# Inspection and Examination Report of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC

*December 2022 Winter Storm Outages and Blackouts*

Docket No. ND-2023-1-E

August 25, 2023

Prepared for the South Carolina Office of Regulatory Staff by

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ENGINEERS & CONSULTANTS

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## Glossary

| | |
|---|---|
| BA | Balancing Authority |
| BAA | Balancing Authority Area |
| CAP | Corrective Action Plan |
| CHP | Combined Heat and Power |
| CRSG | Carolinas Reserve Sharing Group |
| CT | Combustion Turbine |
| DCC | Distribution Control Center |
| DEC | Duke Energy Carolinas, LLC |
| DEP | Duke Energy Progress, LLC |
| DESC | Dominion Energy South Carolina, Inc. |
| DOE | United States Department of Energy |
| DSM | Demand-Side Management |
| ECC | Energy Control Center |
| EEA | Energy Emergency Alerts |
| EOP | Emergency Operations Plan |
| EMS | Energy Management System |
| EPR | Extended Planned Reserve |
| FERC | Federal Energy Regulatory Commission |
| GDS | GDS Associates, Inc. |
| [redacted] | [redacted] |
| GLRP | General Load Reduction Plan |
| GW | Gigawatts |
| IMT | Internal Meteorology Team |
| IPP | Independent Power Producer |
| IRP | Integrated Resource Plan |
| IT | Information Technology |
| LEU | Large Electric Utility |
| MW | Megawatts |
| NCPS | North Carolina Public Staff |
| NCUC | North Carolina Utilities Commission |
| NERC | North American Electric Corporation |
| NGCC | Natural Gas Combined Cycle |
| OATT | Open Access Transmission Tariff |
| ORS | South Carolina Office of Regulatory Staff |
| PJM | Pennsylvania-New Jersey-Maryland Interconnection |
| PNG | Piedmont Natural Gas Pipeline |
| RC | Reliability Coordinator |
| RLS | Rotational Load Shed |
| RTO | Regional Transmission Organization |
| SCPSC | Public Service Commission of South Carolina |
| SEEM | Southeast Energy Exchange Market |
| SERC | Southeastern Reliability Corporation |
| Transco | Williams Transcontinental Interstate Pipeline |
| TSP | Transmission Service Provider |
| [redacted] | [redacted] |

# Executive Summary

On the evening of Friday, December 23, 2022, the Duke Energy Progress, LLC ("DEP") and Duke Energy Carolinas, LLC ("DEC", collectively "Duke Energy" or the "Companies") service areas in North and South Carolina began to experience very cold weather caused by Winter Storm Elliott. As the winter storm progressed into the morning of Saturday, December 24, 2022, Duke Energy instituted rolling blackouts, or load shed actions, that left Duke Energy customers without power. Load shed is an electric industry term that refers to the controlled interruption of service to customers, which is implemented as a last resort to maintain electric grid balance. In South Carolina, approximately 94,893 customers were affected by the Companies' load shed actions. On average, customers were without power for just under three (3) hours, with some affected for over ten (10) hours. This Report examines the causes of the customer outages, the communication from the Companies, the role of the Southeast Energy Exchange Market ("SEEM"), lessons learned, and any areas for improvement.

Ultimately, the cause of Duke Energy's customer outages was an **inadequacy of supply to meet demand** on the morning of December 24. In their 2022 Integrated Resource Plan ("IRP") updates, the Companies projected a total winter system peak demand for 2023 of 31,671 megawatts ("MW"). The Companies also projected to have 37,639 MW of generation capacity and 966 MW of demand-side management ("DSM") capacity. The difference provided for a projected 6,934 MW planning reserve margin. The hourly integrated peak load Duke Energy served on the morning of December 24 was 34,884 MW from 6:00 to 7:00 AM, whereas the estimated actual peak demand would have been 36,543 MW from 8:00 to 9:00 AM. During the estimated peak load hour, Duke Energy had 5,326 MW of generation capacity unavailable due to a combination of planned and forced outages that occurred prior to December 24, or forced outages that occurred on December 24.[1] Also during the estimated peak hour, Duke Energy utilized 684 MW of DSM, which is 282 MW below the projected DSM capacity. As compared to the 2022 IRP planning projections, the combination of higher peak load and resource unavailability led to an operational shortfall and power outages for Duke Energy customers.

There are several issues that contributed to Duke Energy's supply inadequacy. Duke Energy significantly **under-forecasted its load requirements**, which contributed to deficiencies in Duke Energy's short-term supply planning. Despite those deficiencies, Duke Energy's short-term supply planning showed a substantial decrease in available excess supply as early as the morning of Wednesday, December 21, to which Duke Energy did not adequately respond.

[1] This total includes Bad Creek Unit 3 which, as detailed below, was on a multi-year upgrade outage.

Duke Energy also had **large amounts of generation resources unavailable** to serve customers. First, Duke Energy had generation unavailable prior to Winter Storm Elliott due to planned fall maintenance outages that extended through December and forced outages that occurred earlier in the fall and winter. Second, several Duke Energy plants simply failed to perform on the morning of December 24, primarily due to the cold weather. Third, **generation contracted by non-Duke Energy utilities in North and South Carolina also failed to perform** on December 24, which aggravated Duke Energy's supply inadequacy due to its role as Transmission Service Provider ("TSP") and Balancing Authority ("BA"). Finally, Duke Energy purchased power for December 24 on a day-ahead basis, but the Companies' **purchases were significantly curtailed** by the providers.

The need to balance increased demand and reduced available supply caused Duke Energy to interrupt service to its retail customers. Duke Energy utilized software (the "Rotational Load Shed" tool or "RLS") designed to automatically rotate customer outages on a continuous basis - which was intended to achieve the required amount of load shed, limit the duration of individual customer outages, and allow Duke Energy to restore service in a timely manner. Duke Energy's **automated RLS software failed**. Therefore, the Companies were forced to employ a manual load shed and restoration process. Duke Energy's manual load shed and service restoration process caused individual customer outages to be lengthened considerably, and overall customer outages extended through the afternoon of December 24. The contributing issues to Duke Energy's supply inadequacy as well as its load shed implementation failure are discussed further in Section 3. Table ES-1 below lists the causes of customer outages.

**Table ES-1:** Causes of Customer Outages

| Cause | | Description |
|---|---|---|
| Cause #1 | Load Forecasting & Supply Planning | The Companies significantly under-forecasted load and peak demand during Winter Storm Elliott and failed to adequately respond to supply adequacy risk. |
| Cause #2 | Generation Outages and Failures | Several generation resources were unavailable going into the cold weather event, and several others failed during the critical period on the morning of December 24. |
| Cause #3 | Curtailed Purchases | Duke Energy's power purchases from neighboring utilities were curtailed. |
| Cause #4 | Network Customers | Generation contracted by non-Duke Energy utilities failed and contributed to the Companies' supply inadequacy. |
| Cause #5 | Load Shed Implementation | The Companies' RLS tool failed, extending customer outages and delaying power restoration. |

Areas that did not directly contribute to customer outages included fuel supply, transmission congestion, load reduction programs, and SEEM, which are discussed in Section 4. The Companies' communications with its customers, the media, and regulatory bodies regarding the Load Shed Event are detailed in Section 5. Finally, lessons learned identified by the Companies and additional areas for improvement recommended by the South Carolina Office of Regulatory Staff ("ORS") are discussed in Section 6. Table ES-2 below lists these recommendations.

**Table ES-2:** Recommended Areas for Improvement

| Topic | Recommendation |
|---|---|
| Load Forecasting and Supply Planning | 1. Use the learned experience of Winter Storm Elliott to improve load forecast models.<br>2. Develop protocols to ensure load forecasts are updated intra-day around significant weather events. |
| Generation | 3. Planned Outages<br>a. Avoid planned outages in winter months, including December.<br>b. Change the Allen Steam Station staffing and operating status when several other facilities are in prolonged maintenance outages.<br>c. Evaluate Extended Planned Reserve ("EPR") procedures and protocols to assess the feasibility of returning a unit to service within appropriate timeframes required to respond to system conditions that could dictate a return to service.<br>4. Start-up Failures<br>a. Test remotely-operated combustion turbine ("CT") units prior to the winter season and ahead of approaching winter storms to ensure they are operational and ready for service.<br>b. Proactively stage technicians onsite at remote start CTs to minimize potential troubleshooting time.<br>5. Winterization<br>a. Install windscreens or other walls and shelters in areas that could be affected by freezing conditions.<br>b. Install additional temporary freeze protection measures when a severe storm is approaching.<br>c. Include more detailed and specific direction for personnel performing inspections of heat tracing and insulation on critical equipment and instrumentation lines.<br>d. Ensure that existing freeze protection measures are installed as designed/intended.<br>e. Review site-specific cold weather preparedness procedures and checklists at each generation station.<br>6. Fuel Assurance<br>a. Conduct a winter fuel assurance review with a focus on natural gas deliverability to ensure fuel is available during extreme cold weather conditions based on the Winter Storm Elliott experience. |

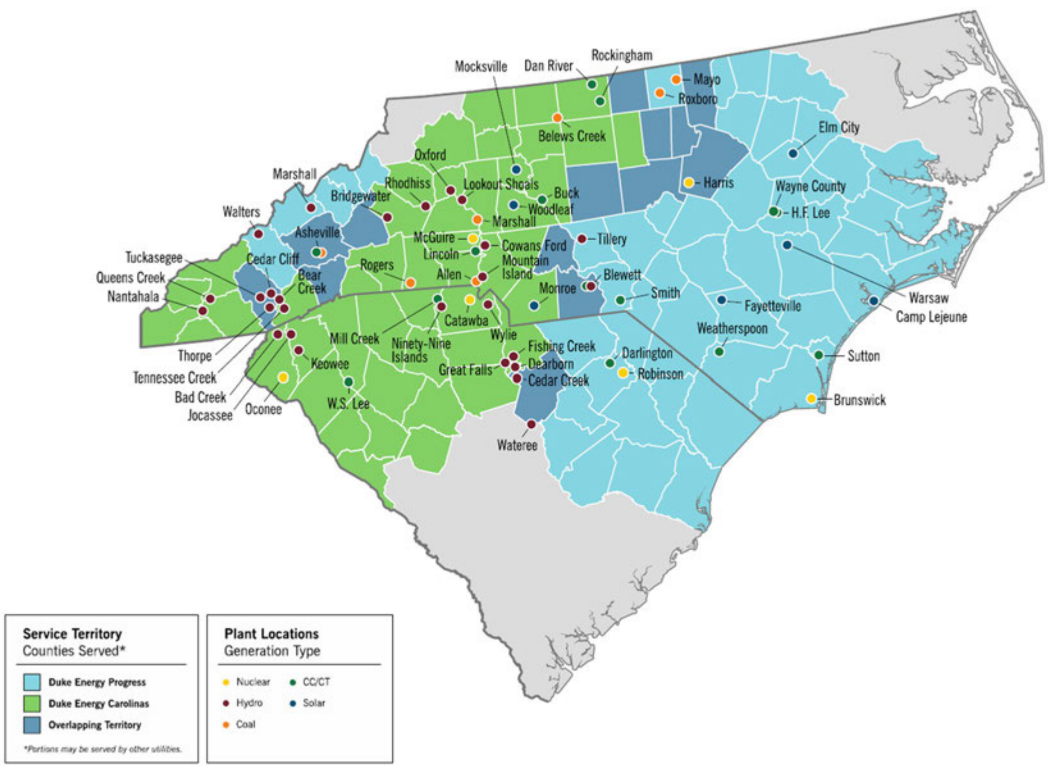
| Topic | Recommendation |
| --- | --- |
| Load Shed Implementation | 7. Continually update the RLS tool and other software packages with interdependencies.<br>8. Expand review of the RLS tool by creating a software system interdependency chart to formally track relationships between systems to inform testing and review when updates occur. |
| Active Load Reduction Programs | 9. Ensure DSM programs can be, and are, used to their maximum capabilities during critical emergency events, even on holidays and weekends.<br>10. Reflect the capability of DSM programs in short-term supply planning to accurately reflect the ability to rely on those programs during an emergency. |
| Network and Wholesale Customer Interaction | 11. Review policies and procedures to improve communication and coordination with network and wholesale customers during emergency or load shed events.<br>a. Ensure network and wholesale customers address supply issues when they occur or can be instructed to reduce load in a timely manner. |
| Customer Communications | 12. Implement a notification process that alerts customers to load shed or rolling outages before the outages occur.<br>13. Ensure that more accurate timeframes for power restoration can be provided in these notifications via the RLS tool. |

The investigation and conclusions drawn by ORS in this Report are based upon data provided to ORS by Duke Energy. Other entities, including but not limited to the Federal Energy Regulatory Committee ("FERC"), the North American Electric Reliability Corporation ("NERC"), the Southeastern Reliability Corporation ("SERC"), and the North Carolina Utilities Commission ("NCUC"), are conducting independent investigations regarding the operations of the electric system during the winter weather conditions that occurred during Winter Storm Elliott. Due to the timing of these investigations, ORS has not reviewed the results or preliminary conclusions of those investigations, which may be different in scope than that contemplated in Public Service Commission of South Carolina ("SCPSC" or "Commission") Order No. 2023-21. Accordingly, these investigations may reach different conclusions or identify additional conclusions and recommendations regarding the effects of Winter Storm Elliott and potential areas for improvement or lessons learned.

# 1 Background

The Companies are vertically integrated, regulated electric utility subsidiaries of Duke Energy Corporation that serve over 2.7 million customers in South and North Carolina.[2] Figure 1-1 below provides a map of the 24,000 square-mile service territory that Duke Energy serves in the Carolinas. Because DEC and DEP are owned by the same parent company and have protocols in place to jointly dispatch resources, this Report refers to the collective Duke Energy for clarity and simplicity. When subsidiary company-specific issues are relevant, DEC and DEP information is discussed separately.

**Figure 1-1:** Duke Energy Service Territory[3]




Beginning with strong winds on December 23, 2022, the service territories of Duke Energy experienced a winter storm with colder-than-normal temperatures that worsened on December 24 and persisted through December 25 ("Winter Storm Elliott"). The winter storm affected most of the eastern United States, causing higher electric demand for other utilities which limited Duke Energy's ability to import power. On the morning of December

[2] Duke Energy Corporation also owns electric utility companies in Florida, Indiana, Ohio, and Kentucky, but DEC and DEP are the focus of this Report.

[3] Duke Energy Allowable Ex Parte Briefing materials, available in Docket No. ND-2023-6-E.

24, the cold temperatures led to increased demand and an insufficient supply of electricity that forced Duke Energy to engage in controlled load shed, leading to widespread customer outages. Duke Energy directed firm load shed in South Carolina to occur from approximately 6:00 to 10:00 AM ("Load Shed Event"), but customer outages were lengthened and persisted into the afternoon because of an extended manual restoration process.[4]

## 1.1 PREVIOUS WINTER WEATHER EVENTS AND ORS INVESTIGATIONS

South Carolina and the United States broadly have experienced several extreme winter weather events in recent years that stressed the electric system. Polar Vortex events in 2014, 2015, and 2018 impacted the eastern half of the United States and led to federal investigations and reports.[5] More recently, an extreme cold weather event occurred in February 2021 (often referred to as "Winter Storm Uri") which led to large amounts of customer outages in the middle portion of the country, primarily in Texas.[6] Although that event impacted a particular geographic region, the significance of the event was so large that it triggered reviews and assessments across the utility sector.

Following the February 2021 event in Texas, South Carolina Governor Henry McMaster called for a comprehensive review of South Carolina's public and private power grid. ORS subsequently solicited information from the State's utilities on the matter. In December 2021, the *Final Report on the Resiliency of South Carolina's Electric and Natural Gas Infrastructure Against Extreme Winter Storm Events* ("Resiliency Report") was published by ORS pursuant to Docket No. 2021-66-A. One of the overall findings of the report was that Large Electric Utilities ("LEUs"), like Duke Energy, "…generally offered sufficient qualitative evidence to illustrate their readiness and ability to respond to winter weather events." The Resiliency Report provided several recommendations to the LEUs. The most

[4] The load shed directive for both DEP and DEC began between 6:00-7:00 AM, and the DEP load shed directive ended earlier than DEC's (see timeline in Section 2). For simplicity, the Load Shed Event will generally be shown for Duke Energy as 6:00-10:00 AM.

[5] NERC Polar Vortex Review
https://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf (accessed July 28, 2023).
NERC 2015 Winter Review
https://www.nerc.com/pa/rrm/ea/ColdWeatherTrainingMaterials/2015_Winter_Review_December_2015_FINAL.pdf (accessed July 28, 2023).
2019 FERC and NERC Staff Report "The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018."
https://www.nerc.com/pa/rrm/ea/Documents/South_Central_Cold_Weather_Event_FERC-NERC-Report_20190718.pdf (accessed July 28, 2023).

[6] FERC, NERC and Regional Entity Staff Report The February 2021 Cold Weather Outages in Texas and the South Central United States https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and (accessed July 28, 2023).

applicable recommendations from the Resiliency Report align with load forecasting and weatherization areas of improvement identified in Section 6.1 of this Report.

## 1.2 PROCEDURAL BACKGROUND

On January 12, 2023, the Commission issued Order No. 2023-21, which requested ORS to conduct an inspection and examination of outages and blackouts associated with the Load Shed Event.[7] In the Order, the Commission requested that the ORS inspection and examination investigate the following:

1. The cause(s) of any outages and blackouts,
2. Communication from the Companies with customers, the media, and any and all regulatory bodies, including, but not limited to SCPSC, SC ORS, the FERC, and/or any other state or federal agencies, either before, during or after the rolling blackouts and/or outages began,
3. The role, if any, of SEEM,
4. Any lessons learned,
5. Areas for improvement, if any, and
6. Additional areas ORS deems appropriate to explore with regard to any outages and blackouts during the December 2022 Winter Storm Elliott.

The ORS engaged GDS Associates, Inc. ("GDS") to assist with the inspection and examination and subsequently, to develop this Report. The Report examines the Load Shed Event as a reliability event that led to a loss of service for Duke Energy's customers. Separately, the economic impacts of Duke Energy's actions during the Load Shed Event are reviewed in Duke Energy's annual fuel cost dockets.[8] On February 27, 2023, Duke Energy participated in an Allowable Ex Parte Briefing to the Commission.[9] In addition to information presented by Duke Energy during the Commission briefing, ORS and GDS conducted extensive discovery to acquire information utilized and referenced throughout this Report.

## 1.3 WEATHER EVENT BACKGROUND – WINTER STORM ELLIOTT

Winter Storm Elliott moved in a general west-to-east direction across the United States. The storm front brought high wind gusts and cold weather that impacted the mid-continent on December 23 as well as minimum temperatures that reached the mid-Atlantic and Southeast on December 24. By December 25, colder-than-normal weather persisted but

[7] Commission Docket No. ND-2023-1-E.
[8] *See* Commission Docket Nos. 2023-1-E and 2023-3-E.
[9] Commission Docket No. ND-2023-6-E.

had begun to abate from the previous day's extreme lows. Figure 1-2 below illustrates the deviation between the 30-year average normal temperatures versus the actual average temperatures from December 23 through December 25. On December 24, the majority of South Carolina was over 20 degrees colder than the 30-year normal temperature, and most of the Eastern Interconnection experienced similarly severe cold weather.[10]

**Figure 1-2:** December 23-25 Average Temperature Departure from Normal[11]

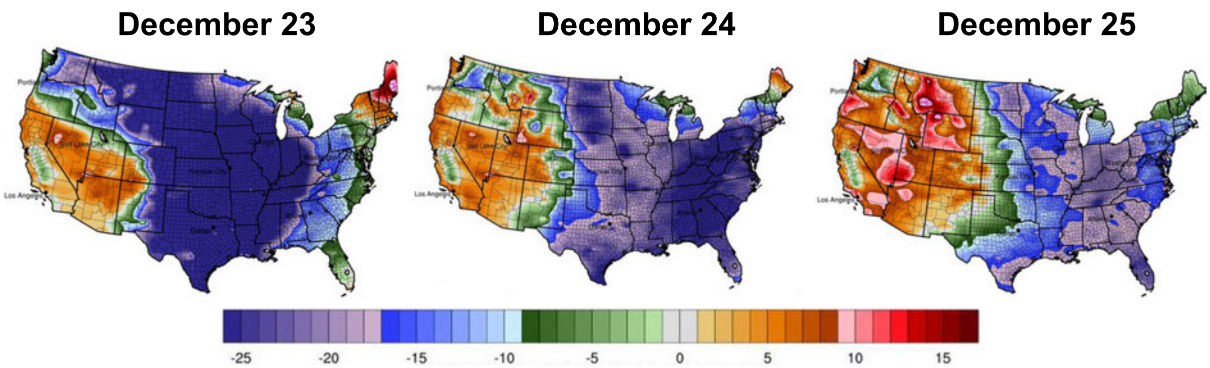



Figure 1-3 below tracks the average temperatures across Duke Energy's service territory from December 23 through December 26. Temperatures on the morning of December 23 were moderate but began dropping after 9:00 AM. Average temperatures became sub-freezing by mid-afternoon and continued to drop throughout that evening and overnight. A minimum temperature of 12 degrees Farenheit occurred on the morning of December 24. Temperatures subsequently increased after 8:00 AM throughout the rest of the day, reaching a high of 29 degrees Farenheit by that afternoon. Temperatures decreased again overnight but generally increased over the next several days.

