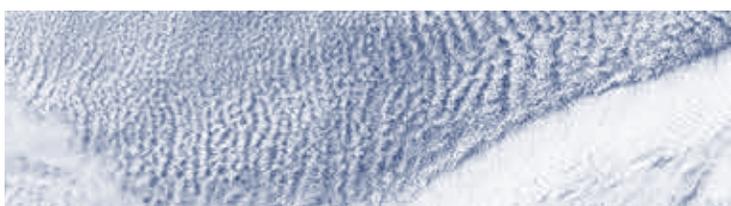
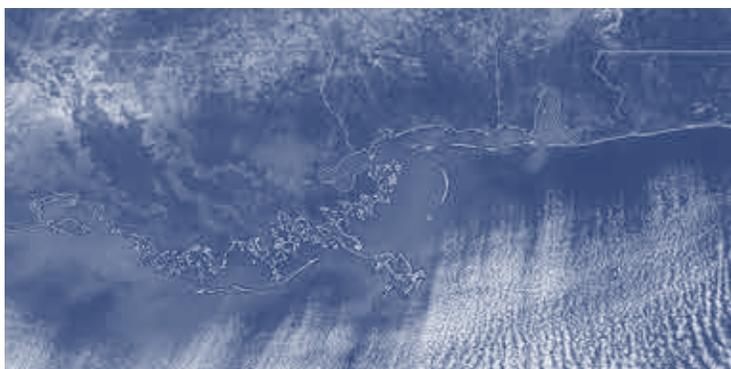


2019 FERC and NERC Staff Report

The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018



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FERC and NERC Staff Report July 2019

This report was prepared by the staff of the Federal Energy Regulatory Commission in consultation with staff from the North American Electric Reliability Corporation and its Regional Entities.

This report does not necessarily reflect the views of the Commission.

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Acknowledgement

This report¹ results from the combined efforts of many dedicated individuals in multiple organizations. The team behind the report (the Team) consisted of individuals from the Federal Energy Regulatory Commission (FERC or the Commission), the North American Electric Reliability Corporation (NERC), Regional Reliability Entities Midwest Reliability Organization (MRO), SERC Corporation (SERC), ReliabilityFirst Corporation (RF), and Western Electricity Coordinating Council (WECC),² all of whom are named in Appendix A. They were assisted by other non-Team members within their respective organizations. The inquiry which led to the report arose out of two presentations describing the January, 2018 event to FERC Staff: one by Midcontinent Independent System Operator, Inc. (MISO), and the other a combined presentation by Southwest Power Pool, Inc. (SPP), Tennessee Valley Authority (TVA), and the Southeastern Reliability Coordinator (SeRC)/Southern Company (SoCo), as well as other Joint Parties to a settlement between MISO and SPP, namely Associated Electric Cooperative, Inc. (AECI), Louisville Gas and Electric/Kentucky Utilities (LG&E/KU),

¹ This report is written for a reader who is already familiar with principles of energy markets, transmission system operations and generation unit operations. For readers who are not as familiar, the Team has provided a variety of appendices which may be helpful. *See, e.g.*, Appendix B, Primer on Electric Markets and Reliable Operations of the Bulk Electric System (BES)(begins at page 104), Appendix C, Reliability Coordinator and Transmission Operator Tools and Actions to Operate the BES (begins at page 109), Appendix D, Glossary of Terms Used in the Report (begins at page 114), Appendix E, Categories of NERC Registered Entities (begins at page 123), and Appendix F, Acronyms Used in the Report (begins at page 124). In addition, the Reliability Primer prepared by Commission Staff (<https://www.ferc.gov/legal/staff-reports/2016/reliability-primer.pdf>) and appendices from the Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011: Causes and Recommendations (<https://www.ferc.gov/legal/staff-reports/08-16-11-report.pdf>) may be helpful. Helpful appendices in the 2011 report include: Electricity: How it is Generated and Distributed, Power Plant Design for Ambient Weather Conditions, Impact of Wind Chill [on generating units], Winterization for Generators, Natural Gas: Production and Distribution, Natural Gas Transportation Contracting Practices, and Impact of Cold Weather on Gas Production. Appendix G of this report, which begins at page 126, contains the 2011 report's Recommendations on Preparation for Cold-Weather Events.

² Although the Event did not occur in WECC's footprint, WECC was invited to participate due to its experience with issues relating to the "seams" or borders between two Reliability Coordinator footprints.

and PowerSouth. Following these presentations, the Commission and NERC announced a joint inquiry with the Regional Entities, citing, among other factors, “reports of multiple forced generation outages, voltage deviations and near-overloads during peak operations,” and the need to “understand and underscore the importance of seamless RC-to-RC interactions.”³

Without the excellent cooperation of these entities, the Team could never have produced a thorough analysis. In addition to the owners of generating units affected by the extreme weather conditions, the Team would especially like to thank the staffs of MISO, SPP, TVA, SeRC/Southern Company, AECI, LG&E/KU, and PowerSouth. All of these entities provided data, and the non-generator entities attended multi-day meetings to answer questions and share perspectives. Some answered multiple rounds of questions as the Team clarified its understanding of key concepts. All were generous with their data and time, and the Team is grateful.⁴ The Team conducted outreach to share its preliminary findings and recommendations. Those invited to outreach sessions included MISO, SPP, TVA, Southern Company, and the Joint Parties, the Regional Entities not already participating in the Inquiry, market monitors for MISO and SPP, and industry groups including the ISO/RTO Council, Edison Electric Institute, the Electric Power Supply Association, the North American Transmission Forum, the North American Generator Forum, the National Rural Electric Cooperative Association, the American Public Power Association, the Electricity Consumers Resource Council, the Canadian Electricity Association, and the Transmission Access Policy Study Group. The Team thanks all who participated in the outreach for their insight.

³ <https://www.ferc.gov/media/news-releases/2018/2018-3/09-12-18.pdf>

⁴ The entities provided data to the Team with the assurance that it would be kept confidential until the entities provided permission to release it publicly. The Team has obtained permission from the entities to share the data included in the report.

I. Executive Summary

On January 17, 2018, a large area of the south central region of the United States experienced unusually cold weather. The below-average temperatures in this area resulted in a total of 183 individual generating units within the Reliability Coordinator (RC)⁵ footprints of SPP, MISO, TVA,⁶ and SeRC experiencing either an outage, a derate,⁷ or a failure to start between January 15 and January 19, 2018. Between Monday, January 15, and the morning peak hour (between 7 and 8 a.m. Central Standard Time (CST)) on Wednesday, January 17, approximately 14,000 MW of generation experienced an outage, derate or failure to start. Including generation already on planned or unplanned outages or derated before January 15, the four RCs had over 30,000 MW of generation unavailable in the south central portions of their footprints by the January 17 morning peak hour. MISO declared an Energy Emergency,⁸ because it had insufficient reserves to balance generation and load in the MISO South portion of its footprint, while all four of the RCs experienced constrained bulk electrical system (BES)⁹ transmission

⁵ See Appendix E, “Categories of NERC Registered Entities.”

⁶ TVA is a Reliability Coordinator for its TVA Balancing Authority area as well as for the Balancing Authority areas of AECI and LG&E/KU. This report will clarify whether it is referring to TVA as the RC, including AECI and LG&E/KU, or only to TVA’s own Balancing Authority area.

⁷ Reductions in capacity of a generating unit short of a total outage.

⁸ See Appendix C, “RC and TOP Tools and Actions to Operate the BES in Real Time.”

⁹ The Commission’s jurisdiction extends to the Bulk-Power System, defined by Section 215(a) (1) of the Federal Power Act as “facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof), and electric energy from generating facilities needed to maintain transmission system reliability.” The mandatory Reliability Standards apply to owners and operators of the bulk electric system (BES). In Order No. 773, the Commission approved a definition of BES that generally covers all elements operated at 100 kV or higher, with a list of specific inclusions and exclusions. Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure, Order No. 773, 141 FERC ¶ 61,236 (2012); order on reh’g, Order No. 773-A, 143 FERC ¶ 61,053 (2013), order on reh’g and clarification, 144 FERC ¶ 61,174 (2013). This report will use BES because its primary audience is most familiar with that term.

conditions across portions of their footprints, spanning all or parts of nine states. While the system remained stable, this combination of an Energy Emergency and wide-area constrained transmission conditions on January 17 meant that had MISO's next single contingency generation outage in MISO South of 1,163 MW¹⁰ occurred, continued reliable BES operations would have depended on system operators shedding firm load promptly to prevent further degradation of BES conditions.

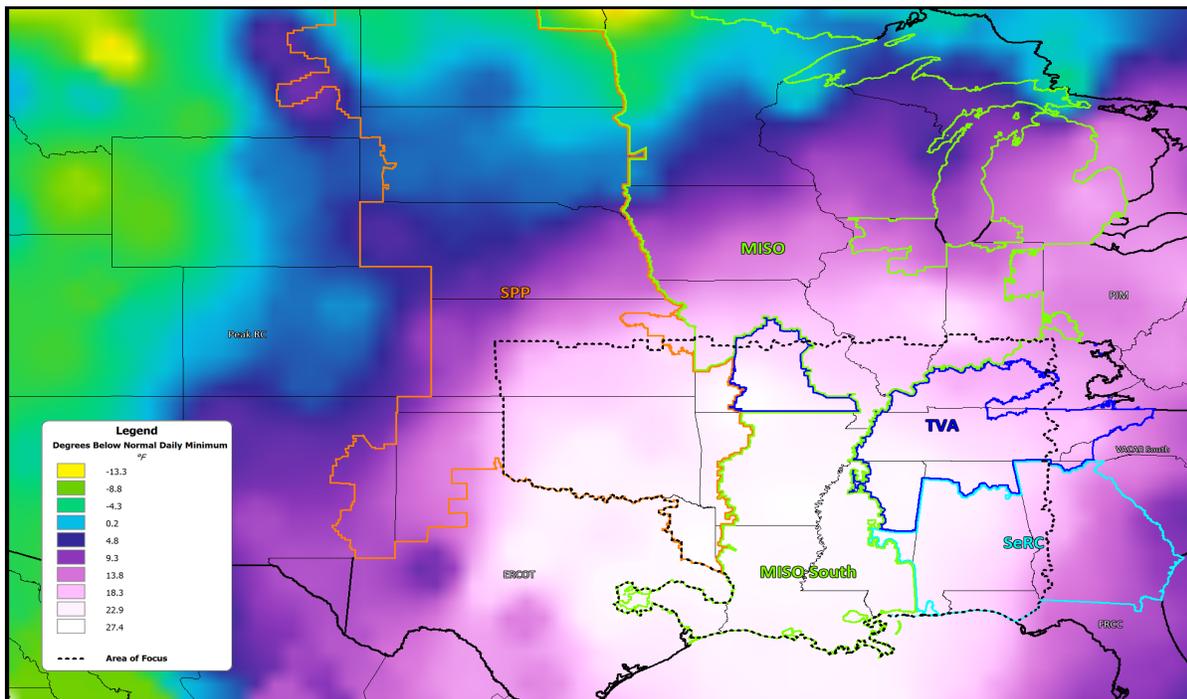
The combination of an Energy Emergency and wide-area constrained conditions constitutes the South Central U.S. Cold Weather BES Event of January 17, 2018, hereafter referred to as “the Event,” which occurred in an area (the “Event Area”)¹¹ consisting of:

- MISO South (Arkansas, eastern Texas, Louisiana, and Mississippi)
- Southeastern portion of the SPP RC footprint (lower Kansas-Missouri border, the eastern half of Oklahoma, Arkansas, eastern Texas, and Louisiana)
- Western portion of the TVA RC footprint (western Tennessee, lower Missouri, northeastern Oklahoma, northern Mississippi and Alabama)
- Western portion of the SeRC footprint (southern Mississippi and Alabama).

¹⁰ The mandatory Reliability Standards set forth requirements that provide for the reliable operation of the BES. Federal Power Act (FPA) § 215(a)(3). In turn, “reliable operation” is defined in the FPA as “operating the elements of the [BES] within equipment and electric system thermal, voltage and stability limits, so that instability, uncontrolled separation or cascading will not occur as a result of a sudden disturbance, including a cybersecurity incident or unanticipated failure of system elements.” *Id.*

¹¹ The sources or credits for all Figures are listed in Appendix H, “Source of Figures Used in the Report (begins at page 139).”

Figure 1: January 17, 2018 Event Area – Low Temperature Deviation From the Normal Daily Minimum



Below-average temperatures began to occur as early as Friday, January 12, from the Great Plains south through the Mississippi Valley. Going into the work week beginning Monday, January 15, MISO, SPP, and the other RCs, which are located within the MRO, SERC, and RF regions,¹² knew that Wednesday, January 17, was likely going to be the coldest day of an extremely cold week for much of their respective footprints. Because their footprints stretch further eastward than SPP's, MISO, TVA and SeRC also expected cold weather conditions for their respective areas on Thursday, January 18, as forecasts showed the cold weather moving eastward. With temperatures forecast by the National Oceanic and Atmospheric Administration to be "much below normal" for January 17, RCs in the Event Area expected very high system loads.

Planned and unplanned generation outages already existed going into the week of January 15, but as the colder weather conditions developed, MISO was projecting extremely tight reserve margins for MISO South in meeting its forecast peak load for the morning of January 17, beginning at 7 a.m. CST. Still, even with a high system load forecast and pre-existing generation outages, MISO did not expect to have a problem

¹² These are among the Regional Entities to which NERC has delegated some of its duties as the Electric Reliability Organization, as part of the statutory scheme which gave rise to mandatory Reliability Standards.

meeting customer demand on January 17 in MISO South, based on anticipated generator availability and precautionary measures that MISO took to increase projected reserves. However, an extraordinary amount of continuing generation outages and derates increasingly tightened already tight reserves, requiring emergency measures. In addition, MISO's five-day, four-day and three-day-out MISO South load forecasts for January 17 were less accurate (underestimating load by approximately 18.9%/6,000 MW, 10.2%/3,250 MW, and 6.1%/1,900 MW, respectively) than the other RCs' forecasts for the same period. Improved forecasting accuracy for future extreme weather conditions could increase MISO's ability to rely on long-lead-time resources and give it more time to prepare for severe weather events. The Team recommends that MISO work with its Local Balancing Authorities and adjacent RCs to improve the accuracy of its near-term load forecasts for MISO South.

In order to meet forecast load plus reserves for the morning peak hour (7 to 8 a.m.) on January 17, MISO instructed its local balancing authorities (LBAs) in MISO South to issue public appeals to reduce demand.¹³ MISO estimated the total load reduction achieved from this effort was 700 MW. Some of the Load Modifying Resources (LMR)¹⁴ participating in MISO's load reduction required more notice than MISO was able to provide at the time of this appeal.¹⁵ MISO also needed to purchase emergency energy from suppliers in adjacent RCs to meet its peak load.

The MISO South footprint was severely stressed as the morning peak hour approached. During the peak hour, MISO system analysis showed that if it incurred the worst single contingency generation outage of 1,163 MW in MISO South (hereafter MISO South WSC),¹⁶ it would need to rely on post-contingency manual firm load shed

¹³ MISO attributed the need for public appeals to "forced generation outages and higher than forecast load."

¹⁴ Load Modifying Resources are demand resources or behind-the-meter generation.

¹⁵ On January 18, the day after the Event, when MISO was able to provide more notice, it achieved 930 MW of Load Modifying Resources.

¹⁶ In addition to the Most Severe Single Contingency (MSSC) for its entire BA area (for the morning of January 17, 2018, MISO's MSSC was a 1,732 MW facility in the Midwest region of its BA), which MISO is required to cover under the Reliability Standards, MISO planned for sufficient reserves in MISO South to cover its worst single contingency in the MISO South portion of its footprint. It is this latter "worst single contingency" that the report will discuss and refer to as the MISO South WSC.

to maintain voltages within limits and shed additional firm load to maintain system balance and restore reserves for the MISO South region. MISO South's load peaked at 31,852 MW on January 17. At one point on January 17, MISO South had as much as 17,000 MW of generation unavailable, including 13,000 MW of it unplanned.¹⁷

MISO was not the only RC that lost generation in the Event Area. Going into Wednesday January 17, SPP, TVA RC and SeRC had 8,300 MW, 5,000 MW, and 1,400 MW of generation unavailable, respectively. The entire Event Area had as much as 33,500 MW of total unavailable generation (including planned outages) at one point on January 17, out of approximately 118,000 MW of capacity in the Event Area, and over 30,000 MW unavailable by the start of the morning peak load timeframe.¹⁸

The majority of the problems experienced by the many generators that experienced outages, derates, or failures to start during the Event were attributable, either directly or indirectly, to the cold weather itself. For the entire Event Area, from January 15 to January 19, Generator Owner/Operators (GO/GOPs) directly attributed 14 percent of the generator failures to weather-related causes, including frozen sensing lines, frozen equipment, frozen water lines, frozen valves, blade icing, low temperature cutoff limits, and the like. Another 30 percent were indirectly attributable to the weather, occasioned by natural gas curtailments to gas-fired generators (16%) and mechanical causes known to be related to cold weather (14%).¹⁹ The Team found that total outages from January 15 to 19 increased as temperatures decreased, with correlation coefficients of between -0.5 to -0.7, depending on the city. More than one-third of the GO/GOPs that lost generation during the Event did not have a winterization plan. Given the relationship between the cold and generator outages, the wealth of prior voluntary recommendations for generators to prepare for winter weather,²⁰ and that 70% of the unplanned outages occurred in gas-fired units, with 16% of those outages were directly attributed to gas supply issues, the Team recommends a three-pronged approach to address generator

¹⁷ Substantial percentages of the MISO South generation fleet were unavailable in Louisiana (57.1%), Arkansas (23.5%), and Mississippi (16.8%).

¹⁸ See Figure 22, Total Unavailable Generation. Peak non-coincident system loads for January 17 in the four BA footprints combined was 222,924 MW. See Figure 18, January 17, 2018 Peak Loads for Relevant Entities. The peak load figures cover the entire MISO, SPP, TVA and SeRC, footprints, whereas the capacity figure of 118,000 is an estimate of generating capacity just within the Event Area.

¹⁹ All percentages in this and the preceding sentence are based on number of units.

²⁰ See discussion in Recommendation 1, in Section VIII below.

reliability during extreme cold weather. This approach includes NERC developing one or more mandatory Reliability Standards that require Generator Owner/Operators to prepare for the winter and to provide information regarding their preparations (or lack thereof) to their RCs and Balancing Authorities (BAs), as well as enhanced outreach to the GO/GOPs, and market incentives for those GO/GOPs in organized markets.

In addition to the primary cause of the Event, which was the significant unplanned loss of generators in the Event Area that correlated with the drop in ambient temperatures, several other factors contributed to the BES conditions faced by system operators, including:

- increased customer electricity demand across the Event Area due to extreme low temperatures;
- large power transfers:
 - MISO's Regional Directional Transfer (RDT)²¹ from MISO Midwest to MISO South, which exceeded its contractual firm and non-firm limit (Regional Directional Transfer Limit (RDTL)) of 3,000 MW to provide replacement for MISO's generation outages and derates in MISO South; but also
 - remote generation power transfers, including MISO's and SPP's dispatch of wind generation output from distant locations; and
 - transfers between SPP and the ERCOT Interconnection via SPP's High Voltage Direct Current (HVDC) ties.

On January 17, MISO relied on its contractually-available transmission capacity under the RDT to schedule power to flow from generation in MISO Midwest into MISO South, to help cover the record winter electrical demand plus reserves. The RDT flow steadily increased in a north-to-south direction affecting the BES transmission system footprints of MISO, SPP, RC and SeRC, and it exceeded MISO's 3,000 MW RDTL during the early morning hours of January 17, reaching a maximum of 4,331 MW, as measured in real time, around 6:30 am CST. Although MISO exceeded the RDTL, and did not reduce the RDT below the 3,000 MW limit within 30 minutes as contemplated by the settlement agreement, MISO operators communicated with adjacent RCs (which are parties to the settlement agreement that established the RDT) that MISO would be exceeding the limit, and that if MISO's RDT flows caused a system emergency for the adjacent RCs, MISO would take appropriate actions. While the adjacent RCs did not determine that their systems were in an emergency state during the Event, they were made aware of the continuing generation outages and derates in MISO South, of MISO's

²¹ See section II.B and Figure 32 for background on MISO's RDT.

Energy Emergency declaration, and of MISO’s likely need to perform firm load shed if its next-worst contingency occurred.

Before the morning of January 17, none of the RCs had anticipated the multiple-wide-area²² constrained transmission conditions that simultaneously occurred in the SPP, TVA, SeRC, and MISO South RC footprints. The Team recommends seasonal studies that consider more-severe conditions, modeling same-direction simultaneous transfers and other stressed but realistic conditions, and sharing the results with operations staff to aid in planning for more extreme days like January 17. These widespread constrained conditions caused reserves to be stranded from MISO South.²³ The Team also recommends that RCs consider deliverability of reserves, and that MISO notify the other RCs when it is counting on the as-available, non-firm portion of the RDT to meet its reserves for MISO South, so that the RCs can timely communicate if conditions on the other RCs’ systems are projected to limit MISO’s ability to rely on the RDT.

The RCs also did not expect the numerous mitigation measures they would need to take to maintain BES reliability on January 17, including Transmission Loading Relief, transmission reconfiguration, and the need to be prepared to shed firm load in the event of an outage of the MISO South WSC of 1,163 MW. Had this outage occurred, during the morning peak hour on January 17, MISO would have likely had to order firm load shed in MISO South for two reasons. First, MISO would not have had sufficient deliverable reserves to cover its MISO South region peak load, and second, it concurrently would have likely needed to shed firm load to alleviate low voltages at many locations that were calculated to be significantly below their limits. Normally, voltage stability is a greater risk during summer than winter, however, there can be an increased risk of voltage stability under extreme cold winter weather conditions, heavy imports, and facility outage conditions.²⁴ Although the system remained stable on

²² The “wide area” each RC is responsible for includes its “entire RC Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits.” (See NERC Glossary of Terms). The January 17 event involved critical flows experienced concurrently in four RC areas.

²³ By “stranded,” the Team means reserves that cannot be delivered due to transmission constraints which cannot be alleviated.

²⁴ It has been studied that under high loads and heavy imports in a different winter-peaking area of the U.S., credible single and multiple contingencies could result in widespread post-contingency steady state voltage instability. The entity has identified these conditions as an Interconnection Reliability Operating Limit (IROL). In this

January 17, the Team recommends that MISO and other RCs perform voltage stability analysis when under similarly constrained conditions, benchmark planning and operations models against actual events which strained the system, perform periodic impact studies to identify which elements in the adjacent RCs' systems have the most impact on their own systems, and perform drills with entities involved in load shedding to prepare to execute load-shedding for maintaining reserves while at the same time alleviating severe transmission conditions.

Actions by operators to address real-time issues were effective and timely. The RC operators for SPP, MISO, TVA, and SeRC had situational awareness, communicating and coordinating their analyses and discussing mitigation actions necessary to maintain BES reliability, up to shedding firm load. RC operators also communicated as necessary with the Transmission Operators to verify that System Operating Limits (SOLs) took into account the extreme cold temperatures. Because some SOLs which operated as constraints on January 17 were based on summer temperatures or on static, year-round ratings, the Team recommends that SOLs and their associated equipment ratings be based on, at a minimum, ambient temperature conditions that would be expected during high summer load and high winter load conditions, respectively.

System conditions began to gradually improve after the morning peak ended at 8 a.m. CST and as the cold weather moved out of the Event Area. Warmer temperatures resulted in some generators returning to service, and decreased system loads. While MISO still sought emergency power for the evening peak on January 17, wide-area BES conditions were not as constrained as they were approaching the morning peak.

The affected RCs performed a post-Event analysis. Among the areas they identified for improvement was the joint Regional Transfer Operations Procedure (RTOP) used to govern MISO's use of the RDT, which was in effect at the time of the Event. The improvements they made to the RTOP, along with the Team's additional recommendations to add specificity and clarity during emergency situations, underscore the need for clear operating procedures for the system operators, to address similar multiple-wide-area constrained transmission conditions. The Team's recommended changes to the RTOP would clarify roles and timing, require affected entities to declare an emergency before MISO sheds firm load to reduce the RDT, and implement studies to

instance, voltage stability analysis (VSA) is conducted daily for the next operating day to determine if the limit can be increased or decreased depending on system conditions (i.e., load, power flows, internal generation in the area, outages, etc.). The IROL is also monitored in real time using VSA to perform real-time calculations for the IROL limit based on real-time conditions.

be performed before temporarily changing the RDTL or making emergency energy purchases.

In addition to the Team's recommendations, the report discusses sound practices followed by the entities involved in the Event, and reaffirms recommendations from the 2011 Report.²⁵

II. Background

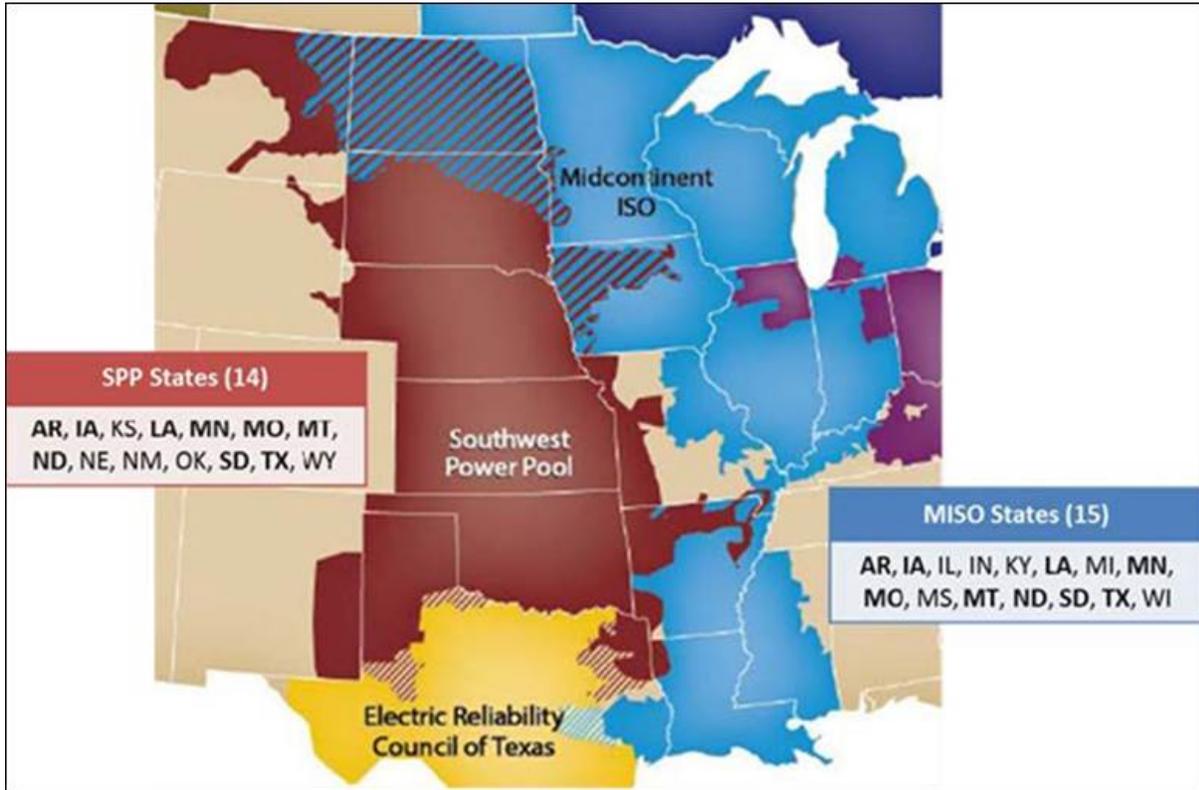
A. Affected System Overview

The Event Area is located within the Eastern Interconnection (which stretches from the East Coast to the Rocky Mountains, omitting the majority of Texas), and from eastern Canada to the Gulf Coast. Of the 15 NERC-approved RCs in North America which are responsible for having the wide-area view to oversee grid reliability, four were responsible for the reliable operations of the BES in the Event Area: MISO, SPP, TVA and SeRC.

The extra-high voltage (EHV) (345 kilovolts (kV) and above) portion of the Event Area comprises 500 kV transmission facilities spanning Arkansas, western Tennessee, Mississippi, Louisiana and Alabama. These 500 kV facilities are connected to the north and west within the Event Area via transformers to 345 kV transmission facilities located in lower Missouri and Kansas, and which run through Oklahoma and along the eastern border of Texas. There are two asynchronous HVDC connections between these 345 kV transmission facilities and ERCOT (to the west, in Texas), which operates as a functionally separate interconnection. These two HVDC ties to ERCOT (the North DC Intertie, and the East DC Intertie) allow power exchanges with the Eastern Interconnection through SPP. SPP also has several DC ties with the Western Interconnection. Other high-voltage BES transmission facilities within the Event Area include 230 kV, 161 kV, 138 kV and 115 kV facilities.

²⁵ See Appendix G, "2011 Recommendations on Preparation for Cold-Weather Events."

Figure 2: MISO and SPP Regional Transmission Organization Footprints

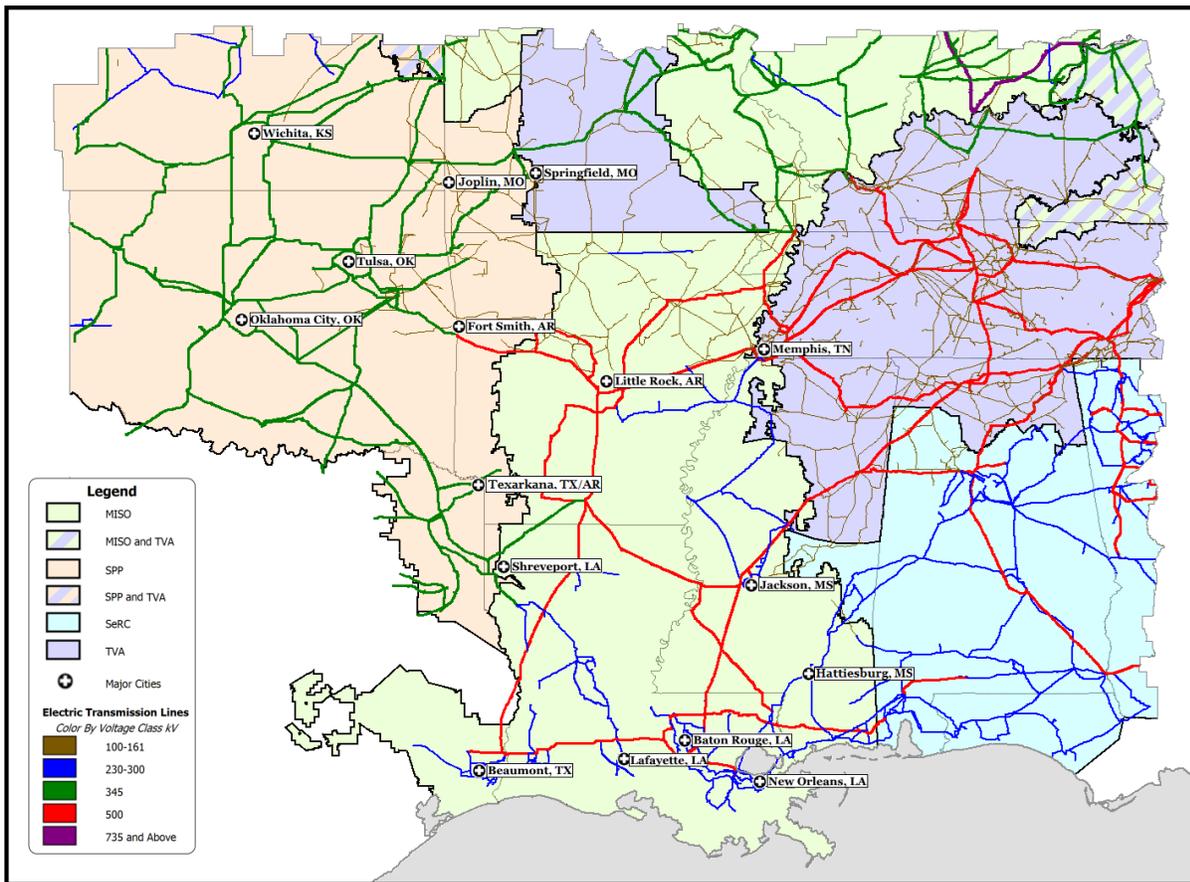


As the table below illustrates, the BES system between MISO and SPP is far more extensive than the limited number of ties between MISO Midwest and MISO South:

Figure 3: Tie Lines Between MISO and SPP RC Versus Within MISO

Voltage Level (kV)	Number of Tie-lines between MISO and SPP	Number of transmission lines between MISO Midwest and MISO South
69	85	0
115	30	0
138	5	0
161	41	0
230	13	0
345	16	0
500	3	1
Total	193	1

Figure 4: Electric Transmission Lines and Cities Within the Event Area



Transmission facilities within the Event Area serve load centers such as:

- | | | | |
|-------------------|-----------------|-----------------|------------------|
| Oklahoma City, OK | Tulsa, OK | Joplin, MO | Springfield, MO |
| Ft. Smith, AR | Little Rock, AR | Memphis, TN | Texarkana, TX/AR |
| Shreveport, LA | Lafayette, LA | Jackson, MS | Hattiesburg, MS |
| Baton Rouge, LA | Beaumont, TX | New Orleans, LA | Wichita, KS |

These BES transmission facilities also span many rural locations, serving thousands of smaller cities and towns, as well as large commercial, agricultural, and industrial loads located across portions of the south central U.S. This region of the country is normally not generation-capacity-limited. Under normal conditions MISO South has a substantial surplus of capacity, often leading to transmission flows in a southern-to-northern direction. This was not the case on January 17, 2018, due to the extensive generation outages experienced.

B. MISO Regional Directional Transfer and Related Agreements

MISO and SPP Regional Transmission Organizations (RTOs) share a border, or seam, and are parties to a Joint Operating Agreement designed to address power flows and improve operations along that seam. On December 19, 2013, MISO expanded its footprint by integrating the Entergy Operating Companies, among others, as transmission owning members (they now comprise the MISO South region). Since that date, MISO has two regions within its BA area, joined by a single firm transmission path: MISO Midwest, and MISO South. The addition of MISO South extended the seam between MISO and SPP to its current length: from the Canadian border in the north to the Gulf of Mexico in the South.

At the time the Entergy Operating Companies considered joining MISO, a dispute arose between MISO and SPP about interpreting provisions in the MISO-SPP Joint Operating Agreement about whether and/or how the two would share available transmission capacity on their respective transmission systems, particularly as to the amount of power flow, known under the Agreement as Regional Directional Transfer, or RDT, which MISO could use for intra-market flows between MISO Midwest and MISO South. The dispute was the subject of numerous filings and proceedings before the Commission and included parties in addition to MISO and SPP that were also affected by operations of the expanded MISO footprint.²⁶ The parties resolved the dispute by entering into a Settlement Agreement, which the Commission accepted on January 21, 2016.²⁷ Under the Settlement Agreement, MISO agreed to a Regional Directional Transfer Limit, or RDTL,²⁸ which limits MISO's north-to-south intra-market flows to 3,000 MW (1,000 MW being firm and 2,000 MW being non-firm, as-available) and

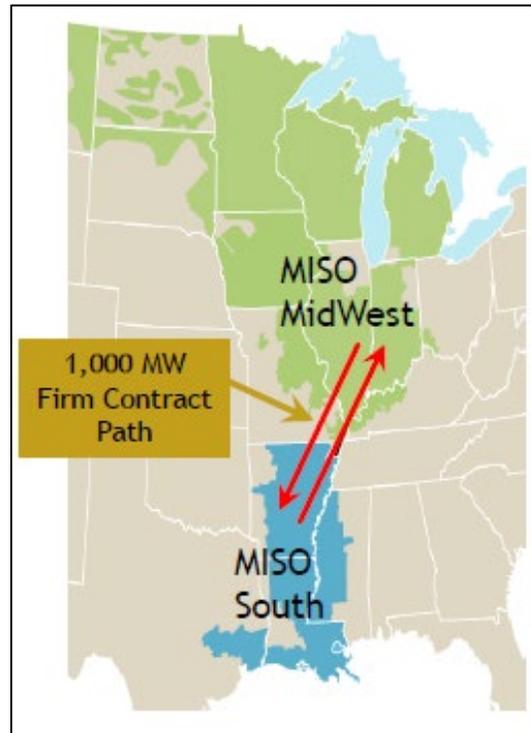
²⁶ See, e.g., Sw. Power Pool, Inc., 146 FERC ¶ 61,231 (2014) (consolidating the proceedings in Docket Nos. EL11-34-002, EL14-21-000, EL14-30-000, and ER14-1174-000, and establishing hearing and settlement judge procedures).

²⁷ Sw. Power Pool, Inc., 154 FERC ¶ 61,021 (2016). The parties to the Settlement Agreement are SPP, MISO, AECL, Southern Company, TVA, LG&E/KU, PowerSouth, and NRG Energy, Inc.

²⁸ The Settlement Agreement between MISO and SPP refers to the flows between MISO Midwest and MISO South as Regional Directional Transfer ("RDT"). On the other hand, within MISO, the RDT-related constraint on flows is referred to as Sub-Regional Power Balance Constraint (SRPBC). In either case, the limit is contractual in nature, and is not an actual physical transmission constraint.

2,500 MW flowing south-to-north from MISO South (1,000 MW being firm and 1,500 MW being non-firm, as-available).

Figure 5: MISO Midwest to MISO South Intra-Market Regional Directional Transfers (RDT)



Section 7.2.1 of the Settlement Agreement provided that the RDTL may be temporarily increased or decreased to avoid a transmission system emergency or during such an emergency, as long as the increased flow does not cause an emergency on the system of another party to the Settlement Agreement. Any party requesting an RDTL increase or decrease must contact the affected RCs and notify all other RCs via a posting to the Reliability Coordinator Information System (RCIS). The affected RC must assess the effects of an RDTL increase or decrease, and then notify the requesting RC whether it can accommodate such a change.

To implement the Settlement Agreement in real-time operations, the parties have a joint Regional Transfer Operations Procedure (RTOP), which addresses actions to be taken when the RDT is exceeded, requests to raise or lower the RDTL, congestion management, the effect of system emergencies and a procedure for conducting post-event reviews of events.

III. Review of Entities' Preparations for Winter 2017/2018

BES operations for any season begin well in advance, with planning and preparation based on certain historical data and assumptions. As real-time operations approach, this planning is refined with ever-more-accurate information. The Team reviewed how the relevant entities (RTOs, RCs, BAs and GO/GOPs) planned for the upcoming winter 2017/2018 season, and how those preparations assisted in, or could be improved for, ensuring reliable BES operations during the Event. The Team reviewed the relevant entities' 2017/2018 winter season:

- forecast peak loads,
- resource (generation) adequacy,
- transmission assessments, and
- generation winterization plans.

As part of its review, the Team asked the entities if they had considered relevant recommendations from similar events in their winter 2017/2018 planning.

A. Entities' Preparations for Winter 2017-2018 Operations

1. Projected Resource Adequacy for Winter 2017-2018

Historically, MISO and SPP are summer-peaking entities, TVA's BA has summer and winter peaks of similar magnitude, and SoCo BA (comprising the majority of the SeRC footprint) has more recently been a winter-peaking entity, with winter heating loads as a primary contributing factor. The table below shows the winter 2017-2018 peak forecast load, actual peak load, and actual peak load for January 17, 2018 for the entities' respective footprints.

Figure 6: Forecast 2017/2018 Winter Peak Loads

	MISO (Total)	MISO South Region	SPP	TVA BA	SoCo BA
Previous All-Time Winter Peak (GW)	109.3	31.1	41.5	33.4	45.9
2017/2018 50/50 Forecast Peak (GW)	103.4	28.4	41.1	31.9	41.0
2017/2018 Extreme Forecast Peak (GW)²⁹	110.6	31.2	42.5	33.4	47.0
2017/2018 Actual Peak (GW) / Date	106.1 / 1/17/2018	32.1 / 1/17/2018	43.5 / 1/17/2018	32.5 / 1/18/2018	44.4 / 1/18/2018
January 17, 2018 Peak (GW)	106.1	32.1	43.5	31.6	41.6

Above 50/50 Forecast Peak / Above Extreme Forecast Peak

None of the affected RCs forecast having a shortage of generation to meet their winter peak loads. MISO, SPP, TVA BA and SeRC all provided resource adequacy projections for their entire footprints for winter 2017-2018 as part of NERC’s 2017-2018 Winter Reliability Assessment, which ranged from 32% to 67% resource reserve margins (excluding planned and expected unplanned generation outages), well-above their required reserve margins of 12% to 17%.³⁰ The 29.6% reserve margin predicted for the MISO South region was also much higher than any of the required reserve margins.³¹

The above reserve margin values do not take into account planned or scheduled generation outages to perform maintenance, or refueling outages for nuclear generation. In portions of the south central U.S., where winter typically brings relatively mild temperatures, lower system loads, and adequate reserve margins (i.e., 30% or greater),

²⁹ SPP and SeRC calculated extreme scenario forecasts, while MISO and TVA used 90/10 scenarios.

