agreement provisions with neighboring parties to facilitate adequate emergency assistance and fairly compensate emergency energy. (SPP Report at 13, Tier 2, Action) • Update SPP's Emergency Communications Plan annually and share as appropriate with stakeholders. The plan will include: o Processes that ensure stakeholders have a dependable way to receive timely, accurate and relevant information regarding emergencies. o Plans to drill emergency communications procedures with all relevant stakeholders. o Procedures for ensuring SPP's contact lists include appropriate members, regulators, customers, and government entities and stay up-to-date. ((SPP Report at 14, Tier 2, Action) • Evaluate and propose needed enhancements to communications tools and channels, including but not limited to enhancements to SPP's websites, development of a mobile app, automation of communications processes, etc. (SPP Report at 14, Tier 2, Assessment) • Form a stakeholder group whose scope would include discussion of matters related to emergency communications. (SPP Report at 14, Tier 3, Action) • To increase public awareness of and satisfaction with SPP, develop materials intended to educate general audiences on foundational electric utility industry concepts and SPP's role in ensuring electric reliability. (SPP Report at 14, Tier 3, Action) • MISO will leverage the Long-Range Transmission Planning (LRTP) activities to identify intra- and inter-regional planning to ensure reliability as the resource mix continues to evolve and disruptive weather events become more

	frequent. In particular, LRTP will evaluate further north-south transfer capability which would have helped during the Arctic Event. (MISO Report, at 47) • Transfer capability - MISO will examine load pockets as part of transmission planning and resource accreditation. (MISO Report, at 47) • Along with LRTP, MISO will also continue to work with all of its seams partners to identify ways to increase coordination. For example, MISO and SPP are currently engaged in an effort focused on the SPP – MISO seam. (MISO Report, at 47) • Since identifying this action item following the 2018 Cold Weather Event, MISO has improved communication with Joint Parties on RTD exceedances. MISO will continue to look for ways to better coordinate with Joint Parties. (MISO Report at 51) • When MISO requests a Regional Dispatch Transfer (RDT) limit increase and one or more of the Joint Parties deny MISO's request, MISO needs a better understanding of Joint Parties' system challenges such as congestion, flows, and outages, and reasons for MISO's request for a limit increase is being denied. MISO plans to address this issue in the current contract renegotiations. (MISO Report at 51) • Review schedules at a more granular level and target cuts to those with greater impact to RDT. Develop a tool that MISO operations can use to visualize what is driving impacts to the RDT. (MISO Report at 51) • Increase the shadow price for RDT prior to emergency events. Increasing the RDT shadow prices will limit flows and allow more efficient management of the RDT limit. (MISO Report at 51) • Design tools to provide better visualization of the system and its pain points. (MISO Report at 52) • Implement more efficient analysis programs to more easily and quickly inform operators of critical information needed to inform decision-making, such as a tool to help MISO understand the drivers of the RDT calculation. (MISO Report at 52) • MISO will continue to leverage collaboration tools to allow newer Operations staff to observe during real-world emergency events. (MISO Report at 52)

	• Proactively assess internal, regulator, and stakeholder data needs to identify sources for the data and standardize the format for delivering the data. (MISO Report at 54) • Leverage this Arctic Event Report as well as other Reliability Imperative messaging to raise emerging issues and provide context for stakeholders, state regulators, and federal regulators. (MISO Report at 54) • Promote use of the newly launched MISO Mobile app, which gives users access to MISO's real time data visualization tools (LMP Contour Map, Real-Time Total Load, and Real-Time Fuel Mix). MISO Mobile also provides important real-time notifications and alerts. (MISO Report at 54) • Study the potential benefits and costs of adding additional high-voltage transmission between ERCOT and its neighboring interconnections. ERCOT is unique among Although additional transmission lines would not have been able to bring in enough additional energy to fill the deep shortfall ERCOT experienced on the morning of February 15, 2021, they could help to prevent or ameliorate future grid operational problems, particularly black-start energy that could be invaluable to rebuild the grid in the event of a future collapse. Last, given Texas' wealth of wind, solar and natural gas resources, the state could benefit from exporting generation. These issues and opportunities should be studied in a thorough and apolitical fashion. An independent expert committee studied the question of transmission integration (called alternative current interconnection) with the Eastern Interconnection in 1995-6 pursuant to a 1995 Legislative directive. That study concluded that the costs exceeded the benefits of such interconnection. The new SB1 budget authorization directs the PUCT to again study the costs and benefits of interconnection with the Eastern and Western Interconnections and with Mexico. Such a study can address the questions above. (Recommendation 6-4, Mitchell Report) • Improve completeness and timeliness of resource outage reporting (ERCOT Presentation, page 58)

LOAD SHEDDING/ Transmission Operations and Reserves, System Operating Limits Recommendations	• Grid conditions deteriorated rapidly early in February 15 leading to blackouts. So much power plant capacity was lost relative to the record electricity demand that ERCOT was forced to shed load to avoid a catastrophic failure. (UT Report at 8, applies to ERCOT only)
	• Evaluate alternative means of determining each transmission operator's allocation of load-shed obligations. (SPP Report at 12, Tier 2, Assessments)
	• Implement improvements to load-shed processes to be developed by the Operating Reliability Working Group (ORWG), such as:
	  ○ Utilize real-time load values when determining load-shed ratio shares.
	  ○ Train and drill on multiple overlapping load-shed instructions.
	  ○ Perform a detailed review of models used to determine load shed ratio shares.
	  ○ Develop and document procedures and processes to address the timing and responsibility of curtailing exports before and during a load-shed event. (SPP Report at 12, Tier 2, Action)
	• Develop a policy to ensure TOP emergency response and load-shed plans have been reviewed, updated, and tested on an annual basis to verify their effectiveness, with attention to critical infrastructure. (SPP Report at 12, Tier 2, Policy)
	• MISO will encourage Local Balancing Authorities (LBAs) to refine emergency load reduction plans to include winter event load shedding, when cutting power can have different consequences than in the summer. MISO will encourage the refined emergency load reduction plans to consider which elements are critical and what to do if the requested emergency load reduction exceeds their capacity to rotate outages. (MISO Report at 48)
	• Require Texas TDUs to modify distribution circuits for more granular outage management. The PUCT should order utilities to modify their distribution systems using sectionalization devices wherever feasible to cut up each

	circuit into smaller sections, starting on those circuits hosting critical facilities so that a single hospital doesn't lock in service for a giant chunk of a city and leave others literally out in the cold. (Recommendation 3-1, Mitchell Report) • Texas should require large industrial and commercial customers to be able to reduce load remotely. Require large industrial and commercial customers, including State of Texas facilities, to have the capability to reduce load remotely by at least 30% under emergency circumstances, and require these facilities to cut their loads before ERCOT orders residential customer load-shedding. (Recommendation 3-2, Mitchell Report) • Texas should require all critical facilities to have two days' worth of backup power. The Legislature should require most critical facilities to have two days' worth of backup power (combination of PV, battery, and low-emissions propane or diesel generation). This offers two major benefits—it will improve community resilience in the face of diverse threats (such as extreme weather disasters or cyber-attack), and it will help each critical facility and its community ride through a brief grid outage or outage management failure. (Recommendation 3-3, Mitchell Report) • Facilitating rotation of higher load shed amounts in ERCOT (ERCOT Presentation, page 58) • Improve accuracy of telemetry related to frequency-responsive capability (ERCOT Presentation, page 58) • Sufficient transfer capability within and between regions is critical to enabling the advantages of regional diversity (Addressed through Long Range Transmission Planning) (MISO Presentation, April 27, 2021 at page 7) • Information Provided by Retail Electric Provider. Requires a retail electric provider to inform retail customers of involuntary load shedding procedures. Specifies the types of customers who can be considered "critical care residential customers," "critical load industrial customers," or "critical load according to PUCT rules." (Texas SB3, Section 9) • Ancillary Services. Provides the PUCT with the authority necessary to facilitate transmission of electric energy available at reasonable prices with the terms and conditions that are not unreasonably preferential, prejudicial,

	discriminatory, predatory, or anti-competitive." Requires the PUCT to require ERCOT to modify for design, procurement, and cost allocation of ancillary services in a manner that is consistent with cost-causation principles and on a nondiscriminatory basis. (Texas SB3, Section 14) • Involuntary and Voluntary Load Shedding. Requires the PUCT to promulgate rules for load-shedding by ERCOT. Requires the PUCT to issue rules that categorize the types of critical load that may receive the highest priority for power restoration. Requires the PUCT to issue rules that these entities maintain a list of customers willing to voluntarily participate involuntary load reduction and to coordinate with municipalities, businesses, and customer that consume large amounts of electricity to encourage voluntary load reduction. Requires the PUCT and ERCOT conduct load shedding exercises during both the summer and winter. (Texas SB3, Section 16) Note this Section has another recommendation about gas production captured below. • Distributed Generation Reporting. Owner or operator of distributed generation must register with ERCOT; Owner or operator must provide interconnecting transmission and distribution utility information necessary for the interconnection of distributed generator. (Texas, SB3, Section 19)
Category Natural Gas	**Recommendation**
Natural Gas Failures	• Failures within the natural gas system exacerbated electricity problems. Natural gas production, storage, and distribution facilities failed to provide the full amount of fuel demanded by natural gas power plants. Failures included direct freezing of natural gas equipment and failing to inform their electric utilities of critical electrically-driven components. (UT Report at 9, applies to ERCOT only) • Failures within the natural gas system began prior to electrical outages. (UT Report at 9, applies to ERCOT only) • Some critical natural gas infrastructure was enrolled in ERCOT's emergency response program. (UT Report at 9, applies to ERCOT only) • Natural gas in storage was limited. (UT Report at 9, applies to ERCOT only)

