Final Report on the Resiliency of South Carolina's Electric and Natural Gas Infrastructure

Against Extreme Winter Storm Events

Prepared for the South Carolina
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Following the February 2021 winter storm that left nearly seventy percent (70%) of Texans without electrical power and nearly half the State without running water,[1] South Carolina Governor Henry McMaster called for a comprehensive review of South Carolina's public and private power grid. The South Carolina Office of Regulatory Staff (ORS) subsequently filed a motion with the Public Service Commission of South Carolina (Commission) in Docket No. 2021-66-A to solicit information from the State's utilities on the matter and commissioned Guidehouse, Inc. (Guidehouse) to support a corresponding review.[2] The ORS provides this Final Report on the Resiliency of South Carolina's Electric and Natural Gas Infrastructure Against Extreme Winter Storm Events, in response to Governor McMaster's request. This Final Report communicates findings related to the South Carolina power grid review that incorporate input provided by Utility Providers in response to ORS information requests.

Scope

The ORS, supported by Guidehouse, examined information and evaluations provided by electric and natural gas Utility Providers under the jurisdiction of the Commission and other electric and gas non-regulated utilities that willingly participated in the review (collectively referred to as Utility Providers). The information requested from the Utility Providers primarily targeted eight (8) general assessment areas:

- Identification of threats to utility service
- Identification of the impacts to utility service
- Assessment of vulnerabilities
- Assessment of risks to utility service
- Identification of resiliency solutions
- Identification of other federal and state reliability requirements
- Assessment of current utility processes and systems to withstand potential ice storms and other winter weather conditions
- Identification of best practices, lessons learned and challenges to utility service

Approximately sixty-five (65) Utility Providers participated in the ORS review, and four (4) non-utility stakeholders expressed documented interest in the review, for a total of sixty-nine (69) respondents.

Approach

To review the Utility Provider information and evaluations, Guidehouse professionals (Evaluators), on behalf of the ORS, applied a Utility Adverse Weather Assessment Framework (Assessment Framework) adapted specifically for winter weather events. This Assessment Framework enabled Evaluators to assess utilities across eleven (11) indicator areas and five (5) categories to identify the stage of maturity for each Utility Provider by indicator area.

Evaluators clustered the Utility Providers into four (4) assessment groups based on the general sizes and services provided.

- Large investor-owned or state-owned electric utilities (LEUs)
- Large investor-owned natural gas utilities (LGUs)
- Smaller electric municipal departments, boards, or commissions or customer-owned electric cooperatives (SEUs)
- Smaller natural gas municipal departments, boards, or commissions (SGUs)

For municipal utilities and electric cooperatives, the utility operating models are uniquely distinct from one another, and because of the relevance of findings and applicability of the recommendations, Evaluators included both utility types in the same assessment group. Moreover, Evaluators further segmented the review of the LEUs by considering the impacts of extreme winter weather events on energy generation, bulk power delivery services, and utility distribution services.

Findings and Recommendations

The review's findings and resulting recommendations are consolidated by utility type (natural gas and electric utilities) and utility size (large utilities and smaller utilities).

Notably, the State's large utilities (LEU and LGU) wield the greatest influence related to winter weather resiliency of the South Carolina power grid and its ability to withstand winter weather events. SEUs and SGUs pose a much lower overall risk to the statewide infrastructure resiliency due to their size and limited impacts on larger utility systems within the state.

Given the information provided by the participating Utility Providers, the Evaluators conclude that the South Carolina energy system and Utility Providers are adequately prepared to prevent and respond to outages caused by ice storms and winter weather events. The State's large Utility Providers, the LEUs and LGUs, generally offered sufficient qualitative evidence to illustrate their readiness and ability to respond to winter weather events.

Table ES 1 describes the maturity assessment levels for the LEUs, LGUs, SEUs, and SGUs. Evaluators conducted assessments at the indicator level and assigned a maturity level to each indicator based on weighted scores ranging from 0 to 5.

Table ES 1. Maturity Level Descriptions

	Maturity Level	Maturity Score	*Maturity level and score signify:*
🟢	***ADVANCED***	4.0 or greater	Advanced components in place and positioned for emerging needs
◓	***LEADING***	from 3.0 to 3.9	Foundational components in place and forward-looking plans or practices
🔵	**FOUNDATIONAL**	from 2.0 to 2.9	Foundational components in place and current standards followed
◒	**LAGGING**	from 1.0 to 1.9	Some foundational components in place
🟡	**NASCENT**	less than 1.0	Lacking or undeveloped foundational components

Table ES 2 summarizes the overall Assessment Framework scoring and associated maturity level by indicator area for each utility category (LEU, LGU, SEU, and SGU).

Detailed findings by utility category can be found in the following sections:

- **Appendix F. Assessment and Recommendations – Large Electric Utilities**
- **Appendix G. Assessment and Recommendations – Large Gas Utilities**
- **Appendix H. Assessment and Recommendations – Small Electric Utilities**
- **Appendix I. Assessment and Recommendations – Small Gas Utilities**

Table ES 2. Maturity Level Assessment Summary by Utility Provider Type and Size

🟢 Advanced ◓ Leading 🔵 Foundational ◒ Lagging 🟡 Nascent ◌ Insufficient Data

Indicator	LEU	LGU	SEU	SGU
Indicator 1 Emergency Management and Planning	◓	◓	🔵	◌
Indicator 2 Risk Management	◓	🔵	🔵	🔵
Indicator 3 Staffing and Mutual Assistance Support	◓	◓	🔵	◌
Indicator 4 Asset Management and Inspections	◓	◓	◒	◌
Indicator 5 Operational Protocols	◓	◓	🔵	◌
Indicator 6 System Design and Hardening	◓	◓	◒	◒
Indicator 7 Stakeholder Engagement	◓	🔵	◒	◌
Indicator 8 Public Communications	◓	🔵	🔵	◌
Indicator 9* Automation	◓	*Not Scored**	◒	*Not Scored**
Indicator 10 Situational Awareness	◓	🔵	◒	◌
Indicator 11 Compliance to Regulations	◓	◓	🔵	🔵

** Indicator 9 relates to use of smart grid automation technologies and is not applicable for natural gas utilities.*

ACRONYMS

BAA – Balancing Area Authority

BES – Bulk Electric System

BPS – Bulk Power System

DEC – Duke Energy Carolinas, LLC

DEP – Duke Energy Progress, LLC

DESC – Dominion Energy South Carolina, Inc.

DIMP – Distribution Integrity Management Program

ECSC – Electric Cooperatives of South Carolina

EIA – Energy Information Administration

EOP – Emergency Operating Procedure

ERCOT – Electric Reliability Council of Texas

ERP – Emergency Response Plans

FERC – Federal Energy Regulatory Commission

IOUs – Investor-Owned Utilities

LEU – Large investor-owned electric utilities

LGU – Large investor-owned gas utilities

Lockhart – Lockhart Power Company

MISO – Midcontinent Independent System Operator

MW – Megawatt

MWh – Megawatt-Hour

NERC – North American Electric Reliability Corporation

NGA – Natural Gas Authorities

NOAA – National Oceanic and Atmospheric Administration

ORS – South Carolina Office of Regulatory Staff

PHMSA – Pipeline and Hazardous Materials Safety Administration

PJM – Regional transmission organization in the mid-Atlantic area

RC – Reliability Coordinator

RTCA – Real-Time Contingency Assessment

SCAMPS – South Carolina Association of Municipal Power Systems

SERC – Southeastern Reliability Corporation

SEU – Smaller electric municipal department, board, or commission- or customer-owned electric cooperative

SGU – Smaller natural gas municipal department, board, or commission

TIMP – Transmission Integrity Management Program

TPLs – Transmission Plans

VACAR – The Virginia-Carolinas sub region within NERC's SERC

VER – Variable Energy Resources

1 INTRODUCTION

Following the February 2021 winter storm that left nearly seventy percent (70%) of Texans without electrical power and nearly half the State without running water,[1] South Carolina Governor Henry McMaster called for a comprehensive review of South Carolina's public and private power grid. The South Carolina Office of Regulatory Staff (ORS) subsequently filed a motion with the Public Service Commission of South Carolina (Commission) in Docket No. 2021-66-A to solicit information from the State's utilities on the matter[2] and commissioned Guidehouse, Inc. (Guidehouse) to support a corresponding review. The ORS provides this Final Report on the Resiliency of South Carolina's Electric and Natural Gas Infrastructure Against Extreme Winter Storm Events, in response to Governor McMaster's request. This Final Report communicates findings related to the South Carolina power grid review that incorporate input provided by Utility Providers in response to ORS information requests.

South Carolina is home to more than five (5) million residents and over 110,000 establishments that rely on the reliable energy delivery services of the State's more than sixty (60) distribution utilities.[3],[4] While South Carolina's southeast coastal location makes its power grid more susceptible to tropical weather and climate events such as hurricanes and coastal flooding, South Carolina communities are not immune to the impacts of ice storms and other winter weather events. The most recent example of such an event is the Winter Storm of January 2018, which produced record levels of snowfall across the southeast areas of the State and a record-setting duration of snow cover in Charleston.[5]

However, few as they may be, major winter weather events affect communities ill-equipped to mitigate or recover from ice, snow, or cold weather events, and can be as devastating as a major tropical weather event. A recent study on extreme winter weather changes in the U.S., funded by the National Science Foundation (NSF) and published in *Science*, revealed that the major winter storm that led to the collapse of the Texas energy infrastructure in early 2021 was not only deadly – resulting in over 200 deaths across the State – but also unexpectedly expensive.[6] In its examination of the impact of the February freeze, the Federal Electric Reliability Council (FERC) reported that the Texan economy suffered direct and indirect loses estimated at $80 to $130 billion.[7]

1.1 Need for a Comprehensive Review

Governor Henry McMaster requested the ORS undertake a comprehensive review of South Carolina's public and private power grid to evaluate its ability to withstand potential ice storms and other dangerous winter weather. In response to Governor McMaster's request, the ORS filed a motion with the Commission requesting it call for all electric and natural gas utilities provide information regarding measures that have been or will be taken to:

- Mitigate the negative impacts of ice storms and other dangerous weather conditions on the provision of safe and reliable utility service.
- Ensure peak customer demands on the utility system can be met during extreme weather scenarios.

On March 10, 2021, the Commission issued an order opening the requested docket and encouraging comments from interested parties.[8]

In June, the Commission accepted two (2) sets of comments from fourteen (14) stakeholders: initial comments requested by June 11, 2021, and responsive comments requested by June 25, 2021. Concurrent with the Commission's solicitation for comments, the ORS issued information requests to utilities and municipalities across the State to launch its comprehensive review.

This Final Report communicates findings related to the South Carolina power grid review that incorporate input provided by Utility Providers in response to ORS information requests, and additional assessment information.

1.2 Focus of the Review

The review and corresponding requests for information issued to the State's Utility Providers primarily focused on eight (8) key assessment areas:

Threats to utility service: Identify and assess potential threats to the utility system, where threats are anything that may destroy, damage, or disrupt utility service.

Impacts to utility service: Assess the impacts the potential threats may have on utility processes, systems, infrastructure, and end-user customers.

Vulnerabilities: Assess winter weather-related vulnerabilities and the degree to which utility systems and infrastructure may be impacted and where vulnerabilities are weaknesses within utility systems, processes, or infrastructure.

Risks to utility service: Evaluate the potential for loss, damage, or destruction of key assets and resources, as well as factors that could limit the supply of generation over an extended period of extreme weather conditions for each of the State's generation sources.

Resiliency solutions: Measures in place or planned to enable the utility to anticipate, prepare for, adapt to, withstand, respond to, and recover quickly from winter weather-related service disruptions.

Reliability requirements: Identify applicable or observed federal, state, or local reliability and resilience requirements (including, but not limited to, joint reliability plans or assessments, coordinating agreements, and wholesale purchase agreements).

Current utility measures: Identify processes and systems in place to withstand potential ice storms and other winter weather conditions, processes used to determine utility preparedness for meeting peak customer demand under extreme scenarios, and steps taken to address any identified areas of improvement.

Leading practices and lessons learned: Identify leading practice information related to reliability, lessons learned from similar experiences, and challenges to the provision of safe and reliable utility service under extreme weather conditions and other threats.

1.3 Participating Utilities and Other Interested Stakeholders

The focus of the review of the South Carolina power grid on electric and natural gas Utility Providers under the jurisdiction of the Commission and other electric and gas non-regulated utilities that willingly participated.

A total of sixty-five (65) of the State's Utility Providers participated in the review and either submitted comments to the docket or provided responses to ORS information requests. More than half of the respondents (primarily small electric cooperatives or commissions of public works) participated through associations or other representative organizations.

Responding organizations included the following:

Individual Utility Respondents

- Bamberg Board of Public Works
- Central Electric Power Cooperative
- City of Union Utility Department (City of Union)
- Clinton Newberry Natural Gas Authority (Clinton-Newberry)
- Duke Energy Carolinas, LLC (DEC)
- Duke Energy Progress, LLC (DEP)
- Dominion Energy South Carolina, Inc. (DESC)
- Fort Hill Natural Gas Authority (Fort Hill)
- Gaffney Board of Public Works
- Greenwood Commission of Public Works (Greenwood)
- Greer Commission of Public Works (Greer)
- Laurens Commission of Public Works (Laurens)
- Lockhart Power Company (Lockhart)
- Marlboro and Pee Dee Electric Cooperatives
- McCormick Commission of Public Works
- Orangeburg Dept of Public Works
- Piedmont Natural Gas Company, Inc. (PNG)
- South Carolina Public Service Authority (Santee Cooper)

Utility Representative Respondents

- Electric Cooperatives of South Carolina, Inc. (ECSC) (responding for eighteen (18) electric cooperatives)
- Patriots Energy Group (PEG) (responding for three (3) natural gas authorities)
- Piedmont Municipal Power Agency (PMPA) (responding for ten (10) municipal dept/divisions)
- South Carolina Association of Municipal Power Systems (SCAMPS) (responding for eleven (11) municipal electric utilities)

Additional interested stakeholders providing initial or responsive comments to the docket included the following:

- Carolinas Clean Energy Business Association
- Google, LLC
- Vote Solar
- Walmart, Inc.

1.4 Areas Not Evaluated

The review represents an audit-style review based on documented processes, procedures, and measures. Aspects such as proper adherence to stated processes and procedures were not included as part of the review but represent potential areas for future evaluation.

In addition, the Evaluators recognize that the State's power grid faces additional threats beyond winter weather events and notes that the assessment approach taken to conduct the review may apply for other types of threats to the power system. The findings and recommendations documented in this Final Report, however, specifically focus on threats and conditions similar to those faced by the Texas power grid that resulted in its multiday failure in February 2021. Evaluators did not evaluate the impacts of other threats such as hurricanes, cyber threats, extreme heat, flooding, or other threats attributed to climate change.

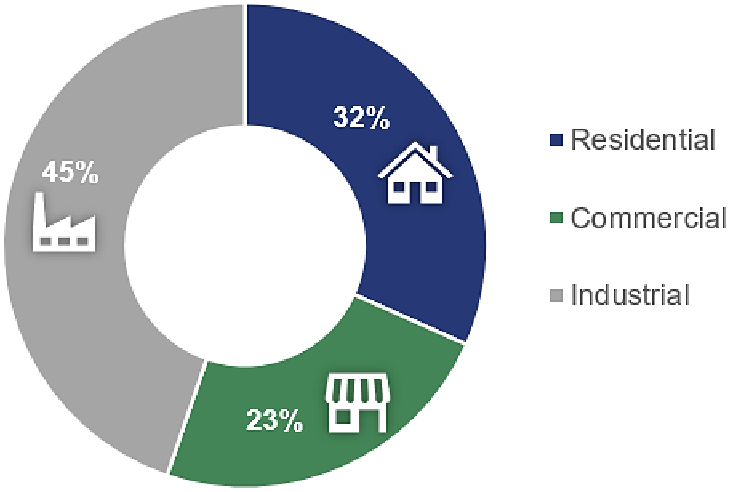
2

SOUTH CAROLINA POWER GRID

2.1 Power System Basics

South Carolinians depend on the state's power grid as an indispensable piece of their local communities. Citizens rely on the electric power grid for cooling their homes and businesses in the humid summer months and for space heating in the winter. As depicted in **Figure 1**, almost one-half (1/2) of the end-use energy consumed in the State (excluding energy consumed for transportation) goes to fueling South Carolina's robust manufacturing sector – a sector for which the reliability and quality of the energy provided can be the most critical.[9]

Figure 1. South Carolina Energy Consumption by End-Users, 2019 (excluding transportation)

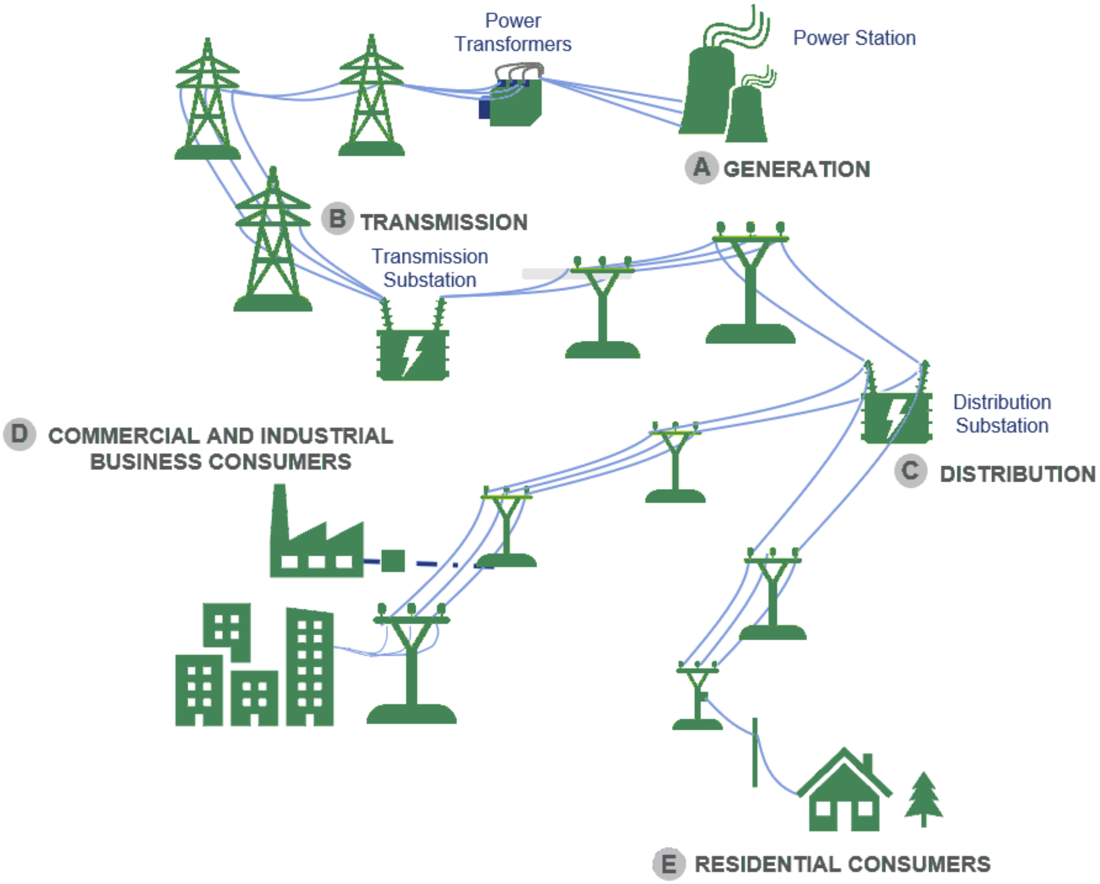


Source: Energy Information Administration, State Energy Data System

Electric Power Supply and Delivery System

South Carolina’s electric power system is comprised of power generation stations, a high voltage transmission system, and a distribution system. **Figure 2** offers a simplistic view of the general electric power system configuration.

Figure 2. Overview of the Electric Power System



Electric power is generated at **A)** a power station and transported in bulk at high voltages to the communities that will consume the power via **B)** the transmission system. Once the bulk power reaches the appropriate substations, **C)** the distribution system transports power at lower voltages to end-users: **D)** businesses and **E)** homes.

Source: Guidehouse

Electric Utility Providers

According to the South Carolina State Energy Office, five (5) electric power generating utilities operate within the State (DEC, DEP, DESC, Lockhart, and Santee Cooper). In 2019, as shown in **Table 1**, these utilities produced over seventy-seven (77) million megawatt-hours (MWh) at their fleets of generation stations.

Table 1. Electric Power Generation Utilities in South Carolina in 2019[4,10, 11,12]

Electric Power Generating Utilities	Total Power Generation (MWh)	Transmission System (line-miles)	Distribution System (line-miles)
DEC	27,090,790	5,031	25,546
DEP	8,573,663	930	9,034
DESC	23,719,708	3,800	26,700
Lockhart	94,000	183	*Unavailable*
Santee Cooper	18,109,830	5,029	2,841
Total	**77,587,991**	**9,944**	**61,280**

Table 2 provides additional high-level descriptions of each of these electric utilities.

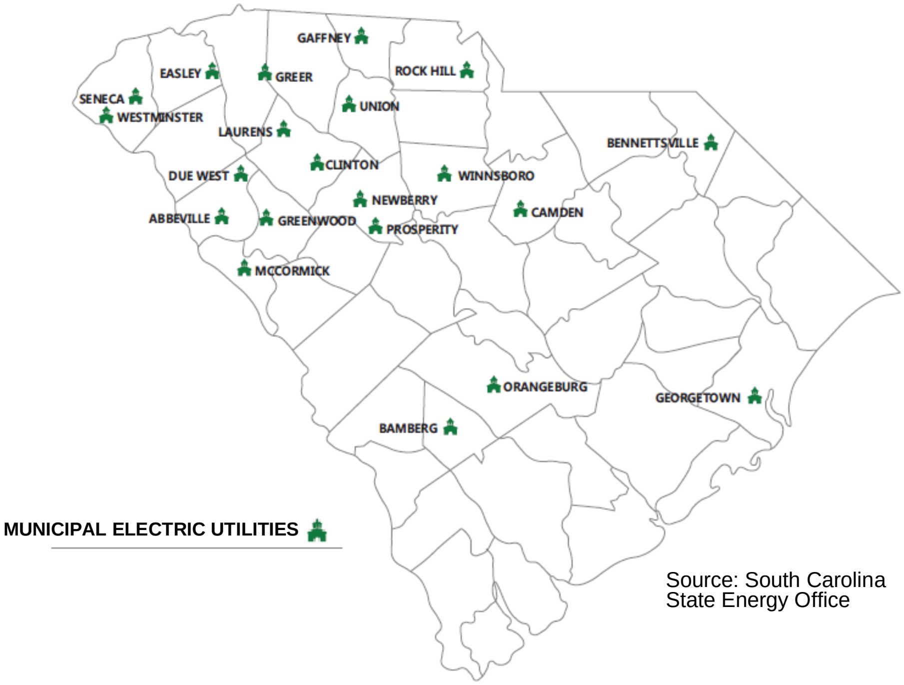
Table 2. General Information about South Carolina Power Generating Utilities[4,13,14]

South Carolina Electric Power Generating Utilities	
Duke Energy *(Parent Company operating in South Carolina as DEC and DEP)*	Investor-owned utility headquartered in Charlotte, North Carolina that supplies electricity in parts of North Carolina, South Carolina, Florida, Ohio, Kentucky, and Indiana DEC and DEP serve 30 counties in South Carolina and provide electric service to more than 733,000 retail customers Owns and operates nearly 34,400 megawatts (MW) of generation capacity across the Carolinas, with 9,779 MW of capacity based in South Carolina
Dominion Energy *(Parent Company operating in South Carolina as DESC)*	Investor-owned utility headquartered in Richmond, Virginia that supplies electricity in parts of Virginia, North Carolina, and South Carolina DESC serves roughly 698,000 electric customers across twenty-four (24) counties in the central, southern, and southwestern portions of South Carolina, including Columbia, Charleston, and Aiken Owns and operates approximately 5,700 MW of firm generating capacity in South Carolina
Lockhart	Investor-owned electric utility located in the Upstate of South Carolina Lockhart serves portions of five (5) South Carolina counties: Spartanburg, Union, Cherokee, Chester, and York Provides power generation, transmission, distribution, and lighting services and delivers electricity to 6,160 customers: approximately 4,900 residential, 1,250 commercial, and eight (8) industrials Peak load is typically between seventy to eighty (70-80) MW with one hundred percent (100%) of the power it generates coming from renewable resources

	South Carolina Electric Power Generating Utilities
Santee Cooper	State-owned electric and water utility governed by a twelve-member board of directors Public power provider and primary source of electricity, either directly or through electric cooperatives, for approximately two (2) million people in all forty-six (46) counties of South Carolina Santee Cooper serves more than 174,000 residential and commercial customers directly in Berkeley, Georgetown, and Horry counties Supplies electricity to twenty (20) electric distribution cooperatives, the cities of Bamberg and Georgetown and twenty-seven (27) large industrial customers Operates an integrated transmission system that includes lines owned and leased by Santee Cooper as well as those owned by Central Electric Power Cooperatives, Inc. Owns and operates approximately 5,300 MW of firm generating capacity in South Carolina

In addition to the five (5) electric power generating utilities, twenty-two (22) non-profit electric cooperatives and twenty-one (21) municipalities also operate electric systems within the State – primarily at the distribution system level. Twenty (20) of the independent distribution cooperatives serve approximately 720,000 members and operate more than 72,000 miles of power lines touching all 46 South Carolina counties.[4] These distribution cooperatives are supported by two (2) statewide organizations: (1) Central Electric Power Cooperative, Inc., which provides planning, wholesale power aggregation services, and wholesale transmission delivery services, and (2) the Electric Cooperatives of South Carolina (ECSC), a statewide trade association that provides political representation, economic development support and a variety of ancillary programs to its members.[4]

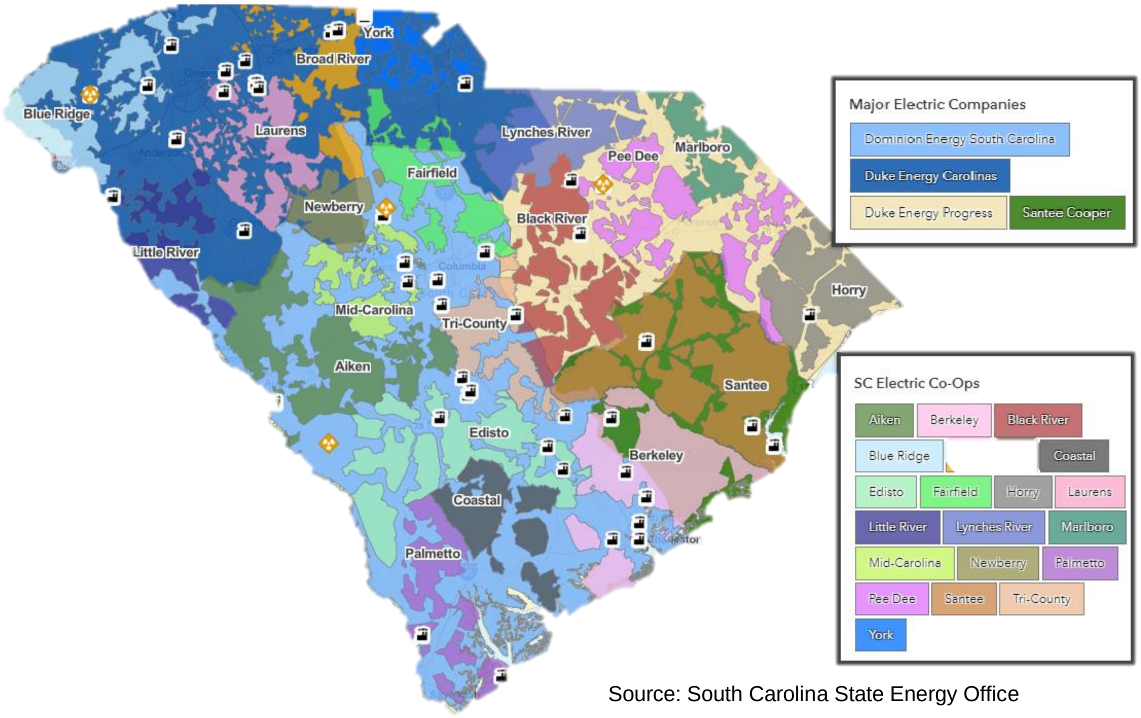
Figure 3. Map of South Carolina Municipal Electric Utilities



Source: South Carolina State Energy Office

The State's twenty-one (21) municipal electric systems – electric distribution systems typically owned and operated by a city, town, county, township – provide electric service to residential, commercial, and industrial customers in their municipalities and to a limited number of customers outside of the incorporated boundaries. These local distribution systems serve approximately 170,000 customers (roughly seven percent (7%) of South Carolina's electric customers).[4] Twenty (20) of the twenty-one (21) municipal electric systems are members of SCAMPS, a nonprofit organization that supports emergency mutual aid assistance coordination, training and education programs, and overall advocacy for municipal electric providers.

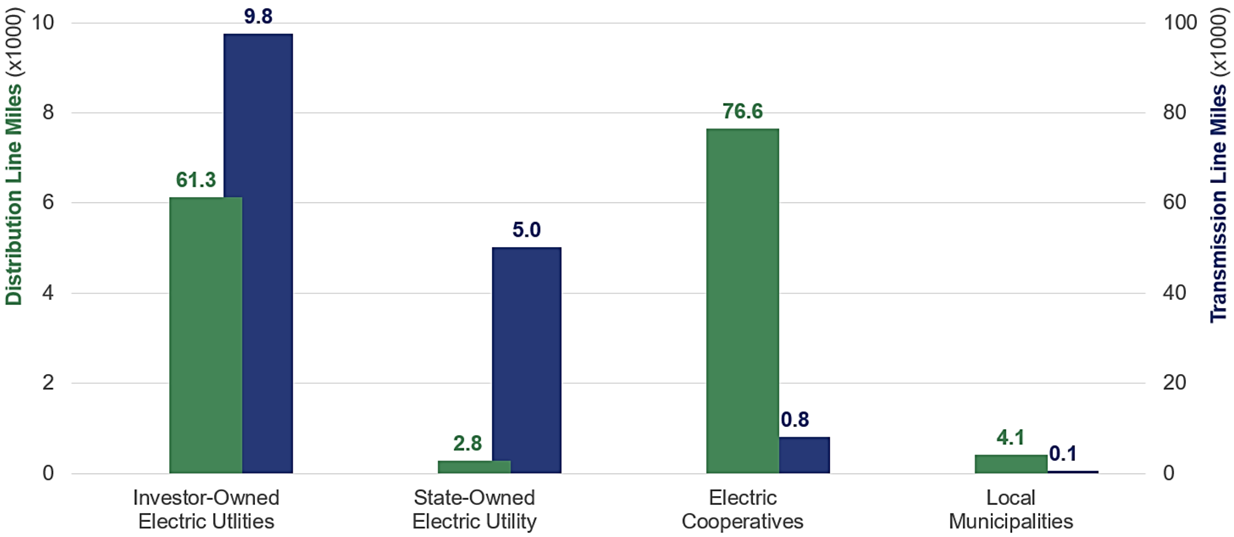
Figure 4. Map of South Carolina Electric IOUs and Electric Cooperatives



Source: South Carolina State Energy Office

Investor-owned utilities own and/or operate well over half of the State's electric transmission grid, and the majority of the State's distribution lines are managed by electric cooperatives. Less than three percent (3%) of South Carolina's electric grid is operated by municipalities (**Figure 5**).

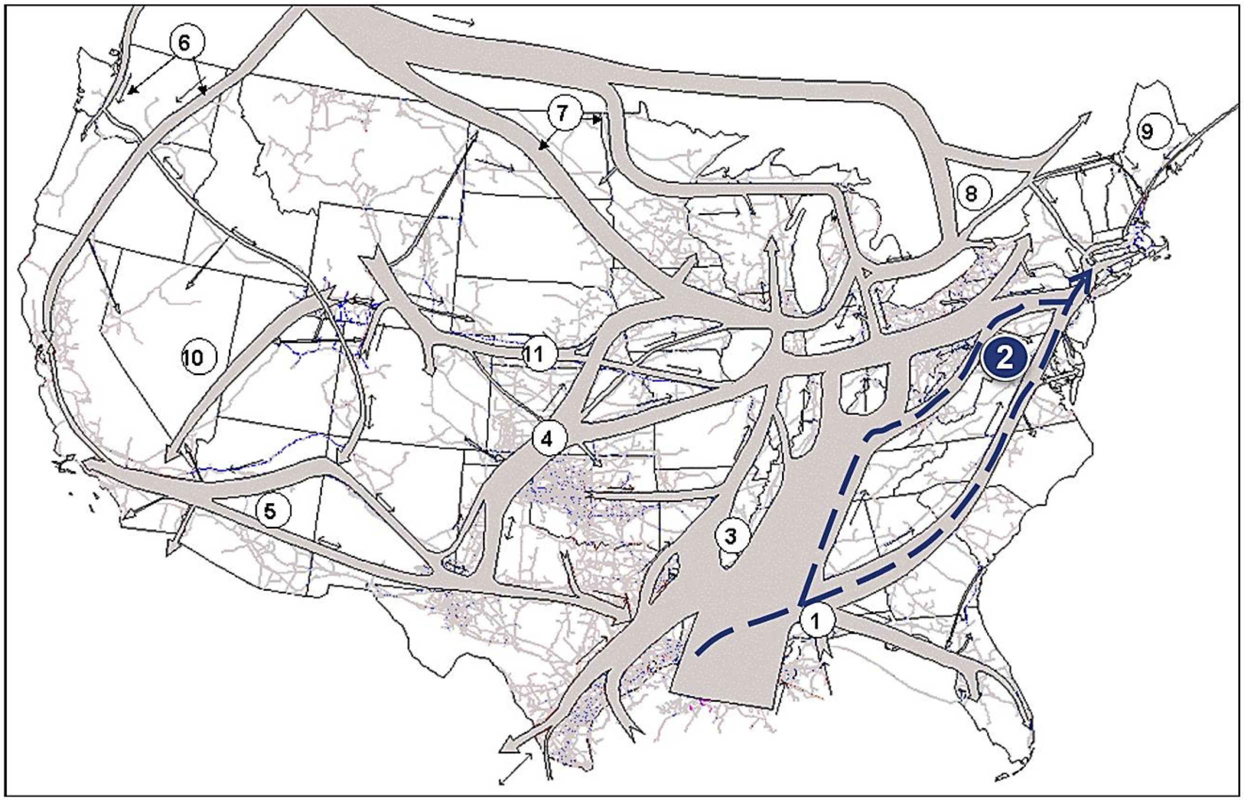
Figure 5. Relative Sizes of South Carolina Electric Systems by Utility Type [4,12]



Natural Gas Supply and Delivery System

South Carolina has no recoverable natural gas reserves and imports its supply through the national natural gas delivery network. The major routes of the natural gas network fall into eleven (11) transmission corridors. The Southwest-to-Northeast corridor (Corridor 2 in **Figure 6)** routes from the gulf states up to the Northeastern U.S. and splits into two (2) sub corridors along the way: one (1) running up through Tennessee, Kentucky, and Ohio and the other through the mid-Atlantic states (Georgia, the Carolinas and Virginia).

Figure 6. Major Natural Gas Transportation Corridors



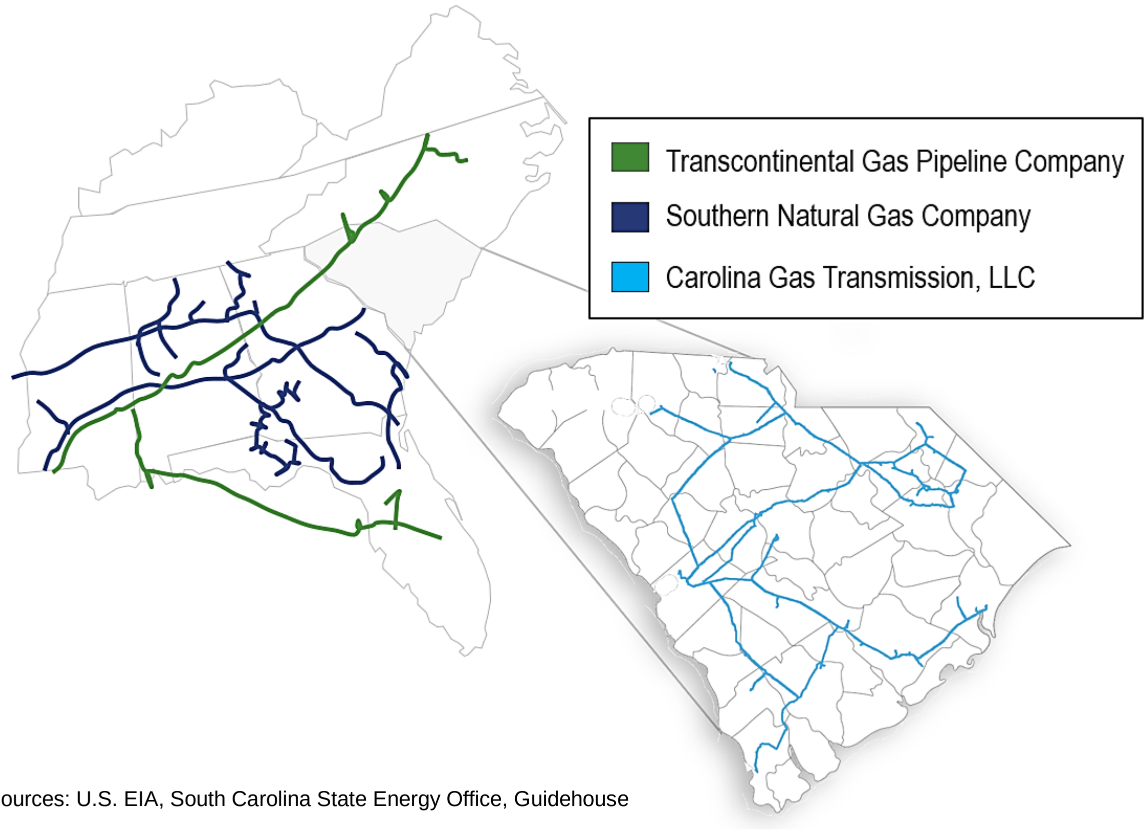
Source: Energy Information Administration, Office of Oil and Gas, Natural Gas Division, GasTran Gas Transportation Information System.

The natural gas imported by those states along the mid-Atlantic segment of Corridor 2, South Carolina among them, is supplied primary by Transcontinental Gas Pipeline (Transco).[15] Specifically, within the Southeast market, the largest pipeline network is operated by Southern Natural Gas Company (SNG).

A third pipeline system, Carolina Gas Transmission, LLC (CGT), formerly Dominion Carolinas Gas Transmission, provides natural gas transportation services to markets within South Carolina.[16] CGT operates approximately 1,500 miles of transport pipeline, predominately in South Carolina, and primarily designed to serve firm (uninterruptable) gas customers. South Carolina is served by all three (3) interstate pipeline networks. (**Figure 7**).

FERC and the Pipeline and Hazardous Materials Safety Administration (PHMSA), an agency within the U.S. Department of Transportation, share oversight for interstate natural gas pipelines.