³⁰ Data Source: NERC 2017/2018 Winter Reliability Assessment, available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_11202017_%20Final.pdf

³¹ The annual Weighted Equivalent Forced Outage Rate (wEFOR) for 2017 for MRO was 10.5%, and for SERC was 7.6%.

generation outages may be planned for the winter months. This allows maximum generation availability during summer, when much higher loads are experienced. MISO and SPP, both summer-peaking entities,³² would have planned more generation outages for the winter season than the summer (as well as during the so-called “shoulder” seasons of spring and fall). While planned outages can be rescheduled at times if system operators have sufficient notice of narrowing reserve margins, eventually the outages must occur to allow required unit maintenance. For example, from September 21-25, 2017, temperatures were unseasonably high throughout the MISO footprint. High planned outage rates, typical of shoulder months, and 1,100 MW of forced outages contributed to tight system conditions, leading MISO to declare a Maximum Generation Event on September 22, 2017.³³ MISO coordinated with Generator Operators during the operations planning horizon, asking them to shift their outages if possible to another time of the year when system loads and planned generation outages were forecast to be lower than the September 2017 conditions. One of the Generator Operators agreed to shift its planned outage until January, 2018, and thus was not available during the January 17 Event.

Winter reliability assessments also do not attempt to quantify the risk of fuel supply interruptions, although the Winter 2017-2018 assessments did include the data below illustrating the capacity of generation resources by fuel type.³⁴

³² The scheduling of significant generation outages during the winter months is less likely in other, winter-peaking areas of the country, where their typical winter temperatures are much lower - resulting in much higher system loads and therefore lower supply reserve margins.

³³ IMM Quarterly Report: Fall 2017, MISO Independent Market Monitor, Potomac Economics, available at https://www.potomaceconomics.com/wp-content/uploads/2017/12/IMM-Quarterly-Report_Fall-2017-Final.pdf.

³⁴ Data source for SPP and MISO: NERC Winter 2017/2018 Reliability Assessment. Data for SeRC/Southern and TVA BA was aggregated into SERC into the NERC Winter Reliability Assessment; therefore, the Team used publicly-available data for SeRC and TVA BA.

Figure 7: Generation Capacity Data by Fuel Type

	MISO		SPP		SeRC-SoCo BA		TVA BA	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Biomass	535	0.4%	39	0.1%	116	0.2%	---	---
Coal	61,452	42.7%	23,995	34.6%	16,890	36.0%	8,200	20.4%
Hydro	1,237	0.9%	4,771	6.9%	1,661	3.5%	5,149	12.8%
Natural Gas	60,328	41.8%	33,873	48.8%	19,514	41.6%	15,371	38.2%
Nuclear	12,866	8.9%	1,943	2.8%	3,680	7.8%	8,609	21.5%
Other	---	---	62	0.1%	3	0.0%	---	---
Petroleum	3,168	2.2%	1,717	2.5%	---	---	---	---
P. Storage	2,562	1.8%	482	0.7%	1,095	2.3%	1,615	4.0%
Solar	159	0.1%	197	0.3%	2,504	5.3%	1,100	2.7%
Wind	1,675	1.2%	2,247	3.2%	1,474	3.1%		

As the above table demonstrates, MISO, SPP, TVA and SeRC rely on a substantial amount of natural gas-fired generation. None of these RCs expected any gas pipeline issues for the winter 2017-2018 that would detrimentally impact electric generation availability, based on their communications with pipeline operators. For instance, MISO stated in its 2017-2018 Winter Readiness presentation³⁵ that lessons learned from the 2014 Polar Vortex helped it to plan for the coming winter, including monitoring of, and communications with gas pipelines; gas/electric market timeline changes; and gas usage profiles of generators. However, as discussed below in section VIII, gas pipeline issues did adversely affect electric generation during the Event.

2. Seasonal Transmission Assessments for Winter 2017-2018

MISO, SPP, and the other relevant Planning Coordinator entities generally perform seasonal transmission assessment studies several months before the winter and summer seasons, which are intended to test system performance under conditions anticipated that season, including expected transmission outages and realistic estimates of load, generation and transfers across the system. The affected entities performed their

³⁵ Data Source: MISO Winter Readiness Presentation, October 19, 2017.

winter 2017-2018 assessments in three separate, although somewhat coordinated, processes.

MISO: MISO performed its Coordinated Seasonal Transmission Assessment in the fall of 2017 to analyze transmission performance for north-to-south and south-to-north intra-market power transfers to determine power transfer limits for the 2017-18 Winter Peak season. MISO works with members and neighboring planning entities on the study scope, modeling and outage updates, and analysis review; the results then inform winter readiness efforts, such as MISO's annual Winter Readiness Workshop.

MISO's winter 2017-18 Coordinated Seasonal Transmission Assessment included five analyses: 1) Steady-State AC Contingency Analysis; 2) First Contingency Incremental Transfer Capacity Analysis; 3) Critical Interface Voltage Stability Analysis; 4) Wind Generation Sensitivity; and 5) Phase Angle Analysis. MISO modeled transfers by increasing generation in the study export area while reducing generation in the study import area and honoring maximum generation limits. MISO's First Contingency Incremental Transfer Capacity Analysis included transfers from MISO Midwest (MISO North and Central Regions) to MISO South, the same transfer path at issue in the Event, resulting in an inter-regional transfer capability of 4,650 MW. Since the agreed RDTL for real-time flows from MISO Midwest to MISO South Region is 3,000 MW, the study indicated that the 4,650 MW transfer capability was considered adequate for the upcoming winter season. To reach this conclusion, MISO adjusted transfers in its First Contingency Incremental Transfer Capacity analysis by increasing or decreasing generation in the desired area(s) on a sliding scale. The analysis did not model the outages of individual generators that would likely occur during actual system conditions.

MISO explained that power transfer distribution factors³⁶ are sensitive to, and vary substantially on, the generation dispatch modeling in the study. While the 2017-18 Coordinated Seasonal Transmission Assessment showed a winter season First Contingency Incremental Transfer Capacity of 4,650 MW, during the Event, SPP, TVA and other affected entities started experiencing constraints on their systems when MISO's Midwest to South transfers were much lower than 4,650 MW (e.g., at or below 3,000 MW).³⁷ MISO's First Contingency Incremental Transfer Capacity analysis was not used to inform lowering or raising of the RDTL, leaving the RDTL changes to be determined in the real-time operations horizon, without the benefit of any insights which could have been gleaned from the First Contingency Incremental Transfer Capacity Analysis. Even if the First Contingency Incremental Transfer Capacity analysis in MISO's Coordinated

³⁶ See Appendix D.

³⁷ See Section V, below.

Seasonal Transmission Assessment had indicated a lower transfer limit for a particular set of inputs (available generation, transfers, load, etc.), MISO did not use the Seasonal Transmission Assessment results to support MISO in its requests to raise or lower the RDTL for any particular days of that season.

SPP performed its winter assessment by creating two different snapshot cases for each week covering the study period of November 2017 through the end of March 2018, using Wednesday and Sunday cases to represent high-load and low-load periods for each week. SPP performed an initial contingency analysis to observe any transmission or voltage violations caused by loss of the contingency elements. To remedy any limit exceedances found in the contingency analysis, SPP applied a security constrained redispatch (SCRD) to each case as needed. The SCRD simulated iterative changes to SPP's generation dispatch in order to reduce or eliminate violations, while minimizing the creation of additional constraints. Once the redispatch was completed, a final contingency analysis was performed and any resulting violations were analyzed for further mitigations, overlapping outages that need rescheduling, or reported for further study. SPP's winter assessment revealed no expected issues and noted that extreme weather or fuel delivery issues could result in localized or brief capacity constraints, but that existing SPP congestion management procedures, documented mitigation strategies and operating guides appeared to be sufficient to manage any potential issues. SPP did not analyze intra-market transfers, such as those that might result from widespread generation outages.

TVA and SeRC participate in SERC's seasonal assessment. As a measure of projected transmission system performance for the 2017/18 winter season, the relevant study utilized assessments of incremental transfer capabilities among the SERC member systems. SERC's analysis to determine transfer capabilities was similar to MISO's in that transfers were simulated by increasing generation in an exporting area and decreasing generation in the associated importing area. However, in some instances, loads were reduced within subregions in SERC, to provide sufficient capacity to model desired levels of transfer. The studies did not identify any constraints relevant to the Event.

3. 2017-2018 Winterization Readiness Preparation

a) Reliability Coordinators and Balancing Authorities

RCs have the wide-area view of the BES (typically including multiple BAs and TOPs) and are responsible for its reliable operation, while the BAs' responsibilities within their BA footprint include integrating resource plans and maintaining generation-

load balance.³⁸ The Team found that MISO, SPP, TVA and SeRC routinely take steps to verify that the BES Generator Owners/Operators on which they depend are prepared for winter weather and extreme cold events. To better understand the topic of generators preparing for winter in the Event Area, one must first understand common differences between generating facilities in northern areas versus those in southern or other warm weather areas.³⁹

Geographic location and the corresponding ambient weather conditions, including expected temperatures and wind speed, have a direct impact on the preferred design for generating facilities. In the northern regions of the United States, most generating plants (especially steam-cycle plants) are designed and constructed with the boilers, turbines/generators, and certain ancillary equipment housed in one or more enclosed buildings. In the colder months, heat radiated from boilers, other generation equipment, and supplemental heaters maintain temperatures at a high enough level to prevent freezing. Enclosed areas are generally designed and constructed with fresh air inlets and roof-mounted exhaust ventilators for cooling purposes during the hot weather months.

Figure 8: Enclosed Coal-fired Power Plant in the Northeastern United States



In the southern and other warm weather regions of the U.S., generating plants are designed and constructed without enclosed building structures, with the boilers, turbine/generators, and other ancillary systems exposed to the weather, in order to

³⁸ NERC Glossary of Terms.

³⁹ The following two paragraphs, including the photographs, are drawn from the “Appendix: Power Plant Design for Ambient Weather Conditions” to the joint Commission/NERC Staff Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011: Causes and Recommendations, found at <https://www.ferc.gov/legal/staff-reports/08-16-11-report.pdf>

avoid excessive heat build-up. For the colder months, when temperatures may fall below freezing, Generator Owners and Operators undertake specific freeze protection efforts, which typically involve a combination of heat tracing, insulation, temporary heating, and temporary wind breaks (to prevent heat loss from normal operations and from supplemental heating sources).

Figure 9: Non-Enclosed Coal-fired Power Plant in the Southern United States



Generally, the affected RCs and BAs had issued winter readiness guidelines to Generator Owners/Operators within their footprints for the winter 2017-2018 season. PowerSouth, TVA BA, and Southern Company included specific freeze protection plans for generating units, as well as other winter assessment processes, to be performed prior to the winter season, as early as October in some instances. Some of these assessment processes included identifying systems and equipment within generating plants requiring winterization; completing items on a winter preparation checklist; and engaging meteorologists to preview winter forecasts and assess risks for extreme temperatures.

Some of the RCs and BAs also checked on generating units prior to winter weather to confirm the units' winter readiness. For instance, LG&E/KU (within TVA RC) held calls with individual generating plants to verify the plants had prepared for winter. TVA BA conducted winter readiness inspections of its units. Several other entities including PowerSouth (within SeRC), which owns generating units, have winterization plans that include checking plant equipment to ensure it is properly winterized.

MISO issued surveys to its Generator Operators on fuel availability prior to the winter. Some of the surveys included guidelines from the NERC winterization checklist⁴⁰ and ERCOT's winterization process. MISO noted that prior to the 2014 polar

⁴⁰ The NERC Winterization guidelines provide details on specific components that must be addressed in an effective winter weather readiness program, including: (I) Safety; (II) Management Roles and Expectations; (III) Processes and Procedures; (IV)

vortex event, it did not have a process for Generator Operators to report issues pertaining to winter readiness, such as fuel unavailability. However, following the 2014 event, MISO developed and implemented a process for generating units to update MISO about their readiness for the winter, including fuel availability. MISO implemented this process as part of the cold weather alert it issued prior to the January 17, 2018 event.

Most of the affected RCs and BAs educated their personnel and stakeholders on important generator winter readiness preparations through workshops in the fall of 2017. For instance, SPP and MISO held “Seasonal Preparedness” and “Winter Readiness” workshops, respectively. The workshops included discussions on high load and extreme outage scenarios, adequacy of generation resources to meet demand, and weather forecasts for the upcoming winter season. Southern Company, PowerSouth (in SeRC) and LG&E/KU (in TVA RC), which also own generating units, reported that they trained their operators to address freezing weather hazards to personnel and equipment. These entities also held post-winter meetings to review successes and setbacks from the previous winter season and get a head start on preparing for the next winter season.

RCs and BAs also prepared for winter by anticipating potential fuel supply issues. At least two large interstate pipelines in the affected regions declared force majeure⁴¹ during the Cold Weather Event, and at least one intrastate pipeline in the affected regions issued a critical notice for its entire pipeline group warning of imminent extreme cold temperatures, which increase demand for gas used by generators as well as to heat homes and businesses. Some generating units in the affected RC areas reported that they did not have firm gas supply or transportation contracts for their generating units. However, Southern Company (in SeRC), with fuel tank storage at its generating facilities, was able to re-supply generating units in the Event Area when their main fuel supplies were interrupted as a result of gas pipeline issues. Gas supply issues caused by the extreme cold temperatures, including interruptible supply, low gas pressure, and other pipeline and gas supply issues, led to outages of 38 generating units, totaling approximately 2,200 MW, during January 15 to 19 in the Event Area.

Evaluation of Potential Problem Areas; (V) Testing; (VI) Training; and (VII) Communications.

⁴¹ Force majeure clauses allow parties to excuse non-performance under a contract when some unavoidable event occurs (such as a hurricane). In the gas pipeline context, declaring force majeure can excuse a pipeline which fails to deliver to shippers which had firm transportation contracts. It can also potentially excuse a gas seller’s failure to deliver.

When fuel supplies are interrupted, dual-fuel⁴² units can help to protect reliability, but only if the unit can successfully switch to its backup fuel. From January 15 to 19, 2018, 40 out of 55 units operated by Southern Company (in SeRC) successfully switched to their secondary fuel sources and provided needed energy supply. Four of the seven BAs had procedures in place to test dual-fuel generating units prior to the 2017-2018 winter season, and TVA BA tests its dual-fuel units routinely during operations. For instance, LGE/KU (in TVA RC footprint) requires twice-yearly tests of dual-fuel units, whereas SeRC entities conducted annual tests to confirm that dual-fuel generating units can successfully switch to their alternate fuels. MISO noted that it does not currently have a program to ensure that generating units can switch fuels, however it would accommodate GO/GOPs that wish to test their fuel switching capabilities. SPP does not currently conduct any tests to confirm the fuel-switching capability of generating units within its service area.

Load Modifying Resources (LMR), and Demand Side Management (DSM) are tools used during capacity shortages to help maintain the energy balance. Entities took varying approaches to ensuring that these resources would be able to perform when needed. For instance, MISO implemented its LMR operational capabilities during the Event, even though those resources were not required to perform in the winter.⁴³ Other RCs reported that no penalties are assessed if their LMR is unavailable due to planned maintenance or force majeure.

b) Generator Owner/Operators

Twenty-one Generator Owner/Operator entities, many of which owned and/or operated multiple generating units, provided data regarding outages that occurred between January 15 and 19, 2018. Of those 21, **more than a third**⁴⁴ did not have winterization procedures at the time of the Event. Those that did have plans to prepare for the winter included one or more of the following elements:

⁴² Some generators have dual-fuel capability – that is, they allow for a unit to switch from its primary source of fuel (e.g., natural gas) to a secondary source of fuel (e.g., oil or coal) if needed. Fuel switching is one method that generators can use to alleviate the strain when a particular fuel source is in short supply. It can also be useful when seeking cheaper alternatives for fuel.

⁴³ Unless the resource had bid in and was dispatched in real time.

⁴⁴ Eight out of 21.

- freeze protection measures (discussed in more detail below);
- enhanced staffing measures, which could include the addition of a “freeze protection operator,” responsible for inspecting critical equipment, ensuring appropriate protections are in place, and the addition of more staff during severe weather; and
- fuel supply and dual-fuel capability: These procedures include checking fuel tank levels at least every other day during seasonal cold weather to ensure sufficient fuel during a cold weather event, and pre-freeze test firing of dual-fuel units that have not fired on their secondary fuel source during the previous year.

The ambient temperature design rating of a generating unit is an important aspect of preparing for winter weather and severe cold weather events, because it specifies the temperature(s) at which the unit’s full output can be achieved. Most of the units in the Event Area for which the ambient temperature design rating is known were rated between -10 and 10 degrees Fahrenheit,⁴⁵ with some exceptions. A handful of units had ambient temperature design ratings to -20 degrees, and four units were rated for use to -40 degrees. Some entities did not know their units’ ambient temperature design ratings, or did not incorporate those ratings into their freeze protection measures.

Several affected entities did account for their units’ ambient temperature design ratings in their operating procedures. For example, one entity set minimum freeze protection temperatures for each plant site, with specific guidance for physical assessment of existing critical freeze protection systems and the development of action plans if those systems do not meet the ambient temperature minimums.

Among the freeze protection measures contained in winterization plans were the following steps:

- Checking and maintaining adequate inventories of all commodities, equipment, and consumables that would aid in severe winter weather.
- Insulating exposed equipment and checking for missing or damaged insulation prior to cold weather.
- Checking heat tracing on all critical lines and piping to ensure that the circuits remain functional. Temperature guns can be used to check that heat tracing is working correctly.
- Closing doors on boiler enclosures to prevent cold air from entering.
- Confirming fuel heaters are in service and working properly prior to cold weather.

⁴⁵ All temperature references in this report will be to degrees Fahrenheit.

- Considering pre-warming scheduled units prior to a forecast cold weather event.
- Checking that all critical site-specific problem areas have adequate protection to ensure operability, and emphasizing the points in the plant where equipment freezing could cause a unit trip, derate or failure to start.
- Placing thermometers in areas containing equipment sensitive to extreme cold conditions and in freeze protection enclosures, ensuring that temperatures are monitored and maintained above freezing.
- Evaluating plant electrical circuits for adequate load capacity and ensuring that Ground Fault Circuit Interrupters are used properly.
- Reviewing work management systems for open corrective maintenance work orders that could affect the operation and reliability of the generating unit in cold weather, and ensuring that the work orders are prioritized correctly so that the work is completed prior to the winter season.
- Ensuring that all modifications and construction activities are performed such that the changes maintain cold weather readiness for the generating unit. (i.e., the changes do not degrade the generating unit's ability to withstand cold weather—for example, tearing pipe insulation).
- Disconnecting sensing lines on pressure transmitters to prevent freezing of these lines.
- Installing wind barriers, such as tarps or semi-permanent barriers constructed of wood or metal, to protect critical instruments, sensing lines, controllers and piping.
- Cleaning coal feed chutes as needed to keep coal supply flowing.
- Closing all building doors to prevent cold air from entering.
- Monitoring and removal of ice and snow.

Proper training of operators on winterization is critical to ensure they will be prepared to take the necessary actions before and during extreme cold weather events. Many of the affected entities employ preventative cold weather training, such as an annual review of site-specific winterization procedure for all operators, or requiring initial and recurring operator certification on procedures which include winterization plan procedures. Less experienced operators may be asked to perform a cold weather checklist with experienced operators.

With a few exceptions, the majority of the GO/GOPs that had winterization plans also conduct “lessons learned” following major weather events, including severe cold weather events. In these evaluations, the entities review their performance during the severe weather, determine root causes of any weather-related problems, and develop additional best practices for future similar events. In many cases, the entities incorporate the takeaways from those evaluations in their written guidance on winter weatherization procedures. Some entities consider best practices from neighboring generation or

industry partners in keeping their winterization processes comprehensive and up-to-date. Some entities provided specific examples of differences between their current winterization procedures and previous ones as a result of lessons learned. Several of these are worth highlighting, such as the required “freeze protection” training for new hires and annual “refresher” trainings for appropriate personnel, and the addition of materials for extended stays of personnel in severe cold weather events (e.g., cots, food, camp stoves).

IV. Near-Term Forecasts and Preparations for the Week of January 15

A. Short Range Weather and Load Forecasts

1. Impending Weather Conditions

In general, average temperatures remained at or above-freezing for the deep south into Monday January 15; however, as arctic high pressure moved from the northern plains to the central and eastern U.S. on January 15-17,⁴⁶ it resulted in average temperatures well below freezing for areas including parts of the plains, the Mississippi Valley, and Tennessee.⁴⁷ This cold front was forecast several days in advance. On Friday, January 12, at 3 p.m., the National Weather Service issued its “US Hazards Outlook” covering the period that included January 15 to 19.⁴⁸ It predicted that an “arctic air mass” would reach the eastern half of the U.S. by January 17 and “last for several days,” bringing “much below normal temperatures,” with “maximum and minimum temperatures 12 -28 degrees [Fahrenheit] below normal.”

2. Mid- and Short-Term Load Forecasts

MISO generates Mid-Term Load Forecasts and Short-Term Load Forecasts within the operating horizon (next four-six days prior to the operating day). MISO’s Mid-Term

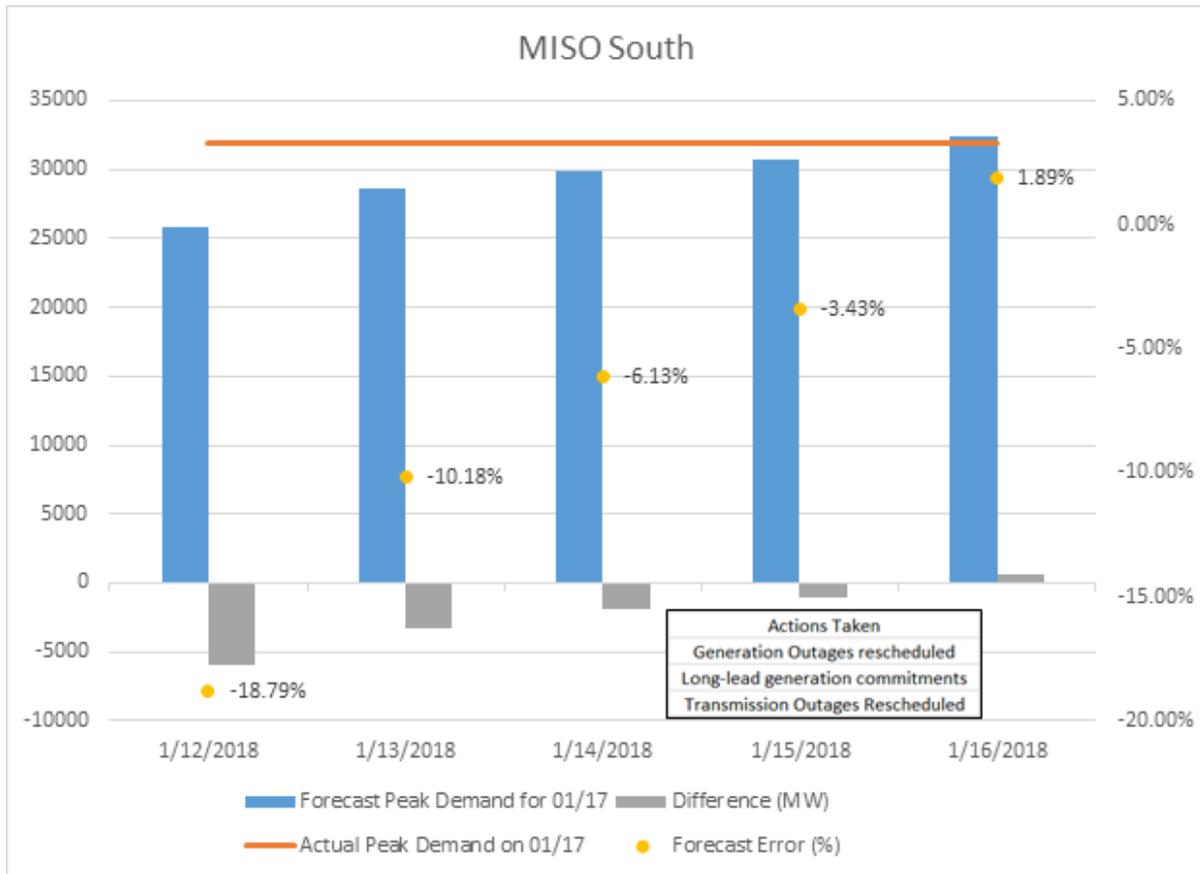
⁴⁶ Source: US HAZARDS OUTLOOK 300 PM EST JANUARY 10 2018, NWS Climate Prediction Center (<http://www.cpc.ncep.noaa.gov/products/archives/hazards/data/2018/KWNCPCMDTHR.20180110>).

⁴⁷ <https://www.timeanddate.com/weather/usa>, based on NOAA historical weather observations.

⁴⁸ <http://www.cpc.ncep.noaa.gov/products/archives/hazards/data/2018/KWNCPCMDTHR.20180112> s

Load Forecasts were the primary load forecasts used as an input to its operational planning to make longer-lead-time resource commitment decisions. The table below compares load forecasts generated on January 12, 13, 14, 15 and 16 for January 17, 2018 for MISO South.

Figure 10: MISO’s Near-term Peak Load Forecasts and Percent Error for MISO South: 5-day, 4-day, 3-day, 2-day, and 1-day ahead of January 17, 2018



MISO’s five-day, four-day and three-day-ahead “mid-term” peak load forecast errors in forecasting the actual MISO South peak load for January 17, 2018 were larger (approximately 18.9%/6,000 MW, 10.2%/3,250 MW, and 6.1%/1,900 MW lower than actual peak load, respectively) than forecast error rates for the same period for the other RCs involved in the event. SPP’s, TVA’s BA, and SeRC’s (SoCo BA) load forecasts comparable to this timeframe were much more accurate (with error rates ranging from 5.6% lower to 3.0% higher than actual peak load for five-days-out, 4.6% lower to 4.8% higher than actual for four-days-out, and 2.8% lower to 4.0% higher than actual for three-days-out). Improved Mid-Term Load Forecast accuracy could have helped MISO plan for additional longer-lead-time actions to be better prepared for the operating day of January 17, 2018. MISO provided the high and low temperature forecasts for January 17

from January 12, 13, 14, and 15, which it incorporated into its load forecasts for January 17, as shown below:

Figure 11: MISO’s High and Low Temperature Forecasts Used in MISO South Load Forecasts: 5-day, 4-day, 3-day, 2-day, 1-day ahead of January 17, 2018

City Name, State	1/12/18 for 1/17/18	1/13/18 for 1/17/18	1/14/18 for 1/17/18	1/15/18 for 1/17/18	Actual for 1/17/18
Little Rock, AR	33/19	30/15	28/12	32/12	29/9
Jackson, MS	41/21	35/16	32/14	33/15	31/10
Baton Rouge, LA	47/31	41/24	40/22	39/20	37/12
New Orleans, LA	51/34	42/27	41/25	38/24	36/19

The forecast temperatures MISO used in its MISO South load forecasts for January 17 on January 12 (five days ahead) were considerably higher than the actual highs and lows on January 17. The five-day-ahead forecast was in the normal range for mid-January, and was therefore not effective in providing a warning for the severity of the upcoming cold snap. The forecasts improved somewhat, but even the forecasts for January 15 (two days ahead) were 3 to 8 degrees higher than the minimum temperature observed on January 17.

B. Generation Unavailable for the Entire Event

Planned generator outages are typically scheduled months or even years in advance, to perform necessary maintenance, or in the case of nuclear power plants, refueling. While Reliability Coordinators like MISO can ask Generator Owners/Operators to reschedule their planned generation outages for system reliability, they cannot require the Generator Owners/Operators to do so. At some point, the maintenance or refueling must be accomplished, and there are only so many opportunities to schedule outages so as to avoid peak system conditions and ensure sufficient generation remains available.

MISO South's planned generation outages totaled 4,049 MW for the week of January 15, 2018, which included three generators larger than 500 MW and one over 1,000 MW. MISO was able to reschedule 1,700 MW of generation outages during the week of January 15, which would otherwise have added to the 4,049 MW. In addition to the planned generation outages, MISO South experienced a number of forced generation outages and derates, as shown in the table below. SPP RC, TVA RC, and SeRC's planned and unplanned outages within the Event Area from January 15 to the start of January 17 are also shown in the table below.

Figure 12: Event Area Approximate Planned and Unplanned Generation Outages, at the Start of January 15, and January 17, 2018

	Planned, at the start of:		Unplanned, at the start of:		Total Unavailable, at the start of:		Event Area Approx. Capacity
	Jan. 15	Jan. 17	Jan. 15	Jan. 17	Jan. 15	Jan. 17	
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	
MISO South	4,000	4000	5,700	7,600	9,700	11,600	41,800
SeRC	700	700	300	700	1,000	1,400	24,400
SPP	2,300	2,300	2,500	6,000	4,800	8,300	34,500
TVA RC	100	100	2,100	4,900	2,200	5,000	17,400
TOTAL	7,100	7,100	10,600	19,200	17,700	26,300	118,100

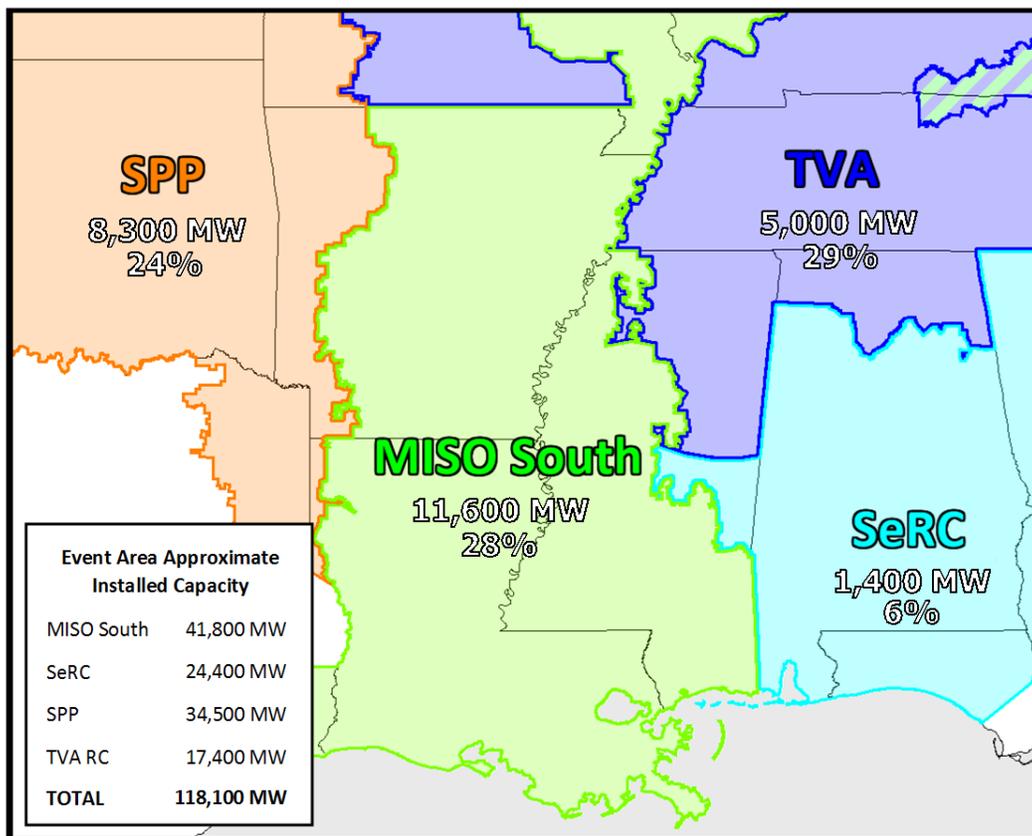
At the start of the week of January 15, MISO forecast the following conditions for its MISO South region:

Figure 13: MISO South Region Forecast Peak Load for January 17, 2018 and Available Generation, at the Start of January 15, 2018

	Approx. Capacity	Total Unavailable Generation	Available Generation	January 17, 2018 Forecast Peak Load
	(MW)	(MW)	(MW)	(MW)
MISO South	41,800	9,700	32,100	30,761

By the start of January 17, 2018, planned generation outages within the MISO South, SPP, TVA RC, and SeRC portions of the Event Area totaled approximately 7,100 MW, and forced generation outages and derates totaled approximately 19,200 MW, for a total of 26,300 MW, or approximately 22%, out of a total Event Area estimated generation capacity of approximately 118,000 MW.⁴⁹ By the start of January 17, outages and derates in MISO South reached 28% of its capacity, and SPP's southern footprint within the Event Area reached 24%. The areas in which generation outages and derates occurred by the start of January 17, and the Event Area generation capacity statistics for each RC, are shown below.

Figure 14: Total Generation Outages and Derates Within the Event Area, Beginning January 17, by RC Footprint



⁴⁹ This total includes forced outaged and derated generation, with some that occurred prior to the week of January 15, as well as on January 15-16. The Event Area did not include the entire footprints of MISO, SeRC, SPP, and TVA. The Event Area generation capacity numbers cited are only a portion of the total generation capacity of MISO, SeRC, SPP, and TVA. The remaining areas of the MISO, SeRC, SPP, and TVA RC footprints were not affected by the Event.

C. Changes/Adjustments Made by RCs Due to Impending Conditions Forecast

1. Pre-real-time Resource Commitment Process

For the week of January 15, MISO performed a “forward reliability assessment commitment” (FRAC) in advance of the January 17 operating day. FRACs occur four- to six-days-ahead of the operating day, and commit longer-lead generation (i.e., units that require 20 hours or more advance notice to come online). MISO’s FRAC projected for January 17 took into account available generation capacity located in MISO South, external interchange imports and exports scheduled for the MISO South region. MISO committed these resources on an hourly basis so that the total (generation capacity and net exchange) met or exceeded the total of the MISO South forecast daily peak loads, plus peak load forecast uncertainty of 5% and MISO South’s single worst contingency.⁵⁰ The FRAC did not rely on MISO’s intra-market RDT capacity to calculate or provide reserves for MISO South.

- During the January 14-16 timeframe, MISO revised its forecast peak load conditions, with each day forecasting a higher peak load for Wednesday, January 17, 2018 for MISO South:
 - On January 14, 3-day-ahead forecast peak load: 29,899 MW
 - On January 15, 2-day-ahead forecast peak load: 30,761 MW
 - On January 16, next-day forecast peak load: 32,455 MW

MISO’s January 16 day-ahead and January 17 real-time unit commitments differed from the four- to six-day-ahead FRAC in that they relied upon the entire 3,000 MW MISO Midwest-to-South RDT (including both the 1,000 MW firm transmission capacity, and the non-firm, as-available 2,000 MW) in its calculation of reserves. Even though MISO included the RDT to meet its MISO South reserves for the next day, in its security-constrained unit commitment and economic dispatch, MISO normally commits or schedules sufficient generation capacity for MISO South, so that the RDT is generally held at a “zero” transfer level between MISO Midwest and MISO South.⁵¹

⁵⁰ Normally MISO South’s single worst contingency was 1,415 MW, but that unit was on forced outage, leaving the 1,163 MW unit as the single worst contingency for MISO South FRAC calculations for January 17.

⁵¹ MISO’s Enhanced Reserves Procurement Process filing, accepted by the Commission in August of 2018, reflected that MISO intends to rely upon the full 3,000

As of January 16, with a higher forecast MISO South peak load (32,455 MW) for the next day, and with MISO South available reserves now forecast to be 2,147 MW, MISO fell short of covering the next-day forecast load + MISO South single worst contingency + load forecast reserve/uncertainty, by 576 MW. The reserves shortfall would need to be in part supplied from MISO Midwest, using MISO’s RDT, unless other actions were taken by MISO, such as scheduling imports directly into MISO South, via power transfers from directions other than the north-to-south RDT. MISO made the following declarations as January 17 approached and its projected reserves narrowed:

Figure 15: Declarations Made by MISO in Preparation for January 17 and 18

<u>Declaration</u>	<u>MISO Region</u>	<u>Issuance</u> (CST)	<u>Start Time</u> (CST)	<u>End Time</u> (CST)
Conservative Operations ⁵²	South	1/15/18 4:59	1/15/18 5:00	1/18/18 13:00
Cold Weather Alert ⁵³	South	1/15/18 15:00	1/16/18 5:00	1/16/18 13:00
Maximum Generation Alert ⁵⁴	South	1/16/18 21:50	1/17/18 4:00	1/17/18 11:00

MW of RDT, including the as-available, non-firm portion, in establishing reserves for MISO South. *Midcontinent Independent System Operator, Inc.*, 164 FERC ¶ 61,129 (2018).

⁵² MISO’s “Conservative System Operations” procedure identifies the actions resulting from this declaration. Actions include additional control center staffing and deferring or canceling maintenance or testing of BES generation and transmission equipment, and critical computer systems (e.g. energy management systems). SO-P-NOP-00-449 Rev 0 Conservative System Operations.pdf (#1981). The reasons given for the Conservative Operations declaration were record low temperatures and high loads forecast, forced generation outages and derates, as well as delayed outage returns.

⁵³ MISO’s “Cold Weather Alert” procedure identifies the actions resulting from this declaration. Actions include communication to GOPs to implement plans to winterize units and plants to ensure availability during emergency conditions, coordinate personnel staffing to ensure all scheduled combustion turbines and diesel generators are available for loading during load pick up period, and review fuel supply/delivery schedules availability during emergency conditions. Reliability Coordinator Information System (RCIS) log.

⁵⁴ MISO attributed the Maximum Generation Alert to forced generation outages and higher than forecast load. Among other measures, the Maximum Generation Alert

SPP, TVA BA and SeRC had similar near-term processes for their generation/resource commitment, and they each predicted sufficient generation supplies across their respective footprints for the next day, January 17. In addition to meeting their respective footprint's electrical demand, as described further below in section V of the report, both TVA BA and SeRC/Southern Company were able to provide emergency energy to MISO South on January 17.

2. Next-Day Operational Planning Analysis (OPA) of Transmission Conditions (Performed on January 16, 2018 for the January 17 Operating Day)

In order to develop their Operational Planning Analyses (OPA),⁵⁵ MISO RC, SPP RC, TVA RC, and SeRC performed next-day contingency analyses, including both steady-state thermal and voltage stability analyses. The completed contingency analyses were compared against relevant limits, including SOLs and IROLs, as well as voltage limit criteria,⁵⁶ which are shown in Figure 16.

declaration called for all available economic resources to be committed to meet load, firm transactions and reserve requirements, as well as verification of available LMRs that could help reduce system load if called upon. Note that at this point, MISO only verified the LMRs; i.e., the Maximum Generation Alert does mean that it issued scheduling instructions for the LMRs to modify their load by a certain time, for a given duration. Source: Reliability Coordinator Information System (RCIS) log.

⁵⁵ Under the mandatory Reliability Standards, each RC (e.g., MISO, SPP, TVA, SeRC) is required to “perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day [sic] will exceed SOLs and Interconnection Operating Reliability Limits (IROLs) within its Wide Area,” as well as an Operating Plan to address any potential SOL and IROL exceedances revealed by the OPA. IRO-008-2 R1&R2. Transmission Operators have a similar requirement to perform daily OPAs, and prepare Operating Plans to address the OPA's findings, under TOP-002-4 R1&R2. See Appendix B, “Primer on Electric Markets and Reliable Operations of the BES,” for more information on the RCs' OPA processes.

