

The Offices of Electric Reliability and Enforcement and North American Electric Reliability Corporation (NERC) staff are pleased to present the preliminary findings and recommendations of the Joint FERC/NERC/Regional Entity Inquiry into the February 2021 Cold Weather Event in Electric Reliability Council of Texas (ERCOT), Midcontinent Independent System Operator, Inc. (MISO) and Southwest Power Pool, Inc. (SPP). Final findings and recommendations will be included in the full report, which is expected to be issued by this winter.

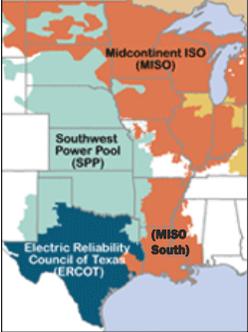
The inquiry team consists of nearly 50 subject matter experts from the staff of Commission offices OER, OE, OEP, OEPI, OEMR, OEIS and OGC, NERC and all of its Regional Entities: Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), ReliabilityFirst Corporation (RF), SERC Corporation (SERC), Texas Reliability Entity (TRE) and the Western Electricity Coordinating Council (WECC); as well as the Department of Energy and the National Oceanic and Atmospheric Administration (NOAA).

The team would like to thank the many entities that provided data and participated in calls to answer questions and share perspectives, including the owners and operators of generating units affected by the extreme weather conditions, transmission entities, ERCOT, SPP and MISO, and especially the non-jurisdictional natural gas producers, processors and pipelines that voluntarily cooperated with the inquiry.

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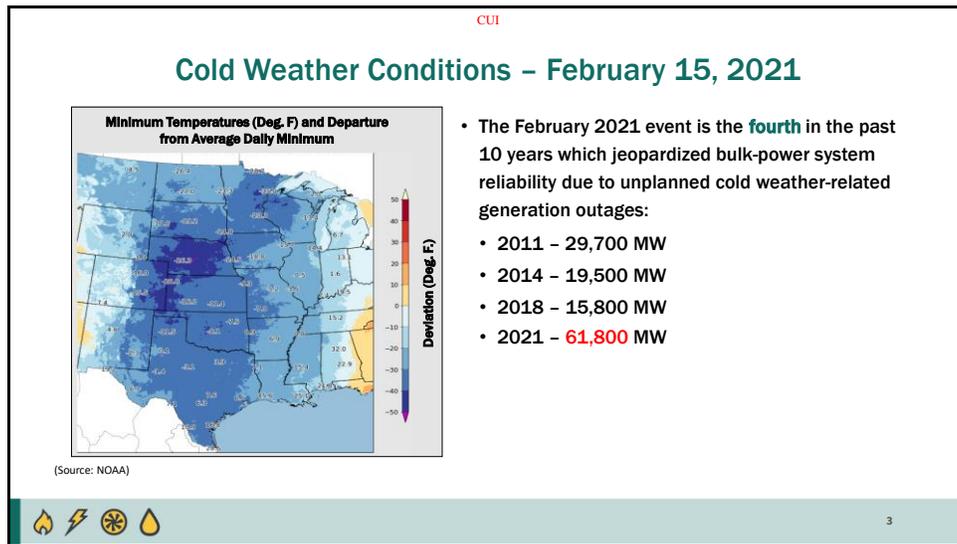
Inquiry Commencement Cold Weather Week of February 14, 2021

- Unprecedented electric generation outages
- Affected Balancing Authorities (BAs) declared Energy Emergencies and ordered firm load shed at different points of time within their respective footprints, in total exceeding **23,400** MW during severely cold weather to avoid entire system blackouts.
 - ERCOT BA: nearly three consecutive days and at its worst point, **20,000** MW
 - SPP BA: approximately five hours total and at its worst point, **2,700** MW
 - MISO BA (MISO South): over two hours and at its worst point, **700** MW



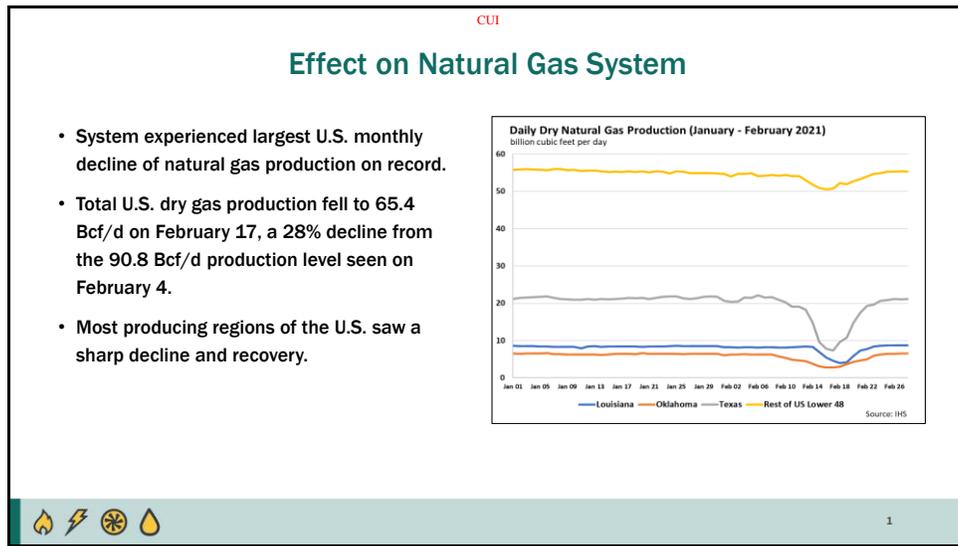
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The Event which is the subject of the inquiry occurred from February 8 through 20 2021, during which the extreme cold weather and precipitation caused large numbers of generating units to experience outages, derates or failures to start, resulting in energy and transmission emergencies (referred to as “the Event”). The total Event firm load shed was the largest controlled firm load shed event in U.S. history and was the third largest in quantity of outaged megawatts (MW) of load after the August 2003 northeast blackout and the August 1996 west coast blackout. The Event was most severe from February 15 through February 18, 2021, and it contributed to power outages affecting millions of electricity customers throughout the regions of ERCOT, SPP and MISO South shown on the slide (referred to as “Event Area”). On February 16, 2021, the Commission and NERC announced a joint inquiry with the Regional Entities, to “examine the root causes of the reliability events that have occurred throughout the country, in particular the regions served by ERCOT, MISO and SPP.”



