- Low system-wide offer cap (LCAP)
- Lubbock Power and Light (LP&L)
- Market Design Blueprint (Blueprint)
- Marginal Effective Load Carrying Capability (MELCC)
- Megawatt-hour (MWh)
- Megawatts (MWs)
- Midcontinent Independent System Operator (MISO)
- Minimum Contingency Level (MCL)
- Municipally owned utilities (MOUs)
- Nodal Protocol Revision Requests (NPRRs)
- Non-Spinning Reserve Service (Non-Spin Reserve)
- North American Electric Reliability Corporation (NERC)
- Office of Public Engagement (OPE)
- Office of the Attorney General (OAG)
- Operating Reserve Demand Curve (ORDC)
- Organization of MISO States (OMS)
- Performance Credit Mechanism (PCM)
- Physical Responsive Capability (PRC)
- Provider of Last Resort (POLR)
- Public Utility Commission of Texas (PUCT)
- Public Utility Regulatory Act (PURA)
- Qualified Scheduling Entity (QSE)
- Railroad Commission of Texas (RRC)
- Regional State Committee (RSC)
- Regional Transmission Organization (RTO)
- Retail electric providers (REPs)
- Rules and Projects Division (RAP)
- Sale, transfer, or merger (STM)
- Seasonal Assessment of Resource Adequacy (SARA Report)
- Senate Bill (SB)
- Service Provider Certificate of Operating Authority (SPCOA)
- Small and Rural ILEC Universal Service Plan (SRIUSP)
- Southwest Power Pool (SPP)
- Southwestern Electric Power Company (SWEPCO)
- Southwestern Public Service Company (SPS/Xcel)
- Specialized Telecommunications Assistance Program (STAP)
- State-Issued Certificate of Franchise Authority (SICFA)
- Streamlined Expedited Release (SER)

- System Improvement Charge (SIC)
- System Wide Offer Cap (SWOC)
- Technical Advisory Committee (the TA Committee)
- Texas Commission on Environmental Quality (TCEQ)
- Texas Department of Public Safety (DPS)
- Texas Division of Emergency Management (TDEM)
- Texas Energy Reliability Council (TERC)
- Texas High-Cost Universal Service Plan (THCUSP)
- Texas Telephone Association (TTA)
- Texas Universal Service Fund (TUSF)
- Texas Water Code (TWC)
- the Electric Reliability council of Texas (ERCOT)
- the Institute of Electrical and Electronic Engineers (IEEE)
- the National Association of Regulatory Utility Commissioners (NARUC)

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Texas Universal Service Fund Report – August 31, 2022

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Texas Electricity Supply Chain Security and Mapping Committee

Mapping Report

January 2022

MAPPING REPORT

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MAPPING REPORT OF THE TEXAS ELECTRICITY SUPPLY CHAIN SECURITY AND MAPPING COMMITTEE

I. Introduction

As part of SB 3, the Legislature created the Texas Electricity Supply Chain Security and Mapping Committee (the Committee). The Committee is composed of the executive director of the Public Utility Commission of Texas (PUCT), the executive director of the Railroad Commission of Texas (RRC), the chief of the Texas Division of Emergency Management (TDEM) and the president and chief executive officer of the Electric Reliability Council of Texas, Inc. (ERCOT).[1] The executive director of the PUCT serves as the chair of the Committee. Among other things, the Committee is charged with mapping the electricity supply chain in Texas and identifying the critical infrastructure sources in the electricity supply chain.[2] The electricity supply chain map must be completed no later than September 1, 2022.[3] No later than January 1, 2022, the Committee is required to provide a report to the Governor, Lieutenant Governor, Speaker of the House of Representatives, the Legislature and the Texas Energy Reliability Council addressing progress in fulfilling its statutory obligations. Specifically, the Mapping Report must:

A. provide an overview of the Committee's findings regarding mapping the electricity supply chain and identifying sources needed to operate critical infrastructure;

B. recommend a communication system for the PUCT, RRC, TDEM, ERCOT and critical infrastructure sources to ensure that electricity supply is prioritized for critical infrastructure during extreme weather events; and

C. include a list of best practices and recommended oversight and compliance standards to prepare natural gas and electric service facilities to provide service to critical infrastructure in extreme weather events.[4]

The Committee submits this Mapping Report in compliance with PURA §38.204(a). This Committee's work on each of these objectives is ongoing and this report outlines the Committee's progress to date on meeting the objectives of this statute. Although SB 3 only requires the mapping report to be submitted one time, §38.203(b) requires the Committee to update the supply chain map at least once a year. The Committee further commits to prepare an updated Mapping Report for the Legislature by January 15 of each odd-numbered year. This schedule corresponds to the schedule for the PUCT to file its Biennial Report as required by PURA §12.203.

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[1] Public Utility Regulatory Act (PURA), TEX. UTIL. CODE ANN. §38.201(c) (West Supp. 2021).
[2] *Id.* at §38.203(a)(1) & (2).
[3] Acts 2021, 87th Leg., R.S., ch. 426 (SB 3) §37 (eff. June 8, 2021), Tex. Sess. Law Serv. 832, 852.
[4] PURA §38.204(a).

II. Executive Summary

The Committee has made substantial progress in identifying sources for information needed to create the electricity supply chain map. The Committee will use a combination of existing data from Committee member agencies and third party data to create a comprehensive electricity supply chain map. The initial supply chain map must be completed by September 1, 2022. However, the Committee is working to complete the map well before this date.

For purposes of this initial Mapping Report, the requirement to recommend a communication system for the Committee members and critical infrastructure sources includes an update on improvements in communication and coordination among Committee members and the electric and natural gas industries. This Report also provides an update on how each of the Committee members is preparing for the winter of 2021-2022.

Finally, on the best practices, recommended oversight and compliance standards that must be addressed in this Report, the Committee has provided an update on the legislative implementation activities of each Committee member, including all completed and ongoing rulemakings to implement SB 3 and House Bill (HB) 3648.

III. Status of Mapping Electricity Supply Chain and Identifying Sources Necessary to Operate Critical Infrastructure

A. Mapping the Electricity Supply Chain

The PUCT, RRC and ERCOT have been actively working on multiple aspects of the electricity supply chain map. Much of this work began in the summer of 2021 and is ongoing. The Committee has met monthly since August 2021. The Committee has established various teams composed of staff members from the PUCT, RRC and ERCOT to compile the data that will be needed for the supply chain map. The primary Committee teams are:

1) critical facilities;

2) database;

3) mapping; and

4) weatherization.

Each of these teams is led by one or more PUC staffers and includes staff from the RRC and in some cases, ERCOT. These teams have been meeting regularly since August 2021. The mapping team meets on a weekly basis. The activities of the database and mapping teams are discussed below. Additional activities of the PUCT, RRC and ERCOT related to the identification of critical natural gas facilities will be discussed in more detail in throughout this Report.

MAPPING REPORT

Database and mapping issues:

Database and Information Sharing

The PUCT and RRC have executed a memorandum of understanding (MOU) that will allow the agencies to share the confidential datasets needed to prepare the electricity supply chain map. The PUCT and RRC are working to add ERCOT and TDEM to the MOU. After all Committee members have executed the MOU, the Committee will consider allowing other agencies that are not members of the Committee (e.g., Texas Department of Transportation and possibly the Department of Public Safety) to sign the Non-Disclosure Agreements to be able to view the electricity supply chain map and pertinent facilities as appropriate and necessary.

Mapping and IT personnel from the PUCT and RRC have agreed on a method to integrate gas and electric industry information into a single database that can be used to create the electricity supply chain map. These agencies are also actively meeting and working with gas and electric industry market participants on various data and mapping issues. The PUCT has also had several discussions on mapping and related information and technology (IT) issues with ERCOT staff. Finally, the PUCT and RRC will coordinate with TDEM to ensure that the electricity supply chain map will include all relevant information needed by TDEM at the State Operations Center (SOC) to respond to extreme weather emergencies.

Data Collection Process and Mapping

PUCT

The PUCT has conducted an initial inventory of its current electric facility dataset that includes transmission lines, electric generation facilities, and transmission substations. The PUCT has also researched various options, including S&P Global and U.S. Department of Homeland Security's Infrastructure Foundation Level Data (HIFLD) and ERCOT to update the PUCT's current electric facility dataset. The PUCT has received updated electric datasets from several outside sources (open-source and vendor). The PUCT is currently aggregating data from multiple sources, including data securely provided by ERCOT, into a single, reliable dataset that can be included in the electricity supply chain map. ERCOT will update its information for the PUC dataset quarterly. Updates from S&P Global and HIFLD will be incorporated as they become available. PUCT geographic information system (GIS) experts have converted data received from ERCOT into a format that can be used with the PUCT's mapping software. The PUCT will continue a thorough gap analysis to identify information needed and available or needed but currently lacking to complete the electricity supply chain map. The RRC and PUCT have agreed to securely share GIS datasets through ArcGIS online.

RRC

Data collection for the supply chain map by the RRC will be through three main methods:

1) data requests directly sent by the RRC to critical gas suppliers;

2) the RRC's existing data sets and;

3) data received from critical gas suppliers as required under the RRC's new critical gas infrastructure rule discussed in more detail below.

The RRC will be using its existing online filing system, RRC Online, to collect critical customer information from natural gas facilities that are designated either as:

1) critical gas suppliers or

2) critical customers of electric utilities municipally owned electric utilities, and electric cooperatives.

Natural gas facilities that are designated as either critical gas suppliers or critical customers under the RRC's newly adopted Rule 3.65[5] will be required to submit a completed Form CI-D and Form CI-D Attachment. The forms must include information such as facility location, contact information, gas production/handling volumes, and electric utility electric service identifier (ESI-ID) number and information. These forms are available on the RRC's website. The critical natural gas entities will also be required to submit a copy of the same forms to their electric delivery service provider via email, as required by recent amendments to PUCT's Rule 25.52.[6] While the critical designation rules are in place to ensure that electric utilities have the correct information regarding natural gas facilities for purposes of planning load shed, the RRC forms will provide helpful information in the Committee's mapping endeavors. The RRC will facilitate access to the critical customer information by the PUCT and ERCOT as required by the MOU terms. The RRC GIS Mapping staff has also provided transmission pipeline datasets to PUCT staff for a proof-of-concept map layer that when finalized, will provide read-only access to members of the Committee for review. The RRC is currently compiling additional datasets from internal sources that will be provided to PUCT as they are completed. Each of these datasets will add a new feature set and increase the robustness of the supply chain map.

As of November 2021, the RRC's mapping team has developed a preliminary map for those pipelines that directly serve a power plant, as well as a map layer for underground storages.

<u>*ERCOT*</u>

ERCOT has provided power generation facility, transmission line and substation data to the PUCT. ERCOT will provide the PUCT updated data on a regular basis. ERCOT is also reviewing and preparing its digital electric facility data to be used in building the electricity supply chain map. Much of ERCOT's data has been designated as ERCOT Critical Energy

[5] 16 Tex. Admin. Code §3.65.
[6] *Id.* at §25.52.

Infrastructure Information (ECEII) under the ERCOT protocols and is therefore confidential. ERCOT and the PUCT have agreed upon a process to facilitate sharing of digital facility data between ERCOT and the PUCT.

TDEM

The mapping team has met with TDEM Leadership and TDEM Operations Technology GIS staff to:

1) introduce TDEM staff to the mapping work undertaken thus far on the electricity supply chain map;

2) underscore the importance of TDEM's input on the final product that will be used at the SOC when the SOC is activated; and

3) set-up protocols to coordinate and share GIS layers that TDEM maintains that can augment the electricity supply chain map.

The mapping team now includes TDEM staff participating in the weekly mapping team meeting to construct the electricity supply chain map. The PUCT SOC representative will work closely with the RRC SOC representative and TDEM to ensure the mapping team collects and includes on the electricity supply chain map the attribute data for each piece of critical infrastructure that will be the most useful in an emergency.

TDEM manages an enterprise GIS system that operates on the same mapping software platform that the PUCT, RRC and ERCOT utilize. Going forward, this will allow TDEM to seamlessly share and collaborate GIS web maps, data, and geospatial analysis with those agencies during inclement weather and power outages. TDEM maintains a Common Operating Picture (COP) Web Map Portal within its GIS system that delivers geospatial maps and data in a secure manner to Texas State Operations Center (SOC) member agencies and external emergency management agencies.

TDEM manages a crisis information management system (CIMS) that is used to manage information among TDEM, the Texas State Operations Center (SOC) and TDEM's regional and district offices and its local emergency management stakeholders. TDEM is developing a CIMS and COP web portal in FY-22 for ESF-12 ENERGY[7] for managing maps, CIMs data and analysis in one secure location for SOC support during energy related emergency incidents.

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[7] Emergency Management in Texas is divided into 15 Essential Functions as designated in the Texas Emergency Management Plan. The PUCT is the lead agency designated in the Texas Emergency Management Plan for Energy Support Function (ESF) 12-which addresses the energy sector of the state. For more information on the PUCT's activities in support of ESF-12, *see* Attachment 1 of this Report.

TDEM is taking additional steps in fiscal year (FY)-2022 to ensure its cloud server system meets newly implemented standards required by Texas Government Code § 2054.003 (13) and is adding an additional data management software system to enhance access to critical infrastructure data.[8]

B. Identifying Sources Needed to Serve Critical Infrastructure

SB 3, sections 4 and 16, and HB 3648 enacted by the 87th Legislature require the PUCT to collaborate with the RRC to adopt establishing a "process to designate certain natural gas facilities and entities associated with providing natural gas in this state as critical during energy emergencies."[9] The PUCT, RRC, ERCOT and gas and electric industry market participants worked together to establish criteria to identify critical natural gas facilities and to prioritize electric service to these facilities. As required by HB 3648[10], both the RRC and PUCT have adopted their critical natural gas facility rules as of December 1, 2021. The details of the rules adopted by both agencies are outlined below.

<u>RRC Rule 16 Tex. Admin. Code §3.65--Critical Designation of Natural Gas Infrastructure</u>

The RRC has adopted a new rule on the designation of critical natural gas facilities as required by HB 3648 and section 4 of SB 3.[11] HB 3648 requires the RRC to adopt the rule no later than December 1, 2021.[12] The RRC adopted its critical designation rule on November 30, 2021. Rule 3.65 implements the requirements of HB 3648 to establish a process to designate certain natural gas facilities and entities associated with providing natural gas in this state as critical customers or critical gas suppliers during energy emergencies.

The new rule defines "energy emergency" and "critical customer information" and clarifies how to calculate gas volumes as indicated in the rule. The rule designates the following facilities as "critical gas suppliers" during an energy emergency:

1) gas wells producing gas more than 15 Mcf/day;

2) oil leases producing casinghead gas more than 50 Mcf/day;

3) gas processing plants;

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8 8 TDEM's activities in this area are governed by Chapter 20154 of the Texas Government Code. Section 2054.001 states that information and information resources of the State of Texas are strategic assets belonging to the residents of Texas and must be managed as valuable state assets.
9 PURA §38.074(a) (West Supp. 2021).
10 Acts 2021, 87th Leg., R.S., ch. 931 (HB 3648) §3 (eff. June 8, 2021) Tex. Sess. Law Serv. 2372, 2373.
11 *See* TEX. NAT. RES. CODE §81.073(a) (West Supp. 2021).
12 Acts 2021, 87th Leg., R.S., ch. 931 (HB 3648) §3 (eff. June 8, 2021) Tex. Sess. Law Serv. 2372, 2373.

4) natural gas pipelines and pipeline facilities including associated compressor stations and control centers;

5) local distribution company pipelines and pipeline facilities including associated compressor stations and control centers;

6) underground natural gas storage facilities;

7) natural gas liquids transportation and storage facilities; and

8) saltwater disposal facilities including saltwater disposal pipelines.

A critical gas supplier will be required to weatherize provided other statutory requirements are also met.

The rule also defines "critical customers" which are a subset of "critical gas suppliers." Critical customers are critical gas suppliers who need electricity provided to operate. The new RRC rule requires a critical customer to send its "critical customer" information, such as account number and premise identifying information, to its electric utility for load shed planning purposes during an energy emergency.

Subsection (c) of the rule allows facilities that are not designated as critical gas suppliers or critical customers to apply to be designated as critical if the facility's operation is required for another critical facility to operate. Objective evidence must be included with the application and the request may be approved or rejected by RRC Staff. Additionally, a facility that is not designated as critical in subsection (b) but is later included on the electricity supply chain map published by the Committee must apply to the RRC to be designated as critical.

Section 4 of SB 3 states that the RRC cannot designate as critical facilities that are not prepared to operate during a weather emergency. Such a facility would require an exception from designation as a critical facility. Based on comments received, the adopted rule includes a list of facilities that are not eligible for an exception to the critical designation because of their importance to the natural gas supply chain. The facilities that are not eligible for a critical facility exception are the following:

1) a facility included on the electricity supply chain map produced by the Texas Electricity Supply Chain Security and Mapping Committee;

2) gas wells or oil leases producing gas or casinghead gas more than 250 Mcf/day;

3) gas processing plants;

4) natural gas pipelines or pipeline facilities that directly serve local distribution companies or electric generation;

5) local distribution company pipelines or pipeline facilities;

6) underground natural gas storage facilities;

7) natural gas liquids storage and transportation facilities; and

8) a saltwater disposal facility, including a saltwater disposal pipeline, that supports a facility listed in (1) through (7) above.

The final rule adopted by the RRC requires operators of critical facility to provide critical customer information to the RRC and the operators' electricity utilities. The RRC will provide both the PUCT and ERCOT with access to the critical customer information to assist with creating the electricity supply chain map.

<u>PUCT Rule 16 Tex. Admin. Code §25.52—Reliability and Continuity of Service</u>

PUCT Rule 16 TAC §25.52 was amended to implement HB 3648 and PURA §38.074 that require the PUCT to collaborate with the RRC to establish a process to designate certain natural gas facilities and entities associated with providing natural gas in this state as critical during energy emergencies.[13] The rule defines the terms "critical natural gas facility" and "energy emergency" and clarifies that critical natural gas standards apply to each facility in Texas designated as critical customer under the RRC's rule 16 TAC §3.65. Section 25.52 applies to transmission and distribution utilities (TDUs) municipally owned utilities (MOUs), and electric cooperatives (Coops). Under the rule, critical natural gas facilities must provide critical customer information to their respective electric delivery service providers and to ERCOT. This information must be provided by email using RRC's form CI-D and any attachments.

The PUCT must maintain a list of utility email addresses to be used to communicate critical customer information. Utilities are required to provide updates to their contact information within 5 business days. The rule also requires utilities to evaluate critical customer information within ten days of receipt, for completeness and provide written notice to natural gas facility operator regarding the status of its critical designation.

The utility is required to notify the operator of the natural gas facility about its critical status, the date of its designation, any additional classifications assigned to the facility by the utility, and to notify the operator that its critical status does not constitute a guarantee of an uninterrupted supply of energy.

Under the rule as adopted, neither a utility nor an independent system operator receiving or sending critical customer information regarding a critical natural gas facility may release critical customer information to any person unless authorized by the PUCT or the operator of the critical natural gas facility. This prohibition, however, does not apply to the release of such information to the PUCT, the RRC, the utility from which the critical natural gas facility receives electric delivery service, the designated transmission operator, or the independent

[13] A similar provision was included in SB 3. *See* TEX. NAT. RES. CODE § 81.073(a) (West Supp. 2021).

system operator or reliability coordinator for the power region in which the critical natural gas facility is located.

The rule specifies that a critical natural gas facility is a critical load during an energy emergency and further requires a utility to treat a natural gas facility that has self-designated as critical using the voluntary *Application for Critical Load Serving Electric Generation and Cogeneration form* as a critical natural gas facility, as circumstances require.

Finally, §25.52:

1) requires a utility to prioritize critical natural gas facilities for continued power delivery during an energy emergency;

2) allows a utility to use its discretion to prioritize power delivery and power restoration among critical natural gas facilities and other critical loads on its system, as circumstances require; and

3) requires a utility to consider any additional guidance or prioritization criteria provided by PUCT, RRC, or the reliability coordinator for its power region to prioritize among critical natural gas facilities and other critical loads during an energy emergency.

For the winter of 2021-2022, the TDUs, MOUs and Coops will rely on the voluntary critical load applications submitted by natural gas entities. ERCOT TDUs have advised that to prepare for the 2021-2022 winter season, they must have received critical load applications by no later than November 1. These critical load application requests will be incorporated into the load shed plans of the TDUs.