⁵⁶ Planning coordinators and transmission planners use voltage criteria in planning for future BES conditions for their respective footprints, which includes N-0 (no contingencies) and N-1 (outage of a single BES element or “single contingency”). However, the January 17, 2018 event was an “N-many” condition, due to the numerous generation outages during that timeframe. For more information on voltage criteria requirements applicable to transmission planners and planning coordinators, see NERC

Figure 16: Comparison of Transmission Planning Voltage Criteria (Percent) – Low Limits for Relevant RC Footprints in the Event Area

Nominal Voltage Level	SPP RC	MISO South Region	TVA RC	Southern/ SeRC
Normal (N-0) Low Limits:				
500 kV	---	97.5% ¹ / 95%	98% / 95% ²	98%
345 kV	95%		97% ³ / 95% ² /	---
230, 161, 138, 115 kV	95%	95%	94% ⁴	95%
N-1 Low Limits:				
500 kV	---	95%	98%	97%
345 kV	92% ⁵ / 90%		95% ³ / 90%	---
230, 161, 138, 115 kV	92% ⁵ / 90%	92% ⁶ / 90%		92%
¹ Entergy transmission planning criteria for EHV levels. ² AECI transmission planning criteria. ³ For TVA load-serving buses. Criteria is 98% for non-load-serving buses. ⁴ LGE-KU transmission planning criteria. ⁵ AEP Central-Southwest transmission planning criteria. ⁶ Entergy transmission planning criteria for HV levels.				

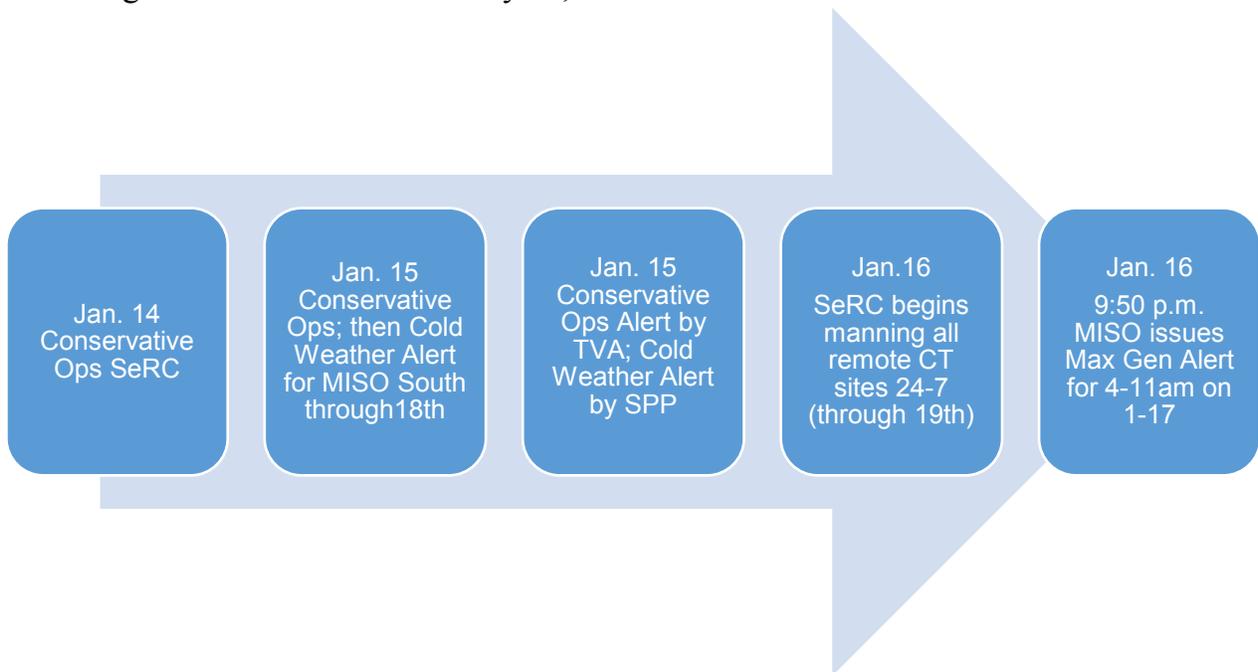
The analyses and resulting next-day Operating Plans were completed by late afternoon on January 16, and thus could not reflect the significant amount of additional unplanned generation outages, derates and failures to start which occurred overnight, and the impacts of the higher power transfer levels and decreased system voltage levels resulting from those losses.

3. Alerts Issued Before January 17

Taking into account the extreme below average colder temperatures, elevated system loads, and unplanned outages that had already occurred, and the extreme temperatures and elevated system loads expected to continue, RC operators took the

Reliability Standards, Transmission Planning (TPL), TPL-001-4 - Transmission System Planning Performance Requirements, Requirement R5 at 7, available at <https://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=United States>

following measures ahead of January 17, 2018:

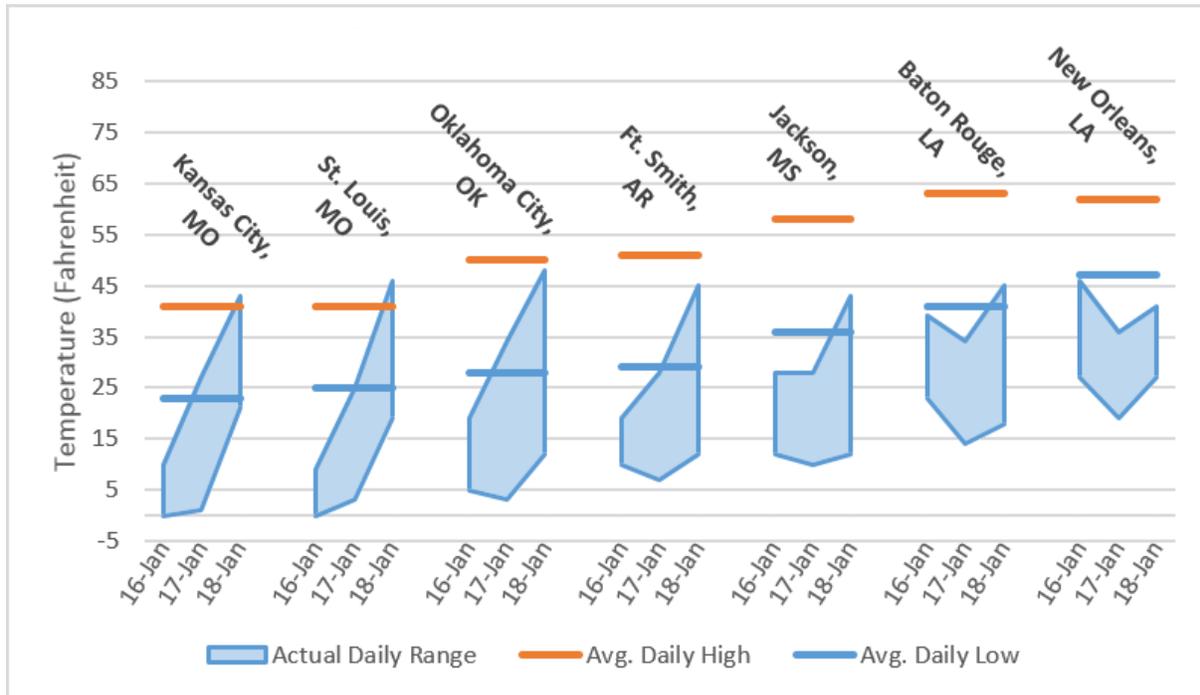


V. **January 17, 2018 Event: Additional Generation Outages, Extreme Below-Normal Cold Weather Conditions, and Wide-Area Constrained Transmission System Conditions**

A. **Extreme Weather and Record Peak Loads**

In addition to the arctic air, the weather front on January 14 to 17 brought snow and ice to parts of the Midwest, South and East. Temperatures in the Event Area dropped far below normal lows, as shown in the tables below. While not record lows, New Orleans recorded its lowest temperature in 29 years, while Little Rock, AR experienced the lowest temperature in 22 years.

Figure 17: Comparison of Actual Highs and Lows to Average Daily High and Low Temperatures, January 16 through January 18, 2018



By early January 17, every Mississippi county reported icy roads.⁵⁷ In addition to having the potential to freeze certain components of open-frame generating units, the icy conditions caused the loss of six (3-230 kV and 3-115 kV) transmission facilities, which occurred the evening of January 16 and during the early morning hours of January 17 in Southern Louisiana, and significantly degraded the transfer capability in that area.

As shown in Figure 18, most of the affected entities' peak loads on January 17 exceeded their forecast 2017-2018 winter peak loads. Further, the January 17, 2018 peak loads for both the SPP footprint, and for the MISO South region reached all-time highs for the winter season - breaking previous winter peak records, and nearing MISO South's all-time summer peak demand of 32,700 MW.

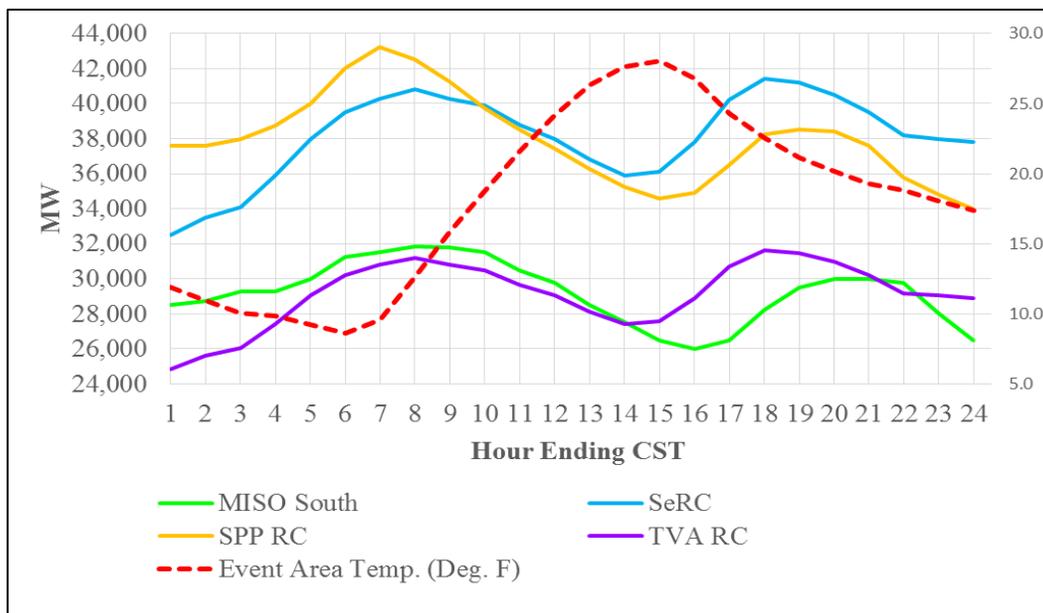
⁵⁷ Source: The Weather Channel (weather.com) January 17 2018 09:00 P.M. EDT (<https://weather.com/storms/winter/news/2018-01-14-winter-storm-inga-midwest-northeast-south-snow-forecast-mid-january>)

Figure 18: January 17, 2018 Peak System Loads for Relevant Entities

	All-Time Peak Winter Loads	Seasonal Forecast 2017-2018 Winter Peak Load	Actual January 17, 2018 Peak Load	Difference
	(MW)	(MW)	(MW)	(%)
MISO BA (total)	109,300	103,400	106,100	3%
MISO South footprint	31,100	28,400	31,582	11%
SoCo BA*	45,900	41,054	41,600	1%
SPP BA	41,500	41,129	43,584	6%
TVA BA**	33,352	31,925	31,640	-1%
* Actual peak occurred January 18, 2018: 44,400 8%				
** Actual peak occurred January 18, 2018: 32,509 2%				

As frigid air moved into the region, it increased system loads for each of the entities. While it is not abnormal for weather patterns to influence hour-by-hour electric use, the below-normal temperature pattern resulted in sharp increases in system loads due in part to electric heating demands throughout the early morning hours, as shown in the following illustration.

Figure 19: January 17, 2018 System Loads and Average Event Area Temperature



B. Growing BES Problems Due to Generation Outages and Derates

- *Unplanned generation outages and derates continued*
- *Throughout the night, MISO focused on meeting MISO South forecast load for morning peak (7-8 a.m. CST)*

At the time MISO issued the Maximum Generation Alert (as described in section IV.C above) for its MISO South region on January 16 at 9:50 p.m. CST, it forecast the following operating reserve conditions for the peak hour, from 7 to 8 a.m. CST:

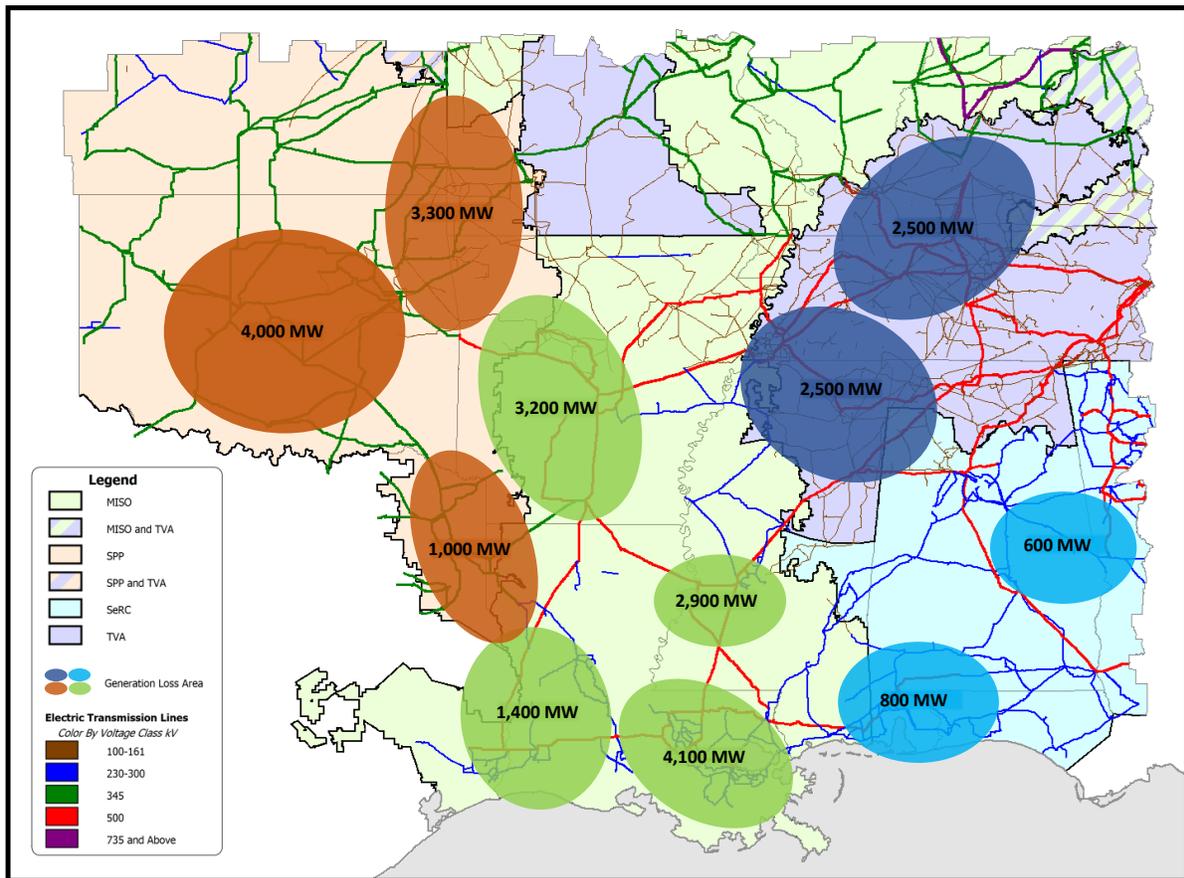
- Forecast load plus operating reserve requirement:⁵⁸ 33,300 MW
- Economic maximum generation:⁵⁹
32,891 MW
- Forecast imports into MISO South: 166 MW
- Projected energy **shortfall** for MISO South: **243 MW**

By the start of January 17, 2018, the Event Area, normally rich in generation capacity, had lost nearly 22 percent of its approximately 118,000 MW of generation by planned and forced outages and derates. MISO South was the hardest hit, with 11,600 MW outaged or derated, while SPP's southern footprint had approximately 8,300 MW outaged/derated. TVA RC had 5,000 MW outaged/derated in its RC footprint, while SeRC had only 1,400 MW outaged/derated.

⁵⁸ MISO's operating reserve for its MISO South sub-area is defined in its FRAC as equaling the forecast load, plus the single worst contingency in MISO South (normally 1,415 MW but 1,163 MW on January 17), plus a load forecast uncertainty of 5%.

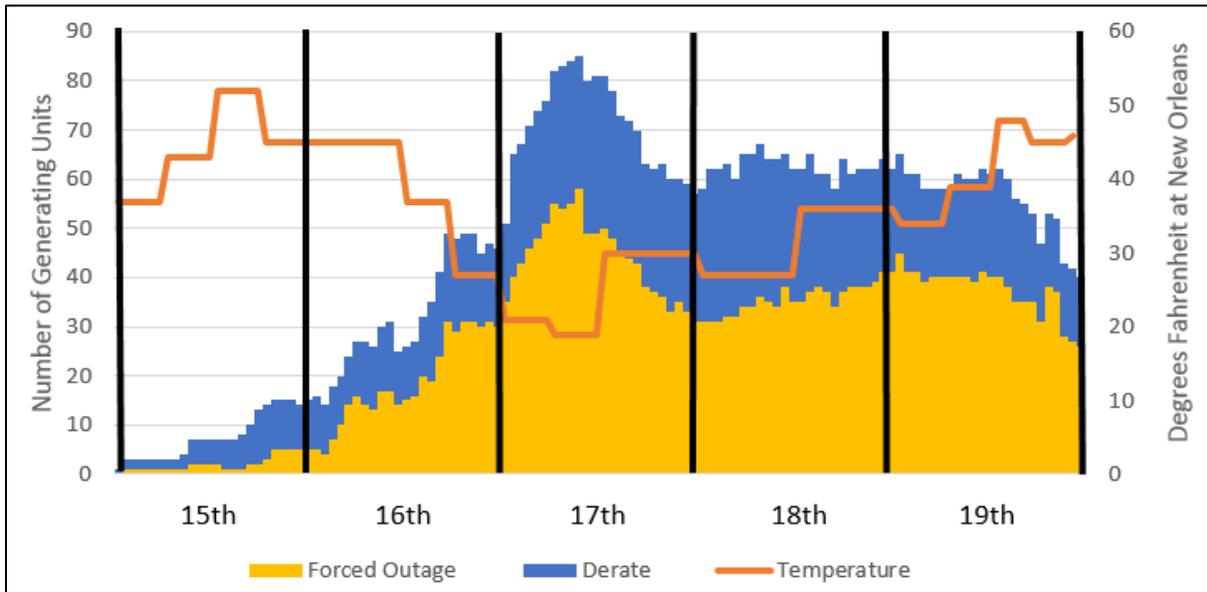
⁵⁹ Includes MISO north-to-south intra-market RDT schedule of 3,000 MW.

Figure 20: Total Generation Outages and Derates Within the Event Area, Beginning January 17, by Approximate Geographical Area



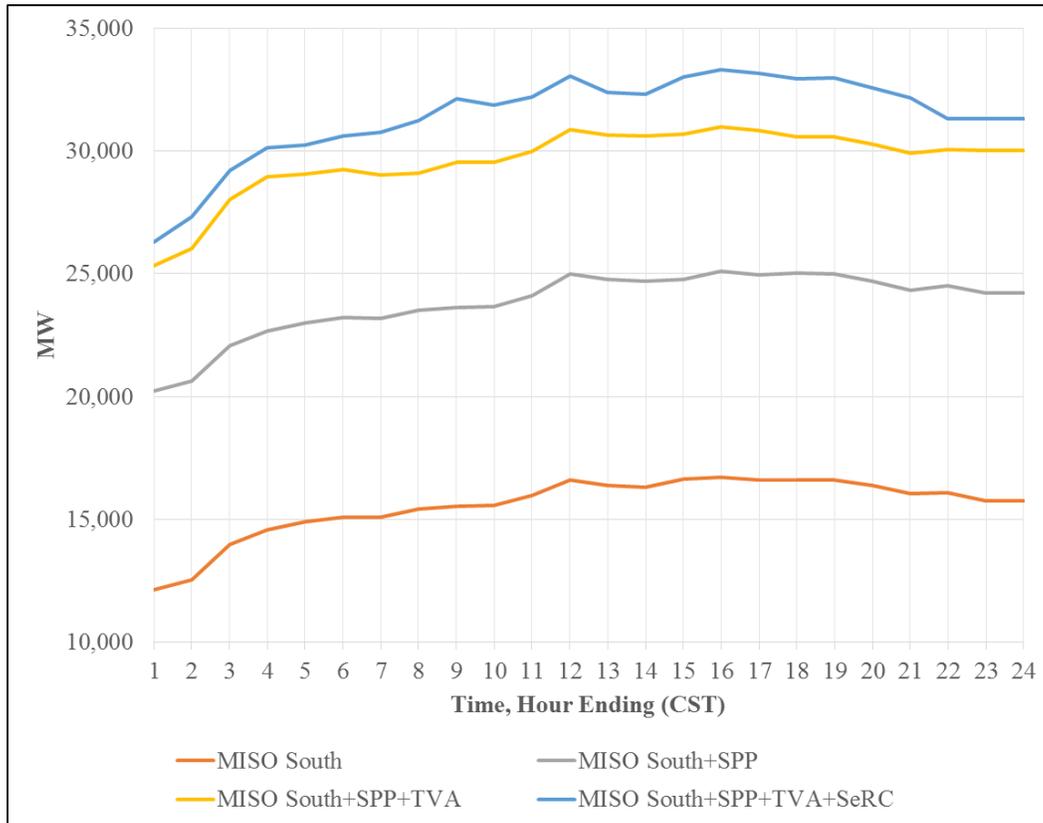
However, none of the RC/BA entities had anticipated what was to occur overnight—that the Event Area was about to lose a significant amount of additional generation at the same time that system loads would increase due to severe cold.

Figure 21: January 15-19, 2018 – Number of Generation Unit Outages and Derates Versus Temperature, by Hour, for Event Area



Through the early morning hours of January 17, as the winter storm and cold weather conditions moved across the region, additional unexpected generation outages and derates caused BES reserve margins to further decrease. The chart below illustrates the trend in total generation outages on January 17, 2018 for the Event Area, which peaked at approximately 33,500 MW.

Figure 22: Total Unavailable Generation over Time, for January 17, 2018, by RC Footprint



MISO South, especially, could ill afford these outages and derates as it already had lost generation output equivalent to approximately 40 percent of its seasonally-forecast winter peak load of 29,000 MW by the start of January 17. But by 8 a.m. that same day, MISO South would lose generation equivalent to nearly 50% of its forecast winter peak load.

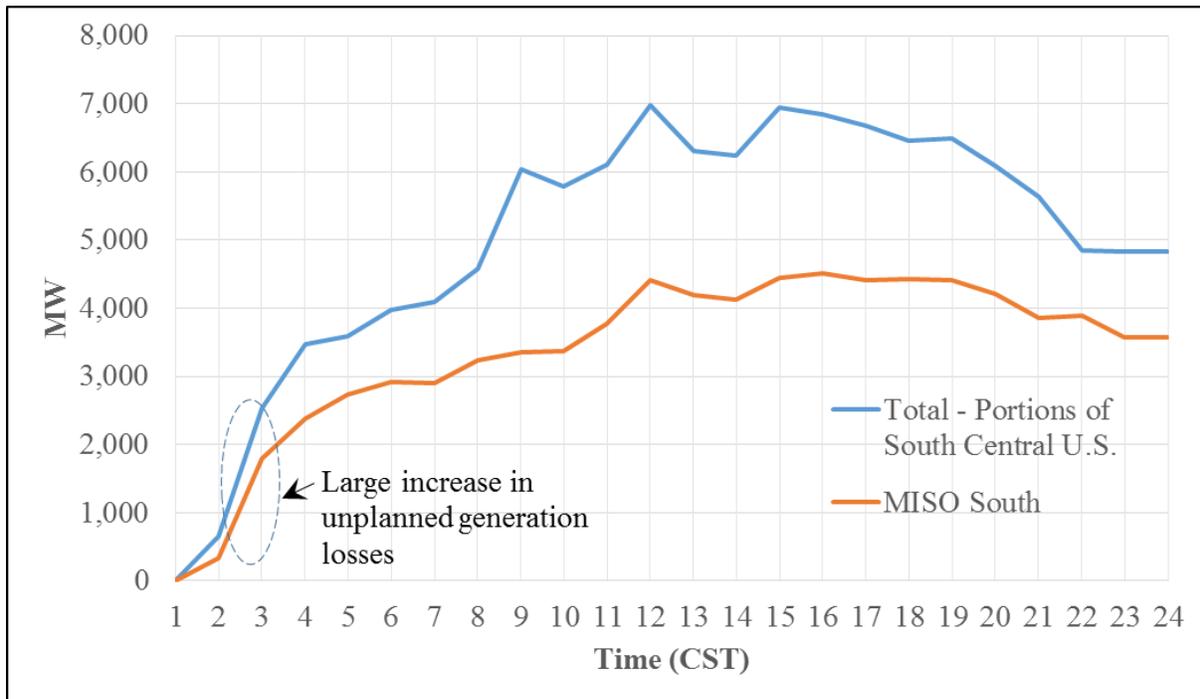
Figure 23: MISO South Region Approximate Generation Outages and Derates at the Start of January 17, 2018, and by Hour Ending 8am Central Time

	<u>Planned Outages</u> (MW)	<u>Pre-existing Unplanned Outages</u> (MW)	<u>By Hour Ending 8am, Additional Unplanned Outages</u> (MW)	<u>Total</u> (MW)
MISO South	4,000	7,600	3,400	15,000

As these additional unplanned generation outages and derates in MISO South unfolded in the early hours of January 17 (see Figure 24), MISO realized it had insufficient available generation capacity to meet its MISO South load (forecast to be at a

morning peak load level between 7:00 and 8:00 a.m. CST) and would have to rely on emergency purchases and north-to-south RDT flows.

Figure 24: Total Incremental Unavailable Generation in the Event Area for January 17, 2018



Shortly after MISO’s above-illustrated increase in unplanned generation outages and derates, it declared an Energy Emergency Alert (EEA) Level 2, and a Maximum Generation Event Step 2 a/b for the MISO South region, due to forced generation outages and higher than forecast load.⁶⁰ Under this declaration, MISO verified commitment of all available resources, and directed load serving entities within the MISO South footprint to initiate public appeals for voluntary load reductions, as well as other load management steps to reduce system load. At the time MISO issued the EEA Level 2, it forecast the following operating reserve conditions for the peak hour, ending at 8 a.m. CST:

⁶⁰ Reliability Coordinator Information System (RCIS) log. MISO has specified in its protocols certain triggering events that require taking action to prevent uncontrolled loss of firm load. In doing so, it has patterned its emergency protocols on the Reliability Standard EOP-011-1 – Emergency Operations, which prescribes EEAs to be declared for Energy Emergencies. EEA Level 2 declares that load management procedures are in effect.

- Forecast load plus operating reserve requirement:⁶¹ 33,300 MW
- Emergency maximum generation: 29,593 MW
- Forecast imports into MISO South: 3,000 MW⁶²
- Projected energy **shortfall** for MISO South: **707 MW**

As part of the EEA Level 2/Maximum Generation Event, MISO sent Load Modifying Resources scheduling instructions for 900 MW of load reduction for hour ending 7 a.m. through hour ending 10 a.m. Central.⁶³ At the same time, realizing that voluntary load reduction alone might not alleviate the shortfall, MISO contacted Southern Company to see if MISO could purchase emergency energy for MISO South to provide sufficient supply for the peak hour from 7 to 8 a.m. Emergency purchases from Southern Company for the MISO South capacity shortfall would also equally decrease their calculated north-to-south RDT.

1. By 2 a.m. CST: BES Transmission Conditions Become a Growing Concern

- *System loads increasing*
- *Transmission congestion first occurs*
- *MISO issues Transmission Loading Relief (TLR)⁶⁴ for transfers sinking in TVA BA*

With increasing generation outages and derates in the Event Area continuing through the early hours of January 17, as part of their real-time monitoring of the BES, SPP’s operators observed that their real-time contingency analysis (RTCA)⁶⁵ results began to show intermittent transmission congestion with flows into portions of the south central U.S.: simulated post-contingency limit exceedances for two transmission facilities in southeast Kansas bordering southwestern Missouri (as shown in the figure below by the orange circles).

⁶¹ See fn. 58.

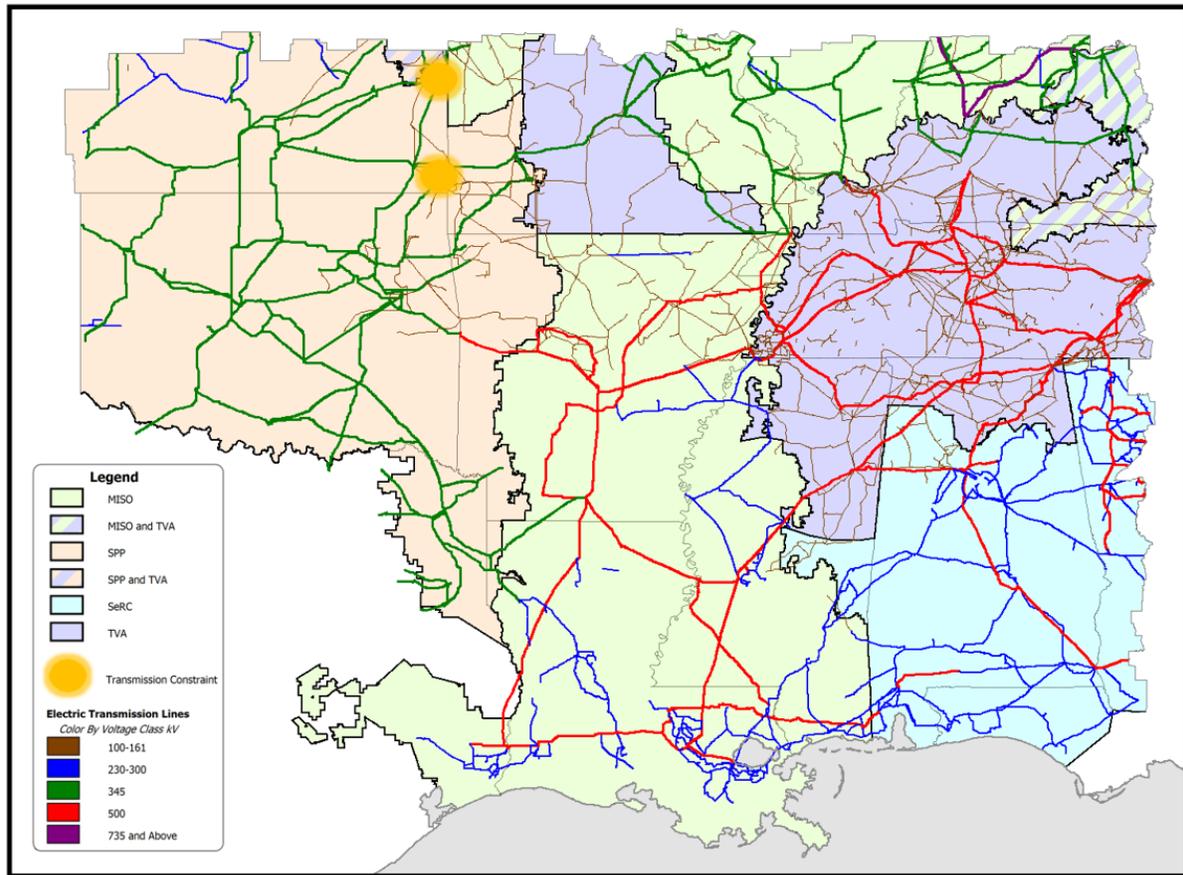
⁶² MISO’s north-to-south intra-market RDT schedule of 3,000 MW.

⁶³ Item 9_LMR Performance During January 2018 Maximum Generation Event.pdf

⁶⁴ See Appendix C, “RC and [Transmission Operator] Tools and Actions to Operate the BES in Real Time.”

⁶⁵ See Appendix C.

Figure 25: By 2am CST – BES Transmission Congestion Began to Occur



Southerly Power Flows and Situational Awareness of Conditions

The effects of simultaneous southerly power transfers began to constrain the BES. These transfers included MISO’s RDT, which by the start of January 17 was approaching 2,600 MW (1,000 MW firm transmission capacity and 1,600 as available non-firm transmission service). In addition to the RDT flow, the more-southern of the congested facilities illustrated above, in southeastern Kansas/southwestern Missouri, was also known to be impacted by flows from neighboring non-market areas, as well as SPP and MISO wind.⁶⁶ Further, the flows on SPP’s transmission facilities in this congested area

⁶⁶ SPP Market Monitoring Unit, State of the Market Winter 2018 at page 32, available at https://spp.org/documents/56890/spp_mmu_qsom_winter_2018.pdf.

would have been increased by nearby unplanned generation outages and derates in SPP.⁶⁷ SPP's operators later performed generation redispatch and discussed the potential need to open the congested facilities.⁶⁸

Also near the start of January 17, based on their real-time monitoring of the MISO transmission system, MISO RC operators issued a TLR to curtail power transfers with non-firm transmission reservations being delivered to TVA BA, because those transfers were affecting transmission flowgates in MISO's Midwest footprint. While MISO's TLR did not have any significant influence on the contingency loading conditions on the congested transmission lines shown above, it showed that RC operators were using their real-time tools to determine and take appropriate actions, which alleviated transmission loadings.⁶⁹

In the early hours of January 17, voltages on the BES were close to what SPP typically experienced for prior January days, and prevailing BES voltages across the four RC footprints were within normal limits (i.e., between 95% and 105% of the “nominal voltage”—such as 345 for a 345 kV bus).

Key RC-to-RC Communications

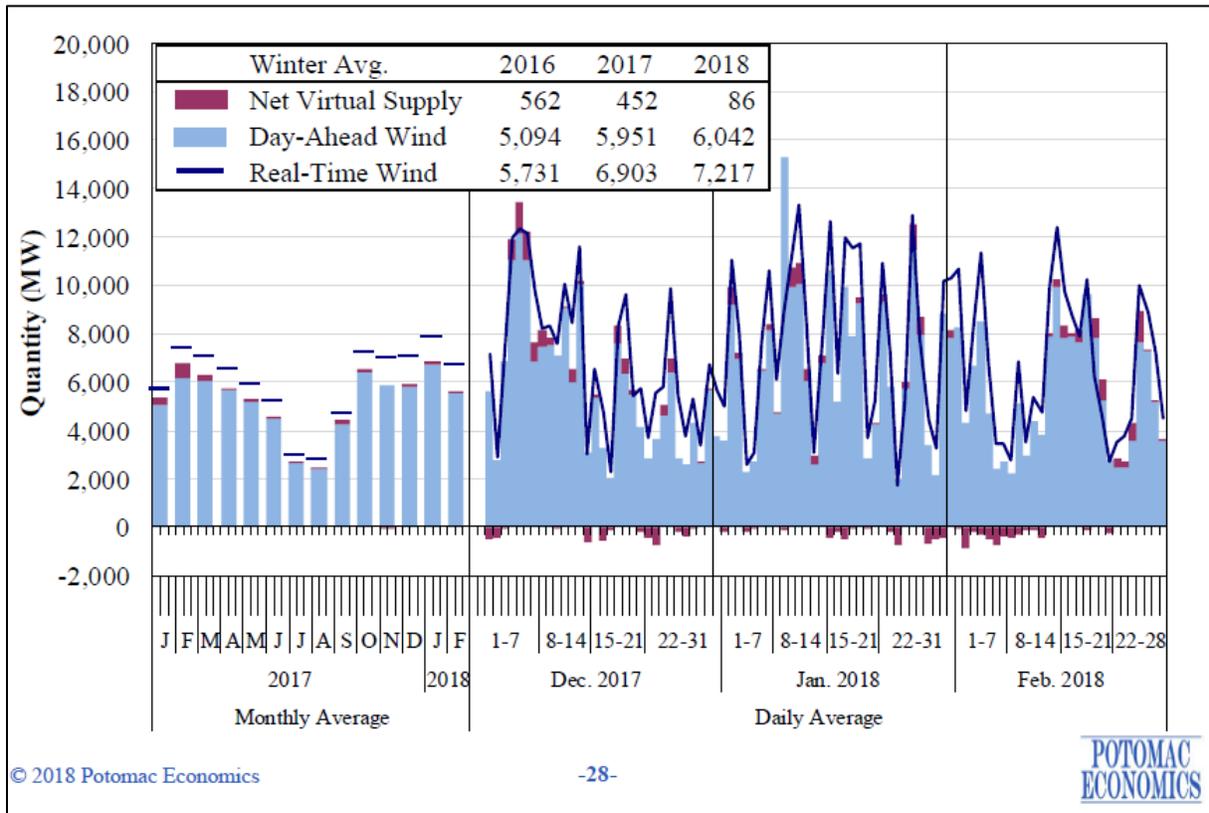
From the onset of the higher transmission loading conditions, the SPP and MISO RC control room operators communicated and took coordinated actions to alleviate transmission loading. During the early morning hours of January 17, the operators' communications focused on managing the dispatch of increasing wind generation output. MISO's actual wind generation on January 17 substantially exceeded its forecast, as the following graphic shows.

⁶⁷ Southwestern Missouri had over 750 MW of unavailable generation during the Event. Transmission flows to serve SPP's firm network transmission customer loads in that area would have contributed to the congested flows.

⁶⁸ 3:53 am call transcript.

⁶⁹ See Appendix C. Under the mandatory Reliability Standards, each RC (e.g., MISO, SPP, TVA, and SeRC) shall ensure that a real-time assessment is performed at least once every 30 minutes, for the purpose of prevent BES instability, uncontrolled separation, or cascading. IRO-008-2, Requirement R4. Transmission Operators have a similar requirement to perform real-time assessments, under TOP-001-4, Requirement R13.

Figure 26: MISO Wind Forecast Versus Actual for Winter 2017-2018



Beginning at 1:04 a.m. CST, in an effort to effectively dispatch increasing wind generation output while avoiding transmission overloads, MISO and SPP RC operators agreed to activate market-to-market binding constraints on several wind-affected flowgates. As the output of wind generation increased, the RC operators continued close coordination in managing these flows throughout the morning hours.

At 1:29 a.m. CST, MISO, SPP, TVA RC, and SeRC, among other RCs, held a normally-scheduled conference call to discuss daily outlook conditions. Both MISO and SPP predicted that their load for the January 17 morning peak (7 a.m. – 8 a.m. CST) would exceed their historic winter peak loads. The MISO South RC operator explained that MISO South was “at the point where we have no reserves” and that MISO would be asking to exceed the RDTL of 3,000 MW and seeking energy from its neighbors, especially Southern Company, because transfers from Southern Company provided one-for-one credit when calculating the RDT.⁷⁰ SeRC and TVA RC reported that they were in conservative operations. SPP reported its projected morning peak load of 42,500 MW

⁷⁰20180117 0229 Call transcript.

would exceed its all-time winter peak by five percent, and that it had sufficient reserves to cover its forecast peak.

MISO measured its RDT flow by two methods, in real time using load and generation telemetered values sourced from State Estimator (often referred to by MISO and SPP as “raw”), and through its Unit Dispatch System (UDS), which runs every five minutes for the upcoming five minute interval (looking 10 minutes out). According to the Regional Transfer Operations Procedure in effect during the Event (RTO-RTOA-OP1-r0 (effective date February 1, 2016)), MISO operators would track, and act on, the UDS rather than the real-time measurements. On January 17, MISO’s real-time/raw and UDS RDT flow measurements diverged substantially at times. For example, at 2 a.m., the real-time RDT was approximately 2,700 MW in a north-to-south direction, but only 2,183 according to the UDS.