ERCOT, SPP and MISO Balancing Authorities, who balance available electric generation and load, knew from weather service forecasts in early February 2021, that an arctic cold front would bring much colder weather. Each Balancing Authority issued cold weather preparation notices to generation and transmission operators in each of their respective footprints (SPP and ERCOT on February 8, and MISO on February 9) to prepare for the cold weather. The arctic cold air mass resulted in average temperatures dropping well below freezing for areas including Texas, Oklahoma, Arkansas, Louisiana and Mississippi. In addition to the arctic air, the cold front brought periods of freezing precipitation and snow to large parts of Texas and south-central U.S., from February 10, extending into the week of February 14, 2021.

Extreme cold weather is a common occurrence in the U.S., and it has jeopardized the reliable operation of the bulk-power system. The February 2021 event is the fourth in the past 10 years which jeopardized bulk-power system reliability. In February 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 with need for firm customer load shed. In January 2014, a polar vortex affected Texas, central and eastern U.S.. This 2014 event also triggered many generation outages, natural gas availability issues and resulted in emergency conditions including voluntary 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 the need for voluntary load shed emergency measures.

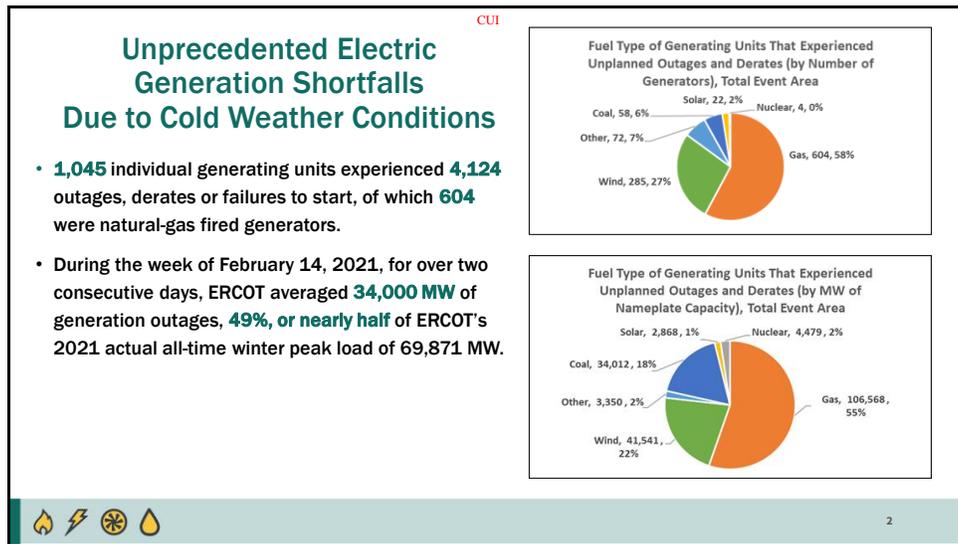


During the Event, shut-ins and unplanned outages of natural gas wellheads, as well as unplanned outages of gathering and processing facilities, resulted in a decline of natural gas available for supply and transportation to many natural gas-fired generating units in the south-central U.S.

Most producing regions of the U.S. saw a sharp decline and recovery: when temperatures fell, regional production dropped, and as temperatures rose after the Event, regional production recovered, ultimately to pre-Event levels. The largest impacts on natural gas production were in Texas, Oklahoma, and Louisiana, where combined daily natural gas production declined to an estimated 20 Bcf/d (exceeding a 50 percent decline, when compared against average production from February 1-5). 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.

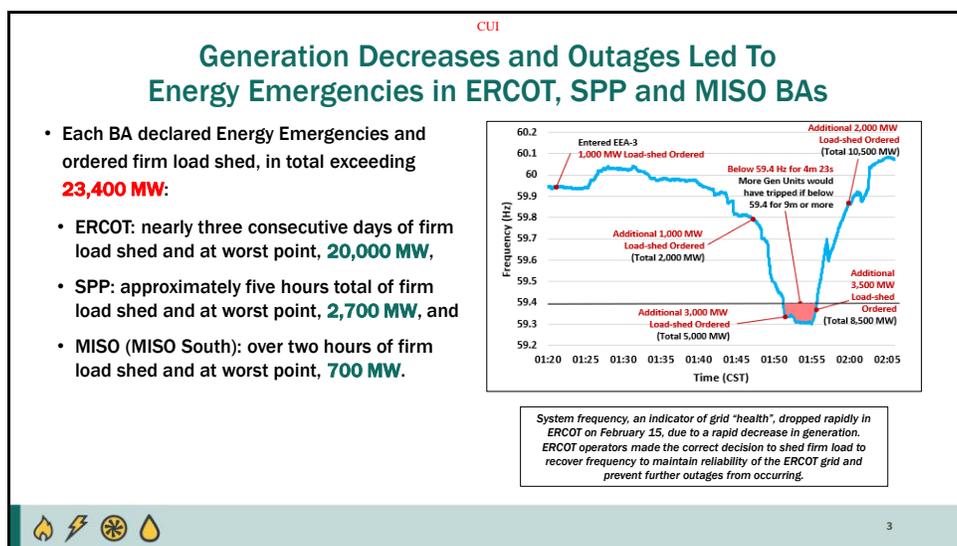
Texas and the south-central U.S. rely heavily on natural gas for fueling electric generation to meet peak capacity and energy needs. Likewise, the natural gas infrastructure relies heavily on electrical power for producing, processing and transporting natural gas to end-users, including natural-gas fired generation and residential heating customers. Careful planning and coordination to manage the needs of the natural gas and electric systems in light of this “interdependency” is important so that both systems are ultimately reliable for consumers, especially during cold