[10] The Eastern Interconnection is the synchronized power grid that extends from Canada to Florida and from the east coast to roughly the Rocky Mountains.
[11] MISO Reliability Subcommittee Overview of Winter Storm Elliott.

**Figure 1-3:** Duke Energy Average Temperatures, December 23-26[i]

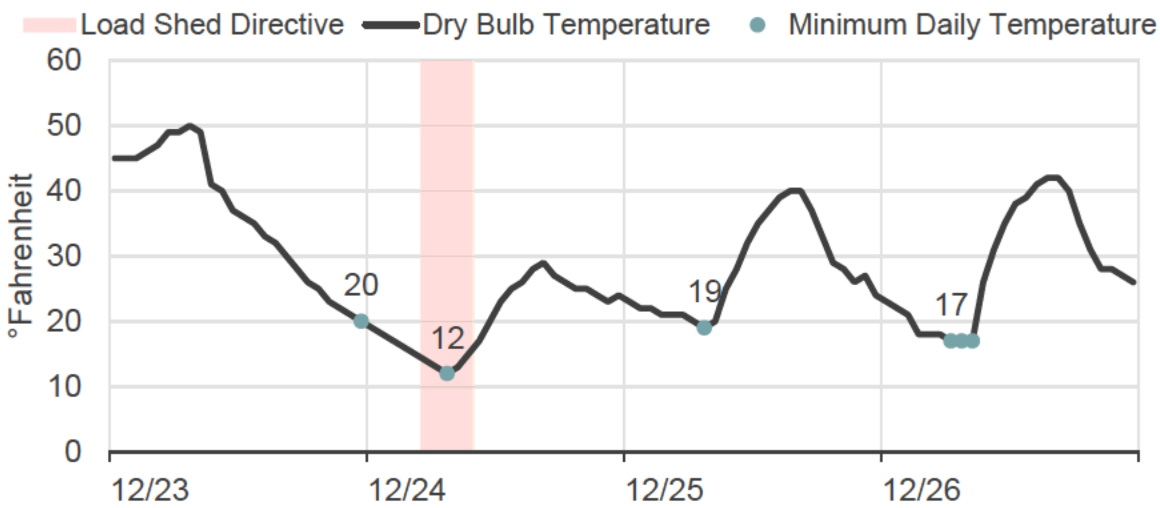
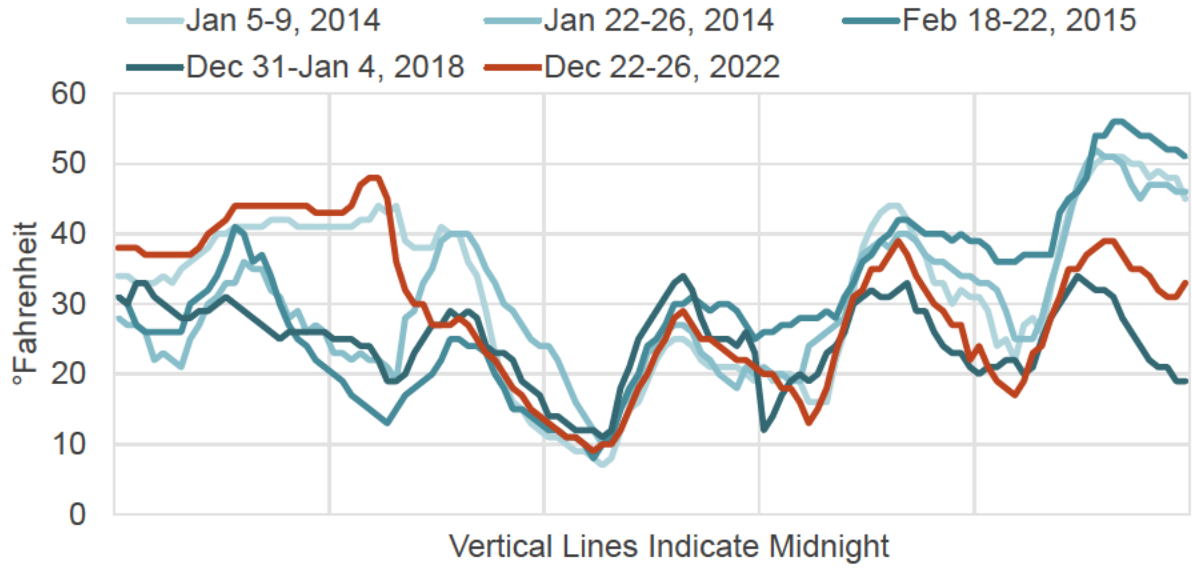



Figure 1-4 below shows a comparison of temperatures to prior winter storm events in the past ten (10) years. Winter Storm Elliott was similar to prior storms in terms of the minimum temperature reached, its timing in the morning hours, a considerable increase in temperatures the same day after the minimum was reached, and a gradual increase in minimum temperatures in subsequent days.

However, in contrast to prior storms, Winter Storm Elliott recorded moderate temperatures on the morning prior to the minimum temperatures, after which point temperatures rapidly dropped, a phenomenon somewhat similar to the Polar Vortex in January 2014. Winter Storm Elliott also occurred earlier in the winter than prior storms, which all occurred in January or February. The 2018 New Year's storm did include low temperatures in late December.

**Figure 1-4:** Temperatures During Prior Winter Storms[12]




## 1.4 DUKE ENERGY EVENT BACKGROUND – LOAD SHED EVENT

Duke Energy projected sufficient supply from its own generation resources and, with the use of imported energy, projected to meet demand as of the night of December 23. However, Duke Energy experienced higher-than-anticipated demand, unexpected generation supply failures, and curtailed power purchases during the early morning of December 24. Duke Energy initiated firm load shed protocols shortly before 6:30 AM, and the Companies reported that service was interrupted for roughly 500,000 customers across the Carolinas.[13] In South Carolina, approximately 94,893 customers were affected by the Companies' load shed actions.[ii] DEP ended load shed protocols by 8:43 AM, and DEC ended load shed protocols at 10:00 AM. On average, South Carolina customers were without power for just under three (3) hours; however, some customers experienced outages for over ten (10) hours due to the Load Shed Event.[iii] Duke Energy completed manual restoration of a majority of South Carolina customers by 4:00 PM on December 24.[14]

[12] Temperatures are based on National Oceanic and Atmospheric Administration ("NOAA") National Weather Service climatological data for Charlotte Douglas International Airport.
[13] Duke Energy press release available at: https://news.duke-energy.com/releases/duke-energy-asks-for-continued-energy-conservation-as-power-restoration-continues-following-extreme-winter-temperatures
[14] On February 27, 2023, in Commission Allowable Ex Parte Briefing ND-2023-6-E, Duke Energy reported that approximately 5% of customers were restarted after 4:00 PM on December 24. In response to ORS Information Request 2-2, Duke Energy reported that the last customer outages due to the Load Shed Event was restored on December 25 at 7:34 AM.

# 2 Load Shed Event Timeline

Duke Energy's curtailment of service to customers (and subsequent restoration) during Winter Storm Elliott was generally contained to December 24. Accordingly, the timeline of events is delineated according to:

1. Events and activities performed by Duke Energy prior to December 24 including seasonal preparation and anticipation for Winter Storm Elliott,
2. Events and activities performed by Duke Energy on December 24 including the Load Shed Event and restoration, and
3. Events and activities performed by Duke Energy after December 24 including return to normal weather and service.

**Wind-Related Outages**

Duke Energy experienced customer outages on Friday December 23, 2022, because of high winds. Although the high winds and associated customer outages were relevant to Duke Energy during the Load Shed Event, the cause of those outages are distinct from the customer outages that occurred on December 24. Wind-related outages occurred in an uncontrolled fashion due to damage on Duke Energy's distribution system, whereas the Load Shed Event involved controlled outages that the Companies initiated because of supply inadequacy.

## 2.1 PRIOR TO DECEMBER 23

Duke Energy defined the winter season as the months of December through February and engaged in certain preparations prior to the start of the season. Duke Energy conducted its 2023 annual winter preparation webinar on November 2, and generally reported that preventative maintenance, training, and other readiness activities had been completed.[iv,v]

Planning decisions and various other events from the fall and earlier in December resulted in outages or derates[15] at several generation facilities prior to December 23. These various planned and forced outages are discussed further in Section 3.2.1.

On December 12, the Companies' Internal Meteorology Team ("IMT") first provided an internal forecast of the potential for a severe cold-weather event over the Christmas

[15] A derate is a decrease in the available capacity of an electric generating unit, commonly due to a system or equipment issue. A derated unit can still operate, but not at full output.

holiday.[vi] The IMT's weather reports are provided across the Companies' functional groups to inform operational and planning aspects such as load forecasting, system conditions, unit availability, and reserve levels. On Monday, December 19, and throughout that week, the IMT continued to forecast a powerful cold front reaching the Carolinas by the upcoming Friday, December 23, bringing gusty winds followed by an arctic air mass with low temperatures for the weekend.[vii] In its "Carolinas Weather Outlook" issued on the morning of December 21, the IMT discussed that the "main story for the holiday weekend is the arctic air mass that will prevail across the eastern US. Temperatures will be 15 to 25 degrees below normal; coldest on Saturday with slight moderation Sunday and Monday."[viii] On December 22, in its Carolinas Weather Forecast Discussion, the IMT expressed concern "that the load models will under-estimate the impact of winds along with the cold air."[ix]

## 2.2 **DECEMBER 23**

On Friday, December 23, the IMT highlighted the risk of significant power outages that may occur later in the day due to high winds, especially in the northwestern portion of Duke Energy's service territory, along with cold temperatures through Saturday morning.[x] Additionally, the temperature forecasts for Saturday morning shifted and indicated lower-than-expected temperatures in the low teens with minimum wind chill reaching -5 to 5 degrees Fahrenheit across the service territories.

Whereas the DEP load forecast for December 23 anticipated higher load manifesting earlier in the day, customer load did not align with DEP's forecast until the evening when load sharply increased. The DEC load forecast significantly under-forecasted the load throughout December 23, and the actual load increasingly outpaced the forecast throughout the day.

On the morning of December 23, Duke Energy projected a peak load of 33,273 MW on the combined DEC and DEP systems to occur from 8:00 to 9:00 AM the following morning. However, the Duke Energy system experienced an actual, daily peak load that night of 32,851 MW.[xi] As discussed further in Report Section 3.1, Duke Energy made an initial load forecast for December 24 on the morning of December 23, but subsequently failed to update its forecast of peak load for December 24 as December 23 progressed.

Operating reserves represent supply that is available to be called upon quickly to respond to unforeseen circumstances. Duke Energy met its December 23 peak load while maintaining over 2,100 MW of reserves.[xii] At 6:00 PM, Duke Energy projected the ability to meet peak demand for the following day, December 24, in both the DEC and DEP service territories and projected adequate reserves of 2,600 MW.[16] Additionally, on December 23, Duke Energy contracted "day-ahead" for 940 MW of firm power purchases. These purchases were primarily sourced from the Pennsylvania-New Jersey-Maryland Interconnection ("PJM") for delivery on December 24. On a day-ahead and intra-day basis, Duke Energy made 370 MW of non-firm power purchases (again primarily sourced from PJM) for delivery during the second half of December 23. From approximately 5:15 to 7:30 PM, DEC experienced curtailment of 300 MW from the non-firm purchases primarily sourced from PJM.[xiii] On an emergency basis, Duke Energy made sales to [redacted] that began in the morning of December 23, increased throughout the day to a maximum amount of 830 MW from 7:00 to 11:00 PM, and subsequently ended early the next morning.[xiv]

The Companies' available generation and scheduled energy imports met peak demand on December 23. Certain generation resources failed but returned to service quickly. Notably, the Dan River Natural Gas Combined Cycle ("NGCC") plant experienced a forced derate just before midnight, and a portion of its capacity was unavailable during the peak demand period on December 24. Additionally, around 7:30 PM the [redacted] an Independent Power Producer ("IPP") contracted by DEC, experienced a forced outage of 175 MW and returned to service roughly two (2) hours later.[xv]

### 2.3 **DECEMBER 24**

On Saturday, December 24, Duke Energy's IMT reported very cold morning temperatures coming in slightly below forecast with an expectation for temperatures to remain cold but gradually warm in subsequent days.[xvi] DEC's updated morning forecast for December 24 projected a peak load nearly 2,000 MW higher than the prior morning's forecast. Similarly, DEP's updated forecast projected a peak load roughly 800 MW higher than the prior forecast.

As the morning progressed, the actual load on the combined Duke Energy system outpaced the day's forecast. Figure 2-1 below illustrates Duke Energy's escalating load on the morning of December 24. The figure depicts both the load Duke Energy actually served and estimated actual demand. The estimated actual demand includes additions to the actual load served for DSM and load shed reductions. The hourly integrated peak load Duke Energy served was 34,884 MW from 6:00 to 7:00 AM, and the estimated actual demand (considering estimated additions for DSM and load shed reductions) was 36,543 MW from 8:00 to 9:00 AM.

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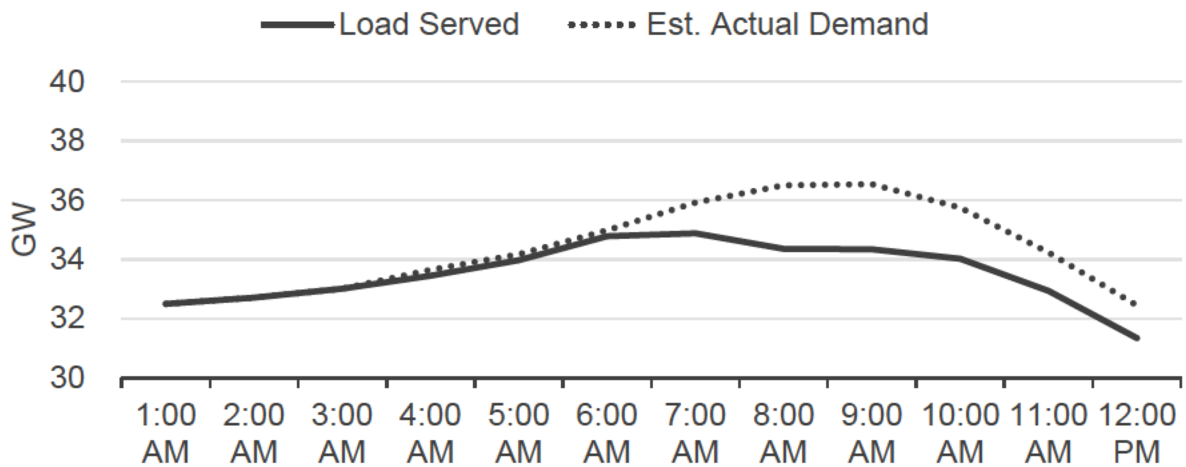
[16] Duke Energy Allowable Ex Parte Briefing materials, available in Docket No. ND-2023-6-E.

**Figure 2-1:** Duke Energy Hourly Demand, Morning of December 24[xvii, 17, 18]

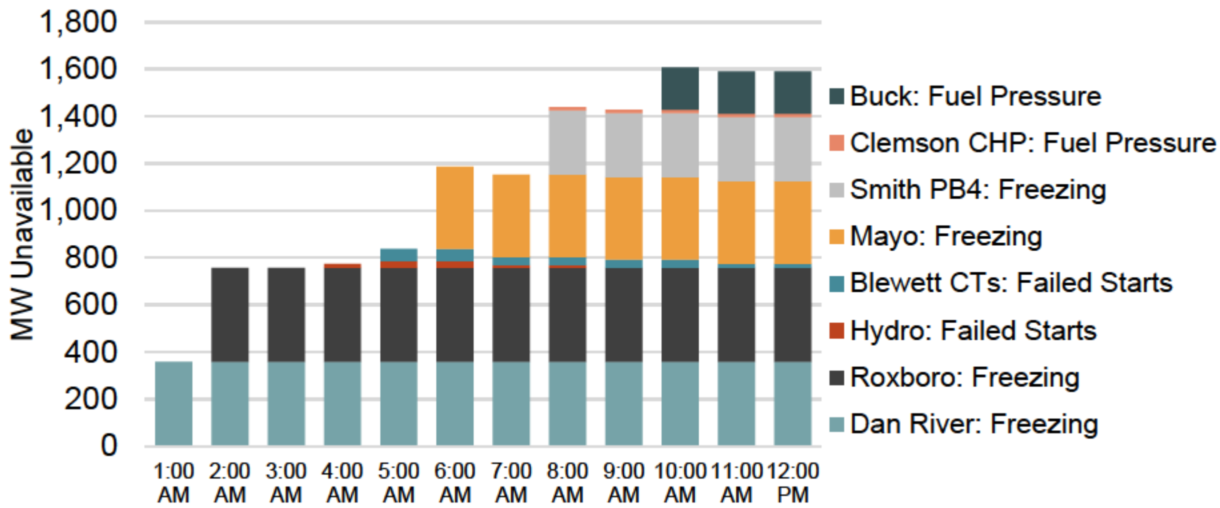



As actual load on the Companies' system increased and outpaced forecasted load, several of Duke Energy's generation resources began to fail. The generation outages and derates that occurred on the Companies' system are discussed in further detail in Section 3.2. There were several generating resources unavailable due to planned maintenance outages, and several others were already in forced outage status for various reasons leading up to the Load Shed Event. Prior to December 24, 3,895 MW of generation was off-line. In the early hours of December 24, depicted by Figure 2-2 below, several plants experienced operational issues associated with the extreme weather conditions and had to be shut down or derated. The operational issues further reduced Duke Energy's available capacity to serve load.

[17] All hourly data in the report is presented on an hour ending basis, meaning 6:00 AM refers to 5:00 AM to 6:00 AM.

[18] Estimated Actual Demand includes estimated amounts added back for load shed and DSM.

**Figure 2-2:** Duke Energy Generation Plant Outages, Morning of December 24[xviii]

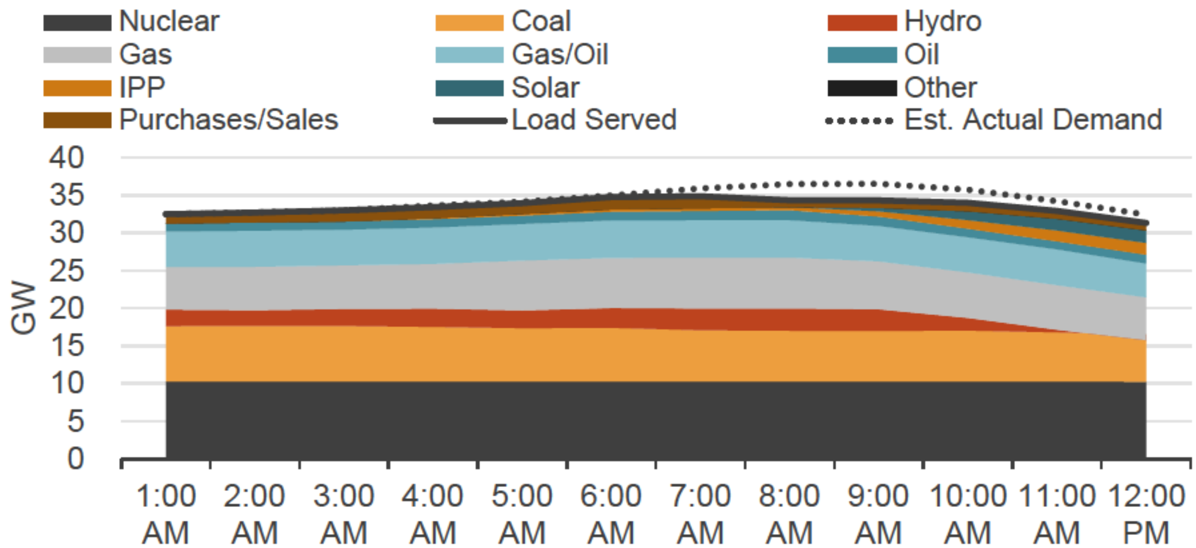



In addition to its owned generation resources, Duke Energy also encountered supply unavailability from third-party sources. Beginning at 5:30 AM, Duke Energy started experiencing curtailments (reductions) to the amount of off-system power purchases it had contracted for on December 23. The entirety of Duke Energy's non-firm purchases was curtailed, and an increasing amount of firm purchases were also curtailed as the morning of December 24 progressed.[xix] Generation resources owned by IPPs located in Duke Energy's Balancing Authority Area ("BAA") also failed to operate during critical hours of the morning.[19]

Figure 2-3 below depicts Duke Energy's actual estimated hourly demand and supply for the morning of December 24. The generation resource failures are reflected as reduced generation output in the respective fuel categories (gas and coal) at the time the failures occurred. Additionally, curtailed power purchases are reflected in reduced purchases/sales. Duke Energy has several generation plants that are capable of dual fuel operation on either natural gas or oil, and Duke Energy switched several facilities to oil during the Load Shed Event as reflected in the aggregate gas/oil category. Duke Energy exhausted available supply in an attempt to meet demand during the Load Shed Event, meaning all available dispatchable generation was utilized. A meaningful amount of solar was generated from 8:00 to 9:00 AM, which, along with declining load due to increasing temperatures, improved Duke Energy's supply and demand balance.

[19] As the Balancing Authority, Duke Energy is responsible for maintaining operating conditions pursuant to mandatory reliability standards issued by the NERC.

