Extreme Cold Weather Report Recommendations

Assurance Program Team

June 2025

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Introduction

This document represents the collected efforts of many individuals in the industry, FERC, NERC, and the Regional Entities. For each artifact (e.g., recommendations, operational practices, key findings, etc.) noted there are additional details contained within the source (i.e., generally event reports) that could help further understand the artifact. The artifacts were determined based on the facts and circumstances of the events and, in general, have matured in terms of articulation over time. The ordering, labeling, and content of the artifacts were largely maintained for inclusion in this document, but it is recommended to go directly to the source if there are any questions. The sources are listed in reverse chronological order to allow a reader to see how the industry responded (or not) over time. The document is not considered the artifact of record and any differences inadvertently made within this document do not supersede nor are they intended to change the original artifact represented within the source. This document will be maintained as needed by the Assurance Program Team.

January 2025 Artic Events Operational Practices[1]

1. Putting more time and effort into ensuring that equipment has the proper winterization measures in place lowers the risk of generating units freezing during extreme cold weather.
2. Increased and improved communication with a larger array of entities and consumers brings with it streamlined, better prepared real-time responses during extreme cold weather conditions.
3. Manually contacting at-risk natural gas generators (non-dual fuel) during cold weather advisories to verify natural gas supply availability can help an entity increase its situational awareness to make more informed decisions on unit commitments during extreme cold weather.
4. Sending natural gas delivery scheduling reminders to generator owners ahead of a holiday weekend helps ensure that better preparations are made before natural gas market liquidity becomes an issue.
5. Joint site visits with Regional Entities in advance of extreme cold weather help entities prepare for winter operations.
6. Increasing the number of operational staff during an event contributes to an entity having the proper resources to prepare for and respond to extreme cold weather.
7. Incorporating staff with natural gas system experience can help improve an electric entity's understanding of natural gas system operations and how natural gas operations impact grid operations.
8. Having an energy management system that monitors blackstart resources can provide an entity with a heightened real-time situational awareness into blackstart availability.

[1] January 2025 Arctic Events—A System Performance Review.

9. Annual fuel surveys and obtaining fuel procurement information contributes to greater transparency and insight into anticipated resource availability and constraints ahead of extreme cold weather.
10. Expanding the number and types of entities involved in winter preparedness drills add insights into anticipated resource constraints and fosters an increase in communication and collaboration that could span across regions.
11. Declaring conservative operations for the affected portion of a footprint while maintaining normal operations in the rest of a footprint could be beneficial in times of stressed conditions.
12. Implementing a generator risk assessment helps entities make more informed decisions on unit commitments and increases awareness of resource availability ahead of extreme cold weather.
13. Firm natural gas supply and transportation contracts, where feasible, help reduce the risk of fuel unavailability during an extreme cold weather event.
14. Implementing a natural gas planning process with increased communication and a 24-hour onsite staff liaison increases the overall situational awareness of fuel availability in advance of and during extreme cold weather.

January 2024 Artic Storms Summary[2]

1. During Winter Storms Gerri and Heather, there was zero system-operator-initiated load shed.
2. Natural gas and electricity entities shared positive steps taken to improve preparation for extreme cold weather, highlighting improved communication and coordination.
3. Generators reported fewer derates/outages as compared to past winter storms potentially attributed to:
   a. Improved winter preparedness;
   b. Proactive generator commitment;
   c. Improved natural gas generator stability due to variable, i.e., non-ratable, fuel supply methods; and
   d. Incorporating operating limitations into operating plans.
4. The challenges highlighted emphasize the need for continued implementation of recommendations from the Winter Storms Uri and Elliott reports and the recent Blackstart Availability Study

December 2022 Winter Storm Elliot Recommendations[3]

Recommendation 1(a): Findings support the need for prompt development and implementation of the remaining recommended revisions to the Reliability Standards from 2021 Report Key Recommendation 1 to strengthen generators' ability to maintain extreme cold weather performance.

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[2] From "Presentation | System Performance Review of the January 2024 Arctic Storms."

[3] From "Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott."

Recommendation 1(b): Findings from the report support the need for robust monitoring by NERC and the Regional Entities of compliance with the currently effective and approved generator cold weather Reliability Standards, to determine whether reliability gaps exist. NERC should identify the generating units that are at the highest risk during extreme cold weather and work with the Regional Entities (and Balancing Authorities, if applicable) to perform cold weather verifications of those generating units until all of the extreme cold weather Standards proposed by the 2021 Report are approved and effective. (Verify highest risk units by Q4, 2023; implement by Q3, 2024).

Recommendation 1(c): Generator Owners/Operators should assess their own freeze protection measure vulnerability, and NERC or the Regional Entities should perform targeted cold weather verifications pursuant to a risk-based approach.

Recommendation 1(d): Generator Owners/Operators of generating units that have experienced outages, derates, or failures to start above their documented operating temperature limits should consider conducting engineering design reviews to: (1) evaluate the accuracy and completeness of existing design information (including as it relates to the documented operating temperature limits) and calculated extreme cold weather operational thresholds: (2) evaluate whether existing freeze protection measures are adequate to protect their identified generator cold weather critical components; (3) evaluate whether design features to address cold weather and freezing conditions are being optimally implemented; (4) evaluate the impact of any modifications or additions to the original design on the documented operating temperature limits; (5) evaluate whether any modifications or additions resulted in new generator cold weather critical components; (6) evaluate the impact a unit's "cold" versus "hot" status has on its design limits, including the identification of a "cold start-up" temperature for each unit, if applicable; and (7) determine whether the generating unit's operating characteristics have been altered in a way that creates a potential "weak link" component.

Recommendation 1(e): Generator Owners/Operators should consider conducting operational/functional testing of their "active" freeze protection systems.

Recommendation 1(f): Generator Owners/Operators should communicate their low temperature limits, and changes to those limits, to their Balancing Authority and Reliability Coordinator on a real-time basis.

