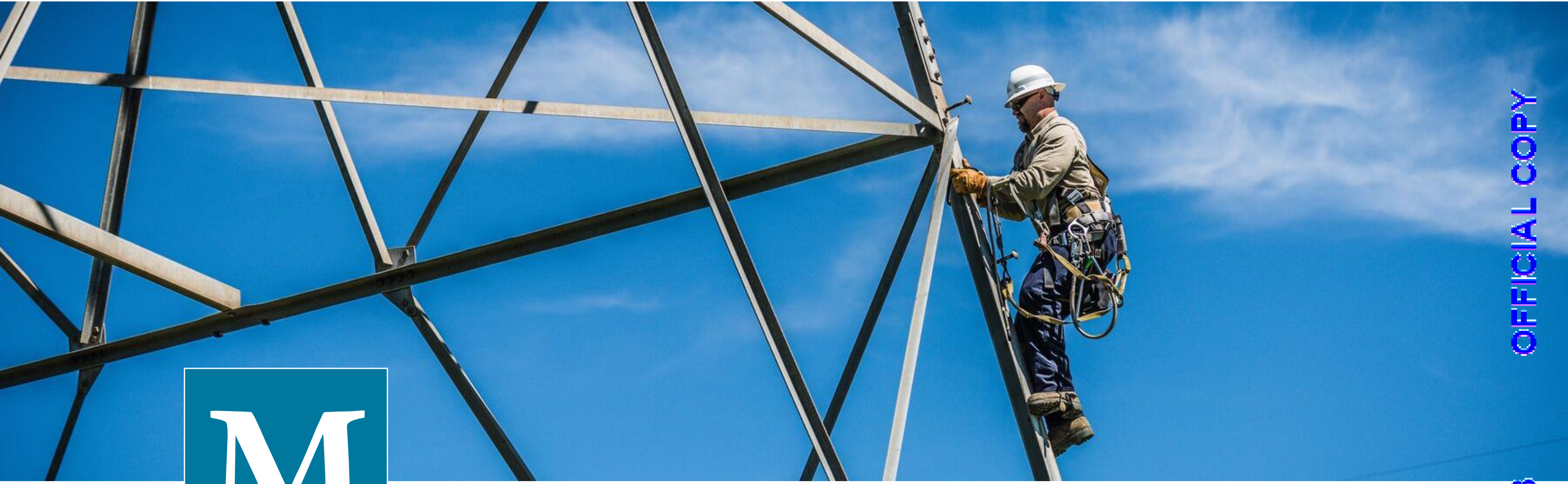

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Reliability and Operational Resilience

Highlights

- Variable renewable and inverter-based generation resources are an important component of the energy transition but will increase operational complexity and impact the predictability of grid operations. An orderly energy transition must ensure grid operators have time to adjust operational practice.

- Many electricity market regions in the United States are facing potential reliability challenges given increasing retirements of existing generators; however the Carolinas can preserve reliability by controlling the pace and composition of the energy transition. Doing so requires ensuring that adequate dispatchable capacity and energy supply is available prior to retiring coal. Gas resources are an important component of the diverse replacements necessary for an orderly transition and will serve as a critical bridge fuel to future zero-carbon resources.

- Extreme weather events have posed a severe test to grid reliability and resilience in recent years, including the Carolinas and surrounding regions' experiences during Winter Storm Elliot. The energy transition and increased reliance on variable, weather-dependent renewables will change the magnitude and nature of these risks.

- The changing resource mix to increasing levels of variable renewables and energy-limited storage has required continuous advances in the modeling of reliability and resource adequacy. New methods and metrics have become necessary to capture low-probability, high-impact reliability events. These efforts will continue to evolve as the industry gains experience through the energy transition.

Reliable electric service is essential to the well-being of the families, businesses, and communities that Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and, together with DEC, the "Companies") serve in the Carolinas. To ensure this well-being, the Companies work to meet their public service obligation to plan and operate their generating fleets and transmission and distribution systems to provide reliable power system operations to their customers 24 hours per day, seven days per week, 52 weeks per year in accordance with federally mandated North American Electric Reliability Corporation ("NERC") Reliability Standards.

To maintain the reliability of the grid in the Carolinas, DEC and DEP have long relied on conventional technologies, such as nuclear, coal, gas and hydropower to serve fluctuating customer demands. However, as discussed in Chapter 1 (Planning for a Changing Energy Landscape), economic, technological and regulatory drivers are creating a changing energy landscape in the demand for electricity and the of mix of generating resources expected to serve those demands. These drivers are affecting the entire utility industry, and the Companies must plan to reliably serve future demand in the face of them. This Carolinas Resource Plan (the "Plan" or "the Resource Plan") projects significant load growth in the Carolinas due to economic growth and increasing electrification (e.g., transportation electrification). While future loads are projected to increase, the broader United States utility industry is exiting coal, where, as discussed in Chapter 1 and Appendix F (Coal Retirement Analysis), the coal industry and its supply chain face mounting pressures that threaten the long-term reliability of existing coal generators.

The least-cost resource planning methods utilized in this Plan project meeting the energy and capacity needs created by increasing electricity demand and the replacement of coal units with a diverse set of resources that include new gas generation, increasing volumes of renewables such as solar and wind, as well as new energy storage (including both battery storage and the Bad Creek II expansion) and advanced nuclear. Each of these resource types have unique operational characteristics that must be balanced to ensure a reliable grid. As examples, gas units provide fast-responding, dispatchable energy and capacity, but can only be relied upon if firm fuel supply is assured; solar and wind hold the promise of "free," zero-emissions renewable fuel, but do so under uncertainties created by fundamental weather variability; new advanced nuclear technologies can provide zero-carbon dispatchability, but require further technological development and will not be available until later in the next decade; and energy storage technologies can increase aggregate resource flexibility, but generate no energy of their own and are subsequently reliant on renewable, fossil or nuclear generation sources to operate.

If properly balanced, these resources hold the potential to maintain or increase the reliability of the grid, but their interplay will change the nature of demands on system operations and the sources of reliability and resilience risks. This Plan has been developed with these changes in mind, and the composition of the resource mix and the pace at which it transitions are major drivers of potential system reliability. To provide context for how reliability considerations have shaped the Portfolios presented in the Plan, this Appendix describes the potential challenges posed by the changing energy landscape and the Companies' strategy and plans for ensuring reliability and resilience.

Maintaining or Improving Reliability

As the grid evolves to meet increasing electricity demands and replace retiring coal generation, maintaining and improving existing levels of reliability is a fundamental requirement of ensuring an orderly energy transition. Even now at the start of the transition, recent years have seen multiple major challenges to grid reliability across the country. In 2020, the California Independent System Operator ("CAISO") was forced to curtail customers due to elevated loads from a sustained regional heat wave. In 2021, customers in the Electric Reliability Council of Texas ("ERCOT") experienced sustained, multi-day blackouts due to the extreme cold and winter weather brought by Winter Storm Uri. In 2022, the east coast of the United States experienced periods of extreme stress due to rapidly advancing extreme cold weather during Winter Storm Elliot. In the latter case, multiple utilities in the southeast (including the Companies) were forced to curtail customer loads to maintain grid stability. And, as discussed later, major regions in the Eastern Interconnection ("EI") are sounding alarms over near- and medium-term reliability as dispatchable resources are projected to retire even as forecasted electricity demand is rising.

These recent events and forward-looking concerns underscore the need to ensure reliability through the necessary retirement and replacement of the Companies' coal units, which currently contribute towards reliability in the Carolinas with 8,400 megawatts ("MW") of capacity and a target of 35 days[1] of on-site fuel inventory. Replacing those contributions before the broader industry exits from coal impairs the reliability of these units and is a complex task which requires a balanced mix of resources. This Appendix addresses key topics important to characterizing the reliability needs of this power system in transition:

- The Companies operate within a regulatory framework where mandatory reliability standards must be met to ensure the stability of the overall grid.

- Variable renewable resources play an important role in the Plan by providing fuel diversity, mitigating fuel cost variability and reducing environmental regulatory risks. However, with renewable generation dependent on the weather (i.e., sunlight and wind), these resources will change the nature and complexity of planning and dispatching the grid by changing the shape of net-load and increasing the uncertainty of power system demands.

- Dispatchable resources including the existing coal fleet (until retirement), gas generators, energy storage and future low-carbon resources such as advanced nuclear are a necessary complement to renewables throughout the transition. However, these resources have considerations of their own that must be met to ensure their contributions to reliability.

- The changing energy landscape is driving similar changes across the United States, but the Carolinas can control the pace and composition of the transition to avoid potential reliability issues facing other regions. Additionally, these changes are reducing the ability to rely on the Companies' neighboring systems for assistance during periods of high demand.

- New inverter-based resources ("IBRs") such as wind, solar and batteries operate using electrical interconnection technologies different from conventional generators. The

[1] 35 days of "Full Load Burn." A day of full load burn is equivalent to running a unit at maximum capacity for 24 hours.

increasing presence of IBRs on the grid allows for potential fast-response essential reliability services but also introduces reliability risks due to configuration and modeling challenges and the potential for IBRs inappropriately responding to grid disturbances.

Meeting Mandatory Reliability Standards

The electric grid in the United States is subject to federally mandated reliability standards developed and enforced by NERC, and under the umbrella of NERC, DEC and DEP are members of the SERC Regional Entity, the reliability region comprised of utilities across states in the southeastern United States. Within this regulatory framework, the Companies are responsible for performing a variety of NERC reliability functions, and each function must maintain compliance with the NERC Operating Standards.