Figure 7. Primary Natural Gas Pipeline Networks Serving South Carolina

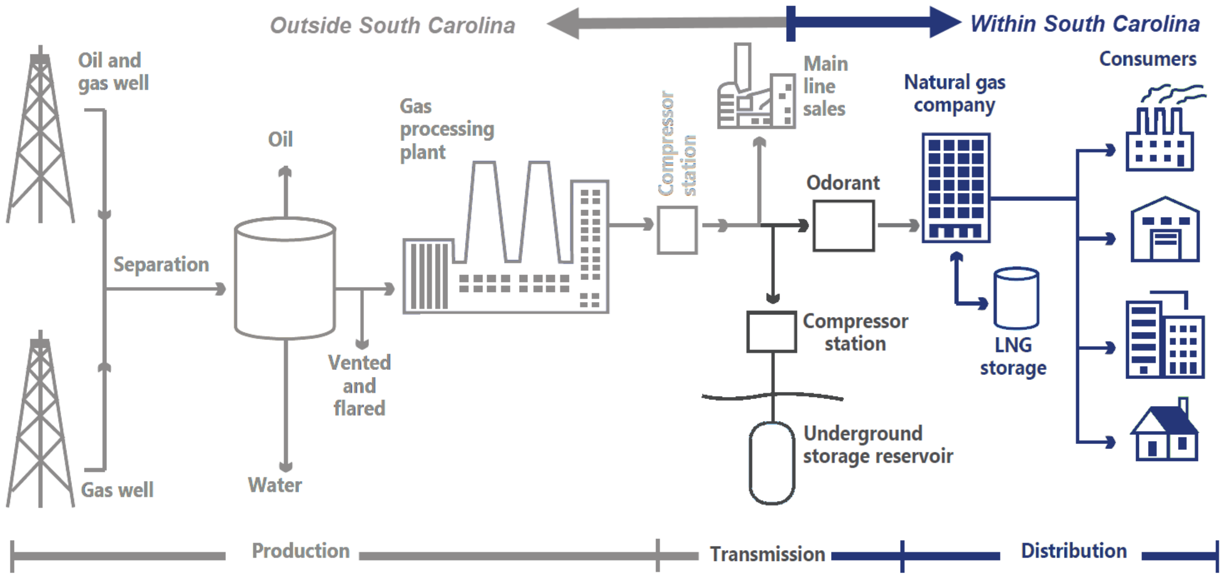


Sources: U.S. EIA, South Carolina State Energy Office, Guidehouse

South Carolina also has an intrastate natural gas delivery system that consists of smaller distribution pipeline networks operated by two (2) investor owned utilities, five (5) natural gas authorities (NGAs), four (4) commissions of public works (CPWs), and five (5) municipalities.[4] **Figure 8** provides an illustrative view of how the transmission pipeline systems support natural gas delivery to distribution pipelines, which are often operated by municipalities to deliver natural gas to their end-use customers.

Apart from pipeline safety, the ORS does not have the responsibility for oversight of municipal systems or NGA.[4]

Figure 8. Natural Gas Delivery



Source: South Carolina Energy Plan, Guidehouse

Natural Gas Utility Providers

According to the South Carolina State Energy Office, two (2) natural gas investor-owned utilities operate within the State (DESC and PNG). **Table 3** provides high-level descriptions of these natural gas utilities.

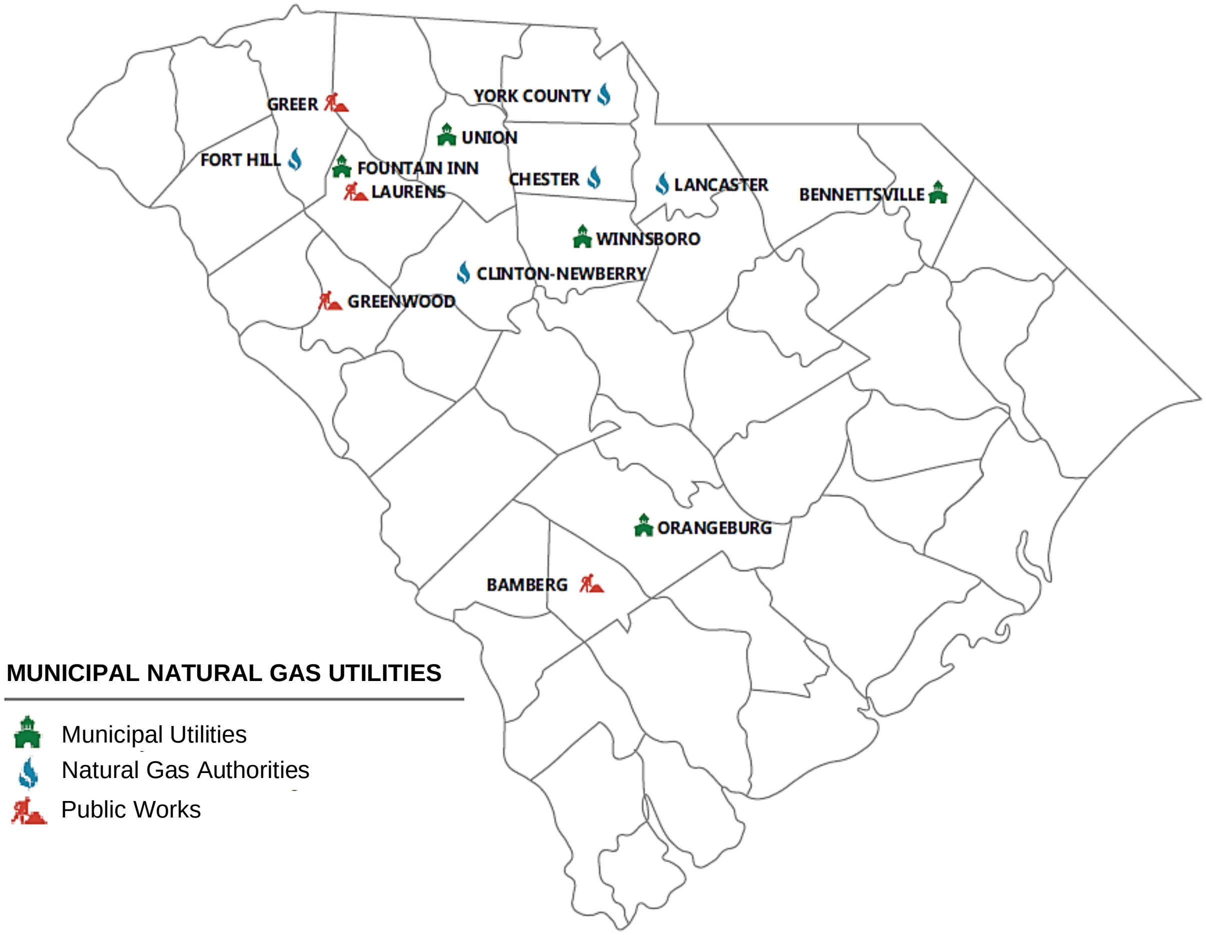
Table 3. General Information about South Carolina Natural Gas Utilities[4]

South Carolina Investor-Owned and State-Owned Natural Gas Utilities	
Dominion Energy *(Parent Company operating in South Carolina as DESC)*	Investor-owned utility headquartered in Richmond, Virginia that supplies natural gas to parts of Utah, West Virginia, Ohio, Pennsylvania, North Carolina, South Carolina, and Georgia Delivers gas to approximately 352,000 residential, commercial, and industrial customers in 35 of the 46 counties in the Midlands, Pee Dee, and coastal communities of South Carolina, including Columbia, Charleston, Aiken, Myrtle Beach, and Florence Operates and maintains 447 miles of high-pressure transmission pipelines and 9,064 miles of distribution mains that serve South Carolina communities
Piedmont Natural Gas Company, Inc. (PNG)	Investor-owned natural gas utility headquartered in Charlotte, North Carolina that supplies natural gas to parts of North Carolina, South Carolina, and Tennessee, and is a wholly owned subsidiary of Duke Energy Serves approximately 150,000 customers and delivered approximately 20 billion cubic feet (BCF) of natural gas to its South Carolina customers in 2019 Operates and maintains 3,789 miles of transmission and distribution mains at operating pressures between 15 and 800 psi in South Carolina Owns and operates three (3) publicly accessible compressed natural gas (CNG) fueling stations in South Carolina to fuel its own natural gas-fueled fleet vehicles

In addition to the two (2) investor-owned natural gas Utility Providers, there are fourteen (14) natural gas municipal systems operating in South Carolina, as illustrated in **Figure 9**. These municipal gas systems serve approximately 239,000 customers and operate and maintain approximately 9,000 miles of natural gas pipeline (representing sixty-one percent (61%) of the State's natural gas distribution network and thirty-two percent (32%) of the state's natural gas customers.[4]

For a complete list of South Carolina's electric and natural gas Utility Providers, see **Table 4**.

Figure 9. Map of South Carolina Municipal Natural Gas Utilities



Source: South Carolina State Energy Office

Table 4. South Carolina Utility Providers

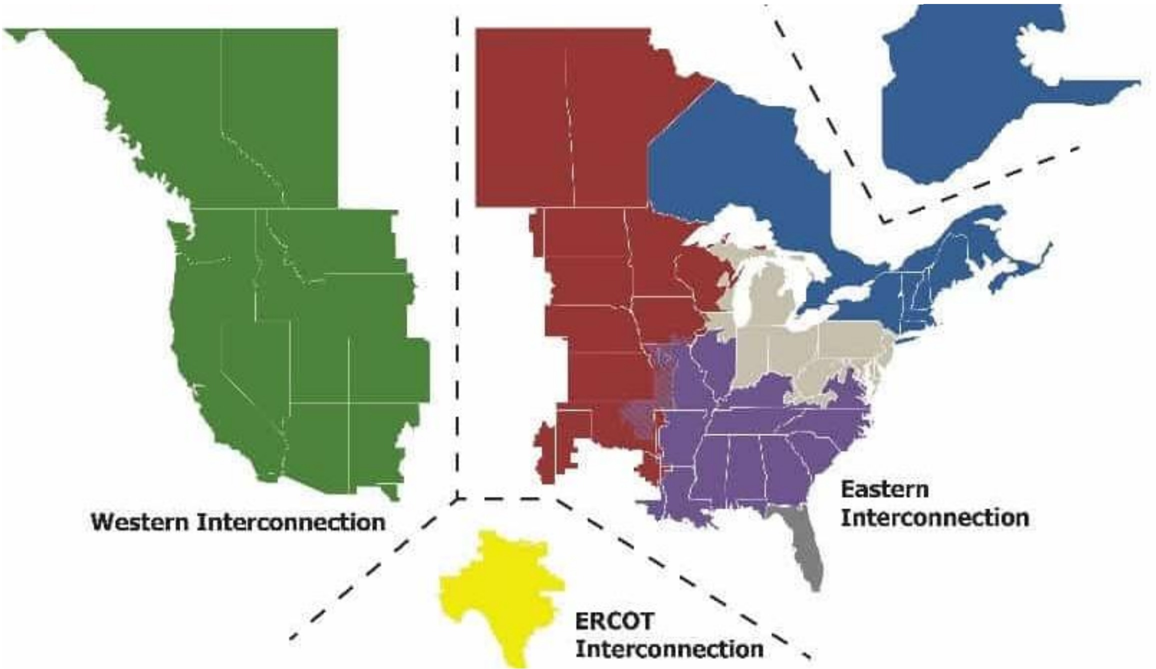
Electric Utility Providers	Natural Gas Utility Providers
Investor-Owned Electric Companies • DEC • DEP • DESC • Lockhart **State-Owned Utility** • Santee Cooper **Customer-Owned Electric Cooperatives** • Aiken Electric Cooperative • Berkeley Electric Cooperative • Black River Electric Cooperative • Blue Ridge Electric Cooperative • Broad River Electric Cooperative • Coastal Electric Cooperative • Edisto Electric Cooperative • Fairfield Electric Cooperative • Horry Electric Cooperative • Laurens Electric Cooperative • Little River Electric Cooperative • Lynches River Electric Cooperative • Marlboro Electric Cooperative • Mid-Carolina Electric Cooperative • Newberry Electric Cooperative • Palmetto Electric Cooperative • Pee Dee Electric Cooperative • Santee Electric Cooperative • Tri-County Electric Cooperative • York Electric Cooperative **Generation and Transmission Electric Cooperatives** • Central Electric Power Cooperative • New Horizons Electric Cooperative **Municipal Departments/Divisions** • City of Abbeville • City of Bennettsville* • City of Camden • City of Clinton • City of Georgetown • City of Newberry • City of Orangeburg* • City of Rock Hill • City of Seneca • City of Union* • City of Westminster • Town of Prosperity • Town of Due West • Town of Winnsboro* **Commissions/Board of Public Works** • Bamberg Board of Public Works* • Easley Combined Utility System • Gaffney Board of Public Works • Greenwood Commission of Public Works* • Greer Commission of Public Works* • Laurens Commission of Public Works* • McCormick Commission of Public Works	**Investor-Owned Natural Gas Companies** • DESC • PNG **Municipal Departments/Divisions** • City of Bennettsville* • City of Fountain Inn • City of Orangeburg* • City of Union* • Town of Winnsboro* **Commissions of Public Works** • Bamberg Board of Public Works* • Greenwood Commission of Public Works* • Greer Commission of Public Works* • Laurens Commission of Public Works* **Natural Gas Authorities** • Chester County Natural Gas Authority • Clinton-Newberry Natural Gas Authority • Fort Hill Natural Gas Authority • Lancaster Natural Gas Authority • York County Natural Gas Authority ** Provides both electric and natural gas utility services*

2.2 Characteristics of South Carolina's Power System

Across the continental U.S., local electric power grids are interconnected to form three (3) large, interconnected (**Figure 10**), but independently operated, electric power networks. These networks, or interconnections, enhance grid reliability.[17]

1) The Eastern Interconnection
2) The Western Interconnection
3) Electric Reliability Council of Texas (ERCOT)

Figure 10. North America Interconnections

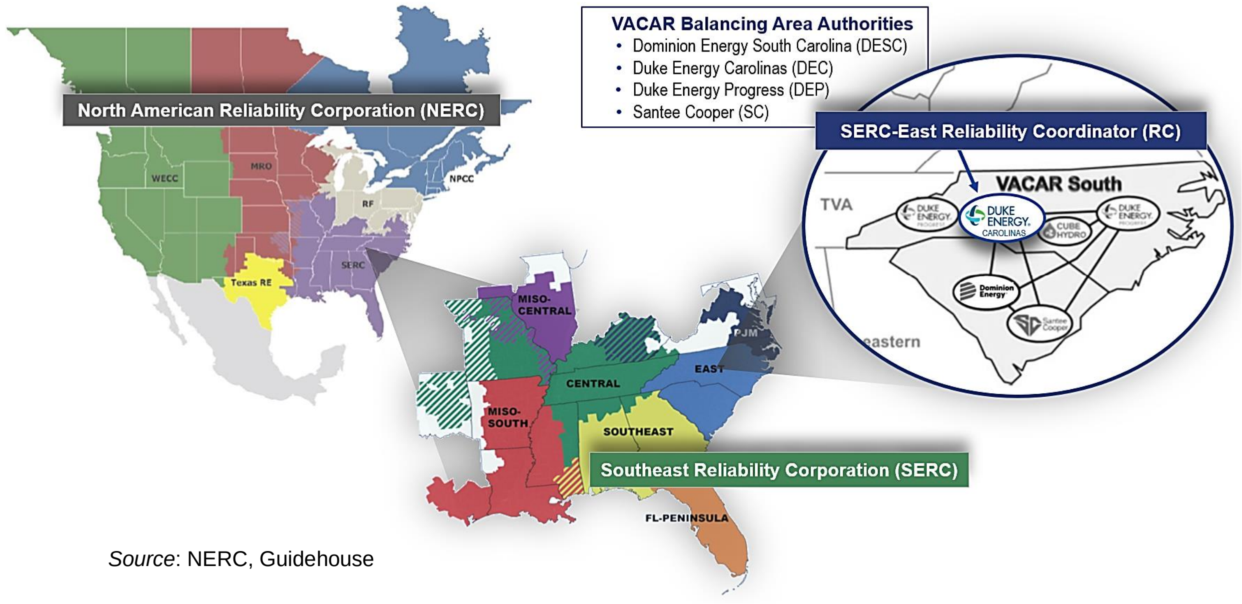


Part of a Large Interconnection

South Carolina's interconnected network of high voltage transmission systems – its bulk electric system (BES) or bulk power system (BPS) – is part of the Eastern Interconnection. Because of the criticality of reliable electricity supply evidenced from prior regional blackouts, oversight of the BPS falls under the authority of the NERC.

Under the authority of NERC, the electric power grid in the U.S. and Canada is comprised of six (6) regional reliability organizations. South Carolina is located within the Southeast Reliability Corporation (SERC) region. Within SERC, there are seven (7) subregions that extend from Illinois to Florida.[18] South Carolina is part of the *SERC-East* subregion, which also includes North Carolina as **Figure 11** illustrates. There are major transmission ties to three (3) of SERC's subregions with import/export limits established for each subregion. **Appendix D** provides a non-exhaustive list of pertinent standards and guidelines applicable to SERC and other subregions related to reliability, protection and recovery from extreme weather events with a specific emphasis on cold weather events.

Figure 11. SERC-East Balancing Area Authorities and Reliability Coordinator



Source: NERC, Guidehouse

Part of a Regionally Coordinated System

Entities (often grid operators) called "balancing area authorities," or "BAAs" are responsible for a specific portion of the power system to ensure real-time power supply and power demand remain balanced – a required condition to avoid local or wide-area blackouts.

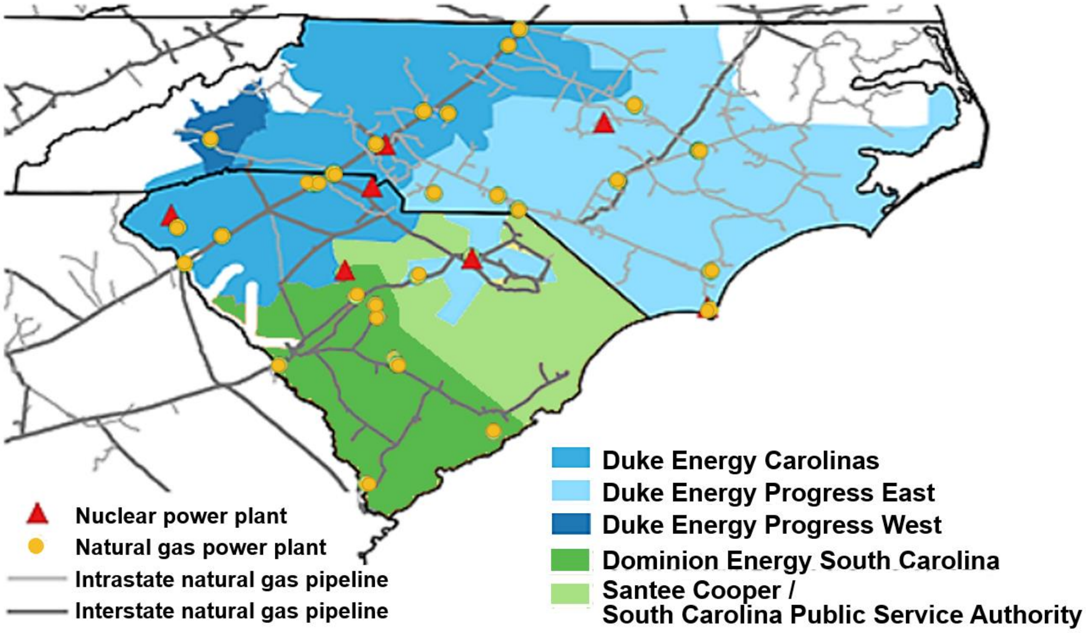
South Carolina has four (4) BAAs – as shown in **Figure 12** – within SERC-East that manage the day-to-day operation of each balancing area that is subject to NERC reliability standards and compliance.

- DEC
- DEP
- DESC
- Santee Cooper

Each BAA has operational responsibility for managing the day-to-day operation of their respective balancing area. To ensure overall BPS reliability across a broad region, NERC reliability standards require the establishment of a Reliability Coordinator (RC). The SC LEUs collaborated in 2005 and created the VACAR South Reliability Coordinator (VACAR-S RC) which has been registered with NERC.[19] To perform certain defined tasks that only a RC can perform, the members of VACAR-South RC have contracted with Duke Energy to act as the VACAR-South agent.

Because of the interconnection and coordination agreement, bulk system reliability for South Carolina must be viewed from a multi-state perspective.

Figure 12. Carolinas Balancing Authorities



Source: U.S. Energy Information Administration

2.3 Comparison to the Texas Power System

Several attributes of South Carolina's power system make it materially distinct from the Texas power system – particularly as it relates to winter weather risks and performance. Following the examination of the widespread power outages across Texas during the February 2021 winter storm, NERC concluded that there were several contributing factors that resulted in the event.[7] Key factors included:

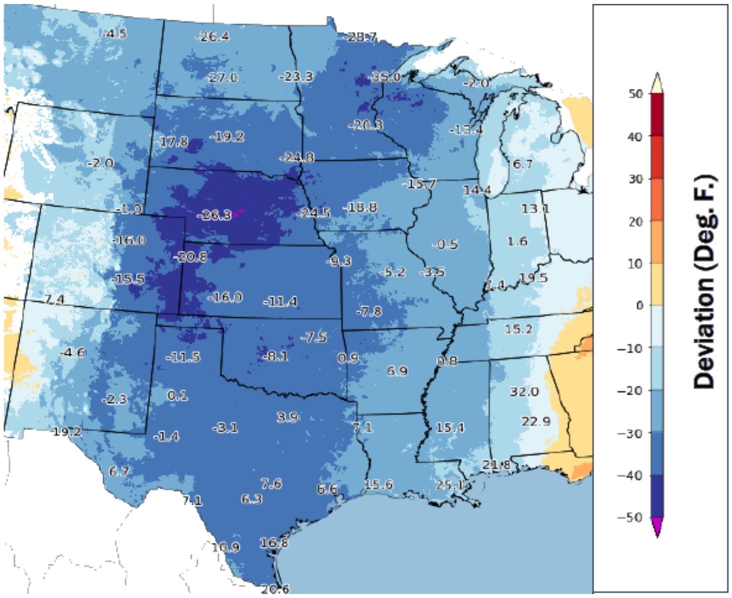
- Colder than expected weather conditions leading to generation shortfalls
- Lack of winterization plans for generating units
- Natural gas fuel supply issues
- Heavy reliance on natural gas for electricity generation (interdependency)
- Generation freezing issues

Moreover, the limited number of transmission ties to adjacent regional systems also contributed to Texas' inability to adequately respond to generation shortfalls as they emerged.

Colder than Expected Forecasts Leading to Generation Shortfalls

The February 2021 winter storm produced extended cold temperatures across Texas – temperatures that in some locations deviated from the average daily minimum temperature by as much as forty degrees Fahrenheit (40ºF) (**Figure 13**). Temperatures dropped to near zero in some areas while Dallas experienced single digit temperatures. This condition resulted in much higher than projected demand on the Texas power system for an extended duration as power system customers attempted to warm their homes and businesses.

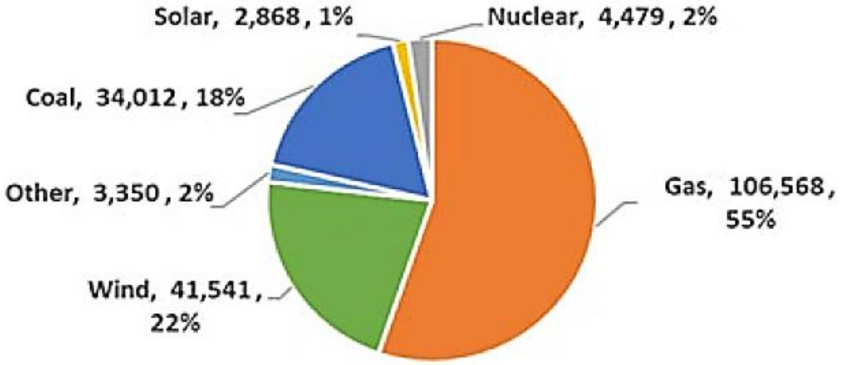
Figure 13. Minimum Temperature and Departure from Average Daily Minimum



Source: NOAA

In addition to the unexpected increase in customer demand, as the cold temperatures persisted for two (2) consecutive days, ERCOT averaged 34,000 MW of generation outages. Of the generating units experiencing outages, derates or failures to start, over half were natural gas generators (**Figure 14**). To ensure system stability, the BAAs worked to balance Texas's energy demand with the dropping supply, ordered grid operators to shed over 20,000 MW of load.[18]

Figure 14. Fuel Type of Texas Generating Units Experiencing Unplanned Outages



Source: NERC

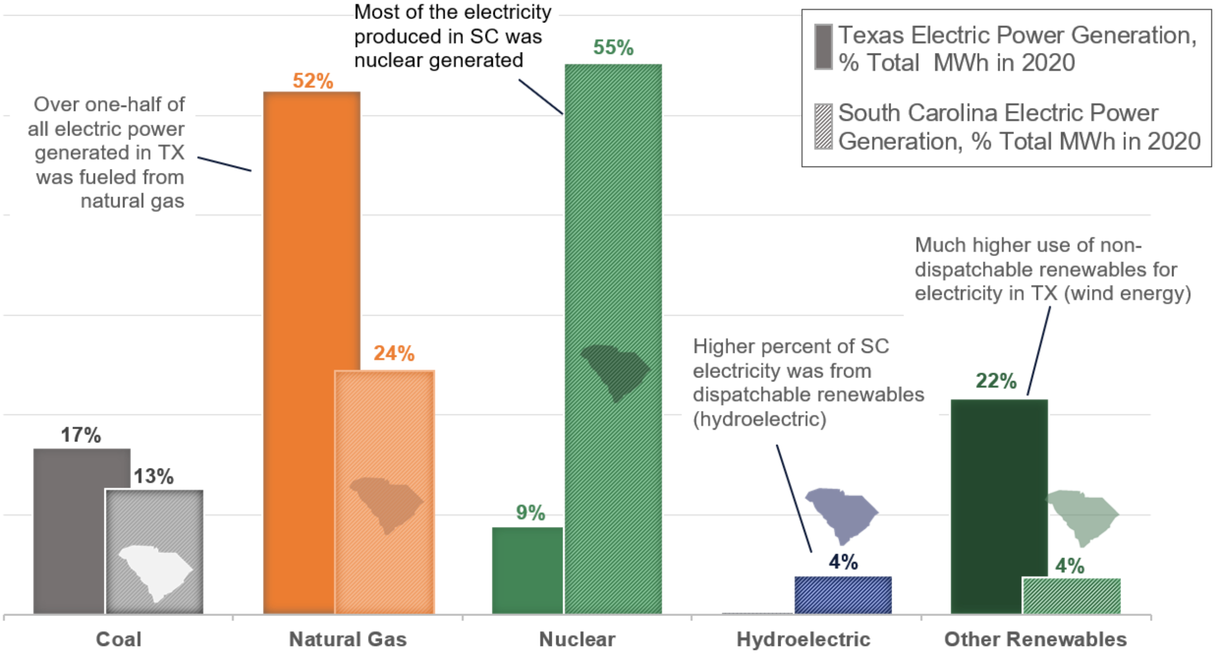
Reliance on Natural Gas for Electricity Generation (Interdependency)

Texas is a large natural gas producer and consequently has a high reliance on natural gas, both for direct end-use and to fuel the state's electric generation facilities. As **Figure 15** illustrates, in 2020 over one-half (1/2) of the MWh generated in the state were fueled from natural gas. Another twenty percent (22%) of the electric power produced in Texas came from non-dispatchable renewable resources – primarily wind energy. By contrast, in South Carolina less than a quarter of the State's electric generation is natural gas-fired. Most of the South Carolina's electric power generation in 2020 came from nuclear resources.[20] This highlights the different levels interdependency between natural gas and electricity within each of these states. A sudden disruption in natural gas supply would have far greater implications to the Texas electric system than that same disruption would have in South Carolina.

During the February cold snap, when temperatures in Texas averaged nearly thirty degrees Fahrenheit (30ºF) lower than normal, natural gas production in Texas fell almost forty-five percent (45%). According the U.S. Energy Information Administration, this decline in natural gas production was mostly a result of water and other liquids in the raw natural gas stream freezing at wellheads or in natural gas production lines. Unlike the relatively winterized natural gas production infrastructure in northern areas of the country, natural gas production infrastructure in Texas is more susceptible to the effects of extremely cold weather.[21]

In South Carolina, the greatest amount of power generated in the State is fueled by nuclear power. Moreover, the natural gas supply that South Carolina imports is sourced from a variety of locations including the Gulf Coast, Mid-Continent, and Appalachia.[22]

Figure 15. Electric Power Generation by Fuel Type for South Carolina and Texas, 2020



Source: U.S. Energy Information Administration, Guidehouse

Loss of Renewable Generation

Table 5 highlights the SERC East region's lower reliance on variable energy resources (VERs) compared to that of Texas. Texas leads the nation in wind-powered generation and produced more than twice as much electricity from wind as from its two (2) nuclear power plants combined in 2020.[9]

By contrast, the renewable power consumed in South Carolina comes primarily from dispatchable resources, such as hydroelectric power and biomass. Dispatchable resources can offer more flexibility for system operators – particularly during times of sharp changes in demand and supply.

Table 5. Reliance on Variable Energy Resources[23]

Source	SERC-East	Texas
Solar	1%	9%
Wind	0%	10%

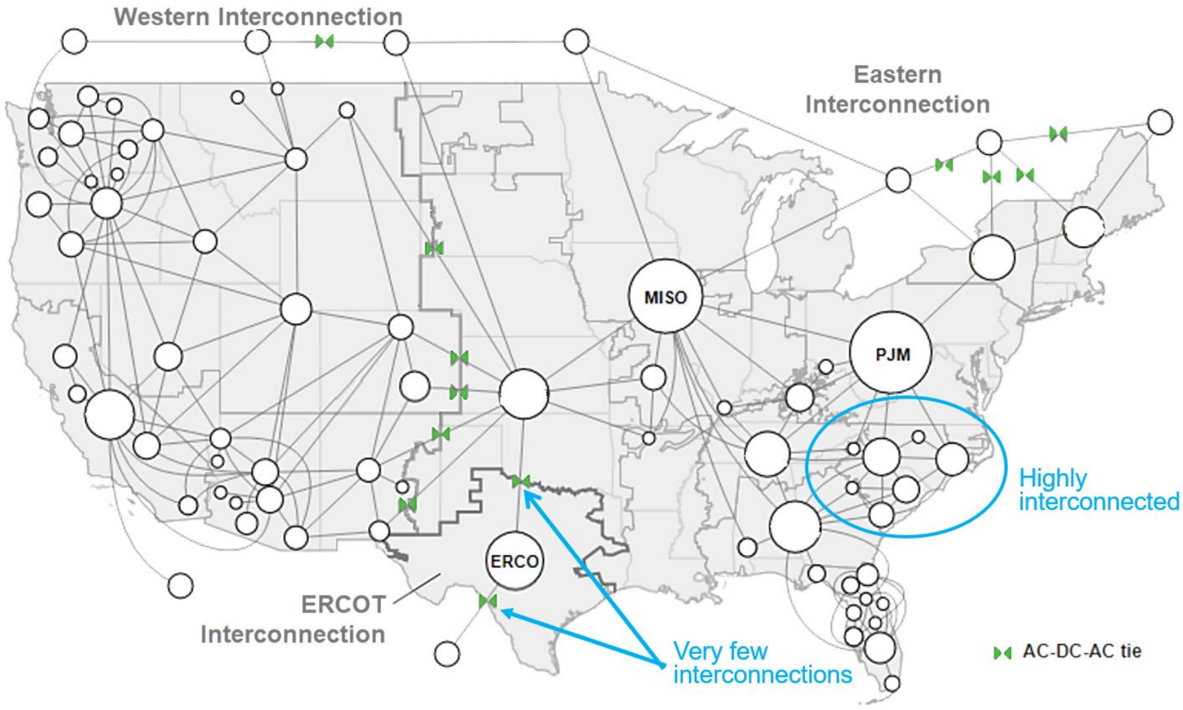
Interconnectedness of the Regional Transmission System

As Texas experienced generation shortfalls during the February 2021 winter storm, Texas grid operators were limited in their ability to quickly import additional electricity from neighboring systems. One of the starkest contrasts between the South Carolina power system and the Texas power system is the number of major interface connections each of these systems have with neighboring power grids. As noted, South Carolina is part of a larger interconnected system (SERC-East). The SERC-East system is interconnected with the other sub-regions within SERC as well as other with subregions from other NERC reliability regions such as PJM and MISO.

SERC uses reliability models to determine and validate capacity limits to be observed when transferring power between each of the seven (7) subregions to maintain overall reliability.[24] For SERC-East, this transfer limit is 3,000 MW and may be lowered during cold weather events as lines approach their operating limits. Further, planned maintenance, unexpected outages, safety issues, and compliance requirements can cause lines to be out of service at any time. Each of these events can reduce import capability to well below 3,000 MW, possibly as low as zero MW.

Conversely, ERCOT, the entity responsible for the reliability of a significant portion of the Texas power grid, operates as a single NERC reliability region and has very limited transmission ties to adjacent power grids (**Figure 16**). Consequently, the limited ability to import power from neighboring systems contributed to the widespread power outages across ERCOT's footprint during the February 2021 winter storm.[25]

Figure 16. Interconnectedness of the Regional Electric Power Grids



Source: U.S. Energy Information Administration, Guidehouse

3

RISKS, THREATS, AND VULNERABILITIES

from Winter Weather Events

3.1 Power Reliabilty and Resource Adequacy

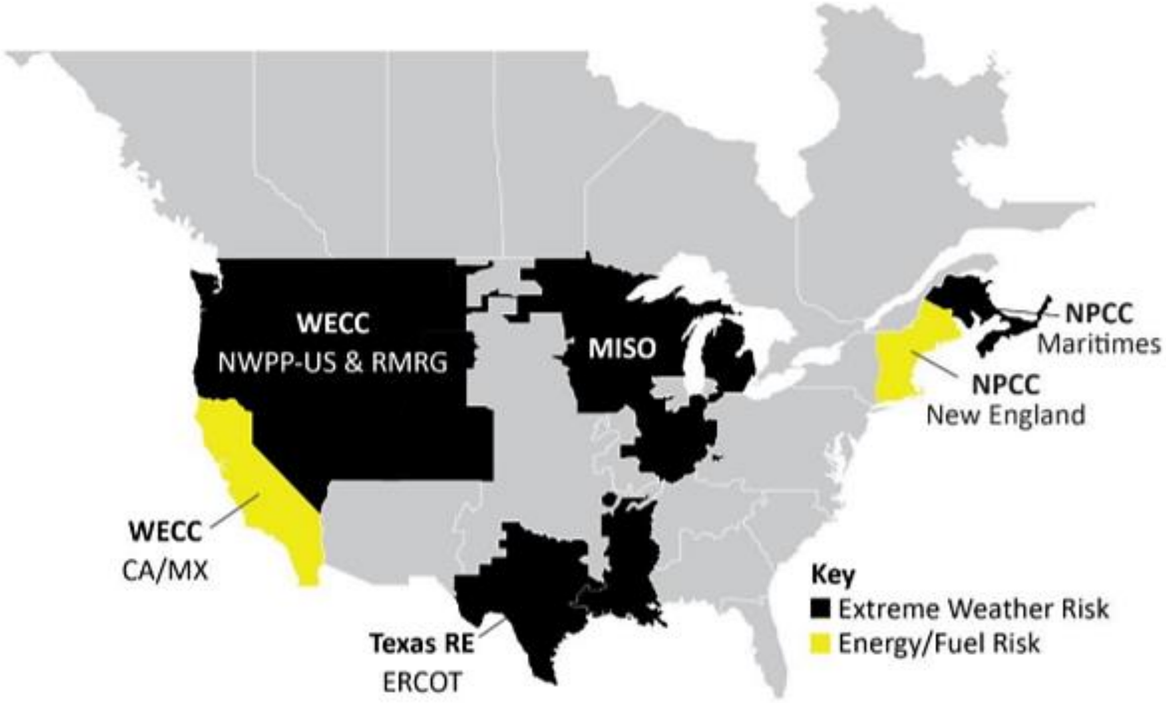
To assess risk, Utility Providers must determine the likelihood of a system component failure that would lead to utility service disruption for customers. To reduce the risk and avoid customer power outages **(reliability)**, Utility Providers must ensure that their systems are designed to withstand the types of weather conditions that might materialize in South Carolina. Similarly, system operators must ensure they are prepared to quickly respond to sudden disturbances, such as an unanticipated loss of a system component, to avoid loss of service to utility customers.

Utility planners must also ensure the system capacity and fuel supply is able to support the total power needs of customers at any given time – including during the loss of a system component (**adequacy**). At the Bulk Power System (BPS) level, adequacy is often assessed by examining generation reserve margins – that is, the amount of installed generation capacity above the maximum peak demand for a given region (e.g., VACAR-South). Operating reliability and resource adequacy are two (2) key measures used by NERC to assess power systems' ability to maintain operations and determine the risk of utility service disruptions.

3.2 Winter Weather Risk to the Bulk Power System

As part of its examination of the February 2021 cold weather outages in Texas, NERC expanded its assessment to identify areas across the U.S. power grid with potential BPS reliability risks due to the type of extreme cold weather and fuel-related issues present during the Texas event. While NERC's findings did identify the New England (NPCC) and the Western Interconnection southwest (WECC) areas as having limited natural gas availability, South Carolina and most of the Southeast BPS were not identified as risk areas (**Figure 17**).

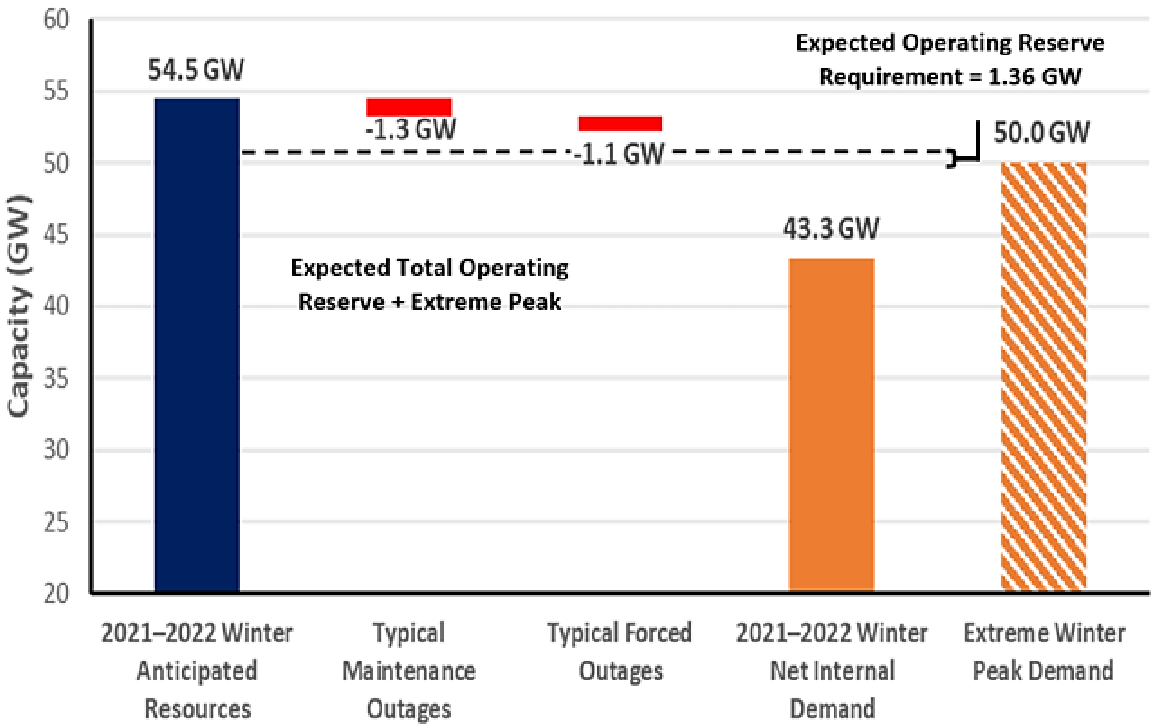
Figure 17. Regions of Potential Winter Risk to BPS



Source: FERC/NERC

SERC in its 2020 Reliability Review Subcommittee report did note that fuel delivery for gas units in SERC-East would be a concern in the unlikely event that a gas pipeline is lost, and highlighted one way to alleviate the concern is through the development of utility sized natural gas storage or dual-fuel capability.[26] After concluding its Reliability Assessment of the BPS for Winter 2021-2022, NERC found that extreme weather events, including extended durations of colder than normal weather, can expose power system generation and fuel delivery infrastructure vulnerabilities and challenge electricity system operators' ability to maintain reliability of the BPS.[27] Regarding SERC-East, the NERC assessment goes on to note that no emerging or potential reliability issues for the upcoming winter season have been noted nor have any significant reliability issues due to fuel supply, inventory, or transportation been identified. **Figure 18** highlights that during the period of highest risk for unserved energy at peak demand hour, during extreme winter peak demand conditions, SERC-East is expected to maintain a reserve margin of well over the 1.36 gigawatts (GW) required.