Recommendation 1(g): Generator Owners/Operators should complete their preparations for winter, including implementing their winter preparedness plans and inspecting and maintaining their generating units' freeze protection measures, no later than the earliest first freeze date for the generating unit's location, as determined by National Oceanic and Atmospheric Administration data. Generator Owners/Operators should maintain those preparations until after the last freeze date, as provided by the same data. Those preparations are in addition to any preparations, inspection or maintenance done in anticipation of a specific extreme cold weather event.

Recommendation 2: NERC should initiate a technical review of the individual causes of cold-weather-related unplanned generation outages caused by Mechanical/Electrical Issues during the Event to identify the root causes of these failures with the goal of determining what can be done to reduce the frequency of these outages during extreme cold weather events. The study should also consider whether additional Reliability Standards are appropriate to address the root causes of these issues. The study should be conducted by either an independent subject-matter expert such as the Electric Power Research Institute or an academic institution, with participation by Generation Owners/Generation Operators on scoping and providing generating-unit-specific technical expertise. (Initiate Technical Review by Q1, 2024).

Recommendation 3: A joint NERC-Regional Entity team, collaborating with FERC staff, should study the overall availability and readiness of blackstart units to operate during cold weather conditions. This study should cover all portions of the U.S. not already studied, and should incorporate existing literature, studies, reports, and other analyses as to the availability and readiness of blackstart units.

The scope of the study should include:

- An evaluation of existing blackstart restoration plans, including a review of potential single points of failure related to natural gas system dependence;
- An evaluation of the sufficiency of existing blackstart availability, readiness, and testing criteria, including whether unscheduled, unannounced, or criteria-based testing (e.g., those used in ERCOT) would improve reliability during cold weather events;
- The need for ensuring that generating units with dual-fuel capability providing blackstart service have appropriate fuel storage (as determined by the balancing authority);
- The need to require blackstart generators to test their fuel switching capabilities seasonally;
- The need to require additional fuel storage due to import constraints;
- The need for transmission operators to incorporate generating units' cold weather preparations into the qualification process for certifying generators as blackstart units; and,
- Any other subject areas identified as areas of substantial interest or concern in the report issued as a result of ongoing efforts to study blackstart unit availability and readiness in ERCOT. (initiate study by Q1, 2024).

Recommendation 4(a): Because extreme cold weather events have repeatedly impaired the production, gathering, processing, and transportation of natural gas, the reliability rules suggested in Recommendation 4 should address, among other topics, the need for natural gas infrastructure reliability rules, from wellhead through pipeline, requiring cold weather preparedness plans, freeze protection measures, and operating measures for when extreme cold weather periods are forecast, and during the extreme cold weather periods.

Recommendation 4(b): The reliability rules suggested in Recommendation 4 should address, among other topics, the need for regional natural gas communications coordinators, with situational awareness of the natural gas infrastructure similar to the grid's Reliability Coordinators, that can share timely operational communications throughout the natural gas infrastructure chain and communicate potential issues to and receive grid reliability information from grid reliability entities.

Recommendation 4(c): The reliability rules suggested in Recommendation 4 should address, among other topics, the need to require natural gas infrastructure entities to identify those natural gas infrastructure loads that should be designated as critical for priority treatment during load shed and provide criteria for identifying such critical loads.

Recommendation 5: The North American Energy Standards Board should convene natural gas infrastructure entities, electric grid operators, and Local Distribution Companies (LDC) to identify improvements in communication during extreme cold weather events to enhance situational awareness. (Q2, 2024).

Recommendation 6: The Commission should consider whether to order Commission-jurisdictional natural gas entities to provide the Commission with one-time reports describing their roles in assessing and responding to natural gas supply and transportation vulnerabilities in extreme cold weather events.

Recommendation 7: An independent research group (e.g., selected National Laboratories from the Department of Energy), should perform one or more studies to analyze whether additional natural gas infrastructure, including interstate pipelines and storage, is needed to support the reliability of the electric grid and meet the needs of natural gas LDCs. The study should include information about the cost of the infrastructure buildout.

Recommendation 8: Balancing Authorities should assess whether new processes or changes to existing ones—such as multi-day risk assessment processes or advance or multi-day reliability commitments—are needed to address anticipated capacity shortages or transmission system-related reliability problems during well-forecast extreme cold weather events. In performing risk assessments or supporting multi-day reliability commitment, BAs should consider the following:

1. How to account for uncertainty in load forecasts, generating unit fuel availability and extreme cold weather availability, and the effects of extreme cold weather across multiple regions; and
2. Committing generating units before the onset of extreme cold weather, including a means of ensuring units are compensated for their commitment costs (including the costs of obtaining fuel), even if no dispatch occurs.

Recommendation 9: Balancing Authorities should improve their short-term load forecasts for extreme cold weather periods by implementing the lessons and practices identified below and sharing newly identified effective practices with peer BAs for continuous improvement.

Recommendation 10: Resource Planners and entities that serve load should sponsor joint-regional reliability assessments of electric grid conditions that could occur during extreme cold weather events. The assessment results can be used in power supply planning to reduce the risk of firm load shed.

Recommendation 11: A team of subject-matter experts (e.g., the Eastern Interconnection Planning Collaborative) should conduct a study of the state of the Eastern Interconnection during the evening of December 23 and early morning hours of December 24, to examine dynamic stability and system inertia, and determine how close the interconnection may have been to triggering an underfrequency load shed event.

February 2021 Winter Storm Uri Recommendations[4]

Key Recommendations

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 (GO) 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 (GOP) 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 forecast cold weather" (1g); and
- GOs to account for effects of precipitation and accelerated cooling effect of wind when providing temperature data to BAs (1c).

Key Recommendation 1 (a through g) (under Section A—Electric Generation Cold Weather Reliability): 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 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.

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.

Key Recommendation 1c: To revise EOP-011-2, R7.3.2273 to require Generator Owners to account for the effects of precipitation and the accelerated cooling effect of wind when providing temperature data.

Key Recommendation 1d: 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

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[4] From "The February 2021 Cold Weather Outages in Texas and the South Central United States."

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.