2. By 6 a.m. CST: BES Energy Emergency and Wide-Area Constrained Transmission Conditions

- *Unplanned generation outages and derates continued, as temperatures reached their lowest levels*
- *System loads increased as the forecast morning peak load approached*
- *Stranded reserves in northern MISO, RDT flows increasing*
- *MISO declared Energy Emergency, arranged emergency purchases*
- *Increasing wide-area transmission congestion*
- *Transmission reconfiguration steps taken to address some congested facilities*
- *For other congested facilities, RC operators relied on post-contingency firm load shedding*
- *BES voltages trending lower*

Figure 27: By 6 a.m. CST – Unavailable Generation, Total and as a Percentage of Event Sub-Area Capacity

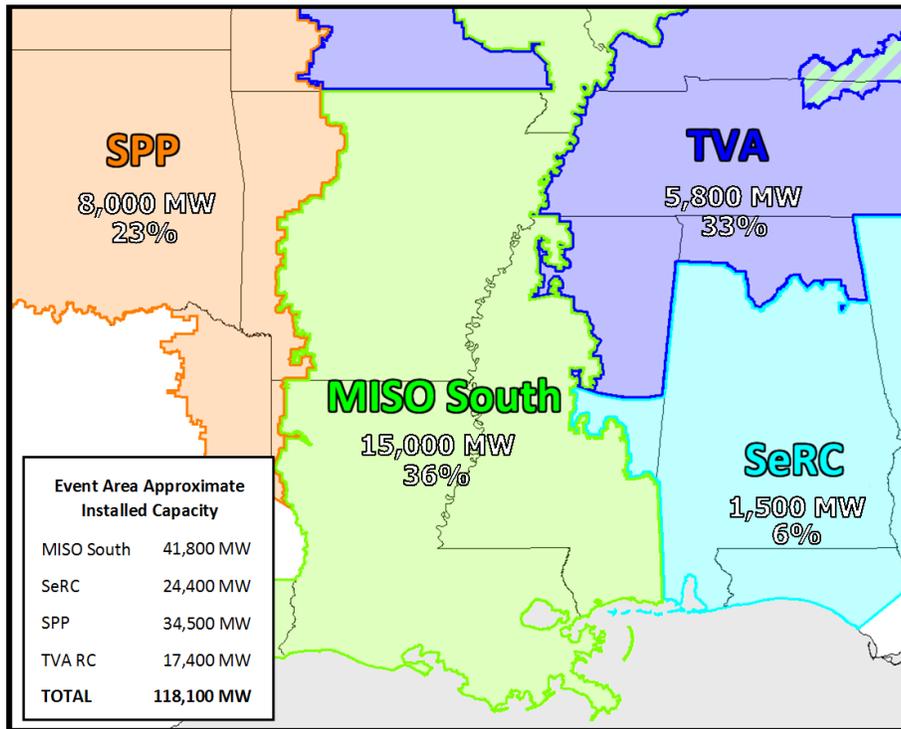
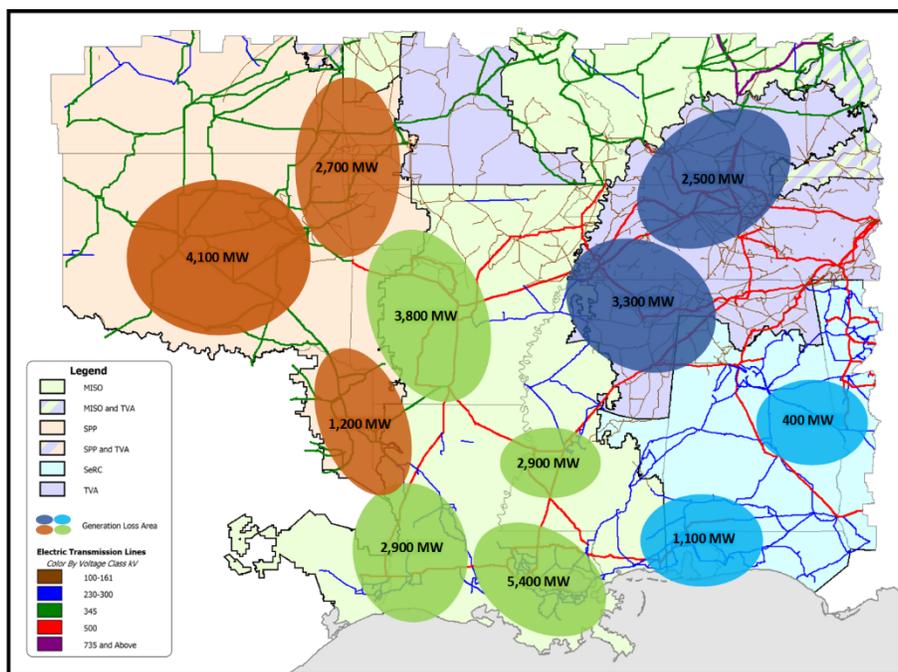


Figure 28: By 6am CST, Total Generation Outages and Derates Within the Event Area, by Approximate Geographical Area



Deliverability of MISO reserves

As described earlier, when MISO declared an EEA Level 2/Maximum Generation Event Step 2 a/b, it allowed MISO to call upon Load Modifying Resources to effectively reduce MISO South system load. By 5 a.m. CST, MISO's RDT real-time metered⁷¹ flow reached 3,000 MW, just as MISO's RC operators had predicted on the 1:29 a.m. CST scheduled RC conference call described above. MISO's overall Balancing Authority Area footprint had sufficient reserves available; however, increasing their RDT scheduled flow to aid in providing reserves for MISO South meant exceeding the north-to-south scheduling limit (RDTL) agreed upon with the Joint Parties, and contributing to the wide-area constrained transmission system conditions. The result was that MISO had reserves that were **stranded** in its northern footprint, limited by transmission system constraints. Because MISO could not reliably provide reserves from its Midwest to its South region without exceeding the RDTL, at 5:04 a.m. CST, MISO asked SPP to agree to raise the RDT north-to-south limit above 3,000 MW.⁷² At 5:14a.m. CST, MISO declared a Maximum Generation Event Step 2 c/d⁷³ for the MISO South region, justified by forced generation outages and higher than forecast load.⁷⁴ At the time MISO made this declaration, it forecast the following operating reserve conditions:

- Peak hour for MISO South sub-area (hour-ending): 08:00 CST

⁷¹ MISO's RDT flow is metered by using the net actual interchange flow for the MISO South footprint, as a means to track their performance in meeting their RDT scheduled flow.

⁷²Under the version of the Regional Transfer Operations Procedure in effect during the Event, a party could request a temporary increase or decrease in the RDT to avoid a system emergency, or address emergent or actual system emergencies. Version RTO-RTOA-OP1-r0, section 3.3.1. See page 71 for SPP's response.

⁷³ Maximum Generation Event steps c and d allowed MISO to:

- Make emergency energy purchases from neighboring BAs through existing Emergency contractual agreements in order to conserve Operating Reserves
- Requested load serving entities to enact load modifying resources to now include issuing public appeals to reduce demand per their internal procedures.

⁷⁴ Source: Reliability Coordinator Information System (RCIS) log.

- Forecast load plus operating reserve requirement:⁷⁵ 33,300 MW
- Emergency maximum generation: 32,000 MW⁷⁶
- Forecast imports into MISO South: 800 MW
- Projected energy **shortfall** for MISO South: **500 MW**

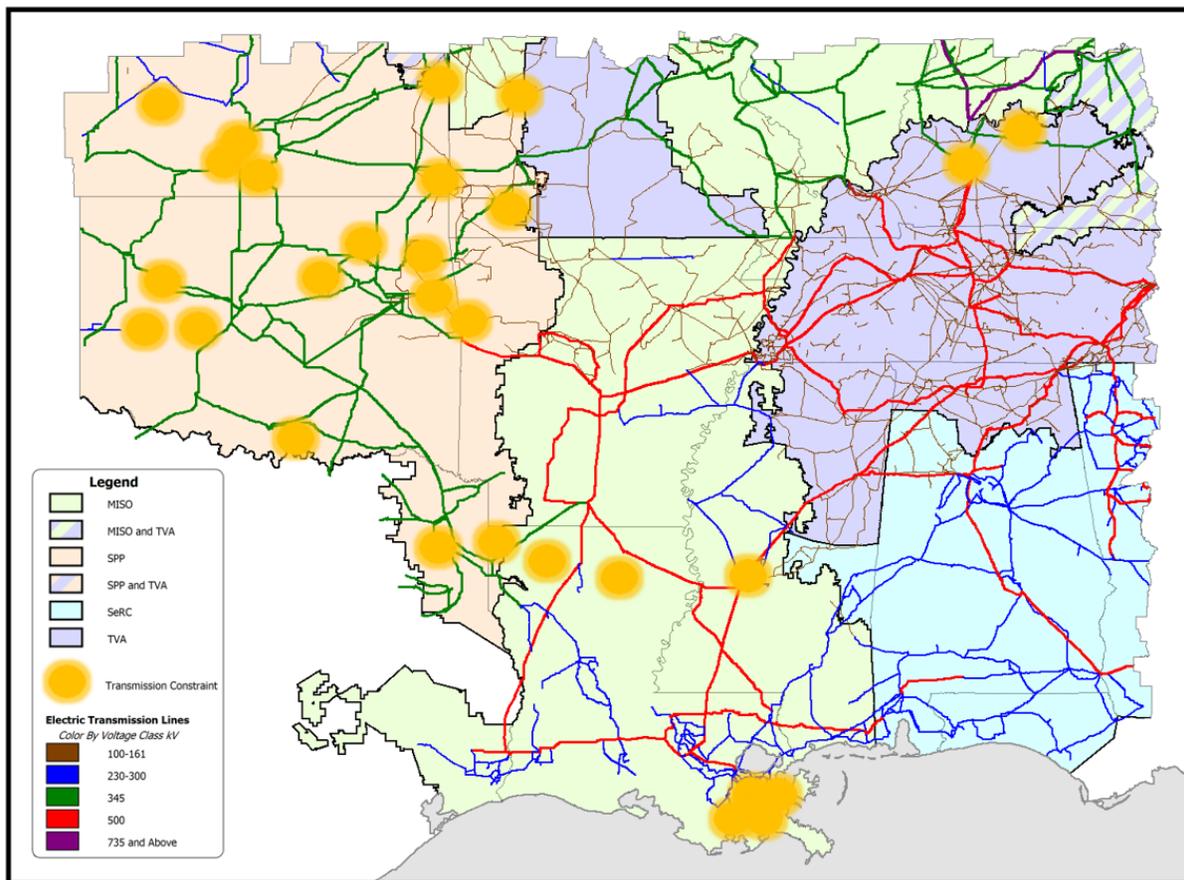
Increasing Wide-Area Constrained Transmission Conditions

As simultaneous north-to-south flows increased to offset generation outages and derates and meet the increasing system electricity demands and MISO’s RDT flow, transmission loading conditions and constraints began to increase in number and severity, across a wider area. From 2 a.m. to 6 a.m. CST, the constrained transmission conditions spread across three RC footprints and five U.S. states. Market-based generation redispatch within MISO and SPP was still being used by the RC operators on a pre-contingent basis as a means to reduce transmission overloads as they arose, including in the southeastern Kansas/southwestern Missouri area. During this time, SPP and TVA RCs used generation redispatch to mitigate more than a dozen post-contingency overloads ranging from 115 to 345 kV. TVA and SPP RC operators, in agreement with the relevant TOPs within their footprints, coordinated their use of transmission reconfiguration to address both real-time and post-contingency limit exceedances during this timeframe. By 4 a.m., there were numerous additional areas where transmission congestion occurred over a wide geographic area within the MISO, SPP, and TVA RC footprints, in Kansas, Kentucky, Louisiana, Mississippi, Missouri, Oklahoma, and eastern Texas, as illustrated below:

⁷⁵ See fn. 58.

⁷⁶ Includes MISO north-to-south intra-market RDT schedule of 3,000 MW.

Figure 29: By 4 a.m. CST – Numerous Additional Transmission Constraints for Wide-Area of South Central U.S.



Critical Role of Accurate Facility Ratings

Opening a BES transmission facility (transmission reconfiguration) to alleviate an actual overload, or to prevent a post-contingency limit exceedance, is one of the more consequential operator actions. Generally, except for planned maintenance, new construction, or to aid in restoration from an outage, transmission facilities are not reconfigured (e.g. opened). On the morning of January 17, as southerly simultaneous transfers placed unpredicted additional loading on the transmission system,⁷⁷ operators began studying the option of transmission reconfiguration to address system overloads. As RC operators acted to manage congestion via methods such as generation redispatch, they noted that some of the power flows would approach the facilities' respective SOLs intermittently, and then decrease in flow. But over time, the operators found that some

⁷⁷ The southeastern Kansas/southwestern Missouri congested facility was projected only to be at 80% loading, not congested, based on SPP's day-ahead Operational Planning Analysis for January 17, 2018.

facilities ceased the intermittent flow patterns previously described, and their actual flows remained near their SOLs, which required additional operator action. The rising power flows caused the RC operators to study the opening some of these facilities; but before taking action, the RC operators verified flows and their associated SOLs.

The RCs were using SOLs based on transmission facility ratings established by the Transmission Owners.⁷⁸ For the most part, these ratings reflected the expected ambient conditions (i.e., winter/low ambient temperatures). In general, using SOLs based on the colder temperatures afford more capacity to transfer needed power to locations within the Event Area.⁷⁹ For example, Southern Company enabled SeRC to have what it called “dynamically rated” transmission lines, based on the extremely cold weather, which effectively raised the SOLs, allowing more power to reliably flow.⁸⁰ Had SeRC used static limits (e.g., year-round/summer limits), it would have needed to employ significant generation redispatch (detrimentally impacting BA contingency reserves), possible transmission reconfiguration, and/or TLRs.

However, SPP monitored flows on certain facilities in the Event Area using SOLs that were based on average ambient conditions (warmer weather) rather than on the

⁷⁸ Under the mandatory Reliability Standards, each Transmission Owner is required to have facility ratings based on their methodology, which includes consideration of “ambient conditions (for particular or average conditions or as they vary in real-time).” FAC-008-3 – Facility Ratings. These facility ratings form the basis for the RCs’ SOL methodologies for the operating horizon (FAC-011-3), which is required to be used by Transmission Planners (TPs) and Transmission Operators (TOPs) in establishing SOLs. FAC-014-2.

⁷⁹ Some SOLs are based on facility ratings of transmission line equipment which is located at the termination points of the transmission line (e.g., protection systems), and do not vary based on the ambient conditions. Transmission Owners commonly strive to upgrade this terminal equipment so that it does not result in limiting the full utilization of the capacity of overhead transmission line investment.

⁸⁰ Southern Company dynamically rated the lines by applying temperature-adjusted limits that were based on the facilities’ ratings for 30 degrees, instead of using static winter limits, due to the extremely cold weather during the Event. These ratings better-reflected the current ambient conditions (e.g. 16 degrees for one facility).

colder weather conditions of January 17.⁸¹ On the morning of January 17, to address the constrained system conditions, SPP operators consulted with their TOP operators to verify these SOLs to aid in determining potential mitigation measures. If the ratings and SOLs had reflected cold weather ambient conditions, SPP may have been able to avoid some of the generation redispatch and transmission reconfiguration measures they took on the morning of January 17.⁸²

In addition to using appropriate SOLs, system operators must carefully study the potential outcomes before using transmission reconfiguration, to ensure that reconfiguring one facility does not place the BES in a less reliable state, such as by shifting the power flow and overloading other BES transmission facilities, or contributing to localized low voltage conditions on the sub-transmission system. The Team reviewed documentation showing that the RCs performed one or more studies before using transmission reconfiguration. For example, during the 4 to 6 a.m. timeframe, TVA RC operators observed that a heavily-loaded transmission facility in northeastern Oklahoma approached 100% of its pre-contingency limit.⁸³ TVA RC analyzed the situation and worked with the local TOP to perform transmission reconfiguration to alleviate the overload.

⁸¹ Within a week of the Event, the following were daytime high temperatures for select cities within the Event Area:

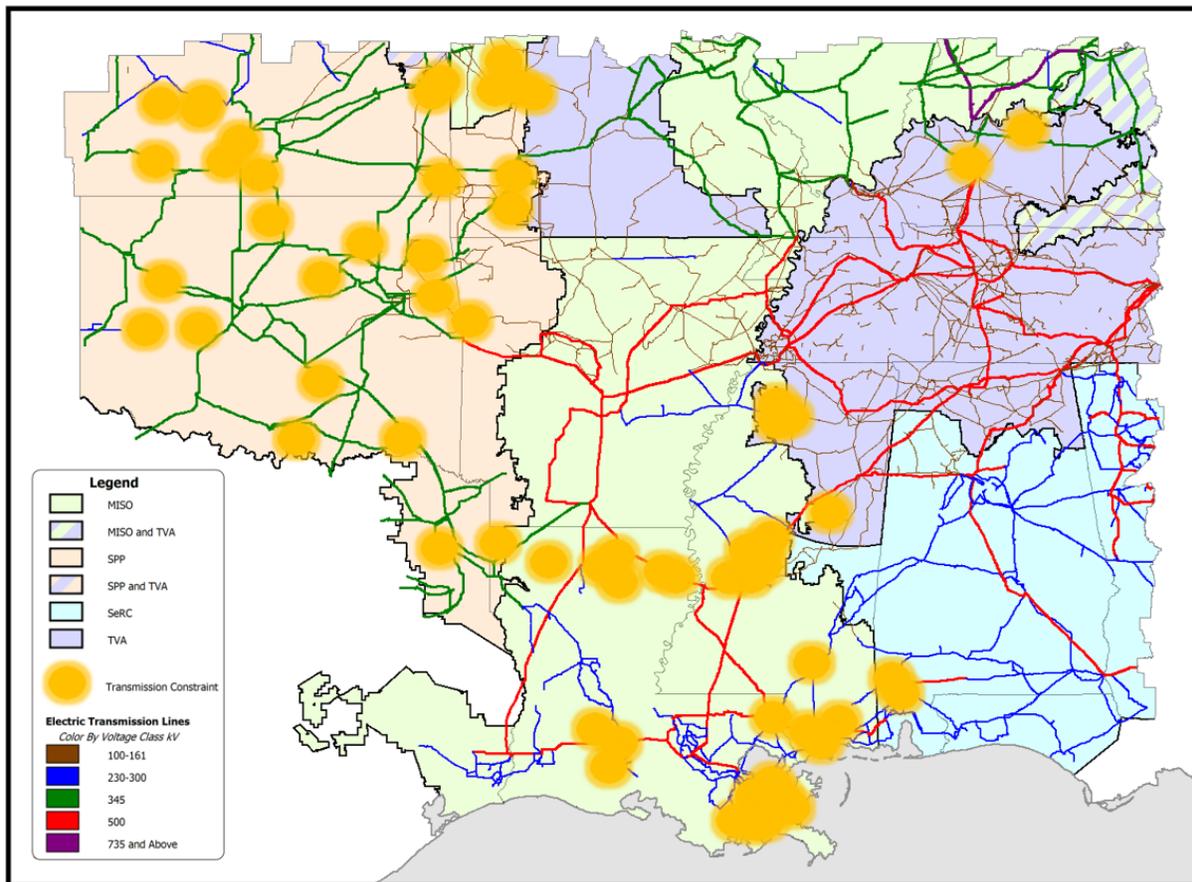
- Kansas City: 64 degrees, on January 21, 2018
- Springfield, MO: 70 degrees, on January 21, 2018
- Tulsa, OK: 70-72 degrees, on January 20-21, 2018
- Little Rock, AR: 66 degrees, on January 21, 2018

⁸² The Team noted that for several facilities, including the southeastern Kansas/southwestern Missouri mentioned earlier, the transmission facility limits the operators were using reflected lower summer season limits, versus ratings one would expect to see for winter ambient temperature conditions, which normally allow for higher power transfers to occur.

⁸³ Even though this facility had a relatively low limit for a 138 kV facility due to a relay limitation (114 MVA, which was especially low as compared to a conductor limitation for the prevailing colder weather conditions), the RC operators were required to operate the BES to the limits set by the Transmission Owner, and to take actions necessary to maintain reliability.

Between 4 and 6 a.m., the RCs had nearly exhausted their less-consequential options, yet system loads and transmission congestion continued to increase. TVA and MISO RCs issued two TLRs to curtail non-firm transmission schedules for flowgates in Kentucky and western Missouri. As generation outages and derates continued to rise, and system loads increased in MISO South, operators had fewer options for generation redispatch to alleviate a growing number of post-contingency limit exceedances. Because BES conditions were so constrained at the time, MISO and the MISO South TOPs agreed to continue operating with the then-existing post-contingency overloads, when normally MISO would have taken mitigating measures in real time, such as redispatching generation or reconfiguring transmission facilities, to bring the facilities' post-contingency loading below 100%. MISO and the TOPs agreed instead that if any facility was lost, immediate load shed would be required. For more severe post-contingency overloads, before relying on post-contingency load shed, MISO analyzed whether the SOL was an IROL, to rule out the need for pre-contingency load shed. SPP also had transmission facilities for which post-contingency load shed was the only option, due to similar conditions of area generation outages and derates, and elevated system loads. By 6 a.m., SPP had five transmission facilities located mostly in Oklahoma and Texas, and MISO had 18 facilities located in Louisiana and Mississippi, for which the RCs and TOPs had agreed to post-contingency load shed plans to alleviate post-contingency flow limit exceedances.

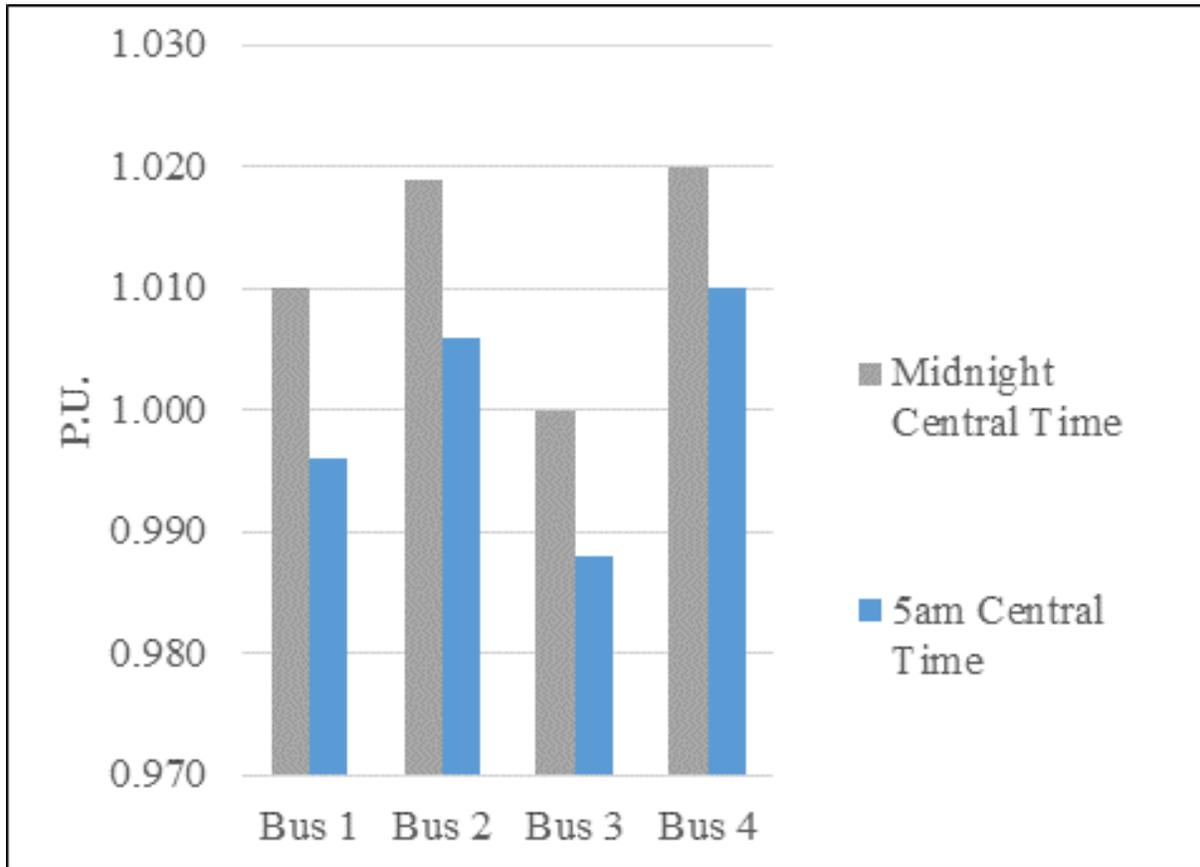
Figure 30: By 6am Central – Further Transmission Constraints Occurring Over a Wide-Area of South Central U.S.



BES Voltage Patterns

During the early morning hours, RC operators monitoring BES transmission flows, congestion, and voltages noted a lower voltage level pattern in certain locations within the Event Area, compared to what they typically would experience on high load days in January. While BES voltages predominantly remained within limits across the Event Area from the start of January 17 until approximately 5 a.m. CST, EHV real-time bus voltages for certain areas had decreased as compared to midnight, as shown in the chart below.

Figure 31: 5am Central: Decrease in Southwestern-to-Southeastern Oklahoma 345kV Bus Voltages, Early Morning Hours of January 17, 2018



By 5:57 a.m. CST, one of MISO’s 500 kV busses dropped below 97.5%, and remained below this level for approximately four hours. Its lowest level was 96.2%.

Key RC-to-RC Communications

During this early-morning timeframe, on a regularly-scheduled conference call among MISO, SPP, TVA RC, SeRC, and other Eastern Interconnection RCs, the MISO operator warned that MISO South was “about tapped out,” and that MISO was contemplating the issuance of a Max Gen Alert/EEA 1, at which point it would “curtail interruptible loads” and “would be asking the parties to the transfer agreement . . . if we could go above that 3,000 MW transfer limit which we’re pretty close to right now.” MISO noted that it had just lost an “800 MW unit which . . . was our cushion,” and that “we’re . . . at the point where we have no reserves and we would be . . . asking neighbors for help.” MISO said it would try “to import as much from Southern [Company] as possible because it’s a one-to-one credit on our [RDT] transfer agreement.”

MISO and SPP RC Operators communicated regularly and cooperated to mitigate system conditions during the early morning hours leading into the peak. For example, at

2:58 a.m. CST, SPP and MISO RC operators spoke by phone to discuss the status of their congestion management efforts. The MISO operator asked about the southeastern Kansas/southwestern Missouri congested flowgate and SPP responded that it was close to overloading in real time and had been “near the top” of its simulated post-contingency loading for an extended period. SPP indicated that it would need to open the flowgate if it were to suffer the outage of the next most-severe contingency. The MISO operator offered to activate/bind the constraint and perform market-to-market redispatch between SPP and MISO, in an effort to alleviate loading conditions on SPP’s congested flowgate.⁸⁴

At 5:04 a.m. CST, MISO emailed SPP, TVA and Southern Company, asking to raise the RDT north-to-south limit above 3,000 MW (as its operator had earlier predicted), although the RDT would not exceed 3,000 according to the UDS until 7 a.m. In support, MISO noted:

MISO is in extremely tight conditions and is forecasting an expected Winter peak for the South Region of 33,911 MW for Hour Ending 0800. Previous Winter peak is 30,930 MW.

MISO has declared a Max Gen Event step 2a-b and a NERC EEA level 2 – due to [the loss of] a number of units (~3,000 MW) and transmission lines over the evening hours due to the cold weather and icing conditions.

MISO is expecting the Regional Directional Transfer to be maximized flowing from North to South at the 3,000 MW limit and possibly exceeding the limit of 3,000 MW. Please consider that MISO has limited ability to reduce the flows on the RDT and would like for all to consider raising the limit.⁸⁵

At 5:33 a.m. CST, as the morning peak hour (7 to 8 a.m.) approached for MISO South, MISO made an official request for emergency energy assistance to SeRC for the purpose of meeting its forecast load plus reserves obligations. Southern Company agreed to provide 700 MW of emergency purchase for a 4 hour period. For approximately an hour, MISO BA coordinated with Southern Company BA arranging for the purchase to start at 6:30 a.m. CST, in time for peak hour conditions.

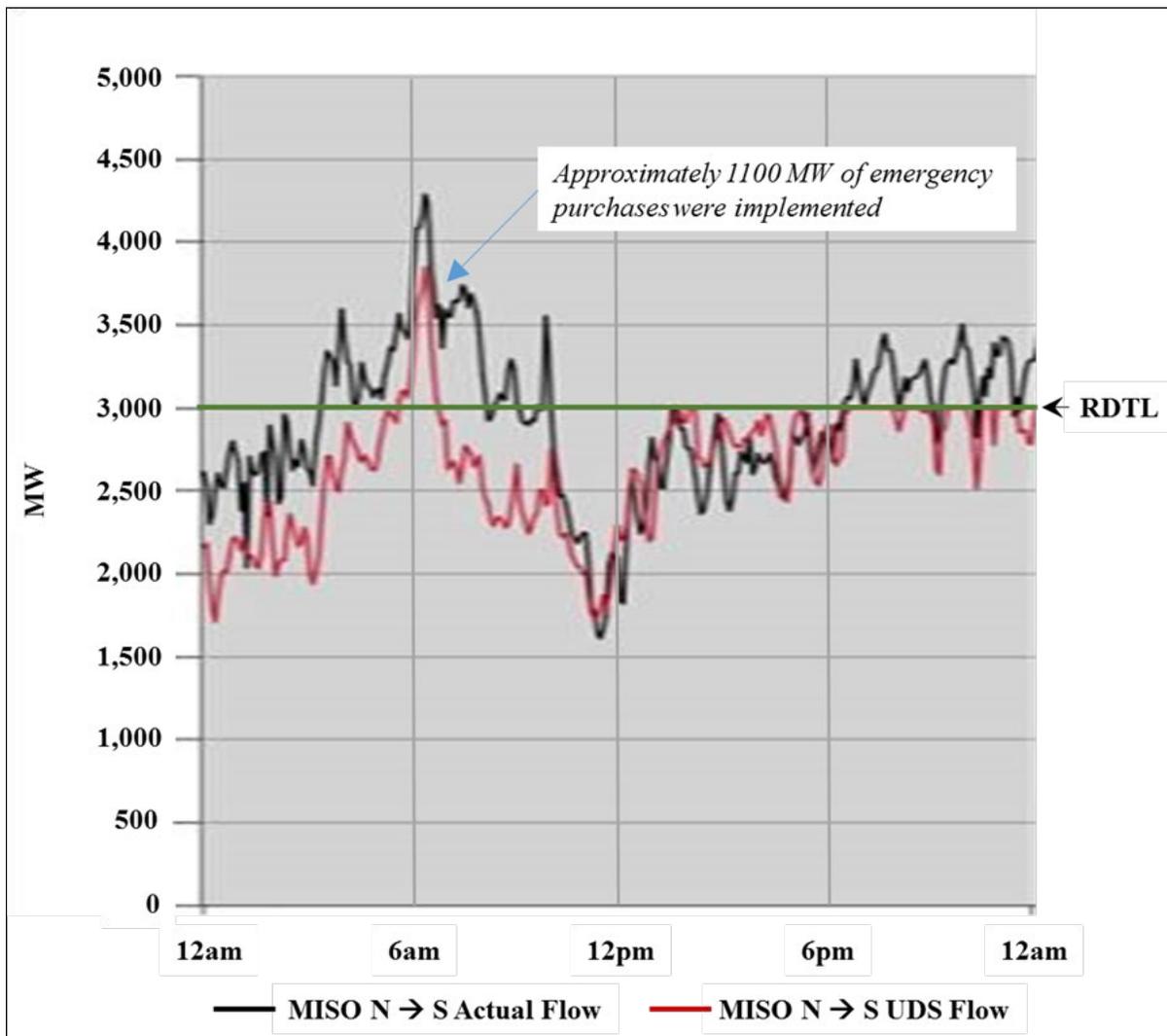
At 5:39 a.m. CST, the MISO South operator informed SPP that the RDT was at its limit and asked about SPP’s system conditions. The SPP operator noted that SPP had multiple flowgates with post-contingency overloads, and one real-time overload (which

⁸⁴ 20180117 02:58 CST Call from MISO North to SPP RC.

⁸⁵ Email from MISO to TVA, SPP and Southern. See page 71 for response.

was mitigated by operator actions as described below). MISO told SPP that it was purchasing emergency power from Southern Company, and should SPP experience emergency conditions, MISO was prepared to take actions necessary to reduce the RDT. SPP indicated that it was not yet experiencing emergency conditions. Within five minutes, the MISO South RC operator had discussed the same information with TVA RC and SeRC. The Regional Transfer Operations Procedure in effect at the time did not clearly address specific actions to be taken when RDT flows were affecting adjacent RCs.⁸⁶

Figure 32: MISO Regional Directional Transfer – January 17, 2018



⁸⁶ As a result of the Event, MISO, SPP, TVA and SeRC revised the Regional Transfer Operations Procedure; the revised version became effective in December 2018.

3. By 8 a.m. CST: MISO Energy Emergency Continues and Four RCs Take More Consequential Steps to Maintain BES Reliability

- *System loads continued to increase as the morning load peaked from 7 to 8 a.m.*
- *RDT peaked at nearly 1,000 MW over the RDTL*
- *MISO South received emergency energy from Southern Company and TVA BA*
- *Additional transmission reconfiguration/more consequential operator steps*
- *Many next-contingency conditions that would lead to firm customer load shed in MISO South and SPP*

System operators were already facing dozens of post-contingency overload conditions as discussed above, but system loads were still increasing due to the severe low temperatures and the approaching morning peak load. Market redispatch or additional non-firm transmission interchange curtailment such as TLRs were less-available options during this timeframe, due to the excessive generation outages and derates in the Event Area.

As for more consequential overload mitigation actions, several transmission facilities were opened in addition to TVA RC's earlier transmission reconfiguration. SPP RC and its TOP operators agreed to reconfigure the southeastern Kansas/southwestern Missouri congested flowgate that had been studied multiple times during the Event, due to the actual/real-time loading of the facility now remaining above 100% of its normal limit of 203 MVA.⁸⁷ Also, based on SPP RC's additional study⁸⁸ to prepare for transmission reconfiguration, SPP and the TOP agreed to open the other facility in southeastern Kansas that had post-contingency overloads showing up in RTCA since late in the evening of January 16. The final decision to open the second southeastern Kansas facility was due to its actual/real-time loading intermittently exceeding its normal limit of 167 MVA at 5:15.⁸⁹ TVA RC operators worked with AECI TOP to reconfigure a 161

⁸⁷ The Team noted that for this 161 kV facility, the transmission facility limits the operators were using reflected summer season limits (lower limits) versus winter ambient temperature conditions, which may have not required the RC operators to perform transmission reconfiguration.

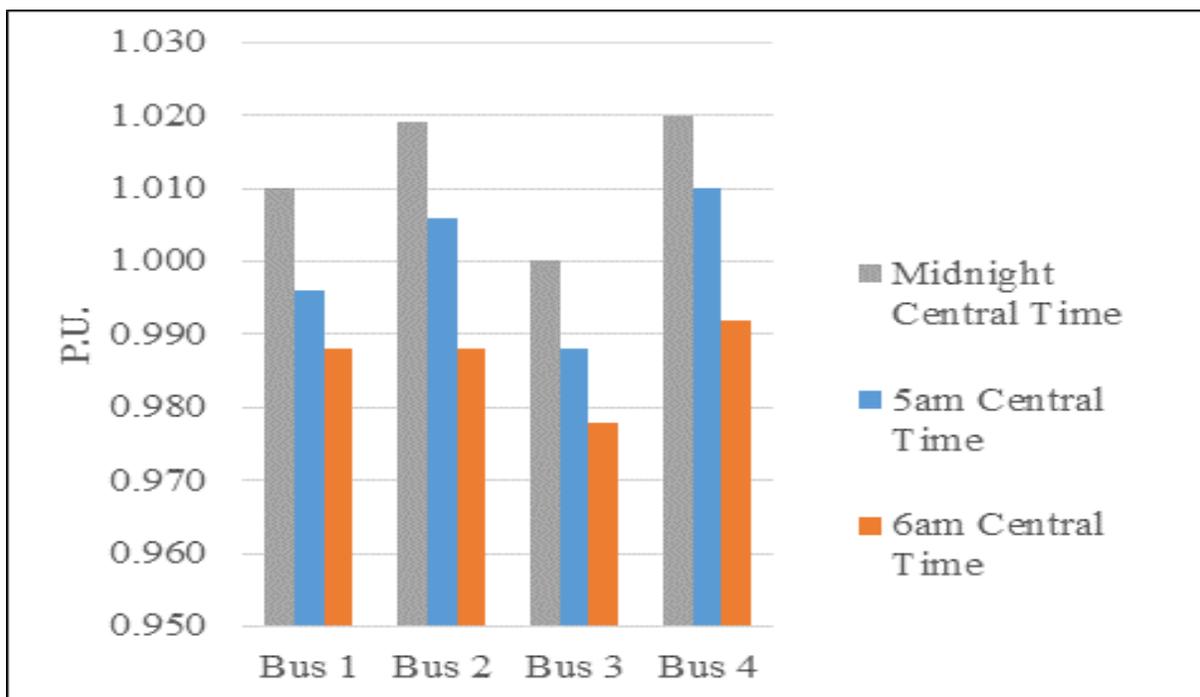
⁸⁸ SPP RC performed contingency analysis study at 7:07 a.m. CST, evaluating reconfiguration of this facility, and the study showed no resultant real-time SOL exceedances.

⁸⁹ The Team noted that for this 161 kV facility, the transmission facility normal and emergency (post-contingency) limits were of equal value. While this is a possibility for terminal-limited transmission lines, Transmission Owners typically address those

kV facility in southwest Missouri because its real-time loading exceeded 100% of its normal limit. By 8 a.m. CST, three other facilities remained open from earlier operator actions, and five others (one in TVA RC, four in Southeastern RC footprints) had post-contingency plans for reconfiguration. MISO operators, out of reserves in MISO South and prepared to shed firm load throughout MISO South for the WSC in MISO South, also had over 20 transmission facilities for which localized load shed would be necessary should the next contingency occur, all of which were in Louisiana and Mississippi, where MISO had suffered generation outages, derates, and failures to start. Approximately 20 of these facilities would require localized load shed if the same contingency (the MISO South WSC) occurred, while approximately six more facilities would require localized load shedding if additional contingencies occurred.

EHV real-time bus voltages trended downward between midnight and 6 a.m. in the southern Oklahoma portion of SPP’s footprint, as shown in Figure 33 below.

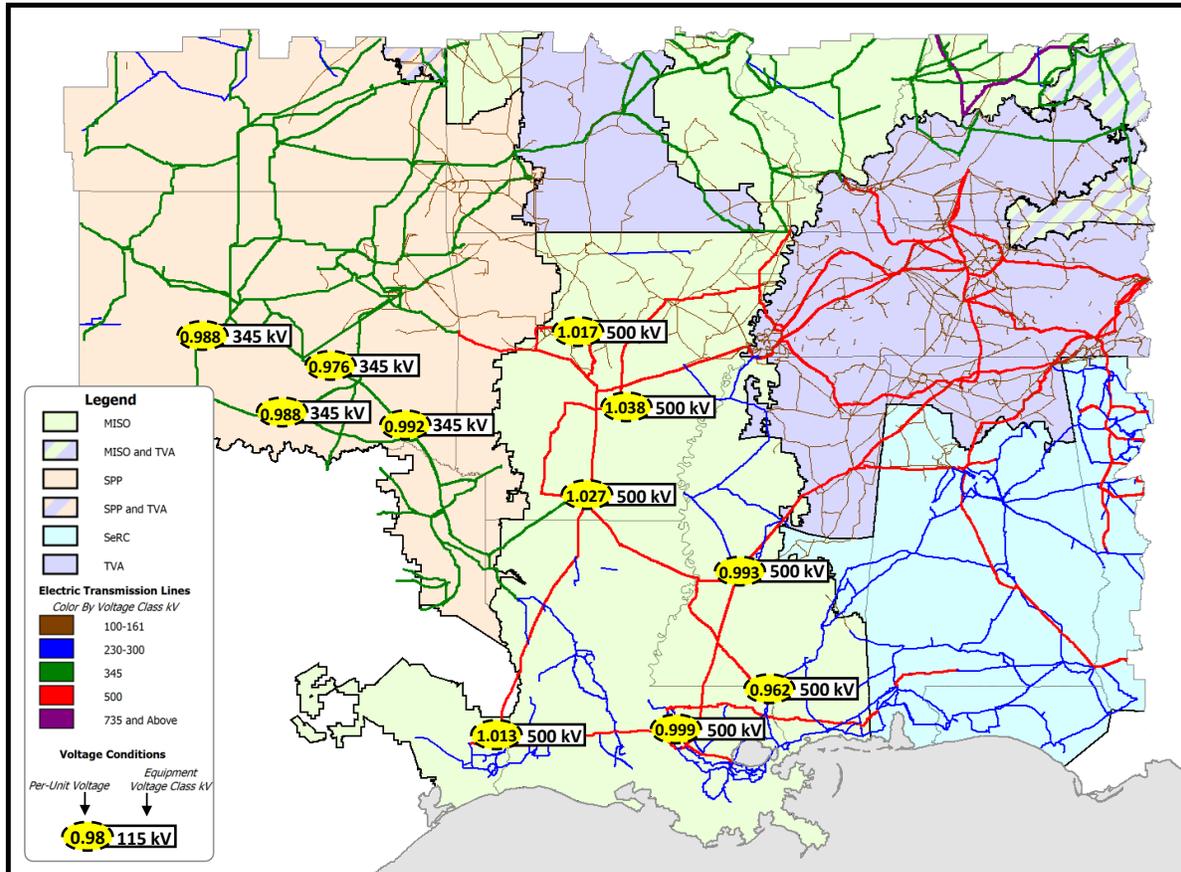
Figure 33: 6am Central: Further Decrease in Southwestern-to-Southeastern Oklahoma 345kV Bus Per Unit Voltages, Early Morning Hours of January 17, 2018



limitations early on to ensure they can achieve maximum value of their transmission facility investment to serve customers’ needs. The Team also noted these limits reflected summer season limits (lower limits) versus winter ambient temperature conditions, which may have not have required the RC operators to perform transmission reconfiguration.