weather conditions when the demand for natural gas and electricity are at their highest levels.



The cold weather conditions in the areas of ERCOT, SPP and MISO South resulted in a total of 1,045 individual bulk-power system generating units experiencing either an outage, a derate, or a failure to start from February 8 through February 20, 2021. A single generating unit can range from a gas turbine, to a 1,000-MW-plus nuclear unit, to a wind farm with multiple wind turbines. To provide perspective on how significant this was, including generation already on planned or unplanned outages, ERCOT averaged 34,000 MW of generation unavailable (based on expected capacity) for two consecutive days from February 15 to 17, equivalent to nearly half of its all-time winter peak electric load of 69,871 MW.

In the southern portions of the 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 build-up. For the colder months, when temperatures may fall below freezing, these facilities are at risk of incurring freezing issues. Other energy production facilities are also at risk of being impacted by cold weather, including wind turbine generators and facilities that are involved in the production of natural gas, such as natural gas wellheads and processing facilities. Owners and operators of these facilities need to undertake specific freeze protection efforts, which typically involve a combination of heat tracing, insulation, wind breaks, temporary heating and other weather protection measures in order to be reliable during the cold weather conditions.



Between February 15 and 18, ERCOT, MISO and SPP Balancing Authorities needed to implement energy emergency measures including firm load shed within their respective footprints. Of the three Balancing Authorities, ERCOT needed to shed the greatest quantity of firm load to balance electricity demands with the generating units that were able to remain online. The firm load shed began when the ERCOT footprint suffered the loss of 15,000 MW of generation in a five-hour period from February 14, 10:00 pm CST (all times in CST) to 3:00 am on February 15. To maintain system reliability during a period of rapid interconnection frequency decline, the ERCOT Balancing Authority operators first ordered 1,000 MW of firm load shed on February 15 at 1:20 am. By 4:30 am, ERCOT had ordered 10,000 MW of firm load shed. ERCOT steadily increased the amount of load shed ordered because of the continued increase in generating units outaged or derated. By 7:00 pm on February 15, ERCOT needed to order 20,000 MW of firm load shed. 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 Mexico. ERCOT did schedule power to be imported to the extent available from the Eastern Interconnection.

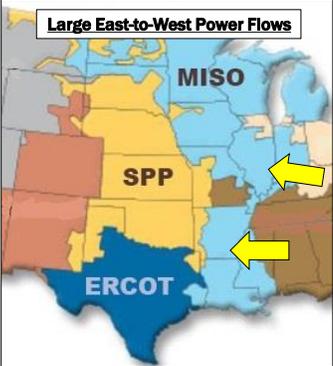
SPP shed 610 MW for approximately two hours on February 15 when its imports were curtailed. On February 16, SPP shed load in two separate steps of 1,360 MW each (33

minutes apart), totaling 2,720 MW, for three hours. In both instances, SPP restored the load it had shed once curtailed imports were restored. MISO declared an energy emergency for MISO South, and on February 16, needed to shed a maximum of 700 MW firm load during its evening peak to provide sufficient reserves.

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Generation Shortfalls Also Led To Transmission Emergencies in MISO and SPP

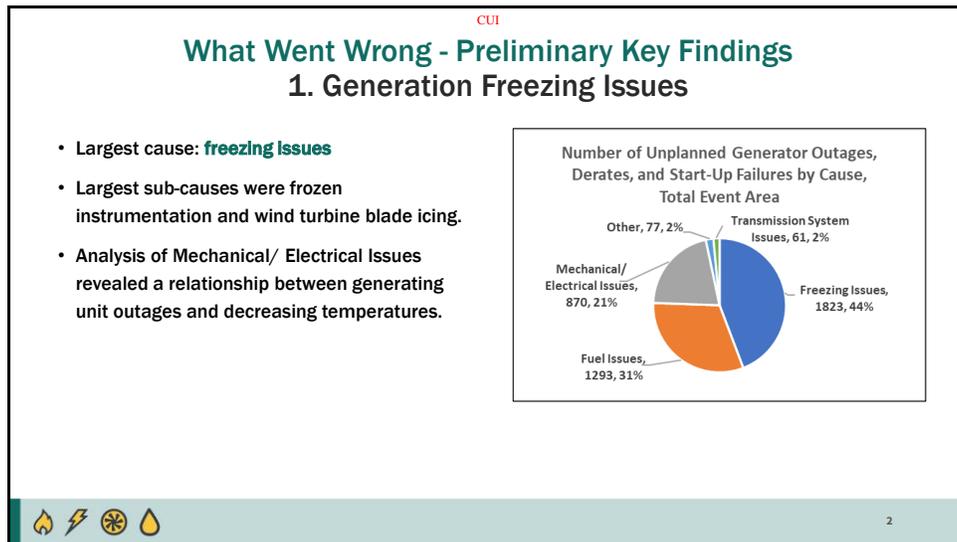
- The bulk-power system was heavily constrained with large power flows.
- On February 15, 2021, east-to-west import power flows approached **13,000 MW** to help mitigate generation shortfalls and meet winter peak energy demands in MISO and SPP.
- MISO shed in total over **2,000 MW** firm load at different points in time on February 15 and 16 to avoid transmission overloads.