Key Recommendation 1e: To revise EOP-011-2, R8, to require Generator Owners and Generator Operators to conduct annual unit-specific cold weather preparedness plan training.

Key Recommendation 1f: 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 ambient temperature and weather conditions should be based on available extreme temperature and weather data for the generating unit's location.

Key Recommendation 1g: 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 forecast cold weather" in TOP-003-5:

- 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," 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 forecast 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 forecast 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, "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.

Key Recommendation 1 (h through j) (under Section C—Grid Emergency Operations Preparedness): The Reliability Standards should be revised as follows:

Key Recommendation 1h: 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.

Key Recommendation 1i: To protect critical natural gas infrastructure loads from manual and automatic load shedding (to avoid adversely affecting Bulk Electric System reliability):

- 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 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.

Key Recommendation 1j: 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).

Key Recommendation 2: 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.

Key Recommendation 3: In the interim before the Reliability Standards revisions approved by the Commission in Order Approving Cold Weather Reliability Standards, 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.

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

Key Recommendation 5: 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.

Key Recommendation 6: 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:

- 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:
  - 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 before 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.

Key Recommendation 7: 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:

- 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;

- Which entity has authority to require certain natural gas-fired generating units to obtain either firm supply and/or transportation or dual 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.

Key Recommendation 8: 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) 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)

Key Recommendation 9: 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. 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:

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 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.

Recommendation 10: 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 used to achieve greater real-time distribution situation 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).

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.

Recommendation 12: Generator Owners and Generator Operators should incorporate weather forecasts into planning the operation of their generating units before 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 forecast wind and/or precipitation). (Winter 2021-2022)

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 for outages related to frequency deviation.

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.

Recommendation 15: 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. These centers 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");
- 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.

Recommendation 16: Balancing Authorities should have staff with specialized knowledge of how weather affects 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 before real-time) load forecast to include multiple models and sources of meteorological information to increase accuracy and should consider regional differences within their footprints.

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.

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)

Recommendation 19: 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)

Recommendation 20: 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 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.

Recommendation 21: Reliability Coordinators, Transmission Operators 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.

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.

Recommendation 23: 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).

Recommendation 24: 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, 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 re-gasification 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 LDCs and may not have sufficient additional firm capacity. Because many pipelines were financed and

constructed to serve LDCs 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.

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.

Recommendation 26: 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.

Recommendation 27: 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.

Recommendation 28: Reliability Coordinators, Balancing Authorities, Regional Entities, Transmission Operators, Transmission Owners, Distribution Providers and one or more entities representing U.S. natural gas infrastructure entities should jointly conduct a study to establish guidelines to assist natural gas infrastructure entities in identifying critical natural gas infrastructure loads 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.

January 2018 Event Findings and Recommendations[5]

Generator Cold Weather Reliability Findings

- The South-Central U.S. Cold Weather BES Event of January 17, 2018 was caused by failure to properly prepare or "winterize" the generation facilities for cold temperatures.
- Gas supply issues contributed to the event, and natural gas-fired units represented at least 70% of the unplanned generation outages and derates.

Generator Cold Weather Reliability Recommendations

Recommendation 1: The team recommends a three-pronged approach to ensure Generator Owners/Generator Operators, Reliability Coordinators and Balancing Authorities prepare for cold weather conditions:

1. Development or enhancement of one or more NERC Reliability Standards,
2. Enhanced outreach to Generator Owners/Generator Operators, and
3. Market (Independent System Operators/Regional Transmission Organizations) rules, where appropriate.

This three-pronged approach should be used to address the following needs:

- The need for Generator Owners/Generator Operators to perform winterization activities on generating units to prepare for adverse cold weather, in order to maximize generator output and availability for BES reliability during these conditions.
- These preparations for cold weather should include Generator Owners/Generator Operators:
  - Implementing freeze protection measures and technologies (e.g., installing adequate wind breaks on generating units where necessary).
  - Performing periodic adequate maintenance and inspection of freeze protection elements (e.g., generating units' heat tracing equipment and thermal insulation).
  - If gas-fueled generating units, clearly informing their Reliability Coordinators and Balancing Authorities whether they have firm transportation capacity for natural gas supply

[5] From "2019 FERC and NERC Staff Report—The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018."

- Conducting winter-specific and plant-specific operator awareness training.

- The need for Generator Owners/Operators to ensure accuracy of their generating units' ambient temperature design specifications.
- The need for Balancing Authorities and Reliability Coordinators to be aware of specific generating units' limitations, such as ambient temperatures beyond which they cannot be expected to perform or lack of firm gas transportation, and take such limitations into account in their operating processes to determine contingency reserves, and in performing operational planning analyses, respectively.

Situational Awareness and RC-to-RC Communication Findings:

- The Relevant RCs (MISO, SPP, TVA and SeRC) had situational awareness throughout the event and communicated as necessary to preserve system reliability.
- The generation outages and derates on January 17 created energy emergency conditions which required voluntary load reduction and plans for firm load shed if MISO's 1,163 MW worst single contingency in MISO South occurred.

Situational Awareness Recommendations:

Recommendation 2: Reliability Coordinators should perform real-time voltage stability analysis in addition to RTCA, for constrained conditions occurring within their own and/or within adjacent Reliability Coordinator areas, such as those experienced by MISO the morning of January 17, and communicate the results of their analysis to adjacent Reliability Coordinator areas. Constrained system conditions during the Event included: multiple generation outages and derates in MISO South, high system loads, large regional transfers due to stranded reserves, transmission outages in generation-limited load pockets, and limited additional transfer capability. On January 17 some of these conditions were also occurring simultaneously in neighboring Reliability Coordinator footprints. Real-time voltage stability analysis could assist Reliability Coordinators in determining if other mitigation actions are necessary as well as whether an emergency condition exists. If such stressed system conditions are projected for the next day, voltage stability analysis should also be performed as part of the Reliability Coordinators' Operational Planning Analyses.