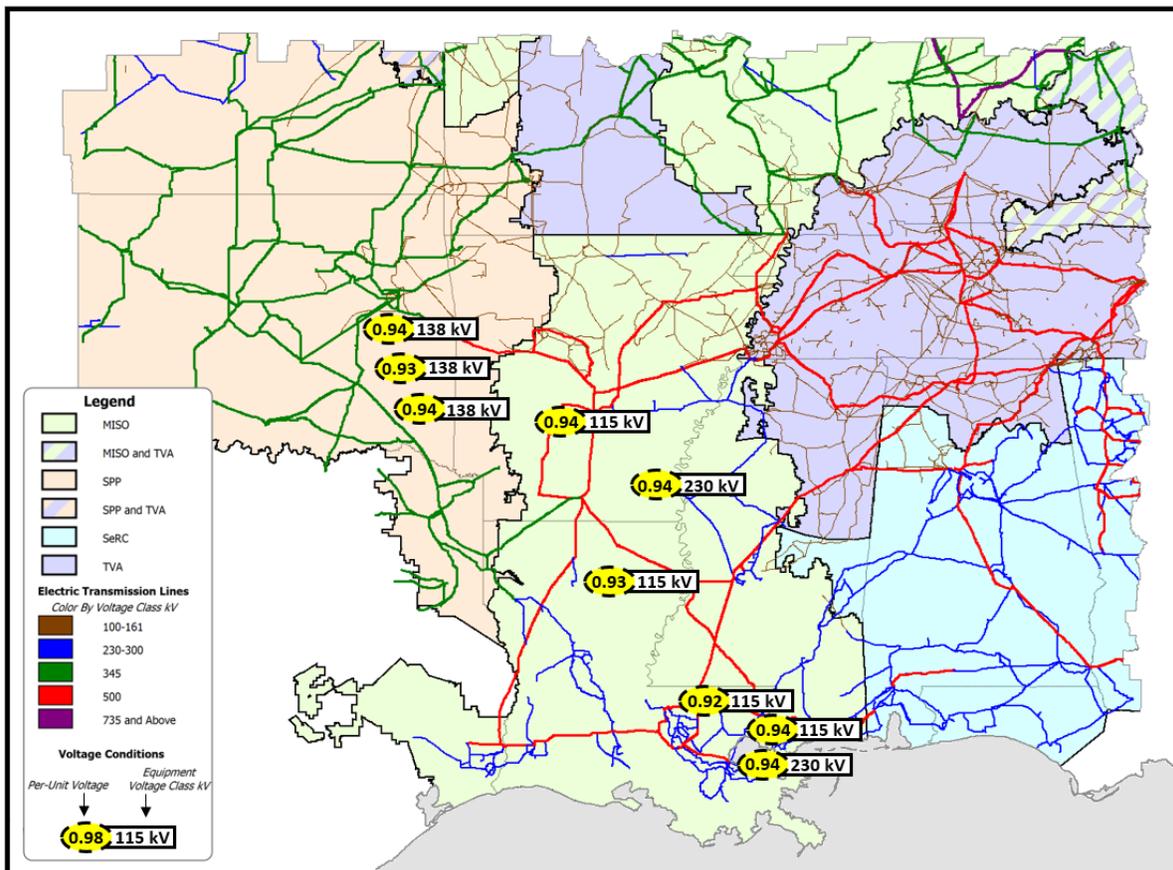
However, for the most part, EHV voltages in Arkansas, Louisiana, and Mississippi remained close to their nominal levels (i.e. 100% or 1 p.u.), as shown in figure 34 below.

Figure 34: BES Pre-Contingency Voltage Conditions (P.U.) for Select EHV Buses, January 17, 2018, Approximately 6am CST



Both SPP and MISO experienced low real-time BES voltages for several rural locations in southeastern Oklahoma, southern Arkansas, and Louisiana, as shown in Figure 35.

Figure 35: BES Voltage Conditions (P.U.) for High Voltage Buses below Normal (Pre-Contingency) Limits, January 17, 2018, Approximately 6am CST



It was clearly evident that real-time BES voltages were decreasing in some areas throughout the early morning hours of January 17, as shown in Figure 33. However, for the most part, EHV voltages remained near nominal levels, as shown in Figure 34. Furthermore, SPP and MISO experienced real-time voltages below 95% at several rural-located BES facilities in eastern Oklahoma, Arkansas, and Louisiana (ranging from 92% to 94% for several 115kV and 138 kV buses) as shown in Figure 35, as well as rural sub-transmission facilities (e.g., 69 kV) in southern Oklahoma and eastern Texas.⁹⁰

⁹⁰ After review of similar rural location voltage data for the day before the event, the Team could not attribute all of SPP's rural location simulated post-contingency voltages to increased power transfers such as the RDT. Nonetheless, SPP identified mitigation measures (e.g., post-contingency capacitors for voltage correction) to address the conditions.

Impact of MISO South WSC for Both Reserves AND Number of Transmission Voltage Limit Exceedances

For the morning of January 17, the MISO South WSC outage of a single 1,163-MW unit would have left MISO South without adequate generation supply and also would have resulted in the most BES facility post-contingency low voltages (nine 115 kV buses, eight 230 kV buses, and three 500 kV buses) within MISO South, based on MISO’s RTCA (as compared to the results of any other single simulated contingency).

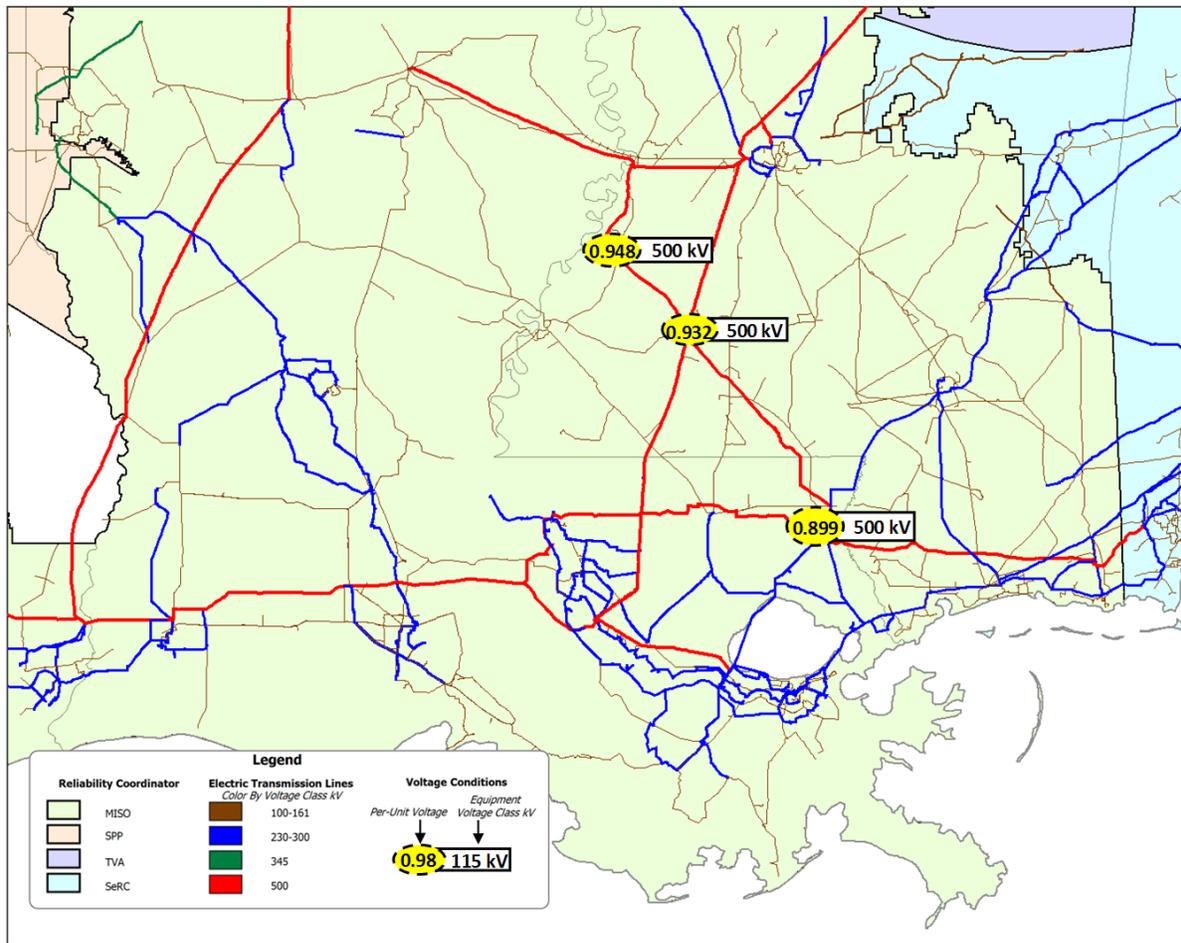
Figure 36: BES Post-Contingency Range of Voltages below Limits for Buses in MISO South, January 17, 2018, at Approximately 06:30am CST, for the Simulated Outage of the MISO South WSC

	Number of Buses	Lowest P.U. Voltage	Highest P.U. Voltage	Mitigation Plan
115kV:	9	0.860	0.964*	Post-contingency load shed
230kV:	8	0.880	0.913	Post-contingency load shed
500kV:	3	0.899	0.948*	Post-contingency load shed

** Monitoring based on nuclear power plant voltage limits.*

While it is important to note that the lowest BES voltages on MISO South buses identified in MISO’s RTCA for the simulated loss of the MISO South WSC were predominantly located in suburban areas of southeastern Louisiana and southwestern Mississippi (north of the urban centers and the industrial corridor in southeastern Louisiana), MISO’s 500 kV network simulated post-contingency voltages were also indicating lower voltages, as shown below. The MISO RC analyzed and discussed its RTCA post-contingent thermal and voltage violations with its TOP system operators, and they agreed on the post-contingent mitigation measures that would be taken in the event of the actual loss of the 1,163 MW generating unit.

Figure 37: BES Post-Contingency Voltage Conditions (P.U.) Below Limits for EHV Buses in MISO South, January 17, 2018, at Approximately 06:30am CST, for the Simulated Outage of the MISO South WSC



The MISO RC analyzed and discussed its RTCA post-contingent thermal and voltage violations with the local TOPs' operators and developed post-contingent action plans. For the loss of the MISO South WSC, there were no unsolved contingencies within the MISO RTCA. This indicated to the MISO operators that upon the loss of any contingency, the area load pockets would remain stable and allow operators the time to implement post-contingent load shed to address each next contingency on a case-by-case basis. SPP also included the MISO South WSC in its RTCA, and relied on the fact that its RTCA case converged as an indicator of voltage stability.⁹¹

⁹¹ SPP's post-contingency results did not indicate any resulting low BES voltages within its footprint, but did confirm low voltages at the same buses in the MISO South region as projected by MISO's RTCA.

While winter season peak electricity demands in general impose less reactive power demand on the BES than summer peak conditions, and urban centers are generally less susceptible under winter peak load conditions to voltage instability than during summer peak load conditions, the loss of the MISO South WSC during the morning peak on January 17, 2018 would have added stress to an already-constrained system, due to the large power transfers needed to compensate for the unplanned generation outages and derates. Any replacement generation would necessarily have been transferred from MISO Midwest, thereby further increasing RDT real-time transmission flows into MISO South through SPP, TVA RC and SeRC footprints. MISO's RTCA showed progressively worsening projected post-contingency voltage results, including voltages as low as 88% on certain 230kV buses, and 20 transmission facilities with projected post-contingency thermal overloads between 7 and 8 a.m. CST.

Additionally, the loss of the MISO South WSC would have further lowered the already-depressed area voltages to a point where voltage stability could have quickly become a concern. Further, had MISO and its TOPs failed to timely perform the post-contingency manual firm load shed on which they were relying to restore voltages before another contingency occurred, voltage(s) could have decreased even more. While the MISO RC operators would be trying to coordinate load shed with the TOPs to restore voltages, they would concurrently have been faced with the likelihood of an EEA Level 3 for the loss of the MISO South WSC, causing them to simultaneously perform MISO South-wide firm load shed to meet load and restore reserves for MISO South.

Neither MISO nor SPP performed voltage stability analysis for the simulated loss of the MISO South WSC that morning.⁹² MISO had online voltage stability tools, and SPP could have performed an offline study, however, preparing its offline study could have taken several hours and thus not provided timely results for the RC operators that morning. Voltage stability studies could have aided MISO and SPP in determining whether SPP needed to declare a system emergency and whether MISO needed to take pre-contingency steps to position their systems for the potential loss of the MISO South WSC. MISO was relying on the TOPs within its footprint to be able to promptly execute the necessary load shed to alleviate the numerous low voltages, if the MISO South WSC had occurred. Voltage stability analysis would be especially important given that MISO recognizes that one of its load pockets is “a voltage/thermal sensitive area and is susceptible to low voltages under outage conditions or a loss of a key transmission

⁹² While voltage stability analysis is not specifically required by the Standards, RCs and TOPs are required to perform a real-time assessment which evaluates system conditions using real-time data to assess existing (pre-contingency) and potential (post-contingency) operating conditions. IRO-008-2, and TOP-001-4.

element.” Sharing the voltage stability analysis with adjacent RC operators would give them another source of simulated post-contingency voltage data to determine if additional pre-contingency protective measures are needed.

Key RC-to-RC Communications

MISO’s RDT flow hit its peak of 4,331 MW by real-time measurement, and nearly 4,000 MW as calculated by UDS, at approximately 6:30 a.m. MISO had already arranged 700 MW of emergency energy from Southern Company, but based on the latest projected supply and demand conditions in MISO South for the upcoming peak hour, beginning at 6:12 a.m. CST, MISO sought additional emergency energy from Southern Company, as well as from SPP and TVA BA. TVA BA had 300 MW emergency power available, and TVA BA and MISO arranged for its delivery, for a total of 1,000 MW the emergency power obtained ahead of the peak hour.⁹³ MISO’s EMS automatically allocates the emergency purchases between MISO’s North and South regions when calculating the RDT, taking into account transmission distribution factors. MISO expected the emergency purchases made for MISO South reserves to decrease the RDT, and shared this expectation with other RC operators. This expectation proved correct when the RDT did begin to decrease just after emergency power deliveries began.⁹⁴

Just before the peak hour, SPP RC denied MISO’s request to raise the RDT limit above 3,000 MW via email, and shortly thereafter, SPP notified MISO that it had emergency power available, but it was not deliverable to MISO South.

LMRs to Aid MISO South During Peak Load Conditions

As part of MISO’s Maximum Generation Emergency/ EEA-2 procedures, MISO sent LMR⁹⁵ scheduling instructions (SI) for load reduction to help cover their MISO South peak load. MISO sent the SI just after MISO’s declaration of EEA Level 2. The Team learned that the LMRs were not obligated to be available in the winter (only required in the summer season), and that long notification times limited the availability of some LMRs for the morning peak. MISO deployed a total of 700 MW of LMR on

⁹³ In response to MISO’s request for additional emergency energy above the 700 MW from Southern Company, Southern Company assisted MISO in obtaining an additional 150 MW of emergency energy from Southern Company BA during the peak hour.

⁹⁴ See Figure 32.

⁹⁵ See fn. 14.

January 17, but was able to increase its LMR to 930 MW by providing notice well in advance of the morning peak on January 18.⁹⁶

4. **Post-8 a.m.-peak hour: Conditions Gradually Improve**

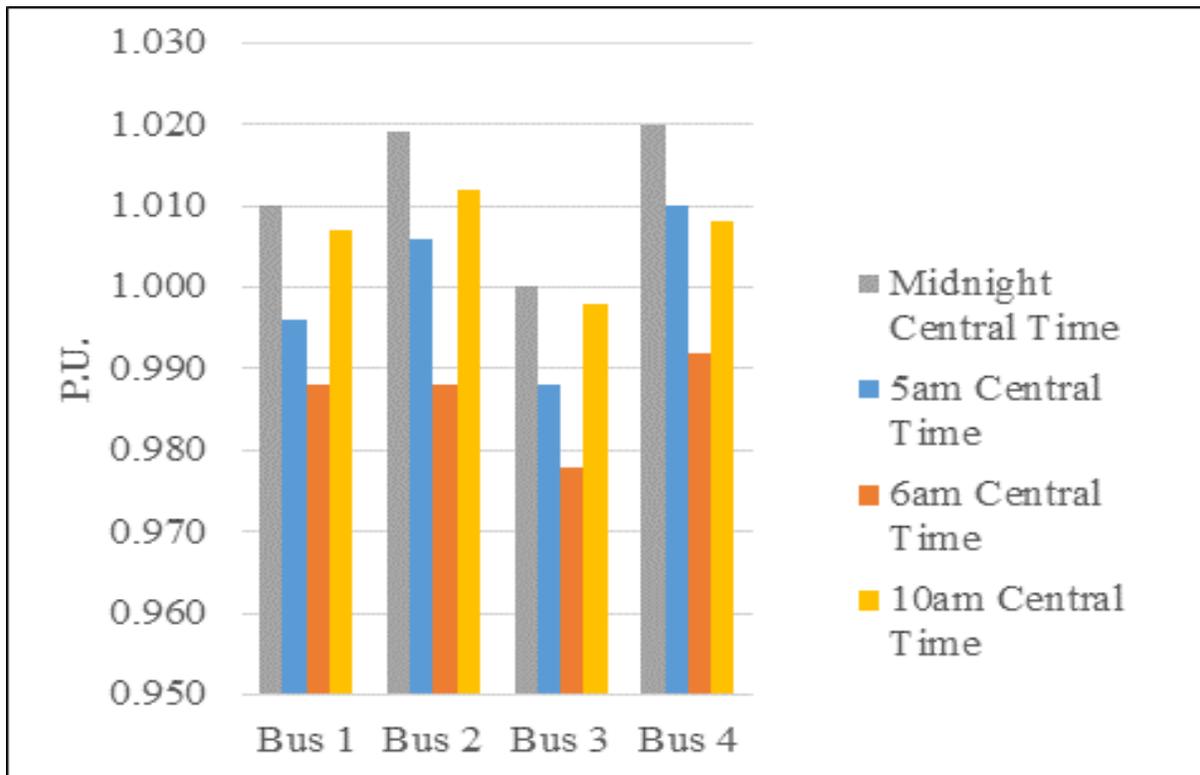
- *System conditions improved after morning peak, as load demands dropped from peak levels*
- *Generation conditions improved as units returned to service with rising temperatures*
- *SPP wind generation decreased sharply after morning peak conditions*
- *SPP EHV voltages returned to more typical levels*
- *Many pre- and post-contingency measures remained in effect*
- *MISO again sought emergency power as it prepared for evening peak*

After the morning peak on January 17, MISO South operators began to focus on evening peak reserves. MISO was still projecting the evening peak to be short of the necessary reserves for MISO South. Before 10 am, MISO RC Operators asked Southern Company if MISO could continue emergency energy purchases for the evening peak. MISO reduced its emergency energy to 350 MW until 1:30 p.m., after which it sought additional emergency energy for the evening peak (predicted to occur between 7 and 10 p.m. CST) from SPP, Southern Company and TVA BA. MISO briefly dropped down to EEA Level 1, returning to EEA Level 2 just before 2 p.m., when it declared Maximum Generation Event Step 2a/b and EEA Level 2 for MISO South effective 7 p.m. until early the morning of January 18. MISO finally dropped back down to EEA Level 1 at approximately 8 p.m. System conditions improved primarily due to the return of some of the generation units which had not been available during the early morning hours.

By 10 a.m. CST, SPP's EHV voltages returned to more typical voltage range for those locations. For example, the following chart shows a comparison between earlier morning real-time voltage levels and those measured at approximately 10 a.m. CST, for southern Oklahoma EHV locations:

⁹⁶<https://cdn.misoenergy.org/2018%20IMM%20Quarterly%20Report%20Winter162312.pdf>; Appendix I.

Figure 38: 10 am CST: Improvement in Southwestern-to-Southeastern Oklahoma 345 kV Per Unit Bus Voltages, Early Morning, January 17, 2018



TVA BA declared a Power Supply Alert I in effect for its Balancing Authority area, and later declared EEA Level 1, which it exited by 1 p.m. TVA BA experienced its winter peak load on January 18, one day later than MISO and SPP, as the cold front moved northeast.

All six MISO South transmission facility outages (3-230 kV and 3-115 kV), which were caused by freezing rain, returned to service by the end of the day:

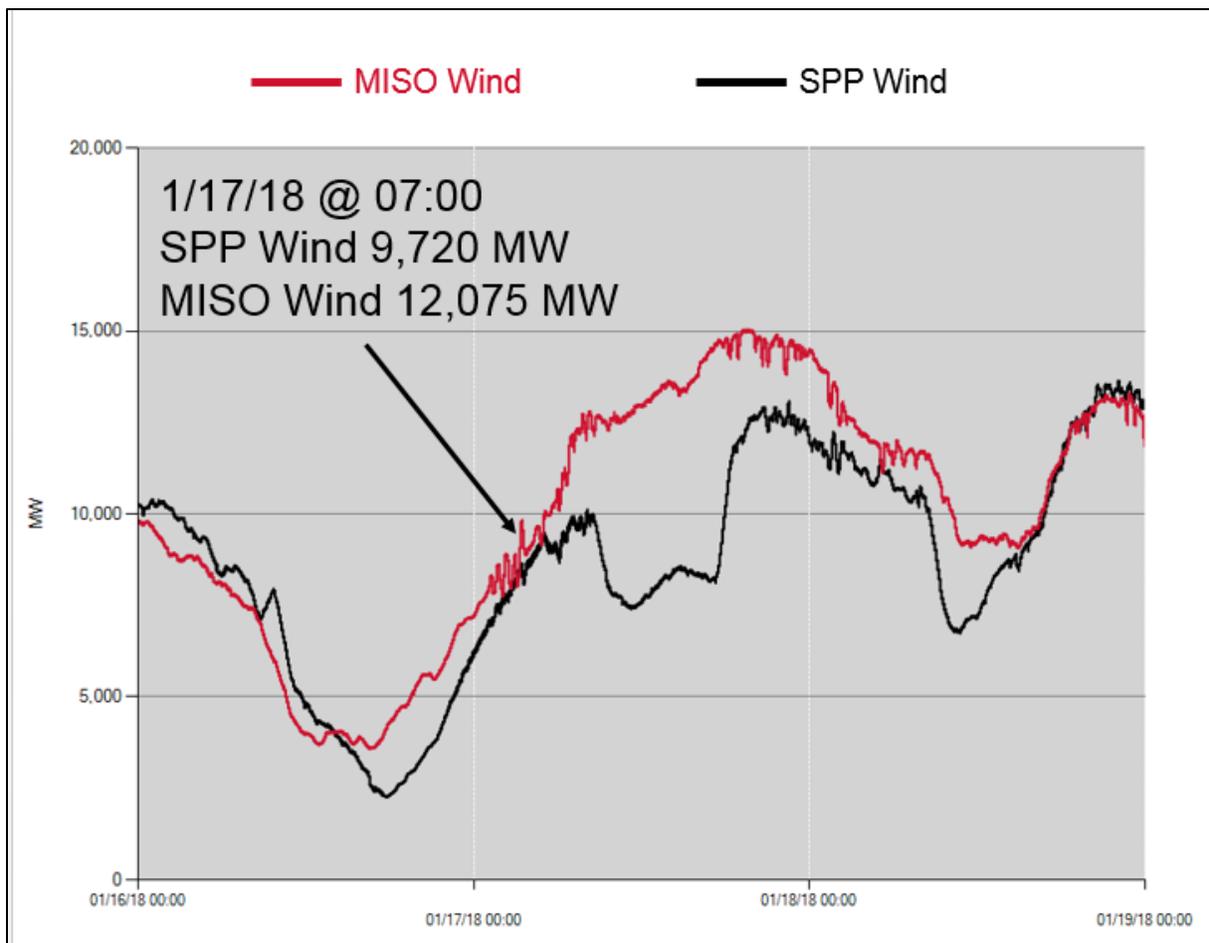
- 2-230 kV lines were restored by January 17, 11:07 a.m. CST,
- 2-115 kV lines were restored by January 17, 11:18 a.m. CST, and
- the two remaining transmission facilities were restored by 11:46p.m. CST.

Post-contingency overload conditions began to shift further east as the cold front moved, occurring more in Missouri, Tennessee and eastern Mississippi. However, many pre- and post-contingency measures already taken remained in effect in SPP, MISO and TVA RC. As new constraints occurred, the RCs coordinated well to manage system conditions. SPP developed post-contingent load-shed plans at four facilities in Oklahoma and Louisiana, as well as plans for post-contingent redispatch coordinated among SPP and TVA. MISO and TVA RC took mitigation actions via transmission reconfiguration

in Mississippi to alleviate a real-time overload as well as a simulated severe post-contingency condition.

MISO's wind generation output continued to rise, reaching a record peak of 15,038 MW on January 17.⁹⁷ SPP's wind generation output decreased significantly just after the morning peak load, from 10,000 MW to 8,000 MW, and remained at around 8,000 MW until just before evening peak, when it sharply increased to almost 13,000 MW (95% of its all-time peak wind generation output), and remained at that output the remainder of January 17.

Figure 39: MISO and SPP Wind Output, January 16 Through 19, 2018



⁹⁷ MISO's previous wind generation peak of 14,683 MW was set in December, 2017. The January 2018 record was broken in March 2019, with 16,317 MW of peak wind generation output.

VI. Post-Event Actions by the RCs and Joint Parties

A. RTOC Meetings and Entities' Report

On March 15, 2018, MISO, SPP, TVA and SeRC met to discuss the event, lessons learned and ways to increase coordination among the four Reliability Coordinators.⁹⁸ The Regional Transfer Operating Committee (RTOC), a six-member committee which includes two members each for MISO, SPP and the Joint Parties,⁹⁹ met at least three times before providing a report to the Team in September, 2018, and continued to work on action items identified in the September report.¹⁰⁰ Among the action items identified by the RTOC were four aspects of improving coordination as to the RDT, which ultimately culminated in a new RDT procedure, as well as a written “statement of understanding” about interim and long-term methods of addressing RDT-impacted flowgates, as discussed in section C, below.

B. FERC Tariff Change on Deliverability of Reserves¹⁰¹

On April 27, 2018, MISO filed proposed revisions to its Tariff to authorize the application of the Tariff’s reserve procurement enhancement provisions to the Sub-

⁹⁸ Although the Regional Transfer Operations Procedure in place during the Event, RTO-RTOA-OP1-r0, provided for a formal “Operations Review” upon request by one of the RCs under circumstances including when an increase in the RDTL had been requested (section 3.4), the Joint Parties did not characterize their report as resulting from a formal “Operations Review,” but it accomplished the purpose of analyzing the event and agreeing on next steps. The RTOC’s post-event analysis, “Regional Transfer Operating Committee Event Review Report (September 9, 2018),” is included as Appendix I.

⁹⁹ The Joint Parties include AECL, LG&E/KU, PowerSouth, Southern Co. and TVA.

¹⁰⁰ See Appendix I.

¹⁰¹ Prior to the Event, MISO had initiated the Resource Availability and Need (RAN) initiative, a broad analysis and plan to confront the increase in Maximum Generation emergencies even though sufficient capacity appeared to be available through the Planning Reserve Auction. The RAN initiative has led to several filings, including some of the filings described below, aimed at improving capacity availability in all seasons.

Regional Power Balance Constraints (MISO’s internal name for the RDTL). The Commission accepted MISO’s filing, effective August 26, 2018.¹⁰² MISO supported its filing by stating that the “reserve procurement enhancement” provisions were designed to address certain problems arising from the fact that the deliverability of reserves was not fully addressed by its Tariff’s then-existing approach to the setting of zonal reserve requirements. However, the original reserve procurement enhancements applied only to transmission constraints and did not apply to Sub-Regional Power Balance Constraints, which are contractual in nature. MISO contended that the contractual nature of Sub-Regional Power Balance Constraints should not preclude the application of the reserve procurement enhancement. MISO asserted that the revisions it proposed will enable it to use reserve procurement to manage flows, including post reserve deployment flows, between MISO Midwest and MISO South in accordance with the RDTL.

C. Revised Regional Transfer Operations Procedure and RDT-Impacted Flowgate Statement of Understanding

In December, 2018, a new version 2.0 of the Regional Transfer Operations Procedure (RTOP), which implements the Settlement among the Joint Parties, became effective. This version “incorporate[es] January 17, 2018 Lessons Learned” according to the Revision History, and, like the earlier version, is approved by MISO, SPP, TVA and SeRC. The revised version improves on the original in the following ways:

- Requiring MISO to ensure that both UDS and real-time RDT remain at or below the RDTL (versus only UDS during the Event).¹⁰³
- Requiring MISO to provide forecasts of the RDT to SPP, TVA, and SeRC.¹⁰⁴ and share key information which could affect the RDT for rolling 5 days into the future.¹⁰⁵

¹⁰² *Midcontinent Independent System Operator, Inc.*, 164 FERC ¶ 61,129 (2018). On March 15, 2019, MISO submitted revisions to conform additional provisions with recently accepted Tariff changes on the consideration of Post Reserve Deployment Constraints, including Sub-Regional Power Balance Constraints.

¹⁰³ 3.1.3.

¹⁰⁴ 3.1.4.

¹⁰⁵ 3.1.4.2.

- Identifying criteria for determining RDT-impacted flowgates.¹⁰⁶
- More specific actions to be taken to address congestion and RDTL exceedances,¹⁰⁷ including an ordering of congestion management procedures and a new subsection on potential load shed conditions.¹⁰⁸

To implement the identification of RDT-impacted flowgates,¹⁰⁹ MISO, SPP and the Joint Parties agreed to a two-step process for performing the necessary calculations for determining RDT-impacted flowgates. The interim step is required because as intra-market flow, MISO's RDT flow is not currently input into the Interchange Distribution Calculator (IDC) used to implement TLRs, but integrating the RDT flow into the IDC is planned for the second phase.

D. Additional MISO Tariff Revisions Relevant Post- Event

MISO has been studying the issue of capacity resources that are not available during periods when the system is under stress, particularly in non-summer periods and particularly in MISO South. Prior to the Event, MISO started a process known as the Resource Availability and Need Initiative. Some of the early fruits of the Initiative are tariff changes to better insure capacity availability, as described below.

On February 19, 2019, the Commission accepted MISO's Tariff revisions that now require LMR resources that become capacity resources to identify the period of the year that they are available and the notification time they require for deployment. This must include the four summer months with a notification time of no more than 12 hours. The resource must be able to justify the availability it identifies. On March 29, 2019, the Commission accepted, subject to condition, MISO's Tariff revisions¹¹⁰ that were intended to supplement the existing Generator Planned Outage process by improving transparency through forward signals and incentives.¹¹¹ MISO's revisions, which included a penalty for planned outages and derates that occur during Max Generation events, were intended to: (1) provide additional incentives for Generator Owners to

¹⁰⁶ 3.1.5.

¹⁰⁷ 3.1.6, 3.2 and 3.3.

¹⁰⁸ 3.3.8.

¹⁰⁹ As discussed in section 3.1.5 of the RTOP.

¹¹⁰ Open Access Transmission, Energy, and Operating Reserve Markets Tariff.

¹¹¹ Midcontinent Independent System Operator Inc., 166 FERC ¶ 61,236 (2019).

schedule Generator Planned Outages and derates well in advance of the scheduled start time and (2) identify times with increased system risk due to correlation of outages and derates. The Commission agreed with MISO's efforts to enhance its Generator Planned Outage scheduling practices, believing that MISO's proposal will "promote advanced scheduling of Generator Planned Outages, improve Generator Planned Outage coordination, and help MISO address the recent increase in the number of declared Emergency events during non-summer seasons."¹¹²

The same day, the Commission accepted, subject to condition, MISO's proposal to enhance the testing requirements in its Tariff for resources that participate in MISO's markets as LMRs.¹¹³ The Commission agreed with MISO's efforts to ensure that the LMRs it relies upon can in fact supply their registered load-reduction capability during emergency events. The Commission found it necessary for MISO to have confidence that LMRs will perform when scheduled, and stated that it expects MISO's proposed testing requirements to enhance LMR performance.

VII. Prior Similar Events

2011 Southwest Cold Weather Event of February 5-11, 2011¹¹⁴

This event, which affected the southwest region of the United States (Texas and New Mexico) during the first week of February, 2011, was similar to the Event in that extreme low temperatures caused widespread generation outages. In the 2011 cold weather event, many cities in Texas and New Mexico experienced a 50 degree drop in temperature. The cold temperature conditions in 2011 were similar to what was found for the Event, where many south central cities experienced a 40-50 degree drop in temperature over a several-day period: daytime high temperatures in the 60s to low-70s on Friday, January 11, in cities such as Little Rock, Texarkana, Shreveport, Jackson, Beaumont, Baton Rouge and New Orleans, dropped to daytime highs in the high teens to upper 20s on January 17. In both events, many generators did not winterize to protect against freezing weather conditions, despite recommendations from the 2011 report to do so. In both events, massive generation outages and derates led to energy emergencies,

¹¹² Id. at P. 60.

¹¹³ Midcontinent Independent System Operator Inc., 166 FERC ¶ 61,235 (2019). See fn. 14 for more information about LMRs.

¹¹⁴ Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011: Causes and Recommendations, found at <https://www.ferc.gov/legal/staff-reports/08-16-11-report.pdf>

however, in the 2011 event, the RC needed to perform controlled load shedding to maintain system reliability, whereas in the Event, emergency energy purchases and LMRs, among other tools, allowed the RCs to avoid shedding firm load (although firm load shedding could have occurred if the MISO South WSC occurred).

2014 Polar Vortex¹¹⁵

The Polar Vortex event of early January, 2014, which affected the Midwest, South- central, and East Coast regions, similarly involved significant unplanned generation outages and derates. Both the Polar Vortex and the 2011 event were similar to January 17, 2018, in that generation reserves were depleted within the event areas, due to significant unplanned generation outages and derates, requiring energy emergency measures ranging from voluntary load reduction to interruptible load shed to rotating blackouts/firm load shedding.

Cold Wave of 1994¹¹⁶

A complicating characteristic of the Event not found in the Polar Vortex or 2011 events was wide-area constrained BES conditions, stretching across four RC footprints. The Cold Wave that occurred the week of January 16, 1994, in the Midwest and Mid-Atlantic states, also had wide-area constrained conditions combined with capacity/reserves shortfalls, similar to the Event. Faced with unusually high electricity demands, and cold weather-related generator outages and reduced fuel supply, utilities with generation shortages imported large blocks of power over their transmission systems from other utilities. System operators managed several transmission paths near their post-contingency transfer limits, to ensure reliability while the large power transfers occurred, although some localized voluntary load shedding occurred.

Could This Happen Again?

The Event, combined with the other events, reaffirms the importance of generators remaining in operation during extreme cold weather conditions, to support reliable BES operations. More recently, MISO and SPP generators performed better in the January 30-31, 2019 Polar Vortex which affected the Midwest. Unlike facilities in warmer climates such as the south central U.S., generating stations in the colder Midwest are typically

¹¹⁵ NERC report on 2014 Polar Vortex, https://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf.

¹¹⁶ NERC report on Electric Utilities' Response to the Cold Wave of January, 1994.

designed and constructed so that their boilers, turbines, and other auxiliary systems are not exposed to ambient weather conditions.¹¹⁷ Unusually cold temperatures in warmer-weather areas, combined with a lack of generator preparation for conditions expected, could again lead to substantial unplanned generation outages, with similar effects on reserves and potentially, BES conditions.

VIII. Findings and Recommendations

Generator Cold Weather Reliability

Finding: 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.

- A comparison of below-freezing temperatures in the Event Area and unplanned generation outages and derates from January 15 through 19 resulted in three cities with correlation coefficients¹¹⁸ of -0.7 or better, and the majority of cities with coefficients of between -0.5 to -0.7, indicating that as temperatures decreased, unplanned outages and derates increased.
- At least 44% of the unplanned outages or derates during January 15 to 19 were directly attributed to, or likely related to, the extreme cold weather, as calculated by numbers of units. Fourteen percent of the generator failures were directly attributed by the Generator Owners/Operators to weather-related causes, including frozen sensing lines, frozen equipment, frozen water lines, frozen valves, blade icing, low temperature cutoff limits, and the like. Another 30 percent were indirectly attributable to the weather (occasioned by natural gas curtailments to gas-fired generators (16%) and attributed to mechanical causes known to be related to cold weather (14%)).¹¹⁹

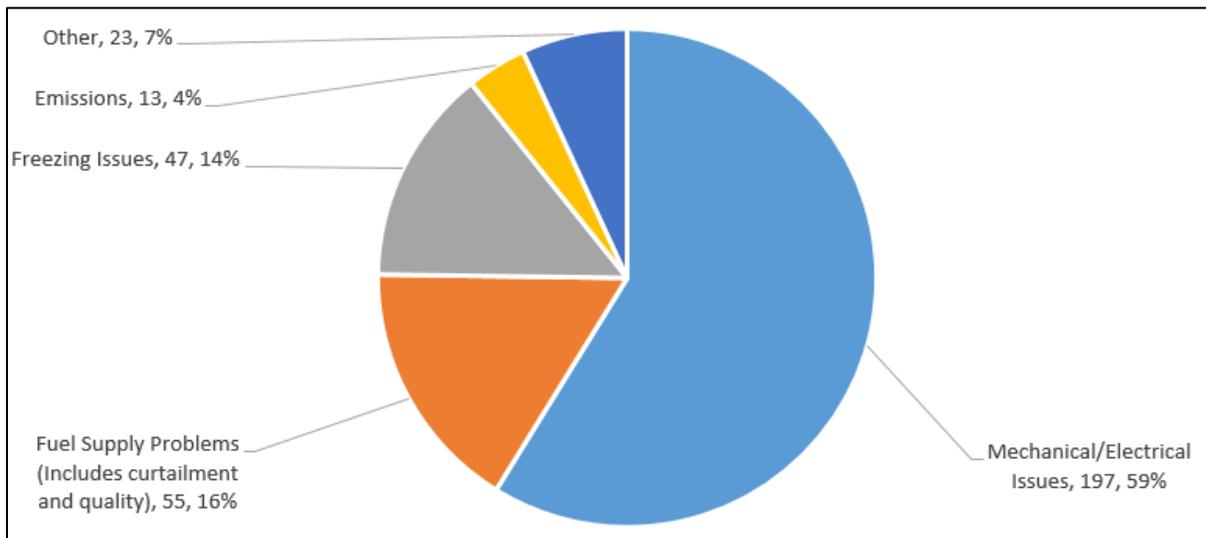
¹¹⁷ 2011 Southwest Cold Weather Event FERC/NERC Report, Appendix: Power plant design for ambient design temperatures at page 142.

¹¹⁸ A correlation coefficient is a number or function that indicates the degree of correlation between two sets of data or between two random variables and that is equal to their covariance divided by the product of their standard deviations. (Source: Merriam-Webster Dictionary.) A negative correlation coefficient indicates that as one variable increases, the other decreases, and vice-versa. In this case, the negative correlation meant that as temperatures decreased, generation outages increased.

