Chapter NC: 2023–2024 CPIRP Update

Duke Energy Carolinas, LLC's ("DEC") and Duke Energy Progress, LLC's ("DEP", and together with DEC, "Duke Energy" or "the Companies") 2023–2024 Carbon Plan and Integrated Resource Plan ("CPIRP") Update is advancing the North Carolina Utilities Commission's ("NCUC" or "Commission") initial 2022 Carbon Plan to meet the planning objectives of Session Law 2021-165 ("HB 951") for customers and communities in the State as the Companies continue to reliably plan and execute this critical energy transition of their generation fleets to achieve an interim target of 70% carbon dioxide emissions reductions ("Interim Target") on the least cost path to carbon neutrality by 2050.[1] The Companies' integrated Carolinas Resource Plan (the "Plan" or "the Resource Plan") constitutes the CPIRP and satisfies all requirements of the proposed Commission Rule R8-60A. This Chapter NC is intended to situate the system-wide Plan within North Carolina law and to more directly address various directives from the Commission's Carbon Plan Order.[2] The South Carolina Chapter similarly speaks to the requirements of South Carolina law and policy governing the Companies' Integrated Resource Plan ("IRP") process.

Since the Carbon Plan Order was issued on December 30, 2022, the Companies have made significant efforts to execute the initial Carbon Plan[3] and prepare this updated CPIRP, including:

- **Advancing Procurement and Development of Supply-Side Resources Approved by Commission:** As highlighted in Chapter 4 (Execution Plan), the Companies have been diligently progressing existing and new supply-side resources (solar, hydrogen-capable gas, batteries and onshore wind) and long-lead-time resources (nuclear, offshore wind, Bad

[1] Capitalized terms not otherwise defined in this Chapter shall have the meaning ascribed to them in proposed NCUC Rule R8-60A, filed as Attachment 1 to the Companies June 15, 2023, Reply Comments in Docket No. E-100, Sub 191.

[2] Order Adopting Initial Carbon Plan and Providing Direction for Future Planning, Docket No. E-100, Sub 179 (Dec. 30, 2022) ("Carbon Plan Order").

[3] See Appendix N (Cross Reference) for details on where the Carolinas Resource Plan addresses the specific NCUC directives, requirements and/or expectations set forth in the Companies' proposed NC Rule R8-60A and the 2022 Carbon Plan Order.

Creek II) near-term actions authorized by the Carbon Plan Order, as well as to prepare new studies and analyses to inform the Commission's review of this CPIRP update.

- **Further Developing EE-DSM Mechanism, Grid Edge and Customer Programs:** The Companies are engaging with stakeholders on modernizing the current Energy Efficiency ("EE")-Demand-Side Management ("DSM") Mechanism and fully and appropriately valuing demand-side customer programs within the context of "shrinking the challenge" for meeting the emissions reductions of the system, enabling customers to better manage their own energy use and helping to meet load growth. The Companies have filed for approval of a number of new programs, initiated new proceedings and are engaging with stakeholders to advance rapid prototyping, new rates and programs, as updated in Chapter 4 and detailed in Appendix H (Grid Edge and Customer Programs).

- **Progressing Strategic RZEP Transmission Projects:** In early 2023, the Companies successfully obtained North Carolina Transmission Planning Collaborative ("NCTPC") approval of the 14 red zone expansion plan ("RZEP") 1.0 projects as part of the 2022–2032 Collaborative Transmission Plan, and have been evaluating the need for future strategic RZEP 2.0 projects, as well as coordinating with other NCTPC members and stakeholders to evolve the NCTPC process to increase transparency and incorporate process improvements that identify the best value transmission expansion projects for customers.

- **Assessing the Impacts of Significant Recent Federal Developments:** The CPIRP integrates the impacts of the Inflation Reduction Act of 2022 ("IRA") and Infrastructure Investment and Jobs Act ("IIJA") in the CPIRP planning process, and considers the potential impacts of other national interests that affect the energy sector including the developments around Mountain Valley Pipeline in the Fiscal Responsibility Act and subsequent actions taken by the Fourth Circuit and Supreme Court of the United States, along with the proposed EPA rules for existing coal and new and existing gas-fired generation under Clean Air Act Section 111.