As owners and operators of Generation and Transmission assets, the Companies are obligated to meet the applicable reliability standards for owning, maintaining and operating grid assets. As independent Balancing Authorities ("BA"), the Companies must plan for and balance generating resources and power deliveries with customer demand for electricity in real time to avoid causing adverse power flow and/or frequency issues that could lead to instability or separation of the power system.

Each BA is responsible for independently complying with its mandatory NERC obligations, including providing its share of frequency support for the Eastern Interconnection, and maintaining demand and resource balance within its BA area. A BA must purposefully plan and dispatch its generating fleet to ensure compliance with NERC standards and cannot rely on unscheduled power flow from neighboring BAs to meet its obligation to maintain demand and resource balance. The realized measures of reliability underlying the Companies' BA obligations are calculated based on real-time supply-demand balance, but as discussed in this Appendix, ensuring adequate resources are available to meet load involves uncertainties and decisions made years, months, days and hour(s) ahead. Ultimately, NERC's regulations make the Companies responsible for maintaining reliable system operations for customers, and this reality is an essential underpinning of this Plan and the Companies' previous Integrated Resource Plans.

Flexible Generation Needs for a Changing Landscape with Increasing Uncertainty

Energy from variable renewables is an important contributor to power system operations and reliability in all Plan Portfolios, helping meet the deficits otherwise created by load growth and coal retirements. However, the available energy from these resources varies with time, and the remaining electricity demand must be served in real time by dispatchable sources to meet NERC reliability standards. As the capacity of variable renewables increases, the electricity demand net of renewable energy contributions, commonly referred to as "net load," will undergo a structural change in its shape, as the timing and magnitude of peaks and valleys begins to increasingly correspond to periods of high renewable output. This will alter the demands on system operations and dispatchable resources relative to the current system where the timing and magnitude of customer demands is the primary driver of operations. Solar, in particular, will contribute to the change in the shape of the Companies' net load due to both the magnitudes envisioned in this Plan as well as the dependence of solar output on solar irradiance during daylight hours. Wind in the Carolinas exhibits a complimentary, opposite pattern with average output higher at night (see example diurnal shapes in Appendix I (Renewables and Energy Storage)), but with less day-to-day consistency in timing.

The Changing Shape of Net Load

Given the day-night (diurnal) pattern of output, on-going growth of solar will change the historical day-to-day shape of generation needs and will increase the complexity and challenges to effectively manage the system. There are two key operational challenges that must be met in future portfolios: (1) very low net loads at midday and (2) the need to manage the associated rapid hour-over-hour decreases and increases in net load as the sun rises and sets known as “load-following” or “ramping.” The figures below illustrate these effects at different levels of solar penetration for a low-load spring day (Figure M-1) and for a significant peak winter day (Figure M-2).

Figure M-1: Spring Low Load + Blue Sky Solar Day Net Load Example Scenarios

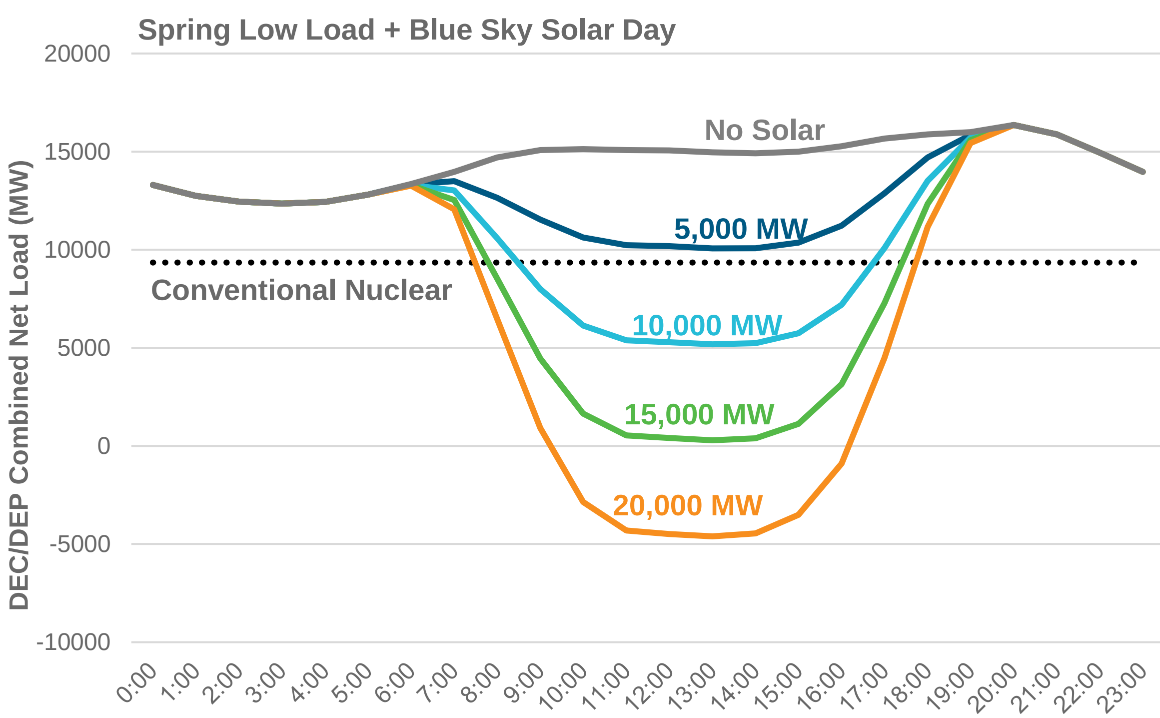
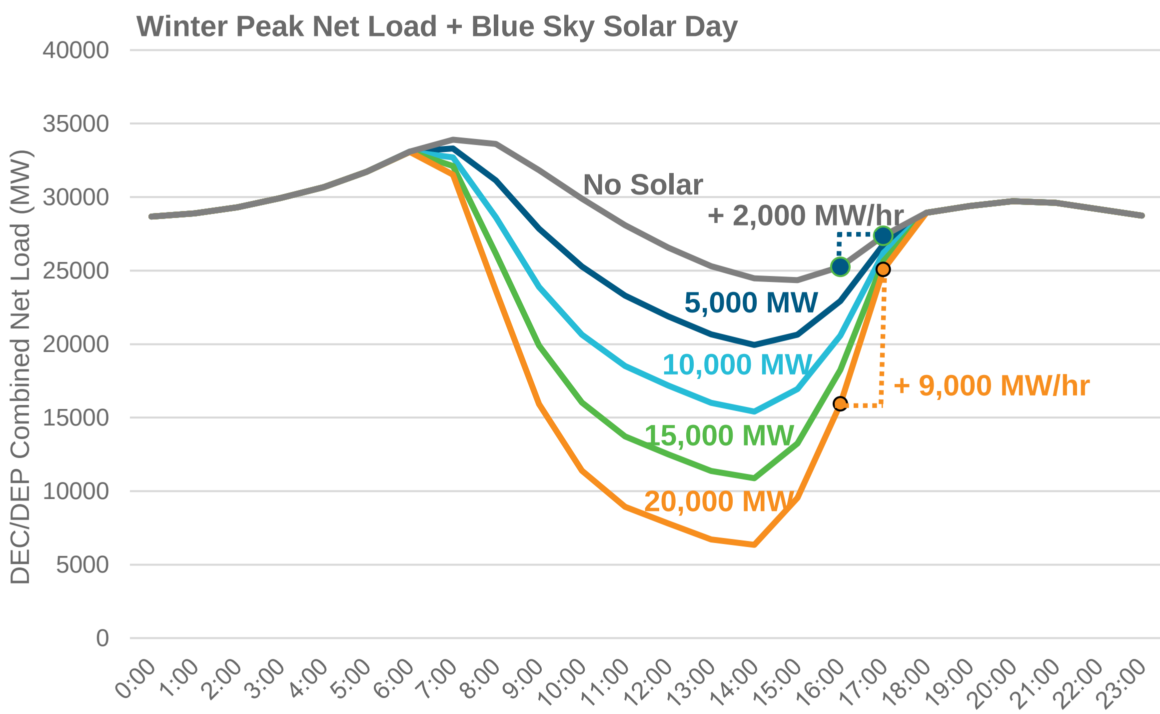


Figure M-2: Winter Peak Net Load Examples with Ramp Requirements



In both the spring and winter examples, high solar output creates a deep valley in the net-load profile during the middle of the day. This valley creates challenges for system operators as high levels of solar can force the remaining units on the system (necessary for meeting load during periods without sunshine) down to their minimum safe operating level. This collective minimum generation level of the system is known as the Lowest Reliability Operating Limit ("LROL"). On the lowest-load days (such as the example mild and sunny spring day), solar energy and other non-solar generation may need to be curtailed in order to maintain system reliability at the LROL if it cannot be absorbed by energy storage or sold at low or negative cost to neighboring utilities, who are increasingly likely to experience similar changes in their net-load shape as well. Even with elevated loads during winter peak, certain resources critical to meeting peak loads (such as coal and nuclear) must remain online and cannot be "cycled" (turned off and then on again within a few hours to a day) while ensuring reliability. Because of this, resources which have the flexibility to cycle, such as combined cycle ("CC") and combustion turbine ("CT") units, will face a more demanding operational environment as frequent starts and stops create wear and tear which may cause additional operational and reliability risk.