¹¹⁹ These causes included issues with specific equipment known to be vulnerable to freezing, including drum level transmitter sensor lines, inlet guide vanes, gas purge valves, steam turbine intercept valves and other valves; issues related to cold oil, such as

- Unplanned generation outages and derates during the period of extreme cold accumulated to approximately 14,000 MW in the Event Area by the morning peak hour ending 8 am CST on January 17, 2018.
- Generator Owners attributed at least 35% of the generation outages and derates on January 17, 2018 to the extreme weather conditions: 19% to freezing-related mechanical issues and 16% to cold-related fuel supply issues.¹²⁰

Figure 40: January 15-19, 2018 - Causes of Unplanned Generation Outages and Derates for Event Area



oil pressure drop or failure to start; wet/frozen coal causing problems with feeders or conveyors; and loss of feedwater.

¹²⁰ More than 35% of the generator outages and derates on January 17 were likely related to the extreme cold. The Team found that for January 15 through 19, 14% of the outages and derates attributed to mechanical causes were actually caused by issues known to be related to cold weather. The Team did not perform this analysis for January 17 alone.

Figure 41: January 15-19, 2018 – Sub-causes for Unplanned Generation Outages and Derates due to Freezing Issues, for Event Area

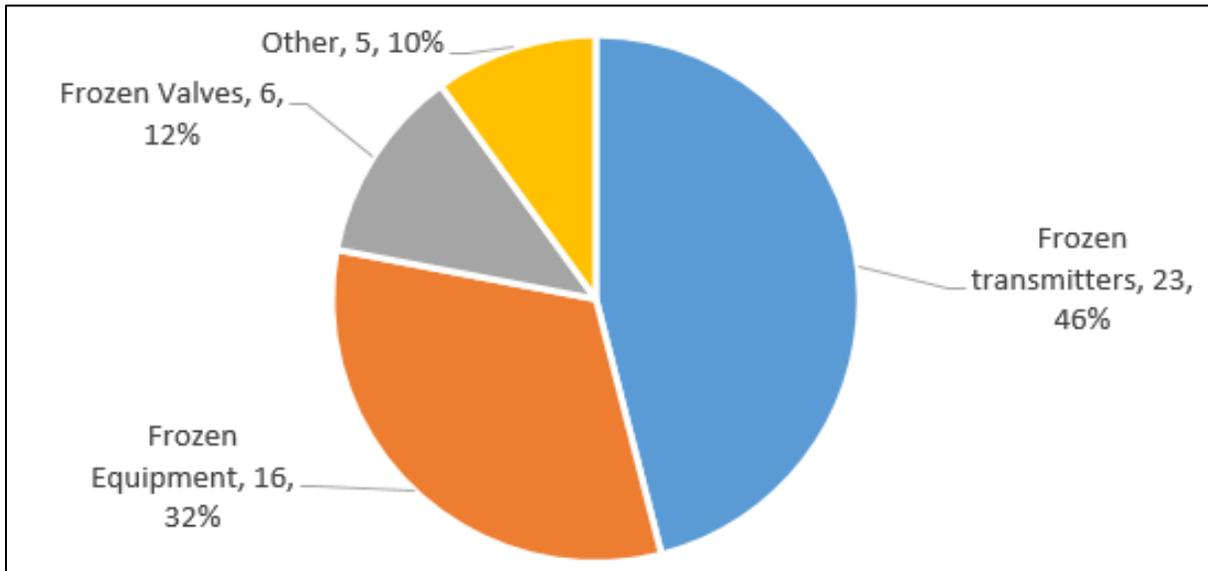


Figure 42: January 17, 2018 - Causes of Generation Outages for Event Area, By RC

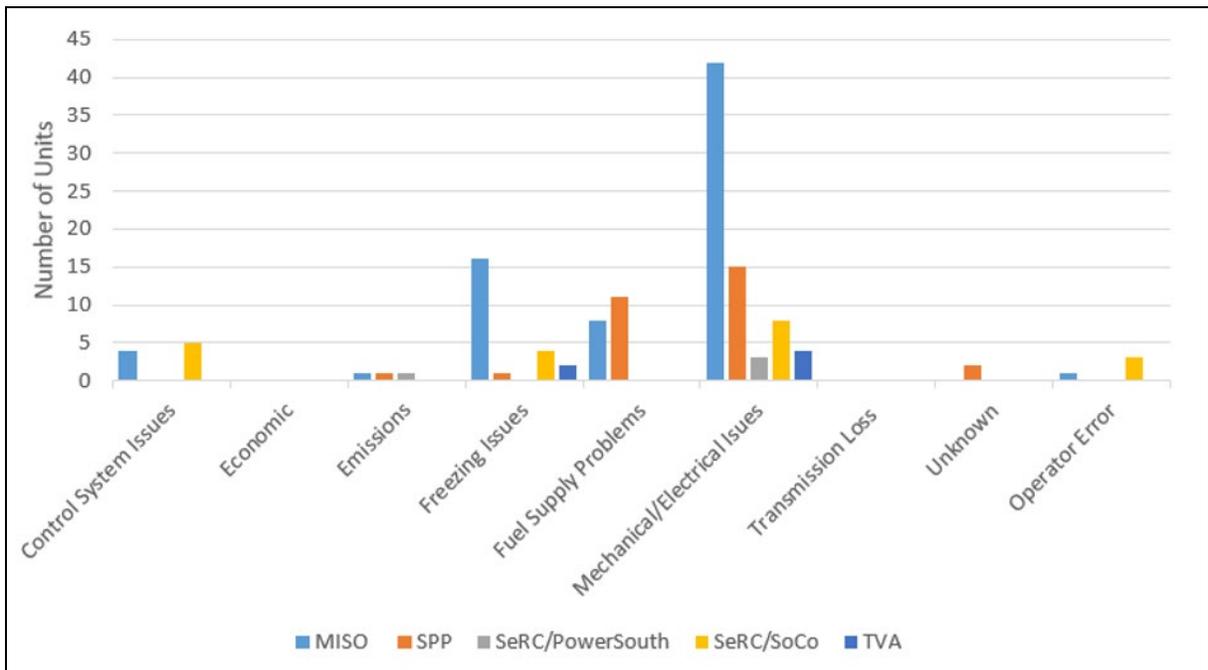


Figure 43: January 17, 2018 – Causes of Unplanned Generation Outages and Derates for Event Area

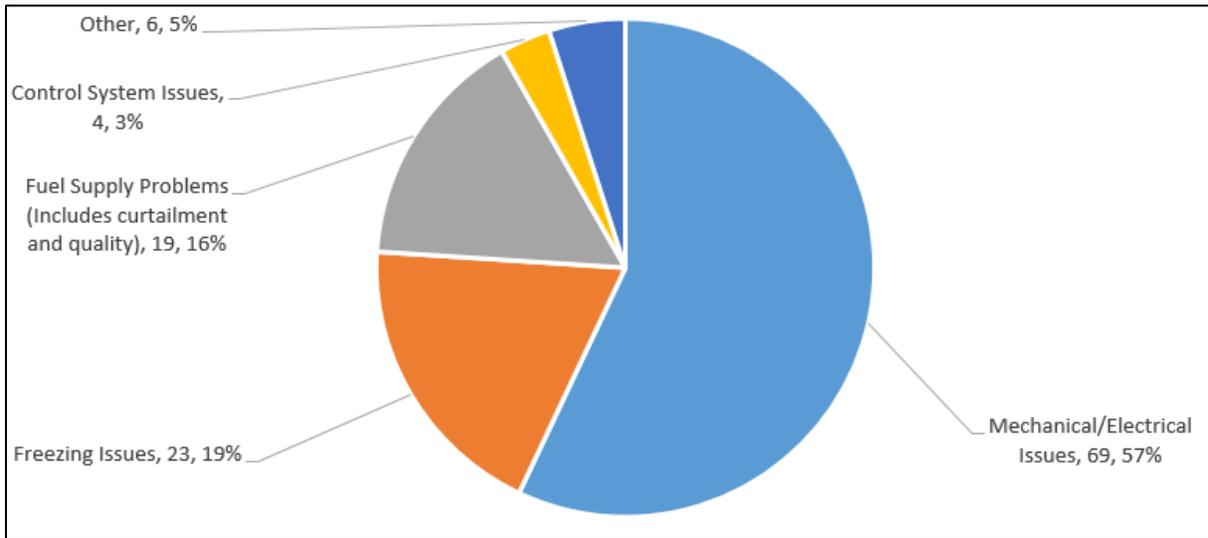


Figure 44: January 17, 2018 – Sub-causes for Unplanned Generation Outages and Derates due to Fuel Supply Problems, for Event Area

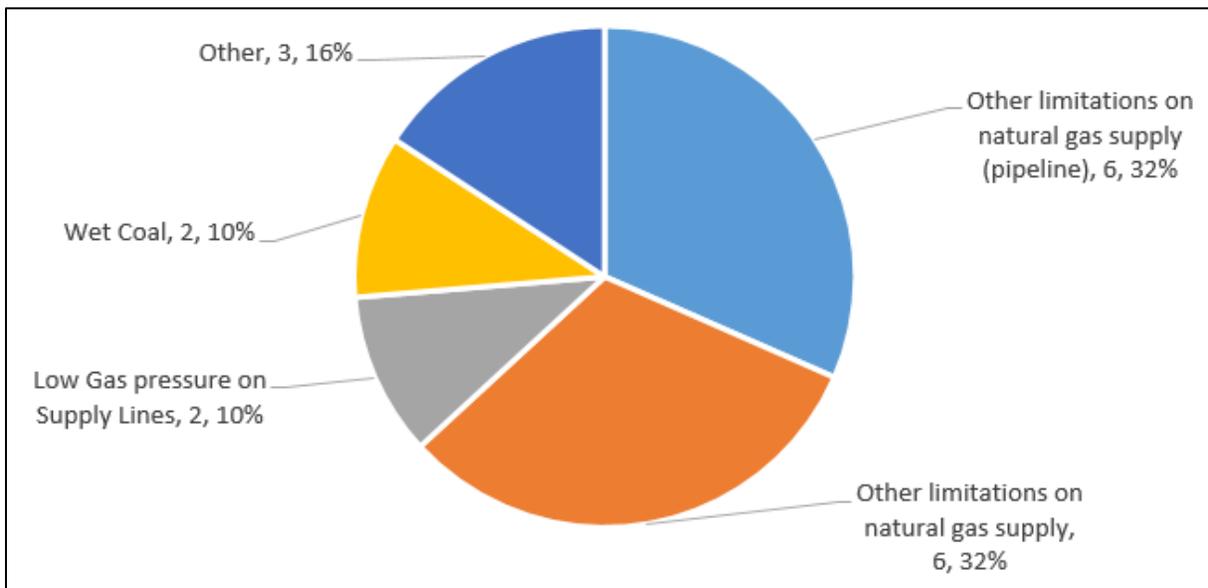
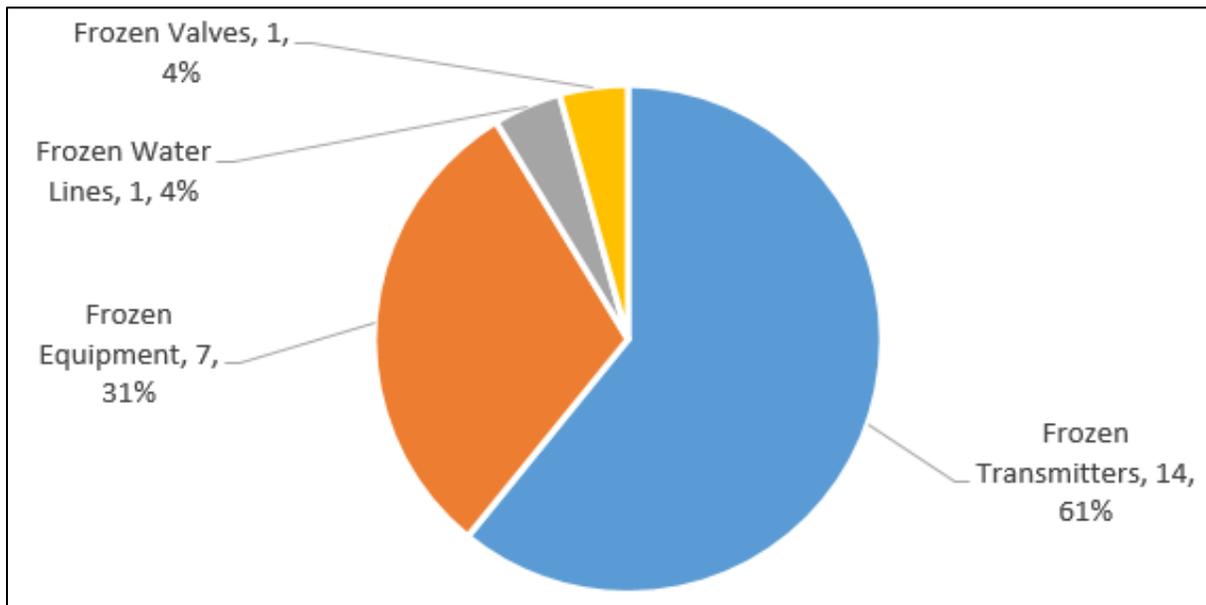


Figure 45: January 17, 2018 – Sub-causes for Unplanned Generation Outages and Derates due to Freezing Issues, for Event Area



Finding: Gas supply issues contributed to the Event, and natural gas-fired units represented at least 70% of the unplanned generation outages and derates.

- From January 15 to 19 in the Event Area, natural gas-fired units were 70% of the unplanned generation outages and derates when calculated by numbers of units, and 74% when calculated by MW.
- During the same period, gas supply issues caused by the extreme cold temperatures, including interruptible supply, low gas pressure, and other pipeline and gas supply issues, led to outages of 38 units, for a total of approximately 2,200 MW.
- The Team found that temperatures in the Event Area were generally above the ambient temperature design specifications¹²¹ for many natural gas-fired generating units.

¹²¹ Most of the units in the Event Area have an ambient temperature design rating between -10 and 10 degrees, with some exceptions. A handful of units have an ambient temperature design rating to -20 degrees, and four units are rated for use to -40 degrees. Some entities did not incorporate (or did not know) their units' ambient temperature design ratings.

Figure 46: January 15-19, 2018 – Sub-causes for Unplanned Generation Outages and Derates due to Fuel Supply Problems, for Event Area

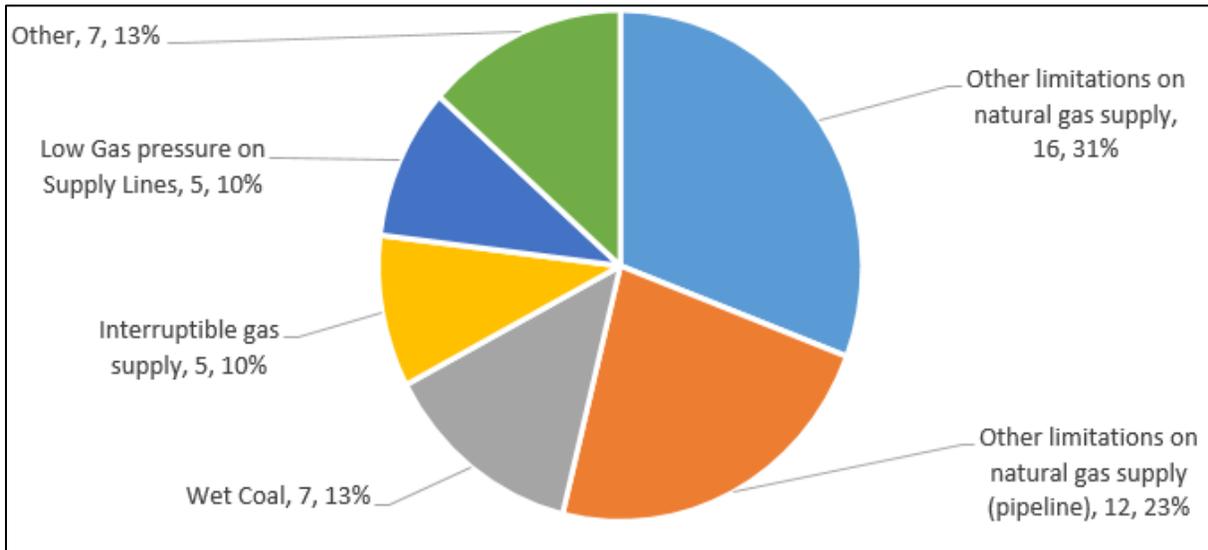


Figure 47: January 15-19, 2018 – Fuel Type for Unplanned Generation Outages and Derates due to Freezing Issues, for Event Area (by Number of Generators)

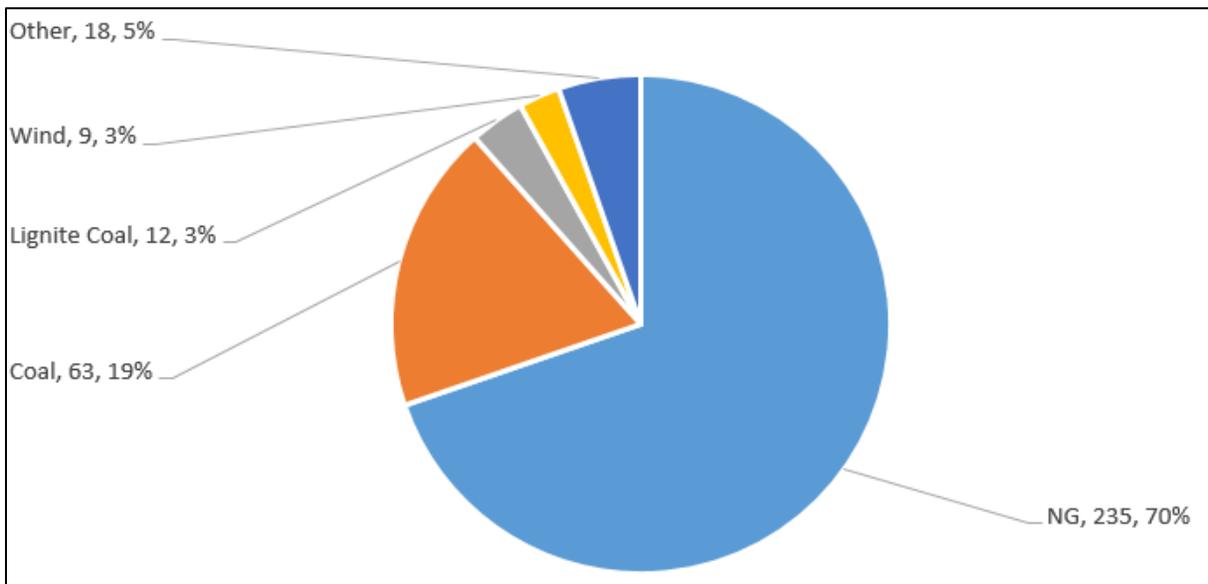
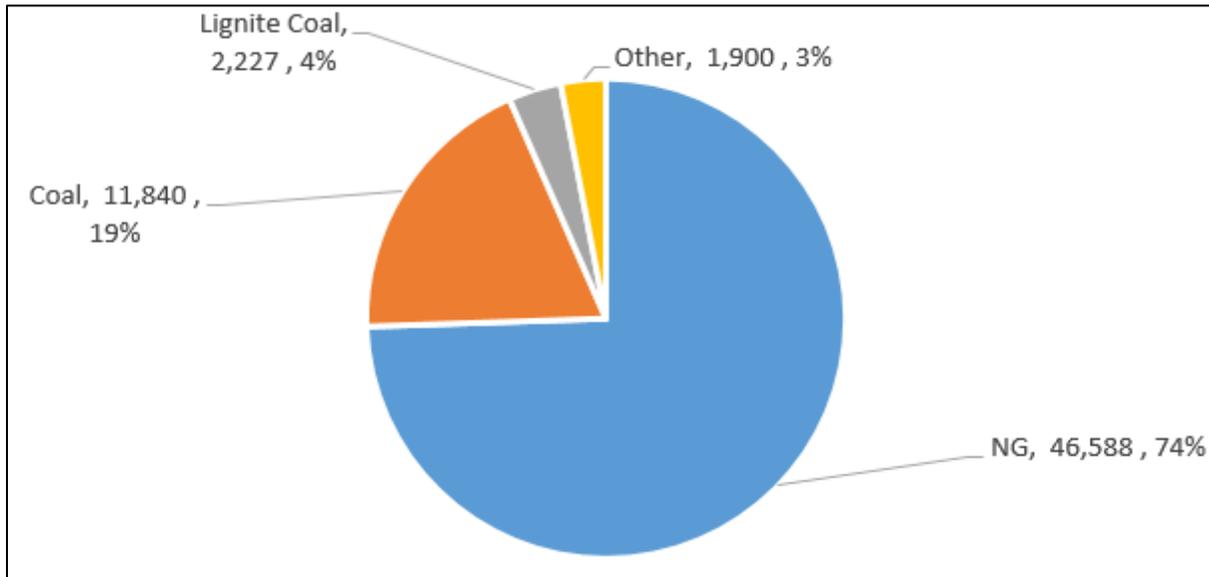


Figure 48: January 15-19, 2018 – Fuel Type for Unplanned Generation Outages and Derates due to Freezing Issues, for Event Area (by MW of Generation)



Generator Cold Weather Reliability

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 approach¹²² 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:

¹²² While any one of the three approaches may provide significant benefits in solving this problem, the Team does not view any one of the three as the only solution. The Team envisions that a successful resolution of the problem will likely involve concurrent use of all three.

- **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**
 - **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.¹²³ The accurate ambient temperature design specifications and expected generating unit performance, including for peak winter conditions, should be incorporated into the plans, procedures and training for operating generating units, and shared with Reliability Coordinators and Balancing Authorities.**
 - **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.**

Staff analysis of the outages between January 15 and 19 found that of 183 total units affected, the Generator Owners/Operators directly attributed 16% to freezing, and 14% to fuel supply issues related to the extreme cold. An additional 14% were likely caused by the extreme weather conditions. Outages in this last subcategory had been placed in the “mechanical/ electrical failures” category (59% of the outages between January 15 and 19) by the Generator Owner/Operators, but based on more detailed information, were found to be caused by problems known from earlier cold-weather events to be associated with extreme cold. Adding the categories directly attributed to and likely related to the extreme cold (16% plus 14% plus 14%) results in 44% of the total outages being directly or likely related to cold. Inquiry Staff also found that the total generation outages for January 15 through 19 (including all categories and subcategories)

¹²³ The Team found that temperatures were generally above the ambient temperature design specifications for many natural gas-fired generating units (See fn 121).

were statistically correlated with temperatures, with a -0.7 correlation overall. One-third of the GO/GOP entities surveyed had no winterization provisions.

These findings echo those from the Joint FERC-NERC Report on Outages and Curtailments during the Southwest Cold Weather Event of February 1-5, 2011 and the NERC 2014 Polar Vortex Report, both of which found that many generators failed to adequately prepare for winter weather conditions.

One of the recommendations from the 2011 Southwest Cold Weather Event was to create a mandatory winterization Reliability Standard. In September, 2012, NERC submitted a Standard Authorization Request (SAR) which proposed to require Generator Owner/Operators to:

- report generating unit capabilities based on anticipated winter weather using criteria developed by the standard drafting team using stakeholder input.
- ensure winter weather preparation plans are created, maintained, implemented and monitored as appropriate to help ensure generating units can operate to the criteria developed above. The plans shall include appropriate annual winterization measures.

When NERC's Operating Committee proposed a voluntary Reliability Guideline titled Generating Unit Winter Readiness, instead of a mandatory Reliability Standard, the Standards Committee rejected the SAR.¹²⁴

In addition to the recommendations made in the 2011 Southwest Cold Weather Event and the 2014 Polar Vortex Reports on winter preparedness, and NERC's Reliability Guideline, other voluntary steps have been taken since 2011, including:

- NERC video on "Winter Weather Preparedness"
- NERC webinar on "Winter Preparation for Severe Weather Events"
- Numerous NERC "Lessons Learned" documents issued pertaining to winter weather preparedness

¹²⁴ The rejection was also based on industry comments and a recommendation from NERC's Reliability Issues Steering Committee. See NERC's July 2013 letter to the proponent of the SAR:

https://www.nerc.com/pa/Stand/Project%20201301%20Cold%20Weather%20Preparedness/SAR_Response_Letter_SM_071813.pdf For more information regarding the proposed SAR, see https://www.nerc.com/pa/Stand/Pages/Project2013-01_Cold_Weather.aspx

- NERC-developed training package on “Extreme Weather Events” posted for industry use,
- Gas and Electrical Operational Coordination Considerations Reliability Guideline developed by the NERC Operating Committee, and
- Regional Entities’ cold-weather guidance (e.g. SERC’s Cold Weather Preparedness efforts,¹²⁵ ReliabilityFirst’s cold weather resources, including Winterization Visit Best Practices and Review of Winter Preparedness Following the Polar Vortex¹²⁶).

However, despite the guidance above, cold-weather events continue to occur involving extensive unplanned generation outages, which imperil reliable BES operations. A mandatory Reliability Standard would require Generator Owner/Operators to properly prepare for extreme cold weather, and would help RCs and BAs identify units which may not be able to perform during an extreme weather event. However, the process from SAR to Commission approval of a mandatory Reliability Standard could take a year or more. In the meantime, enhanced outreach and actions by ISOs/RTOs to incent generator performance can also help to prevent a recurrence of the large-scale unplanned outages like those seen during the Event, the Polar Vortex and in ERCOT in 2011.

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.**
 - RCs were regularly performing real-time assessments to determine system state and next courses of action, including identifying operating limit exceedances and voltage conditions for both real-time and for simulated post-contingency conditions.
 - The RC operators communicated and coordinated their analyses and discussed mitigation actions necessary to maintain BES reliability, up to shedding firm load.
 - During the Event, the Joint Parties affected by transfers between MISO Midwest and MISO South, including the four RCs, had a written procedure, the Regional Transfer Operations Procedure, which covered their interactions as to MISO’s Regional Directional Transfer.

¹²⁵ www.serc1.org/coldweatherprep

¹²⁶ <https://rfirst.org/KnowledgeCenter/Risk%20Analysis/ColdWeather>

- After the Event, the Joint Parties implemented a revised Regional Transfer Operations Procedure, RTO-RTOA-OP1-r2.0, effective December 1, 2018.
- **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.**
 - MISO invoked energy emergency alerts and purchased emergency energy for MISO South due to stranded reserves within its BA footprint.
 - The system in the Event Area was severely capacity-constrained. Even after emergency purchases, MISO South's reserves were down to 172 MW for the hour ending 8 a.m. CST.
 - Constrained transmission conditions spanned a large area, across all or portions of nine states (Arkansas, Alabama, Kansas, Louisiana, Mississippi, Missouri, Oklahoma, Tennessee, and Texas), and four RC footprints (MISO, SPP, TVA and SeRC).
 - As the morning peak (7 to 8 a.m. CST) neared on January 17, for the MISO South WSC, it would have likely resulted in firm load shed across the MISO South region to maintain generation and load balance and prepare to meet the next worst single contingency, while simultaneously triggering further and additional firm load shed in specific areas of the MISO South footprint to maintain BES voltages within post-contingency limits.

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 post-contingency manual firm load shed to maintain voltages within limits, while faced with potential additional firm load shedding to maintain system balance and restore reserves 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.

Had the MISO South WSC occurred during the morning peak hour of 7 to 8 a.m. CST, it would have required replacement generation from MISO Midwest, thereby further increasing RDT transmission flows into MISO South partly through parallel paths within SPP, TVA RC and SeRC footprints. Both MISO and SPP included the MISO South WSC as a contingency, both model each other's systems to an extent in their RTCA applications, and both showed their RTCA converging, which means that they did not expect instability or cascading as a result of the simulated outage of the 1,163 MW WSC.

However, MISO's RTCA projected a trend of post-contingency low voltage, including voltages as low as 88% on certain 230kV buses, and 24 transmission facilities with projected post-contingency thermal overloads between 7 and 8 a.m. CST. MISO operators relied on RTCA convergence, which indicates steady-state stability,¹²⁷ to assure that voltage stability could be maintained despite numerous post-contingent system conditions. Also, MISO relied on the TOPs within its footprint to quickly execute the necessary load shed if the MISO South WSC occurred, to alleviate numerous low voltages. This analysis would be especially important given that MISO recognizes that one of its load pockets is "a voltage/thermal sensitive area and is susceptible to low voltages under outage conditions or a loss of a key transmission element," and for MISO's WSC in MISO South of 1,163 MW, it would have likely resulted in the need for post-contingency load shedding steps to alleviate numerous transmission facilities from experiencing low voltage conditions, while faced with potential additional firm load shedding to maintain system balance and restore reserves for MISO South region.

RC-to-RC Communications Recommendations

Version 2.0 of the Regional Transfer Operations Procedure is an improvement on the Procedure in use during the Event. The Joint Parties should consider the following revisions that would further enhance RC communications:

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**

¹²⁷ Capability of an electric power system to maintain its initial condition after small interruption or to reach a condition very close to the initial one when the disturbance is still present.

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.¹²⁸**
- **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 prior to implementing the emergency energy schedule to avoid unintentionally causing detrimental impacts to Regional Directional Transfer-impacted 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”¹²⁹ BES condition, and led the affected entities to transfer power from distant generation into the affected region to cover energy

¹²⁸ Linking the obligation to shed firm load to the Reliability Standards will protect MISO if it needs to shed firm load to reduce the RDT. The RDT is a contractual limit rather than a limit imposed by one of the Commission-approved mandatory Reliability Standards (e.g. SOL, IROL). In the past, the Commission approved a penalty against a Balancing Authority/Transmission Operator that shed firm load when the load shedding was not required by a Reliability Standard. *See In re California System Operator Corporation*, 141 FERC ¶ 61,209 (2012)).

¹²⁹That is, a large number of generation contingencies had occurred (generation units experienced unplanned outages, derates or failures to start).

demands and provide reserves. These large power transfers resulted in wide-area BES transmission-constrained conditions in four RC footprints.

- On a seasonal basis, both MISO and SPP separately performed assessments for the 2017/18 winter and shared their results; however, these assessments neither analyzed simultaneous power flows and transfers like those seen on January 17, nor quantified results of their combined impact.
- On a seasonal basis, MISO had predicted that it could transfer up to 4,650 MW in a north-to-south direction, but this analysis was based on less-severe transfer conditions.
- The transmission system conditions observed on the morning of January 17, 2018, were not solely due to MISO's north-to-south regional directional power transfer (RDT) flow to cover the supply shortfall caused by unplanned generation outages and derates MISO South, but to a combination of the RDT flow and additional factors including generation outages and derates in the rest of the Event Area (e.g., southeastern SPP footprint), high system loads related to extreme low temperatures in the Event Area, higher-than-forecast wind generation power transfers in MISO and SPP, and DC power transfer flows between SPP and the ERCOT Interconnection.
- To address the constrained system conditions, RC operators needed to consult with their TOP operators to verify system operating limits to aid in determining potential mitigation measures, and some RCs opened transmission facilities based on SOLs which did not reflect winter cold weather conditions.
- Although the Event Area normally has generous reserves (i.e., greater-than-20% projected reserve margins for winter peak conditions), the unplanned generation outages and derates created stranded reserves from the distant generation, especially in MISO South.
- In its next-day forward reliability assessment commitment, as well as during the January 17 event operating day, MISO utilized its full 3,000 MW RDT to aid in providing reserves for its MISO South firm load.

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 where 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.

For its Winter 2017-2018 Coordinated Seasonal transmission Assessment, MISO performed transfer studies which included studying MISO Midwest to MISO South intra-Balancing Authority area transfers to determine First-Contingency Incremental Transfer Capabilities for both north-to-south and south-to-north transfers. The maximum power transfer projected was 4,650 MW in a north-to-south direction, and MISO concluded this was adequate for the upcoming 2017-2018 winter season. However, the reported maximum power transfer value was based on less-severe power transfer conditions, since MISO modeled the power transfer by scaling generation between the internal north and south regions for the simulation of the transfer, versus modeling certain generators offline

in MISO South in the study case to yield a transfer capability based on more extreme event conditions. This scaling of generation between the internal north and south regions for the simulation of the transfer did not entirely represent the effects on the power grid that outages of actual generating units would cause, such as loss of voltage support.

Additionally, MISO did not model the simultaneous north-to-south transfers in adjacent RCs (transfers from locations where generation reserves were available to those in which generation outages and derates), as well as high system loads (i.e., in MISO South, and in the southeastern SPP footprint), which occurred on January 17. These simultaneous north-to-south parallel flows contributed to numerous BES post-contingency limit exceedances and lower than normal system voltages, necessitating many post-contingency mitigations to be ready for the next contingency. The MISO and SPP footprints combined cover the entire mid-section of the U.S., and weather patterns may simultaneously and similarly impact their real-time operations, as on January 17.

Loss of southern generation occurred in MISO as well as SPP, and the parallel impact of those flows resulted in lower-than-expected real-time RDT capability. The Team also found that the results of the studies were not used to inform/support MISO's operations staff to aid in management of the RDT (e.g., lowering or raising of the RDT) for the operations planning horizon. If MISO performed more-severe condition studies, operators could use the study results in planning for conditions where more extreme RDT transfers are forecast.

System Operating Limits Recommendation:

Recommendation 9: Transmission Owners and Transmission Operators, as part of establishing facility ratings and System Operating Limits, respectively,¹³⁰ 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.¹³¹ These ratings and limits should be provided to the Reliability Coordinator and other applicable entities for use in tools for operation,

¹³⁰ See fn 89.

¹³¹ Some entities may have, for example, a winter rating based on 32 degrees and a summer rating based on 95 degrees. Other entities may have temperature-dependent ratings, which would also be consistent with the recommendation. Care should be taken when implementing ratings and limits, to account for unseasonal weather, e.g., warmer-than-normal winter days.

such as Energy Management System and Real-Time Contingency Analysis applications.¹³²

EMS systems have the capability to promptly update transmission facility limits for system operators so that they have accurate limits that reflect the current ambient conditions. The Team found that certain overhead-line transmission limits used by system operators during the Event reflected summer season conditions instead of the ambient cold weather conditions experienced during the event. Generally, limits based on colder conditions would have allowed the use of a higher capacity rating. The Regional Transfer Operations Procedure, RTO-RTOA-OP1-r2.0, contemplates in 3.2.2.1 the use of dynamic and emergency ratings as the first step in congestion management, which assumes the existence of such ratings. During its inquiry, the Team observed constrained transmission facilities for which one static rating was used year-round (i.e., Summer Normal = Summer Emergency = Winter Normal = Winter Emergency) and some of which had ratings that were atypically much lower than typical overhead circuit ratings applied at the same voltage. The use of seasonal ratings or dynamic ratings could allow for greater capacity ratings, thereby potentially reducing congestion and potentially ameliorating system conditions during an emergency.

Reserves Recommendations:

Recommendation 10: Balancing Authorities should consider deliverability of reserves to avoid stranded reserves.¹³³

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 non-firm, as-available basis.”¹³⁴ 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

¹³² The Transmission Operator may need to work with the Transmission Owner to obtain facility ratings which do not limit the Transmission Operator’s ability to provide the recommended limits.

¹³³ See *Planning and Reserves* Recommendation No. 3, in Appendix G, 2011 Recommendations on Preparation for Cold-Weather Events.

¹³⁴ Midcontinent Independent System Operator, Inc., 164 FERC ¶ 61.129, at P 37 (2018).

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.

By depending on the total RDT, which consisted of 1,000 MW firm transmission capacity plus 2,000 MW as-available non-firm transmission capacity, MISO ran the risk of curtailment of the “non-firm, as available” portion of the RDT to alleviate transmission overloads, which could result in stranded reserves along with the potential for firm load shed in the MISO South region. These risks could increase further if emergency energy is unavailable or not deliverable from neighboring resources to provide reserves due to RDT curtailment.

Load Forecasting

Findings: MISO's 5- to 3-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.

- MISO South region's five-, four-, and three-day-ahead “mid-term” peak load forecast errors in forecasting the actual peak load on January 17, 2018 were significantly larger (approximately 18.9%/6,000 MW, 10.2%/3,250 MW, and 6.1%/1,900 MW low, respectively) than the other RCs relevant to this event.
- Other RCs' load forecasts within the Event Area were much more accurate (with error rates ranging from 5.6% lower to 3.0% higher than actual peak load for five-days-out, 4.6% lower to 4.8% higher than actual for four-days-out, and 2.8% lower to 4.0% higher than actual for three-days-out).

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.**
- **Re-forecast peak loads to reduce significant differences in forecast error for these timeframes.**
- **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.**

With improved forecasting accuracy during the five-, four-, and three-day-ahead timeframes, additional longer-lead-time actions, including additional Load Modifying Resources, could have been taken to be better prepared for the operating day of January 17, 2018.

A. Sound Practices

Sound practices are just that—practices applied by one or more of the entities involved in the Event, which went beyond the requirements set forth in the mandatory Reliability Standards. The Team did not make a determination 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 BAs¹³⁵ can impact neighboring systems, to improve reliable operation among neighboring BAs and RCs, MISO, SPP and the Joint Parties have established a method for identifying RDT-impacted flowgates based upon simulated power transfers, for:
 - a. The planning horizon, to perform the appropriate prior outage coordination activities and development of operating guides

¹³⁵ These power transfers are not interchange schedules between BAs. Intra-market/intra-BA transfers like these may exist elsewhere in the country and MISO’s experience may prove helpful to others.

- 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-impacted 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 generation¹³⁶ 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 at 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. 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.¹³⁷ 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 impacting BA contingency reserves), possible transmission reconfiguration, and/or TLRs.

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.

¹³⁶ MISO and SPP wind generation provided one source of power supply to both footprints which suffered unplanned generation outages and derates.

¹³⁷ See 166 FERC 61,116, ER19-650-000.

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, prior to 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 prior to winter weather.
- 7) Increased operator rounds/increased staffing prior to, 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, prior to 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 decisions.

Appendices

Appendix A: January 17, 2018 Cold Weather Inquiry Joint Team Members

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Appendix B: Primer on Electric Markets and Reliable Operations of the BES

To help ensure that the electric grid operates as reliably and efficiently as possible, Congress granted FERC jurisdiction over electric grid reliability through the enactment of the Energy Policy Act of 2005 (EPAct), by adding a new section to the Federal Power Act, 16 U.S.C. § 215. Pursuant to its EPAct authority, FERC certified the North American Electric Reliability Corporation (NERC) as the Electric Reliability Organization (ERO) responsible for establishing mandatory Reliability Standards, which then must be approved by FERC. FERC also promulgated regulations, approved Regional Entities to serve as regional compliance authorities,¹³⁸ and approved over 100 NERC-proposed mandatory Reliability Standards. This jurisdiction and oversight over the grid's reliability by FERC and NERC is vital to assuring consistent and dependable access to electricity. NERC currently has 16 Reliability Coordinators (RC) in North America to ensure that the grid is run efficiently and reliably. These RCs cover wide areas, and have the operating tools and processes to do so, including the authority to prevent or mitigate emergency operating situations. Midcontinent Independent System Operator (MISO), Southwest Power Pool (SPP), Tennessee Valley Authority (TVA) and Southeastern RC (SeRC) all served as RCs in the Event Area, and MISO and SPP are also Regional Transmission Organizations and Independent System Operators.¹³⁹ In the United States, RTOs and ISOs (hereafter, we will use RTO to refer to both) plan, operate and administer wholesale markets for electricity. MISO and SPP are RTOs that serve much of the Event Area discussed in this report. These entities, which are regulated by FERC, manage markets for energy and related services, for specific regions of the country.

Ensuring reliable operation of the power grid is complex and requires constant analysis and assessment. This is true for two fundamental reasons: (1) it is difficult to economically store large quantities of electricity, so electricity must be produced the moment it is needed; and (2) because alternating current (AC) electricity flows freely along all available transmission paths through the path of least resistance, it must be constantly monitored to maintain electricity flows over transmission lines and voltages within appropriate limits. The power system therefore must be operated so that it is

¹³⁸ The Regional Entities relevant to this event are ReliabilityFirst, Midwest Reliability Organization, and SERC Reliability Corporation.

¹³⁹ See Figure 4 in the body of the report for a map of the Event Area.

prepared for conditions that could occur, but have not happened yet.¹⁴⁰ Should an outage or reliability issue occur, system operators must act promptly to mitigate adverse conditions and remain within appropriate limits. For conditions severe enough that they could cause instability, uncontrolled separation or cascading outages, mitigation must occur within no more than 30 minutes. Equally vital to the continued operation of the grid is that it is restored to a condition where it can once again withstand the next-worst single contingency.