<u>Electric Service to Critical Natural Gas Facilities</u>

Since Winter Storm URI, TDUs have received a substantial increase in the number of registrations from natural gas facilities, seeking to be designated as critical load. The TDUs have expressed concern that the increase in the number of critical load registrants may make it difficult for TDUs to effectively rotate outages during a load shed event. TDUs have been working with natural gas industry market participants to define tiers of criticality so that during a load shed event, TDUs will have an established hierarchy of critical infrastructure for load shed purposes. Natural gas industry market participants, including the Texas Oil and Gas Association (TXOGA) addressed the tiering concept for natural gas facilities in their comments on the RRC critical designation rulemaking and in the PUCT critical designation rulemaking. Based on comments received by the RRC, the Chairman of the RRC provided the Chairman of the PUCT with a letter outlining the facilities that the RRC knows are most important to the natural gas supply chain during an energy emergency. The PUCT will consider this input when issuing tiering guidance pursuant to the PUCT's jurisdiction and the requirements of SB 3 in Tex. Util Code §38.074(b)(2) and (3). The PUCT will be providing guidance in January to its regulated industry on the designation of load shed tiers during a weather emergency.

ERCOT

ERCOT, the PUCT and RRC have been discussing other electric/gas coordination issues. On, October 8, 2021 the RRC sent a letter to all natural gas fired power plants in Texas, requesting the name of each generating facility's gas supplier and pipeline operator. The RRC sent this request to 54 entities that operate natural gas-fired generation plants in the state. Of the 54 entities that received this request, 51 generators provided responses. To date, one generator has failed to respond to the RRC letter. The PUCT and RRC will continue to work with all industry participants to obtain the information necessary to complete the electricity supply chain map.

ERCOT recently issued a request to each generator requesting the name of each generator's gas supplier. ERCOT has received this information for approximately 95% of generation units and will soon make this information available to the PUCT and RRC. Ultimately, the pipeline operator and gas supplier for each gas-fired generator in Texas will be included in the electricity supply chain map.

Current Challenges Related to the Electricity Supply Chain Map

The above-discussed rules by the RRC and PUCT are expected to be very helpful to the Committee in creating the electricity supply chain map. One challenge for the Committee will be obtaining and mapping the electric distribution infrastructure that serves the critical natural gas infrastructure identified in the RRC and PUCT rules. Because the PUCT does not currently have ready access to electric utility distribution level mapping data, the Committee will need to obtain this information from the electric utilities that serve the critical infrastructure sources. To incorporate this information into the electricity supply chain map in an expedient manner, the Committee must provide the electric utilities with lists of premise identifiers that are associated with the critical infrastructure sources the RRC has identified. This information will allow the electric utilities to quickly identify and provide the associated distribution level information to the Committee for mapping. Under the RRC's critical facilities rule, a natural gas facility must, among other things, provide its premise identifier to the electric utility that serves the facility to be considered a critical load. The RRC must share with the Committee members the same data it requires natural gas facilities to provide to electric utilities so that this information may be used to build out the electricity supply chain map and to provide the map's end users with information relevant to maintaining electric service in an emergency event.

TDEM

A primary role of TDEM in supporting the requirements contained in SB-3 is to provide emergency management support through the resources comprised by the State Operations Center Emergency Support Functions (ESFs). TDEM will work with the Committee to update the ESF-12 (Energy) Annex[14] to address lessons learned from the 2021 Winter Storm and add additional agreed upon procedures for: 1) Reporting, 2) Response, and 3) Communications.

The following activities have been identified and are recommended by TDEM as needed to ensure the ESF-12 (Energy) support function and state are better prepared for future energy disruptions:

1) Secure management and access to the energy critical infrastructure map database and map services.

2) Identification of cascading impacts from the failure of key critical infrastructures and remediation procedures and support requirements.

3) Identification of logistical and other support resources needed for responding to energy disruptions and an operational plan for staging and managing resources.

4) Development of a contact database and notification system for energy related critical infrastructure owners, operators, and regulators.

5) An operational playbook for ESF-12 (Energy) that includes procedures for:

   i. Reporting: Procedures for utilities and regulators to report outages or impending outages in a uniform manner.

   ii. Response: Procedures for requesting assistance and activating response and support resources for energy related critical infrastructure types, and specific facilities.

   iii. Communications: Procedures for coordinating, managing, and issuing ESF-12 (Energy) related communications and notifications (citizen, private sector and governmental).

6) On-going training and exercises for ESF-12 (Energy) related incident scenarios.

IV. Communication System to Ensure Electricity to Critical Infrastructure

PURA §38.204(a)(2) requires the Mapping Committee… "to recommend a clear and thorough communication system….to ensure that electricity supply is prioritized to [critical infrastructure] sources during extreme weather events…" The recommended communication system applies to communications among and between the PUCT, RRC, TDEM, ERCOT and critical infrastructure sources. These entities have been working together since the passage of SB 3 to develop a comprehensive and effective communications system to ensure electricity is prioritized to critical infrastructure during an extreme weather event. The development of this

[14] For more information on this issue, *see* Attachment 1 of this Report, *PUCT Responsibilities as a member of the Texas Emergency Council.*

communication system is an ongoing effort that will be reviewed and revised as necessary in the future. Actions taken by each of the Committee members to improve communication are outlined below.

A. Preparation for the winter of 2021-2022

The electricity supply chain map is the key element to improved communication between the PUCT, RRC, TDEM, ERCOT and the gas and electric industries. Once this map is finalized, it will be much easier for these agencies and industries to communicate more effectively and efficiently in a weather emergency. The supply chain map must be completed by no later than September 1, 2022, but the Committee is working to complete the map before September 1. However, as work on the supply chain map continues, the Mapping Committee agencies are working on improving their communications for the winter of 2021-2022.

B. Regular communications between PUCT, RRC and ERCOT

The PUCT, RRC and ERCOT have been communicating regularly on the implementation of key bills passed by the 87th Legislature, especially SB 3 and HB 3648. PUCT Chair Peter Lake and ERCOT President Brad Jones meet weekly to discuss relevant issues including reliability and implementation of legislation.

The Executive Directors of the PUCT and RRC meet weekly to discuss legislative implementation issues, current rulemakings, and mapping committee issues. The Committee, created as part of SB 3, meets monthly to discuss progress and resolve issues related to the creation of the electricity supply chain map. The Committee has established 7 teams to address various aspects of the supply chain map. These teams are:

1) administrative,
2) communications,
3) critical facilities,
4) database,
5) mapping,
6) mapping report and
7) weatherization.

Each of these teams is chaired by a staffer from the PUCT and each includes additional staff from the PUCT and RRC. These teams meet regularly to discuss and resolve various issues related to the supply chain mapping project. Their work is ongoing.

The PUCT, RRC, ERCOT and electric and gas industry market participants have been working to identify certain key natural gas facilities that are critical for the electricity supply chain to be better prepared for the winter of 2021-2022. Some of this work has taken place in the PUCT and RRC rulemakings related to critical natural gas facilities. As noted above in the discussion of the activities related to the supply chain mapping, the RRC's rule on critical natural gas facilities provides a list of the types of natural gas facilities that would be designated as critical for the electricity supply chain.

C. RRC—Winter Preparation

The RRC has taken multiple proactive actions to ensure facilities in its jurisdiction are prepared to operate during Winter 2021-22 to help protect Texans in the event of severe weather.

On October 7, 2021, the RRC issued a notice to operators of gas facilities and gas pipeline facilities to take all necessary measures to prepare to operate in extreme weather. The notice included a reminder to update each facility operator's *Application for Critical Load Serving Electric Generation and Cogeneration* with their respective electric utilities and identified several best practices operators could utilize for winter weather preparations. A second notice with additional best practices that operators could utilize was issued on December 9. Copies of these two notices are attached to this Report as Attachment 2.

In October 2021, in conjunction with the PUCT, the RRC hosted a joint electric and gas industry meeting regarding potential load-shed tiers for use by electric utilities in a potential upcoming load shed event. In late October the RRC sent another notice to remind operators to timely complete and file the ERCOT application with their electric utilities to be designated as critical customers for load shed purposes. Applications for designation as critical load were due on November 1 to allow TDUs to plan for the winter of 2021-2022.

The RRC has also held meetings with executives of major gas pipelines, pipeline facilities, and natural gas producers on their weatherization practices and operation plans. In conjunction with the meetings, the RRC's newly formed Critical Infrastructure Division and field inspectors have been conducting site visits to large natural gas producers, natural gas storage facilities, and natural gas transmission pipelines to observe and inquire about preparedness for the upcoming winter.

From the beginning of fall to mid- December 2021, the RRC has conducted approximately 3,000 site visits which include:

1) oil and gas leases that have more than 17,000 active producing or disposal wells;
2) large gas storage facilities;
3) processing plants;

4) more than 70 pipelines directly serving gas-fired power generators; and

6) more than 200 other transmission pipeline facilities used to transport natural gas.

These site visits will continue through the winter of 2021-2022.

The RRC has also hosted several industry-specific webinars in December for RRC staff and operators. This included a presentation by a major oil and gas producer on how the company prepares for winter operations, which is information beneficial to operators looking for peer guidance.

Other ongoing work includes surveys of experts in other large oil and gas producing states and Canadian provinces seeking their input on best practices. That information is part of the best practices section discussed later in this Report.

The RRC also issued a solicitation for a technical advisory contract to assist the agency on weatherization technology training, audits, and best practices.

Electric generators requested the RRC to create a definition of "firm fuel" and more visibility into when and under what circumstances natural gas suppliers will invoke force majeure in their contracts with generators. The PUC provided draft "firm fuel" language to the RRC and the RRC solicited feedback from natural gas producers on inclusion of this language in future gas contracts with generators. The PUCT, RRC and industry market participants will continue to discuss how best to address this issue.

During an extreme weather event in which natural gas flows may be limited, gas suppliers and pipelines have noted that knowing the amount of gas that will be needed by electric generators would be helpful for gas companies to plan their winter operations. This will require more coordination between electric generators and natural gas suppliers and pipelines. The PUCT, RRC and gas and electric industry market participants are actively discussing these issues. These issues are being actively discussed by members of the Texas Energy Reliability Council (TERC) and its various industry working groups.

D. ERCOT

The ERCOT Protocols currently require generation owners to submit an annual attestation that, in relevant part, requires each owner to identify the natural gas pipelines connected directly to each generating facility it owns and to provide contact information for each pipeline operator. ERCOT is in the final stages of assembling this pipeline information. ERCOT also recently requested that each generation owner identify each of the gas suppliers that sell gas to each generation facility through the pipelines, as the gas supplier is not always the same entity as the operator of the pipeline serving the generation facility. ERCOT has received gas supplier information from approximately 95% of the generation owners and will soon provide this information, along with the pipeline information, to the PUCT and RRC. The names of the natural gas pipeline operators and natural gas suppliers are confidential under the ERCOT Protocols.

ERCOT has also developed a crisis communication plan that outlines roles and responsibilities within ERCOT for communicating during an emergency event. This document will ensure that ERCOT is providing regular, consistent, and accurate information to the PUCT, market participants, the media, legislative leaders, and the public. A copy of this plan is attached to this report as Attachment 3.

Additionally, ERCOT has assigned two staff members to be present in the SOC when the SOC is activated. ERCOT personnel have not traditionally been present in the SOC during an activation. The addition of ERCOT staff to the SOC should enhance the ability of the SOC to respond to weather emergencies.

Finally, ERCOT has been working closely with the PUCT and the generators to assess whether generating units are weatherized and prepared for the winter of 2021-2022 in accordance with recently adopted PUCT rules. ERCOT recently hired a Director of Weatherization and Inspection who will oversee these inspections.

E. TDEM

TDEM is actively participating and communicating with the Committee throughout the planning process. As noted previously in Section III. of this Report, TDEM maintains a crisis information management system that it is customizing for ESF-12 Energy. The CIMS will contain custom data management forms to better manage and communicate ESF-12 related information in the State Operations Center and will include notification capabilities. The CIMS will also be connected to the GIS to ensure TDEM SOC maps immediately display current incident conditions as the information is entered into the CIMS database.

TDEM is also working to deploy enhanced communications infrastructure to better support state notifications, public alerts, public media and social media messages and alternative communications infrastructure and capabilities.

F. TERC

The Texas Energy Reliability Council (TERC) is also in the process of developing improved communication among relevant regulatory agencies and the electric and gas industries. TERC is composed of leaders from the PUCT, RRC, ERCOT and members of the natural gas and electric industry and is intended to ensure that gas and electric industries address critical infrastructure concerns and enhance the coordination and communication in the energy and electric industries. In furtherance of TERC goals, the PUCT has established two Microsoft Teams meeting groups. The first group will consist of the regulatory agencies that are members of TERC. These agencies are the PUC, RRC, OPUC, TCEQ, Texas Transportation Commission, ERCOT, and TDEM. The second Teams group will include the regulatory agencies of TERC and the electric and gas industry market participant members of TERC. These meeting groups are intended to encourage frequent communication among relevant regulatory agencies and gas and electric industry participants on operational and planning issues. The expectation is that frequent communications among these various constituencies will assist TERC members in preparing for emergency operations and sharing of information which in turn should enhance the ability of all TERC members to timely respond to extreme weather emergencies.

TERC is currently meeting monthly to ensure that critical electric and natural gas facilities will be prepared for the upcoming winter. Under SB 3, TERC is required to file reports in even-numbered years on the reliability and stability of the electricity supply chain in this state. The first such report is due on November 1, 2022.

V. Recommended Best Practices and Compliance Standards

A. FERC/NERC Weatherization Standards

In June 2021, NERC adopted three modified Reliability Standards designed to ensure that the North American power system can withstand extreme cold weather events. The newly adopted reliability standards apply to the entire bulk power system in the US, including ERCOT.[15] By order issued on August 24, 2021, FERC approved without changes, these revised NERC reliability standards. A copy of the FERC Order Approving Cold Weather Reliability Standards is attached to this Report as Attachment 4.

The three reliability standards modified by NERC include:

1) EOP-011-2 (Emergency Preparedness and Operations)

2) IRO-010-4 (Reliability Coordinator Data Specification and Collection)

3) TOP-003-5 (Operational Reliability Data)

NERC proposed these changes in response to findings made by a joint NERC/FERC report on a 2018 weather event in the south central US. The changes to these reliability standards require an operator of generation facility to have a cold weather preparedness plan that addresses freeze protection measures, inspection procedures and cold-weather operating limitations, require the reporting of weather-related design specifications and operating limitations to reliability coordinators throughout the US (e.g., ERCOT, the Southwest Power

[15] While the PUCT regulates wholesale market transaction in ERCOT, FERC and NERC have jurisdiction over the reliability of the bulk power network, including ERCOT. FERC and NERC have established six Regional Entities throughout the US to assist FERC/NERC in enforcing federal reliability standards. In ERCOT, the Regional Entity is the Texas Reliability Entity (Texas RE).

Pool, Midcontinent Independent System Operator) require balancing authorities and transmission operators to determine the reliability impacts of generating unit limitations during cold weather. FERC approved NERC's implementation plan for these new reliability standards which have an effective date of April 1, 2023. FERC strongly encourage utilities to comply with the new standards sooner if possible.

The new standards apply to power generators, transmission operators, and other entities responsible for ensuring the reliability of the electric grid, including balancing authorities and reliability coordinators. The entities subject to the new standards will be subject to annual inspections by reliability coordinators and balancing authorities.

B. RRC Best Practices Report

To ensure oil and gas operators in Texas have the most up-to-date information on preparing facilities for severe weather emergencies, the RRC has conducted research on winterization methods and practices and has also been in ongoing contact with energy industry experts in Texas and other large energy producing states and Canadian provinces on best practices. The information compiled by the RRC, and distributed to operators, attached to this Report as Attachment 5.

C. PUCT and RRC rulemakings

In addition to the FERC/NERC reliability standards, the PUCT and RRC are in the process of implementing legislation from the 87th Legislature that is intended to improve the reliability of the electric power supply system in Texas.

<u>PUCT Rulemakings</u>

<u>Project No. 51840—*Rulemaking to Establish Weatherization Standards*</u>—In this rulemaking the PUCT established weatherization standards for electric generators and transmission service providers (TSPs) in ERCOT as required under SB 3. The Commission adopted new 16 TAC § 25.55 on October 26, 2021. New § 25.55 is phase 1 of the Commission's weather emergency preparedness reliability standards. The new rule requires generators in ERCOT to implement the winter weather readiness recommendations outlined in the *2012 Quanta Technology Report on Extreme Weather Preparedness Best Practices* (2012 Quanta Report). The rule also requires ERCOT generators to fix any known, acute issues that arose during the winter of 2020-2021. Additionally, new §25.55 requires TSPs to implement the key recommendations contained in the joint FERC/NERC report from 2011 entitled *2011 Report on Outages and Curtailments During the Southwest Cold Weather Event on February 5, 2011* and to remedy any known, acute issues that arose during the winter 2020-2021. This new rule requires generators and TSPs to provide a notarized attestation from the highest

ranking official from each affected entity attesting to the completion of all actions required by the rule.

New §25.55 requires generation entities and TSPs to submit a "winter weather readiness report" by December 1, 2021. The report must describe the activities undertaken to comply with the weather preparedness standards required by the rule. Most generation entities timely filed winter weather readiness reports. The PUCT's Division of Compliance and Enforcement identified thirteen generation entities owned by 8 companies that missed the filing deadline. On December 8, PUCT staff filed reports of violations against these 8 companies for failing to timely file winter weather readiness reports. The PUCT staff recommended a total of $7.675 million in administrative penalties for these reporting failures. These cases are currently pending before the PUCT.

ERCOT has completed a generation plant inspection form and has begun inspections of approximately 300 generating units for winter readiness. Plants were selected for inspection based on the amount of energy lost during the February 2021 cold weather event. Ss such, the ERCOT inspections will address 85% of the lost MWhs during Winter Storm Uri.

Phase 2 of the PUCT's weatherization standards will be the adoption of more comprehensive, year-round set of weatherization standards for emergency preparedness. The PUCT will begin developing these standards after it reviews the weather study currently being conducted by ERCOT and the Office of the Texas State Climatologist.

Project 52312 – *Review of Administrative Penalty Authority*—SB3 increased the PUCT's administrative penalty authority from §25,000 per violation per day to §1,000,000 per violation per day for noncompliance with the PUCT's weatherization rules. This penalty authority is already in effect under the statute, but the PUCT approved a proposal for publication at the August 19, 2021 open meeting.

Project No. 52345—*Critical Natural Gas Facilities and Entities*—As explained above in Section III., HB 3648 required the PUCT and RRC to collaboratively establish a process to designate certain natural gas facilities and entities associated with providing natural gas in this state as critical during an energy emergency. Both the PUCT and RRC adopted rules on this issue on November 30, 2021. These amendments are described in more detail above in Section III.

ERCOT TDUs have advised that to prepare for the winter of 2021-2022 they must have critical load designations by no later than November 1. Because neither the PUC nor RRC rule regarding critical gas facilities was adopted by November 1, the critical facility designations adopted by the RRC on November 30, 2021 will not be fully incorporated into TDU load shed and service restoration planning until 2022. However, the PUCT and RRC have conducted a joint effort to get as many critical natural gas facilities to self-designate as critical using the voluntary *Application for Critical Load Serving Electric Generation and Cogeneration form* to ensure that electric TDUs, Coops, and MOUs have as much critical information as possible heading into the winter of 2021-2022. Certain gas, and electric industry market participants have suggested that the PUCT and RRC should issue a guidance document on how electric service priority for critical natural gas facilities should be addressed in the winter of 2021-2022. While the RRC does not have jurisdiction over electricity load shed events or electric industry market participants, the RRC's Chairman provided suggestions on possible priority tiers for critical gas facilities in a letter to the PUCT Chairman in November. The PUCT is continuing to discuss this issue with electric industry market participants and expects to issue a guidance document in January.

Project No. 51888—*Review of Critical Load Standards and Processes*—This rulemaking is essentially phase 2 of the PUCT's critical natural gas facilities rule which was adopted on November 30. After TDUs have incorporated critical natural gas facilities into their load shed planning, it may be necessary to conduct a more comprehensive review of all types of critical loads and to establish an overall service prioritization for these loads. Work on this rule is expected to begin in 2022.

Project No. 51841—*Review of 16 T.A.C. 25.53 Relating to Electric Service Emergency Operations Plans*—The purpose of this rulemaking is to amend the PUCT's existing rule requirements for Emergency Operations Plans in response to SB 3. The PUCT approved a proposal for publication of this rule at the December 2, 2021 open meeting.

Additionally, the PUCT will be issuing a request for proposal for an entity to review the existing EOPs of market participants for compliance with commission rules. The PUCT is aiming to have a contractor in place by March or April 2022.

Project No.52287 *Power Outage Alert Criteria*—The purpose of this rulemaking proceeding is to establish a power outage alert system. PUCT Staff and ERCOT staff are drafting a proposed rule. PUCT Staff anticipates that a draft proposal for publication will be considered by the PUCT at its December 16, 2021 Open Meeting.