**Figure 2-3:** Duke Energy Hourly Demand and Supply, Morning of December 24[xx,20]




The imbalance of load and supply manifested in a degradation to the operating reserve levels for the DEC and DEP BAAs. DEC and DEP target minimum levels of operating reserves to comply with NERC standards. These operating reserves provide for regulation, load forecasting error, forced and scheduled resource outages, and local area protection. Figure 2-4 and Figure 2-5 below depict actual levels of operating reserves for the DEP and DEC BAAs respectively versus their relevant reserve targets. Both DEP and DEC carried amounts of reserves exceeding reserve targets until the evening of December 23 when the level of operating reserves rapidly eroded to below targeted levels.

[20] "Estimated Actual Demand" includes estimated amounts added back to include load shed and DSM. "Hydro" category is inclusive of pumped hydro output; "Other" category includes biomass and long-term export. "Purchases/Sales" category is inclusive of Net Actual Interchange.

**Figure 2-4:** DEC Operating Reserves[xxi]

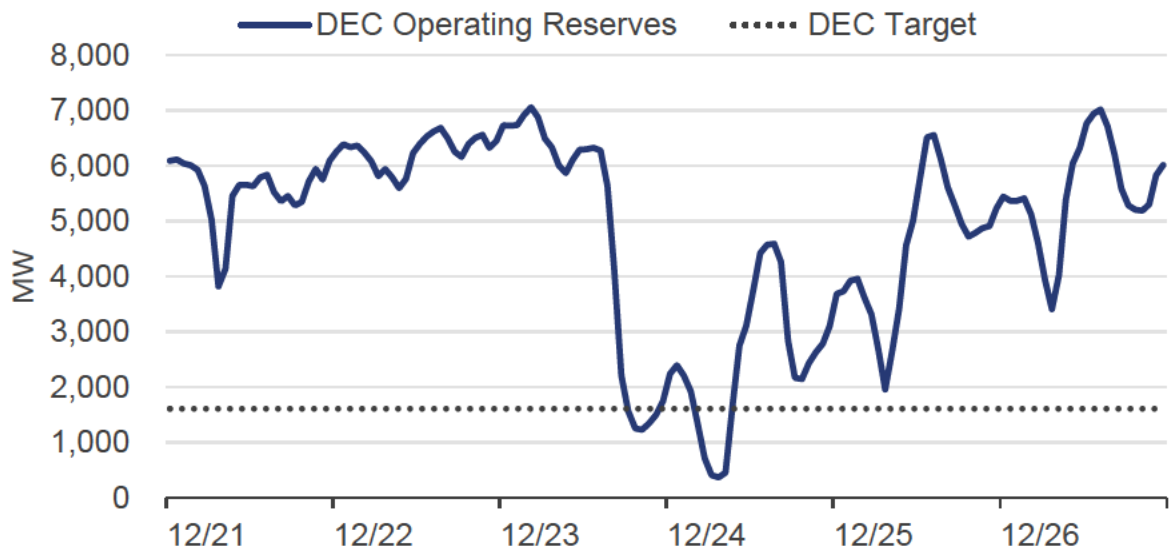
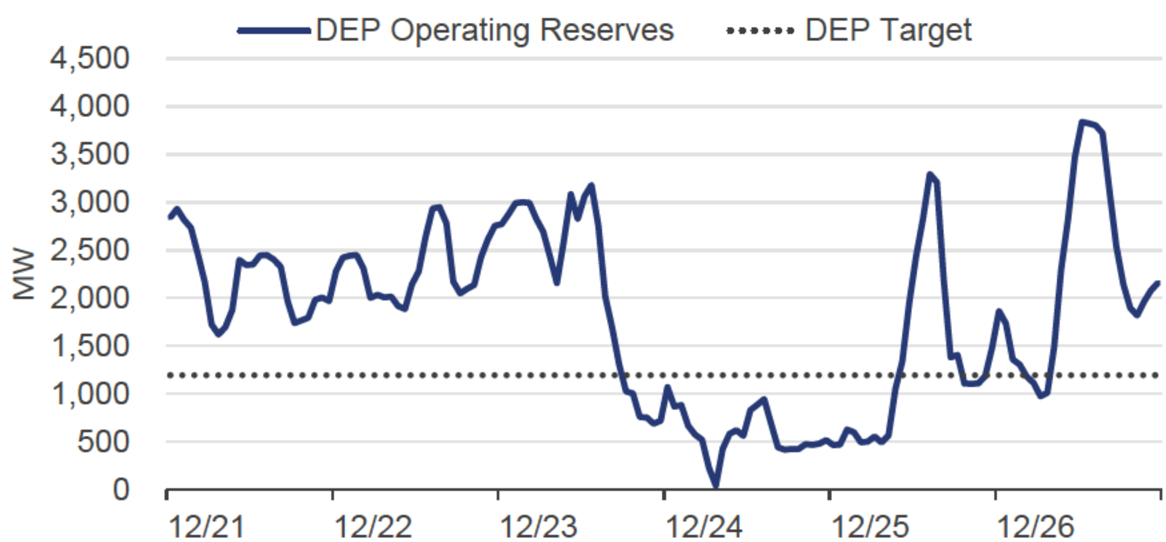



**Figure 2-5:** DEP Operating Reserves[xxii]



Due to the declining operating reserves, the Companies initiated and escalated energy emergency procedures. NERC defines levels of Energy Emergency Alerts ("EEA") that increase in severity, as summarized below: [21]

- EEA 1 - All available generation is being utilized.
- EEA 2 - Load management procedures have been implemented.
- EEA 3 - Firm load shed is initiated.

Table 2-1 below indicates the timing of EEA level declarations by DEC and DEP BAs on December 24. DEC escalated to EEA 3 more gradually than DEP, which escalated from EEA 1 to EEA 3 in approximately 40 minutes. Emergency declarations for the Companies occurred in the early morning and did not return to the EEA 1 Level until late afternoon.

**Table 2-1:** DEC and DEP EEA Declarations[xxiii]

| | EEA 1 | EEA 2 | EEA 3 | EEA 1 |
|---|---|---|---|---|
| **DEC** | 8:25 PM (12/23) | 4:30 AM | 6:10 AM | 3:45 PM |
| **DEP** | 5:37 AM | 6:06 AM | 6:18 AM | 4:20 PM |

After reaching EEA 3, DEP and DEC experienced similar timelines for implementing firm load shed throughout the morning, although the DEC load shed began sooner and lasted longer.

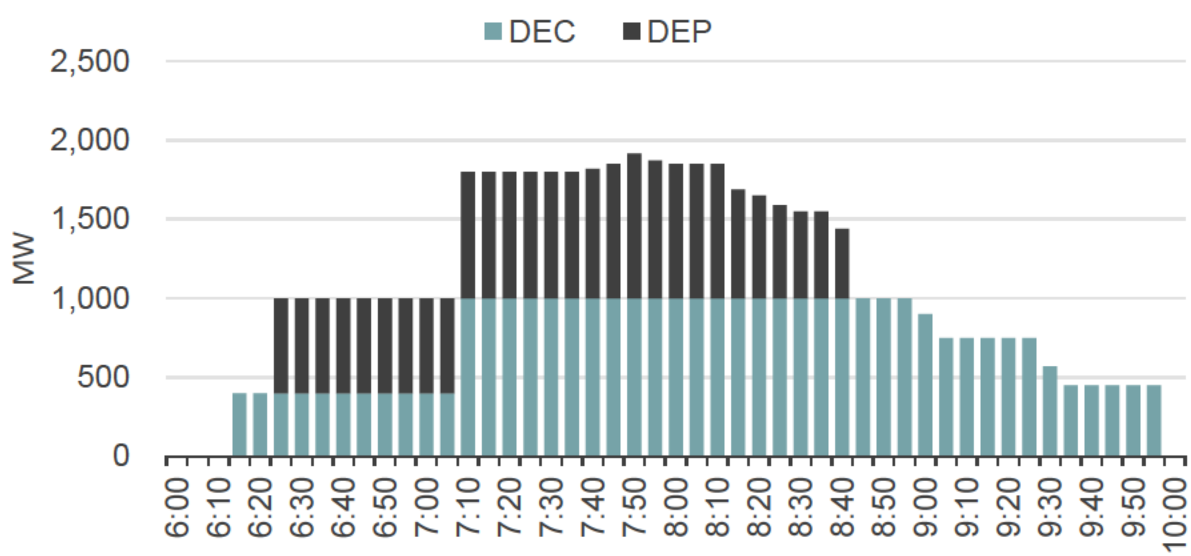
As shown below in Table 2-2 and Figure 2-6, Duke Energy directed increasing amounts of load shed from 6:00 to 8:00 AM and subsequently reduced those directives until they ended at 10:00 AM. At the height of the Load Shed Event, Duke Energy actually implemented an estimated load shed of 1,865 MW from 8:00 to 9:00 AM.[xxiv]

[21] NERC Standard Emergency Operations Plan ("EOP") EOP-011-1, "Emergency Preparedness and Operations."

**Table 2-2:** DEC and DEP Load Shed Directive[xxv,22]

| Time (AM) | DEC Directive (MW) | DEC Total (MW) | DEP Directive (MW) | DEP Total (MW) | Duke Energy Total (MW) |
|---|---|---|---|---|---|
| 6:14 | 400 | 400 | - | - | 400 |
| 6:25 | - | 400 | 600 | 600 | 1000 |
| 7:04 | 600 | 1000 | - | 600 | 1600 |
| 7:10 | - | 1000 | 200 | 800 | 1800 |
| 7:43 | - | 1000 | 50 | 850 | 1850 |
| 7:52 | - | 1000 | 111 | 961 | 1961 |
| 8:12 | - | 1000 | (111) | 850 | 1850 |
| 8:16 | - | 1000 | (200) | 650 | 1650 |
| 8:27 | - | 1000 | (100) | 550 | 1550 |
| 8:43 | - | 1000 | (550) | - | 1000 |
| 9:03 | (250) | 750 | - | - | 750 |
| 9:32 | (300) | 450 | - | - | 450 |

**Figure 2-6:** DEC and DEP Load Shed Directive[xxvi,23]




Duke Energy first experienced failures in its automated RLS tool at 6:57 AM (initially on the DEP system), shortly after implementation of rotating load shed. The Companies shifted to manual load shed procedures at 7:12 AM.[xxvii] The automated RLS tool used by the Companies was designed to rotate customer outages on a 15- to 30-minute basis. Although DEP ended its load shed request by 8:43 AM and DEC by 10:00 AM, the manual

[22] Load shed amounts shown reflect amounts requested by Duke Energy and do not include wholesale customer requested amounts (discussed in Report Section 3.4).
[23] *Id.*

process used by the Companies (due to failure of the automated RLS tool) extended the restoration process, which lengthened some customer circuit outages to 4:00 PM, with approximately 5% of customers restored after 4:00 PM.[24] The last customer outages due to the load shed event were restored on December 25 at 7:34 AM.[xxviii]

## 2.4 **AFTER DECEMBER 24**

Duke Energy's weather-induced generation outages and derates on December 24 were resolved throughout the day on December 25. Additional Duke Energy generating plants that experienced equipment issues on December 23 or 24 were repaired by the Companies and returned to service. Although the Companies forecasted lingering cold weather and the possibility of higher loads on the subsequent business day, Monday December 26, Duke Energy met the peak demand on December 25 and subsequent days. Throughout the remainder of December and into early January, the Companies brought several generation resources back on-line from prior planned and forced outages.

[24] Duke Energy Allowable Ex Parte Briefing materials, available in Docket No. ND-2023-6-E.

# 3 Causes of Customer Outages

There are five (5) causes for the resource inadequacy that led to the customer outages during Winter Storm Elliott:

1. Duke Energy under-forecasted peak load prior to the Load Shed Event and did not make adequate supply planning adjustments as projected operating conditions deteriorated.
2. A large amount of generation was unavailable due to a combination of forced and planned outages prior to the Load Shed Event and additional generation resource outages that occurred during the Event.
3. The Companies adjusted supply plans through execution of day-ahead power purchases, but the day-ahead purchases were ultimately curtailed due to widespread stress on neighboring electric systems.
4. Utilities (Network Customers) that Duke Energy provides transmission service to also experienced generation failures that further stressed the system.
5. Customer outages were extended beyond the resource inadequacy and peak load period because of the failure of the Companies' automated RLS tool.

Each of these causes is discussed in further detail in the Report Sections below.

## 3.1 **CAUSE #1: LOAD FORECASTING & SUPPLY PLANNING**

### 3.1.1 Load Forecasting

DEC and DEP under-forecasted to a significant degree the load and peak demand during the Load Shed Event. The Companies were not unique, as other large electric utilities and Regional Transmission Organizations ("RTO") experienced significant load forecast errors during Winter Storm Elliott.[25] For historical context, Figure 3-1 below shows ten (10) years of winter load for DEC and DEP's combined systems. The load during Winter Storm Elliott was not the highest winter peak load that the Companies have experienced. However, the Load Shed Event occurred much earlier in the winter season than historic peak load events. Duke Energy's forecasting models utilize historical hourly loads and hourly weather forecast variables. The forecast model algorithm also takes into account calendar effects such as time of day, day of week, and holidays. The lack of a similar event so early in the winter hindered Duke Energy's forecasting models. Beyond the

[25] FERC, NERC and Regional Entity Joint Team Status Update December 2022 Winter Storm Elliott Inquiry into Bulk-Power System Operations https://www.ferc.gov/news-events/news/presentation-december-2022-winter-storm-elliott-inquiry-bulk-power-system (accessed July 28, 2023).

inherent difficulty in forecasting load during such extreme weather, there are unique aspects to Duke Energy's forecasting that are noteworthy.

**Figure 3-1:** Duke Energy 10-Year Historical Hourly Winter Load[xxix,26]

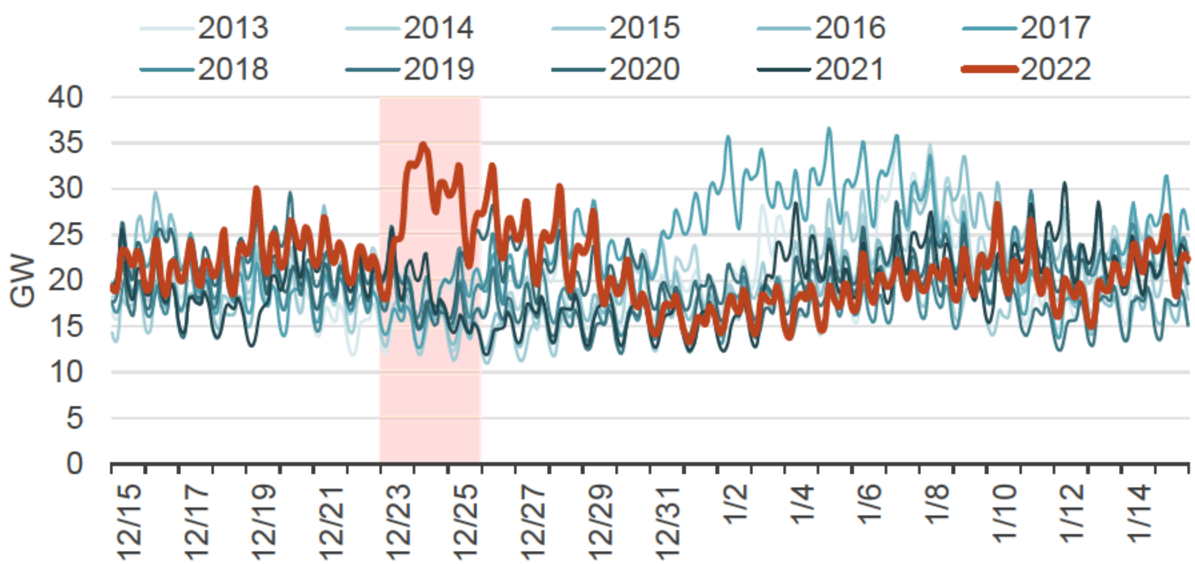



Figure 3-2 below depicts the DEC load forecast and actual load experienced on the system as of the mornings of Monday, December 19, Wednesday, December 21, Friday, December 23, and Saturday, December 24. Figure 3-3 below shows the same information for DEP. For both Companies, the December 19 forecast did not anticipate elevated loads, but the December 21 forecast reflected increased load levels beginning on the evening of December 23. Each subsequent forecast by the Companies increased anticipated load levels.

[26] Year reflects winter year beginning (e.g., 2022 reflects December 2022 to January 2023); Load amounts reflect actual load served without estimated additions for load shed or DSM.

**Figure 3-2:** DEC Hourly Load Forecasts[xxx,27]

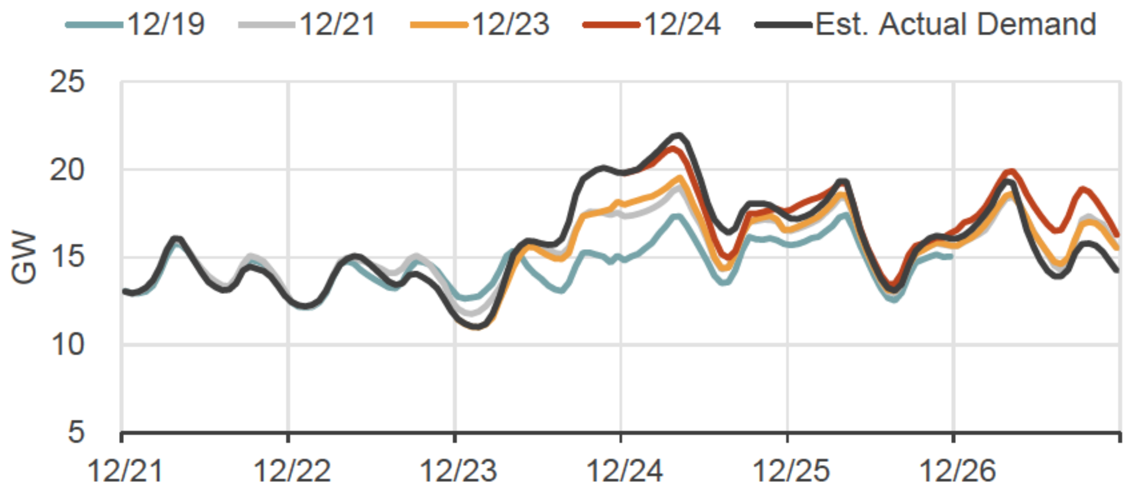
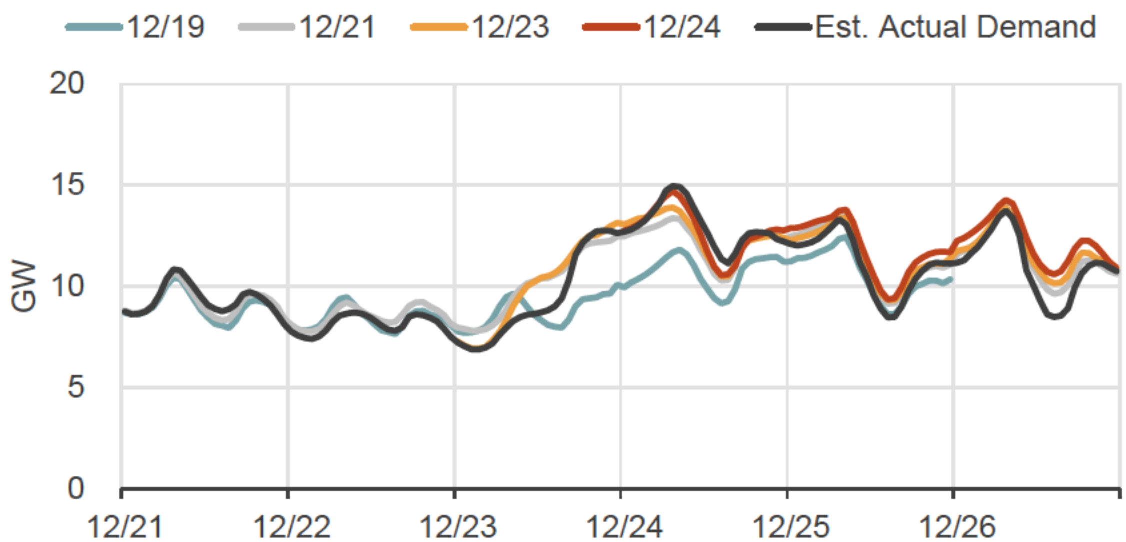



**Figure 3-3:** DEP Hourly Load Forecasts[xxxi]




As shown below in Table 3-1, DEC's December 23 forecast missed actual load levels that same evening by more than two (2) gigawatts ("GW"). Throughout December 23, Duke Energy issued four (4) peak load forecasts for the next seven (7) days and three (3) grid status reports.[xxxii] Despite the large deviation of actual load experienced from forecasted load on December 23, DEC's peak load forecast for the following day, December 24, did not change from the previous morning's forecast of 19,548 MW. The December 23 forecast fell below actual peak load of 21,768 MW by 11.4%.[28]

[27] For Figures 3-2 and 3-3, Estimated Actual Demand includes estimated amounts of load shed and DSM.
[28] Peak load amount includes estimated amounts of load shed and DSM.