Figure 18. Fuel Supply Risk Scenario for SERC-East



Source: NERC

3.3 Risks and Threats to South Carolina's Utility Services

As part of the winter weather resiliency assessment of the South power system, the Commission instructed South Carolina's electric and natural gas Utility Providers to identify cold weather **threats** and **vulnerabilities**. While the top weather threats to the region are related to heat, humidity, and flooding, one of the greater risks could come from low probability events such as extreme cold, snow, or ice if the State's utility sector is not adequately prepared for such rare but highly consequential events. In its 2020 Reliability Assessment report for its subregions including SERC-East, SERC identified several general risk factors with higher likelihood and high impacts:[26]

Threats
Anything that may destroy, damage, or disrupt utility service, and cold weather.

Vulnerabilities
Any weaknesses within utility systems, processes, or infrastructure.

- Changing resource mix (e.g., increased reliance on renewables or natural gas);
- Variable energy Resources (VER) integration;
- Cybersecurity threats resulting from external and internal vulnerabilities;
- Resource uncertainty;
- Fuel diversity and fuel availability; and
- Weather-related (including winter events).

For weather-related high priority risks and fuel supply-related risks, SERC identified mitigation actions that members should undertake. **Table 6** provides a list of these actions. SERC recommends risks be proactively addressed through operating procedures and standards, including emergency operating procedures (EOPs), transmission operating procedures, or transmission plans (TPLs).

Table 6. High Priority Risk Mitigation Actions Identified by SERC[26]

Mitigation Measures for Addressing High Priority Risks to SERC Members

For Weather-Related Risks

- Required reporting of extreme events
- Extreme weather resiliency measures for network modeling, situational awareness of electric systems, and real-time contingency assessment (RTCA)
- Identification of backup measures if RTCA primary tools fail
- Use of alternate tools for manual operation of system or loss of situational awareness
- Response plan for loss of communication data or voice
- Emergency planning for extreme weather conditions

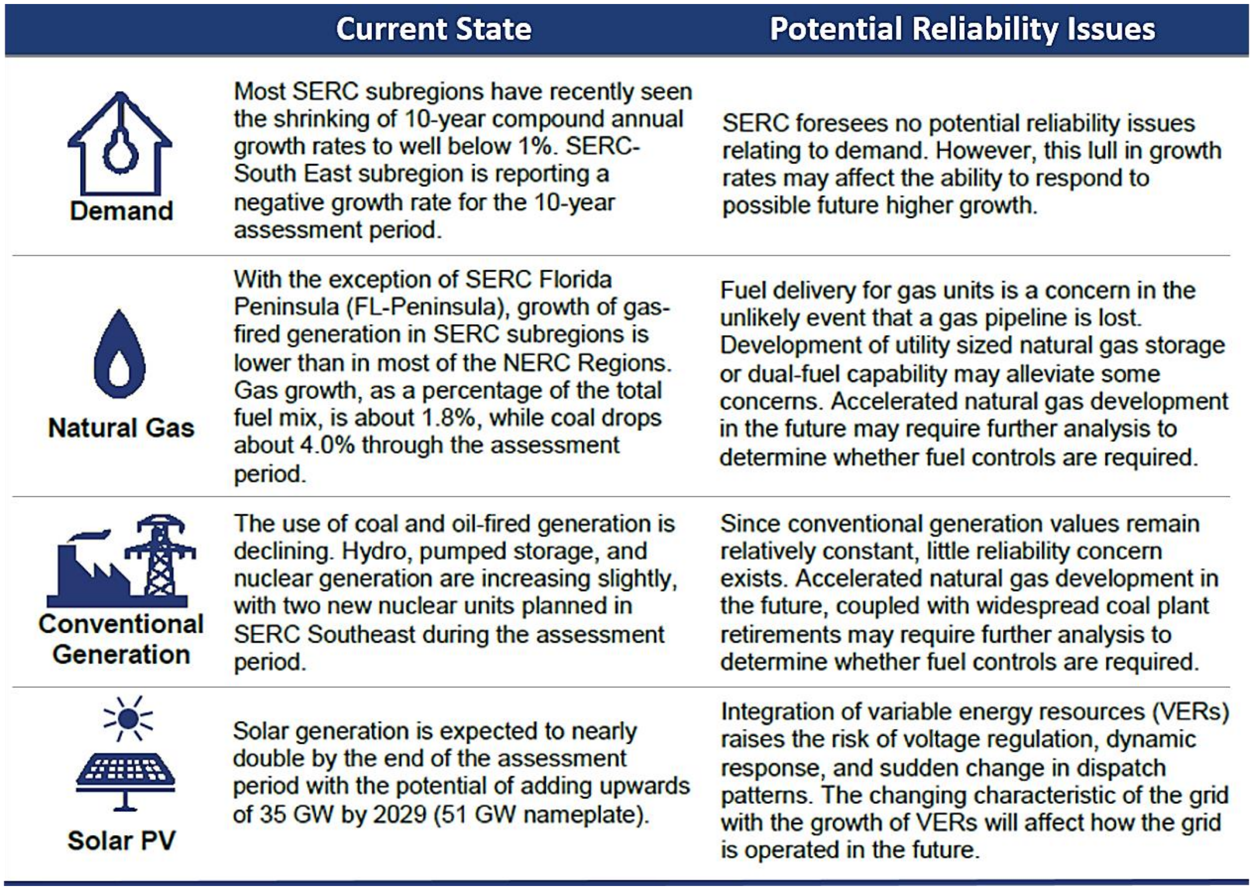
Mitigation Measures for Addressing High Priority Risks to SERC Members

For Fuel Supply-Related Risks

- Resource adequacy
- Situational awareness measures for sudden changes in dispatch and operating conditions
- Identification of forced operating conditions
- Fast-acting capabilities of existing units
- Response plan for a significant event that would affect specific fuel types
- Increased fuel supply diversity

Figure 19 provides potential reliability issues associated with various fuel types and resources, as identified by SERC.

Figure 19. Potential Reliability Issues by Resource Type[26]



	Current State	Potential Reliability Issues
Demand	Most SERC subregions have recently seen the shrinking of 10-year compound annual growth rates to well below 1%. SERC-South East subregion is reporting a negative growth rate for the 10-year assessment period.	SERC foresees no potential reliability issues relating to demand. However, this lull in growth rates may affect the ability to respond to possible future higher growth.
Natural Gas	With the exception of SERC Florida Peninsula (FL-Peninsula), growth of gas-fired generation in SERC subregions is lower than in most of the NERC Regions. Gas growth, as a percentage of the total fuel mix, is about 1.8%, while coal drops about 4.0% through the assessment period.	Fuel delivery for gas units is a concern in the unlikely event that a gas pipeline is lost. Development of utility sized natural gas storage or dual-fuel capability may alleviate some concerns. Accelerated natural gas development in the future may require further analysis to determine whether fuel controls are required.
Conventional Generation	The use of coal and oil-fired generation is declining. Hydro, pumped storage, and nuclear generation are increasing slightly, with two new nuclear units planned in SERC Southeast during the assessment period.	Since conventional generation values remain relatively constant, little reliability concern exists. Accelerated natural gas development in the future, coupled with widespread coal plant retirements may require further analysis to determine whether fuel controls are required.
Solar PV	Solar generation is expected to nearly double by the end of the assessment period with the potential of adding upwards of 35 GW by 2029 (51 GW nameplate).	Integration of variable energy resources (VERs) raises the risk of voltage regulation, dynamic response, and sudden change in dispatch patterns. The changing characteristic of the grid with the growth of VERs will affect how the grid is operated in the future.

3.4 Potential Vulnerabilities in South Carolina's Utility Infrastructure

The variety of asset types and geographic dispersion of the State's utility infrastructure introduce general vulnerabilities consistent with those faced by the critical infrastructure of any sector, including sabotage, unforeseeable natural hazards, and accidental third-party damage. For such vulnerabilities, the most critical infrastructure is equipped with a constantly evolving set of design standards and protective measures to prevent as much potential impact as practical and with emergency response plans (ERPs) to quickly mitigate any harm done. South Carolina's critical utility infrastructure is subject to the same vulnerabilities.

Aside from the more general vulnerabilities of the South Carolina power system (e.g., asset corrosion, equipment malfunction, human error), the State's electric and natural gas Utility Providers identified vulnerabilities specific to winter weather events. **Table 7** provides a subset of those identified by Utility Provider in their responses to ORS information requests.

To address these vulnerabilities and others, the power sector relies on historical data and trends to identify and attempt to protect against vulnerabilities. In today's environment of rapid innovation, technology advancement, and evolving geopolitical outlooks, forecasting based on historical patterns and events may not position the industry well to plan for future events.

Table 7. Vulnerabilities Identified by South Carolina Electric and Natural Gas Utility Providers

Winter Weather-Related Power System Vulnerabilities in South Carolina
Environmental Conditions • **Predictability of winter weather events:** Unlike the long planning runways of hurricanes and other tropical weather, extreme cold weather events are far less predictable and offer limited time for event response preparation.[28] • **Changes to pre-existing conditions:** More frequent and extreme shifts in the environment (extreme heat, excessive humidity, prolonged drought, etc.) can produce unknown changes to local vegetation and equipment conductions, leading to new and unrecognized pre-existing conditions during winter weather events. • **Ice accumulation:** The moderate climate in South Carolina contributes to the threat from ice storms as temperatures may not be cold enough to produce snowfall, but cold enough to cause ice accumulation on power lines or trees near power lines. • **Falling limbs:** Following ice storms, falling trees and limbs pose a danger to line crews, delaying or suspending restoration efforts, sometimes for days, until the ice melts and the threat to crews passes.

Winter Weather-Related Power System Vulnerabilities in South Carolina

Resource and Fuel Supply

- **Interruptible gas curtailment:** During periods of high demand (or supply limitations due to freeze-ups), interruptible gas supply for electric generation may be curtailed.

- **Availability of replacement materials:** During widespread catastrophic issues or events, replacement materials (e.g., transformers, mobile substations, conductors, or specialty items) experience a surge in demand, limiting access and availability.

- **Wholesale power availability:** Regionwide events such as extreme cold significantly limit the availability of purchased power from other utilities or emergency power from VACAR during critical peak loads as neighboring utilities withdraw power available for sharing to meet their own needs.

- **Electric generation reserves:** In prolonged extreme cold conditions, as peak load increases, electric generation reserves diminish, increasing the system's vulnerabilities to sudden generation loss.

- **Limitations in forecasting:** The unpredictability of extreme cold can drive inaccuracies in load forecasts and resource planning that ultimately leads to under-resourced utilities during emergency conditions.

Labor Force

- **Access to labor force:** During severe outage events, particularly those driven by widespread natural disasters or multiple weather events over a short duration, availability of construction contractors and mutual aid crews becomes limited.

- **Access by labor force:** Due to hazardous road conditions and other threats to winter weather-related mobility issues, employees, contractors, or human resources necessary to resolve issues may be unavailable.

Infrastructure and System Design

- **System strain from cold:** Systems and resources that can withstand short periods of cold weather are not necessarily equipped to sustain operation or function over long periods of cold weather (e.g., traditional peaking capabilities not designed for continuous operations, instrumentation, process systems, and fuel supplies, including natural gas and coal piles).

Winter Weather-Related Power System Vulnerabilities in South Carolina

- **Distribution system strain from load:** Extreme peak loads that occur when weather is much colder or more prolonged than average peak condition can lead to damaged equipment (e.g., overloaded distribution lines and distribution transformers), causing cold weather outages.
- **Transmission system strain from load:** Extreme peak loads can result in the transmission system operating closer than normal to the maximum operating limits. This condition limits the operational flexibility need by transmission system operators to import additional power supply from neighboring transmission networks, or to provide emergency capacity to neighboring transmission networks when they are unable to support peak demands.
- **System strain with intermittency:** When the system is strained due to cold temperature exposure or extreme loads, intermittency from solar generation may exacerbate system stability challenges.
- **Supply balancing:** Abrupt changes in demand caused by a downed transmission line or large transformer failure that led to a lower-than-expected load can pose a significant challenge to the balancing authority's ability to balance generation resources. When aggregate loads reach values below the minimum capabilities of the system's generating resources, generating units would need to be taken offline; recovering from such an outage event, including the effects of cold load pickup, becomes more challenging.
- **Power line (feeder) exposure:** Long radial feeders that lack the tie points that allow back-feeding of power for loss of primary source or any single component outage are especially susceptible to the wind and falling trees that accompany winter weather events. Overhead distribution facilities, prevalent in rural areas, are not designed to carry the excess weight of snow and ice.
- **Pipe exposure:** Extended periods of below-freezing temperatures can freeze unprotected exposed service water piping, condensate piping, and instrumentation lines that do not maintain flow. Frozen piping can disrupt control and piping damaged from a freeze may leak as it thaws, creating more operational challenges and even force whole generating units offline.
- **Overwhelmed steam supply line:** The combination of cold temperatures and high winds can overwhelm the natural gas station steam supply line, leading to overheated circuits and impacts to generation capacity.

4

ASSESSMENT OF SOUTH CAROLINA POWER UTILITY PROVIDERS

4.1 Evaluation Approach

The Evaluators reviewed the utility information and assessments and applied a Utility Adverse Weather Assessment Framework (Assessment Framework) that was adapted for winter weather events.

Evaluation Categories

To enable reasonable comparisons of capabilities and to compensate for varying service area sizes and the significant resource gaps between, for example, large investor-owned utilities and smaller local providers, Evaluators clustered the Utility Providers into four (4) assessment groups based on the general sizes and services provided.

- Large investor-owned or state-owned electric utilities (LEUs)
- Large investor-owned natural gas utilities (LGUs)
- Smaller electric municipal departments, boards, or commissions or customer-owned electric cooperatives (SEUs)
- Smaller natural gas municipal departments, boards, or commissions (SGUs)

Although, in cases such as those for municipal utilities and electric cooperatives, the utility operating models are uniquely distinct from one another, because of the relevance of findings and applicability of the recommendations, Evaluators included both utility types in the same assessment group.

The findings and resulting recommendations from this review are consolidated by utility provider type (natural gas and electric utilities) and utility size (large utilities and smaller utilities), as described above.

Table 8 identifies which utilities were assessed individually and which utilities were evaluated as part of a broader category of utilities.

Table 8. Evaluations Conducted by Utility Category

LEU *(Four Evaluations)*

- DEC
- DEP
- DESC
- Santee Cooper

LGU *(Two Evaluations)*

- DESC
- PNG

SGU *(Seven Evaluations)*

- City of Union Municipal Dept
- Clinton - Newberry Natural Gas Authority
- Fort Hill Natural Gas Authority
- Greenwood Commission of Public Works
- Greer Commission of Public Works
- Laurens Commission of Public Works
- Patriots Energy Group
  - Chester County Natural Gas Authority
  - Lancaster Natural Gas Authority
  - York County Natural Gas Authority

SEU *(Six Evaluations)*

- Central Electric Power Coop.
- Electric Cooperatives of South Carolina
  - Aiken Electric Coop.
  - Berkeley Electric Coop.
  - Black River Electric Coop.
  - Blue Ridge Electric Coop.
  - Broad River Electric Coop.
  - Coastal Electric Coop.
  - Edisto Electric Coop.
  - Fairfield Electric Coop.
  - Horry Electric Coop.
  - Laurens Electric Coop.
  - Little River Electric Coop.
  - Lynches River Electric Coop.
  - Mid-Carolina Electric Coop.
  - Newberry Electric Coop.
  - Palmetto Electric Coop.
  - Santee Electric Coop.
  - Tri-County Electric Coop.
  - York Electric Coop. Inc
- Lockhart
- Marlboro and Pee Dee Corp.
  - of Public Works
- Piedmont Municipal Power Agency
  - City of Abbeville
  - City of Clinton
  - City of Newberry
  - City of Rock Hill
  - City of Union
  - City of Westminster
  - Easley Combined Utility System
  - Gaffney Board of Public Works
  - Greer Commission of Public Works
- Laurens Commission South Carolina Assoc. of Municipal Power Systems
  - Bamberg Board of Public Works
  - City of Bennettsville
  - City of Camden
  - City of Georgetown
  - City of Orangeburg
  - City of Seneca
  - Greenwood Commission of Public Works
  - McCormick Commission of Public Works
  - Town of Prosperity
  - Town of Due West
  - Town of Winnsboro

Assessment Methodology and Framework

This Assessment Framework leverages a Capability Maturity Model Integration (CMMI) process and behavioral model. The CMMI process, created by the Carnegie Mellon University Software Engineering Institute,[29] has often been applied to help organizations understand and streamline process improvement, encourage productivity, and improve effectiveness. A common example of a CMMI model used in the power industry is the Smart Grid Maturity Model, a framework used by electric utilities to assess the maturity of a smart grid deployment.

The CMMI-based Assessment Framework applied in the review allowed Evaluators to assess the maturity of a utility’s ability to withstand adverse winter weather and assign that area into one (1) of five (5) levels of maturity, as **Figure 20** shows.

Evaluators conducted assessments at the indicator level and assigned a maturity level to each indicator based on weighted scores ranging from 0 to 5. The maturity level criteria for each indicator are based on accepted and leading industry practices. A non-exhaustive list of leading practices by indicator is available in **Appendix B. Extreme Weather Leading Practices.**

Figure 20. Assessment Framework Levels

	Maturity Level	Maturity Score	*Maturity level and score signify:*
🟢	***ADVANCED***	4.0 or greater	Advanced components in place and positioned for emerging needs
◓	***LEADING***	from 3.0 to 3.9	Foundational components in place and forward-looking plans or practices
🔵	**FOUNDATIONAL**	from 2.0 to 2.9	Foundational components in place and current standards followed
◒	**LAGGING**	from 1.0 to 1.9	Some foundational components in place
🟡	**NASCENT**	less than 1.0	Lacking or undeveloped foundational components

Evaluators consider the maturity scores of 4.0 or greater as ***advanced maturity***, in which Utility Providers are continuously evolving, adapting, and growing to meet the needs of stakeholders and customers. Scores from 3.0 up to 3.9 indicate ***leading maturity*** levels. Evaluators considered maturity scores of 2.0 to 2.9 to be indicative of ***foundational maturity*** **–** i.e., maturity of scored capabilities are as expected and considered to be on par with Utility Provider peers. Maturity scores of 1.0 to 1.9 indicate ***lagging maturity*** in scored areas and indicative of a need for improvement. Maturity scores of less than 1.0 suggest **nascent maturity** in the assessed areas. Utility Providers at this level are likely to be starting out in their journeys towards building specific cold weather resiliency capabilities, and significant development is required.

The Assessment leverages a continuous representation for defined adverse weather process areas and defines capability levels to characterize improvements. The process areas were defined specifically for preparation and response to adverse weather impacts and enables comparisons across organizations on a process area by process area basis. The Assessment Framework allowed the Evaluators to assess utility systems, measures, and practices more consistently across Utility Providers and more comprehensively across the eleven (11) indicator areas. **Table 9** describes the eleven (11) indicator areas the Evaluators considered.

The framework assessment considers each indicator area across the five (5) evaluation categories.

- People and culture
- Governance
- Process
- System and technology
- Data and analytics

Appendix A describes how each of the following five (5) evaluation categories are considered within the eleven (11) indicator areas. The Assessment Framework provided Evaluators a consistent methodology to assess utility provider maturity for the eleven (11) indicator areas of adverse weather resilience and to compare their performance against leading industry practices. Evaluation across the five (5) categories offered greater depth of analysis to identify strengths and improvement needs. The approach taken allowed Evaluators to initially look for trends and may support Utility Providers in tracking improvements in the future.

Moreover, Evaluators further segmented their review of the LEUs to consider the impacts of extreme winter weather events on energy generation, bulk power delivery services, and utility distribution services. For Utility Providers that provided both natural gas and electric services or for Utility Providers that offered both bulk power and distribution services, Evaluators conducted separate evaluations for those areas.

For example, for DESC, a Utility Provider that provides bulk power services, electric distribution, and natural gas services, Evaluators conducted separate reviews for each type of utility service. Conversely, those entities for which information request responses were provided as part of a collective response (i.e., a single organization provided information and assessments on behalf of multiple providers, such as the ECSC), Evaluators conducted a single evaluation of the body of information provided.

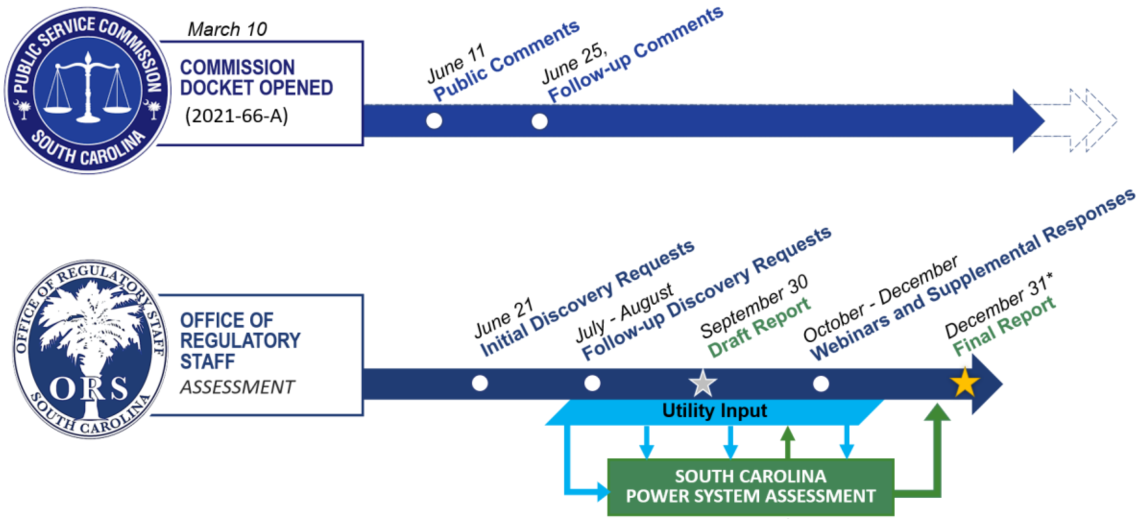
Table 9. Assessment Framework Indicator Areas

Indicator	Assessment Framework Indicator Areas
Indicator 1 Emergency Management and Planning	Emergency management planning and preparation is critical for effective response to potential ice storms and dangerous winter weather conditions.
Indicator 2 Risk Management	Critical infrastructure risk management plans must be developed, and preventative mitigation actions must be identified in advance of adverse weather.
Indicator 3 Staffing and Mutual Assistance Support	Resource planning and acquisition must be sufficient for response to large-scale emergencies.
Indicator 4 Asset Management and Inspections	Asset management practices and asset inspections must assure that critical infrastructure will properly operate during adverse weather events.
Indicator 5 Operational Protocols	Adverse weather operational protocols must be implemented, and employees must be prepared, knowledgeable, and trained.
Indicator 6 System Design and Hardening	The resilient electric or gas utility invests resources to achieve cost-effective resilience and reliability solutions, minimizing the negative impacts of climate change and extreme weather to their customers.
Indicator 7 Stakeholder Engagement	Stakeholder engagement is critical to accurately communicating and developing a utility's resilience strategies and plans, recognizing roles and responsibilities of the community, identifying opportunities for improvement, and implementing solutions that align with stakeholder values and needs.
Indicator 8 Public Communications	Effective communication of resilience information by utilities helps to foster transparency in resilience gaps related to climate hazards, raise industry and community awareness of the activities that are either planned or currently in use to close those gaps, and disseminate effective resilience strategy guidance to close those gaps within the industry and across the nation.
Indicator 9 Automation	Organizations that have achieved a high level of maturity within this domain have an increased capability to use automation and information available from the deployment of smart grid technologies. These organizations have the capability to manage power flows so that power losses are minimized, and the usage of lowest cost generation resources are maximized.
Indicator 10 Situational Awareness	Situational awareness approaches and technologies enable utilities to have a more informed, comprehensive, and actionable preparation and response to severe weather events.
Indicator 11 Compliance to Regulations	Utilities are required to adhere to federal, state, or local reliability and resilience requirements including but not limited to joint reliability plans and assessments, coordinating agreements, and wholesale purchase agreements

Assessment Process

After the Commission opened Docket 2021-66-A to solicit public comments about the guidelines for the assessment, the ORS issued a series of discovery requests to the State's electric and gas Utility Providers (**Figure 21**). Evaluators reviewed the Utility Providers' comments as well as Utility Provider response to ORS discovery requests.

Figure 21. Extreme Winter Weather Resiliency Assessment Plan

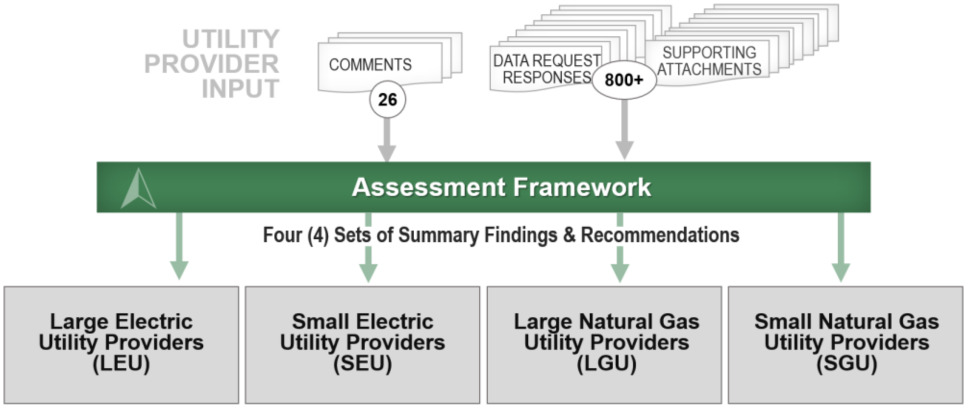


Source: Guidehouse

* Target publication date

In total, Evaluators reviewed twenty-six (26) sets of docketed comments and over eight hundred (800) discovery request responses submitted by the nineteen (19) respondents. Evaluators conducted an assessment for each of the nineteen (19) entities and summarized the findings into the four (4) categories shown in **Figure 22** (LEU, LGU, SEU and SGU). The findings were shared with the State's Utility Providers via a Draft Report, issued in September 2021. Utility Providers had an opportunity to discuss the Draft Report findings and provide additional information to the ORS and the Evaluators. The Final Report incorporates the additional information from the Utility Providers.

Figure 22. Process for Reporting Assessment Findings



Source: Guidehouse

4.2 Overview of Findings

As noted, Evaluators conducted assessments and summarized their finding by categories based on the responding utility type and utility size. Consistent with previous sections, the four evaluation categories are LEUs, LGUs, SEUs, and SGUs, with special consideration taken to assess the resiliency of the regional Bulk Power System (BPS). A summary of evaluation findings and recommendations based on the material provided by the participating Utility Providers are provided in the following subsections.

Bulk Power System (BPS) Findings

In general, the high voltage transmission systems, including both those located in South Carolina and the adjacent systems, are typically not prone to ice and cold weather damage. A rise in variability in temperatures and storms could, however, introduce stress to the regional BPS.

Regarding regional energy supply resiliency, Evaluators determined significant diversity of generation sources (by fuel mix) to meet high winter demands, with minimal reliance on renewables. Approximately thirty percent (30%) of power generation in South Carolina is fueled by natural gas – a natural gas contribution well below many other states in the U.S. However, extreme cold weather events do increase risk of interruption for both import of electricity via transmission interconnections and of natural gas fuel via interstate pipelines.

Evaluators found that VACAR-South (SERC-East) generation reserve margins are well above the levels required to meet the generation reserve sharing agreements among VACAR-South members. The highly integrated design of the regional transmission system positions South Carolina to withstand cold weather conditions and respond reliably to normal and emergency loading conditions, and major outage (i.e., contingency) events. Transmission system operators have established operating procedures and remedial action plans.

The generation diversity, the interconnected design, operating procedures and emergency plans, along with the pre-season assessments and mitigation planning to prepare for severe cold weather events, support the Evaluators' finding that the BPS that serves South Carolina is adequately prepared to withstand extreme weather events and the operators adequately prepared to respond.

Utility Provider Findings

Because of the volume and types of customers served, the State's large Utility Providers (LEU and LGU) wield the greatest influence related to the South Carolina power grid ability to withstand winter weather events.

SEUs and SGUs, while vital to the communities they serve, pose a much lower overall risk to the Statewide infrastructure resiliency when they experience localized failures within their systems. A transmission line outage for an LEU has the potential to cause additional outages on another part the transmission system that may be experiencing peak load or limited power supply conditions. This risk is significantly lower for distribution infrastructure failures at SEUs or SGUs.

Given the information provided by the participating Utility Providers, the Evaluators conclude that the South Carolina energy system and Utility Providers are adequately prepared to prevent and respond to outages caused by ice storms and winter weather events. The State's large Utility Providers, the LEUs and LGUs, generally offered sufficient qualitative evidence to illustrate their readiness and ability to respond to winter weather events.

While the Evaluators did see evidence of basic level risk assessment activities for individual municipalities and use of mutual assistance as a part of overall emergency response plans at several electric cooperatives, the SEUs as a consolidated group did not provide enough qualitative evidence to demonstrate the same level of maturity as the LEUs. However, many of the electric cooperatives have made significant investments in smart grid technologies based on the needs of their individual systems. Moreover, most SGU's did not provide a sufficient level of detailed information to enable Evaluators to conduct a full resiliency assessment. Of the seven (7) entities from the SGUs group that provided discovery request responses, only one (1) Utility Provider made specific reference historic impacts of adverse winter weather on assets and/or service to customers.

Summary of Support for Findings

Table 10 summarizes the overall Assessment Framework scoring and associated maturity level by indicator area for each utility category (LEU, LGU, SEU, and SGU).

Table 10. Maturity Level Assessment Summary by Utility Provider Type and Size

🟢 Advanced ◓ Leading ● Foundational ◒ Lagging 🟡 Nascent ◌ Insufficient Data

Indicator	LEU	LGU	SEU	SGU
Indicator 1 Emergency Management and Planning	◓	◓	●	◌
Indicator 2 Risk Management	◓	●	●	●
Indicator 3 Staffing and Mutual Assistance Support	◓	◓	●	◌
Indicator 4 Asset Management and Inspections	◓	◓	◒	◌
Indicator 5 Operational Protocols	◓	◓	●	◌
Indicator 6 System Design and Hardening	◓	◓	◒	◒
Indicator 7 Stakeholder Engagement	◓	●	◒	◌
Indicator 8 Public Communications	◓	●	●	◌
Indicator 9* Automation	◓	*Not Scored**	◒	*Not Scored**
Indicator 10 Situational Awareness	◓	●	◒	◌
Indicator 11 Compliance to Regulations	◓	◓	●	●

** Indicator 9 relates to use of smart grid automation technologies and is not applicable for natural gas utilities.*

Details to support the findings and recommendation for the four (4) utility categories are provided in the following appendices:

- **Appendix F. Assessment and Recommendations – Large Electric Utilities**
- **Appendix G. Assessment and Recommendations – Large Gas Utilities**
- **Appendix H. Assessment and Recommendations – Small Electric Utilities**
- **Appendix I. Assessment and Recommendations – Small Gas Utilities**

FINAL RECOMMENDATIONS

Based on the Evaluators assessment of the State's natural gas and electric Utility Providers' ability to respond to extreme winter weather events and meet peak customer demand, the Evaluators recommend the following actions be considered:

1. Electric and natural gas Utility Providers should strengthen existing procedures for cold weather preparedness, planning, engineering, operations and coordination to prevent extended interruptions in natural gas and electric service corresponding to the detailed recommendations identified in Appendices F through I. Procedures should provide enhanced and enforced operations and maintenance to mitigate disruption. For entities that are under the purview of mandatory NERC Reliability Standards, see Recommendation No. 3 for the voluntary adoption of the Public Utility Commission of Texas rules.

2. Electric Utility Providers should evaluate bulk power system reliability under more extreme conditions than required by NERC and SERC to include:

   a. Extended cold weather conditions more stringent than SERC's winter criteria (e.g., higher loads and colder temperatures)

   b. Loss of a greater number of transmission lines than those specified in NERC transmission planning contingency criteria

3. South Carolina should form a task force to evaluate the voluntary adoption of practices comparable to those recently adopted in Texas. Refer to the legislatively-mandated rules instituted around winter storm planning and requirements for Generation Entities and Transmission Providers.[30]

4. Electric Utility Providers should adopt the current codes and industry best practices, hardening for greater storm resiliency, and designing for the future. Priority should be targeted at respective systems most susceptible to winter-related outages – apply enhanced design standards for equipment and facilities damaged in the recent storms and/or major events. To harden the transmission and distribution (T&D) infrastructure, physical and structural improvements to lines, poles, towers, substations, and supporting facilities will be needed to make them less vulnerable to the damaging effects of winter-related events.

   a. Electric Utility Providers should determine and enforce safe loading requirements for distribution poles based severe winter weather risks – specifically those used to carry both electric and telecommunications infrastructure.

b. Electric Utility Providers should evaluate strategic, targeted undergrounding of distribution lines in limited, appropriate circumstances based on the exposure to the threat of severe winter events.

5. Natural Gas Utility Providers should consider updates to Distribution Integrity Management Plans (DIMP), Transmission Integrity Management Plans (TIMP), operations and maintenance manuals and design standards to include specific adverse winter weather risk evaluation and mitigation actions.

6. Electric and natural gas Utility Providers are encouraged to collaborate with each other to develop a set of standard emergency preparedness and operating practice guidelines to provide consistent levels of service reliability to all South Carolina electric and natural gas customers. Guidelines may initially be voluntary and evolve to mandatory, once matured.

7. All electric and natural gas Utility Providers should be required to participate in adverse winter weather emergency drills and/or tabletop exercises with state and local emergency management agencies in their respective emergency management planning cycles. The State should consider including propane providers and petroleum pipeline providers in adverse winter weather emergency drills and/or tabletop exercises.

8. Electric and natural gas Utility Providers should consider the feasibility of a study on the costs/benefits of resiliency and reliability enhancements and, as part of that study, consider whether there are any federal funding opportunities.

9. Electric and natural gas Utility Providers should actively participate in regional and national industry groups such as: Electric Power Research Institute (EPRI), American Gas Association (AGA), Southeastern Electric Exchange (SEE), Municipal Association of South Carolina (MASC), and Carolinas Public Gas Association (Carolina SPGA).

10. South Carolina should assess the interdependencies between electric power and other key infrastructure (e.g., water, wastewater, telecommunications, transportation, etc.) to identify and address additional extreme cold weather and event response vulnerabilities.

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Appendix A. Assessment Framework Evaluation Areas

Table A-1 describes the eleven (11) assessment framework indicators assessed across the five (5) assessment areas.

Table A-1. Description of Indicator Assessment Areas

	PEOPLE/CULTURE	GOVERNANCE	PROCESS	SYSTEMS/TECH	DATA/ANALYTICS
INDICATOR 1: **Emergency Management and Planning**	Employees are fully trained and understand their emergency management role.	A formal emergency management governing body is established with clearly defined roles and responsibilities.	Well-defined and efficient Incident Command Structure (ICS) processes have been fully implemented and enable high effective emergency management.	Systems and tools are in place that streamline management and reporting during major weather events.	Complex analytical approaches are used to model and predict damage and are leveraged in pre-event mobilization.
INDICATOR 2: **Risk Management**	Identification and mitigation of risks to critical assets and infrastructure is a strategic priority.	Risk management governance enables identification of risks to critical infrastructure.	Methods and frameworks are in place to manage asset risks within the enterprise risk portfolio.	Integrated systems and tools are used to manage resilience risks and the status of mitigation actions.	Risks are quantified through data and advanced analytics.
INDICATOR 3: **Staffing and Mutual Assistance Support**	Employees proactively participate in well-coordinated advanced resource planning and acquisition for major emergencies.	A centralized governance structure has been established to estimate and acquire resources and assets in preparation for major weather events.	Established processes are enacted during mobilization for adverse weather events.	Defined tools and systems are used to plan and acquire resources and assets in preparation for adverse weather events.	Accurate estimates based on history and weather projections enable timely and proactive resource planning and acquisition.
INDICATOR 4: **Asset Management and Inspections**	Management identifies and prioritizes asset and non-asset solutions with consideration of financial viability, social and environmental responsibility, and cultural outcomes.	Objectives for asset management are identified, and asset performance is measured.	Defined processes are implemented and followed to optimize asset inspections and timely maintenance and repairs.	Enterprise-wide integrated asset management system with asset performance management enables investment planning and decision-making.	Asset data is foundational for enabling asset management functions. Planning for asset renewal and maintenance activities proceeds with full knowledge of asset location, condition, and operation.

	PEOPLE/CULTURE	GOVERNANCE	PROCESS	SYSTEMS/TECH	DATA/ANALYTICS
INDICATOR 5: Operational Protocols	Employees are aware and fully trained on operational protocols and their specific roles and responsibilities during adverse weather events.	A governance structure for operational protocols enhances communication, coordination, and operational effectiveness for response to adverse weather conditions.	Defined operational protocol practices and processes are established to assure effective and timely response to adverse weather events.	Tools and technology required to support execution and tracking of operational protocols supports strong governance and defined processes.	Process and user-related data are used to gauge the effectiveness of operational protocols and associated processes.
INDICATOR 6: System Design and Hardening	Management understands the benefits of resilience investments and evaluates costs and benefits to prioritize and make investment decisions.	Investment planning governance processes assure that the benefits and cost of resilience solutions are evaluated on a common scale.	Transmission and Distribution (T&D) design and hardening standards are developed to provide adaptation for severe weather events and climate impacts.	An investment portfolio management system is deployed to evaluate resilience on a common economic scale.	Advanced analytical approached are used to determine the most cost-effective resilience measures.
INDICATOR 7: Stakeholder Engagement	Utility leadership and employees seek to form a partnership with a diverse set of stakeholders.	Stakeholder engagement for adverse weather events is governed and coordinated at a corporate level.	Processes and roles and responsibilities must be defined to enable meaningful stakeholder engagement.	Online engagement platforms used to educate and gather stakeholder and customer feedback supports informed decision-making.	Gathering detailed stakeholder input is crucial to understanding and ultimately influencing changes to processes, mitigation, and strategy.
INDICATOR 8: Public Communications	Utility leadership seeks to broaden communications, transparency, and accountability across the industry.	Governance is established to assure communications are consistent, understandable, and meaningful.	Processes have been defined to openly gather and share information with key internal and external stakeholders.	A wide variety of communications channels and approaches are used to increase reach to various stakeholder groups.	Data is gathered from internal and external sources and specific targets set for communication effectiveness.