Fuel Assurance	• Develop policies that enhance fuel assurance to improve the availability and reliability of generation in the SPP region. (SPP Report at 11, Tier 1, Policies) • Evaluate and, as applicable, advocate for improvements in gas industry policies, including use of gas price cap mechanisms, needed to assure gas supply is readily and affordably available during extreme events. (SPP Report at 11, Tier 1, Assessment) • Develop policies to improve gas-electric coordination that better inform and enable improved emergency response. (SPP Report at 11, Tier 2, Policy) • MISO will consider the impacts of the generation fleet change on the need for additional coordination with the natural gas sector on issues of fuel assurance. (MISO Report at 48) • MISO will incorporate fuel assurance into scenario planning and drills, with a particular focus on MISO visibility into fuel plans. (MISO Report at 49) • Improved identification of critical gas facilities (ERCOT Presentation, page 58) • Mandatory weatherization to minimum standards for natural gas production and pipelines, with meaningful enforcement (Recommendation 1-1, Mitchell Report) • Creation of Texas Energy Reliability Council. This is a new organization whose function is to foster better communication between the natural gas and electric industries. It is unclear where this organization fits in relation to ERCOT and the PUCT. (Texas SB3, Section 3) • Critical Natural Gas Facilities and Entities Rules. Requires the RRC to work with the PUCT to adopt rules to establish a process to designate certain natural gas facilities and entities associated with providing natural gas in Texas as "critical customers" or "critical natural gas suppliers" during energy emergencies. (Texas SB3, Section 4) • Weather Emergency Preparedness Rules. It applies to gas supply chain facility. In general, requires the Railroad Commission of Texas (RRC) to promulgate a rule that requires a gas supply chain facility operator to implement measures that will enable the facility to operate during a weather emergency. The RRC is required to inspect gas

	supply chain facilities for compliance with rules that it issues. There are penalties associated with noncompliance (Texas SB3, Section 5, Section 6(penalties)) • Landfill Gas-to-Electricity Use. Permits non-utilities to produce, generate, transmit, distribute, store, sell or furnish electricity produced by the use of landfill methane gas. Texas SB3, Section 15) • Rules for Designating Critical Natural Gas Facilities and Entities. Requires, among other things, the PUCT to collaborate with the RRC to adopt rules that establish a process to designate certain natural gas facilities and entities that provide or otherwise associated with providing natural gas as critical during an energy emergency. Requires that ERCOT ensure that all facilities that provide electricity are given the same information under the Natural Resources Code. (Texas SB3, Section 16)
Markets	**Recommendation**
Market Design, Pricing, Credit &Settlement, and other regulatory recommendations	• Develop and improve policies to ensure price formation and incentives reflect system conditions. (SPP Report at 13, Tier 2, Policy) • Develop and implement market design and market-related enhancements identified by the Market Working Group to improve • operational effectiveness and ensure governing language provides needed flexibility and clarity, such as: o Improve the Dispatch Target Adjustment Process. Enhance the Multiday Reliability Assessment Process. (SPP Report at 13, Tier 2, Action) • Develop policies to ensure financial outcomes during emergency conditions are commensurate with the benefits provided. (SPP Report at 13, Tier 2, Policy) • Assess need for a waiver of credit-related provisions in the tariff to avoid expected reduction of virtual activity in the first quarter of 2022. (SPP Report at 14, Tier 2, Assessment) • Evaluate effectiveness of SPP's credit policy during extreme system events — focusing on price/volume risk, determination of total potential exposure, participant/counterparty risk, etc. — and develop warranted policy changes. (SPP Report at 14, Tier 3, Assessment)

	• Clarify tariff language related to SPP's settlements and credit-related authorities and responsibilities. (SPP Report at 14, Tier 3, Action) • Investigate and evaluate market price efficiency during Emergency Events requiring emergency load reduction below the Local Resource Zone levels in order to produce prices consistent with system conditions. (MISO Report at 51) • Investigate and evaluate the allocation of Real-Time Excess Congestion, including Revenue Neutrality Uplift costs, due to scarcity pricing. (MISO Report at 52) • Investigate ways to ensure that preliminary prices are representative of settlement prices during Step 5 emergency load reduction events. Implementation of such changes will have to be prioritized in light of MISO's Market System Enhancements acceleration effort. (MISO Report at 52) • MISO is evaluating if Tariff amendments will help MISO address these types of situations (bankruptcy, default) in the future. A potential solution is amending the Tariff to modify the notice process required to parties to resolve the conflicts recently experienced. (MISO Report at 52) • (Alternative Credit Exposure Calculations) To better address potential future events, MISO may seek to revise the Tariff and allow for alternative calculations that may be used in extreme pricing volatility events with appropriate notifications to parties. This would be more efficient than requesting an emergency waiver from FERC in the middle of an event (MISO Report at 53) • (Alternative Credit Exposure Calculations) MISO is evaluating using the preliminary Locational Marginal Pricing and telemetry data in the credit exposure calculation to cover the expected future S7 settlements. If this approach works, MISO's Credit Policy would need to be revised. (MISO Report at 53) • Due to increased market price volatility, the minimum capitalization requirements are being evaluated to determine in what instances they provide inadequate protection for the market. Other RTO/ISOs have already made or are considering revisions in this area. MISO is working with the other RTO/ISOs for awareness and potential standardization within the industry. (MISO Report at 53)

	• MISO is evaluating approaches that might be used to determine prudent minimum cash equivalent collateral level for market participants, thereby, providing at least some protection to the market in the event of extreme market pricing volatility. (MISO Report at 53) • Re-evaluation of creditworthiness requirements (ERCOT Presentation, page 58) • Wholesale Pricing Procedures for Emergencies. PUCT is required to promulgate rules to establish an emergency pricing program for wholesale electric market Initiation (legislative determination): Goes into effect if the high system-wide offer cap has been in effect for 12 hours in a 24-hour period after initially reaching the high system-wide offer cap. PUCT determines criteria for ceasing emergency pricing program. PUCT implements legislative determination: must prohibit an emergency pricing program cap to exceed any nonemergency high system-wide offer cap. PUCT establishes an ancillary services cap to be in effect during the period an emergency pricing program is in effect. PUCT implements legislative determination: low system-wide offer cap cannot exceed a high system-wide offer cap. PUCT must review each system-wide offer cap program it adopts at least once every five years to determine whether to update aspects of the program. PUCT implements legislative determination: generators to be reimbursed for reasonable, verifiable operating costs that exceed the emergency cap. (Texas SB3, Sec. 18) Note, this Section has another part included above)

Regulatory	
Regulatory Recommendations	• Update Texas building energy codes and require them to be automatically updated as international building codes are updated (Recommendation 2-1, Mitchell Report) • Raise TDU energy efficiency program goals to increase both annual kWh savings and peak reduction (Recommendation 2-2, Mitchell Report) • Increase energy efficiency retrofits for low-income and multi-family housing across Texas. PUCT should require at least 40% of electric utility energy efficiency program savings to come from retrofits of low-income and multi-family housing. The Legislature should modify TDHCA's low-income programs to include weatherization, building repairs and replacement of inefficient heating and cooling appliances and systems. (Recommendation 2-3, Mitchell Report.) • Increase demand response for grid emergencies. All-electric utilities, municipal utilities, and cooperatives should offer customers compensated demand response options and procure demand response that can cut at least 10% of each entity's summer peak load and 10% of each entity's winter peak load through remote actuation. (Recommendation 2-4, Mitchell Report) • Do not add an out-of-market "generation capacity reserve" scheme. The blackouts in February were not due to the lack of generation capacity within ERCOT, but rather to the failure of many generators to prepare their hardware and fuel supplies adequately for the Arctic weather; a capacity market would not have prevented this outcome. Similarly, adding emergency capacity through a fleet of additional generators funded without regulatory scrutiny through a non-market charge or tax will raise costs to every electricity customer and chill other new or existing investors' willingness to compete in the ERCOT market. (Recommendation 5-3, Mitchell Report) • Strengthen Texas' Public Utility Commission. The Legislature should increase PUCT funding and headcount to enable the Commission to hire more expert staff and consultants and improve the ongoing education of staff and commissioners about pressing market and oversight issues. (Recommendation 6-1, Mitchell Report)