RRC Rulemakings

Both SB 3 and HB 3648 require the RRC to adopt rules "to establish a process to designate certain natural gas facilities and entities associated with providing natural gas in this state as critical customers or critical gas suppliers during energy emergencies."[16] As explained above in Section III, the RRC adopted a rule on November 30, 2021 to identify critical natural gas facilities. The RRC received comments from the public, legislators, several electric and natural gas industry participants as well as ERCOT

SB 3 also requires the RRC to adopt a rule within six months after the Committee publishes the electricity supply chain map that will require gas supply chain facilities to implement measures to be able to operate during weather emergencies if the gas supply chain facility is

[16] TEX. NAT. RES. CODE §81.073(a).

designated as critical and is included on the electricity supply chain map.[17] This provision requires the RRC to inspect gas supply chain facilities for compliance with the weatherization standards adopted by the RRC. The RRC has started rulemaking efforts on this issue.

Similarly, the RRC is also required to adopt rules requiring gas pipeline facility operators to adopt measures to maintain service quality and reliability during extreme weather emergencies if the gas pipeline facility directly serves a natural gas electric generating facility supplying power in ERCOT or in ERCOT and an adjacent power region and is included in the electricity supply chain map.[18] The RRC is also required to inspect gas pipeline facilities for compliance with the standards adopted by the RRC.

The RRC is also required under SB 3 to analyze the emergency preparedness reports created by "operators of facilities that produce, treat, process, pressurize, store or transport natural gas and that are included in the electricity supply chain map created under [Utilities Code] § 38.203. . ."[19] The RRC is required to submit a biennial report to the Legislature based on its analysis.

The reliability-related requirements for the RRC included as part of SB 3 and HB 3648 applicable to the natural gas industry will be conducted in 3 phases:

1) rulemaking to identify critical natural gas facilities;
2) mapping of electricity supply chain (including critical natural gas facilities); and
3) rulemaking to enact weatherization standards. Under SB 3, the RRC is required to adopt the weatherization standards for gas supply chain facilities or gas pipeline facilities within 6 months after the completion of the electricity supply chain map.[20]

The deadline for completion of the electricity supply chain map is September 1, 2022, but the Committee is working to complete the map before this date.[21]

Finally, the RRC has also proposed amendments to its existing gas curtailment standards. The RRC's current gas curtailment standards are reflected in what is known as Order No. 489 which was originally adopted in 1973. During Winter Storm Uri, the RRC adopted an emergency order that placed electric generation facilities 2nd on the gas service prioritization list to give a higher priority to electric generators during the winter emergency. The PUC and electric generators have requested that the RRC make this prioritization permanent, and that this policy be memorialized in a rule. In response to stakeholder feedback on its emergency order issued in February 2021, the RRC's proposed rule (16 T.A.C. §7.455), relating to

[17] *Id.* at §86.044(c).
[18] TEX. UTIL. CODE §121.2015(a).
[19] *Id.* at §186.008(b).
[20] Acts 2021, 87th Leg., R.S., ch. 426 (SB 3) §38 (eff. June 8, 2021), Tex. Sess. Law Serv. 832, 852.
[21] *Id.*

Curtailment Program) updates the service priority order. The proposed rule clarifies that firm deliveries have priority over interruptible deliveries during a curtailment event. Additionally, the Uri emergency order included electric generators serving human needs customers in the second priority. The proposed rule expands the second priority to include all electric generation facilities, not just those serving human needs customers. Comments on the proposed rule are due by January 7, 2022. The RRC has proposed an effective date of April 1, 2022, for its Curtailment Program rule.

ATTACHMENT 1

ATTACHMENT 1

PUCT Responsibilities as a member of the Texas Emergency Council

The PUCT is a member of the Texas Emergency Management Council (TEMC) under the authority of Governor Abbott's Executive Order GA-05. The PUCT's membership in the Council pre-dated this executive order, however this order has replaced those before it.

Emergency Management in the State of Texas is broken down into 15 "Essential Functions" as designated in the Texas Emergency Management Plan. These essential functions were developed to align with the National Response Framework which was created by the Homeland Security Act of 2002 and Homeland Security Presidential Directive-5. The 15 defined essential functions and the lead agency for each function are as follows:

- ESF 1 – Transportation (Texas Department of Transportation)
- ESF 2 – Communications (Texas Division of Emergency Management)
- ESF 3 – Public Works and Engineering (Texas Department of Transportation)
- ESF 4 – Firefighting (Texas A&M Forest Service)
- ESF 5 – Emergency Management (Texas Division of Emergency Management)
- ESF 6 – Mass Care (Texas Division of Emergency Management)
- ESF 7 – Logistics and Resource Management (Texas Division of Emergency Management)
- ESF 8 – Public Health and Medical Services (Texas Department of State Health Services)
- ESF 9 – Search and Rescue (Texas A&M Engineering Extension Service)
- ESF 10 – Oil and Hazardous Materials Response (Texas Commission on Environmental Quality)
- ESF 11 – Agriculture and Natural Resources (Texas Animal Health Commission)
- ESF 12 – Energy (Public Utility Commission)
- ESF 13 – Public Safety and Security (Texas Department of Public Safety)
- ESF 14 – Long-Term Recovery, has since been superseded by the National Disaster Recovery Framework
- ESF 15 – Public Information (Texas Division of Emergency Management)

The Public Utility Commission has been identified as the lead agency for ESF 12 in the Texas Emergency Management Plan managed by the Texas Division of Emergency Management. The ESF 12 Appendix to the State Plan is currently under revision by TDEM in cooperation with PUCT and other agencies. In addition to the lead role in ESF 12, the PUCT also has a support role in the following essential functions:

- ESF 1 – Transportation
- ESF 2 – Communications
- ESF 5 – Emergency Management
- ESF 15 – Public Information

While the primary function of the PUCT's Emergency Management Coordinator is responding to activations, there are numerous trainings, planning meetings, and other functions which TDEM hosts which require our involvement.

The State Operations Center (SOC) is activated by order of the Governor and may involve some, many, or all the TEMC member agencies depending on the event. When requested, the PUCT provides personnel to staff the SOC where they function as a liaison between the State and the utility industry. Even if not requested to respond in-person to the SOC, the PUCT may participate in SOC operations remotely, especially during pre and post event operations. The PUCT staff working an activation interact with many entities including the Electric Reliability Council of Texas (ERCOT), municipally-owned utilities (MOUs), electric cooperatives (Coops), and transmission and distribution utilities (TDUs), and electric generators.

Some examples of support the PUCT provides during an activation are as follows:

- Provide event specific information and updates from TDEM to the utilities. (Where possible, this usually begins a day/couple of days prior to the event as information becomes available and is presented during daily calls hosted by TDEM).
- Routine updates of outage counts, locations, and restoration times when known which allows the SOC to better focus their response activities.
- Participation in TDEM's daily calls during an event providing situational updates and outage reports to both state-wide and local officials attending the calls.
- Coordination with TXDoT on route clearing when crews discover downed lines across travel routes which need to be cleared. Conversely, since utility repair crews may be the first folks back into an area (post-hurricane for example), they may have information on routes that is helpful to TXDoT which we are able to share with them.
- Assistance in planning routes for TDEM IRATs (Initial Reentry Assessment Teams) and coordinating with utilities to ensure access.
- Providing a direct link between local officials who reach out needing contact information for local utilities.
- Obtaining outage information for specific locations and facilities such as long-term care facilities, hospitals, water utilities, etc.
- Working with HHS to provide information to support their requests for replacement SNAP benefits of the possible issuance of "D-SNAP" benefits. (SNAP benefits which may become available to a slightly larger population due to a disaster)
- Assisting utilities with the process for reporting damages which TDEM uses when requesting federal disaster declarations.
- Coordination with the Texas Commission on Environmental Quality (TCEQ) on potential enforcement discretion regarding air-quality standards during a disaster.
- Providing utilities an access point to request resources through the SOC. Generally this applies to MOUs and Coops due to their governmental or non-profit nature, however the

SOC can also be utilized to help private companies source or acquire resources at the company's expense.

The duration of the PUCT's involvement in an activation is ultimately up to the Governor or the TDEM Chief. The end of an activation does not necessarily end PUCT's involvement in a particular event. Since 2020, the PUCT has become more involved in the actual recovery process, participating in outreach, calls, and training related to the activities TDEM undertakes after a disaster.

ATTACHMENT 2

RAILROAD COMMISSION OF TEXAS
Oil and Gas Division
Oversight and Safety Division

NOTICE TO GAS FACILITY OPERATORS AND GAS PIPELINE FACILITY OPERATORS

Preparation by Operators for Winter 2021-2022

Senate Bill 3 states the Railroad Commission of Texas shall require gas supply chain facilities and gas pipeline facilities, respectively, to "implement measures to prepare to operate during a weather emergency." Adoption of the rules is tied to the map to be published by the Texas Electricity Supply Chain Security and Mapping Committee no later than September 1, 2022. Operators of gas supply chain facilities and gas pipeline facilities under the Commission's jurisdiction are expected to take all necessary measures to prepare to operate in extreme weather conditions during the winter season of 2021-2022. The Commission's highest priority is to ensure that should another extreme winter weather event occur, all available natural gas under the jurisdiction of the Commission in the state is available to be utilized for reliable energy sources for Texans. The Commission is taking additional steps including on-site visits to assess operator preparedness. To ensure that gas facility operators and gas pipeline facility operators are implementing measures to prepare to operate during extreme weather conditions prior to publication of the map, the Commission's Oil and Gas Division and Oversight and Safety Division jointly issue the following best practices for weatherization:

- Update the *Application for Critical Load Serving Electric Generation and Cogeneration* to your electric utility as early as possible.
    - Ensure that you have submitted and updated the above-referenced application to your electric utility for the upcoming winter season 2021-2022. The application may be found on ERCOT's website at http://www.ercot.com/content/wcm/key_documents_lists/174326/Final_-_pdf_-_App_for_gas_pipeline_load_v020320.pdf.
    - The Commission previously notified operators of the application on March 17, 2021 and it is available on the Commission's website at https://www.rrc.state.tx.us/announcements/031721-updated-application-for-critical-load-serving-electric-generation-and-cogeneration/.
- Methanol injection or drip.
    - Introduction of methanol into the gas stream by chemical injection pumps or into the pipeline by methanol drips lowers the freeze point of gas. Methanol injection can also be used to prevent freezing in pneumatic controllers, as well as in preventing liquids from reaching small orifices and passages in these instruments.
- Water removal by solid absorption.
    - Natural gas may be passed through dry bed or molecular sieves, which absorb water. These methods can be used to achieve very dry gas.
- Cold weather barriers.

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- Cold weather barriers, such as wind walls, may be installed around certain compressors to block cold winds which may exacerbate freezing conditions. Wrapping and insulating surface equipment, injection lines, supply valves, water lines, and other equipment may also help to prevent freezing and stoppage of fluid flow.

- Heat.
  - Heat systems, such as heating blankets, catalytic heaters, fuel line heaters, or stream systems, can be effective for localized freezing problems. Coupling heat systems with insulation is a common technique for protecting flow lines in northern climates.
- Glycol.
  - Natural gas can be passed through glycol inside a contactor. Glycol absorbs water vapor entrained in the stream, allowing dry gas to pass through.
- System Design.
  - Careful planning during the design stage for measurement and regulating systems can reduce the chances of freezing. Any steps that reduce restrictions or prevent areas where liquids can collect will minimize the possibility of freezing. To avoid liquid accumulation, pipe configurations should be set up such that drainage slopes toward drain fittings in low spots. Prevent restrictions by using full opening ball valves and large diameter tubing. Liquids will be drawn toward leaks, so have a leak-free system with tubing that slopes back toward the pipeline.
- Drip Pots.
  - Drip pots and coalescers can be used to eliminate or reduce the amount of water in cases of severe liquid problems or when there is a slug of liquid in a gas supply used for instrumentation.
- Instrument Filters.
  - Filter dryers provide a clean, dry supply of gas to controllers and other instrumentation that functions using instrument gas. These units function under high pressure and can eliminate both liquids and particulates.

Please Forward to the Appropriate Section of Your Company

RAILROAD COMMISSION OF TEXAS
Critical Infrastructure Division

NOTICE TO NATURAL GAS PRODUCERS, GAS FACILITY OPERATORS AND GAS PIPELINE FACILITY OPERATORS

Additional Best Practices for Winter 2021-2022 Preparations

The Railroad Commission of Texas' (Commission's) highest priority is ensuring all natural gas under the jurisdiction of the Commission in the state is available to be used by Texans during the next energy emergency. On November 30, 2021, the Commission adopted Texas Administrative Code §3.65, relating to Critical Designation of Natural Gas Infrastructure, defining critical gas suppliers and critical customers during an energy emergency. In October, the Commission issued a notice with best practices operators should take to prepare for winter. **Operators of gas supply chain facilities and gas pipeline facilities under the Commission's jurisdiction are expected to take all necessary measures to prepare to operate in extreme weather conditions during the winter season of 2021-2022.** That notice is available on the Commission's website at https://rrc.texas.gov/media/r5dbn5b2/2021-nto_preparation-by-operators-for-winter_2021-2022_mlb_10-6-2021.pdf.

Since that notice, the Commission has conducted additional research on weatherization best practices by consulting with energy industry experts in Texas and other large energy producing states and Canadian provinces. RRC inspectors also identified additional processes through site visits, some of which may be appropriate to assist operators' efforts to prepare for extreme weather events. Below is a list of those additional best practices:

- **Line Heaters**
    - Used in wells that flow predominantly gas and small amounts of water, with no appreciable oil, this equipment uses a gas fired flame to heat a fluid filled chamber inside the body of the line heater. Gas passes through a coil that is immersed in a chamber of warmed fluid, which increases the temperature of the natural gas as it passes. When sized appropriately for the volume of gas being produced line heaters effectively heat gas at the first potential point of freezing before it reaches downstream separation or treating equipment.
- **Hot Lubricant and Circulation Heater for Engine Oil or Fuel**
    - Installing external block heaters with an external energy source such as a gas fed flame or electricity can maintain pump or compressor lubricants at an appropriate temperature, even when the equipment is not operational, making it easier to restart the equipment by keeping the oil/fuel in the engine at an elevated temperature. At freezing temperatures pumps designed to circulate lubricant have difficulty functioning,

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but using hot lubricant and external block heaters can keep pumps and compressors functional and prevent freeze-offs.

- **Human Capital**
  - While weather specific technologies are critical to sustain natural gas production during cold weather conditions, the maintenance and operation of these technologies begins with human capital—the people trained and able to ensure natural gas continues to serve its essential function in the electricity supply chain despite adverse conditions. Increasing staffing levels in advance of an extreme weather event ensures that appropriately trained employees are readily available—if not pre-positioned on-site—to resolve any equipment or instrumentation failures should temperatures fall below an acceptable operating temperature for sensitive equipment or instruments.

Please Forward to the Appropriate Section of Your Company

ATTACHMENT 3

December 6, 2021

ATTACHMENT 3

ERCOT Crisis Communications: Principles, Roles & Responsibilities

Implementation of Crisis Communications Activities

The VP of External Affairs will coordinate with the Executive Team to begin and end Crisis Communications Team activities.

Principles

Executive Alignment Process

At the beginning of Crisis Communications Team activities, the Communication Leader for the shift (see "Roles & Responsibilities" section below) will meet with the CEO, Operations and others as needed to establish the communications cadence for the day, depending on the significance, severity and anticipated duration of an event. The VP of External Affairs will then notify the Executive Team of the planned cadence. These meeting will also occur at 8:30 a.m. and 8:30 p.m. each day until the need for team activities is over. If for any reason these meetings do not occur, the cadence on the previous day will be used.

Priority of Crisis Communications Messages

During a crisis, all message development that routinely occurs throughout ERCOT for various key audiences, such as employees and legislators, will be suspended in favor of a centralized process for all audiences. However, internal relationship owners will continue to review and edit all messages. This will prioritize timely and consistent messages across all channels and audiences.

External Resources

At the Communication Leader's direction, the Support Team and Communications Coordinator will develop content and supply key messages for use and distribution to key audiences, including but not limited to legislative, regulatory, news media and employees.

Message Discipline

ERCOT messages should be clearly aligned with both current and crisis ERCOT communications strategies.

Roles & Responsibilities

These are the communications roles and responsibilities during a crisis event. Each of these roles will rotate to a different group of team members every 12 hours.

The Crisis Communications Teams will ensure that all internal groups are provided key communications material to ensure message consistency for the duration of the issue or crisis. Internal groups, besides the Executive Team, include, but are not limited to, Operations, Compliance, Security, IT, HR, Legislative, Legal, and Regulatory. Those groups, in turn, are responsible for communicating to important external groups, including but not limited to, FERC, NERC, TDEM, OPUC, RRC, TCEQ, IMM, TRE, and the ERCOT Board of Directors.

developed and that the communications cadence is maintained. Responsible for ensuring key audience communication including news media, legislators, market participants and employees through news releases, web updates, news conferences, social media and other channels.

Media Specialist
Media spokesperson responsible for media inquiry response, interviews and news conferences. This includes the logistics of hosting news conferences or briefings by phone/video.

Communication Coordinator
Document and triage all incoming media inquiries. Develop key messages, draft news releases/updates, and write answers to frequently asked questions. Responsible for all approvals prior to releases/updates.

Legislative Liaison
Responsible for identifying critical information, setting up and hosting conference calls with Texas elected leaders, Texas legislative leadership/ committees/members, Congressional delegation and staff, responding to specific requests and summarizing areas of concern/needs. This position will closely coordinate with PUC Relations.

Web Communicator
Responsible for all internet site and social media updates/posts. Review real-time analytics and website searches to decide placement of information and identify future communications needs.

Support Team
Outside contractors will provide content as needed with approval of the Communication Leader. They will provide the majority of legislative/regulatory one pagers as well as in-depth situation and media analysis, white papers and development of all anticipated media content.

Client Services
Provide support for Market Participants. Public exposure to calls will be minimized by having Client Services provide data and information to the crisis team about questions and comments being received. Phone calls from the public will be handled in compliance with the "Strategy to Manage Public Inquiries."

Crisis Communications Team Assignments
At the launch of the Crisis Communications activities, the External Affairs department will be divided into three teams, each with assigned responsibilities and assigned work times. The teams and work times will not change during the event, except for substitutions.

Team A (8 a.m. – 8 p.m.)
Team A is primarily responsible for communicating to key audiences, including but not limited to news media, market participants, elected officials, and employees.

Leader – Director, Corporate Communications team member
Media Specialist – TBD (Contractor)
Communications Coordinator – Corporate Communications team member
Support Team – TBD (Contractor)
Web – Digital Content Management team member
Client Services – Director level, Client Services team member

Team B (8 p.m. – 8 a.m.)
Team B is primarily responsible for developing the materials needed the following day for Team A, as well as data analysis to support a strategic communications plan recommendation.

Leader – VP of External Affairs, Corporate Communications team member
Communications Coordinator – TBD (Contractor)
Support Team – Digital Content Management team member
Web – Digital Content Management team member
Client Services – Client Services team member

Team C (Substitutions for extended events)
Team C may be called to occasionally assist Team A, but they are primarily responsible for remaining ready to substitute for other members of the team during an extended event to allow those members to rest.