Recommendation 3: To provide accurate results for the Reliability Coordinators' real-time tools, adjacent Reliability Coordinators should benchmark their planning and operations models to actual events, like the January 17 event that stressed both the Reliability Coordinator and its adjacent Reliability Coordinator(s), and correct any inconsistencies identified.

Recommendation 4: Reliability Coordinators should also perform periodic impact studies to determine which elements of their adjacent Reliability Coordinators' systems have the most impact (i.e., the effect an outaged element located in an adjacent Reliability Coordinator area has on its voltages, facility loadings, or other conditions) on their systems. Reliability Coordinators should consider adding any identified external facilities to their models and should share associated real-time external network data. Beyond the enhanced model incorporation into tools such as RTCA, these sensitivity studies could identify external facilities which have such an impact that the Reliability Coordinator may also implement real-time EMS alerting for the loss of the external facility.

Recommendation 5: Balancing Authorities and Transmission Operators should conduct periodic capacity and energy emergency drills simultaneous with transmission emergency drills with their Reliability Coordinators to ensure readiness, coordination of control room personnel to conduct multiple load-shed related tasks while continuing to maintain situational awareness, and coordination between additional local control center and field personnel. On January 17 during the peak hour, MISO system analysis showed that if its next-contingency generation outage in MISO South of 1,163 MW occurred, it would need to rely on postcontingency manual firm load shed to maintain voltages within limits, while faced with potential additional firm load shedding to maintain system balance and restore reserves for MISO South region. Operators may be required to perform additional tasks if the load shed must be executed within narrow boundaries (e.g., limited load shed options that will result in alleviating transmission overload and/or low voltage conditions), coupled with conditions (such as extreme temperatures), which create the need for rotational load shedding to protect life or health.

RC-to-RC Communications Recommendations

Recommendation 6: Make the following changes to the Regional Transfer Operations Procedure:

- Provide operators with more specificity for applying section 3.1.6.1 through 3.1.6.4 regarding how to return the Regional Directional Transfer to a level at or below the Regional Directional Transfer Limit within 30 minutes, and the relationship between 3.1.6.1 through 3.1.6.4 and 3.2 (congestion management). Also, clarify the roles and/or reference certain steps in the applicable emergency procedures that may assist the operators in taking prompt actions to return Regional Directional Transfer at or below the Regional Directional Transfer Limit.
- Clarify the relationship between 3.1.6.1 and 3.1.6.4 regarding calls to adjacent Reliability Coordinators and when the Reliability Coordinator operator will initiate reduction of the Regional Directional Transfer. Consider a timeline/flowchart of the sequence of communications, similar to the Transmission Loading Relief curtailment timing, found in the Joint NAESB System Operator's Transmission Loading Relief Reference Manual.
- Clarify the section on "Potential Load Shed conditions" (section 3.3.8) to require the adjacent Reliability Coordinators to communicate an emergency condition if conditions in the Reliability Coordinator footprint so warrant. This change further aligns the procedure steps with the Reliability Standards.
- Clarify that when making emergency energy purchases (for example, purchasing emergency energy, for meeting load plus reserves, or to alleviate Regional Directional Transfer flow before shedding load), Reliability Coordinator /Balancing Authority Operators should analyze the flow impacts before implementing the emergency energy schedule to avoid unintentionally causing detrimental impacts to Regional Directional Transfer (RDT)-affected flowgates or lead to an operating Emergency for Transmission Operator(s) area(s).
- In determining the need for temporary changes to the Regional Directional Transfer Limit (see 3.3.1) for the operating horizon/next-day analysis or during the operating day, MISO, in

coordination with SPP and neighboring entities, should determine the maximum simultaneous transfer capability north-to-south (or south-to-north if applicable), based on the latest operating conditions expected during the timeframe for determination. This study should be used to support any decisions on making temporary changes to the Regional Directional Transfer Limit. Transmission Operations and Reserves Findings: The generation outages during the peak hour ending 8 a.m. CST on January 17 created an "N-many" BES condition, and led the affected entities to transfer power from distant generation into the affected region to cover energy demands and provide reserves. These large power transfers resulted in wide-area BES transmission-constrained conditions in four RC footprints.

Seasonal Studies Recommendations:

Recommendation 7: Planning Coordinators and Transmission Planners should jointly develop and study more extreme condition scenarios to be better prepared for seasonal extreme conditions. Examples of more-extreme condition modeling include:

- Removing generation units entirely to represent actual generation outages (especially outages known to occur during severe weather), versus scaling of generating unit outputs;
- Modeling system loads so that the study accurately tests the system for the extreme conditions being studied; and
- Modeling and studying actual extreme events experienced in the Planning Coordinator area and actual severe scenarios experienced in other Planning Coordinator areas. Results of these more extreme condition studies should then be shared with operations staff for training purposes, and to aid in their planning for days when more extreme transfers are expected.

Recommendation 8: MISO and SPP should jointly perform seasonal transfer studies and sensitivity analyses in which MISO and SPP model same-direction simultaneous transfers (e.g., north to south, south to north, west to east) to determine constrained facilities so that they can develop mitigation plans or other procedures for the operators. Such studies should include, but not be limited to:

- Intra-market power transfers, without offsetting transfers in a way that would reduce the impact on determining constrained facilities;
- Transfers of wind generation output to load areas using near-peak wind generation levels;
- Simultaneous generation outages in adjacent Reliability Coordinator footprints (e.g., MISO South and southern SPP footprints); and
- Increasing simultaneous transfers to levels that constraints cannot be fully alleviated. System impacts of the modeled transfers in the studies could vary based on which generators are removed. Sensitivity study cases should be performed, for example, to produce a potential range of transfer capabilities based on varying generation outage scenarios.

System Operating Limits Recommendation:

Recommendation 9: Transmission Owners and Transmission Operators, as part of establishing facility ratings and System Operating Limits, respectively, should conduct analysis that delineates different summer and winter ratings, for both normal and emergency conditions. The established facility ratings and associated System Operating Limits should consider, at a minimum, ambient temperature conditions that would be expected during high summer load and high winter load conditions, respectively. These ratings and limits should be provided to the Reliability Coordinator and other applicable entities for use in tools for operation, such as Energy Management System and Real-Time Contingency Analysis applications.