	• Give ERCOT an independent, expert Board of Directors. We recommend that future ERCOT board members be selected by ERCOT Board members without any external political screening, to avoid any actual or appearance of political interference with critical, complex Board decisions affecting the ERCOT power system. And ERCOT would be better served if the Board contains some non-Texans with valuable expertise and insight to complement and broaden the Texas perspective. (Recommendation 6-2, Mitchell Report) • Release all Texas investigative findings to the public The governor should direct all Texas entities to release all investigation findings on the February outages, with no agency withholding privileges and minimal protection of private entities' commercial information. (Recommendation 7-1, Mitchell Report) • Routinely collect data on all grid and fuel supply failures and make it public. The public deserves to understand what happened when the institutions and infrastructure we rely on fail. Policy-makers need to know why it happened in order to prevent future failures. Understanding energy infrastructure problems requires that both private and public entities and individuals who possess relevant information share it, without excessive retreat behind claims of governmental or commercial privilege. The state should create formal mechanisms and entities to identify, collect and analyze relevant grid and related information for routine and extraordinary conditions (including fuel production and delivery status, power plant and transmission line status, and distribution utility outages and critical facility lists). A few elements of emergency event information may justify protection for the sake of grid security, but we should lean toward requiring all information to be shared analysis and improvement and minimize state agency or commercial barriers against information release. (Recommendation 7-2, Mitchell Report) • Improved public communications of EEA events (ERCOT Presentation, page 58) • Requires the Department of Public Safety "with the cooperation of" the Department of Transportation, the Texas Division of Emergency Management, the governor's

	office, and the Public Utility Commission of Texas (PUCT) to develop "an alert" to be activated when there is a "power outage alert." PUCT is given the authority to adopt criteria for the content, activation, and termination of the alert. (Texas SB3, Sec. 1.) • Texas Electricity Supply Chain Security and Mapping Committee. The Committee's responsibilities include: To map the state' s electricity supply chain; To identify critical infrastructure sources in the electricity supply chain; To establish best practices to prepare facilities that provide electric and natural gas services in the electricity supply chain to maintain service in an extreme weather event and recommended oversight and compliance standards for those facilities; To designate priority service needs and to prepare for, respond to, and recover from an extreme weather event. (Texas SB3, Section 17) • Penalties - Disconnecting Residential Customer During an Emergency. A natural gas provider is prohibited from disconnecting service to a residential customer during an extreme weather emergency. Associated with penalties (Texas, SB3, Section 20) • Public Education and Awareness. The RRC must adopt rules that educate the public regarding pipelines; The RRC must adopt the rules concerning the measures that a gas pipeline facility operator is required to implement in order for the pipeline to maintain service quality and reliability during extreme weather conditions; The RRC must inspect gas pipeline facilities for compliance with rules; An owner/operator must be given a reasonable time to remedy violations. The RRC must report such person to the Attorney General if the violation is not remedied within a reasonable period of time. The RRC must issue a rule requiring a gas pipeline facility operator that experiences repeated major weather -related forced interruptions must contract with a non-employee to conduct an assessment of the operator's plans and procedures for weatherization. The assessment must be presented to the PUCT. The RRC has the authority to require an operator of a gas pipeline to implement the recommendations of the assessment. The RRC must issue a penalty against an operator if it fails to remedy a violation within a reasonable period of time. (Texas, SB3, Section 21, and 22 (penalties).

	• Sec. 33 – State Energy Plan Advisory Committee. Establishes this committee of 12 members chosen by the Governor, Lieutenant Governor, and Speaker of the House. Requires that this committee prepare "a comprehensive state energy plan" by September 2022 that will evaluate methods to improve reliability, stability and affordability of electric service and provide recommendations for removing barriers that prevent sound economic decision. Requires that it evaluate "electricity market structure and pricing mechanisms" that are used to provide electric services including ancillary services and emergency response services. (Texas SB3, Section 33)

Appendix I: Data Sources Including List of Credits for Graphics not Created by Team

Natural Gas Infrastructure Data Collection. The Natural Gas Act grants the Commission authority to regulate "transportation of natural gas in interstate commerce." The Commission ensures that the rates, terms, and conditions of service by interstate natural gas pipelines, including storage and liquid natural gas (LNG) facilities, are just and reasonable and not unduly discriminatory. In addition, the Commission certificates construction and operation of interstate natural gas pipelines, including storage and LNG facilities, upon a finding of public convenience and necessity. The Commission does not have jurisdiction over much of the intrastate pipeline system, and has no jurisdiction over natural gas production, gathering, or processing.

The team asked non-jurisdictional natural gas infrastructure entities to voluntarily provide data, and thanks the many entities that did cooperate with the inquiry. Findings and recommendations for the natural gas industry are based on the following data collection, unless a data source is otherwise identified:

- Pipelines: the team obtained data from entities representing 62 percent of the total interstate pipeline mileage in Texas, 63 percent in Oklahoma, 53 percent in Kansas, and 40 percent in Louisiana. The data also includes approximately 86 percent of the total intrastate transmission mileage in the state of Texas and 22 percent in Louisiana. The team submitted data requests to pipelines based on the size of their footprint in Texas, Oklahoma, Kansas, and/or Louisiana and those most often mentioned as the source of natural gas for generators who were unable to operate due to natural gas supply issues.
- Processing: The team obtained data from processing entities owning approximately one-eighth of the total processing facilities in the affected region. In an attempt to get a representative cross-section, entities were chosen based on factors including size of individual facilities (large, medium, and small); whether the owner/operator is also involved in other parts of the industry supply chain (i.e. they also own gathering systems, pipelines, etc.); the number of facilities each entity owns or operates within Texas, Oklahoma, and Louisiana; the proportion of the region's overall processing capacity the entity holds; and whether one or more of the entity's facilities experienced an outage during the Event. The data obtained represented 15.5 percent (4.4 Bcf/d) of 2017 Texas processing capacity, 27.1 percent (1.6 Bcf/d) of 2017 Oklahoma processing capacity, and less than 1 percent (0.001 Bcf/d) of 2017 Louisiana processing capacity. Many of the recommendations stem from themes common across numerous data responses, giving the team a higher degree of confidence that the experiences of the processing facilities from which we collected data were not outliers.
- Production: Many natural gas producers are small, and they are numerous. Even some of the largest producers in Texas individually account for only approximately 8 percent of the total production. *See* https://stage.rrc.state.tx.us/oil-gas/research-and-statistics/operator-information/top-32-texas-oil-gas-producers/ "Top 32 Texas Oil & Gas Producers" for 2019, available at https://stage.rrc.state.tx.us/media/60870/top32producers2019.pdf. Given the infeasibility of obtaining data from thousands of producers, the team selected entities representative of various sizes of production by volume, as well as to cover the impacted basins in Texas, Oklahoma, and Louisiana. 22.3 percent (4.69 Bcf/d) of average Texas production volumes, 31.9 percent (1.86 Bcf/d) of average Oklahoma production volumes and 16.6 percent (1.31 Bcf/d) of

average Louisiana production volumes, based on EIA monthly production volumes. Some of the producers that provided data also owned gathering facilities, but the team did not attempt to separate gathering facilities from their associated natural gas system components.

List of Credits for Graphics not Created by Team:

- Figure 53: Natural Gas Demand November 2020 – February 2021
    - Credit: S&P Global Platts
- Figure 54: South Central U.S. Natural Gas Inflows and Outflows, February 1 – 20, 2021
    - Credit: Texas Oil and Gas Association
- Figure 55: Texas Natural Gas Inflows and Outflows, February 1 – 20, 2021
    - Credit: Texas Oil and Gas Association
- Figure 56: Texas Natural Gas Flow Changes to Neighboring Regions
    - Credit: S&P Global Platts
- Figure 62: Natural Gas Storage Withdrawals and Injections
    - Credit: UT Report, Figure 2w (attributed to Wood Mackenzie)
- Figure 108: Air-Source Residential Heat Pump Hourly Electric Demand Versus Outdoor Temperature, with Auxiliary Heating Demand
    - Credit: Philip White et al., Quantifying the impact of residential space heating electrification on the Texas electric grid, 298 Applied Energy 1, 1-11 (2021).