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The unforeseen unavailable generation and high electric demands during the cold weather conditions required large power transfers from the eastern portion of the Eastern Interconnection, which was not experiencing the same severe weather, into MISO and SPP in the western portion. MISO Reliability Coordinator (RC) declared several transmission emergencies from February 15 to February 17 to manage the large power flows resulting from transfers needed to help mitigate energy emergencies caused by generation shortfalls and to meet winter peak electricity demands in MISO and SPP. Several transmission constraints in MISO required in total over 2,000 MW of firm load shed at different times and locations on the grid to maintain bulk-power system reliability. Overall, MISO's and SPP's ability to transfer power through their many transmission ties with adjacent Balancing Authorities in the Eastern Interconnection helped to alleviate their generation shortfalls, preventing more severe firm load shed.

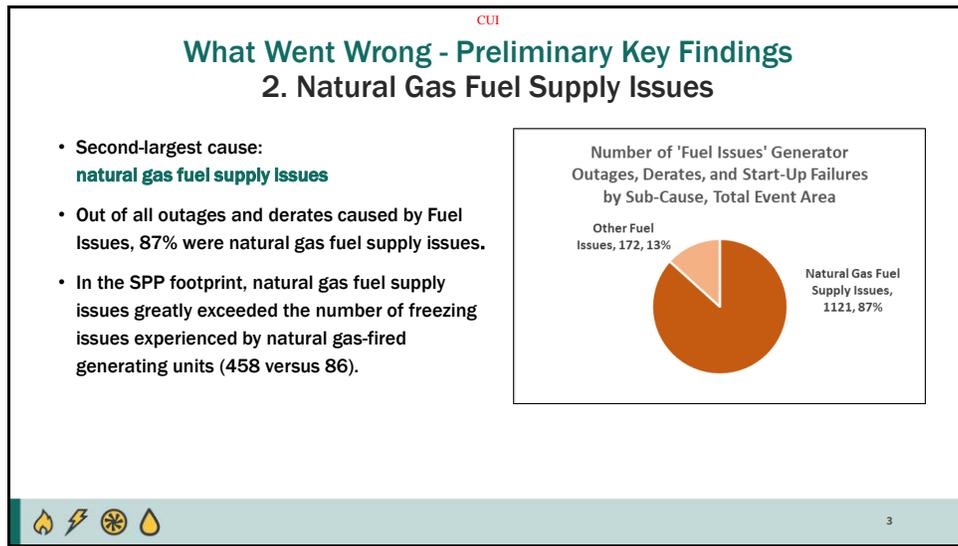
ERCOT, unlike MISO and SPP did not have the ability to import many thousands of MW from the Eastern Interconnection. Had ERCOT been able to import more power, it would have decreased the amount that MISO and SPP would have been able to import.



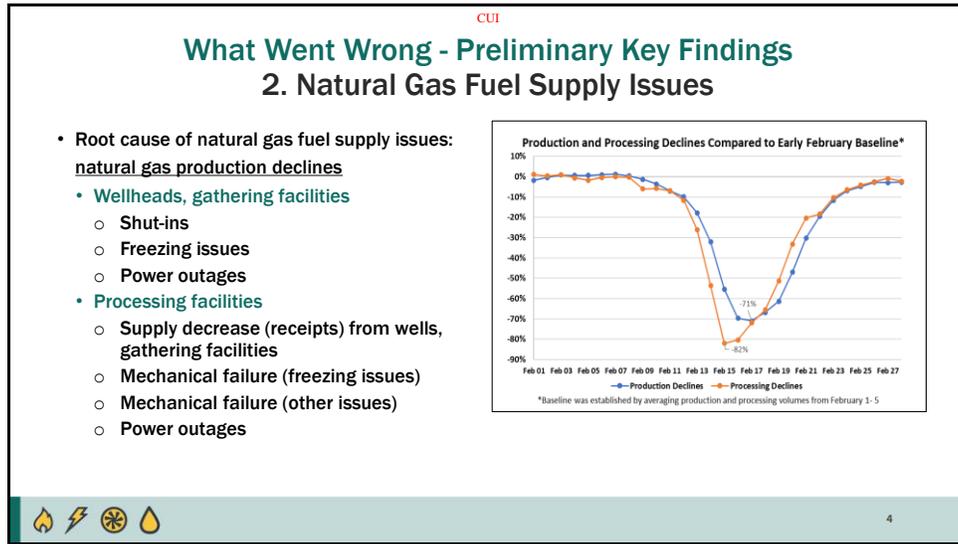
Many generating units experienced multiple outages during the Event from February 8 through 20, as discussed earlier. This pie chart shows the causes for the 4,124 outages, derates or failures to start (e.g., freezing issues, fuel issues). Together, freezing issues and fuel issues accounted for 75% of the unplanned generator outages and derates.

Freezing issues, which in turn are caused by failure to sufficiently “winterize” the generating units for cold weather conditions, are the largest cause. Of the 1,823 unplanned outages, derates, and failures to start caused by freezing issues, 1,244 were in ERCOT, 473 were in SPP, and 106 were in MISO South. The most common sub-causes of generation outages and derates due to freezing issues were frozen instrumentation (sensing lines, transmitters) and icing on wind turbine generator blades.