	PEOPLE/CULTURE	GOVERNANCE	PROCESS	SYSTEMS/TECH	DATA/ANALYTICS
INDICATOR 9: **Automation**	Leadership seeks to prudently invest in grid modernization solutions in response to the primary motivational drivers of emissions reduction, increased systems resilience, customer empowerment and cost containment.	Governance is established to support automation functionalities and utilization of detailed procedures.	Streamlined processes have been developed to assure the maximum value has been derived from automation investments.	Self-healing operations and autonomic computing and machine learning will provide leading grid edge stability.	Data is gathered and captured in a common data lake for advanced analytics.
INDICATOR 10: **Situational Awareness**	Leadership drives the transition from reactive practices to new planning and operating paradigms to proactively ensure preparedness for natural and adversarial events through optimal mitigation strategies.	Governance protocols are established to assure full utilization of situational awareness capabilities.	Processes assure situational awareness is deployed during all phases of severe weather response.	Systems and technology provide advanced capabilities for near-time situational awareness.	Analytics provide information to accurately predict impacts and response to severe weather events.
INDICATOR 11: **Compliance with Regulations**	A culture of compliance and ethics assures that actions are taken to address identified high priority threats, impacts, and vulnerabilities.	Governance is established to assure that an effective compliance framework is executed on an ongoing basis.	Integrated processes have been established to assure severe weather resilience compliance actions, which meet and exceed mandates, are tracked and executed.	Systems and platforms are implemented to provide near real-time monitoring of defined weather resilience actions.	Detailed data and analytics are used to assess threats, impacts and vulnerabilities which may exceed mandates.

Appendix B. Extreme Weather Leading Practices

The following sections capture industry leading practices for protecting and recovering from extreme weather events with a specific emphasis on cold weather events. Leading practices are organized by Assessment Framework Indicator Area.

INDICATOR 1: EMERGENCY MANAGEMENT AND PLANNING

B.1.1 – Emergency Management and Planning – *Power Delivery*

- **Coordination with regional/state reliability organizations:** Generator owners and operators should provide accurate *ambient temperature design specifications* to balancing authorities, Reliability Coordinators (RCs), and transmission operators. Organizations should verify that temperature design limit information is kept current and should use this information to determine whether units will be available during extreme weather events.[1]

- **Coordination with regional/state reliability organizations:** RCs should perform *real-time voltage stability analysis* for constrained conditions occurring within the area or in adjacent areas.[2]

- **Coordination with regional/state reliability organizations:** Planning coordinators and transmission planners *should jointly develop and study more extreme condition scenarios* to be better prepared for extreme conditions. Extreme condition modeling should include removing generation units entirely to represent actual outages, modeling system loads to test the system, and modeling actual extreme events that have occurred.[3]

- **Coordination with regional/state reliability organizations:** Impacted entities should keep the balancing authority up to date on *changes to plant availability, capacity, or other operating limitations.* The RC and transmission operator may also need to be informed.[2]

- **Coordination with regional/state reliability organizations:** Balancing authorities and transmission operators *should conduct periodic capacity and energy emergency drills simultaneous with transmission emergency drills* with their RCs. These drills aim to ensure readiness, coordination of control room personnel to conduct multiple load shed-related tasks while continuing to maintain situational awareness, and coordination between additional local control center and field personnel.[3]

- **Coordination with regional/state reliability organizations:** Proactive communication and coordination, *often using cold weather alerts,* among the RCs and within the RC areas is necessary and will improve situational awareness and rapid response.[2]

- **Emergency operating plans:** File emergency operating plans with the state Homeland Security and Emergency Management office.[1]

- **Logistics in emergency plans:** Leverage logistics and supply chain leading practices related to pre-staging, communication, procurement, lodging, transportation, and other areas to include in the emergency response plan (ERP).[4]
- **ERP:** Provide uniform, corporate-wide approach for managing emergencies by defining roles and responsibilities and accountability.[5]
- **ERP:** Mandatory emergency plans should be put in place with independent review.[1]
- **Incident command center (ICC):** Align ICC and Incident Command Structure (ICS) with Federal Emergency Management Agency (FEMA) leading practices – is it used, are drills performed, is there training, organization charts, etc.?[6]
- **Emergency plans:** Align ERP to FEMA bast practices. [4]
- **Incident management team (IMT):** Establish IMT to streamline processes. IMT to be embedded at regional and headquarter locations to ensure crews are managed and coordinated properly with local agencies. Include safety officers on the IMT to enhance lacking safety protocols.[4]
- **Communication protocols for ERP:** Develop communication protocols between stakeholders and public officials (state/municipal government officials and emergency response agencies) to provide consistent messaging during an event.[4]
- **Telecom/cable communications protocols for ERP:** Expand the ERP to include communication procedures with telephone and cable companies so that vital telecommunications can be restored quickly.[5]
- **Identify roles and responsibilities:** Identify roles and responsibilities for regional planning chief, overall planning chief, communications officers, and liaisons to coordinate with local officials and stakeholders. Establish contacts for these positions.[4]
- **Readiness drills:** Expand emergency readiness drills beyond individual companies to encourage collaboration.[5]
- **ERP trainings:** Design and carry out ERP trainings and exercises to include past scenarios, considering logistics and supply chains.[4]
- **ERP trainings:** Observe other utility ERP drills.[4]
- **Mutual assistance:** Incorporate mutual assistance plans into ERP, including procedures for using additional help.[7]
- **Storm mobilization framework:** Develop storm categorization table to prescribe levels of activation based on storm characteristics, including central dispatch center to storm site mobilization center and regional dispatch site. The storm classification table can also determine when a storm center should be activated, when crews should be mobilized and

external resources acquired, how many resources are needed to reduce outage, and when resources should be increased, released, or reduced.[7]

- **Equipment availability:** Have access to and procedures for reserving and using equipment like helicopters, drones, and infrared cameras in advance of major storms to ensure prompt assessment of Transmission and Distribution (T&D) damage.[8]

B.1.2 Emergency Management and Planning – *Power Generation*

- **Trainings:** Coordinate annual winter-specific and plant-specific trainings.[3]
- **Communication/Leading Practice sharing:** Host workshops and build working relationships with generator operators and owners to improve communications on weatherization leading practices and lessons learned.[7]
- **Coordination with regional/state reliability organizations:** Impacted entities should keep the balancing authority up to date on *changes to plant availability, capacity, or other operating limitations.* The RC and transmission operator may also need to be informed.[3]
- **Operational supplies – freeze protection equipment:** Generator operators and owners should have stock of freeze protection equipment (heat lamps, guns, propane, torches, de-icing material, fuel, insulation, extension cords).[1]
- **Winterization plans:** Generator owners and operators should have one (1) or more winterization plans, freeze protection methods, enhanced staffing measures, identified freeze protection operator, or fuel supply/dual fuel capabilities.[1]
- **Winterization plans/freeze plans:** Develop winter freeze plans to monitor generation facilities' equipment. Use checklists for operations personnel to detect plant abnormalities.[2]
- **Winterization plans:** Include pre-winter operational testing for dual fuel and infrequently run units, winter preparation checklist program, better communication on fuel status, better coordination with natural gas pipelines.[7]
- **Transmission operators:** Ensure sulfur hexafluoride (SF6) gas in breakers and meters or other equipment is at the correct pressure and temperature to operate safely during cold weather events. Determine ambient temperature at which equipment is protected during operations. Maintain operation of power transformers by checking heaters in the control cabinets.[1]
- **Management preparedness:** Set expectations for safety, reliability, and operational performance. Ensure that winter weather preparation procedures exist for each operating location. Consider fleet-wide annual winter preparation meeting or training exercises to share lessons learned.[3]
- **Collaboration:** Share lessons learned with industry.[3]

- **Plant management:** Develop a winter weather preparation procedure and appoint a person responsible for keeping the procedure updated with industry leading practices.
- **Plant management:** Ensure the site-specific winter weather procedures include staffing, procedures, plans, and timelines that direct all key activities before, during, and after an event.[3]
- **Plant management:** Conduct plant readiness review prior to an anticipated event.[3]
- **Work management systems:** Review work management systems for open corrective maintenance work orders that could affect the operation and reliability of the generating unit in cold weather.[2]

INDICATOR 2: RISK MANAGEMENT

B.2.1 Risk Management – *Power Delivery*

- **Sensitivity studies:** Perform sensitivity studies to ensure sufficient generation and reserves are operational. Studies should use previous conditions as extreme scenarios with limits.[1]
- **Predictive damage assessment models:** Develop models for damage severity, resource needs, and restoration times using infrastructure and population databases, terrain, and Geographic Information Systems (GIS) models, existing damage data, tropical weather models, impact models (engineering) resulting in T&D damage assessment, outages, power plant damage, and generation loss.[7]
- **Storm classification framework:** Incorporate weather conditions, storm category and plan, number of projected or affected customers, and estimated restoration time. [7]

B.2.2 Risk Management – *Power Generation*

- **Operator equipment prioritization:** Operators should be trained to identify and prioritize repair orders when problems are unearthed.[1]
- **Risk management:** Maintain additional reserves and improve situational awareness of fuel availability.[1]
- **Winter preparation:** Establish open lines of communication and firm agreements with fuel providers, inventory management, and the use of dual fueled units help to mitigate possible risk of non-deliverability.[1]
- **Winter preparation:** Generator owners and operators should have one (1) or more winterization plans, freeze protection methods, enhanced staffing measures, an identified freeze protection operator, and fuel supply or dual fuel capabilities.[1]

- **Gas preparation:** Inform RCs and reliability authorities where plants have firm transportation capacity for natural gas supply and conduct plant-specific operator awareness training.[1]
- **Critical components and scheduled work:** Identify and prioritize critical components, systems, and other areas of vulnerability that may experience freezing problems or other cold weather operational issues. Schedule any routine cold weather readiness inspections, repairs, and winterization work to be completed prior to the local expected seasonal first freeze date.[9]
- **Schedule:** Winterization work to be completed prior to the local expected seasonal first freeze date. Undoing winterization should wait until after the local expected seasonal last freeze date and be completed prior to summer heat arrival.[9]

INDICTOR 3: STAFFING AND MUTUAL ASSISTANCE SUPPORT

B.3.1 Staffing and Mutual Assistance Support – *Power Delivery*

- **Trainings:** Mutual assistance trainings should be performed throughout the year to ensure they are quick and efficient during actual events.[4]
- **Mutual assistance preparation:** Develop and share response and coordination plans with mutual assistance stakeholders. Perform trainings and share training modules with stakeholders. Maintain familiarity with mutual assistance and response plans.[4]
- **Mutual assistance preparation:** Identify contractors for engagement early. Streamline reimbursement process for utilities and contractors.[4]
- **Mutual assistance preparation:** Evaluate the most effective tools for mutual assistance including Emergency Management Assistance Compact or a memorandum of understanding for mutual assistance to identify and resolve bottlenecks.[4]
- **Mutual assistance preparation:** Define how and when outside assistance will be used, whether through mutual aid or contractors.[4]
- **Mutual assistance preparation:** Be prepared for mutual assistance crews to be unavailable when weather events impact multiple states. Develop plans to request regional mutual assistance help early or retain additional local contractors to make up for lack of available assistance.[14]
- **Mutual assistance preparation – damage assessment:** Include damage assessment plan in mutual assistance deployment plan.[4]
- **Staffing:** Proactive staffing of typically unmanned stations enables more rapid response during winter weather events.[10]

- **Storm mobilization framework:** Develop storm categorization table to prescribe levels of activation based on storm characteristics, including central dispatch center to storm site mobilization center and regional dispatch site. The storm classification table can also determine when a storm center should be activated, when crews should be mobilized and external resource-es acquired, how many resources are needed to reduce outage, and when resources should be increased, released, or reduced. [7]

- **Demobilization:** Include procedures for demobilization including how to extract resources from a specific area.[4]

B.3.2 Staffing and Mutual Assistance Support – *Power Generation*

- **Operator training:** Operators should be trained on freeze protection monitoring, methods to check insulation integrity and reliability, and output of heat tracing.[1]

- **Operator training:** Operations personnel should review cold weather scenarios affecting instrumentation readings, alarms, and other indications on plant control systems.[9]

- **Freeze protection operator:** Identify freeze protection operator who is responsible for inspecting critical equipment and ensuring protections are in place.[2]

- **Trainings:** Coordinate annual winter-specific and plant-specific trainings. Include response to freeze protection panel alarms, troubleshooting and repair of freeze protection circuitry, fuel switching, knowledge of ambient operating temperature, and lessons learned.[3]

INDICATOR 4: ASSET MANAGEMENT AND INSPECTIONS

B.4.1 Asset Management and Inspection – *Power Delivery*

- **Asset condition/risk assessment:** Review work management systems for open corrective maintenance work orders that could impact operation or reliability of the generating unit in cold weather.[2]

- **Asset condition/risk assessment:** Develop procedures, criteria, and systems to assess and rank equipment condition.[11]

- **Asset condition/risk assessment:** For generation assets, evaluate potential problem areas and systems during winter weather including equipment that may: initiate an automatic unit trip, impact unit startup, initiate automatic runback schemes, or cause partial outages, cause damage to the unit, impact the environmental controls that could cause full or partial outages, adversely affect the delivery of fuel or water to the units.[3]

- **Life extension/replacement:** Establish health indices for individual assets or groups of assets that would be used to determine end-of-life and replacement versus repair decisions beginning with the most critical assets.[11]

- **Life extension/replacement:** Reinsulate cable injection as a life extension alternative on cables where the number of splices is low, and it is cost-effective.[11]

- **Gas asset management:** Periodic visual site inspection during cold weather months to recognize evidence of frost heave or thaw settlement. Examination of piping buried above the frost line for evidence of deflection at joints during routine excavations. Visual inspection of sites for frozen standing water around risers or under equipment mounted low to the ground.[12]

- **Poles:** Ensure all poles, including joint use poles, are being properly inspected.[5]

- **Enhanced preventative maintenance and inspections:** Develop a tracking system for equipment mis-operations or failures for areas where data is not centrally managed or tracked.[11]

- **Operations and maintenance (O&M):** Create a formal reporting process for inspection and maintenance reports.[11]

- **Vegetation management:** Consider using drones for T&D inspections and assessments, especially in post-event recovery and in areas inaccessible to workers.[3]

- **Vegetation management:** Assess vegetation and growth rates in the areas of planned lines to establish appropriate right of way (ROW) width. Identify and know the exact boundaries of a ROW in the field.[8]

- **Lidar/GPS:** Use GPS and lidar to accurately identify boundaries to prevent vegetation encroachment.[8]

- **Fiber optic cable restoration:** Fiber optic cable repair as mission critical.[4]

- **Predictive forecasting method:** Engage meteorologists to preview winter forecasts and assess risks for extreme temperatures.[2]

- **Predictive forecasting method:** Storm detection/storm predictability and tracking technology for early warning includes a wide range of products: National Oceanic and Atmospheric Administration (NOAA), media, private and commercial meteorological services, and commercial weather forecasting applications. Data also included: infrastructure and population databases, terrain and GIS models, existing damage data, tropical weather models, impact models (engineering) resulting in T&D damage assessment, outages, power plant damage, and generation loss.[7]

INDICATOR 5: OPERATIONAL PROTOCOLS

B.5.1 Operation Protocols – *Power Delivery*

- **Outage protocol:** Give authority for scheduled outages to be cancelled and expand outage evaluation criteria.[1]
- **Outage protocol:** Review the basis for forced and planned generation *and* transmission outages used in seasonal assessment to ensure that appropriate outage rates for the extreme cases are correct and that unit derates are included. Limit planned outages during possible peak winter periods.[13]
- **Communications:** Primary, secondary, and tertiary communications need to be established in advance of winter weather events, especially response and recovery operations. Protocols for cell, satellite, and very/ultra-high frequency radios need to be established.[4]
- **Equipment availability:** Have access to and procedures for reserving and using equipment like helicopters, drones, and infrared cameras in advance of major storms to ensure prompt assessment of T&D damage.[8]
- **Damage assessment/restoration protocols:** Establish damage assessment and restoration protocols that define the roles and responsibilities of stakeholders including defining standards and formats (maps, topology, load, and procedure) for completing damage assessments and communicating where power has been restored to ensure consistency.[4]
- **Visibility/situation awareness – communication systems:** Control critical-to-mission communication systems, deploy backup communication systems, include IT personnel in command center, and install and maintain permanent backup generation at service centers and communication facilities.[7]
- **Visibility/situation awareness – communication systems:** Install or upgrade wide area and field area communications and add a mobile containerized backup control center.[14]
- **Damage assessment – data collection:** Develop assessment framework and process to collect and transfer damage data to operations center. Use mobile communication technology to streamline collection and reporting including GIS, OMS, and automatic metering reading (AMR) / Advanced Metering Infrastructure (AMI).[7]
- **Damage assessment:** Include damage assessment plan in mutual assistance deployment plan.[2]
- **Customer service portals:** Update, upgrade, or install customer service systems and portals.[4]

B.5.2 Operation Protocols – *Power Generation*

- **Operations management:** Improve operations management awareness on the fuel status of all generators including improved awareness of pipeline system conditions. Awareness plans might include a daily fuel inventory solicitation process, the ability to dispatch plants early in advance of extreme winter weather, and increased communication plans with gas and electric entities.[12]

- **Operational supplies – freeze protection equipment**: Generator operators and owners should have stock of freeze protection equipment (heat lamps, guns, propane, torches, de-icing material, fuel, insulation, extension cords).[10]

- **Inventory:** Keep an inventory of requirements and consumables that would aid in severe winter weather including freeze protection equipment (heat lamps, heat guns, propane, torches, de-icing material, fuel, insulation, extension cords).[10]

- **Ambient temperature design specifications:** Generator owners and operators should provide accurate *ambient temperature design specifications* to balancing authorities, RCs, and transmission operators. Organizations should verify that the temperature design limit information is kept current and should use this information to determine whether units will be available during extreme weather events.[10]

- **Winterization procedures – generator owners and operators[1]**

    - **Heat trace:** Evaluate all heat trace lines and heat trace power supplies, including breakers, fuses, and associated control systems.

    - **Insulation:** Check loose connections, broken wires, corrosion, and other damage to the integrity of insulation.

    - **Heat lamps:** Inspect and evaluate heaters and heat lamps. Make sure facility can handle additional load.

    - **Insulation:** Verify the integrity of the insulation on critical equipment identified in the winter weather preparation procedure.

    - **Wind barriers:** Install permanent or temporary wind barriers as deemed appropriate to protect critical instrument cabinets, heat tracing, and sensing lines.

- **Winterization procedures – gas[1]**

    - **Methanol injection:** To prevent freezing of wellbores and pipelines.

    - **Structures:** Enclosing production equipment and other weather-sensitive equipment in fiberglass buildings or huts.

    - **Glycol dehydration:** To remove water from the gas stream.

    - **Insulation:** Insulate flow lines.

- **Winterization processes – generators**[1]
  - **Heat tracing:** Apply a heat source to pipes, lines, and other equipment.
  - **Thermal insulation:** Apply insulation material to inhibit the dissipation of heat from a surface.
  - **Temporary measures:** Use space heaters, drain non-essential water lines and remove flowing water to reduce freezing, drain liquid from valves, add heat lamps in cabinets.
- **Freeze protection measures**[1]
  - Insulating exposed equipment and checking for missing or damaged insulation prior to cold weather.
  - Checking heat tracing on all critical lines and piping to ensure that the circuits remain functional. Temperature guns can be used to check that heat tracing is working properly.
  - Closing doors on boiler enclosures to prevent cold air from entering.
  - Confirming fuel heaters are in service and working properly.
  - Checking that all critical site-specific areas have adequate protection to ensure operability and emphasizing points in the plant where freezing could cause a unit trip, derate, or failure to start.
  - Placing thermometers in areas containing equipment sensitive to extreme cold conditions.
  - Evaluating plant electrical circuits for adequate load capacity and ensuring ground fault circuit interrupters are used properly.
  - Reviewing work management systems for open corrective maintenance work orders that could affect the operation and reliability of the generating unit in cold weather.
  - Ensuring that all modifications and construction activities are performed such that the changes maintain cold weather readiness for the generating unit.
  - Disconnecting sensing lines on pressure transmitters to prevent freezing.
  - Cleaning coal feed chutes as needed to keep coal supply flowing.
  - Installing wind barriers, such as tarps or semi-permanent barriers constructed of wood or metal, to protect critical instruments, sensing lines, controllers, and piping.

- **Wind turbine winterization:** Wind turbine nacelle-mounted oil coolers can accumulate ice quickly in a snowstorm if the oil is not circulating and creating heat to melt the winter precipitation.[4]
    - During extreme cold, wind turbines should be cycled online to provide flow of cooling oil and aid in the warming of that cooling oil.
    - All cooling equipment for radiators on wind turbines should be disabled for cold weather events.
    - Investigate the purchase of cold weather packs for wind turbines that will enable them to run in cold weather. The packs can provide heat where needed to keep oil and other components at operating temperature.

INDICATOR 6: SYSTEM DESIGN AND HARDENING

B.6.1 System Design and Hardening – *Power Delivery*

- **Structures/towers:** Use dead-end structures and guy wires. Dead-end structures are on poles or towers to stop the cascading effect. When a power line breaks, the unbalanced forces on the pole are significant enough to cause several poles to break. This is useful in large, more extreme ice and snowstorms.[9]

- **Overhead Conductors:** Replace overhead lines with heavier, stronger wire such as *Thermocouple Alloy Insulated Aluminum Conductor Steel Reinforced* wire (T-2 ACSR).[9]

- **Poles:** Straighten and inject concrete grout around bases of existing poles or replace poles with deeper sub-subgrade or engineered foundations. Create shorter distances between poles, installing larger poles and providing wind dampeners. Together these measures increase the strength of the distribution line by sixty-six percent (66%). [9, 12]

- **Conductors:** Review and update asset registry for underground conductor and confirm type, material, diameter, temperature, span between poles, vintage, insulation failure history and known defects. Institute a remediation program to address conductor type of construction most susceptible to failure.[11]

- **Cables:** Evaluate existing replacement program from underground cable. Develop asset registry for primary underground cable and conduct a study to determine the amount to be replaced. Expand underground equipment inspections with new metrics.[11]

- **Underground:** Underground existing or proposed overhead lines when cost-effective. [9]

- **Substation:** Develop criteria for minimum restoration times for single transformer substations. Replace control buildings with modular designs, relocate or elevate substations, install watertight enclosures for control equipment and junction boxes, elevate select equipment and raise air vents, and install water barriers and engineered solutions.[11]

- **Relays:** Install synchronization and blackstart relay systems. Replace existing electromechanical relays with microprocessor-based relays that feature event reporting ability.[5,14]

- **Switches:** Add automated switches with fault detection isolation and restoration capability.[14]

- **Gas:** Replace iron pipe, unknown material pipe, and threaded steel pipe with plastic welded steel pipe in locations known or susceptible to frost heave. Remediate drainage of soil conditions that promote frost heave.[12]

INDICATOR 7: STAKEHOLDER ENGAGEMENT

B.7.1 Stakeholder Engagement – *Power Delivery*

- **Coordination with gas stakeholders:** Establish a gas-electric coordination team with natural gas pipelines to help dispatch in factoring gas availability data into its cold weather planning and scheduling with generators.[10]

- **Communication/Leading Practice sharing:** Host workshops and build working relationships with generator operators and owners to improve communications on weatherization leading practices and lessons learned.[7]

- **Telecom/cable stakeholders**: Improve communication and develop procedures with telecom and cable companies to ensure vital telecommunications can be restored as quickly as possible.[1]

- **Coordination with gas stakeholders**: Coordinate and communicate with gas suppliers, markets, and regulators to identify issues with natural gas supply and transportation so that actions can be developed and implemented for generators to secure firm supply and transportation at a reasonable rate.[13]

- **Coordination with gas stakeholders:** Meet with natural gas suppliers to coordinate maintenance outages and deliveries for peak season. Additionally, test units that have been offline for a significant amount of time to ensure readiness. Work on enhancing existing communication protocols with gas pipeline and distribution system operators to facilitate information sharing.[7]

INDICATOR 8: PUBLIC COMMUNICATIONS

B.8.1 Public Communications – *Power Delivery*

- **Emergency management:** Work with the state to define thresholds that would trigger communication with the State Homeland Security and Emergency Management Office.[4]

- **Communication protocols:** Develop communication protocols between stakeholders and public officials (state/municipal government officials and emergency response agencies) to provide consistent messaging during an event.[4]

INDICATOR 9: AUTOMATION

B.9.1 Automation – *Power Delivery*

- **Supervisory Control and Data Acquisition (SCADA):** Replace damaged SCADA and replace high risk SCADA units. Upgrade substation SCADA backup power systems to provide reliable power for a minimum of 8 hours.[1,14]
- **Distribution Management System (DMS):** Assess role of DMS for advanced applications such as Integrated Volt/VAR control (IVVC), distributed energy resources (DER) integration (monitoring and control), microgrids, electric vehicle initiatives, AMI, advanced protection, and auto-transfer schemes.[11]
- **Advanced Distribution Management System (ADMS):** Install ADMS**.** An ADMS is a DMS with advanced applications, such as IVVC, Fault Location and Service Restoration (FLISR) and Switch Order Management (SOM) installed.[14]
- **Communications:** Identify backup communications and ensure appropriate communications protocols are established. Install new or upgrade wide area and field area communications; add a mobile, containerized backup control center.[14]

INDICATOR 10: SITUATIONAL AWARENESS

B.10.1 Situational Awareness – *Power Delivery*

- **Fuel supply/assessment:** Develop verification measures for units that have fuel switching capabilities for extra precaution during natural gas curtailment times.[1]
    - When gas supplies are disrupted, state utility commissions should work with local distribution companies (LDCs) to ensure voluntary curtailment plans can reduce demand on the system quickly and efficiently.[1]
    - Regulators should work with balancing authorities, electrical generators, and LDCs to determine when residential gas customers should receive priority over electrical generating plants during a natural gas supply emergency.[1]
    - Commissions should also evaluate the relative importance, for human needs customers, of gas-fired generation and residential use and should assess the relative impacts of curtailing generating plants versus gas supply to residences.[1]

  - Test units that have been offline for a significant amount of time to ensure readiness.[7]
  - Independent system operators (ISOs) and regional transmission organizations (RTOs) to conduct seasonal fuel assurance surveys to include gas transportation arrangements, starting oil inventories, and oil replacement capabilities.[10]
  - Industry should also work with gas suppliers, markets, and regulators to quickly identify issues with natural gas supply and transportation so that appropriate actions can be developed and implemented to allow generators to secure firm supply and transportation at a reasonable rate.[13]
  - Increase coordination and communication with natural gas pipeline industry and generation operators, including firm agreements with fuel providers, inventory management, and use of dual fueled units.[7]
  - Review the gas-utilization tool (GUT) developed by the ISO New England (ISO-NE) that improves situational awareness and assists system operations in maintaining a wide area view of the natural gas pipeline infrastructure that feeds the New England area.[7]

- **Coordination with gas stakeholders:** Establish a gas-electric coordination team with natural gas pipelines to help dispatch in factoring gas availability data into its cold weather planning and scheduling with generators.[10]

- **Coordination with gas stakeholders:** Meet with natural gas suppliers to coordinate maintenance outages and deliveries for peak season. Additionally, test units that have been offline for a significant amount of time to ensure readiness. Work on enhancing existing communication protocols with gas pipeline and distribution system operators to facilitate information sharing.[7]

- **Fuel switching:** Document time required to switch equipment, unit capacity while on an alternate fuel, operator training and experience, fuel switching equipment issues, and boiler and combustion control adjustments for operating using an alternate fuel.[2]
  - Dual fuel switching should be tested routinely or semiannually to ensure that units can successfully switch to the backup fuel.[2]
  - Checking fuel supplies and dual fuel capabilities: checking fuel tank levels every other day during seasonal cold weather to ensure sufficient fuel during a cold weather event, and pre-freeze test firing of dual fuel units that have not fired their secondary fuel source during the previous year.[2]
  - Pre-winter operational testing for dual fuel and infrequently run units, winter preparation checklist program, better communication of fuel status, and coordination with natural gas pipelines.[7]

  - Implement dual fuel testing program to ensure generators can switch fuels efficiently and create a program that incentivizes developing more dual fuel facilities.[7]

- **Blackstart:** Ensure blackstart units can be used during adverse weather and emergency conditions.[1]

- **Upgrade substations:** Upgrade substation SCADA backup power system to provide reliable power for a minimum of eight (8) hours.[5]

INDICATOR 11: COMPLIANCE TO REGULATIONS

B.11.1 Compliance to Regulations – *Power Delivery*

- **Vegetation management:** Report all vegetation-caused outages to the bulk electricity system (BES) to North American Electric Reliability Corporation (NERC) to help inform policy decisions going forward. In 2011, FAC-003-1 did not require utilities to report these outages to regional entities or NERC.[8]

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Appendix C. Regional Examples and Practices

The following sections capture regional examples and practices for protecting and recovering from extreme weather events with a specific emphasis on cold weather events. Leading practices are organized regions across North America.

SOUTHEAST EXAMPLES

- **Southeastern Reliability Corporation (SERC) operator freeze training:** Power South, Louisville Gas and Electric and KU Energy (LG&E KU), and Southern Company, which own their generating units, trained their operators to address freezing weather hazards to personnel and equipment. Post-winter meetings review setbacks and successes.[3]
- **SERC balancing authority dual fuel testing:** Four (4) of seven (7) balancing authorities have dual fuel procedures in place to test generating units. The Tennessee Valley Authority (TVA) balancing authority tests units routinely throughout the year, LG&E KU tests twice a year, and other SERC entities conduct annual tests.[3]
    - *Midcontinent Independent System Operator (MISO) and Southwest Power Pool do not have any procedures in place to confirm switching.*
- **SERC operator training:** Power South, LG&E KU, and Southern Company, which own their generating units, trained their operators to address freezing weather hazards to personnel and equipment. Organizations also held post-winter meetings to review setbacks and successes.[3]
- **SERC fuel availability and preparation:** SERC emphasizes open lines of communication, firm agreements with fuel providers, inventory management, and the use of dual fueled units to mitigate and minimize risk of non-deliverability.[2]
- **SERC freeze plans/checklists:** SERC member entities developed winter weather freeze plans to monitor generation facilities equipment including checklists to detect abnormalities. Members must maintain additional reserves and situational awareness of fuel availability.[2]
- **Southern Company – fuel availability:** The company has fuel tank storage at its generating facilities and was able to resupply units in the impacted area when fuel supplies were interrupted.[3]
    - *While the southeast largely experienced outages, Southern Company had forty (40) of fifty-five (55) units switch to secondary fuel sources.*

NORTHEAST EXAMPLES

- **The Regional transmission organization in the mid-Atlantic area (PJM) pay for performance program:** PJM incentivizes generators to meet their commitments to deliver electricity whenever PJM determines they are needed to meet power system emergencies. Through the pay for performance program, generators may receive higher capacity payments and are expected to invest in modernizing equipment, firming up fuel supplies, and adapting to use different fuels.[2]
- **PJM winter plans:** PJM implemented the following steps: prewinter operational testing for dual fuel and infrequently run units, winter preparation checklist program, better communication of fuel status, and better coordination with natural gas pipelines.[2]
    - *These units had a lower rate of forced outage.*
- **PJM coordination with gas stakeholders:** PJM established a gas-electric coordination team with natural gas pipelines to help dispatch in factoring gas availability data into its cold weather planning and scheduling with generators.[1]
- **Independent System Operators - Northeast (ISO-NE) outage protocol:** This protocol gives authority for scheduled outages to be cancelled and expanded its outage evaluation criteria.[2]
- **ISO-NE Gas utilization tool (GUT):** ISO-NE has developed a GUT that improves situational awareness and assists system operations in maintaining a wide area view of the natural gas pipeline infrastructure that feeds the New England area. The key features of the GUT are visibility and awareness of the general conditions of the pipelines, accounting for pipeline use, and forecasting of pipeline availability. The most accurate assumption for the GUT calculation is the forecasted gas consumption from the pipelines by the generators ISO-NE schedules and dispatches.[2]
- **New England Power Pool – fuel availability:** Incentives are provided for generators to procure onsite fuel resources before the winter season begins and for generation owners to contract for liquefied natural gas during the winter.[2]

MIDWEST EXAMPLES

- **MISO generator owner and operator preparation survey:** After the 2014 polar vortex, MISO surveyed generator owners and operators on fuel availability. MISO utilized the guidelines from the North American Electric Reliability Corporation (NERC) winterization checklist to create the survey.[3]
- **TVA Unit winter readiness:** TVA conducted a winter readiness inspection of its units.[3]

- **MISO coordination with gas stakeholders:** MISO increased communication with the natural gas pipeline industry and generator operators to ensure coordination of fuel delivery. Coordination has provided increased intelligence into real-time operations and decision-making as well as outage causes, which are important to track for analysis.[2]

- **Ontario unit availability and testing:** Ontario (IESO) meets with natural gas suppliers to coordinate maintenance outages and deliveries for peak season. It also tests units that have been offline for a significant amount of time to ensure readiness. IESO continues to work on enhancing existing communication protocols with gas pipeline and distribution system operators to facilitate information sharing.[2]

SOUTHWEST EXAMPLES

- **Electric Reliability Council of Texas (ERCOT) training on Best Practies:** The utility aims to improve communications on weatherization leading practices and lessons learned by hosting workshops and building working relationships with generator operators.[2]

- **ERCOT spot check program:** The utility increased the scope of its spot check program, increasing unit visits from thirty (30) in 2011 to seventy-six (76) for 2014. It also included wind turbines prone to icing-related tripping.[2]

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Appendix D. Pertinent Cold Weather Standards and Guidelines

The following sections capture resiliency standards and requirements related to protection and recovery from extreme weather events with a specific emphasis on cold weather events. While the list is not exhaustive, the requirements and standards noted below were identified or referenced by Evaluators during their assessment of South Carolina's power grid.

STANDARDS

NORTH AMERICAN RELIABILTY CORPORATION (NERC)[1]

Resource and Demand Balancing (BAL)

BAL-001-2	Real Power Balancing Control Performance
BAL-002-3	Disturbance Control Standard – Contingency Reserve
BAL-003-2	Frequency Response and Frequency Bias Setting
BAL-005-1	Balancing Authority Control

Communications (COM)

COM-001-3	Communications
COM-002-4	Operating Personnel Communications Protocols

Emergency Preparedness and Operations (EOP)

EOP-004-4	Event Reporting
EOP-005-3	System Restoration from Blackstart Resources
EOP-006-3	System Restoration Coordination
EOP-008-2	Loss of Control Center Functionality
EOP-010-1	Geomagnetic Disturbance Operations
EOP-011-1	Emergency Operations

Facilities Design, Connections and Maintenance (FAC)

FAC-003-4	Transmission Vegetation Management
FAC-008-5	Facility Ratings
FAC-014-2	Establish and Communicate System Operating Limits

Interchange Scheduling and Coordination (INT)

INT-006-5	Evaluation of Interchange Transactions
INT-009-3	Implementation of Interchange

Interconnection Reliability Operations and Coordination (IRO)

IRO-001-4	Reliability Coordination – Responsibilities
IRO-002-7	Reliability Coordination – Monitoring and Analysis
IRO-006-5	Reliability Coordination – Transmission Loading Relief (TLR)
IRO-008-2	Reliability Coordinator Operational Analyses and Real-time Assessments
IRO-009-2	Reliability Coordinator Actions to Operate Within IROLs
IRO-010-3	Reliability Coordinator Data Specification and Collection
IRO-014-3	Coordination Among Reliability Coordinators
IRO-017-1	Outage Coordination
IRO-018-1(i)	Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities

Personnel Performance, Training, and Qualifications (PER)

PER-005-2	Operations Personnel Training
PER-006-1	Specific Training for Personnel

Protection and Control (PRC)

PRC-002-2	Disturbance Monitoring and Reporting Requirements
PRC-004-6	Protection System Misoperation Identification and Correction
PRC-005-1.1b	Transmission and Generation Protection System Maintenance and Testing
PRC-005-6	Protection Sys, Automatic Reclosing, Sudden Pressure Relaying Maintenance
PRC-006-5	Automatic Underfrequency Load Shedding
PRC-008-0	Underfrequency Load Shedding Equipment Maintenance Program
PRC-010-2	Undervoltage Load Shedding
PRC-011-0	Undervoltage Load Shedding System Maintenance and Testing
PRC-012-2	Remedial Action Schemes
PRC-017-1	Remedial Action Scheme Maintenance and Testing
PRC-018-1	Disturbance Monitoring Equipment Installation and Data Reporting
PRC-019-2	Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection
PRC-023-4	Transmission Relay Loadability
PRC-024-2	Generator Frequency and Voltage Protective Relay Settings
PRC-025-2	Generator Relay Loadability
PRC-026-1	Relay Performance During Stable Power Swings
PRC-027-1	Coordination of Protection Systems for Performance During Faults

SERC-Specific Protection and Control (PRC)

PRC-006-SERC-02	Automatic Underfrequency Load Shedding Requirements

Transmission Operations (TOP)

TOP-001-5	Transmission Operations
TOP-002-4	Operations Planning
TOP-003-4	Operational Reliability Data
TOP-010-1(i)	Real-time Reliability Monitoring and Analysis Capabilities

Transmission Planning (TPL)

TPL-001-4	Transmission System Planning Performance Requirements

Voltage and Reactive (VAR)

VAR-001-5	Voltage and Reactive Control

NATIONAL ELECTRIC SAFETY CODE (NESC)

NESC Section 25. Rule 250 D	Extreme Ice with Concurrent Wind[2]

PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINSTRATION (PHMSA)

PHMSA incorporates by reference more than sixty (60) standards and specifications into 49 CFR Parts 192, 193, and 195.[3]

Code of Federal Regulations
49 CFR Part 192, Subpart P Gas Distribution Pipeline Integrity Management (IM)[4]

RULES, GUIDELINES AND BULLETINS

NORTH AMERICAN RELIABILTY CORPORATION (NERC)

NERC Rules of Procedure
Appendix 3A Standard Processes Manual[5]

NERC Guidelines
Generating Unit Winter Weather Readiness – Current Industry Practices[6]

SERC RELIABILTY CORPORATION (SERC)

SERC Guidelines
GUIDE-RMF-505 Extreme Cold Weather Guidelines[7]

U.S. DEPARTMENT OF TRANSPORTATION (USDOT)

USDA Rural Utility Services Bulletin
RUS Bulletin 1730B-2 Guide for Electric System Emergency Restoration Plan[8]

REFERENCES

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[1] NERC. Reliability Standards for the Bulk Electric Systems of North America, October 1, 2021. https://www.nerc.com/pa/Stand/Reliability%20Standards%20Complete%20Set/RSCompleteSet.pdf

[2] National Electric Safety Code, Institute of Electrical and Electric Engineers, C2-2012, April 2011.