Appendix J: Primer on Electric Markets and Reliable Operation of the BES

To help ensure that the electric grid operates as reliably and efficiently as possible, Congress granted FERC jurisdiction over electric grid reliability through the enactment of the Energy Policy Act of 2005 (EPAct), by adding a new section to the Federal Power Act, 16 U.S.C. § 215. Pursuant to its EPAct authority, FERC certified the North American Electric Reliability Corporation (NERC) as the Electric Reliability Organization (ERO) responsible for establishing mandatory Reliability Standards, which then must be approved by FERC. FERC also promulgated regulations, approved Regional Entities to serve as regional compliance authorities,[377] and approved over 100 NERC-proposed mandatory Reliability Standards. This oversight over the grid's reliability by FERC and NERC is vital to assuring consistent and dependable access to electricity. NERC currently has 14 Reliability Coordinators (RC) in North America to ensure that the grid is run efficiently and reliably. These RCs cover wide areas, and have the operating tools and processes to do so, including the authority to prevent or mitigate emergency operating situations. Electric Reliability Council of Texas, Inc. (ERCOT), Midcontinent Independent System Operator (MISO) and Southwest Power Pool (SPP) all served as RCs in the Event Area. ERCOT, MISO and SPP are also Independent System Operators, and MISO and SPP are Regional Transmission Organizations (RTOs).[378] In the United States, RTOs and ISOs (hereafter, we will use ISO/RTOs to refer to both) plan, operate and administer wholesale markets for electricity. These entities, which are regulated by FERC, manage markets for energy and related services, for specific regions of the country.

Ensuring reliable operation of the power grid is complex and requires constant analysis and assessment. This is true for two fundamental reasons: (1) it is difficult to economically store large quantities of electricity, so electricity must be produced the moment it is needed; and (2) because alternating current (AC) electricity flows freely along all available transmission paths through the path of least resistance, it must be constantly monitored to maintain electricity flows over transmission lines and voltages within appropriate limits. The power system therefore must be operated so that it is prepared for conditions that could occur, but have not happened yet.[379] Should an outage or reliability issue occur, system operators must act promptly to mitigate

[377] The Regional Entities relevant to this event are Midwest Reliability Organization, ReliabilityFirst, SERC Reliability Corporation, and Texas Regional Entity.
[378] *See* Figure 1 in the body of the report for a map of the Event Area. ERCOT manages a wholesale energy market which is not regulated by FERC, since the exchange of power between entities occur wholly within the state not through interstate commerce.
[379] NERC's mandatory Reliability Standards require that the bulk-power system be operated so that it generally remains in reliable condition, without instability, uncontrolled separation, or cascading, even with the occurrence of any single contingency, such as the loss of a generator, transformer, or transmission line. This is commonly referred to as the "N-1 criterion." N-1 contingency planning allows entities to identify potential N-1 contingencies before they occur and to adopt mitigating measures, as necessary, to prevent instability, uncontrolled separation, or cascading. As FERC stated in Order No. 693 with regard to contingency planning, "a single contingency consists of a failure of a single element that faithfully duplicates what will happen in the actual system. Such an approach is necessary to ensure that planning will produce results that will enhance the reliability of that system. Thus, if the system is designed such that failure of a single element removes from service multiple elements in order to isolate the faulted element, then that is what should be simulated to assess system performance." *Mandatory Reliability Standards for the Bulk Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, at P 1716 (2007), *order on reh'g*, *Mandatory Reliability Standards for the Bulk-Power System*, 120 FERC ¶ 61,053 (Order No. 693-A) (2007).

adverse conditions and remain within appropriate limits. For conditions severe enough that they could cause instability, uncontrolled separation or cascading outages, mitigation must occur within no more than 30 minutes. Equally vital to the continued operation of the grid is that it is restored to a condition where it can once again withstand the next-worst single contingency.

All of the ISO/RTOs operate both "day-ahead" and a "real-time" energy markets. In the day-ahead market, buyers and sellers schedule electricity production and consumption before the operating day, which produces a financially-binding schedule, the day-ahead generation resource unit commitment, for electricity production and consumption one day prior to the actual generation and use. This provides generators and electricity load-serving entities a forecast of their needs prior to the day's operations and enables system operators to prepare an Operating Plan Analysis for the next day.[380] To perform the day-ahead unit commitment, ISO/RTOs operators look for the most economic generators to schedule to be online for each hour of the following day, taking into account factors such as a unit's minimum and maximum output levels, how quickly those levels can be adjusted and whether the unit has minimum time it must run once started, as well as operating costs. Operators need to take into account forecast electricity demand or load conditions for every hour of the next day, and other factors that could affect grid capabilities such as expected generation and transmission facility outages, any adverse weather conditions (e.g. severe heat or cold, precipitation, high winds), and line capacities. If the analysis suggests that optimal economic dispatch cannot be carried out reliably, more expensive generators may need to replace the cheaper generators to operate reliably.

The current operating day, or real-time market, begins with the Operating Plan Analysis, created with generators who bid into and were chosen in the day-ahead market. It then reconciles any differences between the day-ahead schedule and the real-time load, while taking into account real-time conditions such as forced or unplanned generation and transmission outages, as well as electricity flow limits on transmission lines and other criteria, such as voltage, for BES reliability.

Categories of NERC Registered Entities who Operate the BES

NERC identifies functions for which the entities responsible for operating the BES in a reliable manner can register with NERC. These registrations then guide which of the mandatory Reliability Standards the entity must follow. A single entity can conduct multiple reliability functions and therefore have multiple NERC registrations. The NERC registrations most relevant to this event are Reliability Coordinator, Balancing Authority, Generator Owner and Generator Operator, Transmission Operator and Planning Coordinator.

The RC is the highest level of authority and maintains reliability for its entire footprint. The RC is expected to have a "wide-area" view of its entire footprint, beyond what any single Transmission Operator could observe, to ensure operation within Interconnection Reliability Operating Limits (IROLs).[381] It oversees

[380] *See* Appendix K, "System Operator's Tools and Actions to Operate the BES in Real Time."

[381] An IROL is a System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System. *See* NERC Glossary of Terms at https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

both transmission and balancing operations, and it has the authority to direct other functional entities to take certain actions to ensure reliable operation of the BES. The RC, for example, may direct a TOP to take whatever action is necessary to ensure that IROLs are not exceeded. The RC performs reliability analyses including next-day planning and Real-Time Contingency Analysis (RTCA) for its footprint, but these studies are not intended to substitute for TOPs' studies of their own areas. Other responsibilities of the RC include responding to requests from TOPs to assist in mitigating equipment overloads. The RC also coordinates with TOPs on system restoration plans, contingency plans, and reliability-related services.

The RC is responsible for overseeing transmission operations for the wide area of the interconnection that it oversees. Similar to the TOP, below, the RC ensures the reliable real-time operation of transmission assets by performing operational planning analyses (OPAs) and preparing Operating Plans, but the RC has the "wide-area" view, beyond any individual TOP within an RC footprint. In coordination with other RCs, the RC maintains situational awareness beyond its own boundaries, to enable it to operate within its Interconnection Reliability Operating Limits (IROLs), which are limits necessary to prevent system instability and cascading outages, and it maintains reliability of its RC area. Like the BA, below, the RC ensures the generation-demand balance is maintained, but within the larger RC Area, thereby ensuring that the Interconnection frequency remains within acceptable limits. The RCs for the Event Area include ERCOT, SPP, and MISO.

The BA integrates resource plans ahead of time, contributes to the interconnection[382] frequency in real time, and maintains the balance of electricity resources (generation and interchange) and electricity demand or load within the BA Area. The BAs for the event include ERCOT, SPP and MISO. Within the MISO footprint, local BAs (LBAs) perform a small number of functions, for which they are jointly registered with the MISO BA to perform.

The GO owns and maintains generating facilities. **The GOP** operates generating unit(s) and performs the functions of supplying energy and interconnected operations services required to support reliable system operations, such as providing regulation and reserve capacity, and sharing data with BAs and TOPs as required. Many GO and GOP entities are registered as both GOs and GOPs.

The TO owns and maintains transmission facilities. **The TOP** ensures the real-time operating reliability of the transmission assets within its area. It has the authority to take actions to ensure the continued reliable operation of the Transmission Operator Area. Like the RC, it performs daily OPAs and prepares Operating Plans, but for its smaller TOP footprint. The TOP coordinates with neighboring BAs and TOPs, as well as

[382] An interconnection is a geographic area in which the operation of Bulk Power System components is synchronized such that the failure of one or more of such components may adversely affect the ability of the operators of other components within the system to maintain Reliable Operation of the Facilities within their control. When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec (*See* NERC Glossary of Terms at https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf). The ability to transfer power between two interconnections is limited by the capability of the direct current (DC) tie-lines between them, as well as the limitations of components that exist within in each interconnection.

RCs, for reliable operations. The TOP also develops contingency plans, operates within established System Operating Limits, and monitors operations of the transmission facilities within its area.

The PC is responsible for coordinating and integrating transmission facility and service plans, resource plans, and protection systems, and **the TP** is responsible for developing a long-term (generally one year and beyond) plan for the reliability of the interconnected bulk transmission systems within its portion of the Planning Coordinator Area.