Reserves Recommendations:

Recommendation 10: Balancing Authorities should consider deliverability of reserves to avoid stranded reserves.

Recommendation 11: When MISO Balancing Authority relies upon 3,000 MW of Regional Directional Transfer flows in determining total reserve levels for MISO South, it should remain mindful that, as the Commission noted, “any amount above 1,000 MW of the 3,000 MW north-to-south limit . . . [is] only available on a nonfirm, as-available basis.” MISO should notify the other Reliability Coordinators operating under the Regional Transfer Operations Procedure (SPP, TVA and SeRC) when it needs to rely on any amount of the non-firm, as-available, portion of the Regional Directional Transfer to meet its reserves, due to a capacity shortage in MISO South, so that the Reliability Coordinator Operators can timely communicate and act if conditions in the other Reliability Coordinators’ footprints are projected to limit Regional Directional Transfer flows.

Load Forecasting Findings:

MISO’s five- to three-day out load forecasts for MISO South were significantly lower than the actual peak load on January 17 and less accurate than adjacent RCs’ forecasts for the same period.

Load Forecasting Recommendations:

Recommendation 12: MISO should work with its entities serving load/Local Balancing Authorities in the MISO South footprint to ensure that accurate and realistic load forecasts are provided to MISO in the five-, four-, and three-day-ahead forecasts. The Local Balancing Authorities should incorporate actual historic temperatures and loads from the January 17 event and other cold weather events into their future forecasts to capture potential peak demands during severe cold weather events.

Recommendation 13: MISO should work with adjacent Reliability Coordinators to improve the accuracy of its mid-term peak load forecasts for impending extreme weather conditions. This includes:

- Sharing five-, four-, and three-day-ahead temperature forecasts with adjacent Reliability Coordinators for upcoming extreme weather operating day(s) forecast (e.g., much below or above normal temperature conditions), for regions within their footprints.
- Identifying causes of any significant differences between forecasts.
- Reforecast peak loads to reduce significant differences in forecast error for these time frames.
- Incorporating actual historic temperatures and loads from atypical events like January 17, 2018, into future forecasts to capture potential peak demands during severe cold weather events.

Sound Practices

Sound practices are just that—practices applied by one or more of the entities involved in the event that went beyond the requirements set forth in the mandatory Reliability Standards. The team did not decide that they were "best practices," but found them worthy of note.

Transmission Sound Practices

1. In evaluating next-day system conditions, and due to the time typically needed to start a generating unit, SeRC uses an "N-1-1 tool" for evaluating the need to commit additional generation resources to provide area reliability for voltage and/or thermal line flow problems. The N-1-1 tool will evaluate the outage of a generator as the first contingency (N-1), followed by the removal of a transmission element as a second contingency (N-1-1), to determine if additional online generation resources are needed to reliably operate.
2. Given that large power transfers within BAs can affect neighboring systems, to improve reliable operation among neighboring BAs and RCs, MISO, SPP and the Joint Parties have established a method for identifying RDT-affected flowgates based upon simulated power transfers, for:
    a. The planning horizon, to perform the appropriate prior outage coordination activities and development of operating guides
    b. Real-time operations, to calculate the impact of RDT on flowgates to determine amount of RDT flow decrease needed based on the congestion on the RDT-affected flowgate.
3. Neighboring RC operators demonstrated sound communication and coordination in managing real-time transmission constraints during the January 17, 2018 event. Faced with managing increasing transfers of power from remote generation to the south-central U.S. to serve the record electricity demands, MISO operators contacted SPP operators offering and implementing generation redispatch actions to alleviate transmission constraints through their coordinated market-to-market process. Both RCs' operators communicated and coordinated these types of actions numerous times during the early morning hours on January 17, which aided in reliable BES operation.
4. To improve reliable operation during generation emergencies, MISO modified the rules for its Load Modifying Resources (LMR). The modified rules include requiring an LMR within MISO's footprint to offer its capability based on actual capability in all seasons, and to deploy based on the shortest notification requirement that it can consistently meet. Before the Event, some of MISO's LMRs had very long notification requirements that limited their usefulness during unexpected events like those of January 17.
5. To support reliable operations during extreme weather events such as the Event, SeRC employed what it called "dynamically rated" operating limits for transmission facilities based on the extremely cold weather, which effectively raised the limits allowing more power to reliably flow. Had static limits (year-round/summer limits) been used, it would have resulted in significant generation redispatch (detrimentally affecting BA contingency reserves), possible transmission reconfiguration, and/or Transmission Loading Relief procedures (TLR).

Generation Sound Practices

1. Southern Company (in the SeRC footprint), performed numerous generator fuel switches, using alternative fuel sources to help prevent a fuel supply emergency. Fuel-switching is especially important during cold weather. During extreme cold weather events, natural gas limitations can be predicted/expected to occur as residential and commercial gas heating needs compete with electric generation needs, and gas pipeline entities can be expected to limit pipeline use to sustain gas pressure throughout the cold weather demand.
2. Continuous monitoring of heat tracing systems complete with a display panel and indicator lights.
3. Inspection of heat tracing circuits, including power supplies, before winter.
4. Having regular, periodic operational checks of heat tracing circuits.
5. Annual update of winter preparation checklist, incorporating lessons learned from previous winter.
6. Completion of freeze protection-related maintenance before winter weather.
7. Increased operator rounds/increased staffing before and during winter weather to check for proper operation of plant equipment susceptible to freezing conditions.
8. Addition of a “freeze protection operator,” during adverse weather who is responsible for inspecting critical equipment, and ensuring appropriate protection is in place.
9. Firing of dual fuel units that have not fired on their secondary fuel source during the previous year before a forecast cold weather event.
10. RTO or RC conducting a survey of GO/GOP to determine winter preparedness activities have been completed, and fuel switching testing has been performed.
11. Sharing lessons learned by GO/GOP from extreme events, including through the NERC Events Analysis lessons learned program, or through Regional processes.
12. Developing procedures and training for Generator Operators on when to call for fuel switchable resources.
13. Maintaining inventory of pre-arranged supplies and equipment for extreme weather events by Generator Owners and Operators.
14. Generator Owners and Operators conducting readiness drills on extreme weather preparation.
15. Generators connecting to multiple pipelines when possible to allow for obtaining gas supply during tight market conditions if one or more pipelines has operational issues or high utilization that forces cuts to interruptible supply.
16. Generators keeping close contact with natural gas pipeline companies during events to keep abreast of timely public postings of operational details such as operationally available capacity and unexpected outages, which allows generators to make more flexible and timely decision.