- **Updating Reliability Studies:** The Companies engaged Astrapé Consulting to develop an updated Resource Adequacy Study to determine the appropriate planning reserve margin for the system (Attachment I) and an updated Wind Effective Load Carrying Capability Study (Attachment III) to appropriately value the future capacity contributions of wind energy on the Companies' systems.

- **Developing Proposed CPIRP Rule:** The proposed CPIRP rule presents a new framework for the Commission to oversee progress and biennially update the initial Carbon Plan, while also incorporating the Commission's traditional IRP requirements to ensure the Companies are prudently planning for sufficient resources to meet future load growth and to ensure continued adequate, reliable utility service is achieved via the least cost mix of generation and demand-reduction measures.

- **CPIRP Stakeholder Engagement:** Robust pre-filing engagement with the Public Staff and other stakeholders across numerous technical inputs, modeling assumptions and other aspects of the Companies' operations to develop this system-wide Carolinas Resource Plan and first CPIRP update as discussed in Appendix A (Stakeholder Engagement).

- **Developing Plans to Pursue DEC and DEP Merger:** The Companies are putting plans in place and have launched a costs/benefits study to pursue a merger of DEC and DEP into one operating utility company that will deliver customer benefits and constitutes the best path to fully consolidated operations supporting an efficient and orderly energy transition.

- **Engaging with Customers and Communities:** Developing outreach plans for local engagement with impacted communities discussed further in this Chapter.

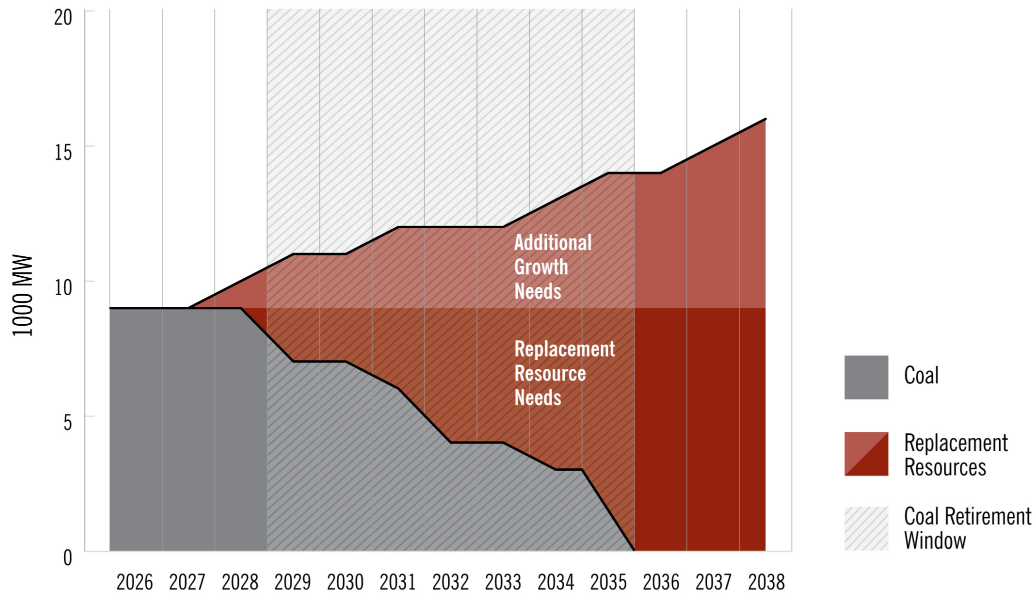
These efforts, as well as others discussed throughout the Plan, meet the directives of the Carbon Plan Order and reflect the Companies' unwavering commitment to reliably executing the state's energy transition towards cleaner energy and lower-carbon emitting resources on the path to carbon neutrality of the Companies' generating fleet.