Key Concepts related to Reliable Operation of the Bulk Power System

- **Voltage Control** – Maintaining consistent voltage levels is imperative, as wide deviations in the voltage levels can have severe consequences. Voltage below certain limits could lead to an electric system imbalance or collapse. Voltages above certain limits can exceed insulation capabilities and lead to equipment damage and outages. Winter peak electricity loads include resistive loads such as resistive heating, which has a higher load power factor than during summer peak conditions. Load power factor is an indicator of reactive demand —the higher the load power factor, the lower the reactive power demand. A relatively small percentage change in power factor, such as a change from 88 percent summer peak load power factor, to a 92 percent winter peak load power factor, can result in 30 percent less need for reactive power to be supplied during the winter. Summer peak electricity load includes air conditioning, which, like other induction motors, has lower power factors and consumes more reactive power than winter loads. Even with more stable voltages during winter peak conditions, system operators must continually monitor and evaluate system conditions, examining reactive reserves and voltages, and adjust the system as necessary for secure operation. [383]
- **Power Flow/Stability Control** – Protection systems (e.g. relays) are implemented and configured to guard against the unplanned loss of a generator or line from resulting in instability. Additionally, power (or angle) stability limits are set to ensure that unplanned losses will not cause the remaining generators or lines to lose synchronism (or operate out of step) with each other, causing equipment damage.
- **Operations Planning** – Operations planning time horizon includes day-ahead, week-ahead, seasonal, and up to one-year planning horizons. The primary focus of operations planning is operational readiness and preparedness to assure availability of existing generation resources and transmission facilities to reliability operate the BES. Operations planning differs from short- and long-term planning horizons. Those focus on one- to ten-year planning horizons and include evaluations to plan for adequate generation resources and transmission capacity to ensure the system will be able to withstand severe contingencies in the future without widespread, cascading outages.
- **Coordination and Communication Between Entities** – the Reliability Standards encourage principal entities (e.g., Reliability Coordinators, Balancing Authorities, Transmission Operators,

[383] U.S.-Canada Power System Outage Task Force "Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations" (April 2004) at 26.

Generator Operators, and Distribution Providers) to communicate effectively in real-time to maintain system balance between generation and load, stay within operating limits, and address issues that arise.

Ultimately, the RCs, BAs, TOPs, and other responsible entities must work individually and together to comply with the mandatory Reliability Standards and to ensure the continued reliable operation of the bulk power system.

Appendix K: System Operator's Tools and Actions to Operate the BES in Real Time

Monitoring of the transmission grid. RCs and TOPs employ system operators and engineers who use various methods to forecast and evaluate upcoming and real-time issues, so as to avoid or mitigate problems that arise in their electric grids. They continually monitor transmission facilities 24 hours a day, seven days a week, for situational awareness of the power grid. System operators typically have available a variety of real-time computer tools for monitoring the system, including State Estimator (SE) and Real-Time Contingency Analysis (RTCA).[384] RC system operators are constantly monitoring RTCA and RTCA-based displays, including lists of facilities that exceed System Operating Limits or have voltages deviating from voltage criteria in real time, and lists of facilities that would exceed System Operating Limits or have voltages deviating from voltage criteria if a contingency were to occur (another system element, such as a line, transformer or generating unit, is outaged) (the latter list is called post-contingency exceedances).

Respecting transmission system limits. For both real-time and post-contingency limit exceedances, the system operators have a number of step-wise mitigating actions they can take to restore the facilities to within system limits or voltages to within voltage criteria. For simulated post-contingency exceedances, some operator actions are taken before the contingency occurs, while for other post-contingency exceedances, the operator relies on mitigation to be taken only if the contingency were to occur. Operators should only rely on post-contingency mitigation if they are confident that there would be sufficient time to complete the mitigation before adverse system conditions (such as instability or cascading outages) would occur.

The mere fact that an actual or real-time system operating limit is exceeded does not necessarily mean that immediate reduction below the limit is required, although it does require immediate operator action. As an example, RC operators may contact Transmission Owners to determine if a temporarily-higher rating is warranted. For a projected next- or post-contingency System Operating Limit (SOL) exceedance, if also projected to exceed an Interconnection Reliability Operating Limit (IROL), meaning that it could lead to instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the BES, RC operators have a maximum of 30 minutes to take actions alleviate the IROL exceedance.[385] Otherwise, for SOLs, operators identify mitigation measures they could take as part of their operating plan, which may include measures that would be implemented prior to, or if the next contingency occurred.

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384 SE constructs a representation of the state of the system using voltages, currents, and breaker status from the real-time data, and calculates values for which data are not directly collected; while RTCA runs frequently, for example, every two to six minutes for MISO and SPP, and informs the operators how the system would be affected for the computer-simulated outage or in other words used interchangeably, "for loss of" (FLO) a specific system facility such as a transmission line or a transformer.

385 This time is defined as the "Interconnection Reliability Operating Limit T_v" which is the maximum time that an Interconnection Reliability Operating Limit can be violated before the risk to the interconnection or other Reliability Coordinator Area(s) becomes greater than acceptable. Each Interconnection Reliability Operating Limit's T_v shall be less than or equal to 30 minutes.

Monitoring power transfers to avoid exceeding transmission limits. To aid in monitoring and regulating power flows across the transmission system (often referred to as managing transmission "congestion"), system operators in RTO areas define "flowgates," by pairing specific transmission facilities and their associated next contingencies that would compound the transmission facility loading if the associated next contingency occurred. In addition to RTCA, RC operators in the Eastern Interconnection possess computer-based flowgate monitoring tools, which use the shared interchange distribution calculator (IDC) to calculate percentages of power flow impacts that each interchange power transfer schedule has on each flowgate; i.e., its transfer distribution factor, or TDF. For instance, if the need arises to reduce flowgate loading to remain within system operating limits, or in other words, alleviate market "congestion", the flowgate monitoring tool enables the operators to determine the appropriate megawatt power flow amount that can be reduced in the external market transfer to achieve this goal.

Security-constrained economic dispatch. To manage the grid, the ISO/RTO takes a wide-area view of all the resources available to it, resulting in a "dispatch stack" that contains generators from all generation-owning members of the region, including utility and non-utility Generator Owners, as well as some generation resources outside the footprint. A security constrained economic dispatch (SCED) algorithm is used to determine the appropriate and least-cost generating units to dispatch at any given time depending on market conditions. SCED aids the RTOs by, among other tasks, simultaneously balancing energy injections and withdrawals, managing congestion, and ensuring adequate operating reserves. The SCED process runs every five minutes to establish dispatch instructions for generators to meet the future load of the next five-minute period. The purpose of the algorithm is to minimize the cost to meet the forecast demand, scheduled interchange, and reserve requirements while also being subject to transmission congestion and other system reliability constraints.

An initial approach to relieving transmission congestion constraints in RCs which are also RTOs is redispatching generation at different locations on the grid, done through SCED. When system operating limits are reached, i.e., when constraints reach a threshold at which other resources will soon need to be dispatched, market operators/RCs proactively enter constraints into SCED to begin preparation for unanticipated system events. When system operators change the day-ahead generation dispatch schedule to accommodate constraints or unexpected transmission or generation outages, it is known as "security constrained redispatch."

Generation redispatch. If non-cost measures do not alleviate the congestion concerns, operators should utilize least-cost redispatch measures, including initiating market-to-market (M2M) redispatch procedures for reciprocally coordinated flowgates (RCFs) between RTOs, or utilizing a transmission loading relief procedure (TLR), which prioritizes the various types of transmission services, allowing system operators to cut less-firm transportation flows first.

Some RTOs that share a "seam," or common border, including MISO and SPP, utilize the M2M coordination process between the RTOs to assist in maintaining efficient, reliable service for their respective regions. The M2M process allows for both RTOs' RCs to coordinate interface pricing by modeling the same constraint. The previously-defined RCFs are monitored closely to gauge the impact of market flows and parallel flows from adjacent regions and markets. MISO and SPP can utilize M2M upon constraint activation in the market. During the course of the Event, MISO and SPP's RC System Operators were in frequent communication with each other, analyzing congestion and engaging in M2M congestion management when necessary to relieve congestion on binding constraints.

Transmission loading relief. In the Eastern Interconnection, RC operators can issue one or more TLR(s) to curtail transmission flowgate loadings due to power transfers on an hour-by-hour basis. TLRs are used to ration transmission capacity when demand for the transmission is greater than the available capacity. TLRs are typically utilized when the transmission system is overloaded to the point where power flows must be reduced in order to protect the system. The rationing is done based upon a priority structure that lowers or limits the power flows based on size, contractual terms, and scheduling, as opposed to the redispatch of lowest cost generation in M2M.[386] This method can be used in MISO and SPP at the RC's discretion.

Emergency measures. If a situation worsens, for example where operators have exhausted use of their tools to alleviate constrained conditions on the BES and an emergency condition is identified, the NERC Reliability Standards require specific actions in the event of an emergency. Reliability Standard EOP-011-1 requires BAs and TOPs to have plans to mitigate operating emergencies in their respective areas. Plans are required to include provisions for operator-controlled manual load shedding that minimizes the overlap with automatic load shedding and are capable of being implemented in a timeframe adequate for mitigating the emergency.