Although outages, derates or failures to start caused by failure to sufficiently “winterize” the generating units were 44 percent of the total, analysis of the 21 percent of outages, derates or failures to start caused by “Mechanical/Electrical Issues” indicated that they are also related to the cold temperatures. As temperatures decreased, the number of generating units outaged or derated due to mechanical/electrical issues increased.



From February 8 through February 20, 2021, of the 1,293 unplanned generating unit outages, derates, and failures to start that were due to fuel issues, 1,121 (87 percent) were due to natural gas fuel supply issues. Natural gas fuel supply issues included 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 pressure. Natural gas fuel supply issues led to a total of 357 individual natural gas-fired generating units experiencing either an outage, a derate or a failure to start (within ERCOT - 185 units, SPP - 141 units and MISO/MISO South - 31 units).



The major causes of the decline in natural gas wellhead production were shut-ins to protect natural gas production and processing facilities from freeze-related impacts, frozen equipment, loss of power supply, and poor road conditions (due to precipitation) that prevented the removal of fluids from production sites or access to facilities to make necessary repairs.

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What Went Wrong - Preliminary Key Findings

3. Natural Gas and Electric Reliability Interdependency

- Natural gas production facility loss of power was primarily due to weather-related power line outages and firm load shed.
- 60% of natural gas-fired generating units affected by fuel supply issues had outages, derates, or failures to start by February 14, and 32% had fuel supply issues before and after February 14.

Natural gas fuel supply reductions caused the outages/derates/failures to start:	2/8 - 2/14 Prior to Firm Load Shed	2/15 - 2/20 Firm Load Shed (2/15 - 2/18)
Total Individual Generating Units	213	258
ERCOT BA Footprint	111	134
SPP Footprint	91	103
MISO South Footprint	11	21

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From February 8 through 20, 2021, loss of power to natural gas wellheads and processing facilities was primarily due to a combination of weather-related power outages and firm load shed. 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 the units affected by natural gas supply reductions had already experienced outages, derates, or failures to start by February 14, before any firm load had been shed, and 32 percent had fuel supply issues during both periods.

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What Went Wrong - Preliminary Key Findings

4. ERCOT Firm Load Shed Affected Natural Gas Facilities

- Most natural gas production and processing facilities surveyed were not identified as critical load or otherwise protected from load shedding.
- As a result, firm load shed implemented by transmission operators to preserve bulk-power system reliability partially contributed to the decline in production of natural gas.
- Because many critical natural gas infrastructure loads are not identified, and both weather-caused and firm-load-shed-caused power outages were coincident, the exact extent of power outages to critical natural gas infrastructure loads due to firm load shed is unknown.

 6

The manual load shed plans of Transmission Operators and automatic underfrequency load shed plans of Transmission Owners and Distribution Providers 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 by the inquiry team were not identified as critical loads or otherwise protected from manual load shedding.

Thus, from early February 15 through February 18, the implementation of manual firm load shed by ERCOT operators to preserve bulk-power system reliability partially contributed to the decline in the production of natural gas.

In this Event, natural gas pipelines were only minimally affected by power outages (because most have backup power) and were largely able to meet their firm transportation commitments. This was not an event that tested the capacity of the natural gas transportation system, as the 2011 event did, because the natural gas pipeline transportation system's inputs (production and processing) and the demand (natural gas-fired generating units) experienced massive losses.

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What Went Wrong - Preliminary Key Findings

5. Manual and Automatic Load Shed Coordination

- From February 15 through 16, 2021, manual firm load shed varied from 10,000-20,000 MW, 14%-28% of ERCOT's peak load.
- ERCOT's manual load shed spanned nearly three days in order to maintain bulk-power system reliability.
- The magnitude and duration of manual load shed needed made it difficult to rotate the outages and required system operators to use automatic/UFLS load shed circuits (configured for 25% of ERCOT's peak load) for manual load shed instead, thereby reducing the circuits available for UFLS.



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The combined magnitude and duration of manual firm load shed needed to maintain bulk-power system reliability in ERCOT caused electric service providers (Transmission Operators, Transmission Owners and Distribution Providers) 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 SPP and MISO, the manual load shed amounts were much smaller and therefore did not require their grid operators to use UFLS-configured electric circuits for implementing manual load shed.

System operators are required to minimize overlap between manual load shed and UFLS. 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 bulk-power system reliability.

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What Went Right - Preliminary Key Findings

6. Electric Reliability Coordination

- SPP, MISO and ERCOT Reliability Coordinators (RCs) coordinated and communicated well with each other.
 - Beginning February 8, SPP and MISO begin management-level discussions about the upcoming severe cold weather forecast and natural gas fuel restrictions expected, and beginning February 14, they kept an open communication channel between control rooms throughout the Event.
 - On February 12, SPP began coordinating with ERCOT about which BA would rely on switchable generation that both BAs depend on as capacity resources.
 - The RCs recognized that all three footprints were simultaneously having emergencies and cooperated to alleviate the most critical conditions first.

 8

The team found that the three Reliability Coordinators effectively managed the constrained bulk-power system conditions. For example, during a period when alleviating emergency grid conditions in MISO and SPP meant curtailing the flow of power into ERCOT Interconnection, all three RCs communicated and prioritized which of their emergencies was the most severe. MISO and SPP RCs' emergency conditions were tolerated for an additional period of time, but the Reliability Coordinator operators were able to maintain the flow of power into ERCOT to aid its emergency energy situation while maintaining bulk-power system reliability.