Changing Energy Landscape in a Critical Phase of Energy Transition

This 2023-2024 CPIRP is based upon an updated "snapshot in time" that reflects numerous significant changes in the energy landscape over the past 12–18 months, as introduced in the Executive Summary and addressed in Chapter 1 (Planning for a Changing Energy Landscape). As highlighted in Appendix D (Electric Load Forecast), North Carolina and South Carolina have recently seen significant new economic development wins that are increasing electricity demand in the Companies' service territories — a positive trend in the Carolinas that Duke Energy is closely monitoring. In addition to typical drivers of demand growth, the Plan critically assesses projected load growth due to the Carolinas' recent economic development successes, as well as increased projections for transportation electrification, to ensure the Plan provides for adequate resources to meet customers' future electricity needs. The profound impacts of these changes for the Carolinas are demonstrated throughout the Plan, including changes in load forecast, planning reserve margin, interstate natural gas supply assumptions, technology costs and resource availability assumptions as discussed in Chapter 2 (Methodology and Key Assumptions) and reflected in the results of the Companies' modeling presented in Chapter 3 (Portfolios). These significant changing market conditions and the growing energy needs of customers have also informed the Companies' assessment of the most reasonable, least-cost plan for the energy transition in the Carolinas and are reflected in the significant acceleration in the pace of execution to add new resources as presented in Chapter 4.

As highlighted in Chapter 4 and illustrated in Figure NC-1 below, this next decade is a critical execution phase for the Companies' electric system and the Resource Plan must chart a course to implement a diverse set of resources sufficient to maintain or improve reliability in light of both the resources to be retired and the projected growth in load that must be served.

Figure NC- 1: Critical Execution Phase in the Energy Transition



To meet these challenges, the Companies have developed a robust, executable Resource Plan for the Carolinas that prioritizes reliability and affordability, meeting the replacement resource needs of the system while also planning for the significant new growth needs that have become substantially more well-defined in the past 12–18 months. In addition to these important Resource Plan activities, the Companies continually evaluate emerging opportunities to pursue prudent incremental supply-side and Grid Edge projects that can meet growing customer needs while conforming with long-term planning objectives outlined in Chapter 2.

Updated Modeling Process Builds on 2022 Carbon Plan Approach

In approving the initial 2022 Carbon Plan, the Commission determined that the Companies' use of the EnCompass modeling platform, the Strategic Energy Risk Valuation Model ("SERVM") Reliability Verification step and overall modeling approach was reasonable for planning purposes. In certain areas, the Commission directed the Companies to engage with the Public Staff to consider whether updates to the modeling approach may provide more precise resource plan results to inform future updates to the initial Carbon Plan.

As further discussed in Chapter 2, Appendix A and Appendix C (Quantitative Analysis), the Companies are again using EnCompass for capacity expansion and production cost modeling and have refined, but not materially changed, their modeling approach since the 2022 Carbon Plan. The Companies also have again used SERVM to evaluate reliability performance and assess the operational risks of each of the Core Portfolios to ensure compliance with HB 951's mandates to ensure reliability is maintained or improved.[4]

In the spring of this year, the Companies also engaged in a series of meetings with the Public Staff to discuss a number of Carbon Plan modeling issues that were challenged in the initial 2022 proposed Carbon Plan proceeding. Based upon discussions with the Public Staff and improvements to the EnCompass model,[5] the Companies have adjusted their approach to modeling solar paired with storage ("SPS") and are now using a dynamic dispatch approach to endogenously model SPS in EnCompass.[6] The Companies also engaged with the Public Staff on modeling set up and optimization periods, explaining that longer-term segmentation runs of 15 years or more at the more precise modeling tolerances used in developing the Plan extended model run times to days versus hours.[7] Completing the capacity expansion modeling of Core Portfolios P1 Base, P2 Base and P3 Base using 16-year optimization period (including all years in the Base Planning Period in the same optimization period) required significant model run times of 43 hours for P1, 60 hours for P3 and 228 hours for P2 for the model to solve. Recognizing that the Companies' planning analysis includes dozens of Variant Portfolios and Sensitivity Portfolios it was infeasible to complete the work required using this significantly longer model-run time. As explained in Appendix C, the Companies have therefore used 7-year optimization periods to best assess competing resources needed for meeting Interim Targets, especially targeting offshore wind, nuclear and new hydrogen-capable gas assets, all optimized within the same optimization period.