DEP's December 23 forecast more accurately reflected the large increase in load that manifested that evening. However, the DEP December 24 peak load forecast similarly did not change from the December 23 morning forecast of 13,913 MW, which missed the actual peak load of 14,824 MW by 6.5%.[29]

**Table 3-1:** DEC and DEP Peak Forecasting Error Leading up to December 24[xxxiii]

| Forecast Date | DEC Peak (MW) | % Error | DEP Peak (MW) | % Error |
|---|---|---|---|---|
| 12/19 | 17,327 | 25.6% | 11,818 | 25.4% |
| 12/21 | 18,973 | 14.7% | 13,377 | 10.8% |
| 12/23 | 19,548 | 11.4% | 13,913 | 6.5% |
| 12/24 | 21,207 | 2.6% | 14,718 | 0.7% |
| 12/24 (Actuals) | 21,768 | - | 14,824 | - |

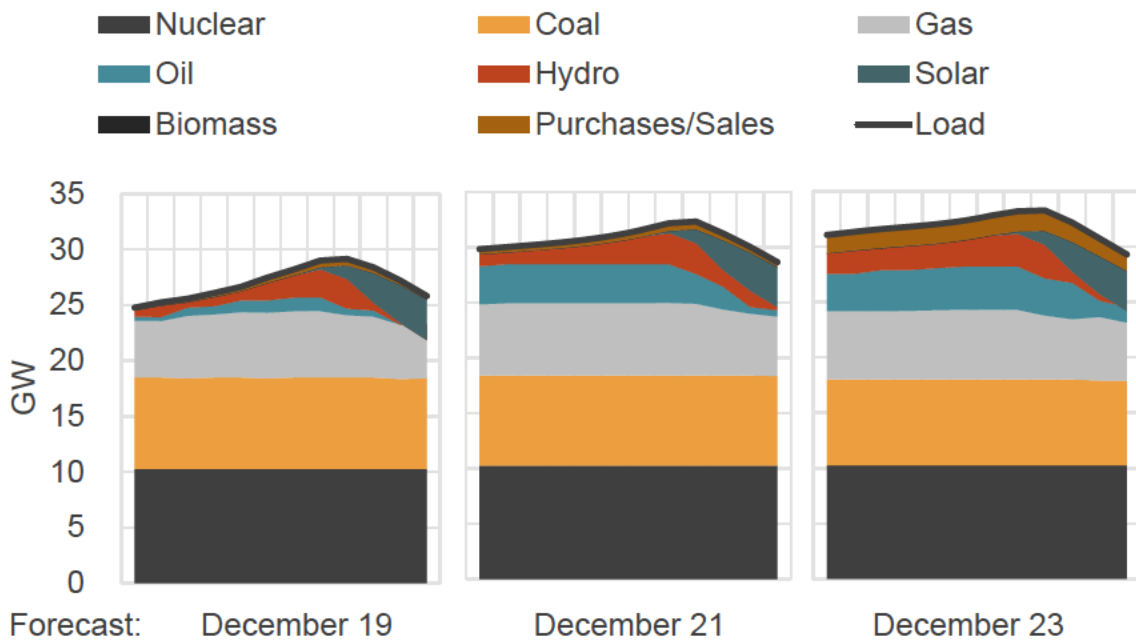
Duke Energy's large load forecasting error contributed to its failure to anticipate the significance of the holiday weekend and led to shortfalls in its supply planning as discussed below in Section 3.1.2.

### 3.1.2 Supply Planning

Duke Energy conducted short-term supply planning by forecasting load as well as the commitment and dispatch of resources to meet that load. Figure 3-4 below depicts the Companies' supply plan for December 24 as of the mornings of December 19, December 21, and December 23. As the forecasted peak load on the combined DEC and DEP systems increased from 29.1 GW on December 21 to 33.3 GW on December 23, the Companies adjusted the supply plan by adding substantial oil-fired dispatch, hydroelectric pump storage discharge, and day-ahead power purchases. Because Duke Energy forecasted the peak to occur from 8:00 to 9:00 AM, the supply plan projected 1.2 GW of solar generation coincident with the peak. Duke Energy projected solar to ultimately increase output to a level of 3.6 GW by midday, while load would decrease to a minimum of 22.7 GW by mid-afternoon. During the midday period of higher solar and lower load, Duke Energy planned to deploy its relevant hydroelectric pumped storage facilities in addition to ramping down natural gas and oil-fired output. [xxxiv]

[29] Peak load amount includes estimated amounts of load shed and DSM.

**Figure 3-4:** Duke Energy Supply Forecasts for December 24[xxxv,30]




A component of short-term supply planning included projections of operating reserve levels based on hourly peak load, available dispatchable capacity, forecasted solar at the peak load hour, available load reduction program capacity, and scheduled power purchases and sales. Figure 3-5 and Figure 3-6 below show the projected operating reserve levels for DEC and DEP, respectively, as of the mornings of December 19, December 21, December 23, and December 24.

On December 19, the Companies projected operating reserve levels to remain well in excess of their reserve targets through December 23 before decreasing somewhat beginning on December 24.

By December 21, the Companies projected a large decrease in operating reserve levels beginning on December 23 and worsening on December 24. DEP projected to be at or below its target operating reserve level beginning December 24 through December 26.

On December 23, the forecasted operating reserve levels for the Companies again worsened. Both DEC and DEP projected operating reserves to be slightly below reserve targets for December 24. DEP also projected to fall below its reserve target for December 26.

[30] Purchases/Sales are inclusive of projected Net Interchange.

On December 24, the operating reserve levels were below zero for that day and forecasted to be close to or beneath the target levels for December 25 and 26.

**Figure 3-5:** DEC Forecasted Operating Reserves[xxxvi,31]

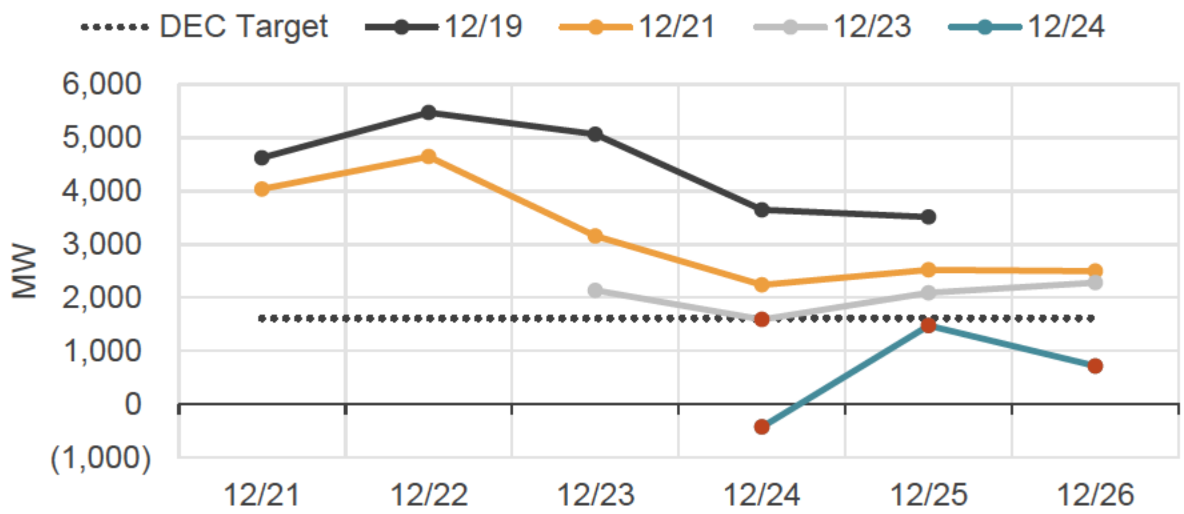
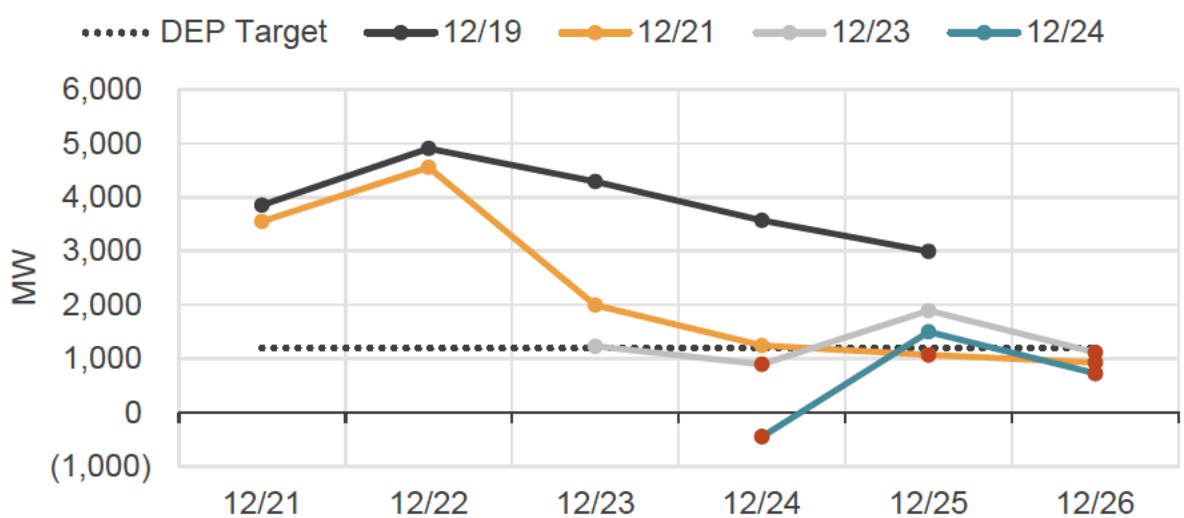



**Figure 3-6:** DEP Forecasted Operating Reserves[xxxvii,32]




As discussed futher in Section 4.3 below, Duke Energy made a supply planning decision not to utilize certain demand response programs on December 24. The decision was

[31] Based on DEC's first morning forecast for each day; reserve level includes load reduction capacity and a reduction for solar forecast error. Red dots indicate reserves falling short of the target.
[32] Based on DEP's first morning forecast for each day; reserve level includes load reduction capacity and a reduction for solar forecast error. Red dots indicate reserves falling short of the target.

motivated by Duke Energy's under-appreciation for the significance of the December 24 supply adequacy risk.

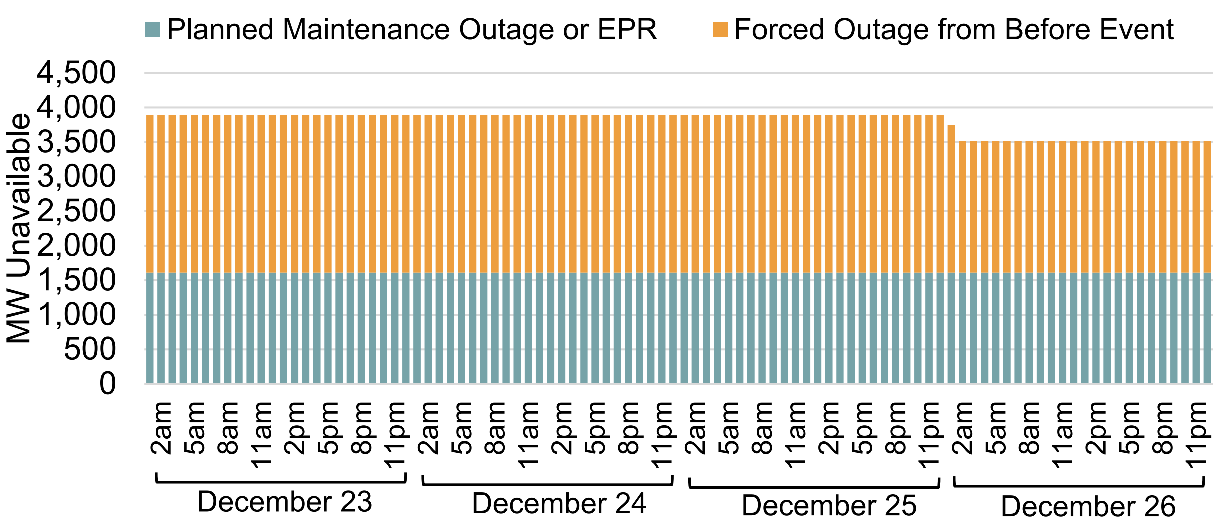
Despite the significant load forecast error, Duke Energy's supply planning still identified risk and a deterioration of supply adequacy for December 24. Duke Energy failed to respond to that risk and plan for additional supply.

## 3.2 CAUSE #2: GENERATION OUTAGES AND FAILURES

Multiple outages and derates at Duke Energy's generation plants limited the Companies' ability to serve load during the Load Shed Event. This section summarizes the plant outages and failures that resulted in decreased generation capacity during Winter Storm Elliott.

Figure 3-7, Figure 3-8, Figure 3-9, and Figure 3-10 below show the hourly capacity impact of generation outages on the DEC and DEP systems from December 23 through December 26. Figure 3-7 shows the outages that were already underway prior to the arrival of Winter Storm Elliott. These outages are further discussed in Section 3.2.1 below.

**Figure 3-7:** Pre-Load Shed Event Generation Plant Outages[33, xxxviii]




[33] EPR is a designation for a generation facility that is operational but placed in reserve status because it is not economical to operate. The utility will hold the facility in reserve and have procedures in place to bring it on-line to operate in the event capacity is needed. Further details can be found in Section 3.2.1.3.

Figures 3-8 and 3-9 below depict the unplanned outages and derates that occurred in the hours immediately prior to and during the Load Shed Event. The unplanned outages were in addition to the outages that started prior to Winter Storm Elliott. These unplanned outages are further discussed in Section 3.2.2.

**Figure 3-8:** Unplanned Generation Plant Outages During Event by Cause/Reason[xxxix]

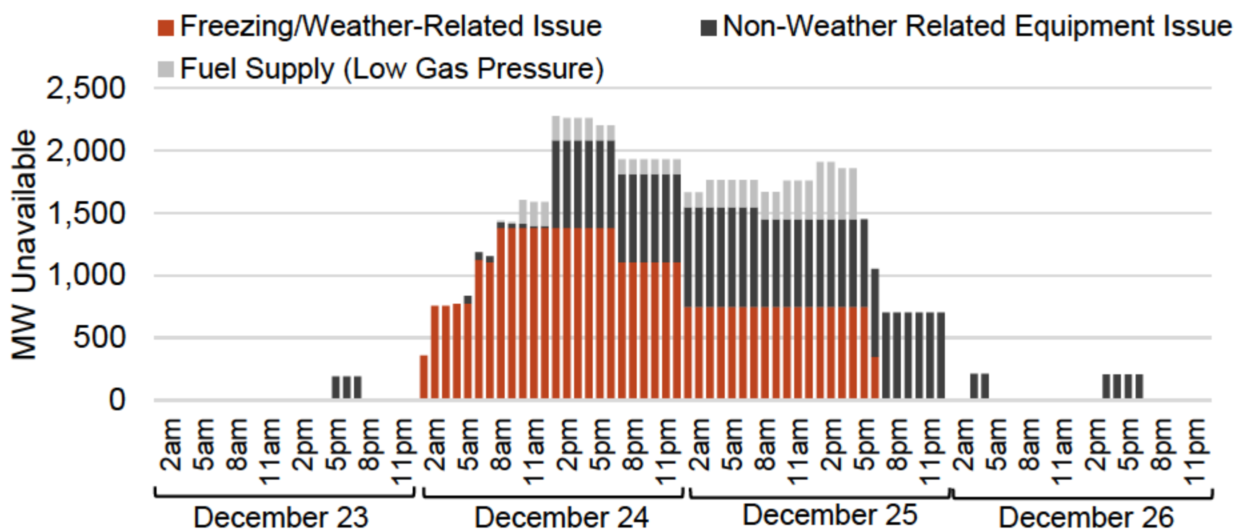



**Figure 3-9:** Unplanned Generation Plant Outages During Event by Plant Type[xl,xli]

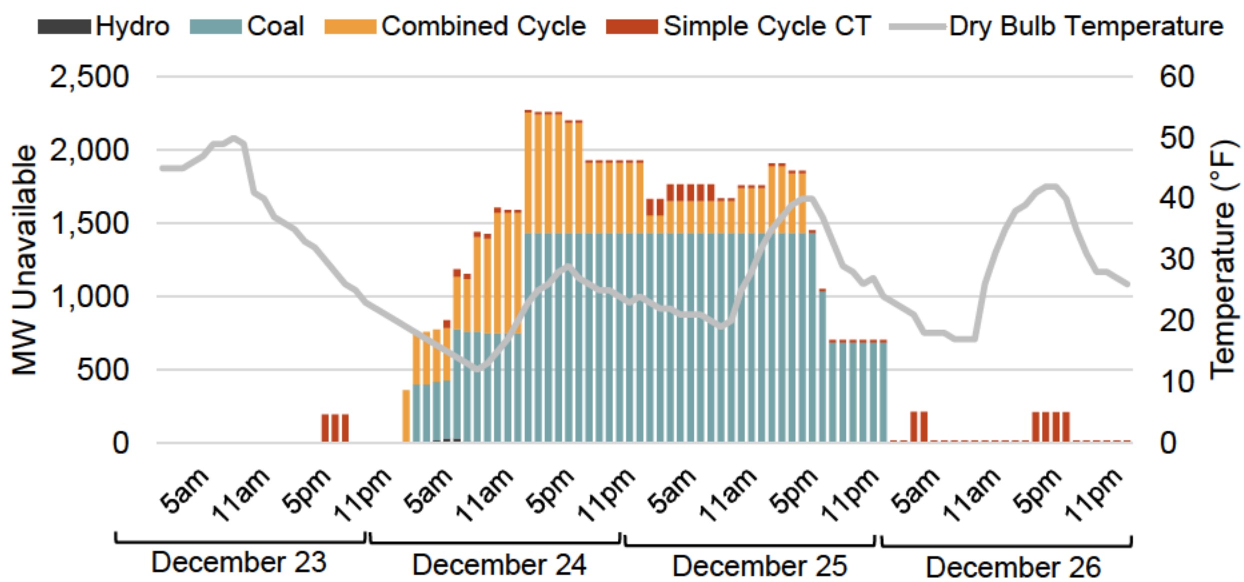
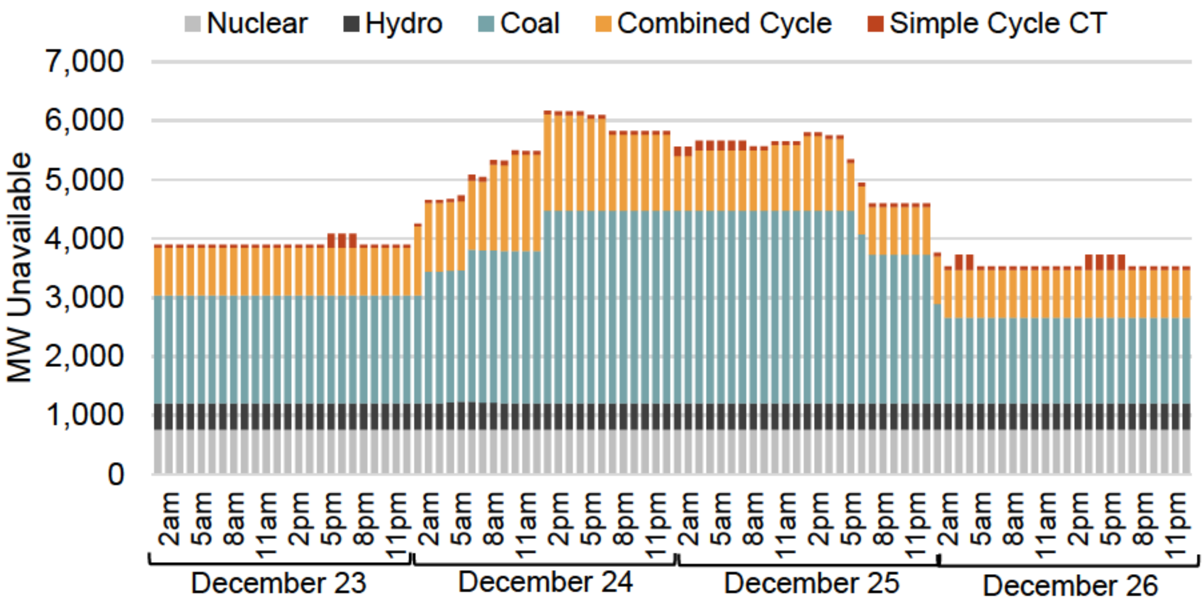


Figure 3-10 below shows all of the generation plant outages from December 23 to December 26 combined. A more detailed list of all of the generation plant outages is provided in Appendix C.[xlii]

**Figure 3-10:** All Generation Plant Outages by Plant Type



### 3.2.1 Planned and Forced Outages and Derates Prior to the Load Shed Event

Prior to Winter Storm Elliott, several of Duke Energy's generation plants were off-line due to planned or forced outage conditions. Also, some plants were derated, meaning they were unable to operate at their full capacities. Table 3-2 summarizes these outages, and Sections 3.2.1.1 and 3.2.1.2 provide descriptions for the outages.