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Preliminary Recommendations

- 28 Recommendations, which include:
 - Nine key recommendations, including Reliability Standards changes
 - Five recommendations for further study
- Each have recommended timeframes for implementation
 - before Winter 2021/2022
 - before Winter 2022/2023
 - before Winter 2023/2024

} Most are recommended within these timeframes
- Some could extend beyond winter 2023-2024, but should be completed as soon as possible

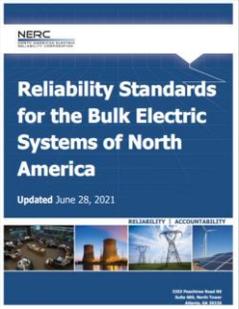
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The team made 28 preliminary recommendations, nine of which are key recommendations which we detail in this presentation. Each recommendation includes one of four timeframes within which the inquiry team recommends that it be implemented. The team recommends that each winter's recommendations be implemented by November 1. For 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. The inquiry team expects that some of its members will follow the implementation of these recommendations and report back to the Commission, NERC, and the Regional Entities on the status of implementation efforts.

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Key Preliminary Recommendations Reliability Standards

1. Revise the Reliability Standards to require:
 - Generator Owners (GOs) to identify and protect cold-weather-critical components
 - GOs to build new generating units, and retrofit existing 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
 - Annual training on winterization plans
 - GOs that experience freeze-related outages to develop Corrective Action Plans



These recommendations are above and beyond the NERC Reliability Standards revisions to address cold weather. See 176 FERC ¶ 61,119 (August 2021).


1

These recommendations are above and beyond the revisions which the Commission approved in August.

- Generator Owners are to identify and protect cold-weather-critical components and systems for each generating unit. Cold-weather-critical components and systems 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.

(Implementation Timeframe before Winter 2023/2024)

- Generator Owners are to design new or retrofit existing generating units to operate to a specified ambient temperature and weather conditions (e.g., wind, freezing precipitation). The specified ambient temperature and weather conditions should be based on available extreme temperature and weather data for the generating unit's location, and account for the effects of precipitation and accelerated cooling effect of wind.

(Implementation Timeframe before Winter 2023/2024)

- Generator Owners and Generator Operators are to conduct *annual* unit-specific cold weather preparedness plan training.

(Implementation Timeframe before Winter 2022/2023)

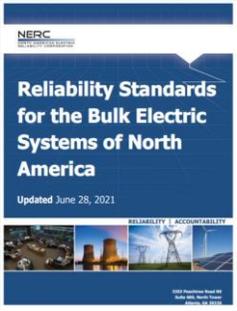
- Generator Owners that experience outages, failures to start, or derates due to freezing are to review the generating unit's outage, failure to start, or derate and develop and implement a corrective action plan for the identified equipment, and evaluate whether the plan applies to similar equipment for its other generating units.

(Implementation Timeframe before Winter 2022/2023)

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Key Preliminary Recommendations Reliability Standards

- Each GO/Generator Operator (GOP) 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,” including reliability risks related to natural gas fuel contracts.
- Each BA to use the data provided by the GO/GOP, combined with its evaluation, based on experience, to calculate the percentage of each individual generating unit’s total capacity that it can rely upon during the forecasted cold weather for its operating plans (season-ahead, day(s)-ahead) and real-time monitoring, and share with the RC.



These recommendations are above and beyond the NERC Reliability Standards revisions to address cold weather. See FERC ¶ 61.119 (August 2021).






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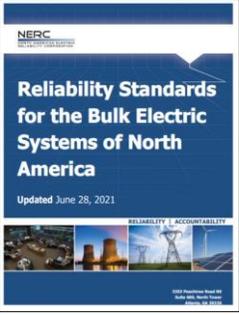
The Reliability Standards should be revised to provide greater specificity about the relative roles of the Generator Owners, Generator Operators and Balancing Authorities in determining the generating unit capacity that can be relied upon during “local forecasted cold weather,” which is language from the revised Reliability Standard TOP-003, R2.3, approved by the Commission in August.

- Each Generator Owner/Generator Operator should be required to provide the Balancing Authority with the percentage of the total generating unit capacity that the Generator Owner/Generator Operator reasonably believes the Balancing Authority can rely upon during the “local forecasted cold weather,” including reliability risks related to natural gas fuel contracts.
- 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 each individual generating unit’s total capacity that it can rely upon during the “local forecasted cold weather,” and share its calculation with the Reliability Coordinator. Each Balancing Authority should be required to use that calculation of the percentage of total generating capacity that it can rely upon to “prepare its analysis functions and Real-time monitoring,” 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. **(Implementation Timeframe before Winter 2022/2023)**

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Key Preliminary Recommendations Reliability Standards

- GOs to account for effects of precipitation and accelerated cooling effect of wind when providing temperature data.
- BAs' and Transmission Operators' (TOPs) manual load shed provisions to include processes for identifying and protecting critical natural gas infrastructure loads from firm load shed to avoid adversely affecting bulk-power system reliability.
- BAs' operating plans for contingency reserves and to mitigate capacity and energy emergencies to prohibit use of critical natural gas infrastructure loads for demand response.



These recommendations are above and beyond the NERC Reliability Standards revisions to address cold weather. See 176 FERC ¶ 61,119 (August 2021).

3

- In EOP-011-2, R7.3.2, Generator Owners are to account for the effects of precipitation and accelerated cooling effect of wind when providing temperature data.