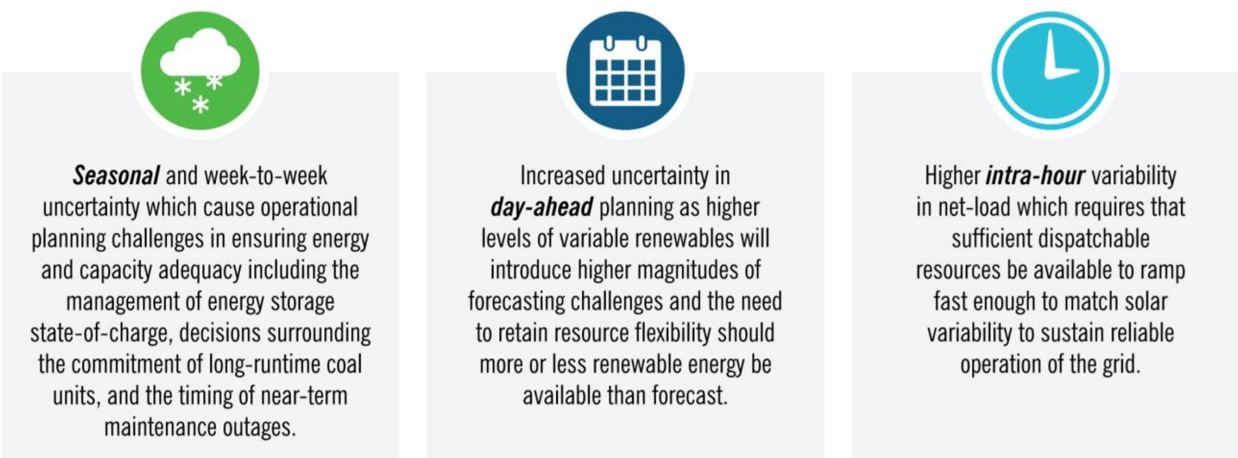
In the absence of solar generation, net load in winter and shoulder seasons would be expected to peak in the morning, decline throughout the day and increase steadily to the evening peak. In following this typical load pattern, the maximum hour-over-hour change in system demand is approximately 2,000 MW per hour with no solar output during the ramp upward to the evening peak. Adding solar to this standard increases the rate of demand change on the system as solar and load follow opposite trajectories. With 20,000 MW of installed solar under sunny conditions, the combined DEC/DEP system would experience a 4 p.m. to 5 p.m. ramp exceeding 9,000 MW — equivalent in magnitude to turning on the full capacity of the Duke Energy-owned nuclear fleet in a single hour.[2] While Figure M-2 above represents these challenges using historical data, changes in load and the installed solar resources may cause future ramps to be even steeper, with ramp rates in the 2033 portfolio modeling potentially exceeding 12,000 MW/hour.

With these demanding operating conditions, new strategies will be required to manage deeper valleys and steeper ramps, and direct control of renewable and storage assets is necessary to enable the more sophisticated co-optimization of traditional generators and new technologies. For example, at very high evening ramp rates, it may become necessary to optimize the complex economic and reliability tradeoffs in utilizing energy — limited storage (between use for ramping or use for meeting peak loads), cycling dispatchable gas/hydrogen units off and on across solar peaks, and proactive solar curtailment to reduce the magnitude of the ramp. An orderly energy transition must allow time for improvements in systems and practices to ensure reliable operations in this new environment.

Renewables and Operational Uncertainty

In addition to changing the shape and magnitude of net load that may be challenging for the power system to manage, the weather-dependence of renewables also increases the uncertainty in forecasting and making operational decisions to balance supply and demand. This uncertainty manifests at multiple time scales shown below in Figure M-3.

Figure M-3: Uncertainty and Operational Planning

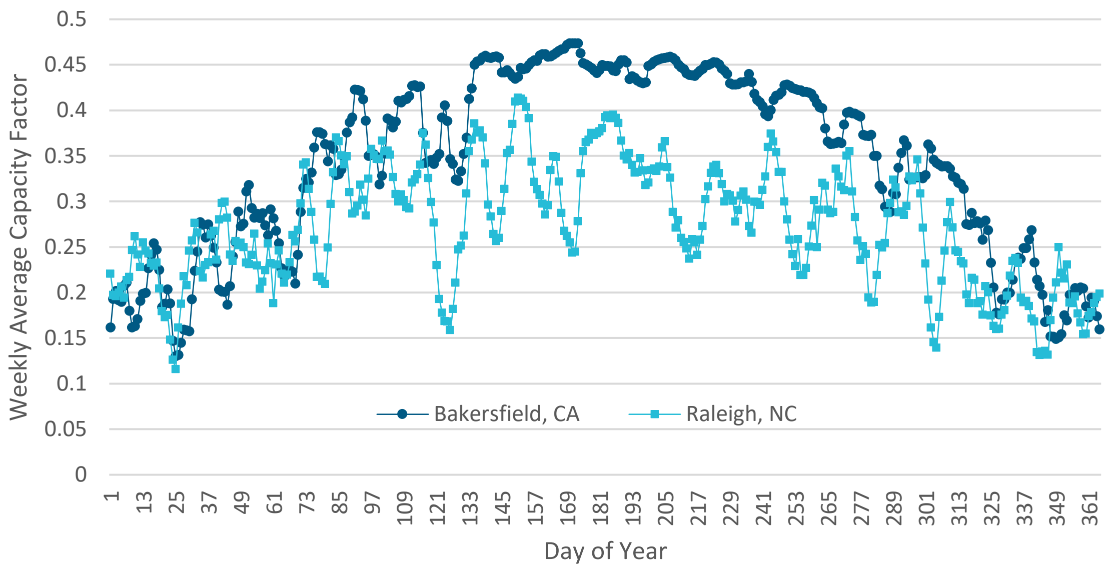


Due to the frequent changes in weather patterns and storm systems typical of the climate in the southeastern United States, variable renewable energy in the Carolinas has more week-to-week uncertainty in output when compared to more favorable (i.e., consistently sunny for solar) locations such as Southern California. Figure M-4 below illustrates this contrast by simulating the output of a

[2] The morning hours present a mirror image of this challenge, where dispatchable resources must ramp down quickly as load recedes and solar output increases.

hypothetical solar site[3] in Raleigh, North Carolina and Bakersfield, California[4] for a typical weather year. To demonstrate longer-term uncertainty, solar output is plotted daily as the weekly moving average capacity factor (the realized fraction of maximum potential output). Shorter-term uncertainties in the day-ahead and intraday are discussed later in this Appendix.

Figure M-4: Regional Comparison of Weekly Average Output from a Typical Solar PV Project



Solar output from the site in the Carolinas is overall lower and more volatile owing to more variable weather patterns that bring cloud cover and precipitation. This effect is seen most clearly during the summer months where southern California generally sees consistent, sunny weather and the Carolinas are prone to frequent thunderstorms. In winter, while both locations experience substantially lower and more volatile weekly output, the Carolinas are more likely to see highly elevated electricity demand and reliability risks due to the potential for cold weather unlike southern California which enjoys a temperate winter climate.

Even at shorter timescales within intraday planning, renewable resources are not perfectly forecastable into the future due to being driven by the weather. Figure M-5 below shows a typical December load shape for the combined DEC/DEP footprints with either 5,000 MW (left panel) or 15,000 MW (right panel) of solar on the system. The bands around the net-load shape show the amount of day-ahead flexibility necessary from dispatchable generation resources to respond to routine load and solar uncertainty.

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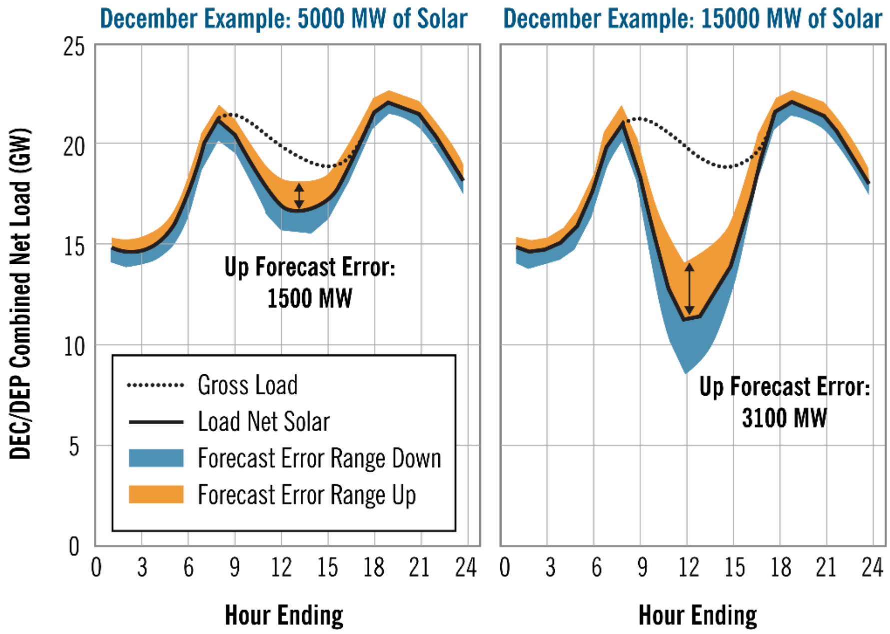
[3] The site configuration is generally consistent with the generic solar technology described in Chapter 2 (Methodology and Key Assumptions) — a bifacial single-axis-tracking project.

[4] The sites are simulated using NREL PVWatts at the location of Raleigh (RDU) and Bakersfield (BFL) airports, respectively. Note that as of 2022 Kern County (home of Bakersfield) has the highest installed solar capacity in the country, exceeding 4,000 MW according to data from the U.S. Energy Information Administration, Form 860, *available at* https://www.eia.gov/electricity/data/eia860.