[3] U.S. Department of Transportation Pipeline and Hazardous Material Safety Administration. Standards and Rulemaking Overview. July 6, 2017. https://www.phmsa.dot.gov/standards-rulemaking/pipeline/standards-and-rulemaking-overview

[4] Title 49, Code of Federal Regulations Part 192 – Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards. February 2, 2010. https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/49_192_highlight_8_15.pdf

[5] NERC, Appendix 3A, Standards Process Manual, Version 4. March 1, 2019.

[6] NERC. Reliability Guideline, Generating Unit Winter Weather Readiness. Version 3. December 15, 2020.https://www.nerc.com/comm/OC_Reliability_Guidelines_DL/Reliability_Guideline_Generating_Unit_Winter_Weather_Readiness_v3_Final.pdf
https://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf

[7] SERC, Guideline: Extreme Cold Weather Guidelines. September 28, 2021
https://www.serc1.org/docs/default-source/program-areas/standards-regional-criteria/guidelines/serc-extreme-cold-weather-guidelines.pdf

[8] U.S. Department of Agriculture Rural Utility Services. Guide for Electric System Emergency Restoration Plan, Revision 3. March 2005. https://www.rd.usda.gov/files/UEP_Bulletin_1730B-2.pdf

Appendix E. Notable Cold Weather Standards and Preparedness Recommendations Resulting from 2021 Texas Event

This appendix captures the recommendations to revisions of North American Electric Reliability Corporation (NERC) mandatory Reliability Standards and recommendation for grid seasonal preparedness as a result of Federal Energy Regulatory Commission (FERC), NERC, and NERC's regional entities' final report examining the impact the February 2021 winter storm on the bulk electric system in Texas.[1] The recommendations noted below are not comprehensive but rather represent those most relevant to South Carolina. Review The February 2021 Cold Weather Outages in Texas and South Central United States Final Report released November 17, 2021 for the complete set of recommendations.

ELECTRIC GRID COLD WEATHER RELIABILITY

Cold Weather Critical Component Identification

- Require Generator Owners to identify cold-weather-critical components and systems for each generating unit. Cold-weather-critical components and systems are those which are susceptible to freezing or otherwise failing due to cold weather, and which could cause the unit to trip, derate, or fail to start. (Implement before Winter 2023-2024)

- Require Generator Owners to identify and implement freeze protection measures for the cold-weather-critical components and systems. The Generator Owner should consider previous freeze-related issues experienced by the generating unit, and any corrective or mitigation actions taken in response. At an interval of time to be determined by the Balancing Authority, the Generator Owner should analyze whether the list of identified cold-weather-critical components and systems remains accurate, and whether any additional freeze protection measures are necessary. (Implement before Winter 2023-2024)

FERC/NERC Considerations: *FERC/NERC's 2018 report on a South Central bulk electric event*[2] *recommended potential new or revised Reliability Standards to address the need for generating units to prepare for cold weather and the need for Balancing Authorities and Regional Coordinators to be aware of specific generating unit limitations, such as ambient temperatures or fuel suppl. That recommendation led to NERC Reliability Standards being revised (effective April 1, 2023) to require, in part, that "[e]ach Generator Owner shall implement and maintain one (1) or more cold weather preparedness plan(s) for its generating units. The cold weather preparedness plan(s) shall include the following, at a minimum: . . . Generating unit(s) freeze protection measures based on geographical location and plant configuration; . . . Annual inspection and maintenance of generating unit(s) freeze protection measures . . ..." Although the revised EOP-0011-2 requires* Generator Owners *to have a plan which includes freeze protection measures, it does not require them to actually implement any specific freeze protection measures on their equipment. Key Recommendations 1a and 1b take the next logical step by requiring* Generator

Owners *to (i) identify the cold-weather-critical components and systems and (ii) identify and implement freeze protection measures for those components and systems. Cold-weather-critical components and systems are the components and systems most responsible for the generating unit outages, derates and failures to start which have plagued grid operators in the four (4) studied cold weather events in the last ten (10) years.*

Precipitation Effects Analysis

- Require Generator Owners to account for the effects of precipitation and the accelerated cooling effect of wind when providing temperature data. (Implement before Winter 2023-2024)

FERC/NERC Considerations: Emergency Operating Procedure (EOP) *EOP-011-2 (Emergency Preparedness and Operations) is part of the Reliability Standards recently approved by the Commission for Cold Weather Reliability Standards. EOP-011-2 (effective April 1, 2023) requires a Generator Owner to include in its cold weather preparedness plan, at a minimum, the generating unit’s minimum design temperature, historical operating temperature or current cold weather performance temperature determined by an engineering analysis. This Key Recommendation would also require* Generator Owners *to understand how precipitation and the accelerated cooling effect of wind limit their generating unit’s performance. Frozen precipitation can lead to icing issues that affect equipment necessary for the operation of the generating unit, for example ice accumulation on wind turbine blades, air inlet filters, and vents necessary for cooling equipment.*

Freeze-Related Corrective Action Planning

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

FERC/NERC Considerations: *NERC’s Reliability Guideline recommends that “after a severe winter weather event, entities should use a formal review process to determine what program elements went well and what needs improvement. Identify and incorporate lessons learned.” The newly-revised Reliability Standard EOP-011-2 (effective April 1, 2023) lacks any corrective action process requirement for freeze-related issues, but PRC-004-6 R5 provides a model by requiring* *a CAP in response to protection system failures. focuses only on the generating units that actually experienced an outage, derate or failure to start due to freezing.*

Cold Weather Preparedness Plan Training

- Require Generator Owners (GOs) and Generator Operators (GOPs) to conduct annual unit-specific cold weather preparedness plan training. (Implement before Winter 2022-2023)

FERC/NERC Considerations: *Newly-revised EOP-011-2, R8 (effective April 1, 2023) added a requirement that* GOs *and GOPs "identify the entity responsible for providing generating unit-specific training, and that identified entity shall provide the training to its maintenance or operations personnel responsible for implementing cold weather preparedness plan(s) developed pursuant to Requirement R7." However, it does not require that the training occur annually. This Key Recommendation simply repeats the prior recommendations for annual training, recognizing the importance of regular training, and would revise EOP-011-2, R8 to require annual training.*

Extreme Temperature Design and Retrofit

- Require Generator Owners to retrofit existing generating units, and when building new generating units, to design them, to operate to a specified ambient temperature and weather conditions (e.g., wind, freezing precipitation). The specified ambient temperature and weather conditions should be based on available extreme temperature and weather data for the generating unit's location. (Implement before Winter 2022-2023)

- Generator Owners should have the opportunity to be compensated for the costs of retrofitting their units to operate to a specified ambient temperature and weather conditions (or designing any new units they may build) through markets or through cost recovery approved by state public utility commissions (e.g., as a reliability surcharge) to be included in end users' service rates. The applicable ISOs/RTOs (market operators) and/or public utility commissions should identify how best to ensure Generator Owners have the opportunity to be compensated for making these infrastructure investments. (Implement before Winter 2022-2023)

FERC/NERC Considerations: *FERC/NERC's 2011 report on cold weather outages and curtailments*[3] *recommended that when Generator Owners build new generating units, they should be designed to operate to the lowest ambient temperature. The 2011 Report also recommended that existing generating units be retrofitted to operate to the lowest ambient temperature. Those voluntary recommendations do not appear to have been implemented. At the time, Generator Owners resisted implementing those and other recommendations, questioning how they would recover the costs of those improvements, and at least one (1) market operator recognized that generators might need to be compensated for the additional costs of preparing for extreme cold events. This Key Recommendation does not ask market operators and public utility commissions* *to make market design changes or add surcharges to end-use-customers' utility bills without obtaining data, testimony or other support for the arguments made in 2011. It only recommends that the market operators and public utility commissions consider the issue and if the Generator Owners convince them that they cannot make these infrastructure investments otherwise, that they provide opportunities for the Generator Owners to be compensated.*

Roles and Responsibilities for Unit Capacity Reporting

- Provide greater specificity about the relative roles of the Generator Owner, Generator Operator, and Balancing Authority in determining the generating unit capacity that can be relied upon during "local forecasted cold weather" in TOP-003-5:
    - Based on its understanding of the "full reliability risks related to the contracts and other arrangements [Generator Owners/Generator Operators] have made to obtain natural gas commodity and transportation for generating units," each Generator Owner/Generator Operator should be required to provide the Balancing Authority with data on the total percentage of the generating unit's capacity that the Generator Owner/Generator Operator reasonably believes the Balancing Authority can rely upon during the "local forecasted cold weather."
    - Each Balancing Authority should be required to use the data provided by the Generator Owner/Generator Operator, combined with its evaluation, based on experience, to calculate the percentage of total generating capacity that it can rely upon during the "local forecasted cold weather," and share its evaluation with the Regional Coordinator.
    - Each Balancing Authority should be required to use its calculation of the percentage of total generating capacity that it can rely upon to "prepare its analysis functions and Real-time monitoring," and to "manag[e] generating resources in its Balancing Authority Area to address . . . fuel supply and inventory concerns" as part of its Capacity and Energy Emergency Operating Plans. (Implement before Winter 2023-2024)

FERC/NERC Considerations: *EOP-011-2 R7.3 (effective April 1, 2023), will require GOs to develop cold weather preparedness plans which include, at a minimum, their generating unit(s)' cold weather data such as the aforesaid capability, fuel supply concerns, environmental constraints, etc. This Key Recommendation takes the next logical step and attempts to eliminate doubt about which entity is responsible to provide information or act on information.*

GRID SEASONAL PREPAREDNESS FOR COLD WEATHER

Anticipated Reserve Margin Calculations

- Planning Coordinators should reconsider some of the inputs to their publicly-reported winter season anticipated reserve margin calculations for their respective Balancing Authority footprints so that the reported reserve margins will better predict the reserve levels that the Balancing Area Authorities (BAAs) could experience during winter peak conditions. The suggested improvements should result in seasonal reserve margin projections which better account for resource and demand uncertainties and align better with each Balancing Authority footprint’s near-term planning during forecast cold weather events. Planning Coordinators should reconsider the following components of winter reserve margins.
    - Planning Coordinators that forecast load within southern states should adjust their 50/50 forecasts to reflect actual historic peak loads that occurred during severe cold weather events in their footprints and reflect the potential for exponential load increase due to the resistive heating used in southern states.
    - Planning Coordinators should revisit how much natural gas-fired generation should be considered as capacity to be included in winter season anticipated reserve margin calculations and projections.
    - Planning Coordinators should revisit how much wind generation should be considered as capacity and included in winter reserve margin calculations and projections. (Winter 2023-2024)

FERC/NERC Considerations: *During winter peak conditions, fuel for natural gas-fired generating units may be in competition with natural gas for residential heating needs. While the local distribution companies that supply natural gas for residential heating normally have firm commodity and transportation contracts, natural gas-fired generating units often have non-firm or interruptible contracts. When natural gas commodity or transportation availability is limited, natural gas-fired generating units without firm commodity and transportation contracts often cannot perform to their full expected capacity). This Key Recommendation encourages Planning Coordinators to recognize that they may not be able to count on the generating units’ full capacity during winter peak conditions.*

OTHER KEY RECOMENDATIONS

Rotating Manual Load Shedding Plans

- Transmission Owners/Transmission Operators, in coordination with Distribution Providers and Reliability Coordinators, should evaluate load shedding plans for opportunities to improve their capacity for rotating manual load shedding, especially when load shedding is required for extended periods during stressed system conditions. These evaluations should consider:
    - Under what circumstances underfrequency load shedding circuits may be used for rotating load during longer duration events;
    - Use of remote-controlled distribution circuit load interrupting devices (e.g., distribution line load break devices) to enable operators to deenergize and reenergize smaller portions of large distribution circuits to improve rotational load shedding; and
    - Whether advanced metering infrastructure could be leveraged to achieve greater real-time distribution situational awareness (instead of being limited to distribution substation circuit-level) to more strategically deploy or better rotate manual load shedding, such as to shed non-critical large loads (e.g., a factory that is not operating during the cold weather event). (Implement before 2023-2024)

FERC/NERC Considerations: *The unprecedented amount of load shed that ERCOT Balancing Authority operators needed to order at the peak of the February 2021 Event to prevent system failure (20,000 megawatts (MW)), the duration of the maximum load shed, and the number of circuits that were off-limits, (whether due to critical load like hospitals and first responders, or Underfrequency Load Shedding (UFLS)/Undervoltage Load Shedding (UVLS) meant that some Transmission Operators (TOPs) could not rotate their outages. Instead, the same customers remained out of service for many hours or even days. For example, during the Event, Austin Energy's general manager said, "[t]here is no more energy we can shut off at this time so we can bring those customers back on," as all available circuits were serving critical load such as hospitals and water treatment centers.*

Behind-The-Meter Intermittent Generation

- In performing their near-term load forecasts, BAAs should analyze how intermittent generation affects their ability to meet the peak load (including the effects of behind-the-meter intermittent generation) (for the entire footprint as well as sub-regions), especially if peak load cannot be met without variable resources. BAAs should consider performing a

50/50 or 90/10 forecast for renewable resources three (3) to five (5) days before real time. (Implement by Winter 2022-2023)

FERC/NERC Considerations: *The near-term weather forecast inputs for all three (3) BAs in the Event Area differed from actual weather forecasts, especially for longer-lead times (i.e., three (3) to five (5) days ahead of the operating day). Their common short-term weather forecast inputs (dry or wet bulb temperature), dew point and humidity, wind speed and chill, cloud cover, solar irradiance or sunshine minutes, and precipitation) were found to possess larger uncertainty for the longer lead-time forecasts. By introducing probabilistic methods for these weather inputs, entities will better be able to take into account weather forecast risk. BAs should analyze a range of forecast scenarios for each of the winter weather inputs for forecasting both the total load and net load (effects of behind the meter intermittent generation) forecasts, as well as for their intermittent resource forecasts.*

Seasonal Bi-directional Transfer Studies

- Adjacent Reliability Coordinators, BAAs and Transmission Operators should perform bi-directional seasonal transfer studies, and sensitivity analyses that vary dispatch of modeled generation to load power transfers to reveal constraints that may occur, to prepare for extreme weather events spanning multiple Reliability Coordinator/Balancing Authority areas like the Event. Such studies should include transmission limits on exports/imports from neighboring areas during stressed conditions, and unusual flow patterns similar to the patterns documented during the Event (east-to -west flows versus normal west-to -east, import flows into and through Midcontinent Independent System Operator (MISO) of well over ten thousand 10,000 MW (or other unusual flows seen during extreme winter weather events for the entities performing the studies). The studies should also consider sub-areas or load pockets which may become constrained. The study results can be used to create operator training simulator training scenarios. (Implement by Winter 2022-2023)

FERC/NERC Considerations: *During the Texas Event, Regional Coordinators, BAAs and Transmission Operators in the Eastern Interconnection reported observing greater than-normal and abnormal export/import transfers between Reliability Coordinator (RC) Areas and across their internal transmission systems. The recommended transfer studies and analyses should model high transfers at high seasonal load conditions, to levels at which constraints cannot be fully alleviated without emergency measures. The results of these studies should be used for operations preparedness, including to develop new operating procedures for the abnormal flows and conditions modeled, as well as incorporated into system operator drills.*

REFERENCES

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[1] FERC February 2021 Cold Weather Outages in Texas and South Central United States, November 16, 2021. https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and

[2] FERC/NERC. The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018. https://www.ferc.gov/sites/default/files/2020-07/SouthCentralUnitedStatesColdWeatherBulkElectricSystemEventofJanuary17-2018.pdf

[3] FERC/NERC. Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011. https://www.ferc.gov/sites/default/files/2020-07/OutagesandCurtailmentsDuringtheSouthwestColdWeatherEventofFebruary1-5-2011.pdf

Appendix F. **Assessment and Recommendations – Large Electric Utilities**

The sections below document detailed findings and recommendations related to South Carolina Large Electric Utilities' (LEUs') ability to protect against and recovering from extreme weather events with a specific emphasis on cold weather events. Note that all assessment findings and recommendations below are a result of tabletop reviews of information and supporting material provided by LEU respondents and interviewees and does not based on direct inspection of utility infrastructure or observations of utility personnel executing plans and practices during drills or events.

To support this assessment, ORS requested information from four (4) LEU entities:

1) Dominion Energy South Carolina (DESC)
2) Duke Energy Carolinas (DEC)
3) Duke Energy Progress (DEP)
4) Santee Cooper

Evaluators assessed each LEU at the indicator level and assigned a maturity level to each indicator based on weighted scores ranging from zero (0) to five (5).

	Maturity Level	Maturity Score	*Maturity level and score signify:*
🟢	***ADVANCED***	4.0 or greater	Advanced components in place and positioned for emerging needs
◓	***LEADING***	from 3.0 to 3.9	Foundational components in place and forward-looking plans or practices
🔵	**FOUNDATIONAL**	from 2.0 to 2.9	Foundational components in place and current standards followed
◒	**LAGGING**	from 1.0 to 1.9	Some foundational components in place
🟡	**NASCENT**	less than 1.0	Lacking or undeveloped foundational components

SUMMARY FINDINGS AND RECOMMENDATIONS

Table F-1 summarizes the LEU-specific findings.

Table F-1. Summary Assessment Findings for LEUs

🟢 Advanced ◒ Leading 🔵 Foundational ◓ Lagging 🟡 Nascent ◌ Insufficient Data

	Indicator	Summary Evaluation	Maturity
⚠	**Indicator 1 –** Emergency Management and Planning	• Incident Command System (ICS) structure has been fully integrated • Emergency management teams are trained specific to their roles • Personnel training programs are fully tracked • Business continuity plan is part of personnel training programs and personnel competencies	◒
?	**Indicator 2 –** Risk Management	• Adequately described the various processes and procedures used to assess and evaluate winter weather threats and risks to safe and reliable electric service, as applicable • Well-documented storm plans that identify potential risks that may impact the system	◒
🤝	**Indicator 3 –** Staffing and Mutual Assistance Support	• Resource planning and acquisition practices in place for responding to large-scale emergencies • Established arrangements for mutual aid • Various programs created to formalize agreements between entities to prepare for major events, most of which addresses supply chain issues	◒

Indicator	Summary Evaluation	Maturity
Indicator 4 – Asset Management and Inspections	• Practices in place to ensure that critical infrastructure will properly operate during adverse weather events • Sufficient documentation provided to depict asset management and inspection programs • Common use of internal lessons learned following outages and major events to drive continuous improvement in extreme weather event planning and response • Use of technology and tools to enhance asset management is a prevalent practice.	◓
Indicator 5 – Operational Protocols	• Utility employees prepared, knowledgeable, and trained on adverse weather operational protocols • Operating procedures appear robust, as reported by the LEU entities	◓
Indicator 6 – System Design and Hardening	• Investments in resources to achieve cost-effective resilience and reliability solutions, minimizing the negative and extreme weather to their customers • Adequate processes demonstrated to stay current with standards while investing in resiliency improvements, as necessary • Adequate documentation provided to depict the overall approach to how entities’ respective planning organizations perform annual transmission system assessments • Appropriately described appliable distribution planning standards and system-specific loading criteria	◓

Indicator	Summary Evaluation	Maturity
Indicator 7 – Stakeholder Engagement	• Demonstrated accurate communications and development of utility's resilience strategies and plans with their stakeholders • In general, identified key stakeholders and have devised associated communication plans • Prevalent use of communication channels such as social media and personalized messages. Critical facility identification and prioritization is not widely practiced – this is an improvement opportunity	◒
Indicator 8 – Public Communications	• Demonstrated fostering of effective public communications of resilience information to identify resilience gaps related to climate hazards • Raised general industry and community awareness of the activities that are either planned or currently in use to close those gaps and disseminate effective resilience strategy guidance to close those gaps within the industry and across the nation • Notably, consistent incorporation of technology into communication plans	◒
Indicator 9 – Automation	• Demonstrated industry-leading use of automation and information available from the deployment of smart grid technologies • Demonstrated a prevalent use of their geographic information system (GIS) to automate the dissemination of information for severe weather planning and operations. However, little information was provided on distribution automation (DA) • Take general advantage of technology to automate (where possible) key processes in assisting their damage assessment	◒

Indicator	Summary Evaluation	Maturity
Indicator 10 – Situational Awareness	• Deployment of situational awareness approaches and technologies to have a more informed, comprehensive, and actionable preparation and response to severe weather events • Entitles reported having the foundational tools and processes for situational awareness	◒
Indicator 11 – Compliance to Regulations	• Demonstrated adherence to federal, state, and/or local reliability and resilience requirements • Entities subject to extensive regulatory oversight by the state and federal government through various regulatory agencies and have demonstrated. via specific references to federal and state laws, the adequacy and quality of service and their internal practices • Transmission operations and planning appears to be in compliance with applicable North American Electric Reliability Corporation (NERC) reliability standards and guidelines. • Readiness plans established for addressing short- and long-term transmission upgrades to ensure no loading or voltage violations for system contingencies	◒

Table F-2 summarizes the key recommendations for LEUs utility category. Common recommendations are summarized in the initial portion of the table.

Table F-2. Summary of Key Recommendations

Common Recommendations *(Applies to all Entities)*
• Assess feasibility of implementing more comprehensive severe weather damage predictive models to improve the emergency processes.
• Define or continue to refine mutual assistance plans and look for areas of improvement.
• Continue improving on the use of analytical tools and incorporate with risk management processes accordingly.
• Increased engagement of stakeholders, at national and local levels. Take advantage of social media platforms to fully incorporate with major event communication plans.
• Enhance capabilities to extend situational awareness tools to use information/data for analytics.
• Consider enhanced tools for business process tracking related to compliance tracking to fully mature the compliance management processes.

LEU-specific Recommendations
• Assess feasibility of implementing more comprehensive severe weather damage predictive models to improve the emergency processes. This will help strengthen their well-established ICS processes.
• Investigate integrating mutual assistance crews' information into the Operation Management System (OMS) (or equivalent operational systems used for work tickets) automatically to reduce manual processing.
• Continue improving on the use of analytical tools and incorporate with risk management processes accordingly. The use of analytics needs to be investigated by the entities to develop use cases in incorporating and quantifying risks.
• Implement robust decision-making processes for long-term investments to reduce adverse weather-related risks. Resiliency key performance indicators need to be developed and tracked. These metrics should be used to measure the effectiveness of investments implemented to reduce adverse weather-related risks.

LEU-specific Recommendations

- Prediction models are used in advance of extreme weather events to estimate system impacts and required resources; this capability needs to continue to be improved to properly plan where to optimally assign mutual assistance crews (including project resource needs).
- Conduct transmission physical condition assessment on vulnerable lines and equipment that have not had detailed inspections over the past five (5) years.
- As an improvement opportunity to further improving the management of crews during a major event, recommend looking into technology solutions to help improve the management of mutual assistance crews – i.e., efficient onboarding and issuing out work tickets that are actively tracked (work activities/status and costs).
- Consider implementing capabilities related to integrated enterprise asset management system with asset performance management. This will enable more efficient operations and maintenance processes and well as investment planning and decision-making processes.
- Each LEU should ensure that the minimum design operating temperature (i.e., ambient temperature) is established for each generating unit and this information communicated to the relevant system operator/system planning organization so informed decisions can be made when assessing supply capacity for severe winter events based on forecasted temperatures.
- Review corporate winter freeze preparation procedures which apply to generation assets and compare to plant specific procedures/processes/checklists to ensure that there are no gaps between the two.
- For all generation units using natural gas as a primary fuel and fuel oil as a backup fuel, ensure local freeze protection procedures include operational testing of fuel switching prior to the winter season. The entities need to implement (if they do not exist) or complete (if pending) any feasibility studies of backup fuel supply reactivation. The entities should ascertain if the affected plants are at risk during the loss of the primary natural gas supply during a severe winter weather event.
- Continued development to use collected information from assets (e g., as recorded by the entities' historian systems) could be further leveraged to provide information for the operating groups including energy system operators. For extreme events, these could be used to capture more information to be used for forensic analysis and for training opportunities.

LEU-specific Recommendations

- Consider establishing a centralized network operations center (NOC) specifically servicing operational technology (OT) assets to leverage real-time information and focusing on infrastructure-related events. During major events, infrastructure issues (such as communication paths and network equipment outages) are oftentimes widespread and could burden the established operational processes (especially the control centers) that highly depend on the OT infrastructure, systems, and networks.

- Consider material storage and delivery methods to improve getting materials to the field quicker for repairs.

- The LEUs need to assess methods to use their foundational capabilities of their installed sensing devices to establish an analytics center to evaluate the effectiveness of resilience investments and to monitor results. The entities provided evidence that they have been incorporating sensors and measurement devices in determining the most effective resilience measures. Further use of information from sensors and measurement devices for predictive analysis can be an improvement opportunity.

- Regarding critical facility identification and prioritization, these lists should be available to that key internal and external stakeholders related to major events are aware of its existence. The list needs to be vetted so that government entities/agencies are aware of the LEU's priority or restoration; the list also needs to be vetted during way ahead of any storm event to minimize political pressure.

- Continue taking advantage of social media platforms to fully incorporate with major event communication plans. Consider analyzing customer sentiment during major events; these could be useful information for continuous process improvement.

- As applicable, stakeholders at a national level need to be part of the communication plan. Major events are usually widespread.

- Implement a more comprehensive documentation of a technology roadmap or corresponding program that governs the development efforts for assessing existing technology and the feasibility of implementing more comprehensive solutions. This can enhance automations capabilities for planning and operations in severe weather planning and restoration efforts.

- The LEUs need to continue to enhance capabilities to extend these situational awareness tools to use information or data for analytics (e.g., extending load forecast capabilities to aid real-time operations as an operational forecasting tool during major events).

- Consider enhanced tools for business process tracking related to compliance tracking (and evidence repository) to fully mature the compliance management processes.

LEU-specific Recommendations

- Modify planning criteria beyond those outlined in NERC and Southeastern Reliability Corporation (SERC) guidelines to include more extreme winter weather conditions, with greater variability than those using in current pre-winter and long-term planning studies.
- Conduct studies to test the vulnerability of the power system under extreme ice loading conditions, including loss of lines and equipment that exceed minimum outage criteria outlined in NERC standards (P1 though P7 contingencies).

DETAILED FINDINGS BY INDICATOR

The following section provides additional details for the findings and recommendations summarized above.

Indicator 1 – Emergency Management and Planning

Assessment:

LEU entities are expected to have more than adequate emergency management planning processes with the associated organizational structures. Preparation is critical for effective response to potential ice storms and dangerous winter weather conditions. From an overall assessment perspective, the LEU entities are on the high end of the **Leading** maturity level, with the scores ranging from 3.4 to 4.2 and an average of score **3.7.**

LEADING

Maturity Score: 3.7

Key observations support this maturity rating:

- The ICS structure has been fully integrated into the LEU entities' enterprise culture. By using the ICS structure, they demonstrate the use of a standardized approach to the command, control, and coordination of emergency response, providing a common hierarchy within which responders from multiple agencies can be effectively managed before, during, and after a major event.
- Support systems and internal and external communications are generally effective.
- Emergency drills, after action reports, and lessons learned are used to implement improvements. The LEU entities' ICS structure is adequately defined with related documentation; organizational maps and assignments are regularly updated. In addition, there is overall support throughout the enterprise for the ICS structure and its implementation. Corporate-wide drills are conducted simulating major events to ensure the ICS structure and roles are fully understood.
- Business continuity analysis is generally performed for the LEU entities' critical assets, and key functions and business continuity plans are regularly updated.

- Emergency management teams are trained specific to their roles. Personnel training programs are fully tracked. Personnel competency on the business continuity plan are part of the personnel training programs.

- Documentation of business continuity and major event plans exists and is disseminated formally via training. Simulated scenarios are included in the training curriculum.

- Use of technology is demonstrated via the use of logistics tools to plan and manage their employees/crews, specify geographic assignments, other logistics needs (hotels, meals, etc.). Crews obtained through mutual aid processes are on-boarded using the logistics tool.

Highlighted practices from the LEUs:

- LEU entities detailed documents demonstrating the ICS structure, the hierarchy, and roles and responsibilities (with some submitting the live organizational charts with identified responsible personnel). This is a leading practice to account for an ever-ready plan consistent to personnel availability and the clarity of roles and responsibilities.

- They provided their documented processes and procedures for storm response for specific business lines involved in the planning, operations, and restoration activities and other supporting business lines (e.g., logistics, communications, IT). There is no one-size-fits-all plan and, therefore, major lines of businesses have their own specific processes and procedures that are coordinated on an enterprise level.

- Within their ICS structure, some have assigned roles to complement the typically defined ICS roles. For example, Duke Energy had a process and modeling methodology used to assess potential winter weather threats and corresponding roles to perform these functions.

- Regarding communications on the LEU entities' emergency preparedness and readiness, Duke Energy provided their documentation of summer and winter readiness webinars covering virtually all major operating functions across DEC and DEC power production and delivery lines of business. These included weather forecasts based on detailed forecasts from its in-house meteorological group.[1]

- Storm drills are common practice internally, but some reported going beyond internal training. For example, DESC participated in storm drills conducted by the Southeastern Electric Exchange (June 2021).

- All LEU entities also participate in the GridEx drill held every two (2) years. GridEx is an unclassified, large-scale electricity grid security and crisis response exercise conducted by NERC.[2]

- Emergency planning is not about just performing the logistics of the emergency or the business continuity plan; it should also involve the necessary engineering analysis to be able to forecast the system's capability to withstand the expected impact of the major event. For example, Santee Cooper performs distribution loading and contingency analysis under winter weather conditions to identify any issues on feeders and the distribution substation and works to address any issues. They have implemented and tested damage assessment procedures, provide a ten (10) day forecast to anticipate high load days on the system, implemented special shift schedules during storms, and centralized control room operations. For better coordination, they have standardized maintenance initiatives and establishing pole inspections. Contingency plans for loss of critical facilities and technology such as the control center, call center, Supervisory Control and Data Acquisition (SCADA), and OMS have also been developed.

Recommendations:

- Continue to assess the performance of their existing technology used for damage prediction. Assess feasibility of implementing more comprehensive severe weather damage predictive models to improve the emergency processes. This will help strengthen their well-established ICS processes.
- Continue to refine the assessment process that is being put in place and look for ways to digitally collect the data and integrate the data collected into the OMS automatically.
- Investigate integrating mutual assistance crews' information into the OMS (or equivalent operational systems used for work tickets) automatically to reduce manual processing.
- Invite outside third parties to review and provide comments on the LEU entities' emergency plans.

Indicator 2 – Risk Management

Assessment:

LEU entities are expected to have more than adequate risk management processes, the lynchpin that prompts the organization's investment strategies and initiatives once high impact risks (although low probability) are identified and assessed as something that needs to be addressed. Critical infrastructure risk management plans must be developed, and preventative mitigation actions put into place in advance of adverse weather. From an overall assessment perspective, the LEU entities are within the **Leading** maturity level, with the scores ranging from 3.4 to 3.8 and an average of score **3.6.**

LEADING

Maturity Score: 3.6

Systematic and defined processes have been established, and the current level of adverse weather resilience risk is well-understood by the LEU entities.

Key observations support this maturity rating:

- The LEU entities adequately described various processes and procedures they use to assess and evaluate winter weather threats and risks to safe and reliable electric and natural gas service (as applicable). They have employed enterprise risk management processes. These processes are used to identify, assess, and respond to a wide range of weather-related and other business continuity risks.

- LEU entities have demonstrated their capability to use the historical experience of their assets to improve their risk management process. For example, DESC described its generation performance during the week of January 6, 2014 cold weather event and how they managed their risks related to inadequate generating reserves. In their report, they pointed out that most of their major generators operated normally during this event. However, Urquhart & Williams generating stations experienced cold weather-related issues: 1,024 MW lost (e.g., frozen gas supply line and other weather and non-weather-related issues). DESC used this event and associated lessons learned to assess its operating posture as part of its ongoing risks assessment process.
- Documentation on risk management and methodology is prevalent; these provide the structure and guidance to integrate risk, including environmental, health, and safety (EHS), equipment, and project risk, into risk registers at all levels under the entity's jurisdiction. For the some of the entities, integrating this information is intended to assist decision-making to effectively manage resources before, during, and after major events.
- LEU entities have well-documented storm plans that identify potential risks that may impact the system. The rigor of the analysis needs to be more detailed. For example, the entities should consider enhancing their asset management program to include qualifiers and key performance indicators for major event resiliency to ensure that a mechanism for continuous improvement can be put in place.
- The entities report the use of damage models (ranging from simple wind damage models to complex weather-dependent models) to aid in major event preparations. It is not a prevalent practice to use the output of the damage models in long-term investment planning.
- Critical to managing risk for supply is managing the reserves – the LEUs are part of the Virginia-Carolinas sub region within NERC's SERC (VACAR) Reserve Sharing Group (RSG). Reserves are allocated among the participants based on each participant's largest unit and previous annual peak demand. Each participant continually carries its allocated reserve share, allowing very fast response to a loss of resource. Being active participants in the RSG significantly mitigates the risk of unplanned resource losses.

Highlighted practices from the LEUs:

- The use of technology and tools to enhance the risk management process enhance the awareness for the entity's emergency management organizations. For example, DESC uses its existing GIS to aid in severe weather planning and restoration efforts. Duke Energy headquarters maintains a NOAA Port Satellite receiver system and computer infrastructure that receives all National Weather Service (NWS) numerical weather models, forecasts, data, satellite, and radar imagery. Duke Energy meteorologists provide forecasts and alerts for weather that may impact transmission, distribution, and generation business units and provide resource modeling for tropical storms, windstorms, and ice storms. In addition, Duke Energy's meteorologists send out automated extreme cold alert notifications whenever the ten (10) day hourly forecasts show a value less than less than 15ºF. This is being highlighted as a leading practice in using technology and tools to aid in the risk management process.

- The use of analytics is not prevalent, but there are examples worth noting for reference. For example, DEC and DEP have indicated that the most significant severe winter weather risk with the potential to impact the reliability of service to their customers are ice storms, which lead to significant levels of ice accretion and infrastructure damage. Duke Energy's most effective assessment of DEC/DEP-specific risk of an impending winter storm is its use of the Outage Event of Customer Outage models produced by its internal meteorology team. These model outputs allow DEC and DEP to make effective preparations, which include resource assessment and, if needed, external resource acquisition and crew staging in areas of highest predicted impact. This is being highlighted as leading practice in using analytics and models to aid in the risk management process.

Recommendations:

- Continue improving on the use of analytical tools and incorporate with risk management processes accordingly. The use of analytics needs to be investigated by the entities to develop use cases in incorporating and quantifying risks.
- For entities that have both electric and natural gas resources, incorporate their electric and natural gas service asset management processes into a framework that would continuously monitor against possible winter weather threats and risks to safe and reliable electric and natural gas service (e.g., improving on their basic GIS ecosystem to include weather threats and risks to electric and natural gas service assets).
- Continue to develop the collection and analysis of operational performance data to build better information around system vulnerabilities and improvement opportunities.
- Implement robust decision-making processes for long-term investments to reduce adverse weather-related risks using advanced approaches and analytics.
- Resiliency key performance indicators need to be developed and tracked. These metrics should be used to measure the effectiveness of investments implemented to reduce adverse weather-related risks.

Indicator 3 – Staffing and Mutual Assistance Support

Assessment:

Because of the seasonal exposure of the South Carolina region to major events (especially hurricane events and occasional extreme winter events), it is imperative for LEU entities to have a high degree of confidence in their resource planning and acquisition (through mutual assistance) to be able to respond to large-scale emergencies. In the electric sector, the worst and most widespread outages occur after a major event, one (1) company may not have the skilled people, trucks, equipment, experts, and data to restore the energy system all by itself. The energy system is an interconnected network and restoring service to the energy system goes faster when utilities can share resources to make the necessary repairs and replace specialized electrical equipment, among other things. Utilities address these resource constraints by using mutual aid or mutual assistance programs that allow companies to pool resources to meet their shared needs during emergency events.

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LEADING

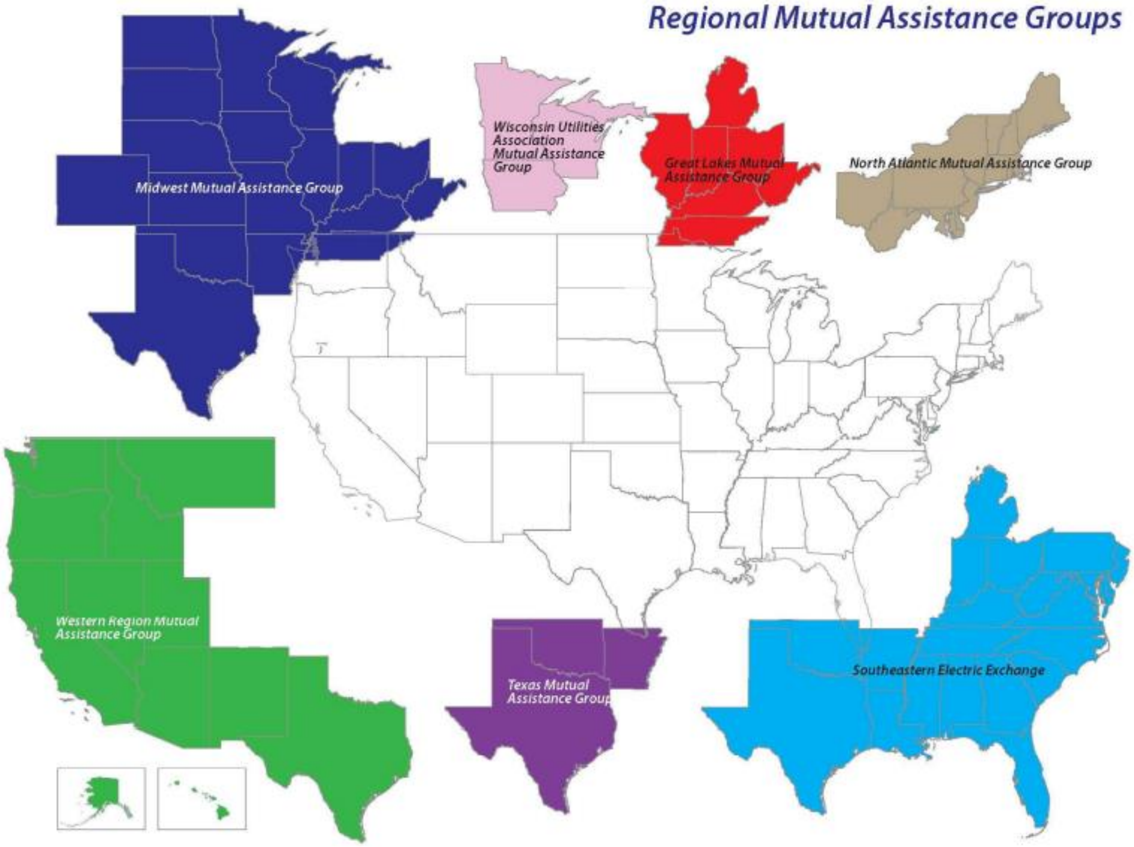
Maturity Score: 3.5

From an overall assessment perspective, the LEU entities are within the **Leading** maturity level, with scores ranging from 3.3 to 3.7 and an average of score **3.5**.