Energy emergencies. For energy emergencies, where there are not sufficient generation resource reserves for system electricity demands within a BA area (or stranded resource reserves exist - not deliverable meet electricity demands within a sub-area of a BA), an energy emergency alert (EEA) is declared. To ensure that all RCs clearly understand potential and actual energy emergencies in the Interconnection, NERC established three levels of EEAs. The RCs use these terms when communicating energy emergencies to each other. An EEA is an emergency procedure, *not* a daily operating practice. The RC may declare whatever alert level is necessary, and need not proceed through the alerts sequentially. The following is a list of the EEA levels and their description:

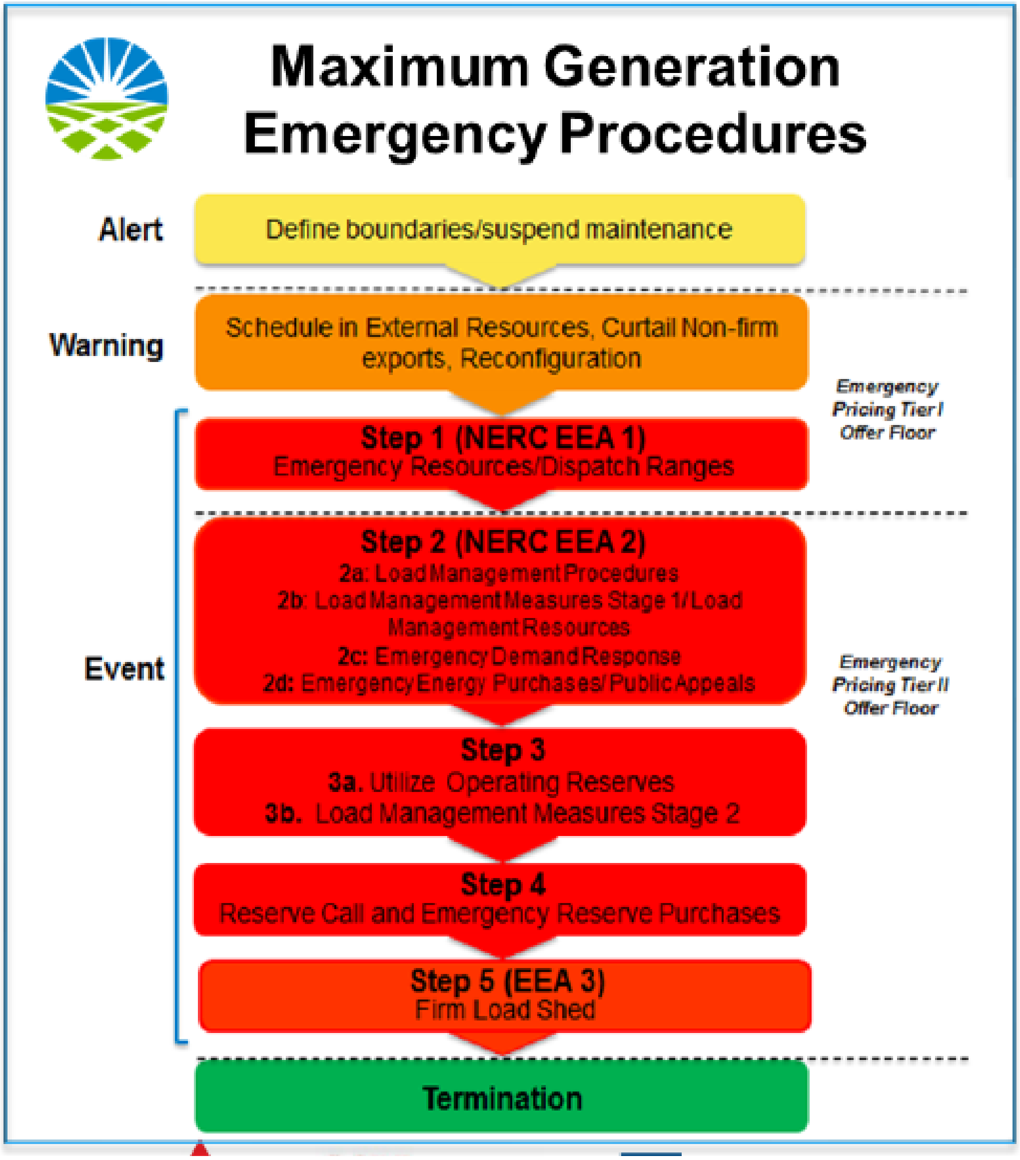
EEA 1 — All available generation resources in use.

EEA 2 — Load management procedures in effect.

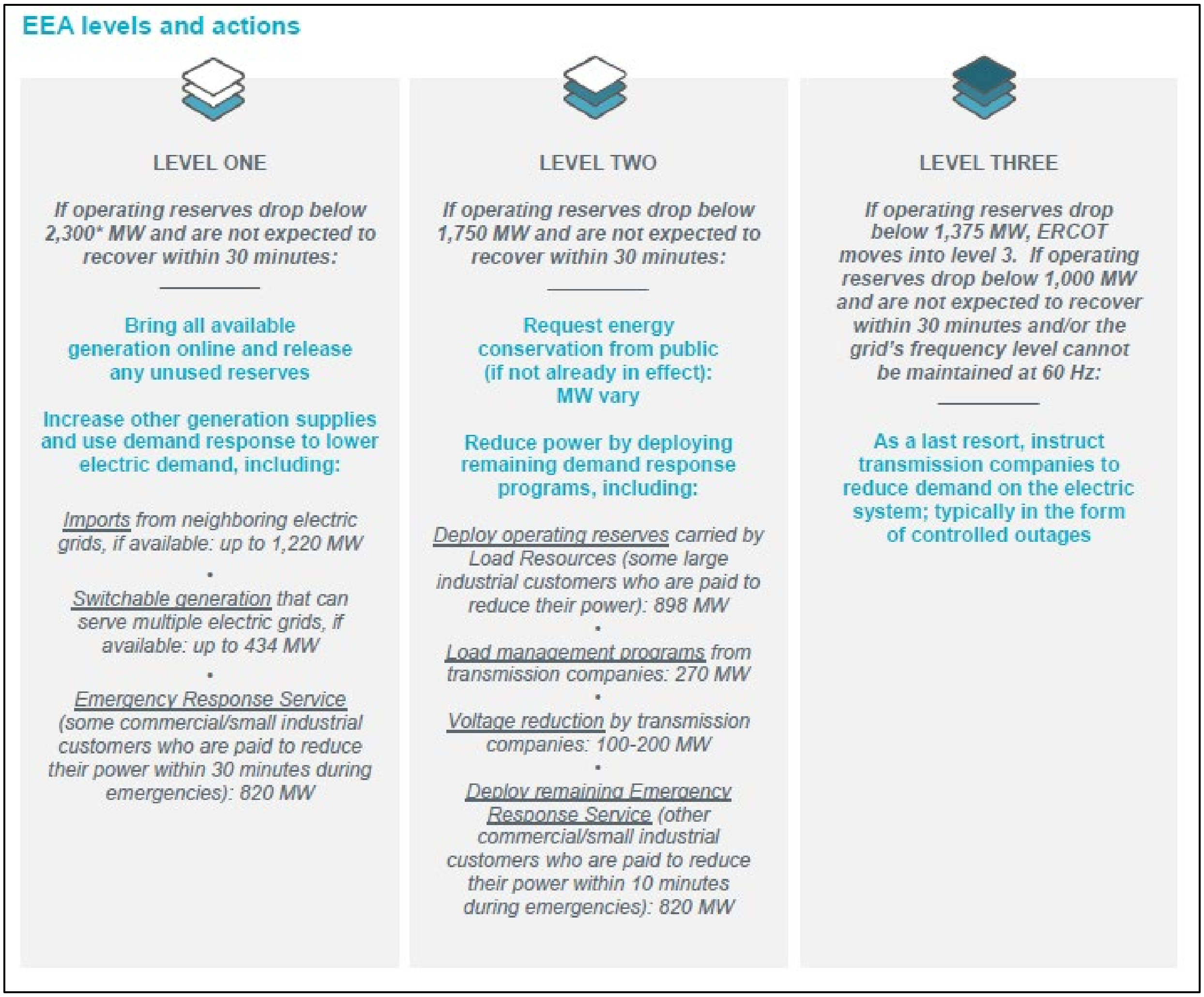
EEA 3 —Firm Load interruption is imminent or in progress.

ERCOT's, MISO's and SPP's procedures are required to be in accordance with these levels. Their procedures may contain specific steps for operators to take within these levels. For example, MISO's procedures include the following steps:

[386] The NERC TLR Procedure is an Eastern Interconnection-wide process that allows Reliability Coordinators to mitigate potential or actual operating security limit violations while respecting transmission service reservation priorities. *See* https://www.nerc.com/pa/rrm/TLR/Pages/default.aspx



ERCOT's energy emergency actions in accordance with the EEA levels are shown in the following illustration:



Transmission emergencies. TOPs may identify BES constrained conditions as being a transmission emergency, where the issue is *not* insufficient resource reserves within a BA footprint, but rather transmission system operating limits have been reached or exceeded and emergency measures are needed to alleviate the condition, such as operator-controlled manual load shedding in a specific location that effectively alleviates the transmission overload condition. TOPs are required to notify its RC when experiencing the emergency.