**Table 3-2:** Planned and Forced Outages and Derates Prior to the Load Shed Event[xliii]

| DEC or DEP | Generation Resource | Capacity Unavailable | Outage/Derate Cause | Planned or Forced |
|---|---|---|---|---|
| DEC | Allen Units 1 & 5 | 426 MW | Extended Planned Reserve | Planned |
| DEC | Bad Creek Hydro Unit 3 | 340 MW | Multi-year major upgrade outage | Planned |
| DEC | Bear Creek Hydro | 9.5 MW | Penstock isolation valve installation | Planned |
| DEC | Cliffside Unit 5 | 100 MW | Coal feeder gearbox failure | Forced |
| DEC | Marshall Unit 1 | 380 MW | Boiler circulating pump failure | Forced |
| DEC | Marshall Unit 2 | 380 MW | Boiler tube leaks | Forced |
| DEC | Mountain Island Hydro Unit 1 | 14 MW | Turbine runner replacement | Planned |
| DEC | Ninety-Nine Islands Unit 4 | 3.4 MW | Turbine and generator inspection | Planned |
| DEC | Oxford Hydro Unit 2 | 20 MW | Broken wicket gate link | Forced |
| DEC | Rhodhiss Hydro Unit 3 | 12.4 MW | Trash rack stop log system installation | Planned |
| DEC | W.S. Lee | 809 MW | Fire damage in steam turbine enclosure | Forced |
| DEP | Mayo Unit 1 | 93-206 MW | Failure of two coal feeders | Forced |
| DEP | Robinson Nuclear Station | 759 MW | Refueling outage | Planned |
| DEP | Roxboro Unit 3 | 73-98 MW | Rebuilding pulverizer | Planned |
| DEP | Roxboro Unit 4 | 211 MW | Grounded motor on an induced draft fan | Forced |
| DEP | Smith Energy Complex Unit 2 | 47 MW | Combustor hardware issues | Forced |
| DEP | Walters Unit 3 | 36 MW | Overhaul and turbine generator work | Planned |

### *3.2.1.1 Planned Outages*

Approximately 1,186 MW of Duke Energy's generation fleet was in a planned outage prior to Winter Storm Elliott. Planned outages are typically scheduled well in advance during non-peak times to allow utilities to perform necessary work. In general, planned outages that have started cannot be terminated early because various critical plant equipment is dismantled for inspections, preventative maintenance, or repairs. In addition, there are specific procedures to start up a generating unit from an outage, which include inspections and testing.

> **Planned vs. Forced Outages**
> Generation resource outages are typically classified as either "planned" or "forced." A planned outage is scheduled in advance to inspect, maintain, or refuel a generating unit. A forced outage occurs when a unit is unexpectedly taken off-line due to unanticipated issues such as mechanical or electrical equipment failures or fuel supply failure.

The DEP 759 MW Robinson Nuclear Plant ("Robinson") entered a planned refueling outage on November 11, which was initially scheduled to be completed on December 19. The Company stated the timing of this refueling outage was primarily driven by the timing of nuclear fuel delivery, regulatory-required inspections, and the availability of both Company and external resources to support the outage.[xliv] The overall approval of schedules and durations of nuclear plant outages are the responsibility of Duke Energy's Fleet Outage Review Board, which is comprised of the Chief Nuclear Officer, Senior Vice Presidents, and Site/Corporate Vice Presidents.[xlv] Due to an emergent issue discovered during an inspection that required repairs before Robinson could be safely returned to service, the planned outage was extended until December 30, and the plant was unavailable for the duration of Winter Storm Elliott.

The DEC 340 MW Bad Creek Hydro Unit 3 was in a multi-year planned major upgrade outage that began in November 2021 and was also unavailable during Winter Storm Elliott.

In addition, 87 MW of capacity from multiple small hydro units were off-line for routine planned outages and were unavailable during Winter Storm Elliott.[34] Duke Energy stated that due to FERC regulatory compliance and seasonal inflow considerations, these outages are often conducted in the winter when regulatory recreation flows are not required, and severe rainfall events are less likely.[xlvi]

[34] Hydro units in planned outage included Bear Creek, Mountain Island, Ninety-Nine Islands, and Rhodhiss for DEC, and Walters for DEP.

### *3.2.1.2 Forced Outages*

Several forced outages that began prior to Winter Storm Elliott rendered 2,260 MW of Duke Energy's generation capacity unavailable to serve load during Winter Storm Elliott.

The largest of these forced outages was at DEC's 809 MW W.S. Lee Steam Station NGCC plant. The W.S. Lee plant was in a forced outage that resulted from a fire in the steam turbine enclosure that occurred on December 11. The plant was returned to service in mid-January 2023.

Another large contributor to Duke Energy's diminished generation capacity was the DEC Marshall Steam Station. Marshall Unit 1, with a nameplate capacity of 380 MW, entered a forced outage in November 2022 due to a failure of the boiler circulating pump, and vendor material delivery delayed the return to service through December. Marshall Unit 2 tripped off-line on December 20, due to boiler tube leaks, forcing an additional 380 MW of capacity off-line until December 26.

In addition to the larger outages, capacity derates and outages at other generation units further decreased Duke Energy's generation capacity by 682 MW during Winter Storm Elliott. The derates included a 211 MW derate at DEP's Roxboro Unit 4, a 100 MW derate at DEC's Cliffside Unit 5, a 93 MW derate and an additional 113 MW derate at DEP's Mayo Unit 1, a 73-98 MW derate at DEP's Roxboro Unit 3, a 47 MW derate at DEP's Smith Energy Complex Unit 2, and an outage at DEC's 20 MW Oxford Hydro Unit 2. Many of these derates required repairs that were delayed due to out-of-stock parts, long lead times for replacements, or other equipment delivery issues.

### *3.2.1.3 Extended Planned Reserve*

EPR is a designation for a generation facility that is operational but placed in reserve status because it has been deemed not economic to operate. While the facility is in reserve status, the utility has procedures in place to bring it on-line to operate in the event capacity is needed.

A unit in EPR is treated as unavailable in Duke Energy's short-term supply planning.[35] Duke Energy's EPR procedures require five (5) days of notice to bring a unit out of EPR. For the DEC 426 MW Allen Steam Station Units 1 and 5 ("Allen Units"), an additional 24 hours are estimated for cold start return to service, and another eight (8) hours to be available for full load.[xlvii] The Companies' EPR procedure noted that, rather than starting an EPR unit, short-term duration runs (a few days) due to hot or cold weather should be

[35] See supra footnote 34.

evaluated on a case-by-case basis, and in most cases, energy should be purchased or transferred from an affiliate if available.[xlviii]

The Allen Units, scheduled for retirement at the end of 2023, were in EPR for all of 2022. Staffing for the Allen Units is supplemented from the Marshall Steam Station.[xlix]

Duke Energy stated in response to ORS discovery that leading up to the weekend of December 24, the system showed adequate reserves without the Allen Units. Therefore, the Company released the employees for the holiday weekend. However, on the afternoon of December 22, the Company determined the Allen Units should come out of EPR and return to service and it would take until at least December 26 or 27 to do so, by which time temperatures were forecast to be increasing.[l] Finally, based on the forecast, Duke Energy made the decision not to return Allen Units 1 and 5 to service for the remainder of the year.[li] Due to the earlier decisions of Duke Energy's management team, the 426 MW of capacity from the Allen Units were unavailable during the Load Shed Event.

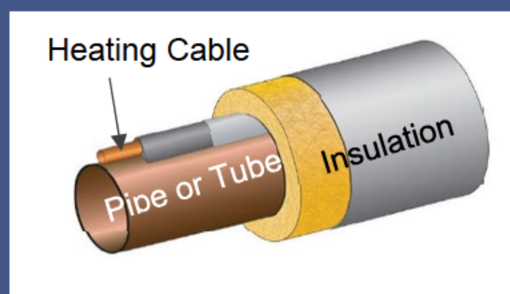
### 3.2.2 Outages During the Load Shed Event

From December 23 through December 26, several Duke Energy generation plants encountered forced outages or derates. Some of the outage and derate causes were the direct result of Winter Storm Elliott's cold weather, and others were unrelated to the cold weather.

#### *3.2.2.1 Weather-Related Outages*

Several of Duke Energy's generation plants experienced equipment failures, causing forced outages or derates, due to freezing conditions during Winter Storm Elliott.

**Insulation & Heat Tracing**
Freeze protection measures commonly used by power plants on piping and instrumentation lines that are exposed to the elements.




#### ***3.2.2.1.1 DEP Roxboro Unit 3: 398 MW Forced Outage***

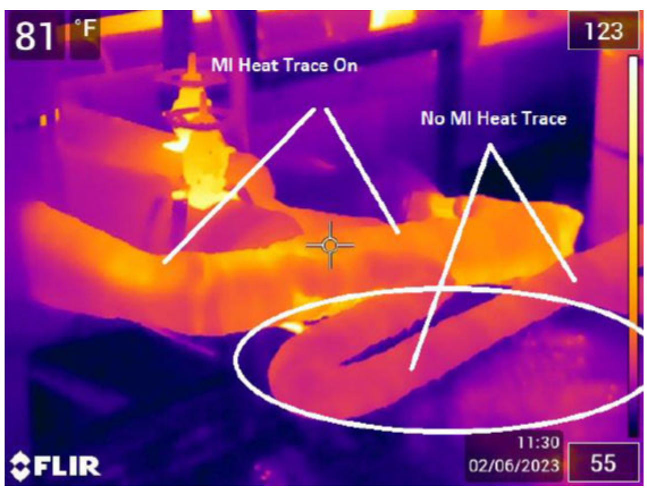
Frozen instrumentation lines and switches forced DEP's Roxboro Unit 3 to derate and resulted in a loss of 398 MW of generation capacity at approximately 2:30 AM on December 24. The boiler feed pump was forced out of service, and even though troubleshooting efforts to return the pump to service began immediately, Duke Energy staff was unable to resolve the issue on December 24.[lii] Troubleshooting resumed on the morning of December 25, and a crack was discovered in the insulation of one of the sensing lines that allowed ingress of cold air. After the sensing lines were thawed and the pump was repaired, the Roxboro unit was brought back on-line that evening.[liii] Figure 3-11 below is a picture provided by DEP identifying the location of the cracked insulation.

**Figure 3-11:** Cracked Insulation on Sensing Lines Discovered at Roxboro Unit 3[liv]

### *3.2.2.1.2 DEC Dan River NGCC Unit 9: 359 MW Forced Outage*

DEC's Dan River Unit 9 tripped off-line just before midnight on December 23 due to frozen instrumentation, resulting in a loss of 359 MW of generating capacity. Dan River Unit 9 was not returned to service until after midnight on December 25. When Duke Energy performed a causal analysis[lv] after the Load Shed Event, it was determined that freezing of the instrumentation lines occurred due to improper application and installation of heat trace tape. As part of the causal analysis investigation, testing was performed on the identically designed Unit 8, which showed that the instrumentation self-regulating heat trace cabling was not contributing to the current (amperage) load on the circuit. The causal analysis concluded that the self-regulating heat trace was not working as designed likely because it was rated for a maximum intermittent process temperature well below what it regularly experienced during operation. In addition, Duke Energy had not updated the drawings to reflect all the installed weatherization measures, specifically the heat tracing, and poor configuration management contributed to the outage. The causal analysis also noted less than adequate quality control and engineering from initial construction of the plant. Figure 3-12 below shows piping where heat trace tape was found not applied.

**Figure 3-12:** Lack of Heat Tracing Discovered at Dan River Unit 9[lvi]

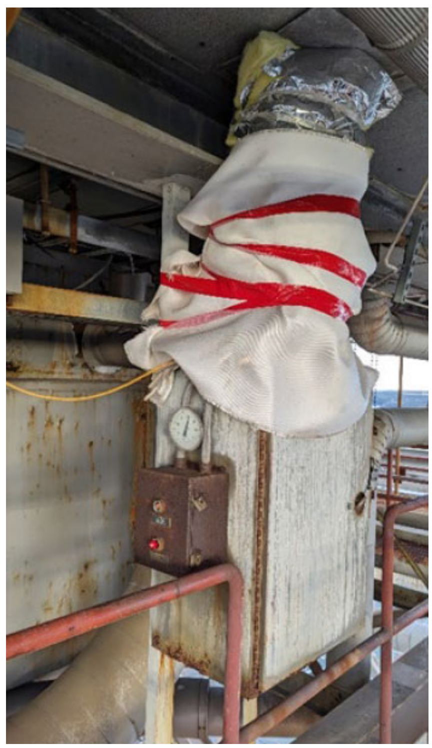


### *3.2.2.1.3 DEP Mayo Unit 1: 336-350 MW Forced Derate*

Frozen sensing lines and frozen limestone resulted in a 336-350 MW derate of DEP's Mayo Unit 1 from 713 MW by from December 24 through December 25. DEP's inspection identified the insulation and heat tracing were intact and operational; however, one section of the instrument line was outside and exposed to cold and wind, which overcame the freeze protection measures in place. The affected section of the line was covered with temporary additional insulation after the issue was discovered.

Figure 3-13 below shows temporary weatherization installed on the sensing line.

**Figure 3-13:** Temporary Mayo Unit 1 Weatherization[lvii]



### *3.2.2.1.4 DEP Smith Energy Complex NGCC Power Block #4 ("PB4") Unit 8: 273 MW Forced Derate[36]*

DEP's Smith Unit 8 experienced issues with frozen instrumentation lines that resulted in an overall plant derate of 273 MW at 8:40 AM on December 24. A small portion of the tubing that leads to the pressure transmitters was found to be uninsulated, which allowed it to freeze.[lviii] The Company reported the most likely cause was less than adequate design/installation, as incomplete insulation and heat trace installation was found in the

[36] Smith Energy Complex NGCC is commonly referred to as "Richmond County CC".

identical configuration on the affected unit as well as an identical unaffected neighboring unit. Furthermore, existing Preventative Maintenance tasks address heat trace functionality and thermal insulation material condition, but with nonspecific language generally intended to ensure systems are "adequately protected." The nonspecific instructions significantly influenced the station's ability to discover this issue prior to Winter Storm Elliott.[lix]

#### *3.2.2.1.5 DEC Mountain Island Hydro Station Unit 2: 17 MW Forced Outage*

DEC's Mountain Island Unit 2 failed during start-up just after 4:00 AM on December 24 due to cold air entering the building through a door that had been left open. This condition increased viscosity of the oil, which decreased the flow and caused 17 MW to fail to start and remain off-line for about three (3) hours during a critical period of high demand on the morning of December 24.

#### *3.2.2.1.6 DEC Clemson CHP: 14 MW Forced Outage*

Due to insufficient natural gas pressure delivered from Fort Hill Natural Gas Authority, the 14 MW DEC Clemson Combined Heat and Power ("CHP") facility tripped off-line at 8:00 AM on December 24 and was off-line until 2:15 PM that day.[lx] Natural gas delivery issues are further discussed in Section 4.1.1.

### *3.2.2.2 Non-Weather-Related Outages*

#### *3.2.2.2.1 DEP Roxboro Steam Plant Units 1 & 2: 685 MW Forced Derate*

The largest forced derate that occurred during Winter Storm Elliott occurred at DEP's Roxboro plant. One of the plant's coal reclaim conveyor belts failed and restricted operations at Units 1 and 2. This condition resulted in an overall loss of 685 MW of generating capacity from December 24 through December 26. The derate at DEP's Roxboro plant was not a result of cold winter weather conditions.

#### *3.2.2.2.2 DEP Smith Energy Complex CT Unit 1: 192 MW Forced Outage*

DEP's 192 MW Smith Energy Unit 1 failed to start on December 23 due to a problem with the generator neutral disconnect. The unit was returned to service later that evening and was available and operating during the Load Shed Event.

#### *3.2.2.2.3 DEC Belews Creek Steam Station Unit 1: 125 MW Forced Derate*

DEC's Belews Creek Unit 1 booster fan tripped on December 22 from high vibration and resulted in a derate of 125 MW. According to DEC, an inspection would have required a full unit outage, and placing the fan back in service could have resulted in another high vibration trip. Therefore, the plant operated at the derated capacity for the duration of the Load Shed Event.

#### *3.2.2.2.4 Other Issues*

In addition to the larger generation plant outages, there were some brief outages of smaller MW quantity that contributed to Duke Energy's decreased generating capacity during Winter Storm Elliott. Start-up failures of DEP's Blewett simple cycle natural gas CT Units 1, 2, and 4 kept 51 MW off-line during the critical peak period of December 24. While Duke Energy was able to make repairs and successfully start up Units 1 and 4 later that day, Unit 2 remained off-line for several days.

DEC's 11.5 MW Tennessee Creek Hydro Station also failed to start at 5:00 AM on December 24, and the plant was returned to service after approximately four (4) hours.

DEC's 95 MW Mill Creek CT Unit 7 tripped while using fuel oil in the early hours of December 25 and was brought back on-line by switching to natural gas later that morning.

In summary, prior to December 24, 3,895 MW of Duke Energy's generation capacity were unavailable due to planned or forced outages. During Winter Storm Elliott, another 2,260 MW was unavailable due to freezing problems or various other equipment issues described above. In total, 5,047 to 5,501 MW were unavailable throughout the Load Shed Event on the morning of December 24, which directly contributed to the Companies' inadequate generation supply.

## 3.3 CAUSE #3: CURTAILED PURCHASES

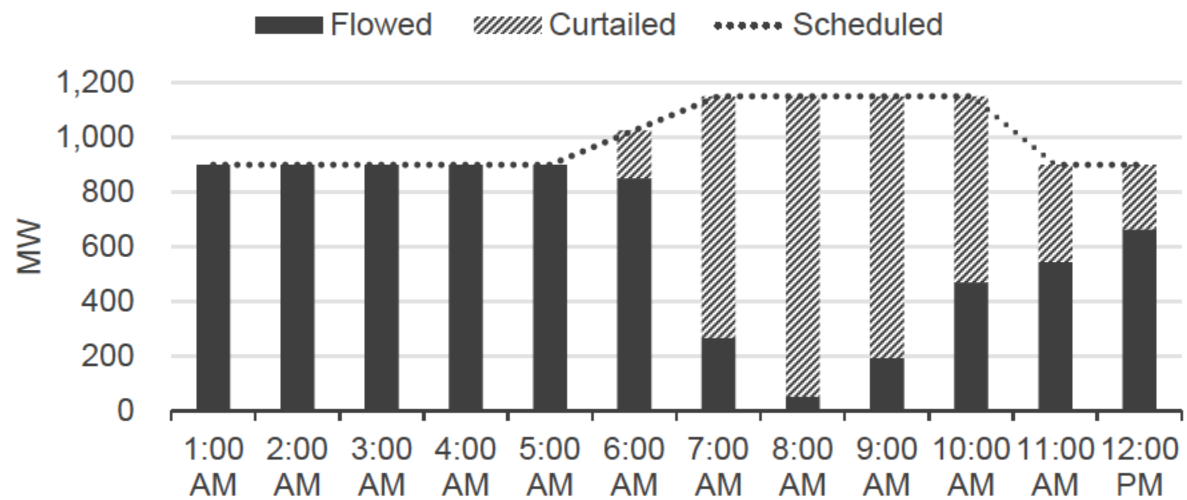
The DEC and DEP BAA footprints neighbor several other utilities including Dominion Energy South Carolina, Inc. ("DESC") and Santee Cooper in South Carolina and TVA and Southern Company outside of the Carolinas. Additionally, Duke Energy is bordered to the north by the PJM Interconnection, which is an RTO comprised of many utility members. Duke Energy may purchase and import power from its neighbors (including from suppliers in PJM) through bilateral identification of willing sellers and arrangement for transmission service to effectuate imports.

**Firm versus Non-Firm**
Power and transmission may be purchased and scheduled on a firm or non-firm basis. The distinction of firm transmission service provides a higher priority of service compared to non-firm transmission service. Non-firm purchases are reliant on available system capacity and will be curtailed if such capacity is not available. Non-firm scheduled purchases will always be curtailed prior to firm scheduled purchases.

Duke Energy made a series of power purchases scheduled for December 23 and December 24 on a day-ahead and intra-day basis, meaning purchases were executed for delivery on the subsequent day. For delivery on December 23, Duke Energy purchased 370 MW for non-firm delivery over, roughly, the second half of the day. For delivery on December 24, Duke Energy purchased 940 MW for firm delivery over almost all hours of the day. On both days, Duke Energy sourced the majority of its purchases from suppliers within PJM.[lxi]

On the evening of December 23, Duke Energy's non-firm purchases from PJM were curtailed for several hours. On December 24, Duke Energy's firm and non-firm purchases from PJM were curtailed starting at 5:30 AM. As shown below in Figure 3-14, the amount of curtailments increased to nearly 100% during the hour of 7:00 to 8:00 AM, which coincided with peak demand on the Duke Energy system during the Load Shed Event. After 8:00 AM, the level of curtailment began to decrease until eventually all curtailment by PJM of firm and non-firm purchases ended after noon on December 24.

**Figure 3-14:** Curtailed PJM Purchases, Morning of December 24[lxii,37]




Based on its wide area impact, Winter Storm Elliott also heavily impacted supply and demand in the PJM footprint driving the RTO to initiate its own emergency procedures in accordance with its FERC approved Tariff and NERC Reliability Standards.[lxiii] After 4:00 AM, PJM entered EEA 2 and among other actions, terminated scheduled energy exports from PJM.[38] The widespread nature of Winter Storm Elliott and its impact on Duke Energy's neighbor utilities eliminated almost all external support to Duke Energy during the peak load hours on the morning of December 24.

## 3.4 CAUSE #4: NETWORK CUSTOMERS

As TSPs, DEC and DEP provide transmission service to other utilities and Load Serving Entities within their BAAs in accordance with the FERC-approved, Open Access Transmission Tariffs ("OATT"). Specifically, there are Load Serving Entities, including other utilities, municipalities, and electric cooperatives interconnected with Duke Energy's transmission system that acquire their own wholesale power supply and utilize transmission service from Duke Energy for delivery ("Network Customers"). Network Customers may contract with IPPs (third-party owned generation). Additionally, Duke Energy is a provider of wholesale power to Load Serving Entities, including other utilities, interconnected to its transmission system. In its roles as BA and TSP, Duke Energy has formal protocols in place that govern communications and scheduling with Generator Operators and Load Serving Entities.[lxiv]

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[37] Based on confidential discovery responses from Duke Energy, PJM sourced purchases include 900 MW of firm purchases, and 250 MW of non-firm purchases between 6:30-10:00 AM.
[38] SCPSC Allowable Ex Parte Briefing ND-2023-6-E, "Duke Energy December 24, 2022, Load Shed Event." p. 10, February 27, 2023.