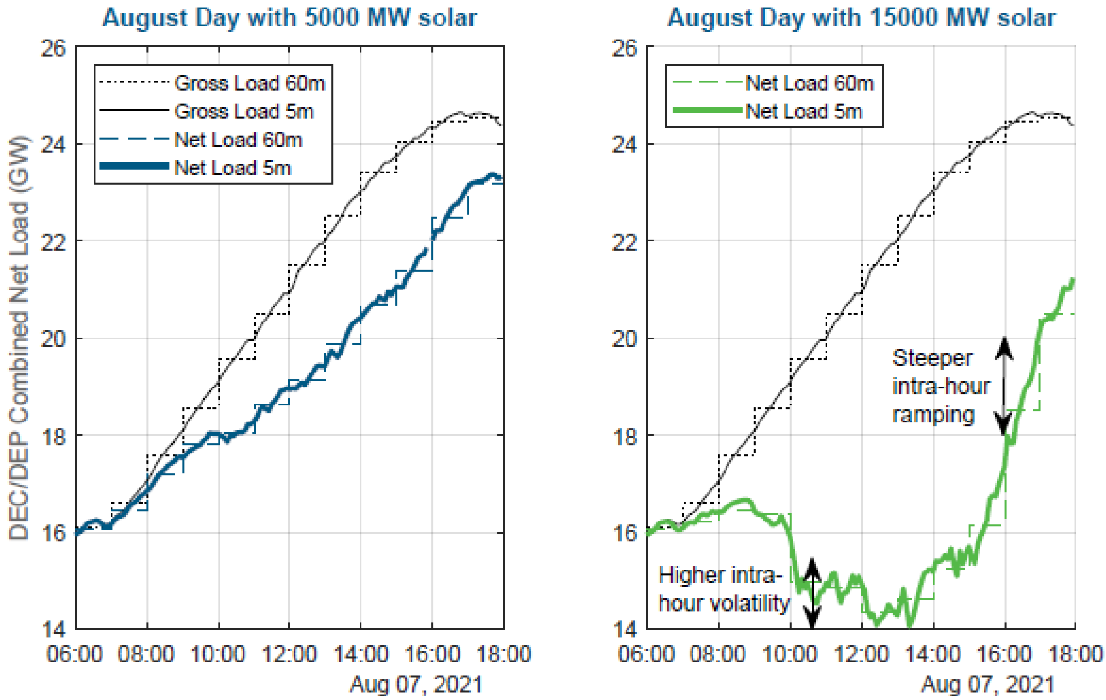
Figure M-5: Example December Day Forecast Error Uncertainty



In this December example, the Companies' system operators ensure the system can respond in a timely fashion to potential forecast errors by ensuring enough additional generating capacity is available during the day-ahead planning process. Enough spare capacity would need to be available from either online units (typically coal and CCs) or units that can start up fast enough to respond to the realization of forecast uncertainties (storage and CTs).

Reliable operation of the grid requires that electricity demand be balanced with supply at all times, and the collection of units committed and online must be able to ramp fast enough to mitigate minute-by-minute deviations in the net load. A larger portion of renewable resources in the generation mix creates a larger requirement of online, fast-ramping dispatchable generation. Operational reserves serving the role of matching intra-hour volatility are commonly known as "regulation" reserves and can respond to updated dispatch instructions every four seconds. Figure M-6 below shows the hourly and intra-hour observations of load and net load for an August day with 5,000 MW or 15,000 MW of solar on the system. The higher solar portfolio highlights the challenges of larger intra-hour deviations and steeper intra-hour ramps, both of which require additional regulating reserves to maintain reliable operation of the grid.

Figure M-6: Example August Day Net Load Volatility



Other regions are already experiencing a growing need for reserves as uncertainty on the power system increases — Midcontinent Independent System Operator ("MISO") has recently added new reserve products and increased its "up" reserve requirements,[5] and power markets across the United States are facing new forecasting and ancillary reserve capacity challenges to integrate increasing amounts of weather-dependent renewables.[6] In the case of both day-ahead and intraday uncertainties, spreading responsibility for holding operating reserves across a larger, more diverse power system can lower the overall ancillary reserve requirements.

Energy Adequacy

Today, the Companies primarily rely on a mixture of nuclear, coal, gas, pumped storage hydro and increasing amounts of solar to provide the capacity and energy necessary to meet peak electricity demands. In the traditional planning environment in which these systems have been designed, resource adequacy has typically been synonymous with having sufficient *capacity* resources available to reliably serve electric demand with consideration given to items including, but not limited to,

[5] MISO Energy, MISO's Response to the Reliability Imperative, January 2022, *available at* https://cdn.misoenergy.org/MISO%20Response%20to%20the%20Reliability%20Imperative504018.pdf.

[6] FERC, Energy and Ancillary Services Market Reforms to Address Changing System Needs: A Staff Paper, Dkt. No. AD21-10-000, September 2021, *available at* https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20210907-4002&optimized=false.

unplanned outages of generating equipment, uncertainties in load and renewable forecasts, fuel availability and weather-dependent renewable output caused by extreme weather events.

With increased levels of renewable generation and storage, capacity adequacy remains relevant, but further review and analysis of *energy* adequacy is needed. Variability in weather patterns and forecasts leading up to peak events may not allow renewables to generate (and storage to shift) energy to meet demand in all hours. Energy adequacy is a particular concern in the winter months during which the Companies' systems experience high customer demand due to electric heating during cold weather events. As weather during the winter has high variability, shorter daylight hours, and the potential for consecutive days of low irradiance (low solar output), periods of extended low output from solar are possible. Energy adequacy considerations are not limited to renewable generation, but also factor heavily into decisions necessary to ensure firm fuel supply and transportation for CCs and CTs as winter heating demand can directly compete with natural gas fuel for power generation during periods of extreme cold. Because of these varied challenges, a balanced mix of resources prevents over-reliance on any single fuel source with resource diversity directly supporting energy adequacy. Solar and wind are complimentary and help minimize additional gas fuel-security needs, while gas resources help backstop energy supply during periods when renewable output is low. Ultimately renewable gas resources contribute to a balanced portfolio alongside the Companies' hydropower and nuclear generators.

Traditionally, strategies for considering adequate fuel or energy supply in planning and operations have been the purview of individual utilities. However, the changing energy landscape is elevating energy adequacy as a core consideration with potential risks to the broader grid should individual utility or regional practices prove inadequate to maintain reliability. Industry recognition of this broader grid risk has been driven by recent events such as the ERCOT experience during Winter Storm URI, in which variability or loss of renewable energy and gas fuel supply have directly contributed to load curtailment and risks to power system reliability. To ensure the adequate treatment of these needs in the operational and reliability planning process, NERC's Energy Reliability Assessment Task Force has initiated the formal standards development process for two new requirements for evaluating and addressing risks related to energy availability.[7,8]

Importance of Dispatchable Capacity Resources

The combination of the increasing electricity demand documented in Appendix D (Electric Load Forecast) and the change in net-load and uncertainty dynamics discussed above results in a need for

[7] NERC, SAR: Energy Assessments with Energy-Constrained Resources in the Planning Time Horizon, June 2022, *available at* https://www.nerc.com/pa/Stand/Project202203EnergyAssurancewithEnergyConstrainedR/2022-03%20Constrained%20Resources%20in%20the%20Planning%20Time%20Horizon%20Standard%20Authorization%20Request.pdf.

[8] NERC, SAR: Energy Assessments with Energy–Constrained Resources in the Operations and Operations Planning Time Horizons, June 2022, *available at* https://www.nerc.com/pa/Stand/Project202203EnergyAssurancewithEnergyConstrainedR/2022-03%20Constrained%20Resources%20in%20the%20Operations%20and%20Operations%20Planning%20Time%20Horizons%20Standard%20Authorization%20Request.pdf.

dispatchable resources to create a balanced mix of generators to meet the energy and capacity requirements of the system when renewable energy is unavailable. Today, the Companies' coal units provide an essential foundation of dispatchable capacity and fuel-security that must be adequately replaced prior to retirement to avoid threats to grid reliability.

As documented in Chapter 3 (Portfolios), a diverse set of resources is needed to fill the energy, capacity, and dispatchability gaps that would otherwise be created by coal retirements. In particular, the combined flexibility of storage and gas generation resources is necessary to reliably operate the system in the net load valleys and manage the steep ramps as solar output increases and then decreases throughout the day. For example, new storage resources such as battery storage and the Bad Creek II project can help mitigate the depth of the net load valley and ease the morning and evening ramps. Additionally, given the seasonal, day-to-day and week-to-week uncertainties in renewable energy availability, all Portfolios rely on existing and new CC and CT units as critical work-horse technologies to provide essential flexibility to ramp and cycle when renewable output is high, and much-needed energy and capacity during periods of extended low irradiance.

To ensure that the transition from coal to a new generation mix is orderly and reliable, it is necessary to address additional inter-related considerations necessary for dispatchable resources to be fully utilized — these include the fuel security of gas fired units, energy-adequacy and operational optimization for new storage technologies, maintaining coal unit capabilities until retirement and the long-term development of zero-carbon, load-following resources.

Natural Gas Fuel Supply and Transportation Dependencies

One of the primary challenges the Carolinas experience as a winter planning system is ensuring adequate natural gas supply during cold weather when gas needs are highest due to a combination of demands from heating and power generation. In future power system scenarios, generation from CC gas units and CTs will be necessary not just to directly meet peak capacity demands, but also as an essential resource to charge energy storage during extended periods of low solar output.

The Carolinas must import natural gas from interstate gas pipelines, and additional firm inter-state gas transportation becomes essential to enable replacing the fuel-security and energy adequacy that has otherwise been ensured by coal units' onsite storage capabilities equivalent to weeks of 24/7 output. If adequate firm transportation is not guaranteed, existing and new CC and CT resources must have adequate on-site storage to meet fuel-security and energy adequacy needs. Appendix K (Natural Gas, Low-Carbon Fuels and Hydrogen) more thoroughly details the Companies' strategy for ensuring future fuel security for the Portfolios modeled in this Plan.