(Implementation Timeframe before Winter 2022/2023)

- To protect critical natural gas infrastructure from manual and automatic load shedding in order to avoid adversely affecting bulk-power system reliability, Balancing Authorities' and Transmission Operators' (TOPs) provisions for operator-controlled manual load shedding are to include processes for identifying and protecting critical natural gas infrastructure loads in their respective areas from firm load shed. Critical natural gas infrastructure loads are natural gas production, processing and intrastate and interstate pipeline facility loads which, if de-energized, could adversely affect provision of natural gas to bulk-power system natural gas-fired generation.

(Implementation Timeframe before Winter 2023/2024)

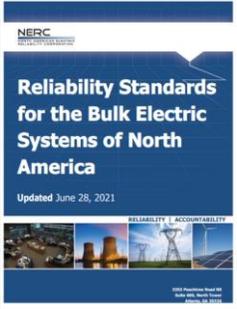
- Balancing Authorities' operating plans (for contingency reserves and to mitigate capacity and energy emergencies) are to prohibit use of critical natural gas infrastructure loads for demand response.

(Implementation Timeframe before Winter 2022/2023)

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Key Preliminary Recommendations Reliability Standards

- The load shed procedures of TOPs, Transmission Owners (TOs) and Distribution Providers (DPs) to separate circuits that will be used for manual load shed from circuits used for underfrequency load shed (UFLS) or serving critical load, use UFLS circuits only as a last resort, and if necessary, start with the final stage (lowest frequency) to minimize the overlap of manual and automatic load shed.



These recommendations are above and beyond the NERC Reliability Standards revisions to address cold weather. See 176 FERC ¶ 61,119 (August 2021).

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- In minimizing the overlap of manual and automatic load shed, the load shed procedures of Transmission Operators, Transmission Owners (TOs) and Distribution Providers (DPs) should separate the circuits that will be used for manual load shed from circuits used for underfrequency load shed (UFLS), undervoltage load shed (UVLS) or serving critical load. UFLS/UVLS circuits should only be used for manual load shed as a last resort and for UFLS circuits, should start with the final stage (lowest frequency).

(Implementation Timeframe before Winter 2023/2024)

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Key Preliminary Recommendations Funding for Generator Winterization

2. Generator owners should have the opportunity to be compensated for the costs of building or retrofitting their units to operate to a specified ambient temperature and weather conditions through markets or through cost recovery approved by state public utility commissions (e.g., as a reliability surcharge) to be included in end-users' electric service rates. The applicable ISOs/RTOs and/or public utility commissions should identify how best to ensure GOs have the opportunity to be compensated for making these infrastructure investments.

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While Reliability Standards are being developed to design generating units to operate to specified ambient temperature and weather conditions, the applicable market operators (Independent System Operators/Regional Transmission Organizations) and/or public utility commissions should identify how best to ensure Generator Owners have the opportunity to be compensated for making these infrastructure investments. (***Implementation Timeframe before Winter 2023/2024***)

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Key Preliminary Recommendations Natural Gas Infrastructure Winterization

3. Congress, state legislatures and regulators with jurisdiction over facilities used for producing, treating, processing, pressurizing, storing, or transporting natural gas should require those gas facilities to have cold weather preparedness plans, including measures to prepare to operate during a weather emergency.

4. Natural gas production, gathering and processing facilities should consider implementing measures to protect against freezing and other cold-related limitations which can affect the production, gathering and processing of gas. Examples include:

- covering or sheltering sensitive facilities, adding heating equipment, and
- installing backup generation at critical sites.



6

Recommendations 3 and 4 are both aimed at having natural gas infrastructure be prepared for the effects of cold weather. Recommendation 3 seeks mandatory requirements while 4 recommends voluntary measures. Recommendation 3 has an implementation timeframe ***before Winter 2023/2024***.

For Recommendation 4, other examples include (noting the report will have the full list):

- implement freeze protection measures, including burial of flow lines;
- ensure necessary emergency staffing, including surge capacity;
- enter into mutual assistance programs, whereby fellow natural gas infrastructure companies that are not affected by the same storm could supply equipment, supplies or staff, to those affected by a cold weather emergency;
- review contracts (firm vs. non-firm/interruptible retail electric power),
- review whether all electrical equipment has been designated as critical load,
- take proactive steps to procure quick turnarounds on requests for environmental waivers for backup generators when needed during cold weather events;
- enhance emergency operations plans to incorporate extreme cold weather response;
- Producers, gatherers and processors should conduct training and drills to exercise their emergency operations plans, including coordinated drills/exercises on severe winter event scenarios, jointly with pipelines.

(Implementation Timeframe before Winter 2022/2023)

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Key Preliminary Recommendations Natural Gas-Electric Reliability Forum

5. 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, and with input from the Balancing Authorities and 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 bulk-power system reliability. Options for establishing the forum could include:

- joint task force with NARUC,
- a Federal Advisory Committee, or
- series of technical conferences.



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FERC should consider establishing a forum in which 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-power system/bulk electric system), and with input from the Balancing Authorities (which are responsible for balancing load and available generation) and gas infrastructure entities, together identify concrete actions (consistent with the forum participants' jurisdiction) to improve the reliability of the natural gas infrastructure system necessary to support bulk-power system reliability during cold weather. Options for establishing the forum could include a joint task force with NARUC, a Federal Advisory Committee, or technical conferences. Ideally, the forum participants will produce one or more plans with deadlines for implementing the concrete actions that identify the applicable entities with responsibility for each action.