January 2014 Polar Vortex Recommendations[6]

The report contains more than a dozen observations and recommendations to improve performance ahead of and during cold weather events. The recommendations include:

- Review natural gas supply and transportation issues and work with gas suppliers, markets, and regulators to develop appropriate actions.
- Review and update power plant weatherization programs, including procedures and staff training.
- Continue or consider implementing a program for winter preparation site reviews at generation facilities.
- Review internal processes to ensure they account for the ability to secure necessary waivers of environmental and/or fuel restrictions.
- Continue to improve operational awareness of the fuel status and pipeline system conditions for all generators.
- Include in winter assessments reasonable losses of gas-fired generation and considerations of oil burn rates relative to oil replenishment rates to determine fuel needs for continuous operation.
- Ensure that on-site fuel and fuel ordered for winter is adequately protected from the effects of cold weather.
- Consider (where appropriate) the temperature design basis for generation plants to determine if improvements are needed for the plants to withstand lower winter temperatures without compromising their ability to withstand summer temperatures.
- Review the basis for reporting forced and planned outages to ensure appropriate data for unit outages and de-ratings.

Observations and Recommendations

Lessons learned from the February 2011 Southwest Event highlighted the importance of preparation for extreme weather events. The following observations and recommendations are based on the analysis in the report:

Observations

1. Generation facilities have made improvements in their winter preparation activities since February 2011; however, every extreme event provides insight for future improvements. Generation facilities across all Regions have indicated that they have reviewed and/or

[6] From NERC's "Polar Vortex Review"; September 2014

implemented recommendations from the February 2011 Southwest Cold Weather Event lessons learned as well as the Generator Winter Weather Readiness guideline.

2. The value of regular training and annual drills was demonstrated during events, as the operators and other RC area entities were able to effectively and successfully implement emergency procedures.
3. Proactive communication and coordination between the RCs and within the RC areas themselves helped ensure appropriate situational awareness was maintained and facilitated rapid response as needed.
4. Planned and forced generation outages in some Regions exceeded the worst-case assumptions used in seasonal assessments. These assumptions warrant further review; in particular, the assumptions for generating unit forced and planned outage rates.
5. Some ISO/RTOs conducted detailed seasonal fuel assurance surveys to include gas transportation arrangements, starting oil inventories, and oil replacement capabilities (oil transportation capability).
6. Many outages, including a number of those in the southeastern United States, were the result of extreme ambient temperatures that were below the design basis of the generating unit.

Recommendations

1. Examine and review the natural gas supply issues encountered during the event. Industry should also work with gas suppliers, markets, and regulators to quickly identify issues with natural gas supply and transportation so that appropriate actions can be developed and implemented to allow generators to be able to secure firm supply and transportation at a reasonable rate.
2. Review and update power plant weatherization programs as a result of lessons learned from this event. This includes review of plant procedures, training programs for severe weather and winter weather events, and availability of material and equipment for response to these events. Entities should continue to follow the Reliability Guideline (Generating Unit Winter Weather Readiness—Current Industry Practices).
3. Continue or consider implementing a program of periodic site reviews of generation facilities' winter preparation. These programs produced tangible benefits in the ERCOT Interconnection by improving generator winter preparation and sharing good industry practices, and can be implemented within an individual company, an ISO/RTO, an appropriate Regional Entity, or any combination.
4. Review the basis for forced and planned generation outages used in seasonal assessments to ensure that appropriate outage rates for the extreme cases are correct and that unit derates are appropriately included.
5. Review generation and transmission outage scheduling processes to limit planned outages during possible peak winter periods.
6. Entity winter assessments should include base assumptions and stress cases for the loss of varying amounts of gas-fired generation and should consider oil burn rates relative to oil replenishment rates to determine the duration of continuous operation for oil-fired generation.

7. Continue to improve operations management awareness of the fuel status of all generators, including improved awareness of pipeline system conditions. This might include a daily fuel inventory solicitation process, ability to dispatch plants early in anticipation of extreme winter weather, and increased communication channels with electric and gas industries during extreme events.
8. Ensure that the fuel on hand and/or ordered for the winter season is appropriately protected from the effects of cold weather at the expected extreme temperatures.
9. Industry should work to identify and protect against outages that occurred within the cold weather design basis of the plant. Additionally, entities should review the winter cold weather temperature design basis for their generating units to determine if improvements are needed, while ensuring that the generating unit's ability to withstand higher temperatures in the summer is not compromised.
10. Industry should review internal processes to ensure they are ready to take proactive actions to secure the waivers (market, environmental, fuel, etc.) from the appropriate entities. For example, PJM requested waivers of certain provisions of PJM's governing documents that would permit them to share certain nonpublic information with natural gas pipeline operators during the forecast extreme weather conditions. FERC responded promptly to PJM's filing, which enabled those communications to commence quickly.

October 2011 Northeast Snowstorm Recommendations[7]

Vegetation Management Recommendations

1. Where appropriate, utilities should take targeted steps to address off-right-of-way danger trees.
2. Utilities should use recognized best practices in managing rights-of-way where feasible.
3. Utilities should lay the foundation for effective vegetation management when establishing new rights-of-way.

Other Recommendations

4. Utilities should evaluate and enhance their storm preparedness and response plans as needed.
5. Utilities should report all vegetation-caused BES facility outages to NERC.
6. Disturbance reports should be clear and complete.