Utilizing New Energy Storage Technologies

Energy storage forms an important part of the diverse resource additions identified in the Carolinas Resource Plan. However, it is important to emphasize that storage technology contributions to grid operations and reliability are wholly dependent on the availability of generation from other resources to operate. Storage technologies can only shift energy from periods of lower need to periods of more value to the grid — and do so with a net loss in energy associated with round-trip efficiencies.

While dependent on other energy sources for operation, storage technologies have many favorable characteristics for ensuring grid reliability, including their ability to shift energy, start, stop, and ramp quickly, and serve various operating reserve needs. However, optimally utilizing new, energy-limited storage technologies such as lithium-ion batteries across these multiple uses introduces new operational challenges magnified by the operational uncertainties of a more renewable grid. A recent example of these challenges occurred in CAISO during an extreme September 2022 heatwave where over 20% of battery capacity allocated for resource adequacy was not able to be deployed during periods of declared Energy Emergency Alerts. The causes of this shortfall are thought to include inter-related operational complexities from the limited time-horizons of real-time market optimization, storage state-of-charge management strategies, ancillary service co-optimization, and interconnection limitations at hybrid facilities (such as solar paired with storage).[9]

Direct operational control of storage assets mitigates some of the complexity and co-optimization challenges present in Regional Transmission Organizations/Independent System Operators ("ISOs"), and DEC has long-standing experience optimizing over 2,000 MW of pumped storage with approximately 20 hours of average storage capability. However, due to inherent uncertainties in load, weather and power system operations the margin of error for optimizing the use of shorter-duration energy storage can be smaller than that for longer-duration storage such as the Jocassee and Bad Creek pumped storage hydropower projects. Caution is required in accelerated storage deployment as new operating paradigms will be necessary to optimally utilize the shorter anticipated duration of new storage additions. Energy storge additions, including stand-alone batteries, the new Bad Creek II project and solar paired with storage will be essential to reliably replacing retiring coal generation, but operating experience and refinement of operational practice with new technologies will be essential prior to relying on their use as critical reliability assets.

Maintaining Coal Units Through Retirements

While much of the discussion in this Appendix focuses on the challenges that must be addressed by new resources to maintain reliability for an orderly retirement of coal units, an equal concern regards the ability of the coal units and the coal industry supply chain to remain reliable through their remaining lifetimes. The changing patterns of net-load will likely lead to a new operating regime for coal units where they will be utilized during seasonal periods of high electricity demand or projected periods of extended low renewable output. Appendix F documents this and other considerations for maintaining coal unit reliability including staffing, availability of replacement equipment, and fuel security in the face of a broader electric power industry exit from coal.

Zero-Carbon Load Following Resources

As the energy transition moves towards deeper decarbonization, new sources of dispatchable and flexible generation will become necessary to ensure future reliability. Assessing technology viability and progress multiple decades into the future is uncertain, but the attributes desirable in new grid sources are knowable based on system needs. In general, it is expected that additional incremental

[9] California ISO, Special Report on Battery Storage, July 2023, *available at* http://www.caiso.com/Documents/2022-Special-Report-on-Battery-Storage-Jul-7-2023.pdf.

reliability and carbon reductions provided by new variable renewables and storage will decrease at very high penetrations. What will be needed to continue the energy transition are resources that do not emit carbon and have the dispatchability and flexibility characteristics that are fundamental to power system reliability (e.g., load-following capabilities).

While not encompassing all future potential candidates for such zero-carbon load following resources, this Plan discusses the potential use of:

1. Hydrogen as a fuel for new CC units and CTs. For further information on how the Companies envision building optionality for hydrogen utilization into new gas units see Appendix K.

2. Advanced nuclear reactor designs which are anticipated to include integrated storage and dispatch flexibility. For more detail, see the discussion on "Advanced Reactors" in Appendix J (Nuclear) and the modeling assumptions for "Advanced Small Modular Nuclear Reactors with Thermal Storage" in Appendix E (Screening of Generation Alternatives).

For discussion on other future technology options which are not included in the Plan, see Appendix E.

Eastern Interconnection Impacts of the Changing Energy Landscape

As discussed in Executive Summary, the Companies are not the only utilities or balancing authorities experiencing the major drivers of the changing energy landscape. One major theme of concern throughout the utility industry is how the general industry exit from coal combined with economic and environmental pressures are causing the accelerated retirement of conventional fossil-fueled generators and their replacement, in large part, by variable renewables. Meanwhile, in many regions, electrification and economic growth are increasing load forecasts and changing the potential timing of peak demand. Expressing broad power industry concerns on these topics, NERC President and Chief Executive Officer, James Robb, has identified that "managing the pace of change is the central challenge for reliability".[10]

Within the EI (to which the Companies are electrically connected), many of the large market-regions ("ISOs") to the north of the Carolinas are expressing alarm at how the current rapid pace of transition is creating potential shortfalls in projected reserve margins:

- The New York ISO ("NYISO") has recently noted that "growth in demand due to electrification coupled with the retirement of fossil fuel based peaker plants is leading to declining reliability margins…"[11]

[10] NERC, The Reliability and Resiliency of Electric Service in the United States in Light of Recent Reliability Assessments and Alerts, June 2023, *available at* https://www.energy.senate.gov/services/files/D47C2B83-A0A7-4E0B-ABF2-9574D9990C11.

[11] New York ISO, 2023 Power Trends: A Balanced Approach to a Clean and Reliable Grid The New York ISO Annual Grid & Markets Report (2023), *available at* https://www.nyiso.com/documents/20142/2223020/2023-Power-Trends.pdf.

- MISO has experienced reserve margin volatility in the last two years, weathering projected shortfalls in 2022[12] while seeing recovery to acceptable levels in 2023.[13] However, MISO notes that this improvement in supply adequacy may be the product of a one-off change to its capacity procurement process and other potentially non-repeatable factors such as deferred retirements and increased imports. MISO continues to anticipate a decline in accredited capacity in both the near-term and long-term as existing thermal generators are retired and replaced in part by new solar and wind.[14]

- PJM Interconnection, L.L.C. ("PJM") — a direct neighbor to the Companies — is facing a similar changing energy landscape with the potential for significant increases in electricity demand from electrification and datacenter proliferation, as well as rapid near-term retirements of fossil fuel generators. These combined trends suggest PJM could face steadily declining reserve margins through 2030.[15]

In general, these concerns are indicative of potential reliability risks within each entity, but also imply a reduced capability to assist the Companies during potential wide-spread weather events or significantly constrained periods with high demand and limited operational reserves. This concern is supported by modeling results which suggest limited import availability for the Companies during the highest periods of need — typically extreme winter peak events. In particular, Attachment I (2023 Resource Adequacy Study) shows substantially lower neighbor assistance into DEP and DEC during winter peaks than previous reliability modeling efforts; in these scenarios adequate transmission capacity exists to enable imports, but most neighbor generation is committed to meeting equally high internal demands. This finding is supported by preliminary results from enhanced modeling activities carried out by PJM in support of its ongoing capacity market reform process, which have produced a "significant shift in the patterns of [modeled] reliability risk to the winter season."[16]

The events of December 23 and 24 during Winter Storm Elliot are a real-world lesson in the risk that similar paths through the changing energy landscape can lead to high correlations in times of power system stress between the Companies and neighboring entities. Multiple utilities were forced to curtail customer loads on both days as neighbor assistance was unavailable or inadequate to prevent

[12] MISO, 2022/2023 Planning Resource Auction Results, April 2022, *available at* https://cdn.misoenergy.org/2022%20PRA%20Results624053.pdf.

[13] MISO, Planning Resource Auction Results for Planning Year 2023-2024, May 2023, *available at* https://cdn.misoenergy.org/2023%20Planning%20Resource%20Auction%20(PRA)%20Results628925.pdf.

[14] MISO, 2022 Regional Resource Assessment, November 2022, *available at* https://cdn.misoenergy.org/2022%20Regional%20Resource%20Assessment%20Report627163.pdf.

[15] PJM, Energy Transition in PJM: Resource Retirements, Replacements & Risks, February 2023, *available at* https://www.pjm.com/-/media/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx.

[16] PJM Resource Adequacy Senior Task Force, Capacity Market Reform: PJM's Proposal, June 2023, *available at* https://www.pjm.com/-/media/committees-groups/cifp-ra/2023/20230621/20230621-item-02a---pjm-cifp-stage-3-proposal---updated.ashx.

emergency operations. In particular, the curtailment of firm imports into DEP and DEC by PJM is a stark reminder that neighbor assistance is not guaranteed at all times of need.[17]

Inverter-Based Resources and System Reliability

The reliable operation of the power system has evolved slowly but steadily over the 100-plus years of electrification in the United States. Consistent across this span of time is the use of "synchronous" alternating current generators, typically physically rotating hydropower, steam or gas turbines, to export electricity to the grid. Grid operations and reliability standards were developed through time with the attributes of these resources in mind. However, many of the new resources in this Plan such as renewables and battery storage, instead connect to the grid through inverters which exhibit different behaviors during periods of stress than existing synchronous generators. The current and future deployment of these IBRs have the potential to challenge or enhance reliability depending on how the energy transition is managed.

System Inertia and Primary Frequency Response

Today, when a generator or transmission line unexpectedly goes offline ("trips"), the supply-demand balance on the system is disturbed and system frequency begins to drop, requiring the remaining generators to respond to maintain system stability. First, synchronous generators intrinsically "push back" against the loss of frequency the disturbance causes. These spinning generators have a physical inertial response that transfers their rotational energy to the electrical system, slowing the rate at which the system loses frequency. The collective response of the grid to frequency deviations is called system inertia. Secondly, unit control systems ("governors") respond to locally sensed frequency deviations and change fuel inputs (e.g., steam, gas, water) to the mechanical system to compensate for the supply-demand imbalance. This reaction is called primary frequency response, the magnitude and timing of which is dependent on the physical properties and control system configurations of each individual generator.