(Implementation Timeframe before Winter 2022/2023)

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Key Preliminary Recommendations Natural Gas-Electric Reliability Forum

5. At such a forum, topics could include:

- Whether and how natural gas information could be aggregated on a regional basis for sharing with 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 provide exclusive or comprehensive authority over natural gas pipeline reliability matters given that it appears that no federal agency has responsibility to ensure the reliability of the interstate natural gas pipeline system.
- Additional state actions (including possibly establishing an organization to set voluntary standards) to enhance the systemic reliability of intra-state natural gas pipelines and other intrastate natural gas facilities.

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In addition to those listed on the slide, other topics could be:

- Programs to encourage and provide compensation opportunities for natural gas facility winterization
- Which entity has authority, and under what circumstances, to take emergency actions to give critical generators pipeline transportation priority second only to residential heating load, during cold weather events when natural gas supply and transportation is limited but demand is high,
- How to identify those instances where requirements for certain natural gas-fired generating units to obtain either firm supply and/or transportation or dual fuel capability would be cost-effective, how such requirements could be structured, including associated compensation mechanisms, and whether additional infrastructure buildout would be needed and 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 generating units should factor in the firmness of a unit's gas commodity and transportation arrangements as well as 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, as well as considering the use of other resources which could help mitigate the risk of loss of natural gas fuel supply.

- Electric and natural gas industry interdependencies (communications, contracts, constraints, scheduling),
- Increasing access to/utilization of market-area and behind-the-city-gate natural gas storage, and
- Whether or how to increase the number of “peak-shaver” gas-fired generating units that have on-site LNG storage.

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Other Key Preliminary Recommendation Areas

6. GO/GOPs should identify reliability risks of natural gas fuel contracts and communicate these risks to BAs.
7. FERC, NERC, and Regional Entities should host joint technical conference to discuss how to improve generator winter readiness.
8. GOs' plans should include performing inspection/maintenance of freeze protection measures prior to and during the winter season, and pre-event when specific cold weather events are forecast.
9. Planning Coordinators should reconsider some of the inputs to their publicly-reported winter season anticipated reserve margin calculations for their respective BA footprints so that the reported reserve margins will better predict the reserve levels that the BAs could experience during winter peak conditions.

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Other key preliminary recommendation areas include:

- Before this winter (**Winter 2021/2022**), Generator Owners/Generator Operators should identify and communicate reliability risks of their natural gas fuel contracts to Balancing Authorities.
- In the interim before the approved Reliability Standards addressing cold weather preparedness 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. (**Implementation Timeframe before Winter 2022/2023**)
- Generator Operators' plans should specify times for performing inspection and maintenance of freeze protection measures, including prior to and during the winter season, and pre-event, to be activated when specific cold weather events are forecast. (**Implementation Timeframe before Winter 2022/2023**)
- And finally, Planning Coordinators should reconsider some of the inputs to their publicly-reported winter season anticipated reserve margin calculations 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. The recommended 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. (**Implementation Timeframe before Winter 2022/2023**)

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Other Preliminary Recommendation Areas

Fourteen additional recommendations covering issues including:

- Effects of cold weather on mechanical fatigue
- Increasing the flexibility of manual load shedding
- GO/GOP use of weather forecasts
- Coordination of protective relay settings associated with generator underfrequency relays
- Coordination of UFLS relay settings with generating unit time-delay protection systems
- Increase real-time monitoring of gas well-heads

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The team makes fourteen other preliminary recommendations to prevent recurrence of similar events, which cover multiple issues as shown here and on the next slide.

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Other Preliminary Recommendation Areas (Cont'd.)

- Emergency response centers for severe weather events
- Improve near-term load forecasts for extreme weather conditions
- Analyze intermittent generation effects to improve load forecasts
- Rapidly-deploying demand response
- Additional load shed training for system operators
- Retail incentives for energy efficiency improvements
- Studies of large power transfers during stressed conditions
- Reducing the time for reporting generation or transmission outages

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The recommendations presented today are preliminary, and the final recommendations will be included in the full report, which is expected to be issued by winter.

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Other Preliminary Recommendation Areas For Further Study

- Black start unit reliability
- Additional ERCOT connections
- Potential measures to address natural gas supply shortfalls
- Potential effect of low-frequency events on generators in the Western and Eastern Interconnections
- Guidelines for identifying critical natural gas infrastructure loads

THE RECOMMENDATIONS PRESENTED TODAY ARE PRELIMINARY.
THE FINAL RECOMMENDATIONS WILL BE INCLUDED IN THE FULL REPORT, WHICH IS EXPECTED
TO BE ISSUED BY WINTER.

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The team also recommends further studies that were beyond scope of the inquiry:

- Black start unit availability in ERCOT during cold weather conditions,
(Implementation Timeframe before Winter 2023/2024)
- Additional links between the ERCOT Interconnection and Eastern, Western, and/or Mexico Interconnections,
(Implementation Timeframe before Winter 2023/2024)
- Potential measures to address natural gas fuel supply shortfalls during extreme cold weather events,
(Implementation Timeframe before Winter 2023/2024)
- Potential effect of low-frequency events on generators in the Western and Eastern Interconnections, and
(Implementation Timeframe before Winter 2022/2023)
- Establish a guideline with criteria for identifying critical natural gas infrastructure loads.
(Implementation Timeframe before Winter 2022/2023)

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February 2021 Cold Weather Grid Operations: Preliminary Findings and Recommendations

FERC, NERC and Regional Entity Joint Staff Inquiry



This report was prepared by the staff of the Federal Energy Regulatory Commission in consultation with staff from the North American Electric Reliability Corporation and its Regional Entities. This report does not necessarily reflect the views of the Commission.

This presentation will be posted on the Commission’s website. This concludes our prepared comments. We would be happy to answer any questions you may have. Thank you.