Report February 2011 Event Key Findings and Recommendations[8]

Findings—Electric

- During the February event, temperatures were considerably lower (+15 degrees) than average winter temperatures and represented the longest sustained cold spell in 25 years. Steady winds

[7] From "Report on Transmission Facility outages During the Northeast Snowstorm of October 29–30, 2011"

[8] From "Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1–5, 2011"

also accelerated equipment heat loss. However, such a cold spell was not unprecedented. The Southwest also experienced temperatures considerably below average, accompanied by generation outages, in December 1989. Less extreme cold weather events occurred in 2003 and 2010. 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.

- While load forecasts fell short of actual load, the forecasts were not a factor in the loss of load. ERCOT manually increased its February 1 and 2 forecasts by 4,000 MW to factor in wind chill and had established sufficient reserves to accommodate both forecast load and the actual load that transpired. The reason blackouts had to be initiated was that over 29,000 MW of generation that was committed in the day-ahead market or held in reserve either tripped, was derated, or failed to start. This was the largest loss of generation in ERCOT's history, including during the prior cold weather load shed event in December 1989 and the two hot weather load shed events in 2003 and 2006. While units of all types (except nuclear generating units) tripped, derated, or failed to start in 2011, in ERCOT, gas combined cycle units had the highest percentage of failures, compared to their percentage of the total fuel mix. (FERC/NERC Staff Report on the 2011 Southwest Cold Weather Event)
- ERCOT and the generators within ERCOT could better coordinate generator scheduled outages, both in terms of the total amount of scheduled outages at a given time and their location. A substantial amount of generation (11,566 MW) was on scheduled outage going into the cold weather event. ERCOT's current Protocols provide that requests for scheduled outages submitted earlier than eight days before the outage is to begin are automatically approved unless they would violate a Reliability Standard.
- ERCOT's fast action in initiating rolling blackouts prevented more widespread and less controlled ERCOT-wide blackouts. Had ERCOT not initiated manual load shedding, its under-frequency load shedding relays would have instantaneously dropped approximately 2600 MW (five percent of system load), a loss that could have created further system disturbances and resulting generation outages. Load shedding by the transmission and distribution operators in ERCOT's footprint was generally carried out in a timely and effective manner.
- Transmission operators and distribution providers generally did not identify natural gas facilities such as gathering facilities, processing plants or compressor stations as critical and essential loads.
- Balancing authorities, reliability coordinators and generators often lacked adequate knowledge of plant temperature design limits, and thus did not realize the extent to which generation would be lost when temperatures dropped.
- The lack of any state, regional or Reliability Standards that directly require generators to perform winterization left winter-readiness dependent on plant or corporate choices. While Reliability Standard EOP-001 R.4 and R.5 refer to winterization as a consideration in emergency plans, these requirements apply only to balancing authorities, transmission owners, and transmission operators.

- Generators were generally reactive as opposed to being proactive in their approach to winterization and preparedness. The single largest problem during the cold weather event was the freezing of instrumentation and equipment. Many generators failed to adequately prepare for winter, including the following: failed or inadequate heat traces, missing or inadequate wind breaks, inadequate insulation and lagging (metal covering for insulation), failure to have or to maintain heating elements and heat lamps in instrument cabinets, failure to train operators and maintenance personnel on winter preparations, lack of fuel switching training and drills, and failure to ensure adequate fuel.
- Gas curtailment and gas pressure issues did not contribute significantly to the amount of unavailable generating capacity in ERCOT during the event. The outages, derates, and failures to start from inadequate fuel supply totaled 1282 MW from February 1 through February 5, as compared to an overall peak net generating capacity reduction of 14,702 MW.

Recommendations—Electric

Planning and Reserves

1. Balancing Authorities, Reliability Coordinators, Transmission Operators and Generation Owner/Operators in ERCOT and in the southwest regions of WECC should consider preparation for the winter season as critical as preparation for the summer peak season.
2. Planning authorities should augment their winter assessments with sensitivity studies incorporating the 2011 event to ensure there are sufficient generation and reserves in the operational time horizon.
3. Balancing Authorities and Reserve Sharing Groups should review the distribution of reserves to ensure that they are useable and deliverable during contingencies.
4. ERCOT should reconsider its protocol that requires it to approve outages if requested more than eight days before the outage, consider giving itself the authority to cancel outages previously scheduled, and expand its outage evaluation criteria.
5. ERCOT should consider modifying its procedures to (i) allow it to significantly raise the 2300 MW responsive reserve requirement in extreme low temperatures, (ii) allow it to direct generating units to use preoperational warming before anticipated severe cold weather, and (iii) allow it to verify with each generating unit its preparedness for severe cold weather, including operating limits, potential fuel needs and fuel switching abilities.

Coordination With Generator Owners/Operators

6. Transmission Operators, Balancing Authorities, and Generation Owner/Operators should consider developing mechanisms to verify that units that have fuel switching capabilities can periodically demonstrate those capabilities.
7. Balancing Authorities, Transmission Operators and Generator Owners/Operators should take the steps necessary to ensure that black start units can be used during adverse weather and emergency conditions.

8. Balancing Authorities, Reliability Coordinators and Transmission Operators should require Generator Owner/Operators to provide accurate ambient temperature design specifications. Balancing Authorities, Reliability Coordinators and Transmission Operators should verify that temperature design limit information is kept current and should use this information to determine whether individual generating units will be available during extreme weather events.
9. Transmission Operators and Balancing Authorities should obtain from Generator Owner/Operators their forecasts of real output capability in advance of an anticipated severe weather event; the forecasts should take into account both the temperature beyond which the availability of the generating unit cannot be assumed, and the potential for natural gas curtailments.
10. Balancing Authorities should plan ahead so that emergency enforcement discretion regarding emission limitations can be quickly implemented in the event of severe capacity shortages.

Winterization

11. States in the Southwest should examine whether Generator/Operators ought to be required to submit winterization plans and should consider enacting legislation where necessary and appropriate.