The amount of inertial mass — number and size of spinning synchronous machines connected to the interconnection — determines rate and magnitude of the change caused by deviations in resource and demand power balance. Inertia intrinsically slows the loss of frequency while governor response then reacts to help restore balance. For these reasons, the more synchronous machines on the system, the less volatile changes to the system's electrical and mechanical speed.

Unlike spinning synchronous generators, IBRs lack an intrinsic physical inertial response that slows the rate of change of system frequency. However, the electronic nature of plant controls can allow an IBR to rapidly modify active power output to provide frequency response during system disturbances. For variable renewables, it may be easier to reduce output in cases of high-frequency conditions (more

[17] During Winter Storm Elliot, PJM curtailed firm exports to other BAs beyond DEP and DEC including Tennessee Valley Authority and Louisville Gas & Electric to avoid load curtailments. PJM itself became reliant on emergency imports from NYISO for a period of time as well. For more information see: PJM, Winter Storm Elliot: Event Analysis and Recommendation Report, July 2023, *available at* https://www.pjm.com/-/media/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.ashx.

electricity supply than demand) than responding to low frequency events (more demand than supply) which would require consistently maintaining headroom for additional active power output at the cost of curtailed generation. Storage IBRs (e.g., batteries) are uniquely flexible and can provide very fast response, and if properly controlled help prevent deep drops in, and assist in the recovery of, system frequency. However, as discussed previously, to enable these capabilities, energy storage must be online and positioned at an adequate state of charge to absorb or inject the necessary amount of power, creating an additional complexity in the operations and control of these resources. While sometimes described as “synthetic inertia”, IBR-based fast frequency responses will necessarily look different than those from rotating units and must be designed and controlled to work in tandem with the physical responses from synchronous generators.

Situated within the EI, DEP and DEC are integrated into one of the largest, strongest grids in the world. As such, there are no immediate reliability issues posed by declining system inertia and the potential increased complexity of frequency response to grid events. However, as the changing energy landscape leads the broader utility industry into a future with an increasing large share of IBRs, the Companies will continue to monitor these issues to ensure they remain compliant with NERC standards to provide their required share of EI frequency response. In the long-term future, generation resources with more conventional capabilities (such as hydropower, the Bad Creek II project, gas/hydrogen CTs and CCs and new and existing nuclear) can complement new IBR technologies as part of a diverse resource mix by providing a strong foundation of reliability services.

System Short-Circuit Strength

In addition to having different frequency response characteristics compared to existing synchronous generators, IBRs will also contribute differently to how the grid is capable of safely responding to unexpected events. During normal operations, electricity safely flows across carefully managed paths between generators and end-users through the transmission and distribution systems. If grid equipment is damaged or malfunctions, electricity can accidentally flow where it is not intended (such as into the ground from a downed power line or across otherwise unconnected pieces of equipment). This unintended flow of electricity is called a “short-circuit” and is a severe safety hazard to the public and power system workers when areas and equipment which should otherwise remain safe become electrified.

Because of this safety risk, the power system is designed with layers of protections to — rapidly and automatically — isolate faulty equipment when the grid senses a disturbance. This process of “clearing faults” is driven by protection equipment engaging when abnormally high electric current is detected during a short-circuit event. During a short-circuit, the electrical current produced by conventional generators in the vicinity of a fault will automatically increase, and it is this higher level of current that generally triggers system protections to isolate malfunctioning equipment. Conversely, the typical response of standard IBR controls will inject little to no additional current when sensing abnormal grid conditions (i.e., lower localized voltage during a short-circuit). With IBRs forming an increasingly large share of grid resources, the system strength of the grid could weaken to a point where the lack short-circuit current prevents protection schemes from identifying fault events and operating as intended.

The future grid must be configured such that system strength remains adequate to enable safe and reliable operations. While this Plan does not specifically include dedicated modeling studies to evaluate the potential system strength of the modeled Portfolios, the Companies actively assess short-circuit and stability-related issues as part of their interconnection study processes.

Managing the Configuration of Inverter Based Resources to Maintain Reliability

The rapid growth in IBR deployment across the country has occurred in the absence of updated industry standards for interconnection and performance requirements that address the new operating characteristics of these resources. This has resulted in recent events where significant amounts of IBR-based generation have been unexpectedly lost due to interactions between improperly configured control systems and power system disturbances (such as the loss of a transmission line or generating unit). The most notable examples include losses of hundreds of MW of solar output in CAISO in 2021,[18] similar magnitude reductions in wind output in ERCOT,[19] and two large, repeated losses of solar output in ERCOT in the vicinity of Odessa, Texas. The 2021[20] and 2022[21] "Odessa Disturbances" are of particular concern due to their wide-area nature, magnitude of lost solar generation (over 1,000 MW) and, in the case of the 2022 event, the realization of additional failures modes in some solar projects which had addressed other deficiencies identified in the wake of the 2021 event.

The electric power industry has taken note of these potential reliability risks, with NERC advising the owners of IBR assets to verify that protection and control settings are correctly configured[22] to ensure power system stability. Industry is also beginning to act to systematically improve the process by which these resources were integrated into the grid, with new recommendations for the simulation and modeling, and ultimately, interconnection, of IBRs developed in recent years. In 2022, collaboration between utilities, original equipment manufacturers and expert engineers produced a new formal Institute of Electrical and Electronics Engineers standard for the performance and capabilities of IBRs.[23] Based on this standard, Duke Energy[24] and other peer utilities have developed new interconnection requirements and processes since its publication in 2022. To improve the reliable

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[18] NERC, Multiple Solar PV Disturbances in CAISO Disturbances between June and August 2021 Joint NERC and WECC Staff Report, April 2022, *available at* https://www.nerc.com/pa/rrm/ea/Documents/NERC_2021_California_Solar_PV_Disturbances_Report.pdf.

[19] NERC, Panhandle Wind Disturbance Texas Event: March 22, 2022, August 2022, *available at* https://www.nerc.com/pa/rrm/ea/Documents/Panhandle_Wind_Disturbance_Report.pdf.

[20] NERC, Odessa Disturbance Texas Events: May 9, 2021 and June 26, 2021, September, 2021, *available at* https://www.nerc.com/pa/rrm/ea/Documents/Odessa_Disturbance_Report.pdf.

[21] NERC, 2022 Odessa Disturbance. Joint NERC and Texas RE Staff Report, December 2022, *available at* https://www.nerc.com/comm/RSTC_Reliability_Guidelines/NERC_2022_Odessa_Disturbance_Report%20(1).pdf.

[22] NERC, Industry Recommendation: Inverter-Based Resource Performance Issues, March 2023, *available at* https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC%20Alert%20R-2023-03-14-01%20Level%202%20-%20Inverter-Based%20Resource%20Performance%20Issues.pdf.

[23] Institute of Electrical and Electronics Engineers, Standard 2800–2022, April 2022, *available at* https://ieeexplore.ieee.org/document/9762253.

[24] As of March 27, 2023 the new IBR interconnection requirements are available on the Companies' respective OASIS pages. DEC interconnection requirements are *available at* http://www.oasis.oati.com/woa/docs/DUK and DEP interconnection requirements are *available at* http://www.oasis.oati.com/woa/docs/CPL.

integration of IBRs, NERC has initiated formal standards development on many topics including IBR modeling, event reporting, and performance issue analysis and mitigation.[25] As of the writing of this Plan, the Federal Energy Regulatory Commission ("FERC") is reviewing comments on a notice of proposed rulemaking to direct NERC to further systematically develop IBR reliability standards related to data sharing, model validation, planning and operational studies, and performance requirements.[26]

New and forthcoming standards are a major step forward in ensuring the reliability of a power system with increasing levels of IBRs. However, operating experience across the United States underscores the need to purposefully manage the pace of the energy transition to identify and address new challenges before they materialize into broad-based risks to the power system. The Companies specifically plan to iteratively improve their new interconnection requirements and commissioning processes, both through incorporation of new or improved standards and recommendations,[27] and in concert with project developer feedback with its existing "Revision 0" requirements released this year.

It is important to note that the existing IBR fleet — including solar projects interconnected into DEP and DEC — may still have control and protection settings similar to those highlighted by the ERCOT and CAISO events. Addressing these existing facilities is a necessary step towards creating a stronger reliability foundation from which to expand the contribution of renewable and storage IBRs to the Companies' power systems. To do so, the Companies are implementing an inspection and commissioning test program for new and already-connected IBR projects to ensure they meet critical performance and capability interconnection requirements.

Modeling Resource and Energy Adequacy

Historical practice in resource planning and reliability modeling has been to evaluate potential generation portfolios against their likelihood of experiencing an event which would require a utility to involuntarily shed customer loads to maintain the balance between electric supply and customer demand. Traditionally, the industry has relied upon a rule-of-thumb planning threshold of allowing no more than one day in 10 years to experience a loss-of-load event when evaluated against potential scenarios of electricity demand and generator availability. In practice this reliability threshold is measured as the Loss of Load Expectation (LOLE), wherein the "1-in-10" principle is measured as an average of 0.1 event-days per year.