Appendix L: Primer on Natural Gas Production, Processing, Transportation and Storage

Natural gas production is not comprehensively regulated, and no government agency monitors daily production activity. However, some aspects of production are subject to regulation; gas-producing states monitor well drilling and permitting, and in Texas, for instance, the Railroad Commission has jurisdiction over oil and gas wells located in the state and over persons owning or engaged in drilling oil and gas wells located in the state.[387] Congress deregulated the price on natural gas at the wellhead.[388] FERC does not regulate natural gas producers, and retail natural gas sales to consumers are regulated by state public utility commissions, not by FERC.

FERC's jurisdiction over the transportation of natural gas under the Natural Gas Act (NGA) or the Natural Gas Policy Act of 1978 (NGPA),[389] which also includes the provision of natural gas storage services, begins when the gas is delivered to an interstate pipeline and continues until the gas is delivered to the wholesale purchaser, absent some intervening transaction which renders the activity exempt from federal jurisdiction. While generally the activities of intrastate pipelines and local distribution companies are exempt from FERC jurisdiction, when those entities engage in the transportation of natural gas in interstate commerce or wholesale sales for resale of natural gas, their activities are subject to FERC jurisdiction.

FERC's responsibilities include:

- Issuance of certificates of public convenience and necessity to construct and operate interstate pipeline and storage facilities, and oversight of the construction and operation of pipeline facilities at U.S. points of entry for the import or export of natural gas.
- Regulation of transportation and sales for resale in interstate commerce that are not first sales.
- Regulation of the transportation of natural gas.
- Regulation of liquefied natural gas facility siting.
- Establishment of rates and terms and conditions for jurisdictional services.[390]

[387] Among the matters covered by the Texas Railroad Commission regulations are space and density of drilling; prevention of waste; approval of water flood permits; location exceptions; intrastate pipelines; environmental and safety aspects of production, including well plugging; regulation of the injection of carbon dioxide into reservoirs; and maintenance of well records including logs, maps and production reporting. Jack M. Wilhelm, Texas Land Institute, *What Every Landman Should Know about the Railroad Commission of Texas* (2005), available at http://blumtexas.tripod.com/sitebuildercontent/sitebuilderfiles/wilhelm.pdf.
[388] Natural Gas Wellhead Decontrol Act, Pub L. No. 101-60, 103 Stat. 157 (1989).
[389] FERC also has NGA jurisdiction over sales for resale of natural gas that are not deemed first sales. A first sale does not include the sale by an interstate pipeline, intrastate pipeline, or LDC, or affiliate thereof, unless such sale is attributable to volumes of their own production.

[390] The North American Energy Standards Board (NAESB) provides business standards for pipelines in areas such as the scheduling of pipeline transportation.

- Pipelines then publish FERC-approved tariffs that cover to services, terms and conditions and rates for gas transportation.

Most interstate pipelines no longer offer sales services. The two broad categories of transportation service on an interstate pipeline are firm and interruptible transportation, subject to specified exceptions such as force majeure clauses. (The interstate pipeline companies sell transportation, not the gas itself, which is almost always is purchased separately from the producer by the shipper, except for some intrastate pipelines that sell both.) Shippers obtain firm transportation by reserving capacity with a pipeline. Shippers customarily pay a charge for the reservation of guaranteed capacity rights on the pipeline and a separate usage charge; pipeline firm rates thus include cost recovery of pipeline facilities in addition to recovery of variable transportation costs such as fuel. Interruptible service rates are usage charges that are derived from the firm service rates. Interruptible shippers do not reserve any capacity, and the pipeline will only provide service to an interruptible shipper the extent it is available.[391]

Prior to the deregulation of wellhead gas prices and open access transportation established under Commission Order No. 436 in 1985 and Order No. 636 in 1992, producers typically sold gas to both intrastate and interstate pipelines; these entities in turn sold the gas to LDCs that delivered the gas to end users. With the issuance in 1992 of Order No. 636, the Commission required interstate pipelines to unbundle their services to separate the transportation of gas from the sale of gas. Thus, today most interstate pipelines do not engage in the buying and selling of natural gas except for operational purposes. Order No. 636 further required interstate pipelines to set up informational postings to show available pipeline capacity and to ensure that all participants have access to available capacity. Additionally, holders of the firm capacity can, through capacity release, resell those rights on a temporary or permanent basis.

To understand the effects that rippled throughout the natural gas and electric systems as a result of the severe cold weather, it helps to understand a bit about the infrastructure itself. Natural gas production begins at the many thousands of wellheads located throughout the basins. The wellhead consists of equipment on top of the well that is used to manage flows of oil and gas, often produced together, arising from the underground formations. The high-pressure gas in formations is lighter than air and will often rise on its own through the wellhead to surface pipes. In other gas wells, as well as oil wells with associated natural gas, flow requires lifting equipment. Typical lifting equipment consists of the "horse head" or conventional beam pump. The pumps are recognizable by the distinctive shape of the cable feeding fixture, which resembles a horse's head and is often called a "pumpjack." The following two photographs are of a pumpjack and a wellhead, respectively. As the photo shows, the wellhead equipment above ground typically is uncovered and uninsulated, leaving the liquids in it vulnerable to freezing.

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391 Pipeline Knowledge and Development, The Interstate Natural Gas Transmission System: Scale, Physical Complexity and Business Model (August 2010), available at www.ingaa.org/File.aspx?id=10751.

 

Wells and lift equipment are monitored on a daily basis and maintained by oil and gas company employees, who are often referred to as "pumpers" or "gaugers." Their responsibilities include reporting malfunctions and spills, and ensuring that field processing equipment is operational and that production is correctly measured. Onshore gaugers may drive many miles per day to monitor dozens of wells and are dependent on the roads remaining passable.

The natural gas used by consumers consists almost entirely of methane. However, produced gas often contains other hydrocarbons such as water vapor, hydrogen sulfide, carbon dioxide, helium, nitrogen, and other compounds. Some field processing occurs near production wells to remove the water and condensates, but complete processing usually occurs at gas processing facilities. Natural gas processing facilities remove other hydrocarbons to produce what is known as "pipeline quality" dry natural gas that meets the heating content and other restrictions necessary for the safe operation of pipeline and distribution company facilities. The removed hydrocarbon natural gas liquids are sold separately.[392] Natural gas is transported to processing facilities[393] typically through small diameter and low-pressure gathering pipelines.

After gathering and processing, interstate and intrastate transmission pipelines transport gas to local distribution companies (as well as to directly attached users such as generating units). Within the United States, the pipeline network delivers gas to 76.9 million residential, commercial, industrial, and power generation customers.[394] It includes at least 210 gas pipeline systems with a total of more than 301,955 miles of transmission pipelines.[395] The pipeline system also includes more than 1,400 compressor stations, 1,000 delivery points, 5,000 receipt points, and 1,400 interconnection points.