Plant Design

12. Consideration should be given to designing all new generating 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.
13. The temperature design parameters of existing generating units should be assessed. Maintenance/inspections generally.
14. Generator Owner/Operators should ensure that adequate maintenance and inspection of its freeze protection elements be conducted on a timely and repetitive basis. Specific Freeze Protection Maintenance Items

Heat Trace

15. Each Generator Owner/Operator should inspect and maintain its generating units' heat tracing equipment.

Thermal Insulation

16. Each Generator Owner/Operator should inspect and maintain its units' thermal insulation.

Use of Wind breaks/enclosures

17. Each Generator Owner/Operator should plan on the erection of adequate wind breaks and enclosures, where needed.

Training

18. Each Generator Owner/Operator should develop and annually conduct winter-specific and plant-specific operator awareness and maintenance training.

Other Generator Owner/Operator Actions

19. Each Generator Owner/Operator should take steps to ensure that winterization supplies and equipment are in place before the winter season, that adequate staffing is in place for cold weather events, and that preventative action in anticipation of such events is taken in a timely manner.

Transmission Facilities

20. Transmission Operators should ensure that transmission facilities are capable of performing during cold weather conditions.

Communications

21. Balancing Authorities should improve communications during extreme cold weather events with Transmission Owner/Operators, Distribution Providers, and other market participants.
22. ERCOT should review and modify its Protocols as needed to give Transmission Service Providers and Distribution Service Providers in Texas access to information about loads on their systems that could be curtailed by ERCOT as Load Resources or as Emergency Interruptible Load Service
23. WECC should review its Reliability Coordinator procedures for providing notice to Transmission Operators and Balancing Authorities when another Transmission Operator or Balancing Authority within WECC is experiencing a system emergency (or likely will experience a system emergency) and consider whether modification of those procedures is needed to expedite the notice process.
24. All Transmission Operators and Balancing Authorities should examine their emergency communications protocols or procedures to ensure that not too much responsibility is placed on a single system operator or on other key personnel during an emergency and should consider developing single points of contact (persons who are not otherwise responsible for emergency operations) for communications during an emergency or likely emergency.

Load Shedding

25. Transmission Operators and Distribution Providers should conduct critical load review for gas production and transmission facilities and determine the level of protection such facilities should be accorded in the event of system stress or load shedding.
26. Transmission Operators should train operators in proper load shedding procedures and conduct periodic drills to maintain their load shedding skills.

Findings—Natural Gas

- Extreme low temperatures and winter storm conditions resulted in widespread wellhead, gathering system, and processing plant freeze-offs and hampered repair and restoration efforts, reducing the flow of gas in production basins in Texas and New Mexico by between 4 Bcf and 5 Bcf per day, or approximately 20 percent, a much greater extent than has occurred in the past.
- The prolonged cold caused production shortfalls in the San Juan and Permian Basins, the main supply areas for the LDCs that eventually curtailed service to customers in New Mexico, Arizona, and Texas.
- Wellhead freeze-offs normally occur several times a winter in the San Juan Basin but are not common in the Permian Basin, which is the supply source that LDCs in the Southwest region typically rely upon when cold weather threatens production in the San Juan Basin.
- Electrical outages contributed to the cold weather problems faced by gas producers, processors, and storage facilities in the Permian and Fort Worth Basins, with producers being more significantly affected by the blackouts; however, based on information obtained from a sampling of producers and processing plants in the region, the task force concluded that the effect of electric blackouts on supply shortages was less important than the effect of freezing temperatures.
- Although producers in the New Mexico and Texas production areas implemented some winterization measures such as methanol injection, production was nevertheless severely affected by the unusually cold weather and icy road conditions, which prevented crews from responding to wells and equipment that were shut in.
- The extreme cold weather also created an unprecedented demand for gas, which further strained the ability of the LDCs and pipelines to maintain sufficient operating pressure.
- The combination of dramatically reduced supply and unprecedented high demand was the cause of most of the gas outages and shortages that occurred in the region. Low delivery pressures from the El Paso Natural Gas interstate pipeline, caused by supply shortages, contributed to gas outages in Arizona and southern New Mexico.
- Some local distribution systems were unable to deliver the unprecedented volume of gas demanded by residential customers.
- No evidence was found that interstate or intrastate pipeline design constraints, system limitations, or equipment failures contributed significantly to the gas outages.
- The pipeline network, both interstate and intrastate, showed good flexibility in adjusting flows to meet demand and compensate for supply shortfalls.
- Additional gas storage capacity in Arizona and New Mexico could have prevented many of the outages that occurred by making additional supply available during the periods of peak demand. Natural gas storage is a key component of the natural gas grid that helps maintain reliability of gas supplies during periods of high demand. Storage can help LDCs maintain adequate supply

during periods of heavy demand by supplementing pipeline capacity and can serve as backup supply in case of interruptions in wellhead production. Additional gas storage capacity in the downstream market areas closer to demand centers in Arizona and New Mexico could have prevented most of the outages that occurred by making additional supply available in a timelier manner during peak demand periods.

Recommendations—Natural Gas

1. Lawmakers in Texas and New Mexico, working with their state regulators and all sectors of the natural gas industry, should determine whether production shortages during extreme cold weather events can be effectively and economically mitigated through the adoption of minimum, uniform standards for the winterization of natural gas production and processing facilities.
2. The gas and electric sectors should work with state regulatory authorities to determine whether critical natural gas facilities can be exempted from rolling blackouts.
3. State utility commissions should work with LDCs to ensure that voluntary curtailment plans can reduce demand on the system as quickly and efficiently as possible when gas supplies are disrupted.
4. State utility commissions should work with balancing authorities, electrical generators, and LDCs to determine whether and under what circumstances residential gas customers should receive priority over electrical generating plants during a gas supply emergency.
5. State utility commissions and LDCs should review the events of early February 2011 and determine whether distribution systems can be improved to increase flows during periods of high demand
6. State utility commissions should work with LDCs to determine whether the LDC distribution systems can be improved so that curtailments can be implemented, when necessary, in a way that improves the speed and efficiency of the restoration process.