Communications Coordinator – Outside Contractor
Web – Penney Christian, Priyanka Parthasarathy
Support Team – Outside Contractor
Client Services - TBD

<u>Maximum Frequency for Researching, Developing and Distributing Messages (from Crisis Plan)</u>

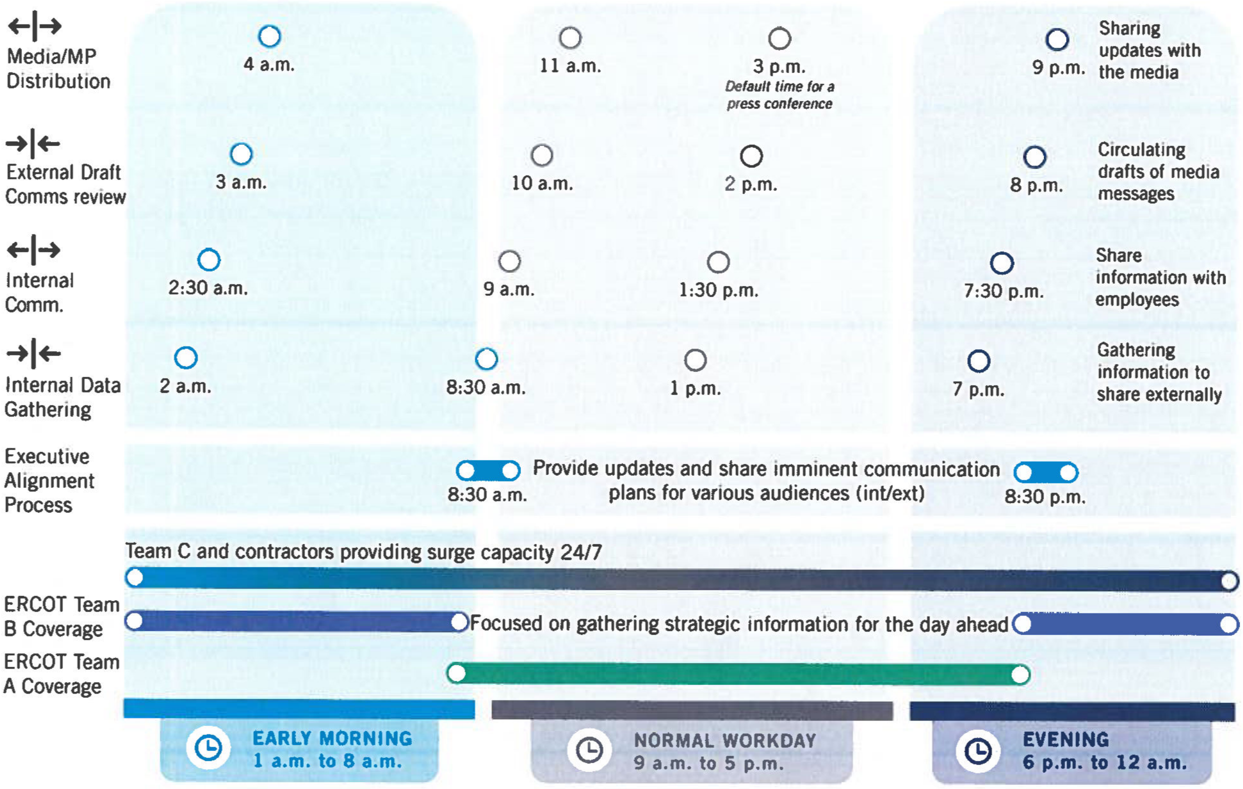
	ERCOT Internal Data Gathering	Internal Communications	External Draft Comms Circulation	Media/MP Distribution
Morning	2 a.m.	2:30 a.m.	3 a.m.	4 a.m.
Mid-Day	8:30 a.m.	9:00 a.m.	10 a.m.	11 a.m.
Evening	1 p.m.	1:30 p.m.	2 p.m.	3 p.m.
Night	7 p.m.	7:30 p.m.	8 p.m.	9 p.m.

<u>NOTES:</u>

1.) <u>The default time for a press conference should always be 3 p.m.</u>
2.) <u>This cadence represents the maximum frequency; actual event cadence will be determined at the start of the event based on significance, severity and anticipated duration.</u>

December 6, 2021

Timeline for Daily Crisis Communications (Maximum Frequency)



ATTACHMENT 4

176 FERC ¶ 61,119
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Richard Glick, Chairman;
Neil Chatterjee, James P. Danly,
Allison Clements, and Mark C. Christie.

North American Electric Reliability Corporation — Docket No. RD21-5-000

ORDER APPROVING COLD WEATHER RELIABILITY STANDARDS

(Issued August 24, 2021)

1. On June 17, 2021, the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO), submitted a petition seeking approval of proposed Reliability Standards EOP-011-2 (Emergency Preparedness and Operations), IRO-010-4 (Reliability Coordinator Data Specification and Collection), and TOP-003-5 (Operational Reliability Data) (collectively, the Cold Weather Reliability Standards).[1] NERC requested that the Commission approve the proposed Cold Weather Reliability Standards on an expedited basis. As discussed in this order, we approve the Cold Weather Reliability Standards, their associated violation risk factors and violation severity levels, NERC's proposed implementation plan, and the retirement of the currently-effective Reliability Standards immediately prior to the effective date of the revised Reliability Standards.

I. Background

A. Section 215 and Mandatory Reliability Standards

2. Section 215 of the Federal Power Act (FPA) requires a Commission-certified ERO to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval. Reliability Standards may be enforced by the ERO, subject to Commission oversight, or by the Commission independently.[2] Pursuant to section 215 of

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[1] The proposed Reliability Standards are not attached to this order. The proposed Reliability Standards are available on the Commission's eLibrary document retrieval system in Docket No. RD21-5-000 and on the NERC website, www.nerc.com.

[2] 16 U.S.C. 824o(e).

the FPA, the Commission established a process to select and certify an ERO,[3] and subsequently certified NERC.[4]

B. NERC Petition and Proposed Cold Weather Reliability Standards

3. On June 17, 2021, NERC filed its petition for approval of the Cold Weather Reliability Standards. NERC maintains that the proposed modifications to the Reliability Standards are consistent with Recommendation 1 of the 2018 Cold Weather Event Report;[5] specifically, NERC states that the proposed Reliability Standards "require generators to implement plans to prepare for cold weather and require the exchange of certain generator cold weather operating parameters that would help enhance situational awareness in the operational planning and Real-time operations timeframes."[6]

4. NERC proposes to revise currently effective Reliability Standard EOP-011-1 by adding two new requirements, Requirement R7 and Requirement R8, related to generator cold weather preparedness, including freeze protection and training. In addition, NERC proposes revising two requirement parts, Requirements R1.2.6 and R2.2.9, related to the consideration of the reliability impacts of cold weather conditions in transmission operator and balancing authority emergency operating plans.[7] Further, NERC proposes to revise the currently-effective title of Reliability Standard EOP-011-1 from "Emergency Operations" to "Emergency Preparedness and Operations" in proposed Reliability Standard EOP-011-2 and to modify the purpose statement to reflect the addition of the

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[3] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, 114 FERC ¶ 61,104, *order on reh'g*, Order No. 672-A, 114 FERC ¶ 61,328 (2006).

[4] *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *aff'd sub nom. Alcoa, Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

[5] FERC and NERC Staff, *The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018*, at 89, (Jul. 2019), https://www.ferc.gov/sites/default/files/2020-07/SouthCentralUnitedStatesColdWeatherBulkElectricSystemEventofJanuary17-2018.pdf, (2018 Cold Weather Event Report).

[6] NERC Petition at 13.

[7] *Id.* at 14.

generator owner as an applicable entity responsible for compliance with the proposed Reliability Standard.[8]

5. NERC proposes to revise the data requirements in the currently-effective versions of the Reliability Standards in proposed Reliability Standards IRO-010-4 for reliability coordinators and TOP-003-5 for balancing authorities and transmission operators to include cold weather data developed by the generator owner under Reliability Standard EOP-011-2, Requirement R7.[9] NERC also proposes to replace the term "Special Protection System" with "Remedial Action Scheme" throughout proposed Reliability Standards IRO-010-4 and TOP-003-5 to align the Reliability Standard language with the approved revised NERC Glossary definition of Remedial Action Scheme.[10]

6. NERC proposes an 18-month implementation plan for each of the Cold Weather Reliability Standards beginning on the first day of the first calendar quarter following the date of applicable regulatory approval. NERC explains that it considered the time necessary for generator owners to develop, implement, and train on their cold weather preparedness plans as well as the time for reliability coordinators, balancing authorities, and transmission operators to develop, issue, and receive data specifications with cold weather parameters.[11] NERC also requests retirement of the currently-effective Reliability Standards EOP-011-1, IRO-010-3, and TOP-003-4 immediately prior to the effective date of the revised Reliability Standards.

7. In addition to the proposed Reliability Standards, NERC also describes potential measures it may take to support reliability prior to the Cold Weather Reliability Standards' mandatory and enforceable date. For example, NERC explains that it may perform outreach and training; use the NERC Alert System; issue compliance practice guides; or use its Winter Reliability Assessment. NERC commits to keeping Commission staff aware of its cold weather preparation efforts.[12]

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[8] *Id.*

[9] *Id.* at 21-22.

[10] *Id.* at 23 (citing *Revisions to Emergency Operations Reliability Standards; Revisions to Undervoltage Load Shedding Reliability Standards; Revisions to the Definition of "Remedial Action Scheme" and Related Reliability Standards*, Order No. 818, 153 FERC ¶ 61,228 (2015)) (approving the revised definition of Remedial Action Scheme).

[11] *Id.* at 23-24.

[12] *Id.* at 24-25.

8. Finally, NERC notes that the joint inquiry by the Commission, NERC, and Regional Entities staff on the causes of the February 2021 cold weather event in the Midwest and South Central states is currently underway.[13] NERC states that, to the extent the inquiry leads to recommendations for further modifications of the Reliability Standards, it is "prepared to address those recommendations promptly through its standard development process."[14]

II. Notice of Filing and Responsive Pleadings

9. Notice of NERC's June 17, 2021 Petition was published in the *Federal Register*, 86 Fed. Reg. 37,750 (2021), with comments, protests, and motions to intervene due on or before July 29, 2021. The Edison Electric Institute filed a timely motion to intervene and the Electric Power Supply Association (EPSA) filed a timely motion to intervene and comments. PJM Interconnection, L.L.C. (PJM) and the Midcontinent Independent System Operator, Inc. (MISO) filed an out of time motion to intervene and comments.

III. Comments

10. EPSA expresses support for the proposed modifications to the Reliability Standards, noting that "it is imperative that preserving system reliability remain front of mind for policymakers and electric system stakeholders."[15] EPSA also highlights the comprehensive record supporting the need for modifications of the Reliability Standards to address recommendations from the 2018 Cold Weather Report.[16]

11. PJM and MISO state that they support NERC's proposed Cold Weather Reliability Standards.[17] PJM and MISO also recommend that the Commission encourage earlier implementation in certain regions at the "earliest date practicable within those regions."[18] PJM and MISO emphasize the need for comparability among entities' weatherization plans and "encourages" the Commission to clarify "its expectations as to the

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[13] *See FERC, NERC to Open Joint Inquiry into 2021 Cold Weather Grid Operations*, News Release (Feb. 16, 2021), https://www.ferc.gov/news-events/news/ferc-nerc-open-joint-inquiry-2021-cold-weather-grid-operations.

[14] NERC Petition at 25.

[15] EPSA Comments at 3.

[16] *Id.* at 4-5.

[17] PJM MISO Joint Comments at 3.

[18] *Id.* at 4.

comparability and documentation of the required plans."[19] Finally, PJM and MISO request the Commission clarify the need for annual and seasonal reporting requirements for generator owners to report plans to their Regional Entities for validation, which would provide such plans to reliability coordinators for informational purposes.

IV. Determination

A. Procedural Matters

12. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2020), the timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.

13. Pursuant to Rule 214(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214(d), we grant PJM's and MISO's late-filed motion to intervene and comment given their interest in the proceeding, the early stage of the proceeding, and the absence of undue prejudice or delay.

B. Substantive Matters

14. Pursuant to section 215(d)(2) of the FPA, we approve the Cold Weather Reliability Standards as just, reasonable, not unduly discriminatory or preferential and in the public interest. The Cold Weather Reliability Standards will help to address the reliability of the Bulk-Power System in the event of extreme cold weather.

15. While once described as "unusual," multiple events over the last ten years have highlighted the potential for extreme cold weather to impact the reliability of the Bulk-Power System.[20] Extreme cold weather has led to generating units experiencing outages, de-rates, and failures to start. NERC and Commission reports have identified the lack of generator winterization and lack of accurate data about generator operating limitations for cold weather,[21] which results in inaccurate operational planning analysis, as primary

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[19] *Id.* at 5.

[20] *See e.g.,* FERC and NERC Staff, *Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011: Causes and Recommendations* (Aug. 2011), https://www.ferc.gov/sites/default/files/2020-04/08-16-11-report.pdf; NERC, *Polar Vortex Review* (Sep. 2014) (2011 Report), https://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf; and the 2018 Cold Weather Event Report.

[21] *See, e.g.,* 2011 Report at 196 (noting that balancing authorities, reliability coordinators and generators often lacked adequate knowledge of plant temperature design limits, and thus did not realize the extent to which generation would be lost when

causes for such events. In response, the Cold Weather Reliability Standards improve situational awareness and enhance reliable operations by requiring generator owners to implement plans to prepare for cold weather and to provide certain generator cold weather operating parameters to the reliability coordinator, transmission operator, and balancing authority for use in their analyses and planning.

16. We agree with NERC that the proposed modifications to the Reliability Standards are consistent with Recommendation 1 of the 2018 Cold Weather Event Report.[22] We also appreciate that NERC completed the modifications in a timely manner, and we find that the modifications address the need to winterize and ensure the accuracy of design specifications for generating units and the need for balancing authorities and reliability coordinators to be aware of, and plan for, generating units' limitations during extreme cold weather.[23]

17. As described above, PJM and MISO emphasize the need for comparability among entities' weatherization plans and suggest that the Commission clarify its "expectations" on the matter. PJM and MISO also request that the Commission clarify the need for annual and seasonal reporting requirements for generator owners to report plans to their Regional Entities for validation, which would then provide such plans to reliability coordinators for informational purposes. PJM's and MISO's comments raise concerns regarding implementation of the proposed Reliability Standards, which are better directed to NERC and the Regional Entities. Accordingly, we deny the request for clarification.

18. Finally, we approve NERC's proposed implementation plan. The implementation plan provides that the Cold Weather Reliability Standards will become effective on the first day of the first calendar quarter that is 18 months after the issuance of this order.[24] This implementation plan is reasonable to accommodate entities that may need time to perform various engineering analysis; provide the required training; and develop the necessary capabilities to satisfy revised data specifications. Nevertheless, we strongly encourage entities that are capable of complying with the Cold Weather Reliability Standards earlier than the mandatory and enforceable date to do so. We also encourage

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temperatures dropped); 2018 Cold Weather Event Report at 78 (noting that a failure to properly prepare or winterize generation facilities was the primary cause of both the 2011 Southwest and the 2018 South Central Cold Weather Events); and *Id.* at 89 (noting the need for reliability coordinators and balancing authorities to have sufficient information to identify units that may not be able to perform during an extreme weather event).

[22] *Id.* at 86-87.

[23] *Id.* at 87.

[24] Specifically, the implementation date will be April 1, 2023.

NERC to pursue the measures it describes in its petition to support reliability during the upcoming winter season and any future winter season that elapses before the Cold Weather Reliability Standards are enforceable.[25]

V. Information Collection Statement

19. In compliance with the requirements of the Paperwork Reduction Act of 1995, 44 U.S.C. § 3506(c)(2)(A), the Commission is soliciting public comment on revisions to the information collection FERC-725S, Mandatory Reliability Standards for the Bulk Power System; EOP Reliability Standards; FERC-725A, Mandatory Reliability Standards for the Bulk-Power System: TOP Reliability Standard; FERC-725Z, Mandatory Reliability Standards for the Bulk-Power System: IRO Reliability Standards, which will be submitted to the Office of Management and Budget (OMB) for a review of the information collection requirements. Comments on the collection of information are due within 60 days of the date this order is published in the *Federal Register*. Respondents subject to the filing requirements of this order will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

20. The information collection requirements are subject to review by the OMB under section 3507(d) of the Paperwork Reduction Act of 1995.[26] OMB's regulations require approval of certain information collection requirements imposed by agency rules.[27] The Commission solicits comments on the Commission's need for this information, whether the information will have practical utility, the accuracy of the burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected or retained, and any suggested methods for minimizing respondents' burden, including the use of automated information techniques.

21. The number of respondents below is based on an estimate of the NERC compliance registry for balancing authority, transmission operator, generator operator, generator owner, and reliability coordinator. The Commission based its paperwork burden estimates on the NERC compliance registry as of May 14, 2021. According to

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[25] NERC Petition at 24 – 25 ("These measures may include winter weather readiness outreach and training, including site visits and webinars; the use of the NERC Alert System, such as to issue recommended actions to entities; and compliance practice guides. NERC may also use its Winter Reliability Assessment to help assess and document the industry's preparedness based on the input from the aforementioned activities and scenario analysis.").

[26] 44 U.S.C. § 3507(d).

[27] 5 C.F.R. § 1320 (2020).

the registry, there are 98 balancing authorities, 168 transmission operators, 943 generator operators, 1,017 generator owners, and 11 reliability coordinators. The estimates are based on the change in burden from the current standards to the standards approved in this Order. The Commission based the burden estimates on staff experience, knowledge, and expertise.

22. The estimates are based combination on one-time (years 1 and 2) and ongoing execution (year 3) obligations to follow the revised Reliability Standards.

23. For Reliability Standard EOP-011-2, balancing authorities and transmission operators have a one-time cost preparing Operating Plans to mitigate operating Emergencies related to cold weather conditions and generator owners creating and implementing cold weather preparedness plans and providing associated training. Additionally, reliability coordinators will need to review Operating Plans of the balancing authorities and transmission operators. In year three and ongoing, the estimates are lower to reflect the Operating Plans and cold weather preparedness plans are in place and applicable entities are following those plans.

24. For Reliability Standard IRO-010-4, in years 1 and 2 the reliability coordinators must update documented specifications for data to include provisions for notification of bulk electric system (BES) generating units during local forecasted cold weather events. Years 3 and ongoing estimates reflect documented specifications are in place and entities being aware of their responsibilities.

25. For Reliability Standard TOP-003-5, in years 1 and 2 the transmission operator and balancing authorities must update documented specifications for data to include provisions for notification of BES generating units' operating limitations during local forecasted cold weather events. Years 3 and ongoing estimates reflect documented specifications are in place and entities being aware of their responsibilities.

26. Burden Estimates: The Commission estimates the changes in the annual public reporting burden and cost as indicated below:

Proposed Changes Due to Final Rule in Docket No. RD21-5-000					
Reliability Standard & Requirement	**Type[28] and Number**	**Annual Average Number of Respons**	**Total Number of Responses (1)*(2)=(3)**	**Annual Average Number of Burden Cost ($)**	**Total Burden Hours (3)*(4)=(5)**

[28] TOP=Transmission Operator, BA=Balancing Authority, GO=Generator Owner, GOP=Generator Operator and RC=Reliability Coordinator.

	of Entity (1)	es Per Entity (2)		Hours per Response[29] (4)	
FERC-725S					
One Time Estimate - Years 1 and 2					
EOP-011-2	168 (TOP)	1	168	60 hrs. $4,005.60	10,080 hrs. $672,940.80
EOP-011-2	98 (BA)	1	98	60 hrs. $4,005.6	5,880 hrs. $392,548.80
EOP-011-2	1,017 (GO)	1	1,017	150 hrs. $10,014	152,550 hrs. $10,184,238.00
EOP-011-2	943 (GOP)	1	943	80 hrs. $2,670.40	75,440 hrs. $5,036,374.40
EOP-011-2	11 (RC)	1	11	40 hrs. $2,670.40	440 hrs. $29,374.40
Ongoing Estimate – Year 3 ongoing					
EOP-011-2	168 (TOP)	1	168	50 hrs. $3,338.00	8,400 hrs. $560,784.00
EOP-011-2	98 (BA)	1	98	50 hrs. $3,338.00	4,900 hrs. $327,124.00
EOP-011-2	1,017 (GO)	1	1,017	40 hrs. $2,670.40	40,680 hrs. $2,715,796.80
EOP-011-2	943 (GOP)	1	943	50 hrs. $3,338.00	47,150 hrs. $3,147,734.00
EOP-011-2	11 (RC)	1	11	20 hrs. $1,335.20	220 hrs. $14,687.20

[29] The hourly cost figures, for salary plus benefits, for the Reliability Standards are based on Bureau of Labor Statistics (BLS) information (at http://www.bls.gov/oes/current/naics2_22.htm), as of May 2020, 75% of the average of an Electrical Engineer (17-2071) - $72.15, mechanical engineers (17-2141) - $77.50. $72.15 + $77.50/2 = 74.825 x .75 = 56.118 ($56.12-rounded) ($56.12/hour) and 25% of an Information and Record Clerks (43-4199) $42.57 x .25% = 10.6425 ($10.64 rounded) ($10.64/hour), for a total ($56.12+$10.64 = $66.76/hour).

Total for FERC-725S(One time)	**2,237**		**2,237**		**244,390 hrs. $16,315,475.40**
Total for FERC-725S(Ongoing)	**2,237**		**2,237**		**101,350 hrs. $6,766,126.00**
FERC-725Z					
One Time Estimate - Years 1 and 2					
IRO-010-4	11 (RC)	1	11	720 hrs. $48,067.20	7,920 hrs. $528,739.20
Ongoing Estimate – Year 3 ongoing					
IRO-010-4	11 (RC)	1	11	360 hrs. $24,033.60	3,960 hrs. $264,369.60
Total for FERC-725Z(One time)	**11**		**11**		**11,880 hrs. $793,108.80**
Total for FERC-725Z(Ongoing)	**11**		**11**		**3,960 hrs. $264,369.60**
FERC-725A					
One Time Estimate - Years 1 and 2					
TOP-003-5	168 (TOP)	1	168	80 hrs. $5,340.80	13,440 hrs. $897,254.40
TOP-003-5	98 (BA)	1	98	80 hrs. $5,340.80	7,840 hrs. $523,398.40
Ongoing Estimate – Year 3 ongoing					
TOP-003-5	168 (TOP)	1	168	40 hrs. $2,670.40	6,720 hrs. $448,627.20
TOP-003-5	98 (BA)	1	98	40 hrs. $2,670.40	3,920 hrs. $261,699.20
Total for FERC-725A(Onetime)	**266**		**266**		**21,280 hrs. $1,420,652.80**
Total for FERC-725A(Ongoing)	**266**		**266**		**10,640 hrs. $710,326.40**

Titles: FERC-725S, Mandatory Reliability Standards for the Bulk Power System; EOP Reliability Standards; FERC-725A, Mandatory Reliability Standards for the Bulk-Power System: TOP Reliability Standard; FERC-725Z, Mandatory Reliability Standards for the Bulk-Power System: IRO Reliability Standards.