The LOLE metric has served, and continues to serve, as a foundation for reliability and resource adequacy modeling. However, the changing energy landscape introduces new risks and drivers of potential reliability events. As has been discussed previously in this Appendix, system reliability in a grid reliant on increasing levels of weather-dependent renewables and energy storage will experience

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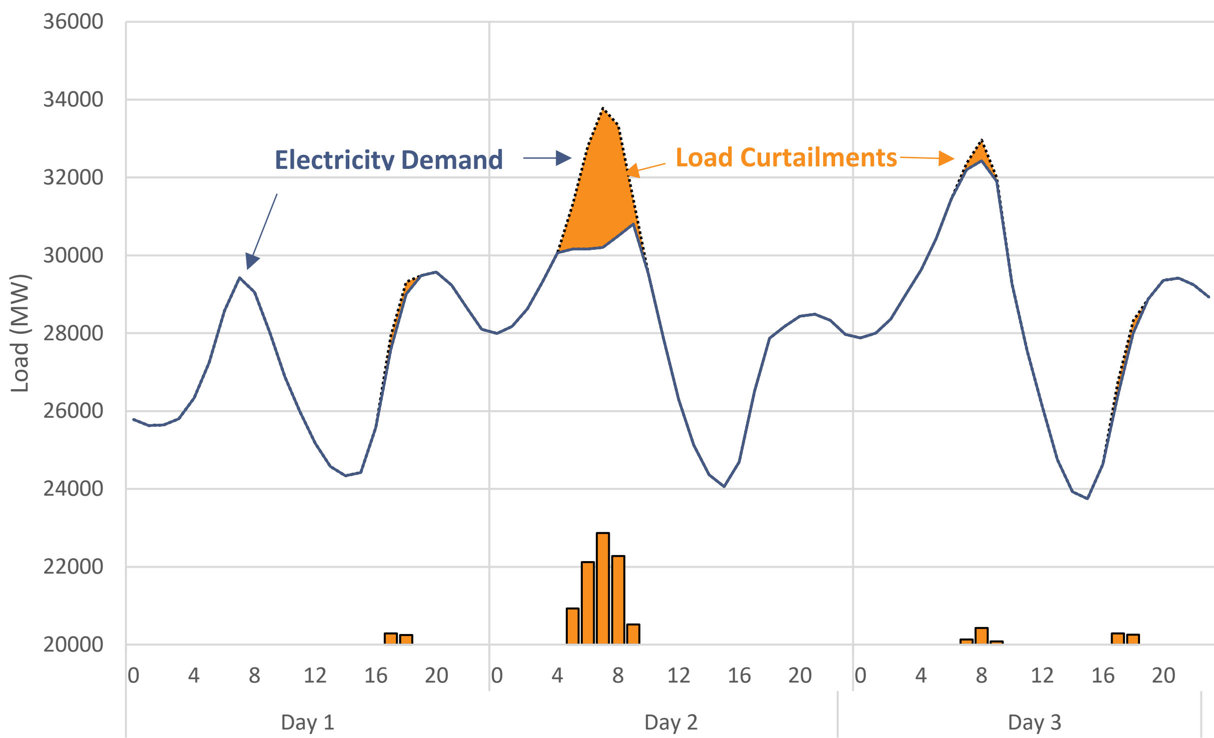
[25] For a more complete list see NERC, Quick Reference Guide: Inverter-Based Resource Activities, June, 2023, *available at* https://www.nerc.com/pa/Documents/IBR_Quick%20Reference%20Guide.pdf.

[26] FERC, Notice of Proposed Rulemaking re Reliability Standards to Address Inverter-Based Resources under RM22-12, November 17, 2022, *available at* https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20221117-3114.

[27] For example, IEEE is currently working on new recommendations for testing and verification of IBR performance. See the IEEE 2800.2 working group, *available at* https://sagroups.ieee.org/2800-2/.

new challenges related to the adequacy of overall energy supply to charge storage resources to meet capacity needs and balance the ramping and load following needs of renewables. In this context, if used in isolation, LOLE may mask other important characteristics of potential reliability events, such as the duration and the depth of the supply-demand imbalance on the grid. Figure M-7 below illustrates this by representing three hypothetical loss-of-load event days.

Figure M-7: Comparison of Reliability Metrics for Days with an Identical LOLE



The first day experiences two consecutive hours with loss-of-load, the second day experiences a more severe event spanning five hours with much deeper load shed, and the third day also experiences five hours of load shed, but split between two periods, one in the morning and one in the evening. Each day counts identically towards the calculation of LOLE but differs on keys elements of duration (Loss of Load Hours ("LOLH")) and overall severity (as measured in Expected Unserved Energy ("EUE")).

In a real-world context, the modeling concept of an "event-day" can have vastly different consequences for residents and businesses in the Carolinas. The customer impacts of a short, shallow rolling curtailment will be substantively different than those experienced in a deep, long-duration blackout. Additionally, system operators will face different challenges in dealing with grid emergencies depending on depth and severity, with more extreme events compounding risks. Given the necessity of electric power to modern life and well-being, major blackouts can cause cascading failures in essential infrastructure as was seen during the 2020 Texas event in Winter Storm Uri, where widespread, multi-day blackouts led to a breakdown of water supply infrastructure.[28]

To that end, the use of reliability metrics in addition to LOLE is an increasing necessity[29] given the changing energy landscape and is becoming regular practice across the utility industry. Among other power system entities, the reliability coordinators Northeast Power Coordinating Council (covering northeastern North America), Western Electric Coordinating Council (western North America) and SERC (southeast United States, to which the Companies are accountable) employ LOLH and EUE to further characterize risk in regional resource adequacy modeling.[30,31] Additionally, as of the writing of this Plan, PJM is proposing to reform its capacity market processes to use EUE directly in the resource accreditation process[32]. Similarly, in Appendix C (Quantitative Analysis), the Companies are reporting EUE, LOLH and other metrics to provide additional context on risk and potential impacts to customers in the Core Portfolios that are otherwise equally reliable when measured in traditional terms of LOLE. The Companies will continue to research and implement best practices in characterizing reliability risk, drawing on strategies and metrics from peers in the electric utility sector, and related actuarial disciplines such as insurance, natural phenomena hazards, and finance.

In addition to improving the metrics by which it characterizes resource and energy adequacy risk, Duke Energy has systematically refined its approach to resource adequacy modeling to incorporate the new complexities introduced by the energy transition. The 2023 Resource Adequacy study introduced a refined long term economic load forecast uncertainty approach and explicitly modeled cold-weather capacity risks based on recent operating experience including Winter Storm Elliott. The Companies' reliability modeling now also includes day ahead uncertainty in load and solar forecasts when validating the reliability of Plan Portfolios. Appendix C contains further details on the methodology and results of the Portfolio validation modeling.

Future System Resilience

Separate from reliability, resilience refers to the ability of the grid to withstand or, if necessary, recover from extreme events. Considerations of resilience look beyond the standard measures of resource

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[28] 69% of Texas residents experienced a power outage and 49% lost running water. See University of Houston, The Winter Storm of 2021, *available at* https://uh.edu/hobby/winter2021/storm.pdf.

[29] See the discussion on probabilistic reliability modeling and metrics in Energy Systems Integration Group, Redefining Resource Adequacy for Modern Power Systems, 2021, *available at* https://www.esig.energy/wp-content/uploads/2021/08/ESIG-Redefining-Resource-Adequacy-2021.pdf.

[30] For examples see the regional profiles discussed in the NERC, 2023 Summer Reliability Assessment, May 2023, *available at* https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2023.pdf.

[31] SERC, 2022–2023 Probabilistic Assessment for Resource Adequacy Report, 2023, *available at* https://www.serc1.org/docs/default-source/committee/resource-adequacy-working-group/2022-2023-serc-probabilistic-assessment-for-resource-adequacy.pdf.

[32] PJM Resource Adequacy Senior Task Force, Capacity Market Reform: PJM's Proposal, June 2023, *available at* https://www.pjm.com/-/media/committees-groups/cifp-ra/2023/20230621/20230621-item-02a---pjm-cifp-stage-3-proposal---updated.ashx.

adequacy to identify low-probability, high-impact events that directly affect grid assets or disable critical enabling infrastructure such as transportation networks and fuel supplies.

First and foremost a resilient grid must be designed to address potential weather extremes. As has previously been discussed, the Companies' power systems are planned to accommodate high loads in both summer and winter in the course of normal operations, but extreme, reliability-challenging events are also possible during the "shoulder seasons" of spring and fall.

Weather Extremes in Summer and Shoulder Season

Planning for summer resilience and reliability in the Carolinas most significantly involves strengthening the Companies' grid to manage the extreme heat possible in the southeast. Prolonged extreme heat places numerous stresses on the power system — high air temperatures can directly reduce the efficiency and maximum capability of thermal generators and transmission lines, high river temperatures (caused by heat and drought) can create additional cooling difficulties that reduce the generation capability at large units and sustained, intense heat creates high electricity demands, which could create energy adequacy challenges for maximizing the use of energy storage.

While extreme temperatures are most naturally associated with summer and winter, even the generally more temperate seasons of spring and fall can pose reliability and resilience challenges. Because these seasons on average experience lower electricity demand, outages for power plant maintenance and upgrades are typically planned for these times of the year. However, these "outage seasons" are still subject to the variability of weather in the Carolinas, with the potential for heat in the upper 90s (even at or above 100 degrees) beginning in May and extending into the fall outage season in September and October. And, importantly, cold weather well below freezing (into the teens or single digits) is also possible at the start and end of typical outage season in March to April and November.

Beyond temperature-driven risks, summer and fall in the Carolinas come with the added risk from major hurricanes and related flooding and infrastructure damage. Historically, Category 3 and 4 storms have made landfall on Carolinas' shores, and Category 4 and 5 storms are known to have passed within close proximity of potential offshore wind sites; Appendix I documents the Companies' research into this low probability but potentially high impact events. Resilience includes a substantial element of recovery from extreme events, and new planning and response measures will be necessary to ensure that distributed wind and solar resources can be repaired and quickly returned to service after potential widespread damage from major hurricanes.