All of the RTOs operate both “day-ahead” and a “real-time” energy markets. In the day-ahead market, buyers and sellers schedule electricity production and consumption before the operating day, which produces a financially-binding schedule, the day-ahead generation resource unit commitment, for electricity production and consumption one day prior to the actual generation and use. This provides generators and electricity load-serving entities a forecast of their needs prior to the day’s operations and enables system operators to prepare an Operating Plan Analysis for the next day.¹⁴¹ To perform the day-ahead unit commitment, RTO operators look for the most economic generators to schedule to be online for each hour of the following day, taking into account factors such as a unit’s minimum and maximum output levels, how quickly those levels can be adjusted and whether the unit has minimum time it must run once started, as well as operating costs. Operators need to take into account forecast electricity demand or load

¹⁴⁰ NERC’s mandatory Reliability Standards require that the bulk-power system be operated so that it generally remains in reliable condition, without instability, uncontrolled separation or cascading, even with the occurrence of any single contingency, such as the loss of a generator, transformer, or transmission line. This is commonly referred to as the “N-1 criterion.” N-1 contingency planning allows entities to identify potential N-1 contingencies before they occur and to adopt mitigating measures, as necessary, to prevent instability, uncontrolled separation, or cascading. As FERC stated in Order No. 693 with regard to contingency planning, “a single contingency consists of a failure of a single element that faithfully duplicates what will happen in the actual system. Such an approach is necessary to ensure that planning will produce results that will enhance the reliability of that system. Thus, if the system is designed such that failure of a single element removes from service multiple elements in order to isolate the faulted element, then that is what should be simulated to assess system performance.” *Mandatory Reliability Standards for the Bulk Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, at P 1716 (2007), *order on reh’g, Mandatory Reliability Standards for the Bulk-Power System*, 120 FERC ¶ 61,053 (Order No. 693-A) (2007).

¹⁴¹ See Appendix C, “RC and TOP Tools and Actions to Operate the BES in Real Time.”

conditions for every hour of the next day, and other factors that could affect grid capabilities such as expected generation and transmission facility outages, any adverse weather conditions (e.g. severe heat or cold, precipitation, high winds), and line capacities. If the analysis suggests that optimal economic dispatch cannot be carried out reliably, more expensive generators may need to replace the cheaper generators to operate reliably.

The current operating day, or real-time market, begins with the Operating Plan Analysis, created with generators who bid into and were chosen in the day-ahead market. It then reconciles any differences between the day-ahead schedule and the real-time load, while taking into account real-time conditions such as forced or unplanned generation and transmission outages, as well as electricity flow limits on transmission lines and other criteria, such as voltage, for BES reliability.

RTOs also act as Reliability Coordinators and/or Transmission Operators, and may also act as Balancing Authorities, to oversee system reliability in their footprints.¹⁴² These are three of the functions for which the entities responsible for operating the BES in a reliable manner can register with NERC. These registrations then guide which of the mandatory Reliability Standards the entity must follow. A single entity can conduct multiple reliability functions and therefore have multiple NERC registrations. The NERC functional entity types most relevant to this event are Reliability Coordinator, Balancing Authority, Transmission Owner, Transmission Operator, Generator Owner, Generator Operator, Planning Coordinator, and Transmission Planner.

The Reliability Coordinator is responsible for overseeing transmission operations for the wide area of the interconnection that it oversees. Similar to the Transmission Operator, below, the Reliability Coordinator ensures the reliable real-time operation of transmission assets by performing OPAs and preparing Operating Plans, but the Reliability Coordinator has the “wide-area” view, beyond any individual Transmission Operator. In coordination with other Reliability Coordinators, the Reliability Coordinator maintains situational awareness beyond its own boundaries, to enable it to operate within its Interconnection Reliability Operating Limits (limits necessary to prevent system instability and cascading outages) and maintain reliability of its area. Like the Balancing Authority, below, the Reliability Coordinator ensures the generation-demand balance is maintained, but within the larger Reliability Coordinator Area, thereby ensuring that the Interconnection frequency remains within acceptable limits. The Reliability Coordinators for the Event Area include MISO, SPP, TVA and SeRC.

¹⁴² See Appendix E, “Categories of NERC Registered Entities.”

The Balancing Authority (BA) integrates resource plans ahead of time, contributes to the Interconnection frequency in real time, and maintains the balance of electricity resources (generation and interchange) and electricity demand or load within the Balancing Authority Area. SPP RC, TVA RC, and SeRC contain multiple Balancing Authority Areas.

Transmission Operator and Generator Operator

The Transmission Operator (TOP) ensures the real-time operating reliability of the transmission assets within its area. It has the authority to take actions to ensure the continued reliable operation of the Transmission Operator Area. Like the RC, it performs daily OPAs and prepares Operating Plans, but for its smaller TOP footprint. The TOP coordinates with neighboring BAs and TOPs, as well as RCs, for reliable operations. The TOP also develops contingency plans, operates within established System Operating Limits, and monitors operations of the transmission facilities within its area. The following TOPs, among others, were affected by this event: AECI, LG&E and KU Services Co., MISO (MISO is registered as Transmission Operator and Transmission Planner in the RF and SERC Regions), PowerSouth, Southern Company Transmission, and TVA.

The Generator Owner (GO) owns and maintains generating facility(ies), while the Generator Operator (GOP) operates generating unit(s) which supply energy. The GOP also performs other services required to support reliable system operations, such as providing regulation and reserve capacity, and sharing data with BAs and TOPs as required. Many entities are both GOs and GOPs.

The Planning Authority (PA) coordinates and integrates transmission facility and service plans, resource plans, and protection systems, while the Transmission Planner (TP) develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority area.

Some of the key concepts to ensure the reliability of the electric transmission grid include:

- Voltage Control – Maintaining consistent voltage levels is imperative, as wide deviations in the voltage levels can have severe consequences. Voltage below certain limits could lead to an electric system imbalance or collapse. Voltages above certain limits can exceed insulation capabilities and cause dangerous electric arcs. Winter peak electricity loads include resistive loads such as resistive heating, which has a higher load power factor than during summer peak conditions. Load power factor is an indicator of reactive demand —the higher the

load power factor, the lower the reactive power demand. A relatively small percentage change in power factor, such as a change from 88% summer peak load power factor, to a 92% winter peak load power factor, can result in 30% less need for reactive power to be supplied during the winter. Summer peak electricity load includes air conditioning, which, like other induction motors, has lower power factors and consumes more reactive power than winter loads. Even with more stable voltages during winter peak conditions, system operators must continually monitor and evaluate system conditions, examining reactive reserves and voltages, and adjust the system as necessary for secure operation.¹⁴³

- Power Flow/Stability Control – Because of the danger resulting from low voltage levels, voltage stability limits are set to ensure that the unplanned loss of a generator or line will not cause dangerously low voltage levels. Additionally, power (or angle) stability limits are set to ensure that unplanned losses will not cause the remaining generators or lines to lose synchronism (or operate out of step) with each other, causing equipment damage.
- Short-Term and Long-Term Planning – Detailed system planning, design, maintenance, and analysis ensure reliable and safe operation of the system in the near- and long-term. Operations planning assesses day-ahead, week-ahead, seasonal, and up to one-year planning horizons. Short-term planning focuses on one- to five-year planning horizons, and long-term planning evaluates adequate generation resources and transmission capacity to ensure the system will be able to withstand severe contingencies in the future without widespread, cascading outages.
- Coordination and Communication Between Entities –the Reliability Standards encourage principal entities (e.g., Reliability Coordinators, Balancing Authorities, Transmission Operators, Generator Operators, and Distribution Providers) to communicate effectively in real-time to maintain system balance between generation and load, stay within operating limits, and address issues that arise.

Ultimately, the RCs, BAs, TOPs and other responsible entities must work individually and together to comply with the mandatory Reliability Standards and to ensure the continued reliable operation of the bulk power system.

¹⁴³ U.S.-Canada Power System Outage Task Force “Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations” (April 2004) at 26.

Appendix C: RC and TOP Operator Tools and Actions to Operate the BES in Real Time

RCs and TOPs employ system operators and engineers who use various methods to forecast and evaluate upcoming and real-time issues, so as to avoid or mitigate problems that arise in their electric grids. They continually monitor transmission facilities 24 hours a day, seven days a week, for situational awareness of the power grid. System operators typically have available a variety of real-time computer tools for monitoring the system, including State Estimator (SE) and Real-Time Contingency Analysis (RTCA).¹⁴⁴ RC system operators are constantly monitoring RTCA and RTCA-based displays, including lists of facilities that exceed System Operating Limits or have voltages deviating from voltage criteria in real time, and lists of facilities that would exceed System Operating Limits or have voltages deviating from voltage criteria if a contingency were to occur (another system element, such as a line, transformer or generating unit, is outaged) (the latter list is called post-contingency exceedances).

For both real-time and post-contingency limit exceedances, the system operators have a number of step-wise mitigating actions they can take to restore the facilities to within system limits or voltages to within voltage criteria. For simulated post-contingency exceedances, some operator actions are taken before the contingency occurs, while for other post-contingency exceedances, the operator relies on mitigation to be taken only if the contingency were to occur. Operators should only rely on post-contingency mitigation if they are confident that there would be sufficient time to complete the mitigation before adverse system conditions (such as instability or cascading outages) would occur.

The mere fact that an actual or real-time system operating limit is exceeded does not necessarily mean that immediate reduction below the limit is required, although it does require immediate operator action. As an example, RC operators may contact Transmission Owners to determine if a temporarily-higher rating is warranted. For a projected next- or post-contingency System Operating Limit (SOL) exceedance, if also projected to exceed an Interconnection Reliability Operating Limit (IROL, meaning that it could lead to instability, uncontrolled separation, or cascading outages that adversely

¹⁴⁴ SE constructs a representation of the state of the system using voltages, currents, and breaker status from the real-time data, and calculates values for which data are not directly collected; while RTCA runs frequently, for example, every two to six minutes for MISO and SPP, and informs the operators how the system would be affected for the computer-simulated outage or in other words used interchangeably, “for loss of” (FLO) a specific system facility such as a transmission line or a transformer.

impact the reliability of the BES), operators have a maximum of 30 minutes to take actions alleviate the IROL exceedance.¹⁴⁵ Otherwise, operators identify mitigation measures they could take as part of their operating plan, which may include measures that would be implemented prior to, or if the next contingency occurred.

To aid in monitoring and regulating power flows across the transmission system (often referred to as managing transmission “congestion”), system operators in RTO areas define “flowgates,” by pairing specific transmission facilities and their associated next contingencies that would compound the transmission facility loading if the associated next contingency occurred. In addition to RTCA, RC operators in the Eastern Interconnection possess computer-based flowgate monitoring tools, which use the shared interchange distribution calculator (IDC) to calculate percentages of power flow impacts that each interchange power transfer schedule has on each flowgate; i.e., its transfer distribution factor, or TDF. For instance, if the need arises to reduce flowgate loading to remain within system operating limits, or in other words, alleviate market “congestion”, the flowgate monitoring tool enables the operators to determine the appropriate megawatt power flow amount that can be reduced in the external market transfer to achieve this goal.

To manage the grid, the RC can take a wide-area view of all the regional resources available to it, resulting in a “dispatch stack” that contains generators from all generation-owning members of the region, including utility and non-utility Generator Owners, as well as some generation resources outside the footprint. Many utilize a security constrained economic dispatch (SCED) algorithm to determine the appropriate and least-cost generating units to dispatch at any given time depending on market conditions. SCED aids the RTOs by, among other tasks, simultaneously balancing energy injections and withdrawals, managing congestion, and ensuring adequate operating reserves. The SCED process runs every five minutes to establish dispatch instructions for generators to meet the future load of the next five-minute period. The purpose of the algorithm is to minimize the cost to meet the forecast demand, scheduled interchange, and reserve requirements while also being subject to transmission congestion and other system reliability constraints.

An initial approach to relieving transmission congestion constraints in RCs which are also RTOs is redispatching generation at different locations on the grid, done through SCED. When standard operating limits are reached, i.e., when constraints reach a

¹⁴⁵ This time is defined as the “Interconnection Reliability Operating Limit T_v ” which is the maximum time that an Interconnection Reliability Operating Limit can be violated before the risk to the interconnection or other Reliability Coordinator Area(s) becomes greater than acceptable. Each Interconnection Reliability Operating Limit’s T_v shall be less than or equal to 30 minutes.

threshold at which other resources will soon need to be dispatched, market operators/RCs proactively enter constraints into SCED to begin preparation for unanticipated system events. When system operators change the day-ahead generation dispatch schedule to accommodate constraints or unexpected transmission or generation outages, it is known as “security constrained redispatch.” If non-cost measures do not alleviate the congestion concerns, operators should utilize least-cost redispatch measures, including initiating market-to-market (M2M) redispatch procedures for reciprocally coordinated flowgates (RCFs) between RTOs, or utilizing a transmission loading relief procedure (TLR), which prioritizes the various types of transmission services, allowing system operators to cut less-firm transportation flows first.

Some RTOs that share a “seam,” or common border, including MISO and SPP, utilize the M2M coordination process between the RTOs to assist in maintaining efficient, reliable service for their respective regions. The M2M process allows for both RTOs’ RCs to coordinate interface pricing by modeling the same constraint. The previously-defined RCFs are monitored closely to gauge the impact of market flows and parallel flows from adjacent regions and markets. MISO and SPP can utilize M2M upon constraint activation in the market. During the course of the Event, MISO and SPP’s RC System Operators were in frequent communication with each other, analyzing congestion and engaging in M2M congestion management when necessary to relieve congestion on binding constraints, particularly during the early morning hours of January 17, 2018. Between the hours of 1 am and 10 am CST on January 17, MISO and SPP’s RC Operators had approximately 20 calls with each other to discuss grid issues and especially congested constraints, ultimately using M2M to alleviate congestion on several constraints.

RC Operators can issue one or more TLR(s) to curtail transmission flowgate loadings on an hour-by-hour basis. TLRs are used to ration transmission capacity when demand for the transmission is greater than the available capacity. TLRs are typically utilized when the transmission system is overloaded to the point where power flows must be reduced in order to protect the system. The rationing is done based upon a priority structure that lowers or limits the power flows based on size, contractual terms, and scheduling, as opposed to the redispatch of lowest cost generation in M2M.¹⁴⁶ This method can be used in MISO and SPP at the RC’s discretion.

¹⁴⁶ The NERC TLR Procedure is an Eastern Interconnection-wide process that allows Reliability Coordinators to mitigate potential or actual operating security limit violations while respecting transmission service reservation priorities. See <https://www.nerc.com/pa/rrm/TLR/Pages/default.aspx>

TLR Levels

TLR Levels		
TLR Level	Reliability Coordinator Action	Comments
1	Notify Reliability Coordinators of potential System Operating Limit (SOL) or Interconnection Reliability Limit (IROL) violations.	
2	Hold T transfers at present level to prevent SOL or IROL violations.	Of those transactions at or above the Curtailment Threshold, only those under existing Transmission Service reservations will be allowed to continue, and only to the level existing at the time of the hold. Transactions using Firm Point-to-Point Transmission Service are not held. See Attachment 1 to IRO-006, Section 2.2.
3a	Reallocation of Transmission Service by curtailing Interchange Transactions using Non-firm Point-to-Point Transmission Service to allow Interchange Transactions using higher priority Transmission Service.	Curtailment follows Transmission Service priorities. Higher priority transactions are enabled to start by the Reallocation process. See Attachment 1 to IRO-006, Section 2.3 and Section 6.0.
3b	Curtail Interchange Transactions using Non-firm Point-to-Point Transmission Service to mitigate an SOL or IROL violation.	Curtailment follows Transmission Service priorities. There are special considerations for handling Transactions using Firm Point-to-Point Transmission Service. See Attachment 1 to IRO-006, Section 2.4 and Section 7.0.
4	Reconfigure transmission system to allow Transactions using Firm Point-to-Point Transmission Service to continue.	There may or may not be an SOL or IROL violation. There are special considerations for handling Interchange Transactions using Firm Point-to-Point Transmission Service. See Attachment 1 to IRO-006, Section 2.5.
5a	Reallocation of Transmission Service by curtailing Interchange Transactions using Firm Point-to-Point Transmission Service on a pro rata basis to allow additional Interchange Transactions using Firm Point-to-Point.	Attempts to accommodate all Transactions using Firm Point-to-Point Transmission Service, though at a reduced ("pro rata") level. Pro forma tariff also requires curtailment/ REALLOCATION on pro rata basis with Network Integration Transmission Service and Native Load. See Attachment 1 to IRO-006, Section 2.6 and Section 6.0.
5b	Curtail Interchange Transactions using Firm Point-to-Point Transmission Service to mitigate an SOL or IROL Violation	Pro forma tariff requires curtailment on pro rata basis with Network Integration Transmission Service and Native Load. See Attachment 1 to IRO-006, Section 2.7.
6	Emergency Procedures	Could include demand-side management, re-dispatch, voltage reductions, interruptible and firm load shedding. See Attachment 1 to IRO-006, Section 2.8.
0	TLR Concluded	Restore transactions. See Attachment 1 to IRO-006, Section 2.9.

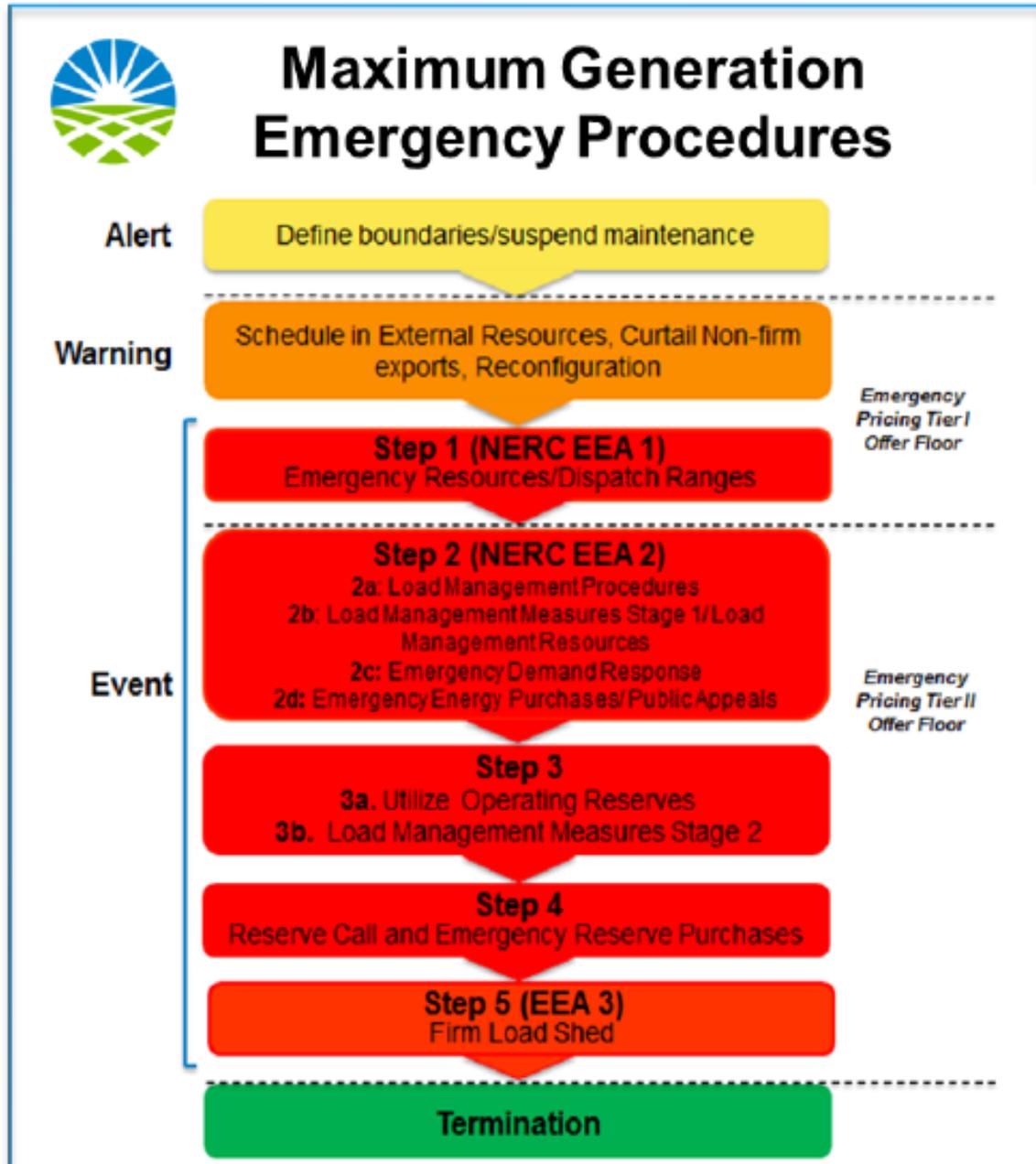
TLR VS M2M (APPLIES TO MISO-SPP)		
	TLR	M2M
Relief Calculation Granularity	Hourly	5 minute
Relief Source	Cuts lowest priority schedule	Redispatch of lowest cost generation
Data Quality	Static (except for market's reporting real-time market flow)	Real-time, sub-second
Usage	RC discretion	Upon constraint activation in market
Settlement	None	Based on Firm Flow Entitlement (FFE) usage
Regulation	NERC ORC / NAESB	JOA (FERC)

The RC operators also used transmission reconfiguration to address real-time or post-contingency overloads during this timeframe. The practice of transmission reconfiguration, which involves mitigating the overload by opening and/or a combination of opening and closing switches (i.e. breakers), is typically not the first tool an operator would use to potentially alleviate overloaded facilities, because it brings with it potential reliability tradeoffs. But it still has an important practice in maintaining system reliability

and preventing worse outcomes, like cascading and uncontrolled loss of firm load. Transmission reconfiguration is included in the TLR process as Level 4. Before using transmission reconfiguration to alleviate overloads, the operators must conduct an assessment to pre-determine that the proposed reconfiguration will not introduce other reliability issues. Issues that operators would want to avoid include other, potentially more severe, real-time or next-contingency System Operating Limit exceedances (thermal, voltage or stability) on other bulk power system facilities, unexpected or unwanted changes to specific normal or emergency operating procedure steps, and changes to the expected behavior (resulting automatic actions) of system protection schemes and/or remedial action schemes which may be needed to clear a faulted condition on the transmission system. After assessment, the operator may determine that other changes need to be made to avoid one or more of the above issues, or may determine that transmission reconfiguration is not a viable option. Some reconfigurations may have already been studied, with pre-set procedures established for certain overload conditions for which system engineers have already analyzed the above issues.

If none of the preceding actions have eliminated the transmission system conditions, operators may need to use emergency procedures, ranging from calling on Load Modifying Resources to emergency energy purchases, up to firm load shed as a last resort. The high flows throughout the Event Area, but especially in MISO and SPP, caused the system operators to use nearly all available actions, short of shedding firm load, to maintain reliability of the bulk-electric system.

The following illustration is a summary of MISO's steps found in their Maximum Generation Emergency Procedures, and how they relate to the EEA levels defined by the Reliability Standards:



Appendix D: Glossary of Terms Used In Report

Adjacent RC - A Reliability Coordinator whose Reliability Coordinator Area is interconnected with another Reliability Coordinator Area.

Alternating Current (AC) - Electric current that changes periodically in magnitude and direction with time. In power systems, the changes follow the pattern of a sine wave having a frequency of 60 cycles per second in North America. AC is also used to refer to voltage which follows a similar sine wave pattern.

Ambient Conditions - Common, prevailing, and uncontrolled atmospheric conditions at a particular location, either indoors or out. The term is often used to describe the temperature, humidity, and airflow or wind that equipment or systems are exposed to.

Asynchronous - In AC power systems, two systems are asynchronous if they are not operating at exactly the same frequency. Two systems may also be considered asynchronous if, at potential interconnection points, there is a significant difference in phase angle between their respective voltage waveforms.

Bulk Electric System - All Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy. The NERC Glossary of Terms Used in the Reliability Standards contains the list of inclusions and exclusions, and can be found at

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

Capacitor - A capacitor is a device that stores an electric charge. Although there is energy associated with the stored charge, it is negligible in terms of its capability to serve load. A capacitor bank is made of up of many individual capacitors. Its purpose is to provide reactive power to the system to help support system voltage by compensating for reactive power losses incurred in the delivery of power.

Cascading - The uncontrolled successive loss of System Elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.

Constrained System Conditions - Conditions where multiple transmission facilities (lines, transformers, breakers, etc.) are approaching, are at, or are beyond their System Operating Limits.

Conductor - In physical terms, any material, usually metallic, exhibiting a low resistance to the flow of electric current. A conductor is the opposite of an insulator. In electric power systems, the term conductor generally refers to the actual wires in overhead transmission and distribution lines, underground cables, and the metallic tubing used for busses in substations. Aluminum and copper are the predominant metals used for conductors in power systems.

Contingency - The unexpected and sudden failure or outage of a power system component, such as a generator, transmission line, transformer, or other electrical element.

Contingency Reserve - Contingency reserve is the provision of capacity deployed by a Balancing Authority to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Organization contingency requirements. Adequate generating capacity must be available at all times to maintain scheduled frequency, and avoid loss of firm load following transmission or generation contingencies. This capacity is necessary to replace capacity and energy lost due to forced outages of generation or transmission equipment.

Curtail / Curtailment - A reduction in the scheduled capacity or energy delivery of an Interchange Transaction.

Demand - 1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer.

Demand Side Management - All activities or programs undertaken by any applicable entity to achieve a reduction in Demand.

Derate - A reduction in a generating unit's net dependable capacity.

Direct Current (DC) - Electric current that is steady and does not change in either magnitude or direction with time. DC is also used to refer to voltage and, more generally, to smaller or special purpose power supply systems utilizing direct current either converted from AC, from a DC generator, from batteries, or from other sources such as solar cells.

Distribution Factor - The portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate).

Emergency - Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System.

Emergency Rating - The rating as defined by the equipment owner that specifies the level of electrical loading or output, usually expressed in megawatts (MW) or MVAR or other appropriate units, that a system, facility, or element can support, produce, or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.

Energy Emergency – A condition when a Load-Serving Entity or Balancing Authority has exhausted all other resource options and can no longer meet its expected Load obligations.

Energy Management System (EMS) - A system of computer-aided tools used by system operators to monitor, control and optimize system performance.

Export – In electric power systems, exports refer to energy that is generated in one power system, or portion of a power system, and transmitted to, and consumed in, another.

Facility - A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)

Facility Rating - The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.

Firm Load (or Firm Demand) - That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions.

Firm Transmission Service/Capacity - The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption.

Flowgate – 1) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions. 2) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System.

Force Majeure - A superior force, “act of God” or unexpected and disruptive event, which may serve to relieve a party from a contract or obligation.

Forced Outage – 1) The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons. 2) The condition in which the equipment is unavailable due to unanticipated failure.

Generation – The process of producing electrical energy from other sources of energy such as coal, natural gas, uranium, hydro power, wind, etc. More generally, generation can also refer to the amount of electric power produced, usually expressed in kilowatts (kW) or megawatts (MW) and/or the amount of electric energy produced, expressed in kilowatt hours (kWh) or megawatt hours (MWh).

Generator - Generally, a rotating electromagnetic machine used to convert mechanical power to electrical power. The large synchronous generators common in electric power systems also serve the function of voltage support and voltage regulation by supplying or withdrawing reactive power from the transmission system, as needed.

Grid - An electrical transmission and/or distribution network. Broadly, an entire interconnection.

Heat Tracing – The application of a heat source to pipes, lines, and other equipment which, in order to function properly, must be kept from freezing. Heat tracing typically takes the form of a heating element running parallel with and in direct contact with piping.

Hour Ending - Data measured on a Clock Hour basis.

Interchange – Energy transfers that cross Balancing Authority boundaries.

Interchange Distribution Calculator (IDC) - The mechanism used by Reliability Coordinators in the Eastern Interconnection to calculate the distribution of Interchange Transactions over specific Flowgates. It includes a database of all Interchange Transactions and a matrix of the Distribution Factors for the Eastern Interconnection.

Import – In electric power systems, imports refer to energy that is transmitted to, and consumed in one power system, which is generated in another power system, or portion of another power system.

Independent System Operator (ISO) - An organization responsible for the reliable operation of the power grid in a particular region and for providing open access transmission access to all market participants on a nondiscriminatory basis.

Interchange - Electrical energy transfers that cross Balancing Authority boundaries.

Interchange Schedule - An agreed-upon Interchange Transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the Source and Sink Balancing Authorities involved in the transaction.

Interconnection – A geographic area in which the operation of Bulk Power System components is synchronized such that the failure of one or more of such components may adversely affect the ability of the operators of other components within the system to maintain Reliable Operation of the Facilities within their control. When capitalized, any

one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.

Interconnection Reliability Operating Limit - A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System.

Interruptible Load - Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment.

Load - See Demand (Electric).

Load-serving – Serves the electrical demand and energy requirements of its end-use customers.

Load Shed – The reduction of electrical system load or demand by interrupting the load flow to major customers and/or distribution circuits, normally in response to system or area capacity shortages or voltage control considerations. In cases of capacity shortages, load shedding is often performed on a rotating basis, systematically and in a predetermined sequence.

Market Flow - The total amount of power flowing across a specified Facility or set of Facilities due to a market dispatch of generation internal to the market to serve load internal to the market.

Most Severe Single Contingency (MSSC) - The Balancing Contingency Event, due to a single contingency identified using system models maintained within the Reserve Sharing Group (RSG) or a Balancing Authority's area that is not part of a Reserve Sharing Group, that would result in the greatest loss (measured in MW) of resource output used by the RSG or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet Firm Demand and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the Sink Balancing Authority).

Near-Term – The time period that covers the next day to multiple days ahead of the operating day.

Operating Plan - A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.

Operating Process - A document that identifies general steps for achieving a generic operating goal. An Operating Process includes steps with options that may be selected depending upon Real-time conditions. A guideline for controlling high voltage is an example of an Operating Process.

Operational Planning Analysis - An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Operating Reserve - That capability above firm system demand required to provide for regulation, load forecasting error, forced and scheduled equipment outages, and local area protection. It consists of spinning and non-spinning reserve.

Outage – The period during which a generating unit, transmission line, or other facility is out of service. Outages are typically categorized as forced, due to unanticipated problems that render a facility unable to perform its function and/or pose a risk to personnel or to the system, or scheduled / planned for the sake of maintenance, repairs, or upgrades.

Peak Load (or Peak Demand) – 1. The highest hourly integrated Net Energy For Load within a Balancing Authority Area occurring within a given period (e.g., day, month, season, or year). 2. The highest instantaneous demand within the Balancing Authority Area.

Post-Contingency - The resulting power system conditions (determined by computer simulation, or by actual real-time data) following the unexpected and sudden failure or outage of a power system component, such as a generator, transmission line, transformer, or other electrical element.

Power - In physics, power is defined as the rate at which energy is expended to do work. In the electric power industry, power is measured in watts (W), kilowatts (1 kW = 1,000 watts), megawatts (1 MW = 1 million watts), or gigawatts (1 GW = 1 billion watts). For reference, 1 kW = 1.342 horsepower (hp).

Power System - The collective name given to the elements of the electrical system. The power system includes the generation, transmission, distribution, substations, etc. The term power system may refer to one section of a large interconnected system or to the entire interconnected system.

Power Transfer Distribution Factor - In the pre-contingency configuration of a system under study, a measure of the responsiveness or change in electrical loadings on transmission system Facilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100%) of the change in power transfer.

Rating - The operational limits of a transmission system element under a set of specified conditions. In power systems, equipment and facility power-handling ratings are usually expressed either in megawatts (MW) or in mega-volt-amperes (MVA). The term is also sometimes used to describe the output capability of generators.

Reactive Power – The portion of electricity that establishes and sustains the electric and magnetic fields of AC equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It is also needed to make up for the reactive losses incurred when power flows through transmission facilities. Reactive power is supplied primarily by generators, capacitor banks, and the natural capacitance of overhead transmission lines and underground cables (with cables contributing much more per mile than lines). It can also be supplied by static VAR converters (SVCs) and other similar equipment utilizing power electronics, as well as by synchronous condensers. Reactive power directly influences system voltage such that supplying additional reactive power increases the voltage. It is usually expressed in kilovars (KVAR) or megavars (MVAR), and is also known as “imaginary power.”

Real-Time – Bulk Electric System conditions, characteristics and/or data representing what actually occurred at specific times or timeframes during the Event.

Real-Time Assessment – An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Real-Time Contingency Analysis (RTCA) – A computer application which evaluates system conditions using real-time data to assess potential (post-contingency) operating conditions.

Regional Entity - An independent, regional entity having delegated authority from NERC to propose and enforce Reliability Standards and to otherwise promote the effective and efficient administration of bulk-power system reliability.

Regional Transmission Organization (RTO) - A voluntary organization of electric Transmission Owners, transmission users and other entities approved by FERC to

efficiently coordinate electric transmission planning (and expansion), operation, and use on a regional (and interregional) basis. Operation of transmission facilities by the RTO must be performed on a non-discriminatory basis.

Reliability Coordinator Area - The collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.

System Operator: An individual at a control center of a Balancing Authority, Transmission Operator, or Reliability Coordinator, who operates or directs the operation of the Bulk Electric System in real-time.

Stability – The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances.

State Estimator – A computer application which evaluates system conditions using real-time data to assess existing operating conditions.

Transformer - A type of electrical equipment in the power system that operates on electromagnetic principles to increase (step up) or decrease (step down) voltage.

Transmission – An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.

Transmission Line – A system of structures, wires, insulators and associated hardware that carry electric energy from one point to another in an electric power system. Lines are operated at relatively high voltages varying from 69 kV up to 765 kV, and are capable of transmitting large quantities of electricity over long distances.

Trip - This refers to the automatic disconnection of a generator or transmission line by its circuit breakers.

Voltage - The force characteristic of a separation of charge that causes electric current to flow. The symbol is “V” and units are volts or kilovolts (kV).

Wide Area - The entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits.

Appendix E: Categories of NERC Registered Entities

All registered entities fall within one or more of the following categories must register with NERC. Many entities carry out multiple roles and therefore have multiple registrations.

Function Type	Acronym	Definition/Discussion
Balancing Authority	BA	The responsible entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time.
Generator Operator	GOP	The entity that operates generating Facility(ies) and performs the functions of supplying energy and Interconnected Operations Services.
Generator Owner	GO	Entity that owns and maintains generating Facility(ies).
Planning Authority/Planning Coordinator	PA/PC	The responsible entity that coordinates and integrates transmission Facilities and service plans, resource plans, and Protection Systems.
Reliability Coordinator	RC	The entity that is the highest level of authority who is responsible for the Reliable Operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.
Transmission Operator	TOP	The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission Facilities.
Transmission Owner	TO	The entity that owns and maintains transmission Facilities.
Transmission Planner	TP	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority area.

Appendix F: Acronyms Used in the Report

AC	Alternating Current
AECI	Associated Electric Cooperative, Inc.
BA	Balancing Authority
BES	Bulk Electric System
CST	Central Standard Time
DC	Direct Current
DSM	Demand-Side Management
EEA	Energy Emergency Alert
EHV	Extra-High Voltage
EMS	Energy Management System
EOP	Emergency Operations Planning
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
FERC	Federal Energy Regulatory Commission
FRAC	Forward Reliability Assessment Commitment
GFCI	Ground Fault Circuit Interrupter
GO	Generator Owner
GOP	Generator Operator
HVDC	High Voltage Direct Current
IROL	Interconnection Operating Reliability Limit
ISO	Independent System Operator
kV	Kilovolt
LBA	Local Balancing Authority
LG&E/KU	Louisville Gas and Electric/Kentucky Utilities
LMR	Load Modifying Resources
MSSC	Most Severe Single Contingency
MISO	Midcontinent Independent System Operator, Inc.
MRO	Midwest Reliability Organization
MVA	Megavolt-Ampere
MW	Megawatt
NERC	North American Electric Reliability Corporation
OPA	Operational Planning Analysis
PC	Planning Coordinator
RC	Reliability Coordinator
RCIS	Reliability Coordinator Information System
RDT	Regional Directional Transfer
RDTL	Regional Directional Transfer Limit
RF	ReliabilityFirst Corporation
RTCA	Real-Time Contingency Analysis

RTO	Regional Transmission Organization
RTOC	Regional Transfer Operating Committee
RTOP	Regional Transfer Operating Procedure
SCED	Security Constrained Economic Dispatch
SCRD	Security Constrained Redispatch
SERC	SERC Corporation
SeRC	Southeastern Reliability Coordinator
SOL	System Operating Limit
SPP	Southwest Power Pool, Inc.
SRPBC	Sub-Regional Power Balance Constraint
TLR	Transmission Loading Relief
TO	Transmission Owner
TOP	Transmission Operator
TP	Transmission Planner
TVA	Tennessee Valley Authority
UDS	Unit Dispatch System
VSA	Voltage Stability Analysis
WECC	Western Electricity Coordinating Council
wEFOR	Weighted Equivalent Forced Outage Rate
WSC	Worst Single Contingency

Appendix G: 2011 Recommendations Regarding Preparation for Cold-Weather Events

In September, 2011, after an inquiry into the controlled shedding of 4,000 MW of firm load in Texas's ERCOT footprint, NERC and the Commission issued a group of recommendations aimed at helping other entities in warm climates avoid losing firm load when extreme cold weather strikes. Many of those recommendations are equally appropriate for this event, so we reprint them below, with minor edits as shown in italics. Supporting text has been edited to make it more broadly applicable. The numbers [may] not be sequential due to the omission of highly ERCOT-specific recommendations. We also briefly discuss actions taken in response to the recommendations.

PLANNING AND RESERVES

1. Balancing Authorities, Reliability Coordinators, Transmission Operators and Generator Owner/Operators in *summer peaking areas* should consider preparation for the winter season as critical as preparation for the summer peak season.

The large number of generating units that failed to start, tripped offline or had to be derated during the event demonstrates that the generators did not adequately anticipate the full impact of the cold weather. While plant personnel and system operators, in the main, performed admirably during the event, more thorough preparation for cold weather could potentially have prevented many of the weather-related outages. Capacity margins going into the winter were adequate on paper. But those margins did not take into account whether many of the units counted would be capable of running during the severe cold weather that materialized in mid-January. While the probability of a winter event in the predominantly summer peaking south-central U.S. appears to be low, shedding load in the winter places lives and property at risk. The task force recommends that all entities responsible for the reliability of the bulk power system in the Southwest prepare for the winter season with the same sense of urgency and priority as they prepare for the summer peak season.

2. Planning authorities should augment their winter assessments with sensitivity studies incorporating *conditions like the Event* to ensure there are sufficient generation and reserves in the operational time horizon.

All of the affected RCs undertake planning studies to ensure that sufficient reserves are available to meet seasonal peak loads. However, conditions experienced on January 17 were more severe than predicted in seasonal studies.

Planners should undertake a sensitivity study, using the 2011 actual conditions [*or another actual severe winter event*] as a possible extreme scenario that reflects expected limits on available generation. These limits would include those due to planned outages, limited operations during periods of extreme cold weather, ambient temperature operating limitations, and any likely loss of fuel sources. This sensitivity study should be used by operational planners to identify various system stress points, and by Reliability Coordinators, Balancing Authorities, and Transmission Operators to improve and refine strategies to preserve the reliability of the bulk power system during an extended cold weather event. These strategies should include procedures relating to utilization of generators with fuel switching capabilities and implementing early start-ups for generators with long start-up times.

3. Balancing Authorities and Reserve Sharing Groups should review the distribution of reserves to ensure that they are useable and deliverable during contingencies.

This recommendation is designed to ensure that Balancing Authorities take into account transmission constraints, other demands on reserve sharing resources, the possibility that more than one reserve sharing group member might experience simultaneous emergencies, and other factors that might affect the availability or deliverability of reserves.

4. This Recommendation was focused on ERCOT's specific outage request protocol, which ERCOT changed as a result of the Recommendation. Some of the supporting text may be helpful and remains below.

ISOs, RCs and TOPs should consider whether they have the authority to cancel previously approved outages in cases of approaching extreme weather conditions, even up to the time of the event itself. In making this evaluation, they should take into account the costs that would be imposed on the generator as well as the practical difficulties of returning it to service if plant components are disassembled, as well as the generator's need to perform maintenance at some point while also avoiding the high-demand summer season. In addition to the criteria for outage evaluation currently provided the report also recommended taking into consideration the potential loss of units based on weather conditions beyond their design limits, and the effects likely to result from the totality of scheduled and proposed outages.