Action: Reductions to Existing Collections of Information FERC-725S, FERC-725A, and FERC-725Z.

OMB Control Nos: 1902-0270 (FERC-725S); 1902-0276 (FERC-725Z); and 1902-0244 (FERC-725A).

Respondents: Business or other for profit, and not for profit institutions.

Frequency of Responses: On occasion (and proposed for deletion).

Necessity of the Information: Reliability Standards EOP-011-2 (Emergency Preparedness and Operation), IRO-010-4 (Reliability Coordinator Data-Specification and Collection) and TOP-003-5 (Operation Reliability Data) are part of the implementation of the Congressional mandate of the Energy Policy Act of 2005 to develop mandatory and enforceable Reliability Standards to better ensure the reliability of the nation's Bulk Power system. Specifically, the revised standards ensure generating resources are prepared for local cold weather events and that entities will effectively communicate information needed for operating the Bulk Power System.

Internal review: The Commission has reviewed NERC's proposal and determined that its action is necessary to implement section 215 of the FPA.

27. Interested persons may obtain information on the reporting requirements by contacting the Federal Energy Regulatory Commission, Office of the Executive Director, 888 First Street, NE, Washington, DC 20426 [Attention: Ellen Brown, e-mail: DataClearance@ferc.gov, phone: (202) 502-8663].

28. All submissions must be formatted and filed in accordance with submission guidelines at: http://www.ferc.gov. For user assistance, contact FERC Online Support by e-mail at ferconlinesupport@ferc.gov, or by phone at (866) 208-3676 (toll-free).

29. Comments concerning the information collections and requirements approved and associated burden estimates, should be sent to the Commission in this docket and may also be sent to the Office of Management and Budget, Office of Information and Regulatory Affairs [Attention: Desk Officer for the Federal Energy Regulatory Commission]. OMB submissions must be formatted and filed in accordance with submission guidelines at www.reginfo.gov/public/do/PRAMain. Using the search function under the "Currently Under Review" field, select Federal Energy Regulatory Commission; click "submit," and select "comment" to the right of the subject collection.

30. Please refer to the appropriate OMB Control Number(s) 1902-0270 (FERC-725S); 1902-0276 (FERC-725Z); and 1902-0244 (FERC-725A) and Docket No. RD21-5-000 in your submission.

VI. Document Availability

31. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (http://www.ferc.gov) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington, DC 20426.

32. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

33. User assistance is available for eLibrary and the Commission's website during normal business hours from the Commission's Online Support at (202) 502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

The Commission orders:

The Commission, hereby, approves the Cold Weather Reliability Standards, associated violation risk factors and violation severity levels, implementation plan, and the retirement of the currently-effective Reliability Standards EOP-011-1, IRO-010-3, and TOP-003-4 immediately prior to the effective date of the revised Reliability Standards, as discussed in the body of this order.

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.

ATTACHMENT 5

ATTACHMENT 5

RRC Report on Natural Gas Facility Weatherization Best Practices

Background

In 2021, the Texas Legislature (SB 3, 87th Legislature, Regular Session, 2021) created the Texas Electricity Supply Chain Security and Mapping Committee comprised of executive leadership from the Public Utility Commission, the Railroad Commission, ERCOT, and the Texas Department of Emergency Management. Senate Bill 3 directed the Committee to establish best practices to prepare facilities that provide electric service and natural gas service in the electricity supply chain to maintain service in an extreme weather event and recommend oversight and compliance standards for those facilities.

The February 2021 winter storm in Texas resulted in a historically high demand for energy. Senate Bill 3 implemented new regulatory oversight to establish compliance standards, provide regulatory oversight for critical infrastructure that are part of the natural gas supply chain for power generation in Texas, and mitigate the risks of system outages during extreme weather conditions.

This report seeks to offer best practices to enhance weather preparedness for the natural gas industry.

Introduction

Natural gas production is broadly affected by several circumstances in a cold weather event. In addition to inadequate weatherization measures, loss of power, loss of telecom and inability to access facilities due to icy road conditions can lead to freeze-offs at natural gas facilities.

The natural gas industry depends on electric utilities to power the instrumentation, compression, pumps, and processing equipment that help move gas from the production fields to end users. The temporary loss of electric power can put a gas production, processing, compression, or storage facility out of service, and the resulting gas outages can then contribute to electricity shortages due to reduced fuel supply to gas fired electricity generating plants. Rolling electric blackouts or customer curtailments that can shut down electric pumping units or compressors on gathering lines may also result in prolonged gas production reduction.

Icy roads can prevent maintenance personnel and equipment from reaching wells to haul off produced water which, if left in holding tanks at the wellhead, can cause wells to shut down automatically. Icy roads can also cause an industry stop work order that prevents third party service personnel from driving on icy roads or inclement conditions. Stop work authority conditions can limit third party service companies from installing, servicing, and maintaining equipment to implement best practices for winter weather conditions.

Keeping gas production facilities in service is critical to maintain an adequate supply of natural gas, while keeping electric-powered compressors running is equally important to maintain adequate pressure in gas transmission lines. Critical load review for gas production and transmission facilities should identify the appropriate priority for power delivery in the event of system stress or load shedding.

Operators of gas supply chain facilities and gas pipeline facilities under the Railroad Commission's jurisdiction are expected to take all necessary measures to prepare to operate in the upcoming winter. The Commission's highest priority is to ensure that should another extreme winter weather event occur, all available natural gas under the jurisdiction of the Commission in the state is available as a reliable energy source for Texans.

Known Risks

Natural gas services, like electric services, can be negatively impacted by extended extreme weather conditions. Extreme weather conditions can trigger temperature related negative direct effects, as well as negative indirect effects that stem from those circumstances directly related to the weather event. During a period of prolonged winter weather conditions, it is critical for the state's electric and natural gas infrastructure systems to function despite the negative effects associated with below freezing temperatures.

Direct effects include icy roads, freezing of products in flow lines and instrumentation, as well as freezing of physical equipment such as compressors, pumps, or separation equipment, along the pathway of natural gas production and transportation. Examples of how these direct effects can impact operations are below:

1. Icy Roads can create unsafe travel conditions for those trained personnel who maintain producing equipment in good working order or to restart an equipment when there is a power outage.
    a. When winter weather conditions remain in an area for an extended period industry field staff may be unable to travel safely on icy roads to well sites, pipelines, or compressor stations to supply and maintain the installed weatherization equipment.
2. Water disposal may be impeded by icy roads, an electrical outage, or inadequate weatherization measures. These circumstances could result in an operator shutting in a well or shutting down a gas treating facility. To maintain stable gas production an operator must, in many instances, be able to dispose of salt water produced from gas wells or dispose of produced water removed at a gas treating facility.
    a. Generally, produced water is temporarily stored in tanks at producing locations and then removed by pumping it through pipes to disposal facilities, or by trucking the produced water from the production site to a disposal facility. If roads are too icy for trucks to operate, and water cannot be moved in other ways when the temporary on-site storage capacity is full, an operator must temporarily shut-in a well. If the water

pumps pushing the water through flow lines are powered by electricity provided by utility companies, an interruption in electrical service can both temporarily cause the operator to shut in the well, and indirectly cause the water lines to freeze up once the water stops moving.

b. Water removal from gas processing facilities faces similar challenges in extreme weather conditions. Electrically powered water pumps experiencing power outages, can experience problems associated with lubrication oil becoming too viscous due to cold temperatures and non-flowing water in the flow lines freezing. Pump equipment at gas processing facilities often rely on power delivered from the electric grid. If electrical power is impaired and water is not removed, once temporary storage capacity reaches its limit, the operator must shut down a gas treating facility.

c. Saltwater disposal well (SWD) operators often require electricity to power injection pumps. If facilities lose electricity, they are unable to take the salt water, often impacting many producing operators and facilities.

3. Natural gas flows directly from the producing wellhead can experience "freeze-offs" when outside temperatures fall below freezing in producing fields. When water produced entrained with natural gas crystallizes or freezes in surface flow lines, it can block the gas flow and can force the shutdown down of a well. A freeze-off can also occur with mechanical separation equipment at producing locations. Liquid dump valves used on separation equipment can become ineffective when outside temperatures fall below freezing unless the equipment is wrapped and warmed by an independent heat source. When separation equipment malfunctions, oil, gas, and water are not separated properly. An operator must shut-in a well until separation equipment can be restarted.

4. Instrumentation plays a large role in the safe and effective operation of production facilities, compressor stations, and gas processing. Instrumentation is included in an information loop that controls a process. Instruments often relay their information, such as pressure, flow rates, temperatures, or RPMs, to a central processor or directly to a controller via pressurized air lines. Any moisture in these air lines can easily freeze when outside temperatures fall below freezing. Although the volumes of moisture are quite small, the impact on an instrument's communication with its control device can often require an operator to shut down producing equipment, compressors, or gas processing facilities until a service technician can troubleshoot the blocked air lines.

Indirect effects can happen when electric power demands are shed from segments of the power grid. The loss of electricity can cause critical natural gas production equipment such as compressors, pumps, or separation equipment to experience a temporary interruption beyond the control of the gas producer, transportation company, or treating plant operator. If natural gas producing equipment lacks adequate electric supply, equipment cannot reliably deliver available gas, including gas needed to generate additional electricity. Rolling electricity blackouts or customer curtailments managed by utility companies can inadvertently cause disruptions in natural gas production. Modern electrically powered equipment at producing facilities, compressors, or processing facilities can be subject to electrical power disruptions during winter storms, which can limit the supply of natural gas to electrical power generating facilities. The interconnected natural gas and electrical power generation facilities are the first link of the supply chain in the state's critical infrastructure during an extreme weather event.

Best Practices

Identifying best practices relies on analysis of the following criteria: effectiveness, efficiency, relevance, sustainability, and the possibility of duplication. Implementing best practices depends on the specific geography and geology of individual well sites. Each operator is expected to take all necessary measures to prepare to operate in extreme weather conditions, given the unique circumstances of their well locations. To ensure that gas facility operators and gas pipeline facility operators prepare to operate during extreme weather conditions, the Commission's Oil and Gas Division and Oversight and Safety Division, through experience and research, identified the following best practices for weatherization:

- Submit appropriate critical load designation application forms for the winter season
- Instrument filters
- Methanol injection or drip
- Water removal by solids absorption
- Cold weather barriers
- Line heaters
- Glycol contact towers
- Drip pots
- Hot oil
- Hot lubricant and circulation heater for engine oil or fuel

This list is not all encompassing, but rather is informative of the practices that exist across the oil and gas industry. Other techniques such as installing instrument covers or heat tracing equipment for critical valves and regulators should be considered as additional preventative measures. Removing sludge and buildup from production and flow lines at a well site or a storage facility will also allow gas to flow unimpeded by frozen water molecules, should be done regularly as preventative maintenance. Keeping additional parts onsite can shorten the down cycle if repairs or replacement are necessary during extreme weather conditions.

The Commission will continue to identify best practices as we survey industry experts and other regulators and leverage contracted technical advisory services.

Submit appropriate critical load designation forms for the winter season

The Electric Reliability Council of Texas (ERCOT) provides an application through which a natural gas operator may request its facility be designated as a "Critical Load Serving Natural Gas-Fired Electric Generation." This designation is an important component of extreme weather preparedness. Forms must be filed with the local electric service provider. In 2021, the form needed to be filed no later than November 1, 2021 to allow electric service providers time to complete their winter extreme weather planning. To allow for summer extreme weather planning, the form is generally due in March of each year.

The Railroad Commission sent several notices to operators in 2021 to review the ERCOT application and file, as appropriate, with the local electric service provider(s).

The Railroad Commission new rules adopted on November 30, 2021 specify the criteria and process by which entities associated with providing natural gas in Texas are designated as critical customers or critical gas suppliers during an energy emergency. Upon final approval of the new rules found in 16 TAC §3.65, §3.107, an operator shall submit a bi-annual acknowledgement of its designation as a critical customer in accordance with the new rule.

Instrument filters

Instrument filters are a critical part of natural gas producing systems and should be installed, maintained, and verified to be in good working order, especially during winter weather. If the water in an air system leading to a control panel freezes it could send a false reading with the potential to cause associated problems, including shutting in equipment. Control of the producing system can often be maintained remotely, even if personnel are unable to reach a facility, if the control panels are receiving high quality responses from their various sensors. Instrument filters generally only clean small volumes of gas or air, and as such tend to work reliably well. They are often installed with redundancy so a filter can be used, shut off and diverted to another filter to allow the filter or desiccant inside the filter to be replaced. A maintenance program is critical for the continuous proper function of inline filters. Filter dryers provide a clean, dry supply of gas to controllers and other instrumentation that functions using instrument gas. Units function under high pressure and can eliminate both liquids and particulates. Filter dryers are in-line devices that hold either a shaped filter made from a material that will collect both fluids—oils and water—as well as solid particles of known sizes, or a dry material bed that acts as a desiccant for collecting moisture and filtering out solids. In-line ensure that control panels receive unimpeded signals from sensors at the well, along the flowlines, or at processing facilities. Proper signals at the control panels ensures that an operator can monitor and manage all equipment regardless of the weather.

Methanol injection or drip

Methanol injection is a well-documented, practical method to reduce the negative impact that hydrates can have on gas flow. Injecting methanol into gas flow streams can lower the freeze point of hydrates, which will effectively inhibit the formation of ice like structures in the flow stream. Hydrates are physical combinations of water and other small molecules found in natural gas that can produce a solid that has an appearance similar to ice. At low ambient temperatures, hydrates can develop a structure able to block normal gas flow in lines and orifices. Liquid methanol can be cost effective to prevent the accumulation of these ice-like structures when injected in a low-pressure point in the gas flow stream. The amount of methanol required to inhibit hydrates is directly related to the amount of water that is found in the gas stream. Methanol injection can replace the need for upstream glycol dehydration in some gas streams and allow gas to flow until it arrives at a processing facility where the remaining water is removed and gas is conditioned the to meet pipeline specifications. Methanol can also be used in gas reinjection systems installed to assist with gas lift for high-volume liquid (oil and water) horizontal wells.

Water removal by solids absorption

In a vapor state all gasses have the capacity to hold water, with drier gas devoid of water molecules that can freeze in low temperatures. Under properly managed conditions, a solid absorption system can reliably work in any weather condition to absorb water as natural gas passes through dry chemical beds. Water removal by solids absorption (desiccant bed) methods can achieve a very dry natural gas stream under certain conditions. On a producing location at the well pad, wet gas is directed into an inlet separator to ensure removal of contaminants and free water from the original gas stream. After the separator, the gas stream is directed into an adsorption tower where water is adsorbed—the adhesion of atoms, ions or molecules from a gas, liquid or dissolved solid to a surface—by the desiccant. When the adsorption tower approaches maximum loading, the gas stream is automatically switched to another tower allowing the desiccant in the first tower to be regenerated. This method usually requires at least two desiccant towers to ensure that a tower is always full of a dry desiccant, rather than a water saturated desiccant. When the equipment is designed and installed properly, and the desiccants are systematically replenished, the removal of water by mechanical and solids absorption is an effective method for creating a dry steam of natural gas with little potential to freeze downstream of the separators. Care must be taken to analyze the amount of water remaining in the gas stream after leaving the separator.

Cold weather barriers

In extreme weather environments locating critical equipment underground or inside heated buildings is required for much of the year and provides necessary safeguards for points along the path of natural gas flow. Cold weather barriers, although effective, are generally not temporary or short-term solutions, and are not as prevalent in all climates. Cold weather barriers, such as wind walls, may be installed around certain compressors to block cold winds which could exacerbate freezing conditions. Wrapping and insulating surface equipment, injection lines, supply valves, water lines, and other equipment may also help to prevent freezing and stoppage of both natural gas and produced water flow. The methods for installing weather barriers and insulating natural gas equipment from cold air temperatures are diverse. Burying flow lines is an effective method to control flowline temperatures. Insulated wrapping can be effective for some equipment, while forced air heating inside buildings as well as small pumps to circulate compressor lubricants can maintain equipment temperatures above the freezing point. Cold weather barriers need to be systematically reviewed, designed, and implemented based on weather conditions that are known to exist at a specific natural gas facility.

Line heaters

Line heaters are a common form of equipment in the production of natural gas and a best practice for some geographic areas, specifically for gas wells that are being choked back at the wellhead, often earlier in a well's producing life. Line heaters heat the gas to avoid freezing immediately downstream of the wellhead. They are commonly used in wells that flow predominantly gas and small amounts of water, with no appreciable oil. The equipment uses a gas fired flame to heat a fluid filled chamber inside the body of the line heater. Gas passes through a coil that is immersed in a chamber of warmed fluid, which increases the temperature of the natural gas as it passes. Line heaters can be sized for high or low pressured wells that pass natural gas through a wellhead choke, which can cool gas to the point of freezing—a Joule-Thompson effect that functions much the same as a conventional refrigeration system. This type of cooling can create an ice formation, particularly when ambient temperatures around the choke are at or below freezing. Line heaters, when sized appropriately for the volume of gas being produced, effectively heat gas in the vicinity of the wellhead before it reaches downstream separation or treating equipment. Downstream of a line heater the potential still exists for freezing with low ambient temperatures, but a line heater can effectively mitigate freezing at the first potential point of freezing off the wellhead.

Glycol contact towers

Glycol units are an accepted industry standard practice and are effective at removing water from a stream of natural gas typically to meet typical pipeline and process specifications. Dry gas that leaves a glycol unit has little propensity to freeze. Relatively low-cost glycol absorption towers can be installed quickly, with a single skid able to service more than one well. This allows a range of options and flexibility to configure systems to address a broad range of gas flow rates and water volumes. While operational costs are generally proportional to the flowing natural gas volumes, such systems can vent releases of both steam and a measurable quantity of hydrocarbon gases. Used as a liquid desiccant, glycol can be introduced through a series of trays, or stages within a unit placed downstream of the wellhead before gas enters a commercial pipeline. Wet gas enters at the bottom of an absorber tower and ascends through a mist extractor where water is removed. As the gas rises through the tower's packing or bubble cap trays water is absorbed by the descending lean glycol, which is continually pumped to the top of the tower. Drier gas exits the top of the tower and passes through a heat exchanger to the gas outlet. The removal of water by glycol is an effective method for creating dry natural gas with little potential to freeze downstream of the separators.

Drip pots

Drip pots are a best practice for most producing systems that can be incorporated along with other winterization practices. Drip pots and coalescers can eliminate or reduce the amount of water when there is a slug of liquid in a gas supply used for instrumentation, or other severe liquid issues. Drip pots come in many shapes that are made primarily from the same materials as the flowlines carrying natural gas. They are located immediately after pressure changes, abrupt increases in flow area, or the lowest elevations in a continuous producing system. Drip pots work by allowing gravity to separate water from gas where the temperature of gas decreases following a significant pressure change. The cooling effect of a notable pressure change can cause liquids to fall out of the gas stream into the drip pot. The natural effects of gravity can cause water to drop from gas at low spots in a flow line. These low spots in flow lines can be an ideal place to locate a drip pot where water is likely to collect. A manual valve or collection system can pull water from the gas stream; a collection system on a timer with servo controls can also automatically dump accumulated water. Drip pots primarily remove larger volumes of water that collect in flow lines, which can cause a hydraulic impedance increasing the pressure drop along a flowline. Drip pots do not generally dry gas or winterize a producing system, but they can reduce the amount of water that reaches downstream natural gas separation or treating facilities. The removal of water will reduce the potential for freezing at points along the gas producing system.

Hot oil

Hot oil can be used to remove paraffins and dissolve asphaltenes to help keep wellbores clean. A hot oil unit uses propane carried on a truck to heat fluid that is drawn into an onboard tank, and then pumped back into the original container—a tank or well—on location. Heating produced oil is one method used to break an oil water emulsion that is susceptible to freezing. Circulating oil through a hot oil truck can raise the temperature, and thus lower the interfacial tension between the oil and water breaking the emulsion. Once the emulsion is broken oil will float to the top of the tank and water settle at the bottom. When the water has had a requisite settling time, a vacuum truck can remove the water from the bottom of the tank. This technique is preventative in its removal of water before it can freeze.