Recent experience has also revealed the potential for unexpected interactions between extreme weather phenomenon and the changing energy landscape. One such example is the potential for regionally severe wildfires to lower air quality and visibility to the point that output from solar generators can be materially reduced as was observed in California in 2020[33] and the East Coast of the United States (including ISO New England, New York ISO and PJM) in 2023.[34]

Planning for Winter Weather in the Carolinas

As has been seen in recent years — including the Companies' experience during Winter Storm Elliot — winter is a season with elevated risks across multiple dimensions that a resilient grid must be planned to withstand:

- Extreme cold weather creates high loads that the Companies must plan adequate resources to meet, and the system average temperature in both the DEC and DEP regions has dipped into the upper single digits Fahrenheit and is susceptible to even colder temperatures. Within recent history, 1985 brought a low of -5 ºF to the DEC regions and -1 ºF to DEP. Electricity demand for heating can increase rapidly at very cold temperatures as heat pump technologies become insufficient and electric strip heaters (typically known as "emergency" or "auxiliary" heat) must kick on to maintain a comfortable indoor environment. Heating-related loads will continue to increase as home appliance electrification accelerates as part of the changing energy landscape, creating new challenges in forecasting cold-weather related peak demands.

- Extreme cold temperatures can cause reliability issues by increasing the probability of unexpected unit outages. Elevated outage rates among thermal generators were key contributors to the emergency load curtailment events and emergency operating conditions seen in Texas during Winter Storm Uri[35] and Tennessee, the Carolinas, and PJM during Winter Storm Elliot.[36] Based on a preliminary analysis from the joint FERC-NERC inquiry into the December 2022 events, these losses of capability are driven by a combination of freezing issues, mechanical and electric failures, and fuel supply limitations.[37]

- A substantial amount of regional heating demand is met by natural gas-fired furnaces, limiting spare gas capacity during cold weather events when the fuel is in high demand for both heating and electricity generation purposes. Without adequate pipeline capacity, this across-the-board

[33] US EIA, Smoke from California wildfires decreases solar generation in CAISO, September 2020, *available at* https://www.eia.gov/todayinenergy/detail.php?id=45336.

[34] PJM, Quebec Wildfire Smoke Reduced Solar Output, Electricity Demand in PJM Region, June 2023, *available at* https://insidelines.pjm.com/quebec-wildfire-smoke-reduced-solar-output-electricity-demand-in-pjm-region/.

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

[36] FERC and NERC, December 2022 Winter Storm Elliott Inquiry into Bulk-Power System Operations Status Update, Jun 2023, *available at* https://www.ferc.gov/news-events/news/presentation-december-2022-winter-storm-elliott-inquiry-bulk-power-system.

[37] Per the FERC-NERC preliminary findings, in total, over 70,000 MW of generation was lost in the Eastern Interconnection throughout Winter Storm Elliott.

elevation of natural gas demand can contribute to pipeline pressurization issues which can influence cold-weather unit availability as noted above.

- Cold weather risks can be compounded by winter precipitation where extreme events such as an ice storm could disrupt unit refueling operations, and the presence of ice and snow on solar panels may suppress renewable output for a day or more. Winterization issues with wind turbines were also noted during the Texas blackout as ice accumulation on turbine blades prevented some wind farms from operating.[38]

- Emergency import assistance can no longer be automatically assumed to be available during winter extreme weather events as neighboring utility systems are also on pathways towards increasing electrification and a growing contribution of renewable energy. This fact is underlined by the experience of having firm purchases curtailed into the Companies and other utilities within the Companies' BAs on December 24, 2022.

Ensuring Resilience in the Changing Energy Landscape

As previously discussed, weather extremes, particularly wide-spread and prolonged cold and heat patterns, increase demand and place added load and stress on the electric system. The events of Winter Storm Elliott across the utility industry generally, and the Companies' experience of emergency load curtailments on December 24 specifically, underline the importance of planning for reliability and resilience during the energy transition. To that end, Duke Energy is reviewing actions to address current and future resilience and reliability challenges. While they come in the wake of the events of December 2022, the following topics are being reviewed to continue addressing resilience in the face of risks from all sources and in all seasons:

- Ensuring power-plant resilience by reviewing operating experience during periods of extreme cold weather and high loads, reviewing weatherization enhancements, and re-baselining plant performance as necessary to properly account for generator availability risks in the resource planning and reliability processes.

- Reviewing outage planning strategies to minimize risks from overlapping and/or over-concentrated planned outages on key generating units. As discussed above, resilience and reliability risks are not isolated to periods of cold and winter weather, and the timing of planned outages is an essential component of year-round reliability.

- Continued assessment of fuel security, resilience, and adequacy for the Companies' supplies of natural gas and coal. A critical need for system resilience is adequate firm gas transportation and fuel flexibility, including ensuring adequate coal supply through retirement.

- Continued improvements to cross-functional organizational awareness and communication during periods of tighter system conditions and heightened risks.

[38] FERC and NERC, The February 2021 Cold Weather Outages in Texas and the South Central United States.

Continued Resilience Against Power System Attacks

Extreme weather is not the only resilience concern for the power system. Both physical security and cybersecurity remain a front-of-mind concern for reliable and resilient grid operations. The power industry is a prime target for criminal organizations and nation-state actors, and a changing grid with new resource configurations (reliance on distributed resources, customer-sited generation, and load reductions) creates new areas for attack against the grid. Cyber risks to the grid can also come from impacts to critical infrastructure including fuel supply, which was made clear by the Colonial Pipeline hack in 2021.

The importance of the physical security of power system infrastructure was also brought to the forefront in 2023 as distribution infrastructure was attacked in multiple states, including substations in Tacoma, Washington[39] and two of the Companies substations in Moore County, North Carolina.[40] While Duke Energy has subsequently taken actions to review and enhance its security strategies for electric assets,[41] these events underscore the importance of resilience to withstand and recover from security-related disruptions as well as extreme weather occurrences. FERC has a strong focus on grid reliability and security, relating to both extreme weather and physical security, and has taken several recent actions to further address NERC requirements.[42]

Conclusion: An Orderly Transition to Ensure Reliability and Resilience

This Appendix has introduced many of the new operating challenges and considerations that can be expected in the Carolinas as the energy landscape changes with the retirement of dispatchable coal units and their replacement with a diverse, equally reliable set of future resources.

Driven by the need for increasingly clean resources and declining costs, the addition of new, inverter-based weather-dependent renewables (and storage) to the system will increase uncertainty in system planning and operations. These uncertainties include increased volatility in the remaining needs of the power system across timescales ranging from seconds and minutes to days and weeks. Reliably

[39] Tacoma Public Utilities, Physical Damage to Our Substations, January 2023, *available at* https://www.mytpu.org/physical-attacks-on-our-substations/.

[40] Duke Energy, Duke Energy completes restoration to all customers in Moore County and surrounding counties, December 2022, *available at* https://news.duke-energy.com/releases/duke-energy-completes-restoration-to-all-customers-in-moore-county-and-surrounding-counties.

[41] Duke Energy, Written Testimony of Mark Aysta, Duke Energy to the House Energy and Commerce Committee's Subcommittee on Energy, Climate and Grid Security Field Hearings on the Moore County Incident, June 2023, *available at* https://d1dth6e84htgma.cloudfront.net/06_16_23_Testimony_Aysta_cf955febbc.pdf?updated_at=2023-06-14T20:09:08.470Z.

[42] FERC, Docket Nos.: RD23-2-000 Evaluation of the Physical Security Reliability Standard and Physical Security Attacks to the Bulk-Power System, AD23-8-000 FERC-NERC Joint Inquiry into Winter Storm Elliott, RM22-10-000 Transmission System Planning Performance Requirements for Extreme Weather, RM22-16-000 One-Time Informational Reports on Extreme Weather Vulnerability Assessments, AD21-13-000 FERC Climate Change, Extreme Weather, and Electric System Reliability.

managing these new system demands will require new dispatchable resources with natural gas playing a foundational role as a bridge fuel throughout the energy transition. The changing nature of the resource mix is making energy adequacy an increasingly essential consideration in operations to ensure that an appropriate mix of future generation resources is operationally proven and can manage extended periods of low renewable outputs. Ensuring that gas serves as reliable complement to new renewable resources will require actions to ensure fuel security through new firm interstate transportation and/or onsite fuel storage.

As discussed in this Plan, the retirement of the Companies coal units is necessary before maintenance and supply chain challenges undermine their ability to be operated reliably. However, to maintain a reliable foundation during this energy transition, the coal fleet must be carefully managed to ensure that the dispatchability and on-site fuel security these units currently contribute to reliability, is adequately retained prior to retirement. These competing challenges become a tug-of-war between a transition which is “too fast” and incurs risks to reliability from a lack of firm fuel supply, system instability or inadequate capacity, and a transition that is “too slow” and operates the existing coal fleet beyond a point at which continued availability and fuel security are no longer assured while loads are increasing.

The Companies are not alone in facing these challenges, and other regions of the EI are experiencing similar economic and regulatory drivers but can only indirectly navigate the coming energy transition. As discussed, they are explicitly warning about the speed of the transition and are forecasting declining system reserves margins. Importantly, the Carolinas sit at a critical execution phase of the energy transition with the ability to directly control how and when coal units are replaced. These considerations of pace and composition can ensure that the energy transition documented in this Plan is an orderly one, with operational reliability and system resilience maintained in the face of a changing energy landscape.