On December 24 shortly after 5:00 AM, an IPP contracted with Network Customers serving load in the DEC and DEP BAAs tripped off-line. Duke Energy requested the Network Customer schedule replacement generation resources to balance the Network Customer load; however, the Network Customer's agent reported that no other replacement generation resources were available.[lxv] The IPP, 501 MW [redacted] serving municipal wholesale transmission customers in both the DEC and DEP service territories, ultimately did not return to service until after 10:00 AM at which point Duke Energy's load shed directive had ended.[lxvi] DEC provided uninterrupted service to the Network Customers through the IPP outage.

In its role as a TSP, Duke Energy provided uniterrupted service to the Network Customers through the applicable period of IPP unavailability during the Load Shed Event.[39,lxvii] Duke Energy's Joint OATT contains provisions for "Spinning Reserve Service" (OATT Schedule 5) that 1) generally applies to the first ten (10) minutes following an unplanned outage of a Network Customer's generation resource and 2) "Supplemental Reserve Service" (OATT Schedule 6) that is generally not available immediately and served by on-line but onloaded or quick-start generation. The Joint OATT Schedule 5 and 6 Reserve Services do not necessarily have time limits for service.

However, the Joint OATT Section 13.6 "Curtailment of Firm Transmission Service" states, in part:

> When the Transmission Provider determines that an electrical emergency exists on its Transmission System and implements emergency procedures to Curtail Firm Transmission Service, the Transmission Customer shall make the required reductions upon request of the Transmission Provider. However, the Transmission Provider reserves the right to Curtail, in whole or in part, any Firm Transmission Service provided under the Tariff when, in the Transmission Provider's sole discretion, an emergency or other unforeseen condition impairs or degrades the reliability of its Transmission System. The Transmission Provider will notify all affected Transmission Customers in a timely manner of any scheduled Curtailments.

Additionally, the Joint OATT Section 33 "Load Shedding and Curtailments" require Network Customers to establish load shedding and curtailment procedures and further reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to curtail network integration transmission service.[40]

[39] Duke Energy reported that it did request load shed from one of its wholesale customers at 7:04 AM.
[40] Joint Open Access Transmission Tariff of Duke Energy Carolinas, LLC Duke Energy Florida, LLC and Duke Energy Progress, LLC.

Duke Energy reported that its Joint OATT contains provisions for curtailment and load shed of Network Customers. However, Duke Energy also stated there was no viable or practical mechanism in place to curtail the Network Customer load in the needed timeframe.[lxviii] Accordingly, Duke Energy provided Supplemental Reserve Service to the affected Network Customers throughout the IPP outage and Load Shed Event; the provision of Supplemental Reserve Service contributed to Duke Energy's resource inadequacy.

Another IPP, 615 MW [redacted] serving electric cooperative Network Customers in the DEC service territory, tripped off-line at 8:22 AM and returned at 8:57 AM.[lxix] DEC provided uninterrupted service to the Network Customers through the brief IPP outage.

DEC and DEP did curtail five (5) wholesale customer feeders during the Load Shed Event. These curtailments were unrelated to the IPP outages.[lxx]

## 3.5 **CAUSE #5: LOAD SHED IMPLEMENTATION**

Duke Energy's Energy Management System ("EMS") Load Shed Application Procedure[41] was updated in May 2022 and contained detailed, step-by-step actions for how Duke Energy Transmission System Operators should utilize the RLS tool.

The Load Shed Application Procedure states that the utilization of the Distribution Load Shed Reduction Tool should be used first for system or area-wide load shedding, meaning Duke Energy should shed its retail load at the distribution level before higher priority action is taken. [redacted] The RLS tool automates the load shed and restoration process via the software selection and interruption of service to distribution circuits before restoration of service after a 15- to 30-minute interval and rotation of the outage to a subsequent circuit.[lxxi]

On December 24, the DEC and DEP Energy Control Centers ("ECCs") directed load shed on both systems, and the RLS tool failed for both systems. The failure caused Duke Energy to resort to a manual load shed and restoration process, which extended the duration of customer outages. Under the manual process, customers may experience an outage for an hour or more.[lxxii]

[41] DEC-EOP-OP32, Rev. 1 05/13/2022.

For the DEC system, a load shed of 400 MW was directed at 6:14 AM and implemented with the RLS tool at 6:27 AM. Two (2) additional load shed requests of 300 MW each were implemented at 7:00 and 7:01 AM with the RLS tool, which resulted in a total load shed directive of 1,000 MW. When an additional 300 MW of load shed was requested at 7:54 AM, the RLS tool failed to function and was disabled. The amount of load shed was ultimately maintained at 1,000 MW. Although DEC did not implement manual load shed, DEC did restore customers manually.[lxxiii]

For the DEP system, a load shed of 600 MW was requested at 6:25 AM and implemented at 6:50 AM. The RLS tool stopped responding at 6:57 AM as the RLS tool attempted to restore load and DEP disabled the tool. At 7:10 AM, an additonal load shed of 200 MW was requested and was implemented manually. At 7:43 AM, an additional load shed of 50 MW was requested. At 7:52 AM, DEP escalated the level of load shed and manually shed approximately 111 MW of load at the transmission level.[lxxiv]

Prior to Winter Storm Elliott, Duke Energy tested the RLS tool in a simulated environment but not at the magnitude of load shed directed on December 24. To avoid actual customer outages, Duke Energy did not test the RLS tool in a production environment. The inability to test the RLS in a production environment combined with the discrepancy between tested and actual amounts of load shed resulted in the RLS tool deficiencies not being recognized by Duke Energy prior to the Load Shed Event. The RLS tool deficiency did not become apparent until it was implemented in a real-world production environment with much higher load shed amounts. Additionally, the RLS tool failures were related to a software update that caused issues related to interdependencies with other Duke Energy software packages. An RLS tool patch has since been installed and tested in a simulated environment.[lxxv]

**Loss of Load Diversity**
An example of load diversity is when multiple air conditioners, refrigerators, well pumps, etc. cycle on and off at different times. As outage time increases, more loads start to cross temperature and pressure setpoints and more loads start running as soon as power is restored. Loss of load diversity causes a significant surge in load current, which may exceed normal load levels expected by protection devices. This condition is known as "cold load pickup" (with 'cold' referring to the unenergized state of the circuit.)

The manual load shed process took longer because of the human interaction required to process the feeder priority list (i.e., determine which areas to shed). Longer outage times resulted due to the human interaction required to select feeders for service restoration as well as some required manual field intervention (including manually operating system control devices). Because outage durations extended beyond 60 minutes, the load pickup time increased (i.e., the amount of load restored at the feeder adds to the system for a short duration). As the outage time increased, the Duke Energy system lost load diversity. The additional load decayed over a comparatively long time (by protective relaying standards), perhaps 30 minutes or more.[42] Duke Energy estimated the amount of load at each feeder to be double due to cold load pickup. The cold load pickup further complicated the restoration process and required the system to be manually isolated at additional points to control how much load was restored at any given point in time.[lxxvi]

For DEC, the ECC notified the Distribution Control Center ("DCC") to release the last of the load shed at 10:00 AM on December 24. If the RLS tool had functioned as designed, customers would have had service restored within 15- to 30-minutes from that time. However, the restoration was extended well beyond that timeframe because of the slower manual restoration process.[lxxvii]

For DEP, the ECC notified the DCC to release the last of the load shed at 8:43 AM on December 24. Similar to DEC, if the RLS tool had functioned as designed, customers would have had service restored within 15- to 30-minutes from that time. The restoration was extended beyond that timeframe because of the slower manual restoration process.[lxxviii]

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[42] See IEEE Guide for Protective Relay Applications to Distribution Lines," in *IEEE Std C37.230-2020 (Revision of IEEE Std C37.230-2007)*, pp.1-106, 19 March 2021.

Figure 3-15 below shows the number of customers with an outage on December 24. The figure includes customer outages in both North Carolina and South Carolina for any reason (load shed, wind event, other). DEC experienced its maximum amount of customer outages around 7:00 AM, whereas DEP's peak outages were an hour later at 8:00 AM. For the Companies, the manual restoration process gradually reduced the number of customer outages throughout December 24.

**Figure 3-15:** North and South Carolina Customers on Outage, December 24[lxxix]

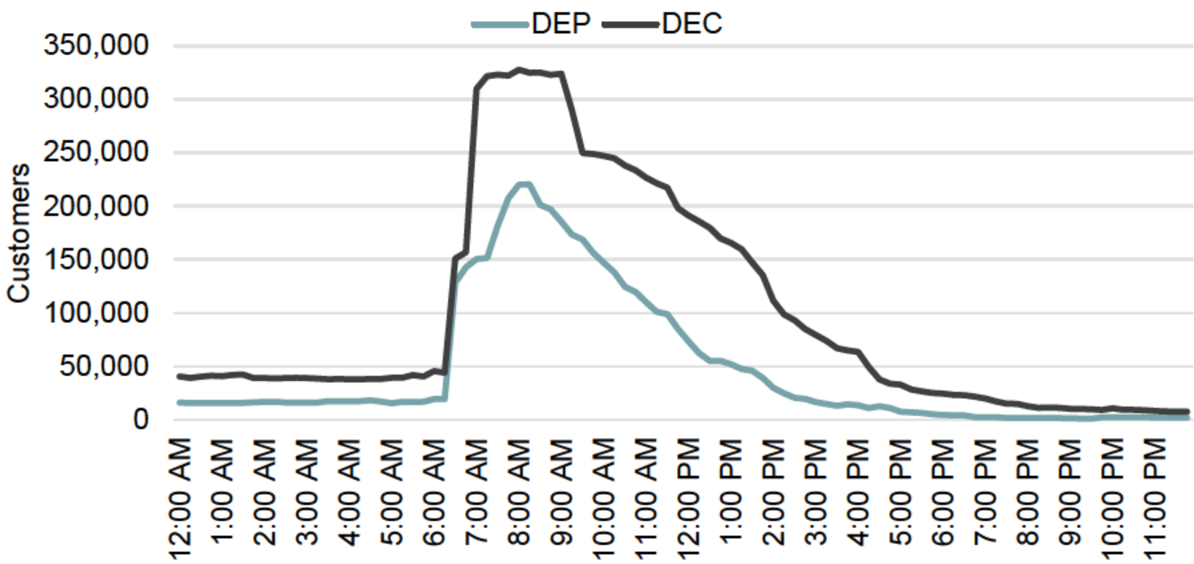
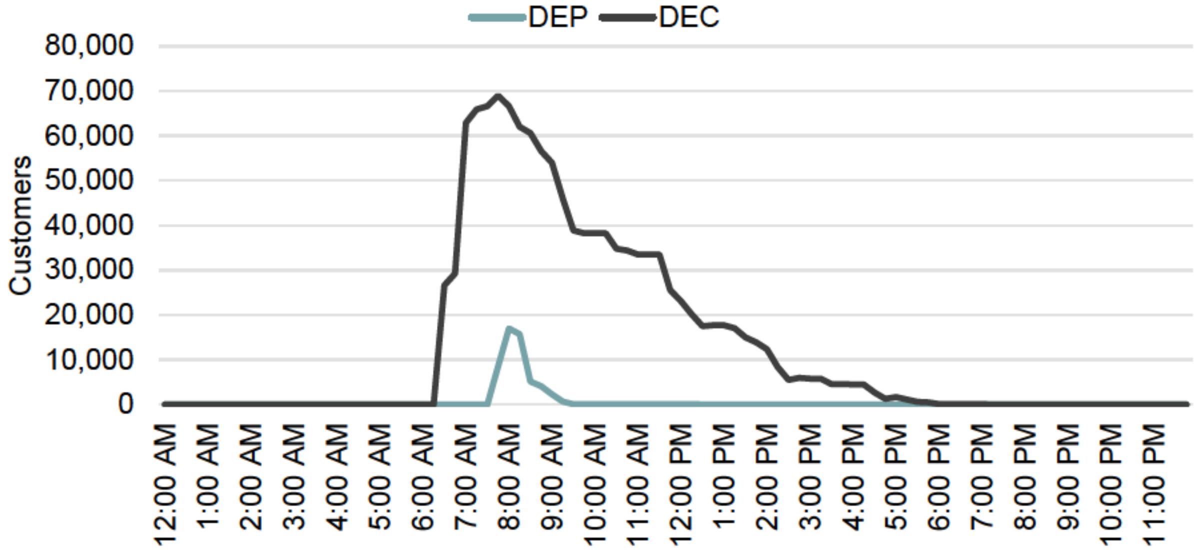



Figure 3-16 below depicts the number of customer outages in South Carolina and is inclusive only of outages caused by load shed. Based on each Company's service territory and the areas prioritized for load shed, a larger number of DEC customers experienced outages versus DEP customers. For DEC, the customer-weighted average outage time was 186 minutes and the maximum outage time was 610 minutes. For DEP, the customer-weighted average outage time was 49 minutes, and the maximum outage time was 414 minutes.

**Figure 3-16:** South Carolina Load Shed Outages, December 24[lxxx]




Because of the failure of Duke Energy's RLS tool, customer outages were extended and restoration was delayed. If the RLS tool had operated successfully, customer outages would have been limited to 15- to 30-minutes and restoration would have been completed more quickly.

# 4 Areas That Did Not Directly Contribute to Outages

## 4.1 FUEL SUPPLY

### 4.1.1 Natural Gas

Three (3) of Duke Energy's generation plants were forced off-line or forced to derate on December 24 and 25 due to insufficient natural gas pressure delivered from the Williams Transcontinental interstate pipeline ("Transco"), Piedmont Natural Gas Pipeline ("PNG"), and Fort Hill Natural Gas Authority ("Fort Hill"). The DEC Clemson CHP facility tripped off-line at 8:00 AM on December 24 due to low natural gas pressure from Fort Hill and was off-line until 2:15 PM.[lxxxi] The DEC Buck NGCC Station ("Buck") did not receive enough natural gas pressure to operate at full load and was derated by 120 to 178 MW starting at 9:45 AM on December 24. Duke Energy stated the Buck derate did not contribute to the Load Shed Event on December 24 because it occurred after the peak demand period.[lxxxii]

On December 25, the DEC Dan River NGCC Station ("Dan River") was also forced to derate by 100 to 338 MW throughout the day due to low natural gas pressure. According to Duke Energy, the Dan River derate did not contribute to the Load Shed Event because it occurred the day after on December 25.[lxxxiii]

Based on the information provided to ORS from Duke Energy, it appears there were no contractual failures related to the pressure of natural gas delivered by Transco. [redacted][xxxiv]

### 4.1.2 Fuel Oil

Fuel oil was consumed at the Rogers Energy Complex (Cliffside), W. S. Lee Station, Lincoln CT Station, Mill Creek CT Station, Rockingham CT Station, Mayo Plant, Roxboro Plant, Asheville Plant, Blewett CT, Darlington Plant, Smith Energy Complex, Sutton Energy Complex, Wayne County Plant, and Weatherspoon CT Station during the period of December 19 through 26. Over 12.7 million gallons of fuel oil were consumed at the facilities during that time period - approximately 3.4% of the total inventory.[lxxxv] Duke Energy's fuel oil inventories were sufficient for December 19 through December 26. Duke Energy discussed and coordinated additional deliveries for December 23 and 24 with various fuel oil suppliers/transporters.[lxxxvi] Fuel oil was replenished with deliveries at Rogers Energy Complex (Cliffside), W.S. Lee Station, Mill Creek CT Station, Rockingham CT Station, Mayo Plant, Roxboro Plant, and Weatherspoon CT Station on days during and surrounding the extreme weather.

### 4.1.3 Coal

Beginning in the summer of 2021, railroads struggled to keep up with coal-delivery demand, primarily due to staffing shortages after layoffs during the COVID-19 pandemic. Coal supply issues persisted in 2022, and as a result, coal power plants around the country experienced unprecedented supply chain constraints. Despite delivery delays, Duke Energy reported that coal inventories at the Companies' coal generation stations were sufficient to meet the forecasted generation demand during Winter Storm Elliott.[lxxxvii]

## 4.2 **TRANSMISSION**

Duke Energy reported the high-wind event on December 23 had impacts to its distribution system but had no significant impacts on the transmission system. Additionally, because of the holiday, no significant transmission maintenance or upgrades were performed.[lxxxviii] Furthermore, Duke Energy stated that none of the Transmission Loading Reliefs that were initiated during the Load Shed Event affected Duke Energy's resource inadequacy.[lxxxix] Overall, there were no failures or congestion on the transmission system to aggravate Duke Energy's resource inadequacy during the Load Shed Event.

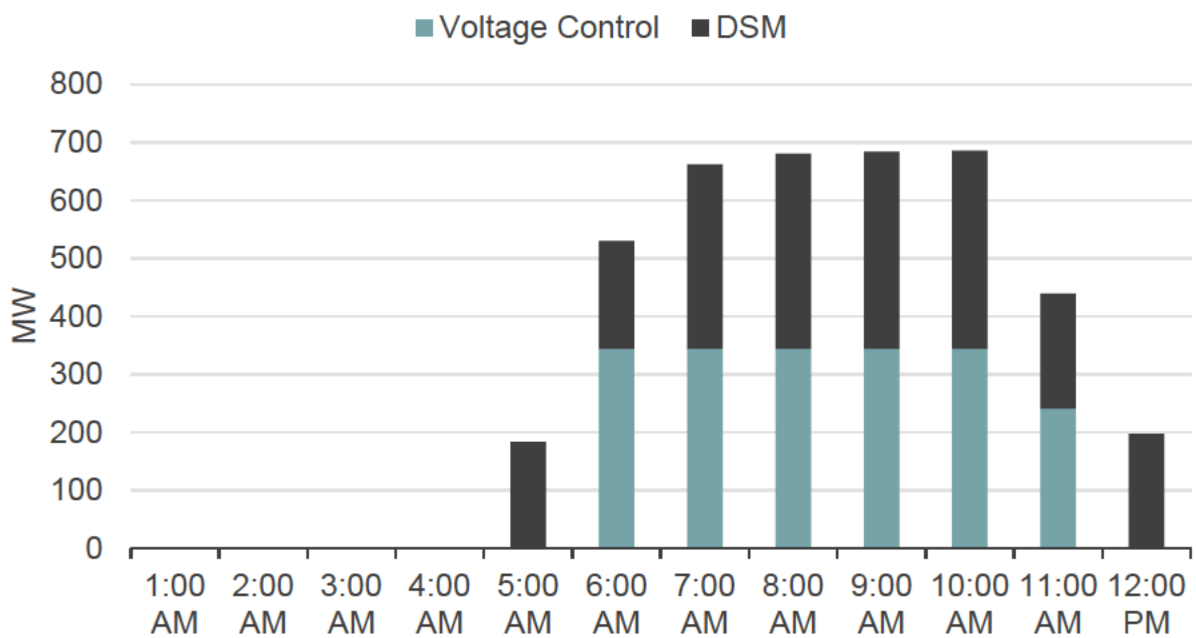
## 4.3 **ACTIVE LOAD REDUCTION PROGRAMS**

Duke Energy has programs designed to reduce load when actively called upon in defined scenarios. These programs consist of residential and commercial demand response (e.g., smart thermostat control), curtailable/interruptible loads (customers that receive compensation for a willingness to reduce loads under certain parameters), and voltage control (controlled system voltage reduction to reduce peak load usage).

Duke Energy activated many of its load reduction programs on December 24 from 4:00 to 6:30 AM prior to initiating load shed. The load reduction programs achieved an estimated reduction of 723 MW with an estimated 47 MW of non-performance from customers in certain programs.[xc] For applicable load reduction programs, overall load reduction capability and customer compliance was reduced due to the request occurring during a holiday weekend.[xci]

On December 24, Duke Energy chose not to utilize certain load reduction programs with total capacities of 40 MW. These programs included its residential programs and a small commercial program.[xcii] On December 23, Duke Energy made a supply planning decision to reserve its residential programs for December 26. The commercial program was not utilized based on its small size and holiday timing.

**Figure 4-1:** Duke Energy Active Load Reduction, Morning of December 24[xciii]




## 4.4 **SOUTHEAST ENERGY EXCHANGE MARKET**

SEEM is a voluntary, 15-minute exchange system implemented in late 2022 as an extension of the existing bilateral market across the non-RTO region of the Southeast. Duke Energy is a founding member of SEEM. SEEM transactions are based on voluntary offers to buy and sell energy by participants that are cleared on an automated basis with pricing based on a 'split the savings' determination. SEEM transactions are facilitated by non-firm transmission service as available.

Because of the widespread nature of Winter Storm Elliott and the voluntary participation of SEEM based on non-firm transmission, SEEM did not contribute or detract from Duke Energy's operations during Winter Storm Elliott. SEEM is a voluntary means to achieve economic efficiencies when SEEM members have excess power available to market and the transmission system has excess capacity to facilitate transactions. However, during Winter Storm Elliott there was no excess power available. Winter Storm Elliott was a reliability event for many SEEM members. Duke Energy confirmed there were no SEEM trades made by any SEEM members from the evening of December 23 through noon of December 26.[xciv]

## 4.5 **CAROLINAS RESERVE SHARING GROUP**

The Companies, along with Santee Cooper and DESC, are members of the Carolinas Reserve Sharing Group ("CRSG"). CRSG members provide contingency reserves to one another pursuant to the bilateral interchange agreements between the members that are on file with and have been approved by FERC. Each CRSG member is required to carry a share of the total amount of contingency reserves for the reserve sharing group. In the event of a particular member's unit loss, such member will utilize its share of reserves and may then request other members provide additional contingency reserves (in an amount in excess of its share of reserves).