Hot lubricant and circulation heater for engine oil or fuel

Large pieces of oil and gas field equipment, such as pumps or compressors, rely on lubricants to move under pressure, as they are designed to reduce metal on metal contact. Lubricants keep these large pieces of equipment from overheating using fluids that are much more viscous than standard engine oils. When equipment is running lubricant is warmed by the mechanical action of the moving parts. At operating temperatures apparent viscosity can be relatively low, but when ambient temperatures drop to near freezing, viscosity can increase causing lubricants to begin to appear as a solid. When machinery is shut down the lubricant temperature can drop increasing its viscosity. At freezing temperatures pumps designed to circulate lubricant have difficulty functioning. Installing external block heaters with an external energy source such as a gas fed flame or electricity can maintain lubricants at an appropriate temperature, even when the equipment is not operational, making it easier to restart the equipment by keeping the oil/fuel in the engine at an elevated temperature. Using these techniques can keep pumps and compressors functional and prevent freeze-offs.

Human Capital

While weather specific technologies, including those discussed above, are critical to sustain natural gas production during cold weather conditions, the maintenance and operation of these technologies begins with human capital—the people trained and able to ensure natural gas continues to serve its essential function in the electricity supply chain despite adverse conditions. Human capital and experience of employees, along with appropriate safety and technical training specific to extreme weather events is an essential component of reliability and resiliency planning. Increasing staffing levels in advance of an extreme weather event ensures that appropriately trained employees are readily available, if they're not pre-positioned on-site, to resolve any equipment or instrumentation failures should temperatures fall below an acceptable operating temperature for sensitive equipment or instruments.

Conclusions

For new installations, careful planning during the design stage for measurement and regulating systems can reduce the chances of freezing. Any steps that reduce restrictions or prevent areas where liquids can collect will minimize the possibility of freezing. For existing installations, the best practices detailed above, along with any other practices not detailed in this report, should be implemented, as appropriate to the site-specific geography and geology, to prepare facilities providing natural gas critical to the electricity supply chain to maintain service in an extreme weather event.

Load Shed Protocols for the Electric Reliability Council of Texas (ERCOT) Region

Public Utility Commission of Texas

August 31, 2022

Senate Bill 1 (SB1),[1] passed by the 87th Texas legislature, requires the Public Utility Commission of Texas (Commission) to study the effects of load shed protocols in the Electric Reliability Council of Texas (ERCOT) power region. ERCOT conducted a load shed study (2021 Study) in 2021 following winter storm Uri. This 2021 Study identified the individual load shed capabilities and rotating load shed capabilities of all 19 transmission operators (TO) in the ERCOT power region.

Rulemakings

Since 2021, the Commission has implemented legislation related to load shed issues including:

- Adding new categories of critical load designations for load shed,
- Establishing a requirement for filing load shed procedures within the emergency operations plans of entities responsible for implementing load shed,
- Requiring retail electric providers to periodically provide information to customers about the electric utility's procedures for implementing load shedding,

[1] SB 1 (General Appropriations Act) Load Shed Protocols Study. "Using funds appropriated to the Public Utility Commission of Texas, the commission shall study the effects of load shed protocols in ERCOT, as that term is defined by Section 31.002, Utilities Code, and issue a report on the conclusions of the study to the legislature not later than September 1, 2022."

- Requiring ERCOT to conduct load shed exercises, and
- Mapping the Texas electricity supply chain.

In doing so, the Commission conducted rulemakings described below.

- In November 2021, the Commission adopted amendments to existing 16 Texas Administrative Code (TAC) §25.52, relating to Reliability and Continuity of Service. These amendments add end stage renal disease facilities to the list of health facilities prioritized during power restoration after a load shed and increase coordination between the electric and gas industries during energy emergencies by requiring designation of certain natural gas entities and facilities as critical during an energy emergency.

- In December 2021, the Commission adopted amendments to 16 TAC §25.479 that require electric utilities and retail electric providers to periodically provide to customers information concerning load shed, type of customers and procedure to be considered for critical care or critical load, and reducing electricity use at times when load shed events may be implemented.

- In February 2022, the Commission adopted a new rule 16 TAC §25.53, which implements standards for emergency operations plans required of electric utilities, transmission and distribution utilities, power generation companies, municipally owned utilities, electric cooperatives, retail electric providers, and ERCOT.

- In May 2022, the Commission adopted new 16 TAC §25.57 that establish the criteria for the content, activation, and termination of regional and statewide power outage alerts.

Load Shed in ERCOT Power Region

ERCOT is the reliability coordinator that can issue load shed instructions in the ERCOT power region. Load shed is a controlled and temporary interruption of electrical service used as a last resort to restore balance to the bulk electric system. Transmission Operators (TOs), Transmission Service Providers (TSPs) and Distribution Service Providers (DSPs) together implement ERCOT's load shed instructions.

A TSP is an entity under the jurisdiction of the Commission that owns or operates transmission facilities in the ERCOT transmission grid. Transmission facilities include power lines, substations, and associated facilities, operated at 60 kV or above. A DSP is an entity that owns or operates a distribution system for the delivery of energy from the ERCOT transmission grid to customers. The distribution system is part of the electric delivery system operating under 60kV. Transmission and distribution systems are commonly thought of as, respectively, the highways and byways of the grid.

Each TSP and DSP interacts with ERCOT through its TO. A TO communicates with ERCOT and is responsible for preserving reliability for a particular portion of the ERCOT system. The ERCOT Protocols require each TSP and each DSP to either register as a TO or designate another entity as its TO. A TO has complete authority to act on behalf of the designating TSP or DSP in the performance of all TO responsibilities. Each TO operating in the ERCOT power region is bound to follow load shed instructions given by ERCOT. In turn, each DSP is also obligated to follow any reasonable instruction given by its TO to fulfill its load shed obligations.

When ERCOT issues instructions for a certain amount of load to be shed, the percentage of that load that each TO is responsible for shedding is its load shed obligation. Load shed obligations are determined by ERCOT for each TO based on its peak load from the prior year. These percentage thresholds are reviewed by ERCOT and revised annually to reflect any new or changed TO designation.

Table 1 below shows the current load shed obligations by TO. Each TO decides how to allocate its load shed responsibility at the distribution level. ERCOT does not have visibility into or authority over which customers or feeders experience a temporary outage during a load shed event.

Table 1: ERCOT Load Shed Obligation by Transmission Operators, 2021

Transmission Operator	2021 Total Transmission Operator Load (% MW)
AEP Texas Central Company	8.41
Brazos Electric Power Cooperative Inc.	4.85
Brownsville Public Utilities Board	0.37
Bryan Texas Utilities	0.52
CenterPoint Energy Houston Electric LLC	25.89
City of Austin DBA Austin Energy	3.54
City of College Station	0.28
City of Garland	0.73
City of Lubbock	0.58
CPS Energy (San Antonio)	6.44
Denton Municipal Electric	0.48
GEUS (Greenville)	0.14
Golden Spread Electric Cooperative Inc.	0.36
Lamar County Electric Cooperative Inc.*	0.07
LCRA Transmission Services Corporation	5.89
Oncor Electric Delivery Company LLC	35.47
Rayburn Country Electric Cooperative Inc. DBA Rayburn Electric	1.34
South Texas Electric Cooperative Inc.	1.92
Texas-New Mexico Power Company	2.72
ERCOT Total	100

*Lamar County Electric Cooperative is a registered TO not on the ERCOT Hotline, City of Garland receives all their calls.
Source: https://www.ercot.com/files/docs/2022/04/18/ERCOT_Load_Shed_Table_Anticipated.xlsx

TOs, along with TSPs and DSPs, determine whether load shed rotation is feasible and how that load shed rotation will be implemented. Load shed rotation or rotating outages prevent individual customers from experiencing extended outages and bearing the full burden of the load shed event.

Discretion for determining load shed and load shed rotation priorities rests with TOs, TSPs and DSPs, because these entities have greater insight into the characteristics and capabilities of their individual systems than ERCOT or the Commission. For example, the load composition, which refers to the mix of different types of load on the system (e.g., transmission-connected industrial, residential, commercial, non-interruptible network, critical, etc.), varies widely by TO, and many of these load types present unique challenges from a load shed perspective. Larger TOs may have as much as 10-20% transmission-connected industrial load, which refers to large industrial facilities that connect directly to the transmission system rather than to the distribution system. Because most load shed is implemented at the distribution level, a high percentage of transmission-connected industrial load makes executing load shed instructions more difficult for these TOs. Similarly, TOs with a larger number of level one trauma centers and other critical facilities must often make deeper cuts in other categories to avoid outages to these facilities.

While the load shed and power restoration priorities established by each entity differ based on the unique characteristics of its system, all entities try to avoid shedding circuits with critical load. Examples of critical load include public safety customers, chronic condition or critical care residential customers, certain industrial customers with potentially hazardous industrial processes, and natural gas facilities that are essential to the electricity supply chain. However, it is important to note that critical status designations do not guarantee customers an uninterrupted supply of energy during a load shed event.

Load Shed Protocols in ERCOT Power Region

There are four main conditions during which load shed is necessary to restore balance to the bulk electric system. A brief overview of these conditions is provided below, and more detailed explanations are found in the ERCOT Nodal Operating Guides available on the ERCOT website.[2]

Under-Frequency Load Shed (UFLS)

The ideal frequency for the ERCOT bulk electric system is 60 Hz, at which supply and demand of power are perfectly balanced. When the system frequency deviates from 60 Hz by certain defined thresholds, North American Electric Reliability Corporation (NERC) reliability standards require TOs to respond with automatic under-frequency load shedding (UFLS). During an under-frequency event, each TO must provide load relief by shedding the required percentage of its DSP load and transmission-level customer load using TO-selected automatic underfrequency relays. Each TO must shed a percentage of its load determined by which frequency threshold has been crossed, as noted on Table 2. TOs must maintain an operational plan for immediate execution that identifies UFLS feeders based on the predictability of

[2]https://www.ercot.com/files/docs/2022/06/30/July%201,%202022%20Nodal%20Operating%20Guide.pdf

demand on these feeders and to achieve geographic diversity in the feeders selected. Overall, at least 25% of the ERCOT system load must be equipped for automatic UFLS at all times.

An under-frequency event that would trigger the use of UFLS is uncommon and would take the sudden loss of approximately 6,265 MW of generation to reach the first UFLS Stage of 59.3 Hz. ERCOT Nodal Operating Guides Section 2.6.1, *Automatic Firm Load Shedding,* describes in detail the TO and DSP responsibilities to comply with these requirements.

Table 2: Under-frequency Relays and TO Load Relief

Frequency Threshold	**TO Load Relief**
59.3 Hz	At least 5% of the TO Load
58.9 Hz	At least 15% of the TO Load
58.5 Hz	At least 25% of the TO Load

Under-Voltage Load Shed (UVLS)

UVLS is a voluntary measure used by some TSPs in certain areas as a safety net to limit the impacts of under voltage conditions or voltage dips. While the effects of these under voltage conditions are localized, they can include voltage instability, voltage collapse, and cascading outages. To mitigate these conditions, a UVLS program uses distributed relays and controls to shed load automatically to restore system balance in the local area. Because these systems are automated, they are not designed to respond to ERCOT directives, rather they are preset to respond to real time conditions. However, a TO will consult with ERCOT while developing a UVLS program.

UVLS programs are governed by NERC reliability standard PRC-010, but there is no requirement for any entity to implement a UVLS program. Furthermore, because UVLS programs address localized issues, load shed as part of a UVLS program – or load shed to address other types of local emergencies – is not limited by or count towards a TO's load shed obligation as listed on Table 1 above.

Emergency Load Shed

During a temporary decrease in available electricity supply it may be necessary to reduce ERCOT system electricity demand by way of shedding load to maintain system reliability. A drop in supply may be caused by an unexpected loss of generation, transmission equipment, or other key facilities.

ERCOT directs load shed after it has used all available resources and measures to respond to sudden system frequency disturbances or to maintain sufficient Physical Responsive Capability (PRC). PRC is the total amount of resource capability online and available to respond to system frequency disturbances. When the ERCOT PRC falls below 1,000 MW and is not projected to recover above 1,000 MW within 30 minutes, or when the average system frequency falls below 59.91 Hz for 25 consecutive minutes, ERCOT directs TOs to shed load in 100 MW blocks to maintain a steady state system frequency at a minimum of 59.91 Hz. ERCOT Nodal Protocols Section 6.5.9.4.2*, EEA Levels,* describes various levels of Energy Emergency Alert (EEA) and the actions ERCOT must take at each level to preserve the bulk electric system.

Load Shed to Maintain Transmission Security

To comply with NERC reliability requirements, ERCOT must operate the bulk electric system within specified operating limits. Failure to operate the system within these limits can permanently damage equipment that generates, delivers, or uses electricity. When all other mitigation measures, such as transmission reconfiguration and re-dispatching generation, are insufficient to secure system reliability, ERCOT will shed load to ensure that the bulk electric system remains within its operating limits. The ERCOT Transmission and Security Operating Procedure describes this process in detail. Load shed may be implemented to prevent cascading outages.

ERCOT Load Shed Study 2021

ERCOT initiated the 2021 Study to gather substantive and current information about the load shed and rotating outage capabilities of all TOs operating in the ERCOT power region. ERCOT sent out Requests for Information (RFIs) to each of the 19 TOs for available load that could be reasonably shed during an emergency event. Two separate RFIs were sent to each TO. To identify summer seasonal variations in the available load that can be shed, an RFI was sent in May 2021. Another RFI was sent in November 2021 to gather information about the winter seasonal variations. The 2021 Study helped ERCOT better understand how fast load shed might occur, increase its overall situational awareness, and adjust communication processes.

Load Shed RFIs

Each TO provided information about its individual percentage share of load shed obligation and specific load shed responsibility in MWs across three peak electricity demand scenarios for the summer and winter seasons. The three summer peak demand scenarios were based on ERCOT system wide loads of 60 GWs, 70 GWs, and 80 GWs, and the three winter peak demand scenarios were based on ERCOT system wide loads of 55 GWs, 65 GWs, and 75 GWs.

The RFIs also sought data about each TO's load responsibility on critical circuits, UFLS, non-interruptible network load, transmission connected industrial load categories, and the remaining percentage of load not in one of these categories.

Critical circuits load responsibility is the portion of each TO's total load on circuits designated as critical. TOs attempt to exclude these circuits from load shed whenever possible. This category can include circuits with end users such as hospitals, police stations, or gas compression facilities.

UFLS load shed responsibility is the percentage of each TO's total load reserved for under frequency load shed and is otherwise excluded from other types of load shed.

Non-interruptible network loads exist in dense downtown areas of major cities and other similar locations that are served by multiple, redundant distribution feeders. These redundancies make shedding load on a feeder-by-feeder basis unworkable. Networked circuits may also power vital communication equipment, hospitals, warming centers, essential government buildings, and streetlights; and shutting down these networks would also shut down these critical facilities.

Transmission-connected industrial load includes facilities such as refineries and manufacturing plants that may have complex industrial processes. Sudden loss of power to these loads could create dangerous conditions at the facility. TOs avoid shedding these loads due to the sensitivity of industrial processes and public safety concerns.

In response to the RFIs, each TO also identified the percentage of its load that can be shed via automated control systems and what percentage can only be shed manually by field personnel. These automated systems, known as Supervisory Control and Data Acquisition

(SCADA) systems, use a combination of computer programs and user interfaces to monitor, control, and manage industrial processes. TOs' abilities to shed load using SCADA systems vary and not all TOs, TSPs and DSPs have SCADA systems.

The RFI required each TO to identify the time periods within which these loads can be shed and whether they can be shed on a rotating basis. Information was also requested about percentage load on UFLS that can be shed by TOs while maintaining the minimum 25% UFLS obligation described above.

ERCOT aggregated the data gathered from the summer RFIs and presented this information at a Commission workshop on July 26, 2021. The specific RFI responses are classified as ERCOT Critical Energy Infrastructure Information (ECEII) and thus cannot be shared publicly.

Load Shed Capability

The 2021 Study results indicate ERCOT's summer load shed capability at a peak demand of 80 GW was 46%. This includes the UFLS megawatt capacity that could be shed while maintaining the requirements that TOs reserve 25% their loads for UFLS load shed. The system wide load shed capability was reduced to 40% if the TO's entire UFLS equipped load – not just the load required to meet the 25% UFLS requirement - was excluded from its load shed. ERCOT's winter load shed capability at a peak demand of 75 GW was 40% when only required UFLS equipped load was excluded and 35% when all UFLS load was excluded.

The decrease in load shed capability from the summer RFI responses to the winter RFI responses is due to differences in how electricity is used by consumers in different seasons. Residential and commercial electricity usage is higher in summer compared to winter. The largest portion of residential and commercial electricity usage is for air conditioning. Accordingly, the seasonal deviation in usage is smaller in regions that have electric heaters rather than gas heaters.

Table 3: ERCOT Seasonal Load Shed Capability

Description		Summer			Winter		
		60 GW	70 GW	80 GW	55 GW	65 GW	75 GW
1	Load Responsibility not on Critical Circuits, UFLS, Network Load (non-interruptible), or Transmission-connected Industrial load MW	23,346	27,494	31,450	18,755	22,637	26,323
2	- SCADA Interruptible	22,910	26,983	30,838	18,405	22,188	25,776
3a	- Can be shed within 5 minutes (SCADA & Manual)	4,677	5,431	6,258	4,078	4,930	5,796
3b	- Can be shed within 10 minutes (SCADA & Manual)	5,883	6,782	7,748	4,539	5,386	6,236
3c	- Can be shed within 15 minutes (SCADA & Manual)	13,265	15,577	17,831	10,298	12,374	14,385
3d	- Can be shed within 30 minutes (SCADA & Manual)	23,001	27,068	30,951	18,018	21,663	25,149
4a	- Can be rotated by SCADA	22,215	26,129	29,846	17,694	21,293	24,704
4b	- Can be rotated Manually	312	360	427	245	296	349
5	UFLS MW that can be shed while maintaining 25% minimum requirement	4,255	5,137	5,921	2,281	2,951	3,716
6	Total Interruptible Load (#1 plus #5)	27,601	32,631	37,372	21,036	25,587	30,040

Load composition within a TO load affects the total amount of load that can be shed or rotated on a TO's system. Some TOs may have no non-interruptible network load or industrial load while other TOs may have over 20% of their load serving non-interruptible network load or industrial load. Additionally, many TOs have 20% to 30% of their load designated as critical circuits. The load shed capability may be limited by the need to avoid the use of circuits that provide UFLS, serve critical loads, or are on non-interruptible networks. Those TOs without any non-interruptible network load have more flexibility for load shed and load rotation.

The RFI responses indicated that TOs' available load shed capability may vary based on specific weather conditions, time of the day, and season. The percentage of transmission-connected industrial load decreases as the total system load increases. Industrial load typically has smaller fluctuations throughout the day than residential and commercial load. It forms a lower percentage of the overall load during the day when the residential and commercial demand is comparatively higher than in the night. During non-peak hours, industrial load makes up a higher percentage of TOs' load because this load voluntarily reduces electricity usage in response to peak electricity prices.

During winter, residential and commercial load is comparatively lower; therefore, industrial load makes up a higher percentage of a TO's load. However, during the summer months, some industrial loads voluntarily reduce demand to lower their transmission costs.

The largest three TOs, by percentage share of ERCOT load shed obligation, have lower load shed capability as compared to other TOs, as shown on Table 4, due to a low percentage of interruptible load.

Table 4: TO Seasonal Load Shed Capability

TO	SUMMER TO Interruptible Load (%) Excluding UFLS and Critical Loads at 80GW	WINTER TO Interruptible Load (%) Excluding UFLS and Critical Loads at 75 GW
TO1	41%	32%
TO2	45%	41%
TO3	31%	31%
TO4	44%	44%
TO5	28%	25%
TO6	27%	26%
TO7	55%	55%
TO8	65%	65%
TO9	N/A	50%
TO10	53%	60%
TO11	30%	31%
TO12	46%	45%
TO13	N/A	57%
TO14	50%	54%
TO15	56%	45%
TO16	40%	34%
TO17	57%	57%
TO18	46%	34%
TO19	50%	41%

**Note: Data for certain new ERCOT members is unavailable for summer season*

Load Shed Implementation

Most TOs use SCADA systems for load shed. Loads that can be shed by using SCADA systems are called SCADA-interruptible loads. These loads can be shed within 30 minutes. While some SCADA-interruptible loads can be shed in as few as five minutes, others take longer due to communication and manual progress tracking that involves identifying and dropping individual feeders and tracking load shed progress. Therefore, only a small portion of load that is on SCADA automated applications can be shed within ten minutes. These progress tracking procedures and processes vary by TO according to their system characteristics and may lead to differences in the time needed to shed load using SCADA systems.

The 2021 Study assessed that at a peak summer electricity demand of 80GWs nearly 38% of ERCOT load was SCADA interruptible load. During the peak winter electricity demand of 75GWs, this figure fell to 34%.