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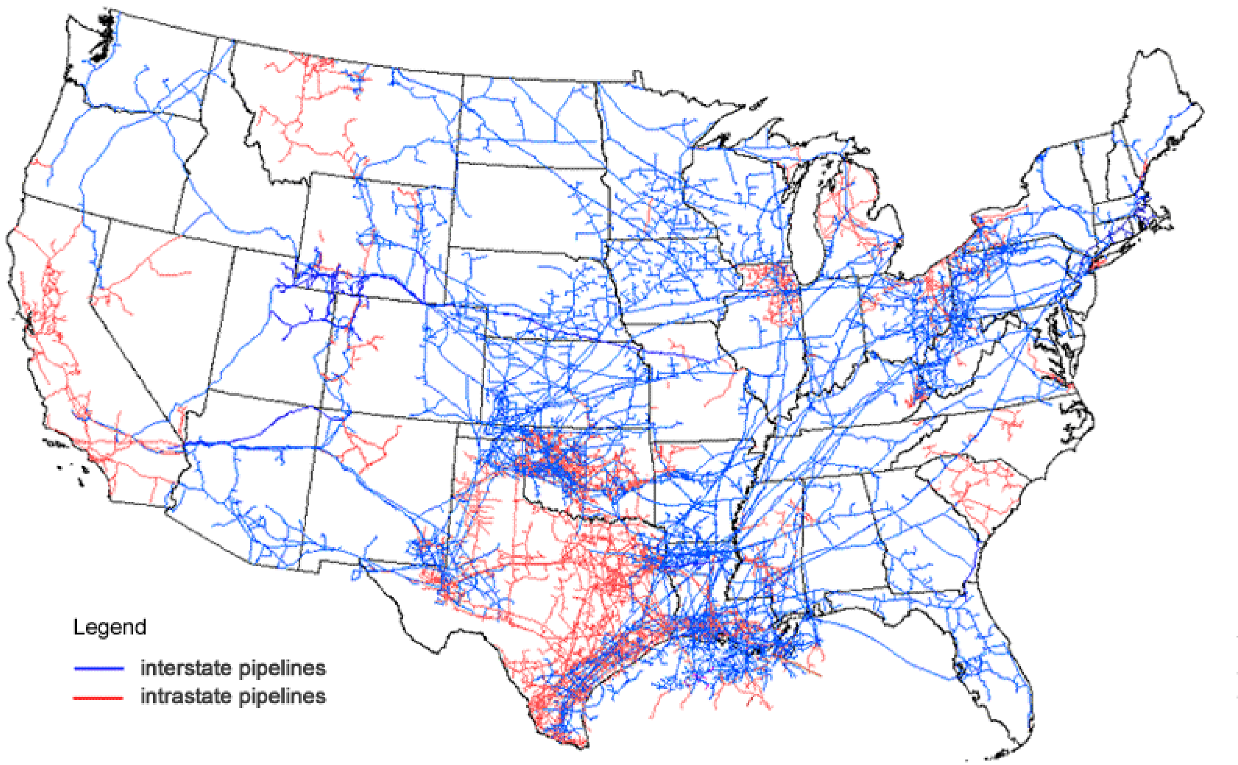
[392] 2011 Report at 34, *see also* https://oilandgasproductionhandbook.blogspot.com/2014/01/reservoir-and-wellheads.html
[393] 510 processing plants operated in the Lower 48 States in 2017 with 183, or 36 percent, in the state of Texas. EIA, *Natural Gas Processing Capacity in the Lower 48 States*, (Feb. 1, 2019), https://www.eia.gov/analysis/naturalgas
[394] https://www.eia.gov/energyexplained/natural-gas/natural-gas-pipelines.php *Last updated: December 3, 2020.*
[395] https://www.phmsa.dot.gov/data-and-statistics/pipeline/annual-report-mileage-natural-gas-transmission-gathering-systems *Last updated: September 1, 2021.*

Figure 133: Map of U.S. Interstate and Intrastate Natural Gas Pipelines



Source: U.S. Energy Information Administration, *About U.S. Natural Gas Pipelines*

Pipeline companies monitor and control gas flow with computerized supervisory control and data acquisition (SCADA) systems, which provide operating status, volume, pressure, and temperature information. In addition to real-time monitoring, the SCADA system may enable a pipeline to start and stop some facilities remotely.

To meet higher gas demand at various times of the year, gas is stored underground in depleted oil and gas reservoirs, aquifers or caverns formed in salt beds. Storage facilities may be interstate and regulated by FERC, or intrastate and non-jurisdictional. There are over 387 active underground storage fields in the Lower 48 states, of which approximately 196 are under FERC jurisdiction. Depleted oil and gas reservoirs account for 87 percent of the total FERC jurisdictional storage capacity, with salt caverns (3 percent) and aquifers (10 percent) accounting for the rest.[396]

[396] https://www.ferc.gov/industries-data/natural-gas/overview/natural-gas-storage/natural-gas-storage-storage-fields *Last updated: July 22, 2020.*

Appendix M: Sensing Lines and Transmitters

There were many reports of frozen transmitters causing generating units to be forced offline during the cold weather event. In almost all cases, it was not the transmitters themselves that froze, but rather sensing lines filled with standing (non-flowing) water routed between the transmitters and the points the sensing lines are measuring.

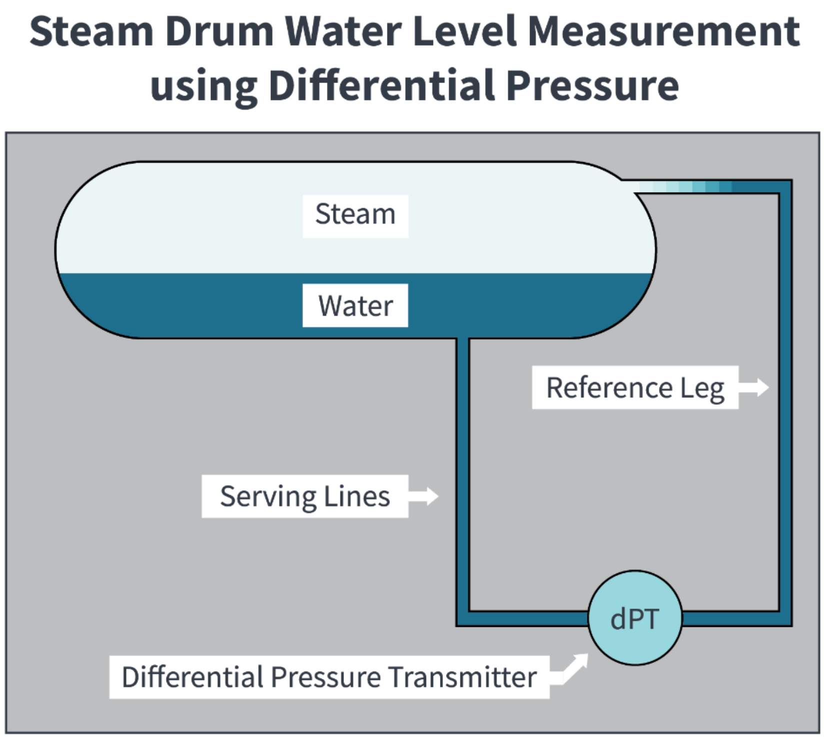
Transmitters. The transmitter assemblies perform three distinct functions. First, they detect the difference in pressure between two water lines, typically with a diaphragm-type sensor that deflects in the direction of, or towards, the lower pressure. Second, they serve as transducers that translate the pressure difference into an electrical signal. Third, they boost or otherwise process the signal for transmitting to the plant's control room, generally using electronics.

Differential Pressure Measurement. The technique of measuring the pressure difference (differential pressure) between two sensing lines filled with water has widespread application throughout power plants, especially in steam-powered generating units. Differential pressure can be used to provide not just a measure of pressure itself, but also of water levels and flow rates. Significant applications include the following:

- **Pressure Measurement**
  - Between a boiler feedwater pump and the steam drum
- **Water Level Measurement**
  - In feedwater heater tanks
  - In the deaerator tank
  - In the steam drum
- **Water Flow Measurement**
  - Feedwater flow
  - Generator stator cooling water flow

Water Level Measurement. Differential pressure can be used to measure water level by virtue of the force of gravity, which results in greater pressure as the water level increases. This is akin to the hydraulic head resulting from water in an open reservoir, which is a measure of water pressure compared against standard atmospheric pressure. The method needs to be modified, however, to account for the fact that the space within a tank above the water is pressurized. Hence the use of differential pressure measurement, with one sensing line connected to the bottom of the tank to sense the water pressure, and the other to the top of the tank to sense the water vapor or steam pressure. The line at the top of the tank is known as the reference line. Even though the reference line connects to the top of the tank, which is above the water level, it will itself still fill up with water because the vapor/steam condenses in the line due to the much cooler ambient air temperature external to the tank.

Figure 134: Steam Drum Water Level Measurement using Differential Pressure



Water Flow Measurement. Differential pressure can be used to measure water flow by virtue of Bernoulli's principle: an increase in the speed of a flowing fluid is accompanied by a decrease in pressure. This increase in speed can be forced by placing a constriction such as an orifice plate or nozzle inside a pipeline, reducing its effective diameter. In order for the rate of flow in gallons per minute, for example, to remain the same, the velocity of the fluid must increase to make up for the fact that it is travelling through a smaller opening. This phenomenon is known as the Venturi effect. The higher velocity translates into lower pressure by Bernoulli's principle. Thus, measuring the differential pressure on either side of the constriction provides a measure of the rate of flow through the pipeline.

For exact flow measurement, the design and dimensions of the constriction are critical. In some cases, however, the concern lies more with changes in flow rate, indicative of blockages in the piping or overall flow path. This concern is important when strainers are used to filter out undesired particles from the fluid, especially in generator stator cooling systems. The strainers provide constriction to the water flow, resulting in a pressure difference. When the strainers are clogged, the pressure difference increases.

Steam flow can also be measured using the Venturi effect. But in that case, long sensing lines are not needed, as pressure immediately on either side of the orifice plate or nozzle is measured.

The Freezing Problem. Since differential pressure measurement requires gauging the difference in pressure between two separate sensing lines, if the water in either or both of those lines freezes, the measurement will be false. When a sensing line is plugged with ice, it cannot convey the intended water pressure to the transmitter location.

The fact that the water in the sensing lines is not flowing makes freezing all the more likely and emphasizes the need for proper freeze protection methods such as insulation and heat tracing. Some sensing lines must run long distances through areas exposed to outdoor ambient air, which significantly exacerbates the risk of false readings.

November 2021

FERC - NERC - Regional Entity Staff Report:

The February 2021 Cold Weather Outages in Texas and the South Central United States

Federal Energy Regulatory Commission

North American Electric Reliability Corporation

Regional Entities