On December 24 at 5:18 AM, the Reliability Coordinator ("RC") initiated a conference call between the CRSG members to inform all that each respective member had entered EEAs and was going to be reserve deficient. The RC informed the members that each would have to rely on load shed for contingency as emergency energy was unavailable.[xcv]

# 5 Communications

## 5.1 CUSTOMERS AND THE MEDIA

On December 21, Duke Energy issued alerts to medical and critical-care facilities warning of the potential for power outages on December 23 due to anticipated high winds. In addition, banners were added to the "Outage Map" and "News" pages of the Duke Energy website. Emails were sent to residential customers, providing links to various resources and information on reporting power outages.[xcvi]

On December 23, high winds damaged Duke Energy's distribution system and resulted in uncontrolled customer outages. Emails were distributed to customers regarding the outages, and text and voice messages were sent to customers without power.[xcvii] The wind-related outages on December 23 were separate and distinct from outages that occurred on December 24 during the Load Shed Event, which involved controlled outages that Duke Energy initiated because of resource inadequacy.

On December 23 around 9:30 PM, official notifications for mandatory load curtailments were sent by Duke Energy to PowerShare[43], interruptible service, and standby generator customers. The original notifications stated that the mandatory curtailment was scheduled for 4:00 AM to 10:00 AM on December 24, and additional notifications were sent later to indicate the curtailment would be extended until 12:00 PM.[xcviii]

On December 24 at 4:43 AM, Duke Energy issued a press release to request energy conservation. After the rotating outages were initiated from 6:15 to 6:25 AM, the Duke Energy website and mobile application experienced technology-performance issues with customer logins due to increased traffic from customers looking for outage information. The website's functionality was not fully restored until around 10:30 AM.[44]

At 7:25 AM, *after* load shed began, the Companies initiated communications to customers to announce the temporary rotating outages via alert banners added to the customer outage map on the Companies' website. At 7:40 AM, similar messages were posted to social media channels such as Facebook and Twitter. At 8:00 AM the Companies published a news release announcing the outages, and at 8:10 AM the voice-response system on the customer service phone line was updated. Due to the issues with the

[43] PowerShare is Duke Energy's demand response program, designed for business customers to curtail their energy use during peak demand periods in exchange for financial incentives. Duke Energy PowerShare website https://www.duke-energy.com/business/products/powershare (accessed July 28, 2023).

[44] Duke Energy Allowable Ex Parte Briefing materials, available in Docket No. ND-2023-6-E.

automated RLS tool, incorrect power restoration timeframes of 30- to 60-minutes were communicated to customers.[xcix]

Representatives from the Companies conducted media interviews throughout December 24.[c] All of the messages were based on the corporate communication plans in Duke Energy's General Load Reduction Plan ("GLRP").[ci]

In the late afternoon and early evening of December 24, messages were updated and requested customers to conserve energy on Christmas morning. The messages were sent via text, social media, and press releases, and were reinforced on Duke Energy's website and mobile app. A similar conservation message was issued on December 25 regarding energy conservation on the morning of December 26.[cii]

## 5.2 **REGULATORY BODIES**

On December 19, prior to the arrival of Winter Storm Elliott a Generation Fleet Status Update for the upcoming week was sent to the North Carolina Public Staff ("NCPS") and NCUC. On December 20, ORS sent an email to the Companies that referenced conversations held earlier that day about winter preparedness for other large electric utilities in South Carolina. On December 22, a grid status update was emailed to NCPS and ORS, including forecasted loads, grid status, and reserve status for December 24 through December 26.[ciii]

On December 23 at 11:44 PM, Duke Energy emailed NCPS a DSM program update, including the status of DSM programs and the scheduled activation of additional programs for December 24. On December 24 at 4:38 AM, DEC informed ORS regarding the activation of the Company's commercial demand response and load curtailment programs.[civ]

As required by federal statute[45] and NERC reliability standard,[46] Duke Energy submitted initial Department of Energy ("DOE") OE-417, "Electric Emergency Incident and Disturbance Reports" to DOE and NERC within one hour of the initiation of the Load Shed Event. Final DOE OE-417, "Electric Emergency Incident and Disturbance Reports" were

[45] DOE is authorized to collect the information on Form OE-417 under the Federal Energy Administration Act of 1974 (Pub. L. No. 93-275, 15 U.S.C. 761 et seq.) as amended, the Federal Power Act (16 U.S.C. 791a et seq.), the DOE Organization Act (Public Law No. 95-91, 42 U.S.C. 7101 et seq.) as amended, and the Public Utility Regulatory Policies Act of 1978, Sect. 209 (Public Law No. 95-317, 92 stat. 3117, 16 U.S.C. 824a-2).

[46] NERC Reliability Standard EOP-004-4 "Event Reporting" accepts the DOE OE-417 form in lieu of EOP-004 Attachment 2 to report events to the Electric Reliability Organization if the entity is required to submit a DOE OE-417 report.

submitted to the DOE after the conclusion of the Load Shed Event to provide additional details of the causes and impacts of the emergency event and the actions taken by DEC and DEP.[cv] The DOE OE-417 "Electric Emergency Incident and Disturbance Report" collects information to detail electric incidents and emergencies. The DOE uses the information to fulfill its overall national security and other energy emergency management responsibilities, as well as for analytical purposes.[47]

On December 24 at 7:20 AM, Duke Energy's state presidents for North Carolina and South Carolina contacted NCUC, NCPS, and ORS to inform staff about the Load Shed Event. Additional details and updates were provided periodically during the Load Shed Event. Outage restoration updates were provided in the afternoon. From the evening of December 24 through December 26, Duke Energy provided updates to NCUC, NCPS, and ORS regarding the status of the system and continued requests to conserve energy.[cvi]

[redacted][cvii]

Beginning in January 2023, the Companies provided presentations on Winter Storm Elliott and the associated Load Shed Event to the NCUC and ORS, including an Allowable Ex Parte Briefing to the SCPSC.[cviii] In addition, [redacted][cix]

[47] Electric Disturbance Events Form Website https://www.oe.netl.doe.gov/oe417.aspx (accessed July 28, 2023).

# 6 Lessons Learned

A key aspect of the inspection and examination requested in Commission Order No. 2023-21 involved the identification of lessons learned and areas for improvement. This Section of the Report describes areas for improvement as identified by GDS and ORS. In response to ORS discovery, Duke Energy provided preliminary observations and a Corrective Action Plan ("CAP") for the Load Shed Event. An unedited version of the Companies' CAP can be found in Appendix D.

## 6.1 GDS AND ORS RECOMMENDED AREAS FOR IMPROVEMENT

The Companies compiled an Event CAP[cx] Tracker to manage corrective actions associated with the Load Shed Event. The confidential CAP is provided in Appendix D.[48] The Companies noted that the corrective actions in the CAP document are based upon observations and not necessarily created to mitigate causes identified in the causal analysis.[cxi] In addition to the items Duke Energy self-identified, GDS and ORS recommend that the Companies consider the improvements which are described below.

### 6.1.1 Load Forecasting and Supply Planning

In addition to using the learned experience of Winter Storm Elliott to improve load forecasting models, Duke Energy should develop protocols to ensure load forecasts are updated intra-day around significant weather events to account for the latest available information. As discussed in Section 3.1, Duke Energy's projection of its peak load did not change in its operating plans and projections throughout December 23. Duke Energy reported that it projected adequate reserves as of the night of December 23; however, conditions deteriorated rapidly before the Load Shed Event. Although Duke Energy's supply options may become more limited when an extreme weather event approaches, accurately forecasting load with the most current information may allow the utility to be as operationally prepared as possible. GDS and ORS recommend the Companies utilize the most up-to-date projected load requirements and available supply to support a supply plan that best accounts for expected supply adequacy.[49]

[48] In response to discovery, Duke Energy classified several documents as privileged, including its Draft Apparent Cause Analysis. Accordingly, the documents have not been incorporated into the GDS and ORS investigation and examination.

[49] This recommendation is similar and related to a LEU-specific recommendation made in the Resiliency Report, "The LEUs need to continue to enhance capabilities to extend these situational awareness tools to use information of data for analytics (e.g., extending load forecast capabilities to aid real-time operations as an operational forecasting tool during major events)."

### 6.1.2 Generation

#### *6.1.2.1 Planned Outages*

Some of Duke Energy's generation resources were off-line during Winter Storm Elliott due to planned maintenance or refueling outages. The timing of these outages is determined far in advance, with the intention to allow Duke Energy to plan around the outages and continue to meet load. However, Duke Energy still ended up with insufficient capacity during Winter Storm Elliott. In addition to avoiding planned outages in January and February, Duke Energy should review their scheduling to avoid such outages during December, including the potential for outage extensions.

GDS and ORS recommend Duke Energy update the Allen Units' staffing and operating status when several other generation resources are in prolonged maintenance outages and Duke Energy is relying on capacity purchases to meet operating reserves in winter months. Additionally, GDS and ORS recommend Duke Energy evaluate the EPR procedures, unit return to service considerations, and protocols to assess the feasibility of returning a unit to service within appropriate timeframes required to respond to system conditions that could dictate a return to service.

Extreme weather events are becoming more common and can no longer truly be considered exceptions to the norm. Therefore, GDS and ORS recommend the Companies plan their generation resource outages accordingly.

#### *6.1.2.2 Start-up Failures*

Duke Energy experienced several start-up failures on simple-cycle CT units designed to start and operate remotely (e.g., the Blewett CT units). On December 24, three (3) of the 17 MW CT units at the Blewett facility failed to start at a critical period in the early morning hours immediately preceding the Load Shed Event. A CT technician was dispatched to the site to troubleshoot the various issues at the units and was able to start two (2) of the (3) three failed units after two (2) to five (5) hours. The third failed unit was not returned to service until January 2023.[cxii] Duke Energy noted the last time these units were started was in August and October 2022.[cxiii] GDS and ORS recommend that Duke Energy test remotely operated units prior to the winter season and impending extreme cold weather to ensure resources are operational and ready for service.[50] As extreme weather approaches, GDS and ORS also recommend that Duke Energy proactively stage technicians onsite at remote start CTs to minimize potential troubleshooting time.

[50] See supra footnote 25.

### 6.1.2.3 Winterization

With colder-than-normal winter weather events occurring more frequently in recent years, many utilities have winterized equipment to withstand cold weather and prevent outages and derates. Utilities are also enhancing maintenance practices, procedures, and inspection programs to focus on areas that could be affected by freezing conditions. In southern states such as the Carolinas that rarely experience harsh winter conditions, power plant equipment is typically constructed semi-outdoors and is therefore exposed to the elements. Whereas, in northern states plants are much more enclosed and protected from exposure to weather. To winterize critical areas of a generating unit, windscreens or other walls and shelters should be installed, and pipes and instrumentation lines should be covered with insulation and lined with heat tracing cables. Fuel supply systems need to be winterized by adding 1) heaters to fuel oil storage, 2) heat tracing to gas line pressure reduction valves and 3) coal anti-freezing chemical additives in coal handling areas.

Minimum design operating ambient temperatures should be established for each generating unit, and this information should be communicated to system operators and planners to inform decisions related to supply capacity for severe winter events.[51] When a severe storm is approaching, additional temporary freeze protection measures should be installed, such as portable heaters and additional insulating coverings. Duke Energy installed winterization measures prior to Winter Storm Elliott; however, during Winter Storm Elliott several units still experienced problems because the freeze protection measures in place were overcome by the low temperatures and high winds.

Freezing issues at power plants are not uncommon, but they are preventable. Since Winter Storm Elliott, Duke Energy performed various assessments and evaluations of the winterization equipment and freeze protection measures at the plants that experienced weather related issues. As discussed in Section 3.2.2.1, Duke Energy discovered cracks and gaps found in insulation and issues with heat tracing at several generation plants that resulted in outages and derates during Winter Storm Elliott. It is clear from the door left open at DEC's Mountain Island Unit 2 that there is room for improvement in the Cold Weather Preparedness Plans at Duke Energy's generation facilities. GDS and ORS recommend Duke Energy include more detailed and specific direction for performing inspections of heat tracing and insulation on critical equipment and instrumentation lines and install additional temporary heat tracing and insulation to areas identified as prone to freezing as winter storms approach.

[51] Resiliency Report, p. F-32.

In response to data requests from FERC after the Load Shed Event, DEP and DEC discussed lessons learned for generation units in their fleet that experienced outages, derates, or start-up failures during Winter Storm Elliott. FERC asked if the Companies had updated their procedures based on the 2021 Winter Event Recommendations published by FERC in response to the problems encountered in Texas and the Midwest during Winter Storm Uri in February 2021. Duke Energy stated the EOP-011-2[52] program does not account for the effects of wind and precipitation, and they did not take into account the wind speed during review of historical data or design data.[cxiv] In the heat tracing design examination reports completed by Duke Energy for Roxboro[cxv] and Mayo[cxvi] after the Load Shed Event, the design examination calculations assumed 40 mph winds at each facility, and the assessments concluded that the *as-designed* heat tracing and insulation should have been sufficient to prevent the freezing issues that occurred at both sites. However, since faults were discovered in the *as-installed* insulation and heat tracing, the units experienced outages anyway. GDS and ORS recommend Duke Energy carefully re-examine existing freeze protection measures at its generation facilities to 1) ensure the installed equipment aligns with the originally intended designs, 2) ensure configuration management between drawings and field condition is maintained and 3) repair problems and install additional winterization equipment as needed. GDS and ORS recommend that each Duke Energy generation station should review its site-specific severe cold weather preparation procedures and checklists to incorporate lessons learned including:[53, 54]

- Verification that doors and louvers that could expose critical equipment to the elements are closed.
- Identification of critical instrumentation cabinets or other equipment where temporary wind breaks and/or heaters may need to be installed.
- Enhanced staffing and increased frequency of operator rounds during severe winter weather events.

[52] NERC EOP-011-2 Emergency Preparedness and Operations https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-011-2.pdf (accessed July 28, 2023)

[53] NERC has published a more comprehensive list of cold weather preparation procedure elements. Reliability Guideline Generating Unit Winter Weather Readiness – Current Industry Practices https://www.nerc.com/pa/rrm/ea/ColdWeatherTrainingMaterials/Relibility_Guideline_Generating_Unit_Winter_Weather_Readiness.pdf (accessed July 28, 2023)

[54] This recommendation is similar and related to a LEU-specific recommendation made in the Resiliency Report regarding review of corporate and plant-specific winter freeze preparation procedures, processes, and checklists.

#### *6.1.2.4 Fuel Assurance*

Duke Energy successfully operated several plants on fuel oil during Winter Storm Elliott, as well as operated several NGCC and CTs on natural gas. Nevertheless, some of Duke Energy's plants encountered natural gas deliverability issues on December 24 and 25. The proximity of these fuel issues to the Load Shed Event is concerning. Accordingly, GDS and ORS recommend that Duke Energy conduct a winter fuel assurance review with a focus on natural gas deliverability to ensure that fuel is available during extreme cold weather conditions.

### 6.1.3 Load Shed Implementation

The RLS tool has several interdependencies with other software packages. These interdependent software packages should continually be updated. Updates to one software package can cause unforeseen issues between dependent software packages. In its CAP, Duke Energy addressed several issues related to its RLS tool, including issues related to software testing. GDS and ORS recommend that Duke Energy expand its review of the RLS tool in this area by creating a software system interdependency chart to formally track relationships between software systems to inform testing and review when updates occur.

### 6.1.4 Active Load Reduction Programs

As discussed above in Section 4.3, Duke Energy did not utilize its residential DSM programs on December 24. Duke Energy should ensure all DSM programs can be, and are, used to their maximum capabilities during critical emergency events, even if the events occur on holidays or weekends. As a part of the full utilization, in its short-term supply planning, GDS and ORS recommend that Duke Energy carefully reflect the capability of these programs, especially on holidays and weekends, to accurately reflect its ability to rely on those programs during an emergency.

### 6.1.5 Network and Wholesale Customer Interaction

As discussed in Section 3.4, Duke Energy's supply inadequacy was heightened by supply issues faced by its Network Customers. Duke Energy stated there was no viable mechanism to curtail network customer load within the relevant timing during the Load Shed Event. GDS and ORS recommend Duke Energy review its policies and procedures to improve its communication and coordination with Network and Wholesale customers during emergency or load shed events. A key part of this review should be to ensure that Network and Wholesale customers address supply issues when they occur or can be instructed to reduce load in a timely manner.

### 6.1.6 Customer Communications

As discussed in Section 5.1, Duke Energy did not notify customers about outages prior to the initiation of the Load Shed Event. When notifications were eventually released, incorrect power restoration timeframes were provided to customers due to problems with the automated RLS tool. In addition, the Companies' website and mobile application experienced functionality issues for several hours on the morning of December 24 due to high traffic.

GDS and ORS recommend that Duke Energy implement a notification process that alerts customers to load shed or rolling outages *before* the power outages occur. In addition, Duke Energy should ensure that more accurate timeframes for power restoration can be provided in these notifications.

Duke Energy stated that they intend to improve customer communications in the event of future load shed or rotating outages. Details of these lessons learned are included in Appendix D.

## 6.2 DUKE ENERGY'S PERSPECTIVE

Duke Energy's CAP Tracker has been marked as Confidential in its entirety. It is attached in Appendix D to this Report. The Load Shed Event CAP Tracker identified corrective action items, groups responsible for addressing each item, and the status of each item listed. Table 6-1 below summarizes the status information in the CAP Tracker as of May 18, 2023, and categorizes the actions by functional area.

**Table 6-1:** Duke Energy Corrective Action Plan Summary[cxvii]

| Category | Actions Complete | Actions In Progress | Actions Not Started | Total |
|---|---|---|---|---|
| Communications | 2 | 3 | 6 | **11** |
| Demand-Side Management | 1 | 10 | | **11** |
| Forecasting | 1 | 4 | 3 | **8** |
| Fuel Supply | 1 | | 1 | **2** |
| Generation | 7 | 4 | | **11** |
| Internal Operations | 2 | | 7 | **9** |
| Load Shed | 23 | 5 | 8 | **36** |
| Long-term Planning | | | 1 | **1** |
| Network Customers | | | 1 | **1** |
| Operational Planning | 3 | 5 | 3 | **11** |
| **Grand Total** | **40** | **31** | **30** | **101** |

## Appendix A: December 24 EEA 3 Resource Inadequacy Summary

| Date | Saturday, Dec 24 | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Hour Ending | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 |
| DEC EEA | 1 | 2 | | 3 | | | | | | | | | 1 | | | |
| DEP EEA | | | 1 | 2/3 | 3 | | | | | | | | | 1 | | |
| Under-forecasted Load | 1,868 | 2,166 | 2,629 | 3,128 | 3,309 | 3,270 | 3,576 | 3,498 | 3,139 | 3,097 | 3,162 | 3,152 | 2,612 | 1,953 | 1,568 | 1,452 |
| Generation Unavailability | Planned Outages (1,612 MW) | | | | | | | | | | | | | | | |
| | Pre-Event Forced Outages (2,283 MW) | | | | | | | | | | | | | | | |
| | Dan River Freezing (359 MW) | | | | | | | | | | | | | | | |
| | Roxboro Freezing (398 MW) | | | | | | | | | | | | | | | |
| | | | Mayo Freezing (350 MW) | | | | | | | | | | | | | |
| | | | | | Smith PB4 Freezing (273 MW) | | | | | | | | | | | |
| | | | | | Clemson CHP Gas Supply (14 MW) | | | | | | | | | | | |
| | | CT Failure (51-17 MW) | | | | | | | | | | | | | | |
| | Hydro Failures (12-29 MW) | | | | | | | | | | | | | | | |
| | | | | | | | Buck Gas Supply (120-187 MW) | | | | | | | | | |
| | | | | | | | | | | Roxboro Coal Conveyor (685 MW) | | | | | | |
| Total, Pre-Event | 3,895 | 3,895 | 3,895 | 3,895 | 3,895 | 3,895 | 3,895 | 3,895 | 3,895 | 3,895 | 3,895 | 3,895 | 3,895 | 3,895 | 3,895 | 3,895 |
| Total, Incremental | 774 | 837 | 1,187 | 1,153 | 1,440 | 1,428 | 1,606 | 1,589 | 1,589 | 2,274 | 2,260 | 2,260 | 2,260 | 2,202 | 2,202 | 1,929 |
| Total | 4,669 | 4,731 | 5,081 | 5,047 | 5,334 | 5,323 | 5,501 | 5,484 | 5,484 | 6,169 | 6,155 | 6,155 | 6,155 | 6,097 | 6,097 | 5,824 |
| Purchase Curtailments | | | 175 | 883 | 1,099 | 956 | 680 | 355 | 236 | | | | | | | |
| Load Shed Directive, Peak | | | | 1,000 | 1,911 | 1,000 | 700 | | | | | | | | | |
| Load Shed Directive, Avg | | | | 357 | 1,487 | 1,243 | 560 | | | | | | | | | |