Table 5: TO Load Shed Systems

Description		Number of TOs
SCADA Systems	Automated Application	8
	Personnel Selected	6
Manual (Field Personnel)		1
Mixture (SCADA and Manual)		4
Total		**19**

SCADA systems can have different operational capabilities, including whether they are personnel selected or automated applications. SCADA-Personnel Selected refers to systems that rely upon TO personnel to select individual load feeders that need to be shed to meet the TOs' load shed obligation. These feeders can only be turned on or off by personnel inside the substations. A TO with this type of system drops one load at a time by opening individual breakers and switches. Although the TO does not have to send personnel to *physically* open breakers and switches, identifying the mix of load to shed and dropping each load one-by-one by utility staff takes time.

SCADA-Automated Application refers to systems that have a single button click in the control system to identify the mix of loads to shed in defined geographic areas. These computerized operations automatically calculate the amount of load on each feeder and when to sequentially turn feeders off and on during a rotation to speed rotate and reduce load fluctuations. Utility staff must continue to monitor a computerized system and may take direct control when circumstances warrant.

Load Shed Rotation Capabilities

Nearly 37% of load could be rotated via SCADA during summer months as compared to 32% during winter months in the ERCOT power region, according to the 2021 Study.[3] TOs have

[3] The 2021 Study only required TOs to provide information related to their load shed and rotating outage capabilities and does not include substantial information or insights about the rotating outage capabilities of DSPs, who are largely responsible for rotating outages at the distribution level.

different capabilities to shed load on a rotating basis. The capability to rotate load depends on characteristics such as TO load composition and the availability of SCADA systems. Most TO feeder breakers have SCADA controls that allow TO personnel to remotely open and close a breaker to shed or restore load. This allows more frequent rotation of load shed. However, not all distribution level systems are SCADA enabled. Non-SCADA systems require a technician to physically go to a location to open or close a breaker or disconnect breakers. The frequency at which a load is rotated also depends on the TOs load shed procedures and the amount of load shed requested.

Moreover, load normally controlled via SCADA can be impacted by abnormal system conditions, communication issues, and cold load pick up issues that would impede the ability to switch remotely. Cold load pick up is the brief initial spike of power when a de-energized load is re-energized before it settles out to normal. This initial spike could, in some cases, cause protective relay actions to trigger or breakers to trip making it difficult to switch or rotate.

There are no guidelines on the amount of time a load can be out of service during a load shed event. Some TOs do not have a defined maximum time to rotate an outage but do have a target time. A common target is 30 minutes, but some larger TOs have a rotating target time of up to several hours. Several TOs noted that rotating outage target time is proportional to the magnitude of the load shed instructions issued by ERCOT.

ERCOT Protocol Revisions

In December 2021, the Commission approved Nodal Protocol Revision Request (NPRR) 1094. This allows a TO and a Transmission and Distribution Service Provider to manually shed load connected to under-frequency relays during an EEA Level 3 event if the affected TO can meet its overall 25% UFLS requirement and load shed obligation.[4] This NPRR increases the load available for rotating outages and helps spread the burden of those outages to a larger and more diverse pool of load.

[4] Nodal Operating Guides Section 2.6.1, Automatic Firm Load Shedding, and Nodal Operating Guides Section 4.5.3.4, Load Shed Obligation.

ERCOT Load Shed Exercises

As required by SB3, ERCOT has conducted two load shed exercises to review load shed procedures and provide training to market participants on various aspects of load shed. A winter load shed exercise was conducted in December 2021 and a summer load shed exercise was conducted in July 2022.

These exercises included ERCOT's explanation of its role in directing load shed – namely, identifying when load shed is necessary and issuing such directives to TOs. ERCOT and stakeholders reviewed the notification requirements in EEA 1, 2, and 3 events along with other communication requirements between market participants and ERCOT during load shed events. ERCOT also conducted simulations of hypothetical events that would eventually require load shed.

Additionally, volunteer TOs presented their load-shed practices and methods, including how they communicate with DSPs and provided explanations of how they would respond to directives issued by ERCOT. Participants shared past experiences, identified tools that assist in efficient load shedding and restoration of service, and recommended best practices. A common issue noted by many participants was that a high percentage of their distribution feeders had at least a small number of critical customers or other critical loads. Such a configuration makes it difficult to execute emergency load shed instructions without shedding any load with these critical designations.

Going forward, these exercises will be held by ERCOT at least twice a year – once during a summer month and once during a winter month. The next exercise is scheduled to be held on December 8, 2022.

Weather Emergency Preparedness Report

Public Utility Commission of Texas

September 30, 2022

Senate Bill 3 (SB3) Section 24, passed by the 87th Texas legislature, requires the Public Utility Commission of Texas (Commission) to analyze emergency operations plans developed by electric utilities, power generation companies, municipally owned utilities, electric cooperatives, and retail electric providers (collectively "entities") and prepare a weather emergency preparedness report on power weatherization preparedness.[1]

The Commission was directed to:

(1) review emergency operations plans on file with the Commission;
(2) analyze and determine the ability of the electric grid to withstand extreme weather events in the upcoming year;
(3) consider the anticipated weather patterns for the upcoming year as forecasted by the National Weather Service or any similar state or national agency; and
(4) make recommendations on improving emergency operations plans and procedures in order to ensure the continuity of electric service.

Overview

The Commission initiated Project Number 51841, Review of 16 TAC §25.53 Relating to Electric Service Emergency Operations Plans, to conduct a formal rulemaking to enact the provisions of Senate Bill 3. The Commission adopted new 16 Texas Administrative Code (TAC) §25.53 on February 25, 2022. The new rule expanded upon the requirements of the Commission's preexisting EOP rule by requiring more entities such as municipally owned utilities to also file emergency operations plans (EOPs) and outlining the specific contents EOPs must contain. The rule also requires each entity to file its EOP in its entirety. Previously, entities were only required to file a summary. Finally, the new rule requires each of the applicable entities to participate in drills to test its plan and provide status updates at the request of Commission staff when the State Operations Center is activated.

The adopted rule applied to the following five entity types that generate power, deliver electricity, or bill customers:

- **Electric utilities (EU)** are defined in Tex. Util. Code §31.002(6) and include transmission and distribution infrastructure owners but exclude the other entities in this list that may own transmission or distribution infrastructure.

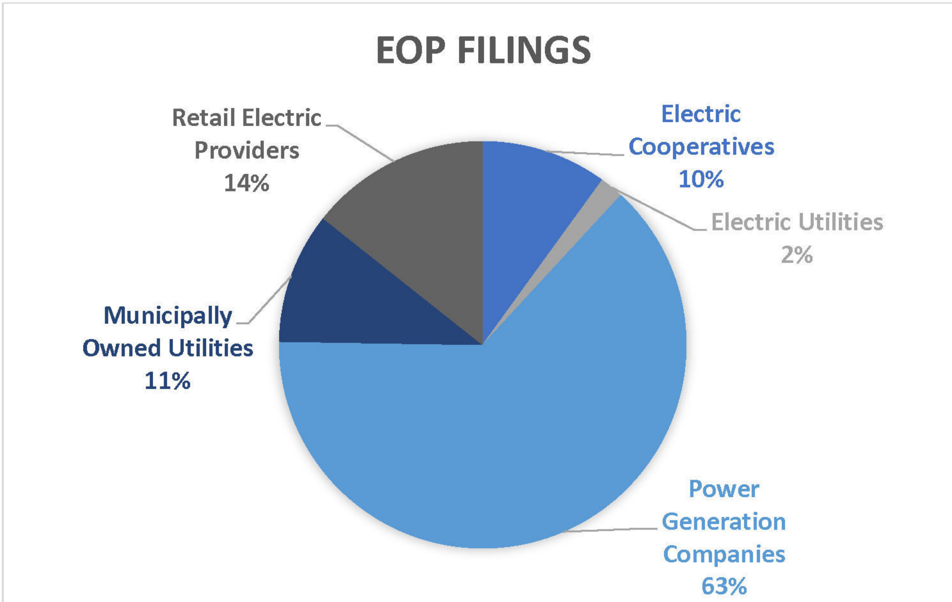
[1] Tex. Util. Code §186.007.

Electric utilities must prepare to ensure continuous delivery of electricity during an emergency event. Some electric utilities also generate electricity and must also prepare to ensure continuous generation of electricity during an emergency event.

- **Power generation companies (PGC)** are defined in Tex. Util. Code §31.002(10) and refer to certain owners of generation facilities that do not own transmission or distribution facilities or have a certificated service territory. These owners are excluded from the definition of an electric utility. Power generation companies must prepare to ensure continuous generation of electricity during an emergency event.
- **Municipally owned utilities (MOU)** are defined in Tex. Util. Code §11.003(11), and refer to utilities that are owned, operated, and controlled by a municipality or by a nonprofit corporation whose directors are appointed by one or more municipalities. A municipally owned utility owns or operates equipment or facilities to transmit or distribute electricity and may also own or operate facilities to generate electricity. A MOU must prepare to ensure continuous delivery of electricity during an emergency event. Those MOUs that also own or operate facilities to generate electricity must also ensure continuous generation of electricity during an emergency event.
- **Electric cooperatives (EC)** are defined in Tex. Util. Code §11.003(9) and refer to corporations organized as electric cooperatives that own or operate equipment or facilities to transmit or distribute electricity. Electric cooperatives must prepare to ensure continuous delivery of electricity during an emergency event. Those ECs that also own or operate facilities to generate electricity must prepare to ensure continuous generation of electricity during an emergency event.
- **Retail electric providers (REP)** are defined in Tex. Util. Code §31.002(17) and refer to entities that sell electricity to retail customers and are prohibited from owning or operating generation assets. REPs prepare to keep their business running and their customers informed during an emergency event.

To analyze and review the emergency operations plans the Commission sought the expertise of a qualified contractor to perform a baseline assessment of the emergency operations plans to develop recommendations for improvements to the plans that can be incorporated in a future rulemaking initiative. Ascenttra, Inc. was selected and began work in April 2022. In total, Ascenttra reviewed and analyzed 691 EOPs filed with the Commission. They evaluated conformance with the requirements of 16 TAC §25.53. Ascenttra also considered additional criteria, identified as best practices within the emergency management community. Appendix 1 to this report is Ascenttra's analysis, exactly as submitted to the Commission without alterations. The analysis below is a summary of Ascenttra's analysis and does not represent the observations or conclusions of the Commission.

The pie chart below shows the 691 EOP filings by entity type.



Ascenttra's EOP review team observed several trends and outliers during the review process. As an example, the entities that filed the EOPs used a variety of plan formats. Many EOPs consisted of standalone documents developed for other purposes that were compiled together to form the plan. Ascenttra reported that this type of filing lacks an organized format and can present difficulty in locating information during an emergency. In contrast, the municipally owned utilities employed a systemized template. Most of the plans included both primary and secondary emergency contacts, as a good practice to ensure prompt responses in an emergency. These trends, in addition to others noted by the reviewers, helped identify strengths and gaps in electric industry best practices.

Methodology

To assess the EOPs, 53 separate criteria were identified from requirements in 16 TAC §25.53. These criteria were then grouped into seven measures[2]:

1. EOP filing
2. Executive summary
3. Record of distribution
4. Emergency contacts
5. Affidavit

[2] The seven measures are referred to as "headings" in Ascenttra's report attached in Appendix 1.

6. EOP required content
7. Required annexes

The EOPs were scored on both the fulfillment of the requirements (i.e., whether the required element was present) and the quality of supporting information provided (i.e., whether the information was clear, complete, and responsive to the requirement).

For each EOP, a score for each of the seven measures was calculated using a simple average of the scores for each criterion under a given measure. Each criterion received a score from zero (worst) to ten (best), with ten indicating the objective was fully achieved. A score for each entity group, by measure, was derived using a simple average of the scores achieved for that measure by all the entities in the group.

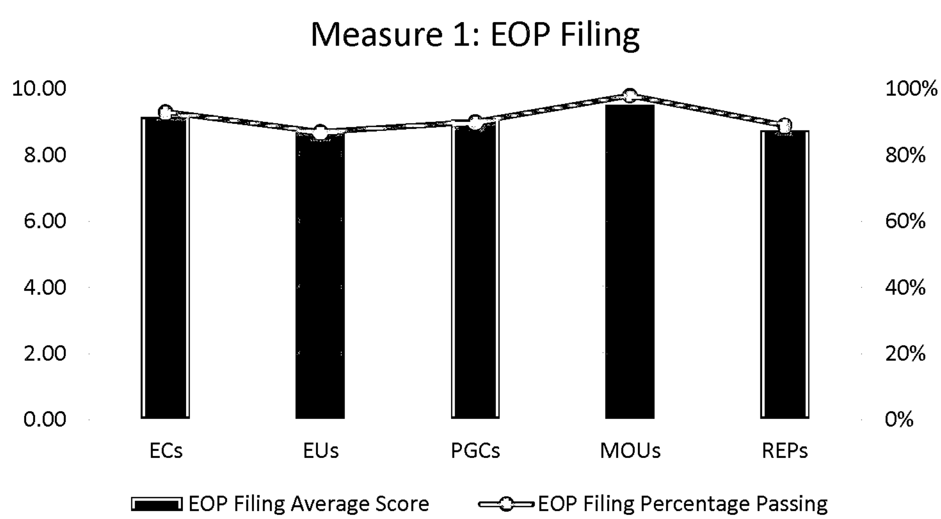
A score of seven or higher for each measure was considered “passing.” The percentage of entities that received a passing score for each measure was also calculated.

Measure #1 - EOP Filing

The criteria for this measure required an entity to:

- File a complete copy with the Commission with all confidential portions removed.
- File an unredacted EOP with ERCOT if operating within the ERCOT power region.
- Make an unredacted EOP available in its entirety to Commission staff, if requested, at a location designated by Commission staff.
- File an EOP annex for each facility that conspicuously identifies the facility to which it applies.
- Demonstrate continuous maintenance of an EOP.

With 91% of entities who filed an EOP receiving a passing score of seven or higher, this was the highest scoring measure. However, many EOPs did not contain a uniform format and were instead a compilation of standalone documents, making information difficult to locate efficiently during an actual emergency. Further, some EOPs were marked "confidential" or "for internal use only" which is contrary to the objective of coordinating with external stakeholders.

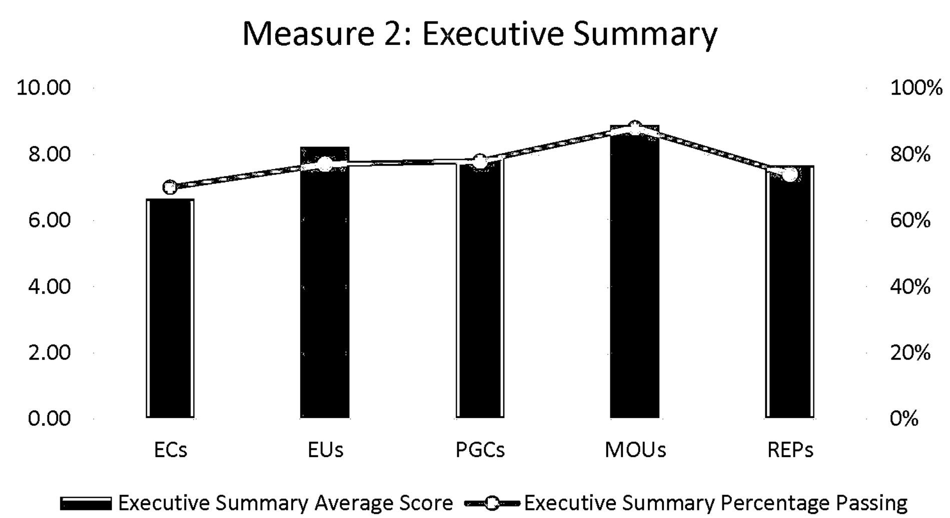


Measure #2 - Executive Summary

The criteria for this measure required the executive summary to:

- Describe the contents and policies contained in the EOP.
- Include a reference to specific sections and page numbers of the entity's EOP that correspond with the requirements of the rule.
- Contain the affidavit required under 16 TAC §25.53(c)(4)(C).

Overall, 78% of the EOPs met the criteria for an executive summary. The municipally owned utilities employed an EOP template with a specific section for the executive summary.

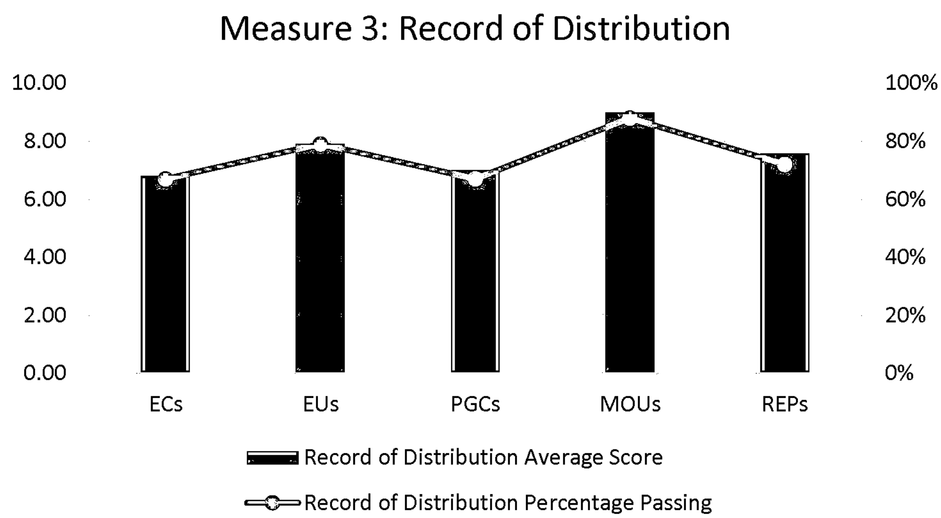


Measure # 3 - Record of Distribution

The criteria for this measure required the EOP to:

- Include a completed record of distribution required under 16 TAC §25.53(c)(4)(A).
- Contain, in table format, the titles and names of persons in the entity's organization receiving access to and training on the EOP.
- Contain dates of access to or training on the EOP.

It was difficult to evaluate the record of distribution because 16 TAC §25.53(c)(4)(A)(ii) provides flexibility whether to file the dates of access to the EOP or dates of training on the EOP.

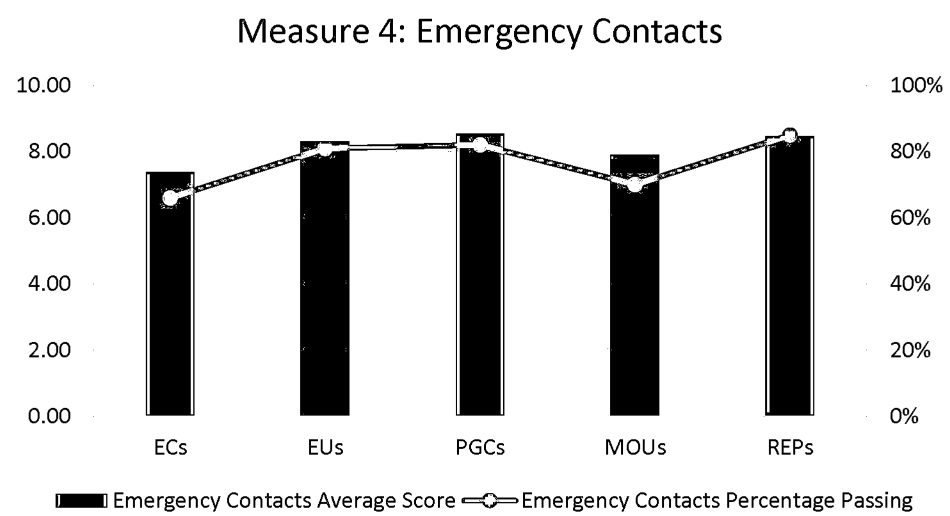


Measure #4 - Emergency Contacts

The criteria for this measure required the EOP to:

- List the primary contacts for the entity.
- List the secondary contacts for the entity.
- Identify specific individuals available immediately to address urgent requests and questions from the Commission during an emergency.

Overall, 80% of the EOPs met the criteria for emergency contacts. Most of the entities provided multiple emergency contacts. However, the information was located in the base plan which would render the plan outdated if there are personnel changes. The list of emergency contacts should be contained in a separate section so that it can be updated regularly to keep up with personnel changes.