In furtherance of these criteria, *ISOs, RCs and TOPs* should:

- Have available the design temperatures of all generation resources.
- Take into consideration as an extreme weather event approaches which plants will not be available based on their design temperature limits.

- Consider increasing reserve levels during extreme weather events.
- Commit, for purposes of serving load and being counted as reserves, only those plants whose temperature design limits fall within the forecast temperature range.
- Determine, prior to approving an outage, if the combination of previously approved scheduled outages with the proposed scheduled outages might cause reliability problems.

5. RCs and TOPs should consider *increasing* responsive reserve requirements in extreme low temperatures, (ii) *directing* generating units to utilize preoperational warming prior to anticipated severe cold weather, and (iii) *verifying* with each generating unit its preparedness for severe cold weather, including operating limits, potential fuel needs and fuel switching abilities.

ERCOT data on forced outages during the 50 coldest days between 2005-2011 show a correlation between low temperatures and forced outages. This was demonstrated not only by the February 2011 event but also by the 1989 event; in both cases, extremely low temperatures led to the loss of large amounts of generation and the implementation of rolling blackouts. Increasing the amount of responsive reserves going into a cold weather event would compensate for the probability that a number of generating units might fail, and would provide better response to system instability in the event of such losses. Additionally, pre-operational warming would help prevent freezing and identify other operational problems. Running a unit prior to the start of extreme cold weather would utilize the unit's own radiant heat to help prevent freezing. And starting it up would permit correction of any problems that otherwise would not be noticed until the unit was called upon for performance. While pre-operational warming has considerable value, issues of whether or how generators are to be compensated for taking such actions at ERCOT's direction would need to be addressed.

COORDINATION WITH GENERATOR OWNERS/OPERATORS

6. Transmission Operators, Balancing Authorities, and Generator Owner/Operators should consider developing mechanisms to verify that units that have fuel switching capabilities can periodically demonstrate those capabilities.

During the *ERCOT* cold weather event, a quarter of the 20 units that attempted to switch fuel were unsuccessful. If a unit represents itself as having fuel switching capability, verification of the adequacy of its capability would provide useful information to the Balancing Authority or Transmission Operator as to the availability of that unit in the event of natural gas curtailments. Fuel switching verification might consist of the following:

- Documented time required to switch equipment,
- Documented unit capacity while on alternate fuel,
- Operator training and experience,
- Fuel switching equipment problems, and
- Boiler and combustion control adjustments needed to operate on alternate fuel.

7. Balancing Authorities, Transmission Operators and Generator Owners/Operators should take the steps necessary to ensure that black start units can be utilized 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.

In order to ascertain actual capabilities during extreme weather conditions, Balancing Authorities and Reliability Coordinators should require Generator Owner/Operators to provide accurate ambient temperature design operating limits for each generating unit that is included in its portfolio (including the accelerated cooling effect of wind), and update them as necessary. These limits should take into account all temperature-affected generator, turbine, and boiler equipment, and associated ancillary equipment and controls. The Balancing Authorities should take steps to verify that Generator Owner/Operators comply with this requirement, and should prepare for the winter season by developing a catalog of individual generating unit temperature limitations. These should be used to determine if forecast temperatures place a particular generating unit in a high-risk category. Lastly, Balancing Authorities and Reliability Coordinators should consider the feasibility of counting on a generating unit whose rating falls below forecast weather conditions, and should consider whether to take into account weather-related design specifications in ranking units in the supply stack during critical 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.

This Recommendation previously referred to Reliability Standard TOP-002-02 R15, which is no longer in effect. Balancing Authorities and Transmission Operators could obtain similar, although perhaps not exact, results through Reliability Standard TOP-003-3, which allows Balancing Authorities and Transmission Operators to designate specific data required from entities like the Generator Owner/Operators. Doing so would allow operators to make proactive decisions prior to the onset of cold weather, including but not limited to:

- Requesting cancellation of planned outages,
- Directing advanced fuel switching,
- Directing startup of units with startup times greater than one day,
- Requesting startup of seasonally mothballed units, and
- Making advance requests for conservation.

Consideration needs to be given to ensuring that there is an adequate cost recovery mechanism in place for reliability measures taken by the generators at *the direction of the Balancing Authority or Transmission Operator.*

10. Balancing Authorities should plan ahead so that emergency enforcement discretion regarding emission limitations [from state or Federal environmental authorities] can be quickly implemented in the event of severe capacity shortages.

WINTERIZATION

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

The task force determined during its inquiry that certain generators were better prepared than others to respond to the February [2011] cold weather event. In many cases the entities that performed well had emergency operations or winterization plans in place to provide direction to employees on how to keep their units operating. Although the implementation of a winterization plan cannot guarantee that a unit will not succumb to cold weather conditions, it can reduce the likelihood of unit trips, derates and failed starts.

. . . [T]he task force recommends that planning take into account not only forecasts but also historical weather patterns, so that the required procedures accommodate

unusually severe events. Statutes should ideally direct utility commissions to develop best winterization practices for its state, and make winterization plans mandatory. Lastly, it is recommended that legislatures consider granting utility commissions the authority to impose penalties for non-compliance, as well as to require senior management to acknowledge that they have reviewed the winterization plans for their generating unit, that the plans are an accurate representation of the winterization work completed, and that they are appropriate for the unit in light of seasonal weather conditions. *In 2011*, NERC staff concluded there would be a reliability benefit from amending the EOP Reliability Standards to require Generator Owner/Operators to develop, maintain, and implement plans to winterize plants and units prior to extreme cold weather, in order to maximize generator output and availability. Accordingly, NERC intends to submit a Standard Authorization Request, the first step in the Reliability Standards development process, proposing modifications to the Reliability Standards for Emergency Preparedness and Operations. *Although NERC did submit the Standard Authorization Request, no such modification was made to the Reliability Standards.*

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.

The ideal time to prepare a generating unit to withstand cold temperatures is in the design stage. For that reason, the low temperatures and wind chills that can occur during the occasional severe storm should be incorporated in the design process.

13. The temperature design parameters of existing generating units should be assessed.

The task force found that for existing generating units, it is often not known with any specificity at what temperature the unit will be able to operate, or to what temperature heat tracing and insulation can prevent the water or moisture in its critical components from freezing. For that reason, Generator Owner/Operators should conduct engineering analyses to ascertain each unit's operating parameters, and then take appropriate steps to ensure that each unit will be able to achieve the optimum level of performance of which it is capable.

The task force recommends the following:

- Each Generator Owner/Operator should obtain or perform a comprehensive engineering analysis to identify potential freezing problems or other cold weather operational issues. The analysis should identify components/systems that have the potential to: initiate an automatic unit trip, prevent successful unit start-up, initiate automatic unit runback schemes and/or cause partial outages, adversely affect environmental controls that could cause full or partial outages, adversely affect the delivery of fuel to the units, or cause other operational problems such as slowed valve/damper operation.
- If a Generator Owner/Operator does not have accurate information about the ambient temperature to which an existing unit was designed, or if extensive modifications have been made since the unit was designed (including changes to plant site), it should obtain an engineering analysis regarding the lowest ambient temperatures at which the unit can reliably operate (including wind chill considerations).
- Each Generator Owner/Operator should ensure that its heat tracing, insulation, lagging and wind breaks are designed to maintain water temperature (in those lines with standing water) at or above 40 degrees when ambient temperature, taking into account the accelerated heat loss due to wind, falls below freezing.
- Each Generator Owner/Operator should determine the duration that it can maintain water, air, or fluid systems above freezing when offline, and have contingency plans for periods of freezing temperatures exceeding this duration.

Maintenance/inspections generally

14. Generator Owner/Operators should ensure that adequate maintenance and inspection of freeze protection elements be conducted on a timely and repetitive basis.

The task force found a number of inadequacies in generating units' preparations for winter performance. These included a lack of accountability and senior management review, lack of an adequate inspection and maintenance program, and failure to perform engineering analyses to determine the correct capability needed for their protection equipment.

The task force recommends the following:

- Each Generator Owner/Operator's senior management should establish policies that make winter preparation a priority each fall, establish personnel accountability and audit procedures, and reinforce the policies annually.

- Each Generator Owner/Operator should develop a winter preventive maintenance program for its freeze protection elements, which should specify inspection and testing intervals both before and during the winter. At the end of winter, an additional round of inspections and testing should be performed and an evaluation made of freeze protection performance, in order to identify potential improvements, required maintenance, and freeze protection component replacement for the following winter season.
- Each Generator Owner/Operator should prioritize repairs identified by the inspection and testing the proper functioning of freeze protection systems will be completed before the following winter.
- Each Generator Owner/Operator should use the recommended comprehensive engineering analysis, combined with previous lessons learned, to prepare and update a winter preparation checklist. Generator Owner/Operators should update checklists annually, using the previous winter's lessons learned and industry best practices.

Specific Freeze Protection Maintenance Items

The task force found that many generating units tripped, were derated, or failed to start as a result of problems associated with a failure to install and maintain adequate freeze protection systems and equipment. Based on these findings, on an examination of freeze protection systems of many of the affected generating units, and in some case on standards issued by the Institute of Electrical and Electronics Engineers, the task force has prepared a number of recommendations designed to prevent a repeat of the spotty generator performance experienced during the February cold weather event. Of course, specific actions should conform to best industry practices at the time improvements are made, as well as to the requirements of any mandatory winterization standards imposed by regulatory or legislative bodies.

Heat tracing

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

Specifically, the task force recommends:

- Each Generator Owner/Operator should, before each winter begins and before forecast freezing weather, inspect the power supply to all heat trace circuits, including all breakers and fuses.

- Each Generator Owner/Operator should, before each winter begins and before forecast freezing weather, inspect the continuity of all heat trace circuits, check the integrity of all connections in the heat trace circuits, and ensure that all insulation on heat traces is intact. This inspection should include checking for loose connections, broken wires, corrosion, and other damage to the integrity of electrical insulation which could cause grounds.
- Each Generator Owner/Operator should, before each winter begins, inspect, test, and maintain all heat trace controls or monitoring devices for proper operation, including but not limited to thermostats, local and remote alarms, lights, and monitoring cabinet heaters.
- Each Generator Owner/Operator should, before each winter begins, test the amperage and voltage for its heat tracing circuits and calculate whether the circuits are producing the output specified in the design criteria, and maintain or repair the circuits as needed.
- Each Generator Owner/Operator should be aware of the intended useful life of its heat tracing equipment and should plan for its replacement in accordance with the manufacturer's recommendations.

Thermal Insulation

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

Specifically, the task force recommends:

- Each Generator Owner/Operator should, before each winter begins, inspect all accessible thermal insulation and verify that there are no cuts, tears, or holes in the insulation, or evidence of degradation.
- Each Generator Owner/Operator should require visual inspection of thermal insulation for damage after repairs or maintenance have been conducted in the vicinity of the insulation.
- Each Generator Owner/Operator should ensure that valves and connections are insulated to the same temperature specifications as the piping connected to it.
- Each Generator Owner/Operator should be aware of the intended useful life of the insulation of water lines and should plan for its replacement in accordance with the manufacturer's recommendations.

Use of Wind breaks/enclosures

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

Specifically, the task force recommends:

- A separate engineering assessment should be performed for each generating unit to determine the proper placement of temporary and/or permanent wind breaks or enclosures to protect and prevent freezing of critical and vulnerable elements during extreme weather.
- Temporary wind breaks should be designed to withstand high winds, and should be fabricated and installed before extreme weather begins.
- Generator Owner/Operators should take into account the fact that sustained winds and/or low temperatures can result in heat loss and freezing even in enclosed or semi-enclosed areas.

Training

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

Operator training should include awareness of the capabilities and limitations of the freeze protection monitoring system, proper methods to check insulation integrity and the reliability and output of heat tracing, and prioritization of repair orders when problems are discovered.

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.

Specifically, the task force recommends:

- Each Generator Owner/Operator should maintain a sufficient inventory of supplies at each generating unit necessary for extreme weather preparations and operations.

- Each Generator Owner/Operator should place thermometers in rooms containing equipment sensitive to cold and in freeze protection enclosures to ensure that temperature is being maintained above freezing and to determine the need for additional heaters or other freeze protection.
- During extreme cold weather events, each Generator Owner/Operator should schedule additional personnel for around-the-clock coverage.
- Each Generator Owner/Operator should evaluate whether it has sufficient electrical circuits and capacity to operate portable heaters, and perform preventive maintenance on all portable heaters prior to cold weather.
- Each Generator Owner/Operator should drain any non-critical service water lines in anticipation of severe cold weather.

Transmission Facilities

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

Transmission Operators reported several incidents of unplanned outages during the February 2011 event as a result of circuit breaker trips, transformer trips, and other transmission line issues. Although these outages did not generally contribute materially to any transmission limitations, some transmission breaker outages did lead to the loss of generating units. Many breaker trips were the result of low air in the breaker, low sulfur hexa-fluoride (SF₆) gas pressure, failed or inadequate heaters, bad contacts, and gas leaks.

Specifically, the task force recommends:

- Transmission Owner/Operators should ensure that the SF₆ gas in breakers and metering and other electrical equipment is at the correct pressure and temperature to operate safely during extreme cold, and also perform annual maintenance that tests SF₆ breaker heaters and supporting circuitry to assure that they are functional.
- Transmission Owner/Operators should maintain the operation of power transformers in cold temperatures by checking heaters in the control cabinets, verifying that main tank oil levels are appropriate for the actual oil temperature, checking bushing oil levels, and checking the nitrogen pressure if necessary.
- Transmission Owner/Operators should determine the ambient temperature to which their equipment, including fire protection systems, is protected (taking

into account the accelerated cooling effect of wind), and ensure that temperature requirements are met during operations

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.

The task force's review of incidents during the event, as well as of operating procedures and protocols in place at the time, indicated that critical employees such as operators had numerous responsibilities that, while manageable in non-emergency situations, could prove impossible to meet during the often-compressed time frame of an emergency situation. In at least one instance, overloading a single on-call operations representative appears to have led to a delay in making emergency power purchases.

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.

Keeping gas production facilities in service is critical to maintaining an adequate supply of natural gas, particularly in the Southwest where there is a relatively small amount of underground gas storage. And keeping electric-powered compressors running can be important in maintaining adequate pressure in gas transmission lines.

The task force suggests that a review of curtailment priorities be made, to consider whether gas production facilities should be treated as protected loads in the event of load shedding.

26. Transmission Operators should train operators in proper load shedding procedures and conduct periodic drills to maintain their load shedding skills.

The task force found that at least one Transmission Operator in WECC experienced a minor delay in initiating its load shedding sequence, due to problems notifying the concerned Distribution Provider. Another Transmission Operator experienced delay in executing its load shedding because the individual operators had never shed load before and had not had recent drills. These incidents underscore the necessity of adequate training in load shedding procedures.

Actions taken in Texas following 2011 Recommendations

Following the issuance of FERC and NERC’s guidance in the February 2011 Cold Weather Report, Texas regulators and lawmakers took affirmative action to investigate and improve industry practices during extreme weather events. In that Report, FERC and NERC made several recommendations directed at improving reliability during extreme weather events, including recommending the assessment of whether minimum standards should be adopted for the winterization of gas production and processing facilities and assessments related to the priority and efficiency of natural gas curtailments.¹⁴⁷

The Texas Public Utility Commission (Texas PUC) required utilities to strengthen their emergency preparedness plans and to ensure those plans included provisions for severe cold weather. The Texas PUC amended its Electric Service Emergency Operations Plans regulation (16 T.A.C. § 25.53) to require that electric generation utilities’ emergency operations plans (filed with the Texas PUC) include “a plan for identification of potentially severe weather events, including . . . severely cold weather,” a plan for “the inventory of pre-arranged supplies for emergencies,” a plan addressing “staffing during severe weather events,” “checklists for generating facility personnel to address emergency events,” and a plan for “alternative fuel testing if the facility has the ability to utilize alternative fuels.” 16 T.A.C. § 25.53(c)(2)(D-G, I) (2018).

The Texas PUC also commissioned a third-party report on best practices for extreme weather preparedness. This report, published in September 2012, made additional recommendations regarding the identification and awareness of extreme weather events, the identification and understanding of critical failure points within plants and adequate staffing levels, and training for such events, and was submitted to the Texas state legislature.

Together, the Texas PUC, the Railroad Commission of Texas, and the Texas State Energy Conservation Office collaborated on an Energy Assurance Plan that was published in November 2012.¹⁴⁸ This Plan demonstrated the thoughtful engagement of these entities on reliability issues surrounding extreme weather events. It included evaluating updates to the 1973 gas curtailment plan and potentially refining the Texas PUC’s list of its critical nodes. Additionally, as part of the Plan, ERCOT engaged a third party to conduct a gas curtailment risk study.

¹⁴⁷ 2011 Report at 214-17.

¹⁴⁸ Texas Energy Assurance Plan, Nov. 2012, found at https://www.puc.texas.gov/industry/electric/reports/energy_assurance/Energy_Assurance_Plan-Texas.pdf (last accessed April 9, 2019).

Appendix H: Source of Figures Used in Report

Figure No.	Title	Created By	Source of Data
1	January 17, 2018 Event Area – Low Temperature Deviation from the Normal Daily Minimum	Commission Staff	NOAA weather data, prepared using ABB Ventyx Velocity Suite© software
2	MISO and SPP RTO Footprints	MISO and SPP	SEAMS WHITE PAPER FOR ORGANIZATION OF MISO STATES (OMS) AND SPP REGIONAL STATE COMMITTEE (RSC) LIAISON COMMITTEE (November 2, 2018) (https://www.spp.org/documents/59006/spp-miso_rsc_oms_response_spp_miso_final_v3.pdf), used by permission from Organization of MISO States.
3	Tie Lines Between MISO and SPP RC Versus Within MISO	Commission Staff	Data provided by entities, prepared using MS® Office 2013
4	Electric Transmission Lines and Cities within the Event Area	Commission Staff	Data provided by entities, prepared using ABB Ventyx Velocity Suite© software
5	MISO Midwest to MISO South Intra-Market Regional Directional Transfers (RDT)	Entities, Commission Staff	Illustration provided by entities, with additional graphics added using MS® Office 2013
6	Upcoming Season Forecast 2017/2018	Commission Staff	Data provided by entities, prepared using MS® Office 2013

	Winter Peak Loads		
7	Generation Capacity Data by Fuel Type	Commission Staff	NERC 2017-2018 Winter Reliability Assessment Resource Adequacy Data – Existing On-Peak Generation (https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_11202017_%20Final.pdf), and other publicly-available data, prepared using MS® Office 2013
8	Enclosed coal fired power plant in the northeastern United States	Previously obtained permission for publication	“Appendix: Power Plant Design for Ambient Weather Conditions” to the joint Commission/NERC Staff Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011: Causes and Recommendations
9	Non-enclosed coal fired power plant in the northeastern United States	Previously obtained permission for publication	“Appendix: Power Plant Design for Ambient Weather Conditions” to the joint Commission/NERC Staff Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011: Causes and Recommendations
10	MISO’s Near-term Peak Load Forecasts and Percent Error for MISO South: 5-day, 4-day, 3-day, 2-day, and 1-day ahead of January 17, 2018	Commission Staff	Data provided by entities, prepared using MS® Office 2013
11	MISO’s High and Low Temperature Forecasts Used in MISO South Load Forecasts:	Commission Staff	Data provided by entities, prepared using MS® Office 2013

	5-day, 4-day, 3-day, 2-day, 1-day ahead of January 17, 2018		
12	Event Area Approximate Planned and Unplanned Generation Outages, at the Start of January 15, and January 17, 2018	Commission Staff	Data provided by entities, prepared using MS® Office 2013
13	MISO South Region Forecasted Peak Load for January 17, 2018 and Available Generation, at the Start of January 15, 2018	Commission Staff	Data provided by entities, prepared using MS® Office 2013
14	Total Generation Losses Within the Event Area, Beginning January 17, by RC Footprint	Commission Staff	Data provided by entities, prepared using ABB Ventyx Velocity Suite© software and MS® Office 2013
15	Declarations Made by MISO in Preparation for January 17 and 18	Commission Staff	Data provided by entities, prepared using MS® Office 2013
16	Comparison of Transmission Planning Voltage Criteria (Percent) – Low	Commission Staff	Data provided by entities, and publicly-available information, prepared using MS® Office 2013

	Limits for Relevant Entities in the Event Area		
17	Comparison of Actual Highs and Lows to Average Daily High and Low Temperatures, January 16 through January 18, 2018	NERC Staff	NOAA weather data
18	January 17, 2018 Peak Loads for Relevant Entities	Commission Staff	Data provided by entities, prepared using MS® Office 2013
19	January 17, 2018 System Loads and Average Event Area Temp.	Commission Staff	Data provided by entities, and NOAA weather data, prepared using MS® Office 2013
20	Total Generation Losses Within the Event Area, Beginning January 17, by Approximate Geographical Area	Commission Staff	Data provided by entities, prepared using ABB Ventyx Velocity Suite© software and MS® Office 2013
21	January 15-19, 2018 – Number of Generation Unit Losses Versus Temperature, by Hour, for Event Area	Commission Staff	Data provided by entities, prepared using MS® Office 2013, and Analysis ToolPak
22	Total Unavailable Generation Over	Commission Staff	Data provided by entities, prepared using MS® Office 2013

	Time, for January 17, 2018, by RC Footprint		
23	MISO South Region Approximate Generation Outages and Derates January 17, 2018, by 8am Central Time	Commission Staff	Data provided by entities, prepared using MS® Office 2013
24	Total Incremental Unavailable Generation in the Event Area for January 17, 2018	Commission Staff	Data provided by entities, prepared using MS® Office 2013
25	By 2am CST – BES Transmission Congestion Began to Occur	Commission Staff	Data provided by entities, prepared using ABB Ventyx Velocity Suite© software and MS® Office 2013
26	MISO Wind Forecast Versus Actual for Winter 2017-2018	MISO Market Monitor, Potomac Economics. Used by permission.	https://www.potomaceconomics.com/wp-content/uploads/2018/03/IMM-Quarterly-Report_Winter-2018_final.pdf Slide 28
27	By 6 a.m. CST – Unplanned Outages, Total and as a Percentage of Event Sub-Area Capacity	Commission Staff	Data provided by entities, prepared using ABB Ventyx Velocity Suite© software and MS® Office 2013
28	By 6am CST, Total Generation Outages and	Commission Staff	Data provided by entities, prepared using ABB Ventyx Velocity Suite© software and MS® Office 2013

	Derates Within the Event Area, by Approximate Geographical Area		
29	By 4 a.m. CST – Numerous Additional Transmission Constraints for Wide-Area of South Central U.S.	Commission Staff	Data provided by entities, prepared using ABB Ventyx Velocity Suite© software and MS® Office 2013
30	By 6am Central – Further Transmission Constraints Occurring for Wide-Area of South Central U.S.	Commission Staff	Data provided by entities, prepared using ABB Ventyx Velocity Suite© software and MS® Office 2013
31	5am Central: Decrease in Southwestern-to-Southeastern Oklahoma 345kV Bus Voltages, Early Morning Hours of January 17, 2018	Commission Staff	Data provided by entities, prepared using MS® Office 2013
32	MISO Regional Dispatch Transfer – January 17, 2018	Entities, Commission Staff	Illustration provided by entities, with additional graphics added using MS® Office 2013
33	6am Central: Further Decrease in Southwestern-to-Southeastern Oklahoma 345kV Bus Per	Commission Staff	Data provided by entities, prepared using MS® Office 2013

	Unit Voltages, Early Morning Hours of January 17, 2018		
34	BES Pre-Contingency Voltage Conditions (P.U.) for Select EHV Buses, January 17, 2018, Approximately 6am CST	Commission Staff	Data provided by entities, prepared using ABB Ventyx Velocity Suite© software and MS® Office 2013
35	BES Voltage Conditions (P.U.) for High Voltage Buses below Normal (Pre-Contingency) Limits, January 17, 2018, Approximately 6am CST	Commission Staff	Data provided by entities, prepared using ABB Ventyx Velocity Suite© software and MS® Office 2013
36	BES Post-Contingency Range of Voltages below Limits for Buses in MISO South, January 17, 2018, at Approximately 06:30am CST, for the Simulated Outage of the MISO South WSC	Commission Staff	Data provided by entities, prepared using MS® Office 2013
37	BES Post-Contingency	Commission Staff	Data provided by entities, prepared using ABB Ventyx

	Voltage Conditions (P.U.) Below Limits for EHV Buses in MISO South, January 17, 2018, at Approximately 06:30am CST, for the Simulated Outage of the MISO South WSC		Velocity Suite© software and MS® Office 2013
38	10am CST: Improvement in Southwestern-to-Southeastern Oklahoma 345 kV per unit Bus Voltages, Early Morning, January 17, 2018	Commission Staff	Data provided by entities, prepared using MS® Office 2013
39	MISO and SPP Wind Output, January 16 through 19, 2018	Entities, Commission Staff	Illustration provided by entities, with additional graphics added using MS® Office 2013
40	January 15-19, 2018 - Causes of Unplanned Generation Outages and Derates for Event Area	Commission Staff	Data provided by entities, prepared using MS® Office 2013, and Stata® Software
41	January 15-19, 2018 – Sub-causes for Unplanned Generation Outages and Derates due to	Commission Staff	Data provided by entities, prepared using MS® Office 2013, and Stata® Software

	Freezing Issues, for Event Area		
42	January 17, 2018 - Causes of Generation Outages for Event Area, By RC	Commission Staff	Data provided by entities, prepared using MS® Office 2013, and Stata® Software
43	January 17, 2018 – Causes of Unplanned Generation Outages and Derates for Event Area	Commission Staff	Data provided by entities, prepared using MS® Office 2013, and Stata® Software
44	January 17, 2018 – Sub-causes for Unplanned Generation Outages and Derates due to Fuel Supply Problems, for Event Area	Commission Staff	Data provided by entities, prepared using MS® Office 2013, and Stata® Software
45	January 17, 2018 – Sub-causes for Unplanned Generation Outages and Derates due to Freezing Issues, for Event Area	Commission Staff	Data provided by entities, prepared using MS® Office 2013, and Stata® Software
46	January 15-19, 2018 – Sub-causes for Unplanned Generation Outages and Derates due to Fuel Supply	Commission Staff	Data provided by entities, prepared using MS® Office 2013, and Stata® Software

	Problems, for Event Area		
47	January 15-19, 2018 – Fuel Type for Unplanned Generation Outages and Derates due to Freezing Issues, for Event Area (by Number of Generators)	Commission Staff	Data provided by entities, prepared using MS® Office 2013, and Stata® Software
48	January 15-19, 2018 – Fuel Type for Unplanned Generation Outages and Derates due to Freezing Issues, for Event Area (by MW of Generation)	Commission Staff	Data provided by entities, prepared using MS® Office 2013, and Stata® Software

Appendix I: Regional Transfer Operating Committee Event Review Report (September 9, 2018)

Date Prepared: Original Draft - 02/05/2018 and finalized – 09/07/2018

Prepared By: Regional Transfer Operating Committee (RTOC)¹

Date of Event: 01/17/2018 – 01/18/2018

Party Requesting the Review: Regional Transfer Operating Committee (RTOC)

Event Summary:

MISO Reliability Coordinator Area

On 01/17/2018 and 01/18/2018 MISO and its members managed operations during a period of record cold in the MISO South Region. Record low temperatures in the MISO South region drove significantly higher load than normal for January, see Figure 1. MISO South region peak load of 32.1 GW on January 17th was only 2% lower than the region’s all-time peak of 32.7 GW set in August 2015. Operating conditions were further complicated by a significant number of unplanned generator outages and de-rates in real time. A total of 4.5 GW of generation was lost overnight on January 16th and into the morning of January 17th.

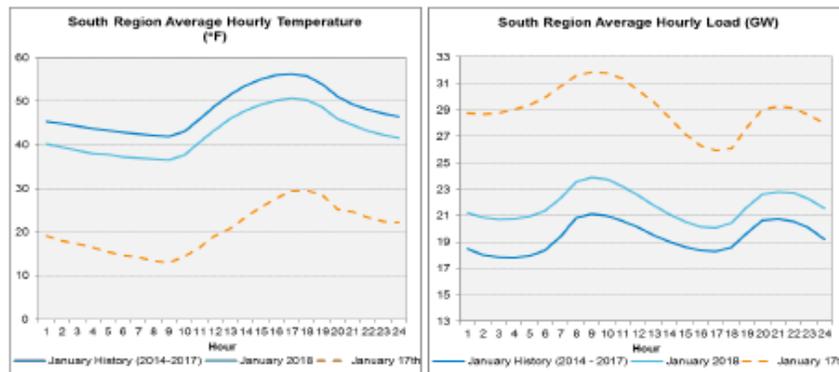


Figure 1. MISO South Region Temperature and Load

Prior to the morning of January 17th MISO issued Conservative Operations and Cold Weather Alerts allowing MISO to commit all available resources and restore all possible transmission outages. Due to significant forced generator outages MISO advanced to Maximum Generation Event Step 2c/d on the morning of January 17th. MISO took all action short of load shed to maintain reliability, including emergency generation, load management, and emergency energy purchases from neighboring Reliability Coordinators. The amount of Load Modifying Resources deployed was 700 MW on the 17th and 930 MW on the 18th. Ultimately what helped MISO avoid shedding load on the morning of January 17 was the emergency energy purchases from neighbors, which were acquired from Georgia System Operations Corp. (150 MW), Southern Co. (700 MW) and TVA (300 MW).

¹ RTOC is a six-member committee comprising two designated representatives for MISO, SPP and the Joint Parties. Joint Parties include: AECL, LG&E/KU, PowerSouth, Southern Co., and TVA.

On the morning of January 17th due to load conditions and the significant number of forced generation outages in the MISO South Region, the Regional Directional Transfer (RDT) flow² between the MISO North and Central regions and MISO South region exceeded the North-South Regional Directional Transfer Limit (RDTL)³ of 3,000 MW, with a maximum exceedance during this timeframe of 936 MW. During this event there was a divergence between the calculated values of the Regional Directional Transfer using MISO UDS data and transfer values based on state estimator data.⁴ As shown in Figure 2 below there were periods over January 17 and 18 where the transfer values based on state estimator data (blue line) exceeded 3,000 MW with a maximum value of 4,331 MW on the morning of January 17, while the RDT flow (green line) calculation using UDS showed exceeding 3,000 MW from 0635-0745 EST on January 17. Subsequent examination indicates that the key drivers for the observed divergence between these calculated transfer flows (UDS versus state estimator data) were largely due to differences in actual and forecasted load.

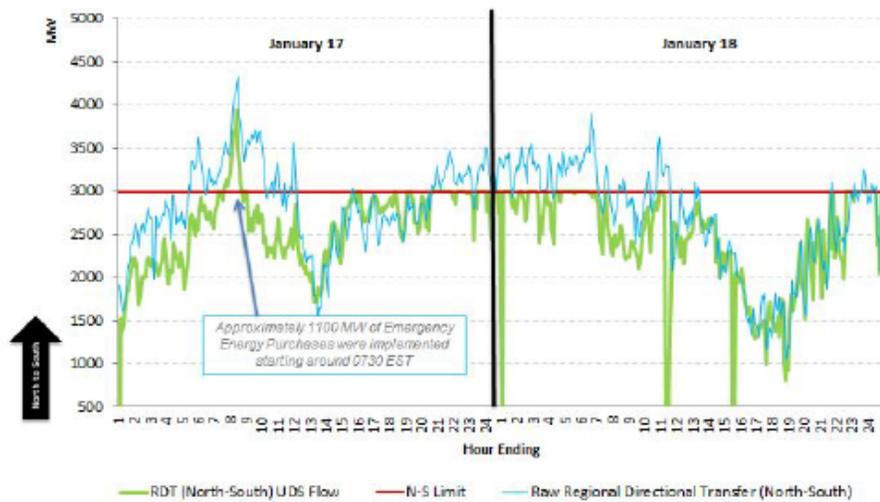


Figure 2. January 17-18 Regional Directional Transfer Values (UDS vs. State Estimator)

² RDT flow is a calculated value defined in the Settlement Agreement entered into between MISO, SPP, and the Joint Parties (AECI, LG&E/KU, PowerSouth, Southern Co., and TVA). The RDT flow calculation at a high-level includes three components to determine the amount and direction of flows between the MISO North and MISO South regions: 1) MISO South region total generation and total load balance; 2) transactions between MISO South and physically connected entities; and 3) pseudo-tie generation flow. The RDT flow is calculated by MISO using data from the latest MISO Unit Dispatch System (UDS) case in accordance with the Settlement Agreement, which represents where load and generation is forecasted to be in the next five-minutes. The results using UDS are intended to serve as a representative proxy for actual flows.

³ RDTL amount of 3,000 MW for transfers from MISO North to South is defined in the Settlement Agreement, and states if the limit is exceeded that MISO will take action consistent with Good Utility Practice to return RDT flow to the limit within 30 minutes.

⁴ The state estimator based transfer flow (blue line in Figure 2) is calculated using real-time load and generation telemetered values instead of data sourced from MISO's Unit Dispatch System.

SPP Reliability Coordinator Area

SPP RC issued a Cold Weather Alert that was in effect from January 15th until 11:00 on the 18th. Loading for SPP RC on January 17th resulted in a new winter peak of 43.5 GW. Due to the high loads in SPP and neighboring systems, combined with the high MISO North to South RDT flows, SPP had numerous flowgates that were above their SOL on a post-contingent basis, and even had some flowgates where SPP and the Transmission Operators (TOP) were depending on post-contingent load shed plans to mitigate the SOL exceedance. In addition to post-contingent exceedances, SPP experienced real-time loading on line sections and was forced to reconfigure transmission to mitigate loading on these elements. SPP also experienced voltage issues during this period in the northeast Oklahoma and Southwest Missouri areas.

To reliably manage SPP's SOL exceedances and low voltages observed on Jan 17th, SPP put into place post-contingent reconfiguration and load-shed plans, in addition to utilizing market redispatch, additional resource commitments, and other pre- and post-contingent manual actions. As a result of these actions, SPP operators were able to maintain reliability for the SPP footprint while also supporting the reliability of neighboring systems. SPP's review of the events of Jan 17th does not indicate any violation of NERC reliability standards for SPP or our members. Additionally SPP remains committed to working with neighboring RCs to improve operational practices and assistance procedures during extreme weather events.

TVA Reliability Coordinator Area

Prior to the excessive RDTF flow, TVA-RC was experiencing heavy loading in all the TVA-RC TOP footprints, and had several N-1 contingencies in the RC footprint that were being mitigated through TVA's normal congestion management processes, and had been planned for during the prior day's Next-Day Analysis. During the excessive high flows from the RDTF, the normal congestion management processes ceased to be effective, resulting in TVA-RC resorting to post-contingency emergency load shed as its only actionable response for numerous mitigations of N-1 contingencies. TVA-RC also had several real-time overloads that had to be mitigated, resulting in additional N-1 overloads during the excessive RDTF flow. TVA was in communication with MISO throughout the morning, and asked MISO to reduce the RDTF as a direct result to the numerous N-1 contingencies.

During this time the TVA BA issued a Conservative Operations Alert and asked for public conservation due to the expected high loads. On the morning of January 17th TVA in response to MISO's request provided 300 MW of emergency energy to Entergy. Starting on January 17th MISO called a TLR 3 [REDACTED], cutting 1000+ MW non-firm flows into TVA, resulting in an EEA 1 for TVA. This TLR was kept active for 30 hours due to on-going concerns by the MISO RC with overloading if the TLR was closed.

Southeastern Reliability Coordinator Area

Southeastern RC also experienced high flows across its system due to heavy cold weather loads and RDT flow but was able to manage the constraints due to the dynamic facility ratings associated with the low temperatures and redispatch of resources in the Southeastern RC footprint. PowerSouth declared an EEA 1 at 05:38 on the 17th due to all resources being deployed. On the morning of January 17th Southern Company, in response to MISO's request, provided 700 MW of emergency energy and facilitated the purchase of another 150 MW from Georgia System Operations Corp.

The SeRC did not experience any SOL or IROL exceedances on January 17th. However, if there were a potential SOL/IROL exceedance, the SeRC would have implemented its congestion management procedures, up to and including, issuing an Operating Instruction to MISO to reduce their real time dispatch flow. Review of the events of January 17th did not identify any NERC Reliability Standards violations for the SeRC or any of the members in the SeRC footprint.

Lessons Learned/Follow Up Items:

MISO, SPP, TVA, and Southeastern Reliability Coordinators met on 3/15/18 and the RTOC met on 6/7/18, 7/26/18, 8/30/18 to review the event, and to discuss lessons learned and potential coordination enhancements. RTOC members are actively collaborating on the following items:

Action Items	Status
1) Schedule follow up discussions between the collective RCs to address reliability concerns associated with use, and management, of as available, non-firm RDT flows between 1000MW and the RDTL.	Representatives of the RCs met on 3/15/18 and as part of the RTOC on 6/7/18, 7/26/18, and 8/30/18. At the 8/30/18 meeting each RC provided an overview of their emergency procedures.
2) Enhance communications among Reliability Coordinators during and prior to emergency events.	1) MISO has provided SPP and the Joint Parties the process to sign-up for MISO's real-time and market notification emails MISO uses to communicate system conditions.
3) Clarify expectations for normal operations and extreme events where BAs/RCs are forced to implement redispatch, reconfiguration or manual load shed to maintain reliability when RDT flows are in excess of 1000 MWs.	2) Anticipate items 2 and 3 will be addressed as part of enhancements to the existing Regional Transfer Operating Procedure among MISO, SPP, and the Joint Parties. 4) Procedures for normal operations and extreme events under development. 4) Goal is to have the enhanced procedures finalized no later than November 1, 2018 in advance of the winter season.
4) Refine processes used to manage reserve levels in MISO South Region to mitigate potential RTDL exceedances.	1) MISO made a FERC filing (ER18-1464) on April 27, 2018 to allow for the MISO reserve procurement process to take into account regional transfer constraints. 2) Filing was accepted by FERC on August 23, 2018 with an effective date of August 26, 2018. 3) MISO is developing a process to share forecasted regional transfers with SPP, TVA, and Southeastern RCs.

Action Items	Status
5) Better alignment of UDS and State Estimator RDT flow values. Explore alternatives to using UDS versus State Estimator calculated RDT for real time operations.	1) MISO has identified the likely causes of the divergence between UDS and State Estimator calculated regional transfer values. 2) First fix scheduled to be implemented by MISO in mid-September, which will modify the load measurement value used in UDS to better align with State Estimator loads. 3) MISO to create metrics to monitor alignment performance and will report out to SPP/JPs in December.
6) Review usage of the TLR process on January 17/18 and address concerns that MISO's "as-available non-firm" flows appeared to have higher priority than tagged non-firm service and apply lessons learned to future TLRs.	1) Discussed at RTOC meeting on 6/7 and 7/30. 2) MISO has discussed with operators the use of TLR on January 17/18 and areas for improvement.
7) Enhance processes for acquiring/delivering emergency energy. Develop and implement a plan for collective Reliability Coordinator drills to exercise Emergency Energy transfers.	1) MISO has developed a training plan for emergency energy purchases. 2) Working with SPP and Joint Parties to schedule a tabletop exercise on emergency energy purchases in September. 3) MISO working on establishing a drill cadence on emergency energy purchases with each neighboring BA.
8) Enhance IDC process to calculate RDT flow impacts on flowgates.	1) IDC Working Group has assigned a sub-group to work on this action item. 2) MISO is developing a tool to calculate the impact of RDT flow on flowgates. Targeting having available for testing by IDC sub-group by mid-September.

In addition to the lessons learned items being addressed by MISO, SPP, and the Joint Parties as part of the Regional Transfer Operating Committee MISO is continuing to evaluate our system's winter readiness and opportunities to improve. MISO's winter readiness process today includes such items as: 1) winter readiness workshop, fuel survey, winterization guidelines for resources that were all enhanced as part of the lessons learned from the 2014 polar vortex. MISO also has kicked-off discussions with stakeholders to evaluate resource availability and need to ensure energy is available every hour of the year. This discussion will continue in 2019.³

³ MISO RAN Issues Statement Whitepaper:
<https://cdn.misoenergy.org/20180405%20RSC%20Item%2007%20RAN%20Issues%20Statement%20White%20Paper164746.pdf>

FERC and NERC Staff Report July 2019

This report was prepared by the staff of the Federal Energy Regulatory Commission in consultation with staff from the North American Electric Reliability Corporation and its Regional Entities.

This report does not necessarily reflect the views of the Commission.