Key observations support this maturity rating:

- The LEU entities have established arrangements for mutual aid. Mutual aid or mutual assistance is an essential part of the electric power industry's service restoration process and contingency planning. The mutual assistance network is a cornerstone of electric utility operations during emergencies. Edison Electric Institute (EEI) members are IOUs, and under EEI guidance there are seven (7) Regional Mutual Assistance Groups (RMAGs) (**Figure F-1**).[3]

Figure F-1. Map of the Regional Mutual Assistance Groups



Source: Edison Electric Institute

Duke Energy and Dominion Energy both have multi-state service territories and are members of one (1) or more RMAGs. This is an advantage because they will have a scale in case of a widespread event. The pertinent RMAG for the South Carolina is the Southeastern Electric Exchange (SEE).[4] This is a trade organization of IOUs founded in 1933, with fifty-nine (59) member operating companies. The entities participate in the mutual aid section of this organization, which provides coordination of storm restoration services to impacted member companies. The primary focus is sharing distribution line resources. EEI also provides public policy leadership, strategic business intelligence, and essential conferences and forums. This is also a forum in which the entities share leading practices and coordinate mutual assistance.

Public power utilities like Santee Cooper are involved with the American Public Power Association (APPA) mutual aid program.[5] These utilities have local, state, and regional contracts and agreements for mutual aid, and there is also a national mutual aid agreement with over 2,000 public power and rural electric cooperatives, that connects utilities, so they are able to help one another when needed. Santee Cooper has existing Mutual Assistance Contracts are with the other utilities (**Table F-2**). The mutual aid roles and responsibilities for public power utilities are defined at the local, state, regional, and national levels. Level two (2) and three (3) events, which are at the local, state, or regional levels, involve utility and network coordinators. A Level four (4) event, which is on a national level, involves the utility coordinator, network coordinator, and APPA serving as national coordinator. For a national level event, APPA works with network coordinators from the following affected industry associations: EEI, the National Rural Electric Cooperative Association, the trade association for the cooperative electric utilities, and other organizations such as the National Emergency Management Association.[6]

Table F-2 – LEU Entities and Corresponding Mutual Assistance Sources.

Entity	Mutual Assistance
DEC and DEP	RMAG membership with SEE, the Great Lakes Mutual Assistance (GLMA), and the Midwest Mutual Assistance organizations (MMA)
DESC	RMAG membership with SEE
Santee Cooper	Mutual Assistance contracts with Orlando Utilities Commission (OUC), Jacksonville Electric Authority (JEA), Gainesville Regional Utilities (GRU), and Dominion Energy South Carolina (DESC)

- Various programs were created to formalize agreements between entities to prepare for major events, most of which addresses supply chain issues. The LEU entities participate as necessary in these programs to meet their needs.
  - Spare Transformer Equipment Program (STEP) is an electric industry program that aids with quicker restoration of the transmission system as a result of terrorist attacks. Any electric utility, regardless of ownership structure, in the U.S. or Canada, can be part of this program. STEP currently has fifty-four (54) utility members and helps to increase the inventory of spare transformers and streamline the process of transferring them to affected utilities when there are transmission outages due to terrorist attacks. Participating electric utilities must maintain a specific number of transformers. The program requires each participating utility to sell its spare transformers to any participating utility that suffers from an act of terrorism that destroys or disables one (1) or more substations, and results in a state of emergency declaration by the U.S. President.
  - SpareConnect is a program for utility asset owners and operators, which allows them to network with other SpareConnect members to share transmission and generation step-up transformers and related equipment, including bushings, fans, and auxiliary components. SpareConnect establishes a formal program which already exists on an informal basis, to communicate equipment needs in the event of emergency or other non-routine failures, and to connect interested utilities more effectively and efficiently.

  - Emerging energy assurance programs: there is a dynamic and growing range of additional private sector responses that address these types of resilience approaches. For example, a product in the market that started up in June 2015 is Grid Assurance LLC, which is a collaborative effort by utilities to cost-effectively improve the resiliency of their transmission and Bulk Electric System (BES). This program will provide utility and transmission-owning subscribers with timely access to emergency spare transmission equipment, which typically take long periods of time to acquire. The equipment is stored in secure warehouses and readily deployable after a major system failure.

Recommendations:

- Logistical coordination is highly complex even to the best planned mutual assistance processes, especially in the process of crew onboarding. Once mutual assistance crews are identified to assist the entity, they must be onboarded so they can receive work orders from the local entity where help is needed. They must be provided essentials (i.e., food, beds, bathrooms). Arranging for these items to be readily available and dispatched on time can be challenging, especially if access to an area is limited due to roads being blocked, for example, by trees or downed power lines. Additionally, hotels can sometimes be filled with local residents displaced from their residences, requiring mobile housing, restrooms, etc. to be brought in. As an improvement opportunity to further improving the management of crews during a major event, recommend looking into technology solutions to help improve the management of mutual assistance crews – i.e., efficient onboarding and issuing out work tickets that are actively tracked (work activities/status and costs).

- Communication and coordination between utilities and state or local emergency operations centers is necessary for determining restoration priorities. This is the cornerstone of the mutual aid process and the entities should continue to identify key communications and technology solutions that improve these processes. Oftentimes the technology is not the limiting factor for improving communications as there are plenty of technology solutions available (e.g., video conferencing, emergency alerts, etc.); the governance structure of the communication process should be tied with the ICS structure and governance.

- Prediction models are used in advance of extreme weather events to estimate system impacts and required resources; this capability needs to continue to be improved to properly plan where to optimally assign mutual assistance crews (including project resource needs).

Indicator 4 – Asset Management and Inspections

Assessment:

The entities must ensure that their asset management strategies and processes take account of asset-related risks and asset system criticalities – ideally managing the preparedness of assets for extreme weather events. From an overall assessment perspective, the LEU entities are fairly consistent and are on the **Leading** maturity level, with scores ranging from 3.4 to 3.5 and an average of score **3.5**.

LEADING

Maturity Score: 3.5

Key observations support this maturity rating:

- LEU entities provided sufficient documentation depicting their asset management and inspection programs. They conduct periodic condition assessments for major systems and equipment to ensure safe and efficient operations. These assessments are typically performed during planned outages in preparation for summer and winter peak seasons and also as part of their preventive maintenance program.
- The LEU entities use internal lessons learned (following outages and major events) to continuously improve on their preparation and response to extreme weather events. They also leverage lessons learned from other utilities in the industry that have been challenged by extreme weather events, which provides additional leading practices that the LEU entities may adopt.
- LEU entities were also able to provide sufficient information or documentation of their process for protecting against generation plant freezes, other winter protection systems, and processes to ensure that their equipment is reliable and functionally tested to be in good working order prior to the arrival of a major winter freeze event.

Highlighted practices from the LEUs:

- The use of technology and tools to enhance the management of assets is a prevalent practice. For example, one (1) LEU uses its existing GIS as the base technology to manage its assets and to trigger work tickets for asset management and inspections.
- Specific to vegetation management, one (1) LEU has implemented a remote sensing program (using LiDAR) to capture data necessary to identify threats and conditions associated with vegetation management work. After extensive threat data is captured electronically and processed, the LEU performs data analytics by using integrated applications to assess the potential impact to grid integrity from vegetation threats in and along the edge of the Right-of-Way (ROW) and to identify potential reliability impacts from off-ROW vegetation threats.
- Use of analytics in asset management and into their day-to-day operations is also being used for extreme weather preparation, damage assessment, and restoration. For

example, one (1) LEU consolidates data from different source systems so that their employees have a single, simple-to-use interface to view, understand and manage work orders and assets. This tool consolidates all performance and maintenance information about a piece of equipment from a variety of data sources. It provides asset information such as work orders, upcoming replacement projects, and a "health rating" (via the use of advanced analytics) affiliated with the piece of equipment and is used to make decision on repairing versus replacing. The use of analytical tools provides insights to aid in the management of the resiliency of the assets and are used to support asset lifecycle extension, preempt failure, asset sparing strategies, and asset project prioritization.

- From a generation perspective, one (1) LEU also demonstrated the use of predictive analytics software as the primary monitoring tool along with temporal (time-based) asset data for additional diagnostics and analytics support. The predictive analytics software provides early warning notification and diagnostics of equipment issues days, weeks, or months before failure. This helps asset-intensive organizations, reduce equipment downtime, increase reliability, and improve performance while reducing operating and maintenance expenditures. The software includes a variety of advanced statistical and model-based comparison applications and business intelligence tools that enable users to spend less time searching for potential problems and thus being alerted to anomalies.
- Generation readiness-specific processes and practices were present, to various degrees, in all the LEU's responses. Examples of these leading practices provided by the LEUs include, but are not limited to, the following:
    - Use of a three (3) layer system to prepare for winter weather: (1) corporate-wide Emergency Action Plan for Power System Disasters, (2) plant-level annual reviews and tabletop exercises of emergency procedures and winter weather preparedness prior to the winter season, and (3) audits conducted prior to the winter season for "at risk" equipment such as heat tracing systems, weatherized enclosures, piping insulation, etc.
    - Implementation of a Code Yellow or Code Red condition, which dictates certain actions to be taken depending on the prevailing outside temperature.
    - Generation plant managers being required to provide a Letter of Seasonal Readiness Certification to indicate that the plant has met seasonal readiness requirements on an annual basis.
    - Use of a winter weather coordinator at the plant level (if needed).
    - Winter weather readiness training and crew briefings.
    - Site challenge review to ensure the site is prepared for the winter weather.
    - Initiation of additional operator rounds during severe winter weather.
    - Functional testing of fuel switching capability for dual fuel units.

    - Site-specific freeze protection procedures list activities based on outside temperature.

Recommendations:

- The LEU entities should consider implementing capabilities related to integrated enterprise asset management system with asset performance management. This will enable more efficient operations and maintenance processes and well as investment planning and decision-making processes.
- Asset data is foundational for enabling asset management functions. Planning for asset renewal and maintenance activities is enhanced with full knowledge of asset location, condition, and operation. Each company should ensure that the minimum design operating temperature (i.e., ambient temperature) is established for each generating unit and this information communicated to the relevant system operator/system planning organization so informed decisions can be made when assessing supply capacity for severe winter events based on forecasted temperatures.
- Review corporate winter freeze preparation procedures which apply to generation assets and compare to plant-specific procedures, processes, and checklists to ensure no gaps between the two (2) (e.g., a corporate procedure says we do steps A, B, and C; however a plant-specific procedure lists only steps A and B, despite step C also being applicable)
- For all generation units using natural gas as a primary fuel and fuel oil as a backup fuel, ensure local freeze protection procedures include operational testing of fuel switching prior to the winter season.

Indicator 5 – Operational Protocols

Assessment:

The entities must ensure that (a) they have adverse weather operational protocols and procedures with associated tools and guidelines have been established; (b) periodic training for operational protocols are completed and tracked; and (c) an operating management and governance assuring operating protocols are followed to assure company and public safety. The entities' operating protocols should fully encompass preparedness, mitigation, response, and recovery for adverse weather events. From an overall assessment perspective, the LEU entities are within the **Leading** maturity level, with scores ranging from 3.4 to 4.1 and an average of score **3.6.**

LEADING

Maturity Score: 3.6

Key observations support this maturity rating:

- Operating procedures appear to be robust as reported by the LEU entities. The LEU entities, as verified by the documentation provided, have methods and procedures that ensure clear communications governance and protocols in place during major events. They fully use the ICS structure, and make full use of an Incident Commander role that is established and usually filled in by a key line of business leader. The Incident Commander (IC) works with the other team members to perform the initial planning and ongoing decision making throughout the event.

- Each LEU entity is cognizant of the requirements for NERC's EOP-005-03 Standard, *System Restoration from Black Start Resources*. They maintain startup and test procedures to ensure reliable operation.

- For fuel supply operational protocols, they have documented process for monitoring onsite backup fuel oil levels against forecasted burn rates. They have set requirements to maintain certain levels for backup supply for their generating plants. For example, one (1) LEU requires all of its natural gas plants on interruptible supply to maintain a seventy-two (72) hour supply of liquid fuel backup on site. Its basis for the seventy-two (72) hour backup liquid fuel supply is the fact that they are all within 100 miles of the tank farms fed by the two (2) interstate pipelines.

- All three (3) LEU entities' plants which burn natural gas as a primary fuel have firm gas supply contracts with the lone exception of one (1) LEU's simple cycle combustion turbine (CT) units which are on interruptible gas supply, however these CT's also have a liquid fuel backup supply with a minimum seventy-two (72) hour onsite supply of backup fuel. Additionally, the majority of plants with natural gas as a primary fuel source also have liquid fuel onsite backup capability.

Highlighted practices from the LEUs:

- One (1) LEU has stated that they are currently working to secure additional emergency trucking agreements which will allow them to have priority trucking rights should they need to replenish their on-site oil inventories during a prolonged winter weather event where natural gas supplies have been curtailed to some of their generating units.

- Another LEU which supports the Carolina Gas Transmission, LLC (CGT) system that serves their gas-fired generating units has natural gas station compressors that are fueled by natural gas, not electricity, so they are not vulnerable to a loss of electric power.

- One (1) LEU's operating procedures are classified by degree of risk and complexity with each category having a specific expectation for how they are to be used by the operator.

- One (1) LEU has contingency plans established for critical procedures which call for a set of hard copies for critical procedures to be available in case access to electronic procedures becomes unavailable.

Recommendations:

- As stated in the assessment, operating procedures appear to be robust as reported by the LEU entities. The documentation provided established protocols and processes for analyzing operational data to aid in keeping track of reliability metrics. Continued development to use collected information from assets (e g., as recorded by the entities' historian systems) could be further leveraged to provide information for the operating groups including energy system operators. For extreme events, these could be used to capture more information to be used for forensic analysis and for training opportunities.

- As an improvement opportunity, LEU entities should consider establishing a centralized NOC specifically servicing OT assets to leverage real-time information and focusing on infrastructure-related events. During major events, infrastructure issues (such as communication paths and network equipment outages) are oftentimes widespread and could burden the established operational process (especially the control centers) that highly depends on the OT infrastructure, systems, and networks.

- The entities should consider use of a knowledge management system (KMS) or learning management system (LMS) to aid in improving training processes. These are efficient methods that could help the entities record operational procedures and could be used for training personnel, including external mutual assistance crews to get the familiarity of the local entities' standards and assets.

- Operating procedures appear to be robust. The entities are encouraged to continue to hold after action reviews and update procedures as needed. An opportunity, if not already done and not mentioned in the documentation, is to investigate ways to ensure materials needed for repair such as poles, crossarms, and braces, are in adequate supply. Also consider material storage and delivery methods to improve getting materials to the field quicker for repairs.

- For generation-specific recommendations, the entities need to implement or complete (if pending) any feasibility studies of backup fuel supply reactivation. The entities should ascertain if the affected plants are at risk should they lose the primary natural gas supply during a severe winter weather event.

- The LEUs that do not use a standardized companywide format and governance control for their generation plant operating procedures are encouraged to consider implementing one to ensure leading practices are identified and implemented at all applicable plants and that the procedures have a common look and feel for all employees.

- All LEUs should ensure that the design minimum operating temperature is known for each of their generation units and that this value is communicated to the relevant system operator/system dispatcher so these values can be used to aid in short term supply planning for severe cold weather events.

Indicator 6 – System Design and Hardening

Assessment:

A resilient electric or gas utility invests resources to achieve cost-effective resilience and reliability solutions, minimizing negative impacts of climate change and extreme weather to its customers. From an overall assessment perspective, the LEU entities are on the low end of **Leading** maturity level, with scores ranging from 3.2 to 3.5 and an average of score **3.3**.

LEADING

Maturity Score: 3.3

Key observations support this maturity rating:

- LEU entities demonstrated adequate processes to keep up with current standards and have invested in resiliency as necessary (based on the information provided in their capital plans). They have demonstrated formalized resiliency investment programs, and the program's effectiveness is communicated to their respective stakeholders.

- The LEUs reported complying to existing standards with regards to their construction standards and have plans to continue re-evaluate and plan for the evolving NESC standards. The loading conditions most relevant to wind and ice/snow build are NESC rules 250B, C, and D which all contain different temperatures, wind speeds, ice thicknesses, and load factors.

- Adequate documentation was provided that depicted the overall approach to how their respective planning organizations perform the annual assessments of the transmission system. These assessments include looking at both short-term and long-term needs of the system based on the performance requirements (such as standards defined by NERC TPL-001-004, *Transmission System Planning Performance Requirements*).

- The LEUs appropriately described their distribution planning standards as well as their loading criteria. All have provided more than adequate documentation of their circuit loading (amps) criteria, pole and wire design criteria for wind and ice/snow build-up, and pole loading verification process. As necessary, the entities provided associated records and tracking processes.

- With regards to one (1) LEU's natural gas assets, the vast majority of its CAPEX budget is growth related. Occasionally these growth-related projects have a secondary system benefit such as providing a secondary tie-in to a distribution system or a partially redundant parallel pipeline. A portion of the annual CAPEX budget is set aside for system improvement work – for instance, replacement of outdated or difficult to maintain equipment (typically at regulating stations). Relating specifically to protecting against winter-weather events, two (2) regulating stations within its service territory have plans to install heaters to prevent freezing during periods of high usage and cold weather.

- All of the LEU's reported having firm natural gas supply contracts for their generation units with natural gas as the primary fuel. The one (1) exception is one (1) LEU has an interruptible gas supply contract for its simple cycle peaking units, however these units have liquid fuel backup capability, and they are required to maintain a minimum of 72 hours of liquid fuel backup supply inventory. It should be pointed out that firm natural gas supply contracts reduce the risk of losing gas supply during extreme weather events but they in no way guarantee that gas supply won't be lost.

- While most of the plants using natural gas as a primary fuel also have secondary liquid fuel capability, one (1) LEU reported that they have one (1) gas plant with no backup fuel capability. This LEU did report, however, that the plant does have onsite oil storage tanks currently not in-service but they are in the process of conducting a feasibility study to determine if these tanks should be returned to service.
- One (1) of the freeze protection measures commonly used at coal plants is to have the coal treated with a freeze conditioning agent prior to delivery. This helps the coal be less susceptible to freezing and clumping during periods of cold weather. Most of the LEU's reported that they either do this as a matter of routine practice or as an optional service, however not all the LEU's reported on this practice.

Highlighted practices from the LEUs:

- Being both part of the EEI and the SEE, two (2) of the LEU's participate in industry benchmarking efforts. Benchmarking especially in foundational and emerging practices and standards to improve system resiliency.
- All LEU entities are adequately addressing winter storm events. For example, one (1) LEU provided its transmission long-term planning criteria which is consistent with NERC and other industry planning standards – this LEU conducts studies that appear to exceed NERC Planning Standard TPL 004 for severe events. Another example from another LEU is that its Distribution Construction Standards and design requirements meet or exceed the loading requirements of NESC rule 250 which includes the expected wind and ice loading as defined therein. This LEU requires its planners to meet or exceed the loading requirements of NESC rule 250, which defines three (3) loading conditions that they adequately described through their responses.
- Topics related to electric grid hardening initiatives (including related technology enhancements) were thoroughgoingly discussed and presented with the documents that they provided. Of note, one (1) LEU provided the following to describe their grid hardening initiatives:
    - Self-optimizing grid (SOG): The SOG program consists of three (3) major components: grid capacity, grid connectivity, and automation and intelligence. The SOG program redesigns key portions of the distribution system and transforms it into a dynamic smart-thinking, self-healing grid. According to this LEU, the grid will have the ability to automatically reroute power around trouble areas and to quickly restore power to the maximum number of customers and rapidly dispatch line crews directly to the source of the outage.

  - Targeted undergrounding (TUG): The TUG program strategically identifies the most outage prone overhead power line sections and relocates them underground to reduce the number of outages experienced by customers. This is now being adopted as an approach by large utilities, especially in the Southeast.
  - Distribution transformer retrofit: The Distribution Transformer Retrofit program converts existing overhead distribution transformers to deliver the same reliability benefits as a modern transformer installed today.
  - Long Duration Interruption/High Impact Sites: This program is designed to improve the reliability for parts of the grid with high potential for long duration outages and for high impact customers like airports and hospitals. This type of prioritization focuses energy service providers to focus on areas that has the most impact for customers during major events.
  - DA: The DA program improves how the distribution system protects the public and itself from unsafe voltage and current levels and significantly reduces the impact experienced by customers due to grid issues.
  - Transmission Hardening & Resiliency (H&R): The transmission (H&R) program works to create a stronger and more resilient transmission grid capable of withstanding or quickly recovering from extreme external events, natural or artificial.
  - Transmission System Intelligence: The Transmission System Intelligence program deploys transformational system monitoring and control equipment to enable faster response to outages and more intelligent analysis of issues on the grid.
  - Transmission Transformer Bank Replacement: The Transformer Bank Replacement program leverages new system intelligence capabilities to target transformers before they fail.
  - Transmission Oil Breaker Replacements: The Oil Breaker Replacement program identifies and replaces oil-filled circuit breakers on the Transmission and Distribution (T&D) systems with modern technology.

Recommendations:

- The LEUs need to assess methods to use their foundational capabilities of their installed sensing devices to establish an analytics center to evaluate the effectiveness of resilience investments and to monitor results. The entities provided evidence that they have been incorporating sensors and measurement devices in determining the most effective resilience measures. Further use of information from sensors and measurement devices for predictive analysis can be an improvement opportunity.
- Several good grid hardening techniques are in place; entities should investigate additional techniques such as:

  - Considering adopting enhanced construction standards for all distribution overhead lines.
  - Investigating material specifications for added winter weather protections for fuses and switches.
  - Reducing distribution wire spans.
  - Continuing selective undergrounding.
  - Incorporating DER for added resiliency (based on analysis of how they benefit grid resiliency).
  - Reviewing material specification for added winter weather protection for insulators, fuses, and switches to prevent ice build-up.
- Investigating enclosing addition substation equipment where possible, especially any open-air substations. For any LEU which currently does not apply a freeze protection agent to their coal supply as a matter of routine it is recommended that they consider adopting this practice on a site-by-site basis if the cost/benefit review is favorable.

Indicator 7 – Stakeholder Engagement

Assessment:

Stakeholder engagement is critical to accurately communicating and developing a utility's resilience strategies and plans, recognizing roles and responsibilities of the community, identifying opportunities for improvement, and implementing solutions that align with stakeholder values and needs. It is expected that a diverse and comprehensive group of internal and external stakeholders are identified and engaged regularly, focused on resilience risks and opportunities, thorough, ongoing, in-depth, and timely dialogues. For example, external engagement with representatives from regulators, science, industry, and community work together to define objectives, goals, lines of responsibility, and areas for collaboration. Internal stakeholder engagement that is clearly identified embeds extreme weather resilience culture into everyday practices.

LEADING

Maturity Score: 3.5

From an overall assessment perspective, the LEU entities are within the **Leading** maturity level, with scores ranging from 3.3 to 3.8 and an average of score **3.5.**

Key observations support this maturity rating:

- The LEU entities have solid processes to identify their critical facilities and customers and designed a process for communications and interactions with key stakeholders.

  - For example, DEC and DEP use their Major Storm Reporting Tool to know when customers who have been flagged as critical have been impacted by an outage. It allows their Liaison Section to understand which critical customers have been impacted and to work with the Operations Section to track those outages to resolution.
  - DESC has an understanding of their stakeholders as documented in their list as maintained by its Government Affairs team. The entity's communication plan is intended during (and in close proximity to) the event only.
  - Santee Cooper establishes points of contact for local government officials and depending on the impact of the extreme weather, Santee Cooper will embed Federal Emergency Management Agency (FEMA's) Emergency Support Function -12 (ESF-12) representatives at the local emergency preparedness operations center. If a winter weather event is expected to have a material effect on Santee Cooper's operations and the State Emergency Operating Center has been activated, then, usually prior a declared state of emergency, Santee Cooper will provide an in-person liaison to support and coordinate with the state's ESF-12.

- Use of technology is adequately documented (e.g., tagging customers for restoration priority in the entity's customer information system (CIS)).
- Critical facility identification and prioritization is not widely practiced – this is an improvement opportunity.

Recommendations:

- Regarding critical facility identification and prioritization, these lists should be available to that key internal and external stakeholders related to major events are aware of its existence. The list needs to be vetted so that government entities/agencies are aware of the LEU's priority or restoration; the list also needs to be vetted during way ahead of any storm event to minimize political pressure.
- The LEUs reported their respective processes in identifying key internal and external stakeholders related to major events. An improvement opportunity is to personalize a communication plan at each stage of the development of the resiliency plan so that the engagement is set earlier on and not only during the event itself.
- Continue improving communications plans to engage regulators, investors, and senior executives to reinforce resilience priorities and address risks and opportunities and to inform strategy, risk management, and enterprise-wide decision-making with regards the entities resilience program.
- Customer sentiment not analyzed during major events; these could be useful information for continuous process improvement.

- Continue enhancing the linking of live status for critical customer facilities into operational systems. These could be used to communicate to key internal and external stakeholders related to major events.

Indicator 8 – Public Communications

Assessment:

Public communications go together with stakeholder engagement. Effective communication of resilience information by utilities helps to foster transparency in resilience gaps related to climate hazards, raise industry and community awareness of the activities that are either planned or in use to close those gaps, and disseminate effective resilience strategy guidance to close those gaps within the industry and across the nation. From an overall assessment perspective, the LEU entities are within the **Leading** maturity level, with scores ranging from 3.5 to 4.1 and an average of score **3.8**.

LEADING

Maturity Score: 3.8

Key observations support this maturity rating:

- The LEU entities are consistent in incorporating technology into their communication plans:
    - For DEC and DEP, critical customers are tracked using the Major Storm Reporting Tool. The tool allows DEC and DEP to know when customers who have been flagged as critical have been impacted by an outage. It allows the Liaison Section to understand which critical customers have been impacted and to work with the Operations Section to track those outages to resolution. They use a mix of mass and direct-to-customer communications to ensure messages are delivered across multiple communication channels. Messages are created by the Public Information Officer or designee and approved by the Incident Commander prior to use. DEP/DEC strategy is to communicate pertinent information in four (4) phases of an event: (a) Phase 1 = Pre event: Messages focus on DEC and DEP preparedness, anticipated storm impacts and how customers should prepare, (b) Phase 2 = Event: Messages acknowledge the event, the impacts, and what to expect as restoration begins, (c) Phase 3 = Post Event: Messages focus on estimated times of restoration, damage and address rumors, and (d) Phase 4 = Reputation Recovery: Messages focus on appreciation, successes and opportunities.
    - DESC stated that its Government Affairs team maintains a database of more than 750 state and local government officials to communicate in advance, during, and after a severe weather event. In accordance with its storm plan, Government Affairs is prepared to communicate via text, phone call, and email at one time via its emergency notification system. In addition to Government Affairs having a

Section Chief in the Emergency Operations Center, it has local managers assigned to geographic areas to serve as a liaison between operations and local governments. The Evaluators assume that the LEU entities have convened the necessary governance structure to support the communications strategy specific to its list of stakeholders.

  - At Santee Cooper, its Corporate Communications Department follows its Crisis Communications Plan. The Crisis Communications Plan is updated by June each year for pre-storm, during storm, or post storm. Messaging changes for each. In the Crisis Communications Plan, key activities and communication are broken down into specific steps for media, employees, website, social media, and customer communications. Santee Cooper works closely with media (social media, TV, radio, online and print newspaper) to provide updates. Santee Cooper reported that its estimated time of restorations (ETRs) are provided from their OMS. If a multiday recovery is expected or if conditions dictate such, ETRs would be suspended, and updates are provided on a general level on the storm outage website and through social media channels.[7]

Recommendations:

- Continue taking advantage of the social media platform to fully incorporate with major event communication plans. Customer responses and sentiment should be tracked so that the communication responses are planned accordingly to provide the needed information.
- As applicable, stakeholders at a national level need to be part of the communication plan. Major events are usually widespread.

Indicator 9 – Automation

Assessment:

Organizations that have achieved a high level of maturity within this domain have an increased capability to use automation and information available from the deployment of smart grid technologies. From an electric infrastructure perspective, mature organizations have the capability to manage power flows so that power losses are minimized, and the usage of lowest cost generation resources are maximized. During major events, automation is used to provide situational awareness for grid operators and for post-event restoration processes. The same principles can be adopted for sensing devices for the natural gas systems.

LEADING

Maturity Score: 3.2

Another aspect of automation is the prevalent use of technology to be able to automate key planning and operation processes for major storm events. For example, automating weather data assessments during major events or mapping out key damage areas for situational awareness.

From an overall assessment perspective, the LEU entities are on the high end of the **Leading** maturity level, with scores ranging from 3.1 to 3.2 and an average of score **3.2.** Compared to the other indicators for the maturity assessment, automation resents opportunities for improvement for the LEU entities.

Key observations support this maturity rating:

- Little information is provided on DA. Evaluate expanding DA such as reclosers, capacitor bank controls and communication fault current indicators (FCIs), and expansion of SCADA, especially with Automation Distribution Management Systems (ADMS), in the future.
- The LEU entities demonstrate a prevalent use of their GIS to automate the dissemination of information for severe weather planning and operations. For example, DESC uses its existing GIS system to aid in severe weather planning and restoration efforts. DESC is assessing its existing technology and the feasibility of implementing more comprehensive solutions. A data request is issued to further expand on detailing their roadmap for development for automation, analytics, and prediction.

Highlighted practices from the LEUs:

- Some of the LEUS entities have implemented the following:
    - Expansion of feeder automation and feeder tie transfer capability, including revised planning guidelines to enable transfer of load to adjacent feeders during interruptions.
    - Enhanced control center monitoring and visualization systems which enable faster identification of outages and crew response.
- The LEU entities generally take advantage of technology to automate (where possible) key processes in assisting their damage assessment process. For example, Duke Energy indicated it maintains a NOAA Port Satellite receiver system and computer infrastructure that receives all NWS numerical weather models, forecasts, data, satellite, and radar imagery. Duke meteorologists provide forecasts and alerts for weather that may impact transmission, distribution, and generation business units and provide resource modeling for tropical storms, windstorms, and ice storms. Duke Energy's meteorologists also send out automated extreme cold alert notifications whenever the ten (10) day hourly forecasts show a value less than less than fifteen degrees Fahrenheit (15ºF) (DEC). This is being highlighted as a leading practice in using technology to aid in automating key planning and operations processes.

Recommendations:

- Implement a more comprehensive documentation of a technology roadmap or corresponding program that governs the development efforts for assessing existing technology and the feasibility of implementing more comprehensive solutions. This can enhance automations capabilities for planning and operations in severe weather planning and restoration efforts.

Indicator 10 – Situational Awareness

Assessment:

LEADING

Maturity Score: 3.5

Situational awareness approaches and technologies enable LEU entities to have a more informed, comprehensive, and actionable preparation and response to severe weather events. They are expected to have advanced near-time weather monitoring to predict the probability and impact of severe weather events (for planning and post-event restoration). There is prevalent use of supporting software systems with accurate data collection and real-time reporting that provides actionable insights to the condition of the electric and gas systems during the preparation, response, and recovery phases of an emergency event. Situational awareness capabilities should be used to complement the LEU entity's communication plan and stakeholder engagement. From an overall assessment perspective, the LEU entities are within the **Leading** maturity level, with scores ranging from 3.4 to 3.7 and an average of score **3.5.**

Key observations support this maturity rating:

- The LEU entities reported having the foundational tools and processes for situational awareness.
    - DEP uses ABB CADOPS (7.2.12), and DEC uses Oracle Network Management System (2.3.0.2.11E); plans for upgrade are November 2022 and 2023, respectively.
    - In its June 10, 2021 filing entitled "Comments of DESC South Carolina, Inc. Regarding Certain Threats to Safe and Reliable Utility Service," Docket No. 2021-66-A, DESC adequately described various processes and procedures that support situational awareness and corresponding organizational processes.
    - Santee Cooper subscribes to numerous weather stations and prediction services that provide good awareness of impending severe weather. Santee Cooper has internal communications protocols to share information observed across their service area with other parts of the company that may be impacted by the severe weather.

Highlighted practices from the LEUs:

- Forecasting the impacts of extreme weather events is a key addition to enhancing situational awareness. As a highlight, Duke Energy is developing its Morecast tool, an in-house forecasting tool that will deliver data-driven, ten (10)-year forecasts of kilowatt-hour consumption for every circuit across Duke Energy jurisdictions (including DEC and DEP). Although focused on long-term planning horizon, this tool could also be used to aid in the operational planning. As mentioned in previous discussions, Duke Energy maintains in-house meteorological staff with real-time and short-term forecasting capabilities that provide critical situational awareness to determine when major winter cold weather or icing events are likely to impact DEC and DEP service territories, enabling storm preparedness and restoration personal, and system operators to take actions to minimize or mitigate potential impacts.

Recommendations:

- The LEU entities demonstrated the use and enablement of foundational tools and processes for situational awareness. The LEU entities need to continue to enhance capabilities to extend these situational awareness tools to use information or data for analytics (e.g., extending load forecast capabilities to aid real-time operations as an operational forecasting tool during major events).
- Incorporating predictive analytics technologies needs to be considered.
- Equivalent situational awareness systems need to further be improved for natural gas systems.

Indicator 11 – Compliance to Regulations

Assessment:

Utilities are required to adhere to federal, state, and local reliability and resilience requirements including but not limited to joint reliability plans and assessments, coordinating agreements, and wholesale purchase agreements. From an overall assessment perspective, the LEU entities are within the **Leading** maturity level, with scores ranging from 3.5 to 3.6 and an average of score **3.5.**

LEADING

Maturity Score: 3.5

Key observations support this maturity rating:

- The LEU entities are subject to extensive regulatory oversight by the state and federal government through various regulatory agencies and have demonstrated via specific references to federal and state law the adequacy and quality of service and the LEU entities' internal practices. With respect to required reliability standards, these entities depend on their respective registration as reliability entities within the NERC Reliability Functional Model.[8] NERC's Organization Registration Program identifies and registers Bulk Power System (BPS) users, owners, and operators that are responsible for performing specified reliability functions to which requirements of mandatory NERC reliability standards are applicable.[9]

- Transmission operations and planning appears to be in compliance with applicable NERC reliability standards and guidelines as outlined in prior indicator responses. Transmission planning criteria and study methods outlined in Data Request (DR) 1.36 and related to DRs appear to be NERC compliant for both short-term operational preparedness and long-term adequacy planning.
- The LEUs prepare pre-winter studies and SERC reports of transmission and bulk system readiness and issues, including transmission and generation availability and their ability to reliably supply winter peak electrical demand.

Highlighted practices from the LEUs:

- Readiness plans are coordinated with VACAR utilities, including reserve sharing agreements and assessment of inter-regional import capabilities.
- In conformance with NERC reliability standards, readiness plans have been established to address short- and long-term transmission upgrades to ensure no loading or voltage violations for system contingencies; special operating procedures have been developed to mitigate violations for facilities that are under or proposed for construction.
- Studies assessing the ability to serve high winter demand under weather and outage conditions that exceed NERC or SERC requirements are conducted by some LEUs.
- As an example of industry-leading practice, DESC utilizes a Governance Risk and Compliance (GRC) tool. The GRC is used to track recurring compliance work activities, milestones related to mitigation plans, and milestones related to implementation of new or revised standards. It sends reminders with escalation as due dates approach. SERC has recognized this as a best practice. In managing risks, DESC has implemented a risk-based compliance oversight program, which considers DESC's unique risk related to each NERC standard. A risk assessment is performed for each applicable NERC standard and includes three (3) parts.
    - First, DESC considers the impact a violation may have on grid reliability using the published NERC Violation Risk Factors.
    - Second, a predictive analysis is performed to determine the likelihood that a violation will occur. This assessment includes factors such as: the number of requirements in the standard, DESC's compliance history, industry top ten (10) most violated standards, the amount of internal coordination required, and NERC's annual risk focus areas.
    - Finally, the assessment considers the internal controls DESC has implemented associated with the standard. The stronger the controls, the more risk is mitigated.

Recommendations:

- Consider enhanced tools for business process tracking related to compliance tracking (and evidence repository) to fully mature the compliance management processes.
- Modify planning criteria beyond those outlined in NERC and SERC guidelines to include more extreme winter weather conditions, with greater variability than those using in current pre-winter and long-term planning studies.
- Conduct studies to test the vulnerability of the power system under extreme ice loading conditions, including loss of lines and equipment that exceed minimum outage criteria outlined in NERC standards (P1 though P7 contingencies).

ENDNOTES AND REFERENCES

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[1] All-time Duke Energy Carolina (DEC) peak (includes North Carolina and South Carolina) of 21,620 occurred in winter (January 5, 2018). Process is informed by System Operations prepared under NERC Project 2019-06: Cold Weather based on Federal Energy Regulatory Commission (FERC) and NERC staff report titled "The South Central United States Cold Weather Bulk Electronic System Event of January 17, 2018." Assessments identified no major line or generating unit outages or system threats identified on the DEC/Duke Energy Progress (DEP) generation and transmission systems for winter 2020.

[2] GridEx is a distributed play grid exercise that allows participants to engage remotely and simulates a cyber and physical attack on the North American electricity grid and other critical infrastructure. Led by NERC's E-ISAC, GridEx gives participants a forum to demonstrate how they would respond to and recover from coordinated cyber and physical security threats and incidents. GridEx offers opportunities for organizations to strengthen crisis communications relationships and provide feedback for lessons learned during the exercise. Additional perspectives on critical security policy issues are gathered at the invitation-only executive tabletop from senior executives in industry and government. While this exercise is not open to the public or media, NERC conducts a media briefing during the exercise (for further information, see https://www.nerc.com/pa/CI/ESISAC/Pages/GridEx.aspx).

[3] The EEI is the association that represents all U.S. investor-owned electric companies. Their members provide electricity for 220 million Americans, and operate in all 50 states and the District of Columbia. In addition to their U.S. members, EEI has more than 65 international electric companies as International Members, and hundreds of industry suppliers and related organizations as Associate Members. Organized in 1933, EEI provides public policy leadership, strategic business intelligence, and essential conferences and forums (for more information, see https://www.eei.org/about/Pages/about.aspx).

[4] Southeastern Electric Exchange is a non-profit, non-political trade association of investor-owned electric utility companies founded in 1933. Its mission include the following: (a) to promote the common interests and growth of its members, (b) to develop and enhance the human, operational and technical resources of members companies to the fullest, and (c) to provide coordination of storm restoration services to impacted member companies (for more information, see https://www.theexchange.org/aboutus.html).

[5] The American Public Power Association (APPA) is the voice of not-for-profit, community-owned utilities that power 2,000 towns and cities nationwide. They represent public power before the federal government to protect the interests of the more than 49 million people that public power utilities serve, and the 96,000 people they employ. We advocate and advise on electricity policy, technology, trends, training, and operations (for more information, see https://www.publicpower.org/about).

[6] American Public Power Association, "Public Power's Mutual Aid Network.", http://appanet.files.cms-plus.com/PDFs/Mutual%20Aid%20Playbook%20Executive%20Summary.pdf

[7] Santee Cooper Storm Center, https://stormcenter.santeecooper.com

[8] The NERC Reliability Functional Model defines the set of functions that must be performed to ensure the reliability of the BES. It also explains the relationship among the entities responsible for performing the tasks within each function. The Functional Model provides the foundation and framework upon which NERC develops and maintains its reliability standards. NERC's reliability standards establish the requirements of the responsible entities that perform the functions defined in this model (for more information, see https://www.nerc.com/pa/Stand/Pages/FunctionalModel.aspx).

[9] Requirements and activities for NERC's Organization Registration Program are embodied in Section 500 (Organization Registration and Certification) and Appendices 5A and 5B of the FERC-approved NERC Rules of Procedure (for more information on the NERC Rules of Procedure, see https://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx).