# Appendix B: Duke Energy 7-Day Supply Plans

**Figure B-1:** Duke Energy Supply Plan, December 19

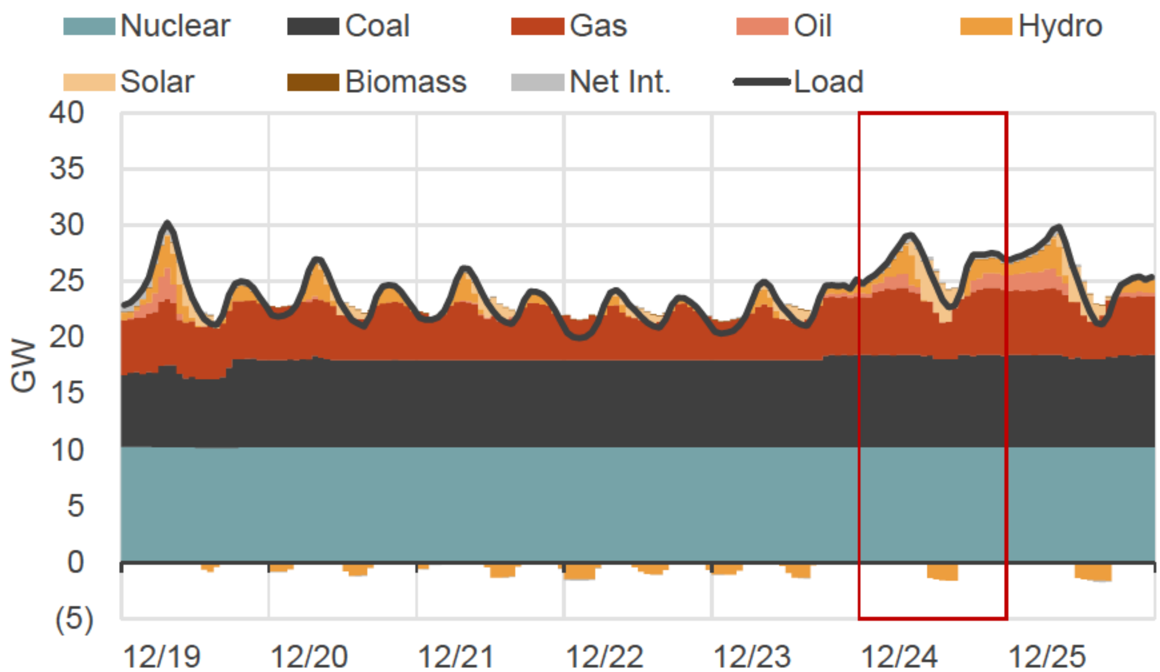



**Figure B-2:** Duke Energy Supply Plan, December 19

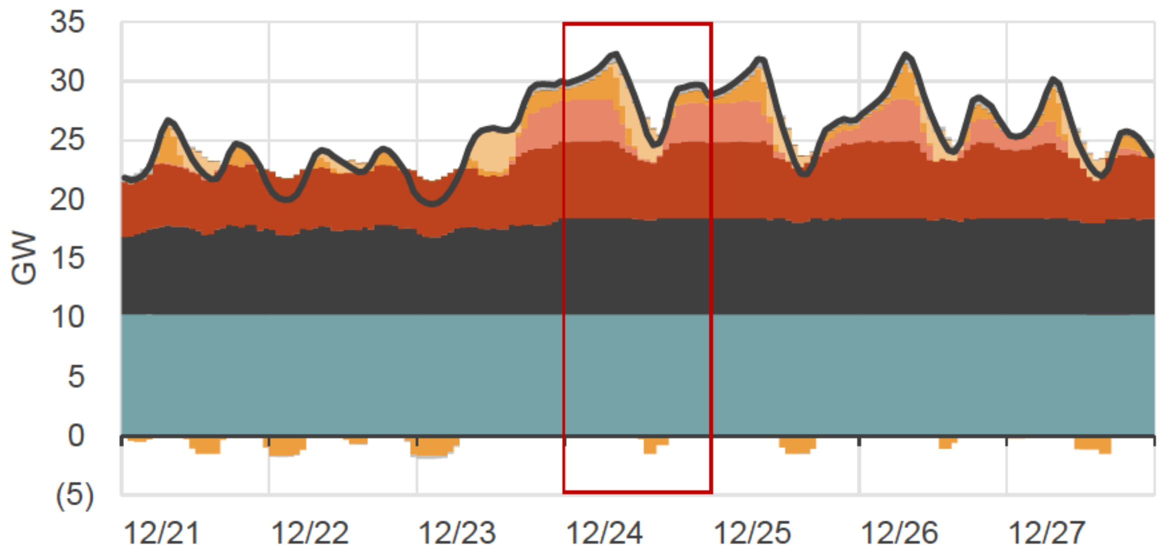
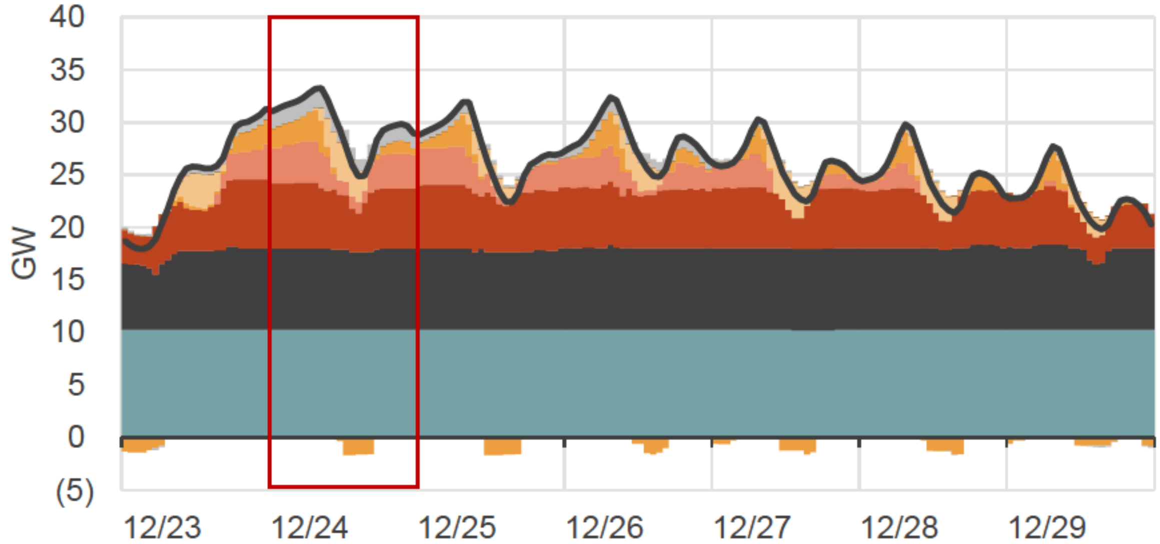


**Figure B-3:** Duke Energy Supply Plan, December 23



## Appendix C: Generation Resource Outages Detail, December 22-26[cxviii]

| DEC or DEP | Generation Resource | Fuel Type | Capacity Unavailable | Outage/Derate Cause | Planned or Forced | Timing |
|---|---|---|---|---|---|---|
| DEC | Allen | Coal | 426 MW | Extended Planned Reserve | Planned | Prior to Event |
| DEC | Bad Creek Hydro Unit 3 | Hydro | 340 MW | Multi-year major upgrade outage | Planned | Prior to Event |
| DEC | Bear Creek Hydro | Hydro | 9.5 MW | Penstock isolation valve installation | Planned | Prior to Event |
| DEC | Belews Creek Unit 1 | Coal | 125 MW | Booster fan high vibration trip | Forced | Dec 22 - Event end |
| DEC | Buck | Natural Gas | 120-178 MW | Low natural gas pressure from Transco | Forced | Dec 24-25 |
| DEC | Clemson CHP | Natural Gas | 14 MW | Low natural gas pressure from Fort Hill | Forced | Dec 24 (6 hrs.) |
| DEC | Cliffside Unit 5 | Coal | 100 MW | Coal feeder gearbox failure | Forced | Prior to Event |
| DEC | Dan River | Natural Gas | 100-338 MW | Low natural gas pressure from Transco | Forced | Dec 25 (14 hrs.) |
| DEC | Dan River Unit 9 | Natural Gas | 359 MW | Frozen LP drum level transmitters | Forced | Dec 23-25 |
| DEC | Marshall Unit 1 | Coal | 380 MW | Boiler circulating pump failure | Forced | Prior to Event |
| DEC | Marshall Unit 2 | Coal | 380 MW | Boiler tube leaks | Forced | Prior to Event |
| DEC | Mill Creek Unit 7 | Natural Gas | 95 MW | Tripped on fuel oil | Forced | Dec 25 (6 hrs.) |
| DEC | Mountain Island Hydro Unit 1 | Hydro | 14 MW | Turbine runner replacement | Planned | Prior to Event |
| DEC | Mountain Island Hydro Unit 2 | Hydro | 17 MW | Failed to start; cold oil from cold ambient air | Forced | Dec 24 (3 hrs.) |
| DEC | Ninety-Nine Islands Unit 4 | Hydro | 3.4 MW | Turbine and generator inspection | Planned | Prior to Event |
| DEC | Oxford Hydro Unit 2 | Hydro | 20 MW | Broken wicket gate link | Forced | Prior to Event |
| DEC | Rhodhiss Hydro Unit 3 | Hydro | 12.4 MW | Trash rack stop log system installation | Planned | Prior to Event |
| DEC | Tennessee Creek Hydro | Hydro | 11.5 MW | Failed to start; faulty contact on breaker door | Forced | Dec 24 (4 hrs.) |
| DEC | W.S. Lee | Natural Gas | 809 MW | Fire damage in steam turbine enclosure | Forced | Prior to Event |
| DEP | Blewett Unit 1 | Natural Gas | 17 MW | Failed to start; control logic issues | Forced | Dec 24 (5.5 hrs.) |
| DEP | Blewett Unit 2 | Natural Gas | 17 MW | Failed to start; fuel card issues | Forced | Dec 24 - Event end |
| DEP | Blewett Unit 4 | Natural Gas | 17 MW | Failed to start; exhaust thermocouple failure | Forced | Dec 24 (2 hrs.) |

| DEC or DEP | Generation Resource | Fuel Type | Capacity Unavailable | Outage/Derate Cause | Planned or Forced | Timing |
|---|---|---|---|---|---|---|
| DEP | Mayo Unit 1 | Coal | 93-206 MW | Failure of two coal feeders | Forced | Prior to Event |
| DEP | Mayo Unit 1 | Coal | 336-350 MW | Frozen drum level sensing lines and limestone | Forced | Dec 24-25 |
| DEP | Robinson Nuclear Station | Nuclear | 759 MW | Refueling outage | Planned | Prior to Event |
| DEP | Roxboro Unit 1 | Coal | 185 MW | Coal reclaim conveyor belt failure | Forced | Dec 24-26 |
| DEP | Roxboro Unit 2 | Coal | 500 MW | Coal reclaim conveyor belt failure | Forced | Dec 24-26 |
| DEP | Roxboro Unit 3 | Coal | 73-98 MW | Rebuilding pulverizer | Planned | Prior to Event |
| DEP | Roxboro Unit 3 | Coal | 398 MW | Frozen sensing lines and switches | Forced | Dec 24-25 |
| DEP | Roxboro Unit 4 | Coal | 211 MW | Grounded motor on an induction draft fan | Forced | Prior to Event |
| DEP | Smith Energy Complex Unit 1 | Natural Gas | 192 MW | Failed to start; neutral disconnect switch issue | Forced | Dec 23 (3 hrs.) |
| DEP | Smith Energy Complex Unit 2 | Natural Gas | 47 MW | Combustor hardware issues | Forced | Prior to Event |
| DEP | Smith PB4 Unit 8 | Natural Gas | 273 MW | Frozen transmitter and sensing lines | Forced | Dec 24 (11.5 hrs.) |
| DEP | Walters Unit 3 | Hydro | 36 MW | Overhaul and turbine generator work | Planned | Prior to Event |
| DEP | Wayne County | Natural Gas | 195 MW | Fuel oil pump issues | Forced | Dec 26 (2 hrs.) |

# Appendix D: Duke Energy Corrective Action Tracker[55][cxix]

[redacted]

[55] In a response to ORS Discovery which was designated as confidential in its entirety by Duke Energy, the Companies' provided the CAP document. The confidential CAP is included in Appendix D to document the Companies' lessons learned. ORS has not edited any of the information in Appendix D from what was provided by the Companies.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

# **Endnotes** – References to Discovery Responses

[i] Duke Energy response and attachments to ORS DR 3-15
[ii] Confidential Duke Energy response and attachment to ORS DR 3-3
[iii] Confidential Duke Energy response and attachment to ORS DR 3-2
[iv] Duke Energy response and attachment to ORS DR 1-1 (NCPS DR 2-03)
[v] Duke Energy response and attachments to ORS DR 1-1 (NCPS DR 2-02)
[vi] Duke Energy response and attachments to ORS DR 3-18
[vii] Duke Energy response and attachments to ORS DR 1-1 (NCPS DR 2-06)
[viii] *Id.*
[ix] *Id.*
[x] *Id.*
[xi] Duke Energy responses and attachments to ORS DR 1-1 (NCPS DR 2-17) and ORS DR 3-15
[xii] Confidential Duke Energy response and attachment to ORS DR 3-2
[xiii] Confidential Duke Energy responses and attachments to ORS DR 1-1 (NCPS DR 2-19) and ORS DR 3-32
[xiv] Confidential Duke Energy response to ORS DR 3-91
[xv] Confidential Duke Energy response and attachment to ORS DR 3-1
[xvi] Duke Energy response and attachments to ORS DR 1-1 (NCPS DR 2-06)
[xvii] Duke Energy responses and attachments to ORS DR 3-24 (Confidential), 3-15, and ORS DR 1-1 (NCPS DR 2-17)
[xviii] Carolinas Unit Capability Timeline, provided in response to ORS DR 1-1 (NCPS DR 2-22)
[xix] Confidential Duke Energy response and attachment to ORS DR 1-1 (NCPS DR 2-19)
[xx] Duke Energy responses and attachments to ORS DR 3-24 (Confidential), 3-15, and ORS DR 1-1 (NCPS DR 2-17)
[xxi] Confidential Duke Energy responses and attachments to ORS DR 3-2 and 3-3
[xxii] *Id.*
[xxiii] Duke Energy response to ORS DR 1-1 (NCPS DR 2-28)
[xxiv] Duke Energy responses and attachments to ORS DR 3-24 (Confidential), 3-15, and ORS DR 1-1 (NCPS DR 2-17)
[xxv] Duke Energy response to ORS DR 3-82
[xxvi] *Id.*
[xxvii] Duke Energy response to ORS DR 1-1 (NCPS DR 2-26)
[xxviii] Duke Energy response and attachments to ORS DR 2-2
[xxix] Confidential Duke Energy response and attachments to ORS DR 3-21
[xxx] Duke Energy response and attachments to ORS DR 1-1 (NCPS DR 2-17)
[xxxi] Duke Energy response and attachments to ORS DR 3-15
[xxxii] Confidential Duke Energy responses and attachments to ORS DR 3-3 and 3-7
[xxxiii] Duke Energy response and attachments to ORS 3-15 and ORS DR 1-1 (NCPS DR 2-17)
[xxxiv] Confidential Duke Energy response and attachments to ORS DR 3-3
[xxxv] *Id.*

[xxxvi] *Id.*
[xxxvii] *Id.*
[xxxviii] Carolinas Unit Capability Timeline, provided in response to ORS DR 1-1 (NCPS DR 2-22)
[xxxix] *Id.*
[xl] *Id.*
[xli] Duke Energy response and attachments to ORS DR 3-15
[xlii] *Id.*
[xliii] Carolinas Unit Capability Timeline, provided in response to ORS DR 1-1 (NCPS DR 2-22)
[xliv] Duke Energy response to ORS DR 3-56.
[xlv] *Id.*
[xlvi] Duke Energy response to ORS DR 3-57
[xlvii] Confidential Duke Energy response to ORS DR 3-55
[xlviii] Duke Energy response and attachment to ORS DR 3-14
[xlix] Confidential Duke Energy response to ORS DR 3-55
[l] Duke Energy response to ORS DR 1-1 (NCPS DR 2-13)
[li] Confidential Duke Energy responses to ORS DR 1-1 (NCPS DR 2-13 and NCPS DR 2-20)
[lii] Confidential Duke Energy response to ORS DR 1-1 (NCPS DR 2-20)
[liii] Carolinas Unit Capability Timeline, provided in response to ORS DR 1-1 (NCPS DR 2-22)
[liv] Roxboro Heat Tracing Thermal Design Examination report, provided in response to ORS DR 3-45
[lv] Dan River CC Unit 9 Freeze KT Analysis Summary, provided in response to ORS DR 3-43
[lvi] *Id.*
[lvii] Mayo Heat Tracing Thermal Design Examination report, provided in response to ORS DR 3-44
[lviii] Smith Energy Complex Unit 8 Event Report #1321400, provided in response to ORS DR 3-46
[lix] Duke Energy Response and Attachments to ORS DR 3-46
[lx] Carolinas Unit Capability Timeline, provided in response to ORS DR 1-1 (NCPS DR 2-22)
[lxi] Confidential Duke Energy response to ORS DR 3-32
[lxii] Confidential Duke Energy response and attachment to ORS DR 1-1 (NCPS DR 2-19)
[lxiii] Duke Energy response to ORS DR 3-35
[lxiv] Confidential Duke Energy response and attachments to ORS DR 3-1
[lxv] Duke Energy response to ORS DR 1-1 (NCPS DR 2-26)
[lxvi] Confidential Duke Energy response and attachment to ORS DR 3-1

[lxvii] Confidential Duke Energy response to ORS DR 3-90
[lxviii] Duke Energy response to ORS DR 1-1 (NCPS DR 2-26)
[lxix] *Id.*
[lxx] Duke Energy Response and Attachment to ORS DR 2-4
[lxxi] Confidential DEC EOP-OP32 EMS Load Shed Application Procedure, provided in response to ORS DR 3-4
[lxxii] *Id.*
[lxxiii] Confidential Duke Energy response to ORS DR 1-1 (NCPS DR 2-19)
[lxxiv] *Id.*
[lxxv] Duke Energy response to ORS DR 3-72
[lxxvi] Duke Energy response to ORS DR 3-79
[lxxvii] Duke Energy responses to ORS DR 3-86 and ORS DR 1-1 (NCPS 2-28)
[lxxviii] *Id.*
[lxxix] Duke Energy response and attachments to ORS DR 3-73 and ORS DR 1-1 (NCPS DR 2-8)
[lxxx] Duke Energy response and attachments to ORS DR 3-73
[lxxxi] Carolinas Unit Capability Timeline, provided in response to ORS DR 1-1 (NCPS DR 2-22)
[lxxxii] Duke Energy response to ORS DR 3-61
[lxxxiii] Carolinas Unit Capability Timeline, provided in response to ORS DR 1-1 (NCPS DR 2-22)
[lxxxiv] Confidential Duke Energy response to ORS DR 3-62
[lxxxv] Duke Energy response and attachment to ORS DR 3-66
[lxxxvi] *Id.*
[lxxxvii] Duke Energy response to ORS DR 3-70
[lxxxviii] Duke Energy response to ORS DR 1-1 (NCPS DR 2-6)
[lxxxix] Confidential Duke Energy response to ORS DR 2-7
[xc] Duke Energy response to ORS DR 3-27 and attachment to ORS DR 3-28
[xci] Duke Energy response to ORS DR 3-30
[xcii] Duke Energy response to ORS DR 3-29
[xciii] Duke Energy response and attachments to ORS DR 3-27 and ORS DR 3-28.
[xciv] Duke Energy response to ORS DR 4-1
[xcv] Confidential Duke Energy response and attachments to ORS DR 2-10
[xcvi] Duke Energy response and attachment to ORS DR 2-24
[xcvii] *Id.*
[xcviii] Confidential Duke Energy response and attachments to ORS DR 1-1 (NCPS DR 2-19)
[xcix] Duke Energy response to ORS DR 2-25
[c] *Id.*

[ci] Duke Energy's General Load Reduction Corporate Communications Plan, provided in response to ORS DR 1-1 (NCPS DR 2-26)
[cii] Duke Energy response and attachment to ORS DR 2-24
[ciii] Duke Energy response to ORS DR 1-1 (NCPS DR 2-26)
[civ] *Id.*
[cv] Confidential Duke Energy responses to ORS DR 2-27 and ORS DR 3-1
[cvi] Duke Energy response to ORS DR 1-1 (NCPS DR 2-26)
[cvii] Confidential Corrective Action Plan Tracker, provided in response to ORS DR 4-2
[cviii] Duke Energy response to ORS DR 1-1 (NCPS DR 2-26)
[cix] Confidential Duke Energy response to ORS DR 2-27
[cx] Confidential Corrective Action Plan Tracker, provided in response to ORS DR 4-2
[cxi] *Id.*
[cxii] Duke Energy response to ORS DR 3-53
[cxiii] *Id.*
[cxiv] Confidential Duke attachments to ORS DR 3-1
[cxv] Roxboro Heat Tracing Thermal Design Examination report, provided in response to ORS DR 3-45
[cxvi] Mayo Heat Tracing Thermal Design Examination report, provided in response to ORS DR 3-44
[cxvii] *Id.*
[cxviii] Carolinas Unit Capability Timeline, provided in response to ORS DR 1-1 (NCPS DR 2-22)
[cxix] Confidential Corrective Action Plan Tracker, provided in response to ORS DR 4-2