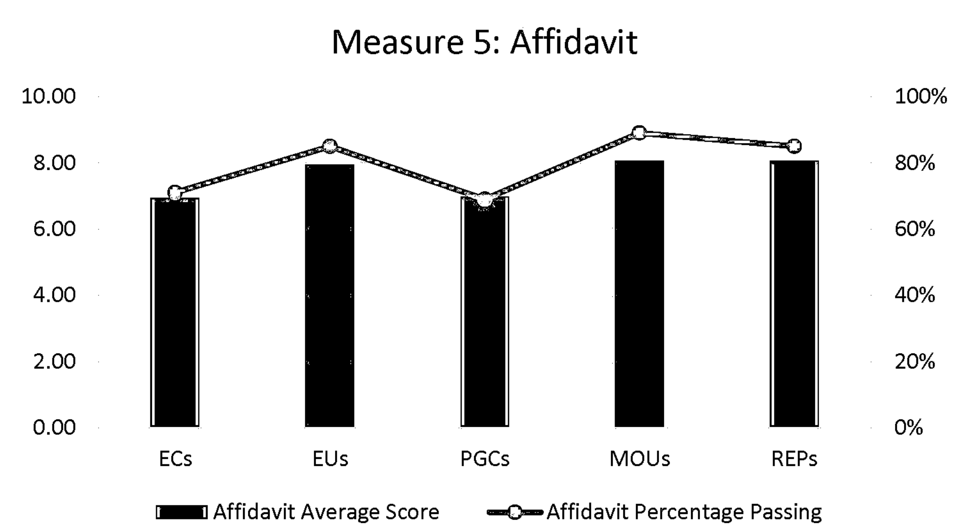


Measure #5 - Affidavit

The criteria for this measure required affidavits to affirm the following:

- Relevant operating personnel have received training on the applicable contacts and execution of the EOP, and such personnel are instructed to follow the applicable portions of the EOP, recognizing that deviation from the plan may be appropriate as a result of specific circumstances during an emergency.
- Appropriate executives have reviewed and approved the EOP.
- Drills have been conducted to the extent required by 16 TAC §25.53(f).
- The EOP or an appropriate summary has been distributed to local jurisdictions as needed.
- The entity maintains a business continuity plan addressing the return to normal operations after disruptions caused by an incident.
- The entity's emergency management personnel who are designated to interact with local, state, and federal emergency management officials during emergency events have received the IS-100, IS-200, IS-700 and IS-800 National Incident Management System training.

The language used in the affidavits often did not contain specific details related to the individual EOP. Some of the content affirmed in the affidavits was not found in the corresponding EOPs.

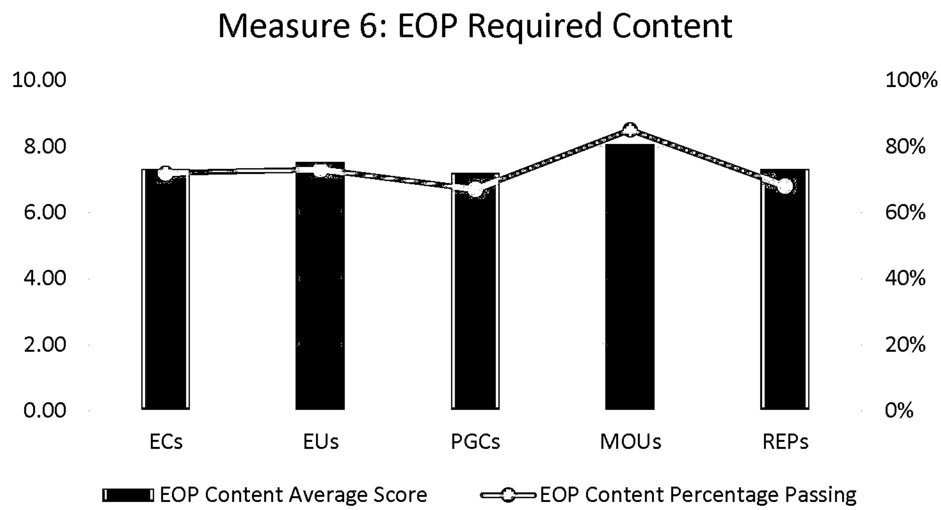


Measure #6 - EOP Required Content

The criteria for this measure requires the EOPs to contain specific items:

- An approval in the form of a signed statement formally recognizing and adopting the plan, how it will be implemented, and indicating that it supersedes all previous plans.
- An introduction.
- An outline of the applicability of the plan.
- A list of the individuals responsible for maintaining and implementing the EOP.
- A list of the individuals who can change the EOP.
- A revision control summary that lists the dates of each change made to the EOP since the initial EOP filing.
- The date the EOP was most recently approved by the entity.
- A communications plan.
- The procedures during an emergency the entity uses for handling complaints.
- Emergency procedures for communicating with the following prescribed groups:
    - the media;
    - customers;
    - fuel suppliers;
    - the Commission;
    - the Office of Public Utility Counsel (OPUC);
    - local and state governmental entities, officials, and emergency operations centers, as appropriate in the circumstances for the entity;
    - the reliability coordinator for its power region; and
    - critical load customers directly served by the entity.
- A plan to maintain pre-identified supplies for emergency response.
- A plan for adequate staffing during emergency response.
- A description of how an entity identifies and plans for weather-related hazards, including tornadoes, hurricanes, extreme cold weather, extreme hot weather, drought, and flooding.
- The process and procedures the entity follows to activate the EOP.

EOP required contents varied widely. Administrative requirements relating to revisions and approval were more readily followed. More information regarding operational processes and procedures relating to communication, ensuring adequate staffing, maintaining critical supplies, implementing procedures for weather emergencies, and activating the EOP is necessary to be better prepared for a weather emergency.


Measure 6: EOP Required Content
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100%
80%
60%
40%
20%
0%
ECs
EUs
PGCs
MOUs
REPs
EOP Content Average Score
EOP Content Percentage Passing

Measure #7- Annexes

The criteria for this measure require specific annexes for each entity type. All entities are required to include annexes that address: a pandemic and an epidemic annex, a hurricane annex including evacuation and re-entry procedures if facilities are located within a hurricane evacuation zone, a cyber and physical security incidents annex, and any additional circumstances appropriate to the entity, in addition to those annexes. Further, these are the only annexes REPs are required to include in their EOPs.

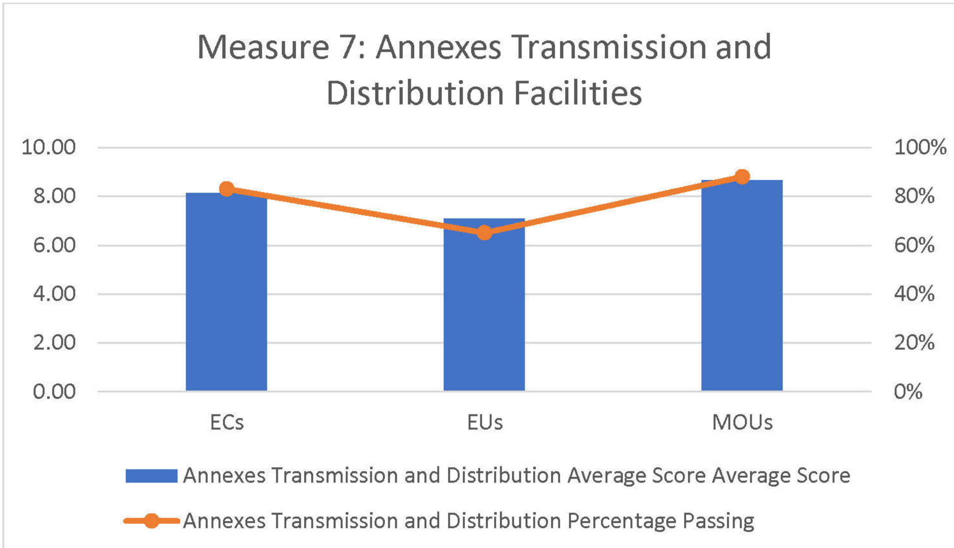
Entities with transmission or distribution facilities must also include:

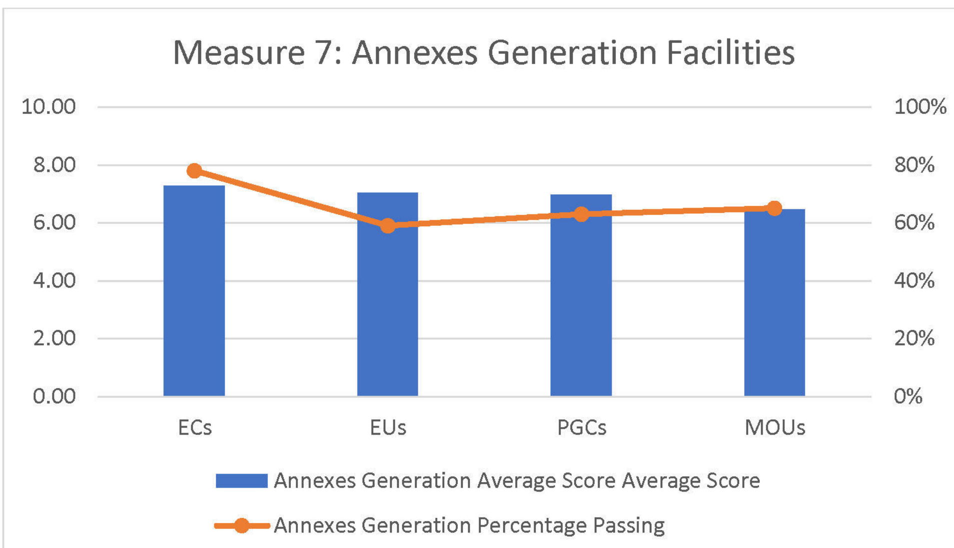
- A weather annex with operational plans for responding to cold or hot weather emergencies and a checklist for facility personnel to use during cold or hot weather emergency response. This annex must include checklists that reflect lessons learned from past weather emergencies to ensure necessary supplies and personnel are available.
- A load shed annex with procedures for controlled shedding of load and lists of priorities for restoring service to customers who were affected by load shedding. This annex must contain procedures for maintaining an accurate registry of critical load customers that is updated as necessary, but at least annually. This annex must also contain procedures addressing aiding critical load customers in the event of an unplanned outage; communicating with critical load customers during an emergency; coordinating with government and service agencies as necessary during an emergency; and training staff with respect to serving critical load customers.
- A wildfire annex.

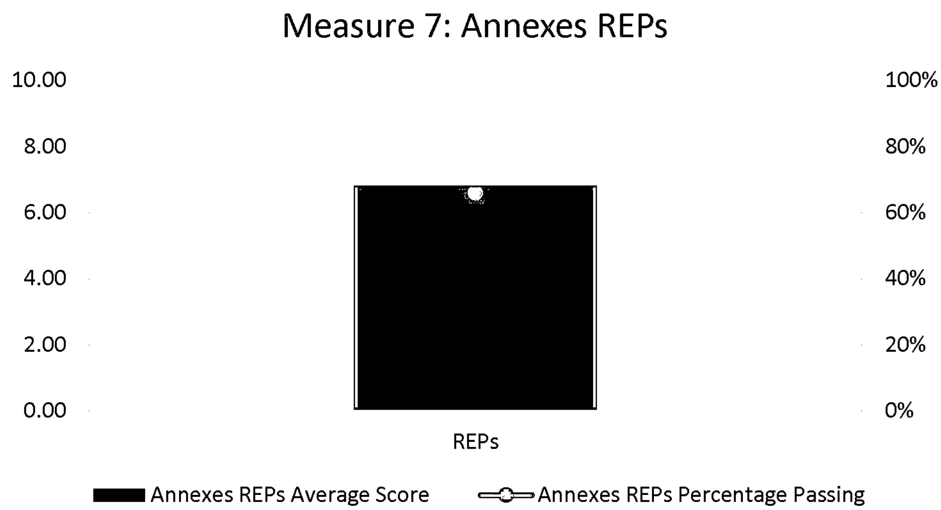
Entities with generation facilities must also include:

- A weather annex that meets all of the requirements of this annex produced by entities with transmission or distribution facilities and also includes a verification of the adequacy and operability of fuel switching equipment, if installed.
- A water shortage annex that addresses supply shortages of water used in the generation of electricity for generation facilities.
- A restoration of service annex that identifies plans and procedures to restore to service a generation resource that failed to start or that tripped offline due to a hazard or threat.

The required annexes and corresponding information varied based on entity type as required by 16 TAC §25.53 (e). However, many entities did not clearly list which annexes were applicable to them. So, for example, some entities did not indicate whether they were located in a hurricane evacuation zone, such that a hurricane annex would be required.






Measure 7: Annexes REPs
10.00
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100%
80%
60%
40%
20%
0%
REPs
Annexes REPs Average Score
Annexes REPs Percentage Passing

Future Weather Considerations

The winter of 2022-2023 is predicted to be slightly colder than average. The coldest month is predicted to be January with an average low of 39°F and high of 57°F. This is because of the effect of La Niña which is expected to continue during the winter months of December 2022 through February 2023.

During a La Niña event, warmer than average sea surface temperatures in the Atlantic and Caribbean Seas as well as weaker tropical Atlantic trade winds predict an above-normal active Hurricane season. It is uncertain when the La Niña event will end, however, there is a 56% chance of transition to ENSO-neutral (a period when La Niña and El Niño patterns are not present) between February and April 2023.[3] According to the National Weather Service Climate Prediction Center, the seasonal temperature outlook during the summer of 2023 makes predictions for above normal temperatures.[4]

The assessment of EOP annexes for hot and cold weather emergencies and hurricanes provides an indication of the preparedness of entities considering the upcoming weather predictions. Overall, electric cooperatives and electric utilities have the highest passing rates for hurricane preparedness around 75%.[5] Electric cooperatives and power generation companies received the highest scores with respect to hot and cold weather preparedness for generation facilities. Municipally owned utilities demonstrated excellent weather emergency preparedness for transmission or distribution facilities with an overall passing rate of 88%.[6]

EOP Best Practices

To strengthen emergency response and grid resiliency, Ascenttra recommended the following best practices be considered for incorporation into EOPs. The Commission will review and consider these best practices for implementation within the bounds of its statutory authority, as appropriate.

- Equipment weather design limits should be defined to identify key factors that lead to an EOP activation. Many electric cooperatives are already doing this.
- Single points of failure for critical assets should be documented in the EOP to identify vulnerabilities and determine support systems and mitigation plans for continuity of service. Similarly, it is important to plan to ensure an uninterrupted supply chain during a weather emergency and to inventory,

[3] National Weather Service, Climate Prediction Center, El Niño/Southern Oscillation (ENSO) Diagnostic Discussion.
[4] National Weather Service, Climate Prediction Center, Seasonal Outlooks Official forecast Jun-Jul-Aug 2023.
[5] This figure was derived from Ascenttra's work papers not included in this report.
[6] This figure was derived from Ascenttra's work papers not included in this report.

maintain, and strategically deploy critical supplies in a weather emergency for efficient equipment maintenance. The identification of single points of failure and linked vulnerabilities presents an opportunity for improvement from entities with generation facilities.

- EOPs should include procedures for plant personnel to periodically test the use of backup or alternative fuel to become familiar with the process if necessary, during an EOP activation. Many power generation companies are currently implementing alternative fuel testing as documented in the EOP.
- EOPs should include a plan to maintain appropriate staffing levels and ensure all surge capacity staff are trained. Many entities address adequate staffing in the EOPs and procedures to train and deploy both internal and contracted surge staff.
- EOPs should include procedures for regular updates to an EOP, especially following an exercise or activation based on lessons learned. 16 TAC §25.53 includes basic requirements for corrective action processes. Nearly a third of entities incorporated more comprehensive continuous improvement planning.

EOP Improvement Recommendations

Ascenttra's EOP assessment identified areas of strength in the EOPs and opportunities for improvements that may be considered by the entities and the Commission. Ascenttra's recommendations include:

- Develop a template. An EOP should be crafted from a comprehensive template that includes a repository for all relevant information and contains internal cross references to streamline documents submitted. Ascenttra recommends use of a template as a best practice rather than a requirement. Each EOP must address every section. Any section that is not applicable should be clearly labeled with an explanation as to why it is not applicable.
- In addition to maintaining a record of internal distribution, require each EOP to maintain a record of external distribution to local emergency management authorities.
- Customize the EOP, as necessary. The EOP should contain information that is relevant and addresses the specific facility characteristics An EOP should clearly identify specific facility information including geographic characteristics, location and function, staffing, and equipment. geographic characteristics, location and function, staffing, and equipment.
    - All critical staffing positions (denoting hazard type, if appropriate) must be listed.
    - All critical supplies (denoting hazard-type, if appropriate) must be listed, specifying locations of supplies as well as primary and alternate vendors for obtaining additional supplies.

    - Weather design limits and single points of failure must be identified so that mitigation strategies and specific response measures can be developed.
- Adopt an all-hazards approach to emergency management. 16 TAC §25.53(d) requires an entity's EOP to address both common operational functions that are relevant across emergency types and annexes that outline the entity's response to specific types of emergencies. However, Ascenttra noted that not all entity's EOPs followed this approach. All-hazards is an emergency management best practice that emphasizes capacities and capabilities rather than scenarios or event types. This type of EOP has a base plan that focuses on processes common to all emergencies such as purpose, planning assumptions, responsibilities, plan maintenance, and authorities.
    - Annexes are used to respond to a specific emergency type and build upon the fundamentals established in the base plan. Planning for specific hazards and vulnerabilities such as weather events or other known threats should be done in annexes.
    - Appendices are used to document areas needing more specificity than the base plan, as well as confidential or perishable information (for example, contact information, training records, and event participation logs). Whenever possible, sensitive information should be located in these sections.
- Utilize checklists. Each EOP should contain checklists that are easily accessible when responding to an emergency to expedite and reliably replicate preparedness for weather events.
- Identify local coordination efforts. Each EOP should document how to coordinate with representatives at the local and regional levels. Specifically, the EOP should include how the entity will implement Incident Command System (ICS) in coordination with local emergency response.
- Require equivalent responsibilities for alternate emergency managers. Both primary and alternate emergency managers should be designated to attend meetings, participate in training and exercises, and coordinate with the emergency preparedness community.
- Specificity in affidavits. Affidavits should affirm specific EOP details rather than boilerplate language. Ambiguity should not be introduced into the affidavit (for example, "will be or has been" or "as needed" qualifiers should be eliminated).

Recommended Commission Actions

Ascenttra recommended the Commission consider the following actions:

- Amend 16 TAC §25.53 to standardize entities' EOPs and require or encourage use of the characteristics noted above.[7]
- Amend 16 TAC §25.53 to conform to Homeland Security Exercise and Evaluation Program (HSEEP) nomenclature. For example, current language uses "drills," which is one of seven different exercise types under HSEEP.
    - For entities located in a hurricane evacuation zone, a mandatory annual hurricane exercise and an exercise for another scenario should be required to ensure entities are prepared to respond to a variety of vulnerabilities.
- Collaborate with TDEM to develop a recommended curricula for emergency managers, facilitate planning workshops, and support entities in completing thorough EOPs.
    - Consider options to support entities in finding training opportunities on weather awareness and EOP development to incorporate into their EOP planning and development processes.
    - Develop processes for receiving and disseminating forecasts.
    - Provide training to personnel regarding how to identify changes in weather conditions.

[7] Tex. Util. Code § 186.007 provides the Commission with limited rulemaking authority to impose requirements on EOPs. Fully implementing Ascenttra's rulemaking recommendations may require additional statutory authority.

TEXAS UNIVERSAL SERVICE FUND REPORT

Public Utility Commission of Texas
August 31, 2022

Executive Summary

In 2017, the Legislature created a new rate of return methodology to determine the amount of support available to small telecommunications providers from the Texas Universal Service Fund (TUSF). This new methodology is found in Public Utility Regulatory Act (PURA)[1] § 56.032. The support amounts calculated under it are set to expire on September 1, 2023.

The Public Utility Commission of Texas (Commission) was directed to:

> *1. Review and evaluate whether the rate of return methodology under PURA § 56.032, and any rules adopted to implement that section, accomplish the purposes of the TUSF and allow small telecommunications providers the opportunity to earn a reasonable return; and*
>
> *2. Review and evaluate whether changes in law to amend or replace the rate of return mechanism are necessary to achieve such purposes.*[2]

Upon review and evaluation, the Commission concludes that:

The rate of return methodology under PURA § 56.032 accomplishes the purposes of the TUSF and allows small telecommunications providers the opportunity to earn a reasonable return. However, changes may be necessary to achieve these purposes more efficiently.

As part of the review, the Commission was directed to submit a report to the Legislature by September 1, 2022, addressing four specific issues and any other relevant information the Commission deemed necessary for inclusion.[3] This report addresses the Commission's evaluation of PURA § 56.032 and the following issues:[4]

1. The continued appropriateness of using the FCC prescribed rate of return for the mechanism established under PURA § 56.032(d) if the FCC still prescribes a rate of return that may be used for that mechanism;

The Commission concludes that it is appropriate to continue to use the Federal Communications Commission's (FCC's) prescribed rate of return.

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[1] Tex. Util. Code §§ 11.001–66.016.

[2] Act of May 16, 2017, 85th Leg., R.S., ch. 1116 (S.B. 586), §2(b), 2017 Tex. Gen. Laws at 4303.

[3] *Id.*, § 2(d), 2017 Tex. Gen. Laws at 4303.

[4] Act of May 16, 2017, 85th Leg., R.S., ch. 1116 (S.B. 586), §§ 1-3, 2017 Tex. Gen. Laws 4301.