Appendix G. **Assessment and Recommendations – Large Natural Gas Utilities**

The sections below document detailed findings and recommendations related to South Carolina Large Natural Gas Utilities' (LGUs') ability to protect against and recover from extreme weather events with a specific emphasis on cold weather events. Note that all assessment findings and recommendations below are a result of tabletop reviews of information and supporting material provided by LGU respondents and interviewees and does not based on direct inspection of utility infrastructure or observations of utility personnel executing plans and practices during drills or events.

To support this assessment, ORS requested information from two (2) LGU entities:

1) Dominion Energy South Carolina (DESC)
2) Piedmont Natural Gas (PNG)

Evaluators assessed each LGU at the indicator level and assigned a maturity level to each indicator based on weighted scores ranging from zero (0) to five (5).

	Maturity Level	Maturity Score	***Maturity level and score signify:***
🟢	***ADVANCED***	4.0 or greater	Advanced components in place and positioned for emerging needs
◓	***LEADING***	from 3.0 to 3.9	Foundational components in place and forward-looking plans or practices
🔵	**FOUNDATIONAL**	from 2.0 to 2.9	Foundational components in place and current standards followed
◒	**LAGGING**	from 1.0 to 1.9	Some foundational components in place
🟡	**NASCENT**	less than 1.0	Lacking or undeveloped foundational components

SUMMARY FINDINGS AND RECOMMENDATIONS

Table G-1 provides a summary of LGU-specific findings, and corresponding recommendations for South Carolina's LGUs follow.

Table G-1. Summary Assessment Findings for LGUs

🟢 Advanced ◓ Leading 🔵 Foundational ◒ Lagging 🟡 Nascent ◌ Insufficient Data

	Indicator	Summary Evaluation	Maturity
⚠	**Indicator 1 –** Emergency Management and Planning	• Incident Command Structure (ICS) or equivalent fully integrated into the LGU entities' enterprise culture • Demonstrate use of a standardized approach to the command, control, and coordination of emergency response, providing a common hierarchy within which responders from multiple agencies can be effectively managed before, during, and after a major event	◓
?	**Indicator 2 –** Risk Management	• Comprehensive Distribution Integrity Management Plans (DIMPs) and Transmission Integrity Management Plans (TIMPs) provided • Formal programs for severe winter weather risks were, however, not identified	🔵
🤝	**Indicator 3 –** Staffing and Mutual Assistance Support	• Leading level of maturity in resource planning and acquisition for responding to large-scale emergencies • Logistics specifically defined in LGUs' ICS structure, however, unclear if resource planning and acquisition is tested in emergency drills • No information provided regarding supporting systems for crew rosters and logging gas mutual assistance • Likewise, no information provided regarding severe winter weather damage prediction models for gas distribution	◓

	Indicator	Summary Evaluation	Maturity
	Indicator 4 – Asset Management and Inspections	• Leading level of maturity in asset management practices and asset inspections to assure that critical infrastructure will properly operate during adverse weather events • Condition assessments completed for severe winter weather during periodic regulator station, main, and services inspections • Some mitigation actions completed in regulator stations, such as adding heaters and heat trace wire, however, formal programs for severe winter weather have not been provided • Specific budgets for severe winter weather programs have not been established	●
	Indicator 5 – Operational Protocols	• Leading level of maturity in implementing adverse weather operational protocols • Identify and correct conditions that may increase vulnerability to extreme cold occur through periodic inspections and patrols, annual maintenance, and monitoring through gas Supervisory Control and Data Acquisition (SCADA) • Periodic inspections and annual maintenance that assess vulnerability to extreme cold and monitor pipeline and regulator conditions through gas SCADA are not, however, substitutes for proactive operating procedures that assess conditions prior to a predicted cold weather emergency event	●

Indicator	Summary Evaluation	Maturity
Indicator 6 – System Design and Hardening	• Foundational level of maturity in investing their resources to achieve cost-effective resilience and reliability solutions, minimizing the negative impacts of climate change and extreme weather to their customers • Adequate demonstration of processes that assure the design standards consider protection of facilities to cold winter weather events (e.g., installation of additional heaters at regulator stations, protection of sensing lines, physical barricades and fences, and other physical security improvements)	●
Indicator 7 – Stakeholder Engagement	• Foundational of maturity in accurately communicating and developing a utility's resilience strategies and plans with their stakeholders • Stakeholder list documented and maintained by assigned teams • Communication plans specifically developed for individual events • Adequate use of technology for by tagging customers for restoration priority in the Customer Information System (CIS)	●
Indicator 8 – Public Communications	• Found level of maturity in fostering effective public communications of resilience information to identify resilience gaps related to climate hazards • Indications of comprehensive database of state and local government officials for the purpose of communicating in advance, during, and after a severe weather event	●
Indicator 9 – *Automation*	• *Not evaluated for natural gas utilities – not applicable for smart grid technologies.*	*Not Scored*

Indicator	Summary Evaluation	Maturity
Indicator 10 – Situational Awareness	• Foundational level of maturity in deploying situational awareness approaches and technologies to have a more informed, comprehensive, and actionable preparation and response to severe weather events • Basic use of a damage prediction models demonstrated • Continued investigation of the feasibility of more comprehensive severe weather damage prediction models	●
Indicator 11 – Compliance to Regulations	• Leading level of maturity in adhering to federal, state, or local reliability and resilience requirements • Specific references provided to assure compliance with various regulations • DIMPs and TIMPs developed by the LGU are comprehensive and well-devised	◒

Table G-2 summarizes the key recommendations for LGUs utility category. Common recommendations are summarized in the initial portion of the table.

Table G-2. Summary of Key Recommendations

Common Recommendations (*Applies to all Entities*)
• Assess feasibility of implementing more comprehensive severe weather damage predictive models to improve the emergency processes. • Define or continue to refine mutual assistance plans and look for areas of improvement. • Continue improving on the use of analytical tools and incorporate with risk management processes accordingly. • Increased engagement of stakeholders, at national and local levels. Take advantage of the social media platforms to fully incorporate with major event communication plans. • Enhance capabilities to extend situational awareness tools to use information/data for analytics. • Consider enhanced tools for business process tracking related to compliance tracking to fully mature the compliance management processes.

LGU-specific Recommendations

- Assess feasibility of implementing more comprehensive severe weather damage predictive models to improve the emergency processes. This will help strengthen well-established ICS processes.
- Continue improving on the use of analytical tools and incorporate to risk management processes accordingly. The use of analytics needs to be investigated by the entities to develop use cases in incorporating and quantifying risks.
- Continue to develop the collection and analysis of operational performance data to build better information around system vulnerabilities and improvement opportunities.
- Major LGU events requiring mutual assistance are generally far less frequent than Large investor-owned electric utility (LEU) storm events. Although the probability of a gas emergency event requiring mutual assistance is low, this capability should be periodically tested. Often, gas emergency drills or tabletop exercises tend to focus on local emergencies not requiring mutual assistance. It is recommended that the LGUs perform, on a periodic basis, an emergency drill requiring external support, including coordination with state and local emergency management agencies.
- Prediction models are used in advance of extreme weather events to estimate system impacts and required resources; this capability needs to continue to be improved to properly plan where to optimally assign mutual assistance crews (including project resource needs).
- The LGUs should evaluate black start capabilities for key purchase points and regulator stations for an extended loss of electric distribution service.
- The LGUs may also wish to consider designation of critical valves with periodic testing as a preparatory action for severe winter weather.
- As stated in the assessment, operating protocols (procedures) are not universal for the LGUs. This is area for improvement opportunities. Evaluation, documentation, and training of severe winter weather operating protocols should not be burdensome and can be accomplished in a cost-effective manner.
- The entities should consider use of a Knowledge Management System (KMS) to aid in improving training processes. These are efficient methods that could help the entities record operational procedures and could be used for training personnel, including external mutual assistance crews to get the familiarity of the local entities' standards and assets.
- If not already considered, the LGUs should develop emergency stock of equipment and parts for a severe winter weather event. This may already be covered in existing emergency stock.

LGU-specific Recommendations

- Establish a defined program for cold winter weather resilience and establish an annual budget. This could provide internal value for tracking planned and completed cold winter weather resilience actions as well as informational value to public stakeholders.
- The LGUs should consider establishing a working group with state and local emergency management agencies to communicate severe winter weather mitigation plans and engage with local stakeholders on severe weather planning.
- The LGU entities reported their respective processes in identifying key internal and external stakeholders related to major events. An improvement opportunity is to personalize a communication plan at each stage of the development of the resiliency plan so that the engagement is set earlier on and not only during the event itself.
- Customer sentiment not analyzed during major events; these could be useful information for continuous process improvement.
- Take advantage of the social media platform to fully incorporate with major event communication plans.
- As applicable, stakeholders at a national level need to be part of the communication plan. Major events are usually widespread.
- The LGU entities demonstrated the use and enablement of foundational tools and processes for situational awareness. The LGU entities need to continue to enhance capabilities to extend these situational awareness tools to use information/data for analytics (e.g., extending their load forecast capabilities to aid real-time operations as an operational forecasting tool during major events).
- LGUs should provide documentation on the process to develop the peak design day and the ability to meet this demand during a severe winter weather event.
- LGUs should consider enhanced tools for business process tracking related to compliance tracking (and evidence repository) to fully mature the compliance management processes.
- Create a task force to identify the impact of a potential interruption of natural gas supply to generators and loads during extreme cold weather events, and approaches to mitigate these impacts.
- Review recent winter weatherization standards adopted by the state of Texas for applicability to the South Carolina generation and power delivery system and incorporate those expected to enhance the reliability of the electric grid in South Carolina.

DETAILED FINDINGS BY INDICATOR

The following section provides additional details for the findings and recommendations summarized above.

Indicator 1 – Emergency Management and Planning

Assessment:

LGU entities are expected to have more than adequate emergency management planning processes with the associated organizational structures. Preparation is critical for effective response to potential ice storms and dangerous winter weather conditions. From an overall assessment perspective, the LGU entities are in the mid-range of the **Leading** maturity level, with scores ranging from 3.1 to 3.2 and an average of score **3.2.**

LEADING

Maturity Score: 3.2

Key observations support this maturity rating:

- The ICS structure or equivalent has been fully integrated into the LGU entities' enterprise culture. By using the ICS structure, they demonstrate the use of standardized approach to the command, control, and coordination of emergency response, providing a common hierarchy within which responders from multiple agencies can be effectively managed before, during, and after a major event.
- Support systems and internal and external communications are generally effective.
- LGUs perform drill and exercises on a routine schedule. Staff are properly trained for their emergency roles.

Highlighted practices from the LGUs:

- DESC conducts an annual company-wide Hurricane Season Kick-off Meeting with all executive, primary, and backup coordinators. Although titled a Hurricane Season Kick-off Meeting, the participants respond to all weather and emergency response events including winter weather.
- DESC, in its response to Data Request (DR) 1.18, indicated that it conducts a two (2) hour stress test annually to ensure that its storm systems will be available and functional during peak times. As part of the test, DESC simulates actual volumes from previous storms. All customer-facing channels (interactive voice response, web, mobile app, texting, and contact center), Oracle NMS, outage maps, and other reporting avenues are included in the testing.
- PNG Emergency Management Program Section 9.4 Exercises defines emergency exercise formats, operations-based exercises, and seven (7) pipeline exercises to be executed on an annual basis.

Recommendations:

- LGU entities need to continue to assess the performance of their existing technology and the feasibility of implementing more comprehensive severe weather damage predictive models to improve the emergency processes. This will help strengthen their well-established ICS processes and operational awareness.
- LGUs should consider severe weather emergency drills that include state and local emergency management agencies.
- Invite outside third parties to review and provide comments on the LGU entities' emergency plans.

Indicator 2 – Risk Management

Assessment:

LGU entities are expected to have more than adequate risk management processes because they systematically evaluate risks and threats through DIMPs and TIMPs. The DIMPs and TIMPs are required per regulation of the US Department of Transportation's (USDOT's) Pipeline and Hazardous Materials Safety Administration (PHMSA). The regulations require operators, such as natural gas distribution companies (LDCs), to develop and implement written integrity management programs addressing the following elements:

●

FOUNDATIONAL

Maturity Score: 2.5

- Knowledge of infrastructure
- Identification of threats
- Evaluation and prioritization of risks
- Mitigation of risks
- Measurement and monitoring of performance
- Periodic evaluation and improvement
- Reporting of threats

The DIMP and TIMP can be considered gas industry standards for the identification or threats, evaluation and prioritization of risks, and risk mitigation. Guidehouse evaluated this indicator based upon of the content contained within each LDC DIMP and TIMP and additional information provided by the LGUs. The DIMPs and TIMPs submitted by the LDCs were completed in a comprehensive manner. From an overall assessment perspective, the LGU entities are within the **Foundational** maturity level, with scores ranging from 2.1 to 2.9 and an average of score **2.5.**

Key observations support this maturity rating:

- The LGU entities provided comprehensive DIMPs and TIMPs. Natural forces risk of severe winter weather is rated low due a history of little or no severe winter weather impacts on infrastructure.

Highlighted practices from the LGUs:

- PNG uses the Integrity Compliance Activity Manager (ICAM), a process/workflow management platform that supports quality management, meets the objectives of a safety management system, and documents the execution of DIMP.
- Within its DIMP, PNG describes development of risk models for the system, segments, farm taps, and regulator stations.
- DESC Gas routinely evaluates regulating stations during annual station maintenance for conditions that would increase asset vulnerability to extreme cold (e.g., standing water around risers, weather caps missing from relief valve vents, danger trees around regulating stations). In addition to annual station maintenance, regulating stations are designed to include in-line heaters or regulator pilot heaters based on pressure cut and flow requirements.

Recommendations:

- Continue improving on the use of analytical tools and incorporate to risk management processes accordingly. The use of analytics needs to be investigated by the entities to develop use cases in incorporating and quantifying risks.
- Continue to develop the collection and analysis of operational performance data to build better information around system vulnerabilities and improvement opportunities.

Indicator 3 – Staffing and Mutual Assistance Support

Assessment:

Resource planning and acquisition is an essential element of emergency preparedness. Resource agreements should be in place and the gas utility should have reasonable estimates for the predicted damage and resources required to respond to a severe winter weather event. Both LGUs have effective plans in place to estimate resources and have resource agreements to effectively staff for severe winter weather emergencies. From an overall assessment perspective, the LGU entities are within the **Leading** maturity level, with scores ranging from 2.9 to 3.9 and an average score of **3.4.**

LEADING

Maturity Score: 3.4

Key observations support this maturity rating:

- Logistics is specifically defined in the ICS organizational structure. However, it is unclear if resource planning and acquisition is tested in emergency drills. Additionally, supporting systems for crew rosters and logging gas mutual assistance were not mentioned.
- Severe winter weather damage prediction models for gas distribution were not specifically indicated for the LGUs.

Highlighted practices from the LGUs:

- Regarding mutual aid coordination for natural gas entities, DESC is a member of a Mutual Assistance Agreement composed of members from the following gas organizations: American Gas Association (AGA), American Public Gas Association (APGA), Northeast Gas Association, Southern Gas Association (SGA), and Midwest Energy Association (MEA). This agreement allows members to request and provide emergency assistance in the form of materials, personnel, supplies or equipment, to aid DESC in restoring natural gas service when it has been disrupted and cannot be restored in a safe and timely manner by the affected company or companies alone.

Recommendations:

- Major LGU events requiring mutual assistance are generally far less frequent than LEU storm events. Although the probability of a gas emergency event requiring mutual assistance is low, this capability should be periodically tested. Often, gas emergency drills or tabletop exercises tend to focus on local emergencies not requiring mutual assistance. It is recommended that the LGUs perform, on a periodic basis, an emergency drill requiring external support, including coordination with state and local emergency management agencies.
- Prediction models are used in advance of extreme weather events to estimate system impacts and required resources; this capability needs to continue to be improved to properly plan where to optimally assign mutual assistance crews (including project resource needs).

Indicator 4 – Asset Management and Inspections

Assessment:

The entities must ensure that their asset management strategies and processes take account of asset-related risks and asset and asset system criticalities – ideally managing the preparedness of assets for extreme weather events. From an overall assessment perspective, the LGU entities are within the **Foundational** maturity level, with scores ranging from 2.5 to 3.4 and an average of score **3.0.**

FOUNDATIONAL / LEADING

Maturity Score: 3.0

Key observations support this maturity rating:

- The LGUs complete condition assessments for severe winter weather during periodic regulator station, main, and services inspections. For an LGU, completion of asset inspections, patrols, and corrective and preventative maintenance are core competencies.
- The LGU have completed some mitigation actions in regulator stations such as adding heaters and heat trace wire. However, formal programs for severe winter weather are not indicated. Additionally, specific budgets for severe winter weather programs have not been established.
- Equipment and asset damage has historically been zero or an extremely low incidence rate.

Highlighted practices from the LGUs:

- Adding heat trace applied to sensitive equipment that is exposed to icing conditions.
- DESC Gas uses its LDF (Leak, Damage, Failure) database to report and document leaks, damages, and failures by cause. The data is collected in the field and input by field personnel as part of the emergency response process. This information is used to feed the DIMP and perform trending analysis for a variety of failure parameters.

Recommendations:

- An enterprise-wide integrated enterprise asset management system with asset performance management enables investment planning and decision making.
- The LGUs should evaluate blackstart capabilities for key purchase points and regulator stations for an extended loss of electric distribution service.
- The LGUs may also wish to consider designation of critical valves with periodic testing as a preparatory action for severe winter weather.

Indicator 5 – Operational Protocols

Assessment:

Operational protocols should be used by LGUs to properly identify the preparedness, mitigation, response, and recovery actions required for abnormal and emergency events to assure company and public safety and the continued operation of gas T&D systems. Operating protocols commonly take the form of written and published operating procedures that are reviewed annually with employees. From an overall assessment perspective, the LGU entities are within the **Foundational** maturity level, with scores ranging from 2.5 to 3.5 and an average of score **3.0.**

FOUNDATIONAL / LEADING

Maturity Score: 3.0

Key observations support this maturity rating:

- Operating procedures need to be comprehensive and encompass all types of emergency response actions. Additionally, documentation should clearly define methods and procedures and ensure clearly communicate governance and protocols in place during major events. Operating procedures will be enacted through gas control or the incident commander if ICS is activated. While the LGUs complete periodic inspections and annual maintenance that assess vulnerability to extreme cold and monitor pipeline and regulator conditions through gas SCADA, they are not substitutes for proactive operating procedures that assess conditions prior to a predicted cold weather emergency event.

- Through periodic inspections and patrols, annual maintenance, and monitoring through gas SCADA, the LGUs identify and correct any conditions that would increase vulnerability to extreme cold. These actions greatly reduce impacts to gas assets during cold weather emergencies.

Highlighted practices from the LGUs:

- For natural gas supply, PNG is highlighted for working to secure additional emergency trucking agreements, which will allow them to have priority trucking rights which is commendable. PNG also has also secured access to offsite storage in both North and South Carolina in case the spot supply is insufficient.

- LGUs have completed improvements identified from previous cold weather events. For example, heat trace equipment has been applied to sensitive equipment that is exposed to icing conditions.

- LGUs have excellent contingency plans in place for back-gas SCADA and loss of telecommunications.

- Development and implementation of gas-adverse weather operating protocols is not universal.

Recommendations:

- As stated in the assessment, operating protocols (procedures) are not universal for the LGUs. This is area for improvement opportunities. Evaluation, documentation, and training of severe winter weather operating protocols should not be burdensome and can be accomplished in a cost-effective manner.

- The entities should consider use of a KMS to aid in improving training processes. These are efficient methods that could help the entities record operational procedures and could be used for training personnel, including external mutual assistance crews to get the familiarity of the local entities' standards and assets.

- If not already considered, the LGUs should develop emergency stock of equipment and parts for a severe winter weather event. This may already be covered in existing emergency stock.

Indicator 6 – System Design and Hardening

Assessment:

Through various capital improvement programs, LGUs are consistently upgrading the safety and operation of the gas distribution system. These upgrades provide risk reduction for cold winter weather and minimize negative impacts of climate change and extreme weather to their customers. From an overall assessment perspective, the LGU entities are within the **Foundational** maturity level, with scores ranging from 2.7 to 3.1 and an average of score **2.9**.

●

FOUNDATIONAL

Maturity Score: 2.9

Key observations support this maturity rating:

- LGU entities demonstrated adequate processes that assure the design standards consider protection of facilities to cold winter weather events. Examples include installation of additional heaters at regulator stations, protection of sensing lines, physical barricades and fences, and other physical security improvements.

- The entities reported complying to existing standards with regards to their construction standards and inspections related to cold weather design.

- With regards to DESC natural gas assets, the vast majority of its CAPEX budget is growth related. Occasionally these growth-related projects have a secondary system benefit such as providing a secondary tie-in to a distribution system or a partially redundant parallel pipeline. A portion of the annual CAPEX budget is set aside for system improvement work. For instance, replacement of outdated or difficult to maintain equipment (typically at regulating stations). Relating specifically to protecting against winter weather events, there are two (2) regulating stations within their service territory with plans to install heaters to prevent freezing during periods of high usage and cold weather.

Highlighted practices from the LGUs:

- Improvements identified from previous cold weather events have been made and efforts continue to harden the gas system for cold winter weather events.

Recommendations:

- Establish a defined program for cold winter weather resilience and establish an annual budget. This could provide internal value for tracking planned and completed cold winter weather resilience actions as well as informational value to public stakeholders.

Indicator 7 – Stakeholder Engagement

Assessment:

●

FOUNDATIONAL

Maturity Score: 2.0

Stakeholder engagement is critical to accurately communicating and developing a utility's resilience strategies and plans, recognizing roles and responsibilities of the community, identifying opportunities for improvement, and implementing solutions that align with stakeholder values and needs. It is expected that a diverse and comprehensive group of internal and external stakeholders are identified and engaged regularly, focused on resilience risks and opportunities, thorough, ongoing, in-depth, and timely dialogues. For example, external engagement with representatives from regulators, science, industry, and community work together to define objectives, goals, lines of responsibility, and areas for collaboration. Internal stakeholder engagement that is clearly identified embeds extreme weather resilience culture into everyday practices.

The LGU entities, on average, are within the **Foundational** maturity level, with only one (1) LGU respondent providing adequate information to demonstrate leading maturity in this capability area and the second LGU respondent providing insufficient evidence to support a conclusion. Evaluators suspect that the second LGU is likely to also have adequate to leading practices for this capability which would result in an overall average maturity level of *Leading*. However, to preserve the integrity of the overall evaluation process, Evaluators conservatively did not incorporate assumptions into assessment scoring.

Key observations support this maturity rating:

- DESC understands their stakeholders as documented in their list as maintained by their Government Affairs team. Their communication plan is intended during (and proximity) of the event only and we are proposing that DESC consider engaging key stakeholders in their resiliency planning process. Use of technology is adequately documented by tagging customers for restoration priority in their CIS.

Recommendations:

- The LGUs should consider establishing a working group with state and local emergency management agencies to communicate severe winter weather mitigation plans and engage with local stakeholders on severe weather planning.
- The LGUs should consider including state and local emergency management agencies in tabletop exercised and gas emergency drills.
- The LGU entities reported their respective processes in identifying key internal and external stakeholders related to major events. An improvement opportunity is to personalize a communication plan at each stage of the development of the resiliency plan so that the engagement is set earlier on and not only during the event itself.
- Customer sentiment not analyzed during major events; these could be useful information for continuous process improvement.

Indicator 8 – Public Communications

Assessment:

Public communications go together with stakeholder engagement. Effective communication of resilience information by utilities helps to foster transparency in resilience gaps related to climate hazards, raise industry and community awareness of the activities that are either planned or currently in use to close those gaps, and disseminates effective resilience strategy guidance to close those gaps within the industry and across the nation.

●

FOUNDATIONAL

Maturity Score: 2.0

The LGU entities, on average, are within the **Foundational** maturity level, with only one (1) LGU respondent providing adequate information to demonstrate leading maturity in this capability area and the second LGU respondent providing insufficient evidence to support a conclusion. Evaluators suspect that the second LGU is likely to also have adequate to leading practices for this capability which would result in an overall average maturity level of *Leading*. However, to preserve the integrity of the overall evaluation process, Evaluators conservatively did not incorporate assumptions into assessment scoring.

Key observations support this maturity rating:

- DESC stated that its Government Affairs team maintains a database of more than 750 state and local government officials for the purpose of communicating in advance, during, and after a severe weather event. In accordance with the DESC storm plan, Government Affairs is prepared to communicate via text, phone call, and email at one (1) time via its emergency notification system. In addition to Government Affairs having a Section Chief in the emergency operations center, it has local managers assigned to geographic areas to serve as a liaison between operations and local governments. Guidehouse assumed that DESC has convened the necessary governance structure to support the communications strategy specific to their list of stakeholders.

Highlighted practices from the LGUs:

- DESC government affairs database and associated communications protocols.

Recommendations:

- Take advantage of the social media platform to fully incorporate with major event communication plans.
- As applicable, stakeholders at a national level need to be part of the communication plan. Major events are usually widespread.

Indicator 9 – Automation

Assessment:

Not evaluated for gas distribution utilities. System Automation is not used to evaluate the capability maturity of gas distribution infrastructure.

Indicator 10 – Situational Awareness

Assessment:

FOUNDATIONAL

Maturity Score: 2.7

Situational awareness approaches and technologies enable LGU entities to have a more informed, comprehensive, and actionable preparation and response to severe weather events. They are expected to have in place advanced near-time weather monitoring to predict the probability and impact of severe weather events (for planning and post-event restoration). Prevalent use of supporting software systems with accurate data collection and real-time reporting that provides actionable insights to the condition of the electric and gas systems during the preparation, response, and recovery phases of an emergency event. Situational awareness capabilities should be used to complement the LGU entity's communication plan and stakeholder engagement.

From an overall assessment perspective, the LGU entities are within the **Foundational** maturity level, with scores ranging from 2.0 to 3.4 and an average score of **2.7**. Compared to the other indicators for the maturity assessment, situational awareness has greater opportunity for improvement for the LGU entities, mainly driven by current technology use and enablement.

Key observations support this maturity rating:

- PNG maintains in-house meteorological staff with real-time and short-term forecasting capabilities that provide critical situational awareness to determine when major winter cold weather or icing events are likely to occur, enabling storm preparedness and restoration personal, and system operators to take actions to minimize or mitigate potential impacts.
- In its response to DR 1.01 indicated in its June 10, 2021 filing entitled "Comments of Dominion Energy South Carolina, Inc. Regarding Certain Threats to Safe and Reliable Utility Service," Docket No. 2021-66-A, DESC adequately described various processes and procedures that support situational awareness and corresponding organizational processes.

Highlighted practices from the LGUs:

- DESC use of a damage prediction model and investigating the feasibility of a more comprehensive severe weather damage prediction model.

Recommendations:

- The LGU entities demonstrated the use and enablement of foundational tools and processes for situational awareness. The LGU entities need to continue to enhance capabilities to extend these situational awareness tools to use information/data for analytics (e.g., extending their load forecast capabilities to aid real-time operations as an operational forecasting tool during major events).
- Situational awareness systems need to be further improved for LGUs.

Indicator 11 – Compliance to Regulations

Assessment:

The Pipeline Hazardous Material Safety Administration (PHMSA) published the final rule establishing integrity management requirements for gas distribution pipeline systems on December 4, 2009 (74 FR 63906). The effective date of the rule was February 12, 2010, resulting in integrity management regulations for gas distribution pipelines (49 CFR Part 192, Subpart P). Operators were given until August 2, 2011 to write and implement their DIMPs. The gas distribution integrity management regulations require operators, such as natural gas distribution companies, to develop, write, and implement an integrity management program with the following elements:

◒

LEADING

Maturity Score: 3.4

- Understand system design and material characteristics, operating conditions and environment, and maintenance and operating history
- Identify existing and potential threats
- Evaluate and rank risks
- Identify and implement measures to address risks
- Measure IM program performance, monitor results, and evaluate effectiveness
- Periodically assess and improve the IM program
- Report performance results to PHMSA and, where applicable, also to states

From an overall assessment perspective, the LGU entities are within the **Leading** maturity level, with scores of 3.4 for utilities assessed and an average score of **3.4**.

Key observations support this maturity rating:

- LGUs are subject to extensive regulatory oversight by the state and federal government through various regulatory agencies. The LGUs provide specific references that assure compliance with these various regulations. The DIMPs and TIMPs developed by the LGU are comprehensive and well-devised.
- Specific to this indicator are federal pipeline laws and Chapter 103, Public Service Commission, Article 4, Gas Systems. Section 103-463. Adequacy of Service states, “The source of supply and transmission facilities for gas, and/or production and/or storage capacity of the gas utility's plant, supplemented by the gas supply regularly available from other sources, must, to the extent reasonably practicable, be sufficiently large to meet all reasonably expectable demands for firm service, unless otherwise authorized by the commission.” This indicator considers any information by the respondents on supply adequacy for the peak design day and actions to monitor and sustain natural gas supply in the event of a sustained electrical outage.

Highlighted practices from the LGUs:

- PNG has incorporated the use of an internally developed algorithm to support the evaluation of the risk per threat. The algorithm is configured to use leak repair data and weight factors that affect both the probability of failure and the consequence of each failure. Weight factors were established by a group of SMEs and are evaluated as part of the annual risk model methodology review. The single reference to adverse weather risk in the document is within the regulator station risk model which contains a reference to pipe icing.

Recommendations:

- LGUs should provide documentation on the process to develop the peak design day and the ability to meet this demand during a severe winter weather event.
- LGUs should consider enhanced tools for business process tracking related to compliance tracking (and evidence repository) to fully mature the compliance management processes.

Appendix H. Assessment and Recommendations – Small Electric Utilities

The sections below document detailed findings and recommendations related to South Carolina Small Electric Utilities' (SEUs') ability to protect against and recover from extreme weather events with a specific emphasis on cold weather events. Note that all assessment findings and recommendations below are a result of tabletop reviews of information and supporting material provided by SEU respondents and interviewees and is not based on direct inspection of utility infrastructure or observations of utility personnel executing plans and practices during drills or events.

To support this assessment, ORS requested information from six (6) SEU entities:

1) Central Electric Power Cooperative
2) Electric Cooperatives of South Carolina, Inc. (ECSC) (responding for eighteen (18) electric cooperatives)
3) Lockhart Power Company (Lockhart)
4) Marlboro and Pee Dee Electric Cooperatives
5) Piedmont Municipal Power Agency (PMPA) (responding for ten (10) municipal dept/divisions)
6) South Carolina Association of Municipal Power Systems (SCAMPS) (responding for eleven (11) Commission/Board of Public Works)

Evaluators assessed each SEU at the indicator level and assigned a maturity level to each indicator based on weighted scores ranging from zero (0) to five (5).

	Maturity Level	Maturity Score	*Maturity level and score Signify:*
🟢	***ADVANCED***	4.0 or greater	Advanced components in place and positioned for emerging needs
◓	***LEADING***	from 3.0 to 3.9	Foundational components in place and forward-looking plans or practices
🔵	**FOUNDATIONAL**	from 2.0 to 2.9	Foundational components in place and current standards followed
◒	**LAGGING**	from 1.0 to 1.9	Some foundational components in place
🟡	**NASCENT**	less than 1.0	Lacking or undeveloped foundational components

SUMMARY FINDINGS AND RECOMMENDATIONS

Table H-1 provides a summary of SEU-specific findings.

Table H-1. Summary Assessment Findings for SEUs

🟢 Advanced	◓ Leading	● Foundational	◒ Lagging	🟡 Nascent	◌ Insufficient Data

Indicator		Summary Evaluation	Maturity
⚠	**Indicator 1 –** Emergency Management and Planning	• Foundational level of maturity in emergency management planning and preparation • Level of detail and specific information provided by the SEUs and their support organizations varied significantly, and the resulting assessment ratings reflect an average value for the SEUs collectively while individual assessments may have scored higher or much lower than the average – specifically those entities that submitted little information for review • Mutual assistance arrangements well-defined • Most SEUs reported monitoring a number of weather services during incoming storm events	●

	Indicator	Summary Evaluation	Maturity
?	**Indicator 2** – Risk Management	• Not all SEUs appear to use ice storm prediction tools and should investigate additional technology to assist with providing better ice storm damage predictions and to help manage resources during the restoration process more efficiently • Foundational level of maturity in developing infrastructure risk management • All SEUs appear to conduct some basic level risk assessment activities (e.g., identifying critical medical customers on their systems, identifying critical customers such as hospitals and sewage treatment facilities, etc.) • No SEU submitted a copy of a vulnerability and risk assessment (VRA) to illustrate the level to which cold weather is taken into consideration • Other than a U.S. Department of Agriculture Rural Utilities Service bulletin, no SEU provided documentation relating to requirements or guidelines for conducting a VRA • Unclear to what extent SEUs conducted formal vulnerability and risk assessments on their system (be it for extreme cold weather events or any outage events in general)	●
🤝	**Indicator 3** – Staffing and Mutual Assistance Support	• Foundational level of maturity in resource planning and acquisition for responding to large-scale emergencies • Reported use of mutual assistance as a part of overall emergency response plans • ECSC and SCAMPS provide coordination services for their members to access additional resources during emergency events	●

Indicator	Summary Evaluation	Maturity
Indicator 4 – Asset Management and Inspections	• Lagging maturity in asset management practices and asset inspections relating to proper operation of critical infrastructure during adverse weather events • Various types of traditional, calendar-based inspection programs implemented, including pole inspections and replacement, visual line patrols, infrared switches, substation relay testing, transformer oil sampling, and inspections • No information provided regarding use of formal asset management software or non-calendar-based approaches • Several SEUs reporting use of Geographic Information System (GIS) for storing inspection records	◕
Indicator 5 – Operational Protocols	• Foundational level of maturity in implementing adverse weather operational protocols • Cold weather checklists presented • Storm preparation procedures identified, however, no specific operating procedures for cold weather events noted	●
Indicator 6 – System Design and Hardening	• Lagging level of maturity in investing their resources to achieve cost-effective resilience and reliability solutions, minimizing the negative impacts of climate change and extreme weather to their customers • National Electrical Safety Code (NESC) Medium Loading for design criteria with Grade C and Grade B construction levels are being followed by the SEUs, which is appropriate for South Carolina conditions • Standard vegetation management practices (e.g., tree trimming) were identified by all SEUs • Several SEUs are building their systems to withstand higher levels of voltage surges, with one (1) SEU planning for all new construction underground to increase storm hardening	◕

	Indicator	Summary Evaluation	Maturity
	Indicator 7 – Stakeholder Engagement	• Lagging level of maturity in accurately communicating and developing a utility's resilience strategies and plans with their stakeholders • Little information related to key customer identification or community leader engagement to support communication plan development and is an area of opportunity for improvement SEU improvement	◒
	Indicator 8 – Public Communications	• Foundational level of maturity in fostering effective public communications of resilience information to identify resilience gaps related to climate hazards • Communication plan and using traditional channels as well as social media, the two (2) areas lacking were in using technology and data analytics to measure the effectiveness of the communications • Little reference made to estimations and communication of outage restoration times during events • No reference made to SEU communication of resiliency plans to the public or solicitation of feedback	●

	Indicator	Summary Evaluation	Maturity
	Indicator 9 – Automation	• Lagging level of maturity in the use of automation and information available from the deployment of smart grid technologies • Level of automation reported varied across the SEUs from none to a fairly robust approach for several • Most SEUs reported extensive Advanced Metering Infrastructure (AMI) and Supervisory Control and Data Acquisition (SCADA) deployments, and several were down the road with advanced distribution management applications • The amount of distribution automation (DA) that can be justified will vary across SEUs depending their size and operating characteristics	◕
	Indicator 10 – Situational Awareness	• Lagging level of maturity in deploying situational awareness approaches and technologies to have a more informed, comprehensive, and actionable preparation and response to severe weather events • Weather service monitoring during an incoming storm event and use of damage prediction tools was noted by some but not all SEUs • No evidence of analytical tools, such as storm damage and restoration tracking dashboards being used however some noted use of SCADA and AMI for situational awareness	◕
	Indicator 11 – Compliance to Regulations	• Electric cooperatives required to comply with some reporting/audit requirements to receive U.S. Department of Agriculture (USDA) Rural Utility Service (RUS) funding, however RUS, does not impose any operational or performance requirements • Those entities under jurisdiction of city government (municipal electric utilities) made no mention of specific reliability compliance requirements	●

Table H-2 summarizes the key recommendations for SEUs utility category. Common recommendations are summarized in the initial portion of the table.

Table H-2. Summary of Key Recommendations

Common Recommendations *(Applies to all Entities)*
• Assess feasibility of implementing more comprehensive severe weather damage predictive models to improve the emergency processes.
• Define or continue to refine mutual assistance plans and look for areas of improvement.
• Continue improving on the use of analytical tools and incorporate with risk management processes accordingly.
• Increased engagement of stakeholders, at national and local levels. Take advantage of the social media platform to fully incorporate with major event communication plans.
• Enhance capabilities to extend situational awareness tools to use information/data for analytics.
• Consider enhanced tools for business process tracking related to compliance tracking to fully mature the compliance management processes.

SEU-specific Recommendations
• While all the SEUs are building to the recommended NESC loading levels for South Carolina, the SEUs should consider adopting the higher level of loading for added resiliency. This would involve adopting Grade B construction as the minimum for all new construction work. Grade B construction is 'sturdier' and allows for twice the ice buildup on the lines versus Grade C. One (1) SEU stated they were already building to Grade B and several others gave examples of where additional hardening measures were being taken.
• Invite outside third parties, governmental agencies, and key customers to review and provide feedback on the Emergency Response Plan (ERP).
• Look for ways to improve collection of mutual assistance crews and storm damage assessment information and digitally add it to the outage management system to reduce manual processing.
• Ensure a minimally detailed ERP, including communications plans and backup contingency plans for critical facilities and infrastructure, are documented, employees are trained, and the plan is exercised at least once a year.

SEU-specific Recommendations

- Not all SEUs appear to use ice storm prediction tools. Investigate additional technology to assist with providing better ice storm damage predictions and to help manage resources during the restoration process more efficiently.
- Track restoration reliability metrics for all outages events to gain insight into the effectiveness of the response plan and to identify areas of opportunities to reduce damage from future storm events.
- All SEUs should perform some basic level of risk management assessment for extreme winter events, document the results, and identify mitigation strategies, where appropriate. The assessment should cover the physical assets in the field and infrastructure such as control center facilities and IT systems used to manage restoration.
- Identify assets that are critical to the operation of your system and develop mitigation plans. Also identify critical customer loads, such as wastewater treatments plants, hospital and medical facilities, public safety facilities or community shelters and develop plans to prioritize restoration or reduce vulnerability to an outage.
- Investigate predictive methodologies and procedures to anticipate resource requirements for major winter events as early as possible.
- Continue to refine mutual assistance plans and look for areas of improvement.
- If not done already, document, formalize, and train on mutual assistance policies and procedures to ensure smooth execution when needed.
- Proactively arrange with local hotels for potential number of rooms and restaurants for serving capacity in the mutual assistance part of the emergency response plan.
- Identify critical assets on the distribution system and develop asset management programs around them, to include cold weather performance, along with the appropriate systems to effectively monitor and manage the data.
- Review standard operating procedures to incorporate any specific cold weather procedures as appropriate.
- Most SEUs mentioned some form of grid hardening is taking place, such as fiberglass crossarms, selective undergrounding and relocation of lines to be more accessible, to name just a few. Continue to evaluate and implement additional grid hardening measures as appropriate.
- Engage vendors to evaluate material specification around withstanding cold weather and extreme ice conditions.

SEU-specific Recommendations

- Investigate additional DA technology for equipment that can provide resiliency to the distribution grids.
- Investigate incorporating Distributed Energy Resource (DER) or microgrid technology to harden the grid where appropriate.
- Not all SEUs tracked outage restoration metrics. These metrics should be tracked to help identify problem areas on the system where grid hardening may be beneficial.
- Formalize a public communications plan to educate the public on the emergency response plan.
- Develop materials to include in the communication plan around resiliency strategies the SEUs are taking as well as strategies customers can embrace for their benefit.
- Develop metrics to measure the effectiveness of the communications plan.
- The benefits of automation may be limited due to the smaller sizes of some of the SEU; however, added automation should be investigated and prioritized for those applications that will bring the most benefit.
- Expanding SCADA, adding communicating fault detectors, and enabling AMI for outage restoration can provide increased visibility and crew efficiencies.
- Investigate additional weather impact tools that might be available, particularly ones that can identify areas of vulnerability on the grid to various weather perils.
- Evaluate expanding the use of SCADA to all substations and communicating field devices such as faulted circuit indicators or reclosers. Consider integrating SCADA into the Operations Management System (OMS) where available to improve operator efficiency.
- If available, evaluate the AMI outage notification and restoration functionality and integrate into the OMS. Additional AMI functionality may be used for power quality monitoring as well.
- Work with municipals and electric cooperatives to define generally accepted operational and design guidelines specific to preparing for and responding to unexpected extreme winter weather events.

DETAILED FINDINGS BY INDICATOR

The following section provides additional details for the findings and recommendations summarized above.

Indicator 1 – Emergency Management and Planning

Assessment:

Even though they may be smaller in size, emergency management and planning for severe winter weather is no less important than it is at the Large Electric Utilities (LEUs). For the SEUs, the level of detail provided regarding their emergency response plans varied, with the electric cooperative organizations providing the most detail regarding their plans. Because of the variability of the information provided, the maturity levels for the SEUs ranged from 1.1 to 3.4, with an average score of **2.4** and a maturity level of **Foundational.**

● **FOUNDATIONAL**

Maturity Score: 2.4

Key observations support this maturity rating:

- The cooperatives provided more detail and received a higher assessment rating. The municipals received a lower rating because they provided little specific information for this area and other areas covered by the maturity assessment.
- Cooperatives are mandated by the USDA RUS Bulletin 1730B-2, *Guide for Electric System Emergency Restoration Plan* to prepare and certify that they have an ERP in place. All cooperatives were in compliance.
- It is implied that municipals may have some level of a formal ERP, but a plan was not specifically mentioned or provided in the documentation. Reference was made to load shedding when experiencing supply issues and identifying critical customers for prioritization for restoration.
- Mutual assistance arrangements are well defined for both for the SEUs. ECSC coordinates mutual assistance for all member cooperatives to restore power when disasters strike, including hurricanes, ice storms, tornados, and other extreme weather events. ECSC also maintains a mutual aid agreement with cooperatives in other states through the National Rural Electric Cooperative Association and other local contractors. SCAMPS coordinates for its members and uses a three (3) tier approach beginning with its local in-state members, then regional resources and up to national resources through the American Public Power Association’s (APPA) national mutual aid network.

Highlighted practices from the SEUs:

- RUS requires member cooperatives to create and certify that an ERP is in place to maintain the ability to borrow money. All are in compliance.
- RUS provides guidelines to the cooperatives on what should be covered in the ERP, but it is up to the individual cooperative to create their plan.

- Incident Command Structure (ICS) is used in some form among the cooperatives. Electric municipals are typically a department within the municipality and participate within the municipality's ICS rather than having their own individual ICS.
- Most SEU entities made mention of monitoring a number of weather services during incoming storm events. Cooperatives mentioned its members have access to the Sperry–Piltz Ice Accumulation Index (SPIA) for ice storms. The SPIA Index is a predictive ice accumulation and ice damage index. It has a long record of accurately predicting the duration, intensity, and damage capability of approaching ice storms.
- Cooperatives are required to exercise their ERP annually by RUS. Period audits have confirmed they are in compliance.
- Some of the SEU entities, but not clear if all do, work with national companies Cooperative Response Center, Inc. and CallNet, which can handle customer calls in an emergency from call centers in Indiana, Tennessee, Texas, and Minnesota.

Recommendations:

Responding to a severe cold weather event such as an ice storm is similar to any other type of major event in terms of preparation and execution of restoration efforts. Having a plan is key, although the level required in each plan may vary due to the size and complexity of the individual SEU.

- Invite outside third parties, governmental agencies, and key customers to review and provide feedback on the ERP.
- Look for ways to improve collection of mutual assistance crews and storm damage assessment information and digitally add it to the outage management system to reduce manual processing.
- Ensure a minimally detailed ERP, including communications plans and backup contingency plans for critical facilities and infrastructure, are documented, employees are trained, and the plan is exercised at least once a year.
- Not all SEUs appear to use ice storm prediction tools. Investigate additional technology to assist with providing better ice storm damage predictions and to help manage resources during the restoration process more efficiently.
- Track restoration reliability metrics for all outages events to gain insight into the effectiveness of the response plan and to identify areas of opportunities to reduce damage from future storm events.

Indicator 2 – Risk Management

Assessment:

Risk management plans should be developed around critical infrastructure so mitigation plans and investment strategies can be developed to minimize the impact from severe winter storm events. For the SEU in this assessment, one (1) of their main risks is the loss of supply feeds from their generation and transmission providers. This risk assessment, however, is focused on the distribution systems for the SEU municipalities and cooperatives.

FOUNDATIONAL

Maturity Score: 2.1

From an overall assessment perspective, the SEU entities are within the **Foundational** maturity level, with scores ranging from 0.5 to 3.5 and an average score of **2.1.**

There was a wide range in the level of risk assessment reportedly performed across the SEUs.

Key observations support this maturity rating:

- For the cooperatives, the RUS Bulletin 1730B-2 requires a vulnerability risk assessment (VRA) be prepared by each cooperative. They give no guidelines on how this assessment is to be performed, but like the mandated ERP, certification needs to be provided that a VRA has been completed. All cooperatives were confirmed to be in compliance with having a VRS on file.

- No SEU provided a copy of a VRA to assess the level to which cold weather was taken into consideration.

- All SEUs appear to do some basic level of risk assessment from identifying critical medical customers on their systems to identifying critical customers such as hospitals and sewage treatment facilities. One (1) SEU reported they had no critical facilities.

- Other than the RUS bulletin, no SEU provided any documentation around requirements or guidelines to conduct a VRA. It is not clear to what extent all the SEU entities conducted a formal vulnerability and risk assessment on their system be it for extreme cold weather events or any outage event in general.

Highlighted practices from the SEUs:

- The RUS bulletin referenced by the cooperatives is the only formal requirement mentioned by the SEUs.

Recommendations:

- All SEUs should perform some basic level of risk management assessment for extreme winter events, document the results, and identify mitigation strategies, where appropriate. The assessment should cover the physical assets in the field and infrastructure such as control center facilities and IT systems used to manage restoration.

- Identify assets that are critical to the operation of your system and develop mitigation plans. Also identify critical customer loads, such as wastewater treatments plants, hospital and medical facilities, public safety facilities or community shelters and develop plans to prioritize restoration or reduce vulnerability to an outage.

Indicator 3 – Staffing and Mutual Assistance Support

Assessment:

From time to time, SEU entities will incur more damage from a storm that they can expect to fix in a timely fashion with their own staff and will require outside resources to help with the restoration effort. Utilities address these resource constraints through mutual aid programs that allow companies to share resources during emergency events. This concept of mutual assistance is foundational to utilities ability to maintain reliable service to their customers.

●

FOUNDATIONAL

Maturity Score: 2.6

From an overall assessment perspective, the SEU entities are within the **Foundational** maturity level, with scores ranging from 1.5 to 3.8 and an average of score **2.6**.

Key observations support this maturity rating:

- All SEU entities reported using mutual assistance as a part of their overall emergency response plans.
- The ECSC and SCAMPS organizations provide coordination services for their members to access additional resources during emergency events. These resources start with other members of the organization, to local contractors, out of state/regional resources and to a national reach through organizations such as the APPA.

Recommendations:

- Investigate predictive methodologies and procedures to anticipate resource requirements for major winter events as early as possible.
- Continue to refine mutual assistance plans and look for areas of improvement.
- If not done already, document, formalize, and train on mutual assistance policies and procedures to ensure smooth execution when needed.
- Proactively arrange with local hotels for potential number of rooms and restaurants for serving capacity in the mutual assistance part of the emergency response plan.

Indicator 4 – Asset Management and Inspections

Assessment:

Asset management practices can vary from basic reactionary break/fix, to calendar-based inspections and maintenance, to sophisticated predictive and condition based analytical approaches. The level of data and tools required for each level also increase in sophistication as your approach reaches the later end of the spectrum. The asset management approach a utility uses is driven by a number of factors, including the associated risk or impact from an extreme winter weather event and the criticality of the loads being served.

◒

LAGGING

Maturity Score: 1.6

From an overall assessment perspective, the SEU entities are at the **Lagging** maturity level, with scores ranging from 0.7 to 2.0 and an average of score **1.6**.

Key observations support this maturity rating:

- The SEU entities all perform various types of traditional, calendar-based inspection programs that include pole inspections and replacement, visual line patrols, infrared switched, substation relay testing, transformer oil sampling, and inspections.
- No SEU reported any asset management activities particularly related to extreme weather events.
- No SEU mentioned using any formal asset management software or non-calendar-based approach. Several SEUs are reported to use their GIS to store inspection records.

Highlighted practices from the SEUs:

- One (1) SEU mentioned using drones for line patrols and inspections.

Recommendations:

- Identify critical assets on the distribution system and develop asset management programs around them, to include cold weather performance, along with the appropriate systems to effectively monitor and manage the data.

Indicator 5 – Operational Protocols

Assessment:

The SEU entities must ensure they have documented operating procedures and that all necessary employees are trained on them to ensure a safe work environment. Operating procedures should take into account the impacts of extreme cold weather.

From an overall assessment perspective, the SEU entities are within the **Foundational** maturity level, with scores ranging from 1.1 to 3.6 and with average of score **2.2**.

●

FOUNDATIONAL

Maturity Score: 2.2

Key observations support this maturity rating:

- Operating procedures appear to be standard for all types of outage events.
- Several SEUs presented cold weather checklists and mention activities to do in order to prepare for incoming storms, but no specific operating procedures for cold weather events were identified.

Highlighted practices from the SEUs:

- Information and documentation on operating procedures was limited. The procedures that were mentioned were standard procedures in the utility industry.

Recommendations:

- Review standard operating procedures to incorporate any specific cold weather procedures as appropriate.

Indicator 6 – System Design and Hardening

Assessment:

System hardening activities varied across the SEU entities. Several mentioned multiple techniques being used while others mentioned none. The one (1) thing what was consistent across all the SEUs is that they all follow the NESC guidelines for Medium Loading zone, which is the recommended loading zone for South Carolina.

From an overall assessment perspective, the SEU entities are on the low end of the **Lagging** maturity level, with the scores ranging from 0.5 to 2.7 and an average of score **1.7**.

◓

LAGGING

Maturity Score: 1.7

Key observations support this maturity rating:

- The NESC Medium Loading design criteria is being followed by the SEUs, which is appropriate for South Carolina. This results in Grade C construction for most overhead lines with Grade B being used for special situations, such as railroad and highway crossings.
- Several SEUs go beyond the prescribed construction grades in instances where it is warranted due to susceptibility to damage or difficulty in accessing for repairs.
- Several SEUs reported system hardening practices being used such as performing regular circuit contingency analysis for loading and making adjustments as needed, selective undergrounding, fiberglass crossarms, shorter wire spans between poles, increasing the insulating levels on new poles, adding overhead emergency ties for switching and backfeeding, moving three (3) phase lines closer to the road for easier access, replacing copper overhead conductor with Aluminum Conductor Steel-Reinforced Cable (ACSR) aluminum and using SCADA for increased situational awareness and remote control capabilities.
- All SEUs mentioned following standard vegetation management (e.g., tree trimming) practices, with one (1) mentioning a specific trimming strategy so ice laden trees fall away from the power lines.
- The use of DA devices varied greatly across the SEUs. Most reported have some level of SCADA installed in some substations and most reported having AMI in place. For more advanced DA, the responses varied from reporting that they use no automation to having a very robust DA program.

Highlighted practices from the SEUs:

- Several SEUs specifically mentioned doing circuit load analysis based on winter peaks temperatures.
- One (1) SEU has a program to replace weaker Class 5 wooden poles with stronger Class 1 wooden poles.
- One (1) SEU noted already building to Grade B construction on new distribution lines.
- Undergrounding is being used as a hardening practice by one (1) SEU.

Recommendations:

- While all the SEUs are building to the recommended NESC loading levels for South Carolina, the SEUs should consider adopting the higher level of loading for added resiliency. This would involve adopting Grade B construction as the minimum for all new construction work. Grade B construction is 'sturdier' and allows for twice the ice buildup on the lines versus Grade C.

- Continue to evaluate and implement additional grid hardening measures as appropriate.
- Engage vendors to evaluate material specification around withstanding cold weather and extreme ice conditions.
- Investigate additional DA technology for equipment that can provide resiliency to the distribution grids.
- Investigate incorporating DER or microgrid technology to harden the grid where appropriate.
- Not all SEUs tracked outage restoration metrics. These metrics should be tracked to help identify problem areas on the system where grid hardening may be beneficial.

Indicator 7 – Stakeholder Engagement

Assessment:

Engaging key stakeholders in the on-going development of any resiliency plans is key to gaining buy-in and support. Key stakeholders can be both internal and external, encompassing employees, emergency service organizations and key customers of the utility. Regular communication with these groups builds support and understanding to implement resiliency strategies that address extreme winter weather events.

LAGGING

Maturity Score: 1.7

From an overall assessment perspective, the SEU entities are in the **Lagging** maturity level, with scores ranging from 0.5 to 2.4 and an average of score **1.7**.

Key observations support this maturity rating:

- While the SEU entities will have contact with customers, local, state, and federal emergency management entities during a storm, little information was provided regarding the level of engagement the SEU entities take to solicit input and educate stakeholders on their resiliency plans.

Recommendations:

- Identify key community leaders and key customers and engage these groups for input and educational opportunities on developing a grid resiliency plan.
- Continue to engage local, state, and federal emergency management groups to identify strategies to address extreme cold weather plans and incorporate into the individual SEU plans.

Indicator 8 – Public Communications

Assessment:

Communications with the public and key stakeholders is as critical as the execution on the emergency response plan itself during a major event. Customers want to have information about the restoration efforts and estimated restoration times following a major weather event. Effective communication of resilience information by utilities helps to foster transparency and builds trusting relationships with customers and other key stakeholders when it is needed the most.

FOUNDATIONAL

Maturity Score: 2.1

From an overall assessment perspective, the SEU entities are within the **Foundational** maturity level, with scores ranging from 1.7 to 2.5 and an average score of **2.1**.

Key observations support this maturity rating:

- Most SEU entities have formal communications protocol as far as who is responsible for external communications during an extreme weather event, and use traditional channels such as TV, radio, newspapers and social media, website, and texting.
- No information was provided pertaining to the SEU entities efforts to communicate with the public about their emergency response or resiliency plans on an ongoing basis.

Highlighted practices from the SEUs:

- Public communications plans are traditional in nature, mostly communication restoration status to customers and emergency agencies involved.

Recommendations:

- Formalize a public communications plan to educate the public on the emergency response plan.
- Develop materials to include in the communication plan around resiliency strategies the SEUs are taking as well as strategies customers can embrace for their benefit.
- Develop metrics to measure the effectiveness of the communications plan.

Indicator 9 – Automation

Assessment:

Automation of the distribution grid improves situational awareness and enables faster control and response on the grid during extreme weather events. Reponses in this area were limited and varied across the utilities. Most mentioned having some level SCADA and extensive AMI implemented. Some mentioned having no automation deployed while only a few mentioned having more robust and extensive DA programs in place.

◒

LAGGING

Maturity Score: 1.4

From an overall assessment perspective, the SEU entities are in the **Lagging** maturity level, with scores ranging from 0.5 to 4.3 and an average score of **1.4**.

Key observations support this maturity rating:

- The level of DA varies greatly across the SEUs from 'none' to very robust deployment of DA devices on their system.
- All SEUs utilize SCADA to varying degrees for operation, control and data gathering on their distribution systems.
- Several SEUs provided information about the types of devices on the distribution grid being controlled or monitored by SCADA.
- All SEUs are using AMI or will soon be implementing an AMI module to their OMS.
- Several SEU notes use of voltage and volt-amp reactive (volt/VAR) controls to manage loads.
- Several SEU made mention of a DMS with advanced applications for grid control being implemented in the next several years.

Highlighted practices from the SEUs:

- One (1) SEU has a pilot to evaluate and deploy a cellular-based communication node with light fixtures throughout the electric service territory. These nodes provide outage & power quality data remotely so that the City can respond without in-person night surveys or reliance on the public to call to report problems. The City is also evaluating this product for remote turn-on/turn-off of City security lights as customer open & close accounts.
- This same SEU is installing traffic signal UPS systems on major roadway corridors throughout the City. These systems communicate through their SCADA system to notify personnel if a traffic signal has lost its primary power source. In the event of power loss, the traffic signal system will automatically switch to its backup power supply until such time as its primary power source is restored. This is a tremendous safety improvement for the traveling public and emergency respondents.

Recommendations:

- The benefits of automation may be limited due to the smaller sizes of some of the SEU, however, added automation should be investigated and prioritized for those applications that will bring the most benefit.

- Expanding SCADA, adding communicating fault detectors, and enabling AMI for outage restoration can provide increased visibility and crew efficiencies.

Indicator 10 – Situational Awareness

Assessment:

As mentioned in Indicator 9, expanded automation can provide additional situational awareness. Early warning of incoming severe weather also provides enhanced awareness that enables utilities the opportunity to prepare resources and material in advance of the event.

From an overall assessment perspective, the SEU entities are in the **Lagging** maturity level, with scores ranging from 1.0 to 2.5 and an average score of **2.0**.

FOUNDATIONAL / LAGGING

Maturity Score: 2.0

Key observations support this maturity rating:

- Most SEU entities mentioned the use of several weather services that provide information and analysis regarding pending weather events, including cold weather.

- Cooperatives have access to the SPIA for ice storms. The SPIA Index is a predictive ice accumulation and ice damage index tool.

- All SEU entities mention the use of SCADA, and AMI is generally fully deployed, which enhances real-time situational awareness.

Highlighted practices from the SEUs:

- Tools being used such as SCADA, AMI and monitoring of weather services during major events are baseline tools for situational awareness (SA).

Recommendations:

- Investigate additional weather impact tools that might be available, particularly ones that can identify areas of vulnerability on the grid to various weather perils.

- Evaluate expanding the use of SCADA to all substations and communicating field devices such as faulted circuit indicators or reclosers. Consider integrating SCADA into the OMS where available to improve operator efficiency.

- If available, evaluate the AMI outage notification and restoration functionality and integrate into the OMS. Additional AMI functionality may be used for power quality monitoring as well.

Indicator 11 –Compliance to Regulations

Assessment:

Responding small utilities have a mixed approach for compliance with regulations. Some electric cooperatives must meet certain requirements for to maintain eligibility for U.S. Department of Agriculture Rural Utilities Service (USDA RUS) funding. Conversely, municipal departments (boards or commissions) that have oversight from city government have no such regulations with which to comply.

● FOUNDATIONAL

Maturity Score: 2.2

From an overall assessment perspective, the SEU entities are in the **Foundational** maturity level, with scores ranging from 2.0 to 2.5 and an average score of **2.2**.

Key observations:

- Members of ECSC are required to provide certain documentation regarding policies and procedures (e.g., emergency response plans and vulnerability assessments) to receive funding from RUS. RUS, however, does not impose any type of performance requirements or minimum reliability standards that have to be met.
- Municipal electric utilities are a part of city government and did not mention having any reliability compliance requirements with local, state, or federal governments.

Highlighted practices from the SEUs:

- All cooperatives were confirmed to be in compliance with the RUS regulations.

Recommendations:

- Work with municipals and electric cooperatives to define generally accepted operational and design guidelines specific to preparing for and responding to unexpected extreme winter weather events.

Appendix I. Assessment and Recommendations – Small Natural Gas Utilities

The sections below document detailed findings and recommendations related to South Carolina Small Natural Gas Utilities' (SGUs') ability to protect against and recover from extreme weather events with a specific emphasis on cold weather events. Note that all assessment findings and recommendations below are a result of tabletop reviews of information and supporting material provided by SGU respondents and interviewees and is not based on direct inspection of utility infrastructure or observations of utility personnel executing plans and practices during drills or events.

To support this assessment, ORS requested information from seven (7) SGU entities:

1) City of Union Utility Department (City of Union)
2) Clinton Newberry Natural Gas Authority (Clinton-Newberry)
3) Fort Hill Natural Gas Authority (Fort Hill)
4) Greenwood Commission of Public Works (Greenwood)
5) Greer Commission of Public Works (Greer)
6) Laurens Commission of Public Works (Laurens)
7) Patriots Energy Group (PEG) (responding for three (3) natural gas authorities)

Evaluators assessed each SGU at the indicator level and assigned a maturity level to each indicator based on weighted scores ranging from zero (0) to five (5).

	Maturity Level	Maturity Score	*Maturity level and score signifies:*
🟢	***ADVANCED***	4.0 or greater	Advanced components in place and positioned for emerging needs
◒	***LEADING***	from 3.0 to 3.9	Foundational components in place and forward-looking plans or practices
🔵	**FOUNDATIONAL**	from 2.0 to 2.9	Foundational components in place and current standards followed
◓	**LAGGING**	from 1.0 to 1.9	Some foundational components in place
🟡	**NASCENT**	less than 1.0	Lacking or undeveloped foundational components

With the exception of Clinton-Newberry, the SGUs provided minimal responses. Therefore, only three (3) of the eleven (11) capability indicators were scored.

SUMMARY FINDINGS AND RECOMMENDATIONS

Table I-1 provides a summary of SGU-specific findings, and corresponding recommendations for South Carolina's SGUs follow.

Table I-1. Summary Assessment Findings for SGUs

🟢 Advanced ◓ Leading ● Foundational ◒ Lagging 🟡 Nascent ◌ Insufficient Data

Indicator	Summary Evaluation	Maturity
Indicator 1 – Emergency Management and Planning	• Indicator not scored and maturity level not calculated due to insufficient data • Basic Emergency Management Plan which defines roles and responsibilities, identifies external agencies, and specifies emergency role training and emergency drills and/or tabletop exercises not submitted or unavailable for assessment	◌
Indicator 2 – Risk Management	• Foundational level of maturity in developing infrastructure risk management • SGU entities are expected to have adequate risk management processes due to the systematic risks and threats evaluation through Distribution Integrity Management Programs (DIMPs) and Transmission Integrity Management Programs (TIMPs), a requirement of the Pipeline Hazardous Material Safety Administration (PHMSA) • No specific programs for severe winter weather risk mitigation in place as SGU have seen no prior history of damage to gas infrastructure and deemed the threat as extremely low risk	●
Indicator 3 – Staffing and Mutual Assistance Support	• Indicator not scored and maturity level not calculated due to insufficient data • Basic information related to staffing and mutual assistance support for severe winter weather events not submitted or unavailable for assessment	◌
Indicator 4 – Asset Management and Inspections	• Indicator not scored and maturity level not calculated due to insufficient data • Basic information related to asset management and inspections not submitted or unavailable for assessment	◌

Indicator	Summary Evaluation	Maturity
Indicator 5 – Operational Protocols	• Indicator not scored and maturity level not calculated due to insufficient data • Basic information related to operational protocols for severe winter weather events not submitted or unavailable for assessment	◌
Indicator 6 – System Design and Hardening	• Lagging level of maturity in investing their resources to achieve cost-effective resilience and reliability solutions, minimizing the negative impacts of climate change and extreme weather to their customers • Capital budgets for gas severe weather resiliency investments not provided • Details regarding gas system severe weather hardening programs not provided • Respondents indicated budgets for gas system reinforcement includes winter weather resilience, however supporting materials not submitted to substantiate • Natural gas engineering standards related to the protection of sensing lines and regulators in natural gas regulator stations and purchase points not provided	◕
Indicator 7 – Stakeholder Engagement	• Indicator not scored and maturity level not calculated due to insufficient data • Basic information related to stakeholder engagement for severe winter weather event planning not submitted or unavailable for assessment	◌
Indicator 8 – Public Communications	• Indicator not scored and maturity level not calculated due to insufficient data • Basic information related to public communications for severe winter weather events not submitted or unavailable for assessment	◌
Indicator 9 – *Automation*	• *Not evaluated for natural gas utilities – not applicable for smart grid technologies.*	*Not Scored*

Indicator	Summary Evaluation	Maturity
Indicator 10 – Situational Awareness	• Indicator not scored and maturity level not calculated due to insufficient data • Basic information related to situational awareness for severe winter weather events not submitted or unavailable for assessment	◌
Indicator 11 – Compliance to Regulations	• Foundational level of maturity in adhering to federal, state, or local reliability and resilience requirements	●

Table I-2 summarizes the key recommendations for each utility category. Common recommendations are summarized in the initial portion of the table.

Table I-2. Summary of Key Recommendations

Common Recommendations *(Applies to all Entities)*

- Assess feasibility of implementing more comprehensive severe weather damage predictive models to improve the emergency response processes.
- Define or continue to refine mutual assistance plans and look for areas of improvement.
- Continue improving on the use of analytical tools and incorporate with risk management processes.
- Increase engagement of stakeholders, at national and local levels. Take advantage of the social media platforms to fully incorporate with major event communication plans.
- Enhance capabilities to extend situational awareness tools to use information/data for analytics.
- Consider enhanced tools for business process tracking related to compliance tracking to fully mature the compliance management processes.

SGU-specific Recommendations

- It is recognized that SGUs may not have the resources to implement the Incident Command Structure (ICS). However, a basic emergency plan which defines roles and responsibilities, identifies external agencies, and specifies emergency role training and emergency drills and/or tabletop exercises is highly recommended. Since many of the are members of the Carolinas Public Gas Association (CPGA), perhaps a joint effort would provide consistency and efficiencies.
- The SGU entities should consider natural forces severe winter weather impact in their next DIMP.
- Prediction models are used in advance of extreme weather events to estimate system impacts and required resources; this capability needs to continue to be improved to properly plan where to optimally assign mutual assistance crews (including project resource needs).

SGU-specific Recommendations

- All SGUs should include a comprehensive list of severe winter weather risks in the next update to their DIMPs and TIMPs.
- All SGUs should include a list of severe winter weather risk mitigation actions in the next update to their DIMPs and TIMPs.
- Where required, SGU should develop mutual aid agreement with SGUs, contractors, and Large investor-owned gas utilities (LGUs).
- The SGUs are encouraged to evaluate common industry practices for severe winter weather critical infrastructure proactive asset management inspections and patrols. These include protection of sensing lines in gas purchase and regulator stations, identification and periodic operation of critical and relief valves and identification of geographical areas prone to freezing.
- SGUs are strongly encouraged to evaluate implementation of severe winter weather operating protocols.
- Evaluation of the black start capability for extended loss of electric supply should be evaluated for key regulator stations and purchase points.
- Establish specific programs and budgets for severe winter weather risk mitigation programs.
- SGUs should begin the process of engaging local stakeholders. An initial step may be to plan emergency drills which include local emergency agencies.
- Establish severe weather emergency communications plans.
- Develop situational awareness plans and protocols for gas-adverse weather readiness.
- SGUs should provide documentation on the process to develop the peak design day and the ability to meet this demand during a severe winter weather event.

DETAILED FINDINGS BY INDICATOR

The following section provides additional details for the findings and recommendations summarized above.

Indicator 1 – Emergency Management and Planning

Assessment:

SGU entities are expected to have more than adequate emergency management planning processes with the associated organizational structures. Preparation is critical for effective response to potential ice storms and adverse winter weather conditions. From an overall assessment perspective, this indicator was not scored due to insufficient response.

Not Calculated

Maturity Score: –

Key observations supporting this maturity rating: N/A

Recommendations:

No matter the size of the entity, emergency preparedness is needed for gas utilities which provide an essential service to communities, business, and industry. It is recognized that SGUs may not have the resources to implement the ICS. However, a basic emergency plan which defines roles and responsibilities, identifies external agencies, and specifies emergency role training and emergency drills and/or tabletop exercises is highly recommended. Since many of the are members of the CPGA, perhaps a joint effort would provide consistency and efficiencies.

- All SGUs should develop a Gas Emergency Plan.
- All SGUs should hold annual training for emergency roles/responsibilities.
- All SGUs should hold annual emergency management drills or tabletop exercises. The drills and exercise should include local emergency management and other key local agencies. A severe winter weather preparedness drill should be held within the next two (2) years.

Indicator 2 – Risk Management

Assessment:

SGU entities are expected to have more than adequate risk management processes because they systematically evaluate risks and threats through DIMPs and TIMPs. The DIMPs and TIMPs are required per regulation of the U.S. Department of Transportation's PHMSA. The regulations require operators, such as LDCs, to develop and implement written integrity management programs addressing the following elements:

●

FOUNDATIONAL

Maturity Score: 2.1

- Knowledge of infrastructure
- Identification of threats
- Evaluation and prioritization of risks
- Mitigation of risks
- Measurement and monitoring of performance
- Periodic evaluation and improvement
- Reporting of threats

The DIMP and TIMP can be considered gas industry standards for the identification or threats, evaluation and prioritization of risks, and risk mitigation. Guidehouse evaluated this indicator based upon the content contained within each SGU DIMP and TIMP and additional information provided by the SGUs. The DIMPs and TIMPs submitted by the SGUs were completed in a comprehensive manner. From an overall assessment perspective, the SGU entities are within the **Foundational** maturity level, with a score of **2.1.**[1]

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[1] One (1) of the seven (7) SGUs assessed did not provide information related to this indicator.

Key observations supporting this maturity rating:

- Within the DIMPs, the SGUs generally rated natural forces severe winter weather risk as extremely low. The extremely low risk was due to a lack of damage to gas infrastructure due to no prior history of damage to gas infrastructure.
- The responding entities have no specific programs for severe winter weather risk mitigation.

Recommendations:

- The responding entities should consider natural forces severe winter weather impact in their next DIMP.

Indicator 3 – Staffing and Mutual Assistance Support

Assessment:

Resource planning and acquisition is an essential element of emergency preparedness. Resource agreements should be in place, and the gas utility should have reasonable estimates for the predicted damage and resources required to respond to a severe winter weather event. The SGUs did not provide responses to the Data Requests (DR) related to staffing and mutual assistance support. From an overall assessment perspective, this indicator was not scored due to insufficient response.

Not Calculated

Maturity Score: –

Key observations supporting this maturity rating: N/A[2]

Recommendations:

- Prediction models are used in advance of extreme weather events to estimate system impacts and required resources; this capability needs to continue to be improved to properly plan where to optimally assign mutual assistance crews (including project resource needs).
- All SGUs should include a comprehensive list of severe winter weather risks in the next update to their DIMPs and TIMPs.
- All SGUs should include a list of severe winter weather risk mitigation actions in the next update to their DIMPs and TIMPs.
- Where required, SGU should develop mutual aid agreement with SGUs, contractors, and LGUs.

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[2] Only one (1) of seven (7) SGUs assessed provided a sufficient information related to this indicator.

Indicator 4 – Asset Management and Inspections

Assessment:

The entities must ensure that their asset management strategies and processes take account of asset-related risks and asset and asset system criticalities, ideally managing the preparedness of assets for extreme weather events. The SGUs did not provide responses to the DRs related to asset management and inspections. From an overall assessment perspective, this indicator was not scored due to insufficient response.

Not Calculated

Maturity Score: –

Key observations supporting this maturity rating: N/A[2]

Recommendations:

- The SGUs are encouraged to evaluate common industry practices for severe winter weather critical infrastructure proactive asset management inspections and patrols. These include protection of sensing lines in gas purchase and regulator stations, identification and periodic operation of critical and relief valves and identification of geographical areas prone to freezing.

Indicator 5 – Operational Protocols

Assessment:

Operational protocols should be used by SGUs to properly identify the preparedness, mitigation, response, and recovery actions required for abnormal and emergency events to assure company and public safety and the continued operation of gas transmission and distribution systems. Operating protocols commonly take the form of written and published operating procedures that are reviewed annually with employees. The SGUs did not provide responses to the DRs related to operational protocols. From an overall assessment perspective, this indicator was not scored due to insufficient response.

Not Calculated

Maturity Score: –

Key observations supporting this maturity rating: N/A

Recommendations:

- SGUs are strongly encouraged to evaluate implementation of severe winter weather operating protocols.

Indicator 6 – System Design and Hardening

Assessment:

Through various capital improvement programs, SGUs are consistently upgrading the safety and operation of the gas distribution system. These upgrades provide risk reduction for cold winter weather and minimize negative impacts of climate change and extreme weather to their customers. From an overall assessment perspective, the SGU entities are on the low end of **Lagging** maturity level, with a score of **1.5**.[3]

LAGGING

Maturity Score: 1.5

Key observations support this maturity rating:

- None of the respondents provided a CAPEX budget for gas severe weather resiliency investments or details regarding gas system severe weather hardening programs.
- Some of the respondents claimed that the budgets for gas system reinforcement includes winter weather resilience but did not provide clear substantiation.
- None of the respondents provided natural gas engineering standards related to the protection of sensing lines and regulators in natural gas regulator stations and purchase points.

Recommendations:

- Basic measures such as freeze-proofing sensing lines in interconnection and regulator stations should be considered.
- Evaluation of the black start capability for extended loss of electric supply should be evaluated for key regulator stations and purchase points.
- Establish specific programs and budgets for severe winter weather risk mitigation programs.

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[3] Three (3) of the seven (7) SGUs assessed did not provide information related to this indicator.

Indicator 7 – Stakeholder Engagement

Assessment:

Not Calculated

Maturity Score: –

Stakeholder engagement is critical to accurately communicating and developing a utility's resilience strategies and plans, recognizing roles and responsibilities of the community, identifying opportunities for improvement, and implementing solutions that align with stakeholder values and needs. It is expected that a diverse and comprehensive group of internal and external stakeholders are identified and engaged regularly, focused on resilience risks and opportunities, thorough, ongoing, in-depth, and timely dialogues. For example, external engagement with representatives from regulators, science, industry, and community work together to define objectives, goals, lines of responsibility, and areas for collaboration. Internal stakeholder engagement that is clearly identified embeds extreme weather resilience culture into everyday practices.

The SGUs did not provide responses to the DRs related to stakeholder engagement. From an overall assessment perspective, this indicator was not scored due to insufficient response.

Key observations supporting this maturity rating: N/A[2]

Recommendations:

- SGUs should begin the process of engaging local stakeholders. An initial step may be to plan emergency drills which include local emergency agencies.

Indicator 8 – Public Communications

Assessment:

Not Calculated

Maturity Score: –

Public communications go together with stakeholder engagement. Effective communication of resilience information by utilities helps to foster transparency in resilience gaps related to climate hazards, raise industry and community awareness of the activities that are either planned or currently in use to close those gaps, and disseminates effective resilience strategy guidance to close those gaps within the industry and across the nation.

The SGUs did not provide responses to the DRs related to stakeholder engagement and consequent public communications. From an overall assessment perspective, this indicator was not scored due to insufficient response.

Key observations supporting this maturity rating: N/A[2]

Recommendations:

- Establish severe weather emergency communications plans.

Indicator 9 – Automation

Assessment:

Not evaluated for gas distribution utilities. System Automation is not used to evaluate the capability maturity of gas distribution infrastructure.

Indicator 10 – Situational Awareness

Assessment:

Not Calculated

Maturity Score: –

Situational awareness approaches and technologies enable SGU entities to have a more informed, comprehensive, and actionable preparation and response to severe weather events. They are expected to have in place advanced near-time weather monitoring to predict the probability and impact of severe weather events (for planning and post-event restoration). Prevalent use of supporting software systems with accurate data collection and real time reporting that provides actionable insights to the condition of the electric and gas systems during the preparation, response, and recovery phases of an emergency event. Situational awareness capabilities should be used to complement the SGU entity's communication plan and stakeholder engagement.

The SGUs did not provide responses to the DRs related to situational awareness. From an overall assessment perspective, this indicator was not scored due to insufficient response.

Key observations supporting this maturity rating: N/A[2]

Recommendations:

- Develop situational awareness plans and protocols for gas-adverse weather readiness.

Indicator 11 –Compliance to Regulations

Assessment:

PHMSA published the final rule establishing integrity management requirements for gas distribution pipeline systems on December 4, 2009 (74 FR 63906). The effective date of the rule was February 12, 2010, resulting in IM regulations for gas distribution pipelines (49 CFR Part 192, Subpart P). Operators were given until August 2, 2011 to write and implement their DIMPs. The gas distribution integrity management regulations require operators, such as natural gas distribution companies, to develop, write, and implement an integrity management program with the following elements:

●

FOUNDATIONAL

Maturity Score: 2.7

- Understand system design and material characteristics, operating conditions and environment, and maintenance and operating history
- Identify existing and potential threats
- Evaluate and rank risks
- Identify and implement measures to address risks
- Measure IM program performance, monitor results, and evaluate effectiveness
- Periodically assess and improve the integrity management program
- Report performance results to PHMSA and, where applicable, also to states

From an overall assessment perspective, the SGU entities are within the **Foundational** maturity level, with scores ranging from 2.5 to 3.5 and an average of score **2.7.**

Key observations support this maturity rating:

- Most of the respondents provided a DIMP or TIMP. The plans were comprehensive. Although not specifically required in the initial data request, Patriots Energy Group provided detailed information on gas supply and peak data requirements at interconnection stations. It is highly recommended that each gas agency submits information related to determination of the peak design day and the ability to meet this demand during a severe winter weather event. Specific to this indicator are federal pipeline laws and Chapter 103, Public Service Commission, Article 4, Gas Systems. Section 103-463. Adequacy of Service states, "The source of supply and transmission facilities for gas, and/or production and/or storage capacity of the gas utility's plant, supplemented by the gas supply regularly available from other sources, must, to the extent reasonably practicable, be sufficiently large to meet all reasonably expectable demands for firm service, unless otherwise authorized by the commission." This indicator considers any information by the respondents on supply adequacy for the peak design day and actions to monitor and sustain natural gas supply in the event of a sustained electrical outage.

Highlighted practices from the SGUs:

- Patriots Energy Group (PEG) and its members continually analyze their peak day requirements (coldest or consecutive coldest days of the year) and, each year, re-establish forecasts. This is especially important as they service a fast-growing region and must have enough assets in place (infrastructure, capacity, and supply) to meet the estimated gas load on a peak day. PEG has engaged outside consultants to assist with this analysis. PEG has provided sufficient information which demonstrates the ability to provide gas during severe cold weather emergencies and design winter days. The defined practices are sound and leading.

Recommendations:

- SGUs should provide documentation on the process to develop the peak design day and the ability to meet this demand during a severe winter weather event.

- SGUs should update the next DIMP/TIMP with specific risk analysis of natural forces risks related to severe winter weather.

  SGUs should consider enhanced tools for business process tracking related to compliance tracking (and evidence repository) to fully mature the compliance management processes.