The Companies have also more generally engaged with the Public Staff, as well as technical representatives and other interested stakeholders, over a series of five pre-filing stakeholder meetings to discuss costs, inputs and assumptions used to model the CPIRP. The Companies considered the recommendations of all active stakeholders — including feedback received at live stakeholder meetings and written feedback — and incorporated much of it in shaping each of the Pathways and Portfolios included in the Carolinas Resource Plan, as discussed in Appendix A.

To assess the most reasonable, least-cost path to achieve HB 951's carbon emission reduction targets, the Companies' modeling approach continues to include similar Portfolio analyses to the analyses prepared to support the 2022 Carbon Plan. For example, Chapter 3 considers the risks and trade-offs of the three Pathways under extensive portfolio variation and sensitivity analysis and against the Companies' core planning objectives for executing the orderly energy transition (maintain or improve reliability, compliance with laws and regulations, least cost planning and affordability, increasingly clean resource mix, resource diversity, accounting for executability and foreseeable conditions). As part of this analysis the Companies again provide present value of revenue requirement ("PVRR") and average residential customer bill impact calculations for each Core Portfolio using the same methodological approach that the Commission determined to be "reasonable for

[4] Carbon Plan Order at 36.

[5] As discussed in Appendix C (Quantitative Analysis), the Companies are using EnCompass version 7.0.5, released in May 2023. EnCompass version 6.0.4 was used to perform the 2022 Carbon Plan modeling.

[6] Carbon Plan Order at 50.

[7] Carbon Plan Order at 49–50.

planning purposes and provide[d] a helpful tool to compare the relative benefits of the different portfolios" in the 2022 Carbon Plan proceeding.[8]

Maintaining or Improving Reliability Remains Core Planning Objective

HB 951 requires the Companies to ensure that "any generation and resource changes maintain or improve upon the adequacy and reliability of the existing grid."[9] The Carbon Plan Order also affirms that HB 951 "unambiguously directs the Commission to guard the reliability of the electric system."[10]

The Companies have approached the Carolinas Resource Plan by prioritizing, maintaining or improving the reliability of the Companies' systems as a core planning objective and critical component of achieving the Companies' orderly energy transition under HB 951. Ensuring system reliability and compliance with mandatory North American Electric Reliability Corporation ("NERC") Reliability Standards throughout the ongoing energy transition is an obligation unique to Duke Energy with oversight by the Commission and the Public Service Commission of South Carolina ("PSCSC"), and the Carbon Plan Order appropriately recognized that ensuring reliability is "nonnegotiable for the continued health and well-being of all North Carolinians."[11] Duke Energy holds this obligation in the highest regard, and ensuring the Companies are able to meet customer demands 24 hours per day, seven days per week, 52 weeks per year is central to all of the Companies' resource planning initiatives.

Ensuring Resource Adequacy Through an Updated Planning Reserve Margin

Foundational to the Companies' Plan to maintain or improve reliability is planning for resource adequacy and ensuring that the system operators have sufficient capacity resource "tools in the toolbox" to meet the growing needs of customers and to navigate the changing energy landscape. Based on the Companies' operational experience and resource-specific data considered as part of the 2023 Resource Adequacy Study, the Plan has been developed based on a higher 22% planning reserve margin for DEC and DEP.[12] The Resource Adequacy Study included unit outage and winter capacity risk based on historical outage data during key cold weather events, including Winter Storm Elliott data through December 2022. The study also incorporated the fact that neighboring systems have shifted towards winter planning with comparable reserve margin levels for ensuring resource adequacy as they are also retiring dispatchable resources, making capacity during extreme winter weather increasingly constrained across the entire region.

[8] Carbon Plan Order at 129.

[9] N.C.G.S. § 62-110.9(3).

[10] Carbon Plan Order at 9.

[11] Carbon Plan Order at 56.

[12] See Attachment I (2023 Resource Adequacy Study for Duke Energy Carolinas & Duke Energy Progress). The most recent Resource Adequacy Study performed in 2020 identified the need for a 17% planning reserve margin, which was also used to develop the 2022 Carbon Plan.

Leveraging Real-World Operational Experience

The Carbon Plan Order recognized that the Companies' changing resource mix and increasing reliance on more "weather-dependent and time-limited resources" brings new challenges for system operators.[13] As a utility industry leader navigating the energy transition, Duke Energy continues to be laser focused on evaluating how real-world operational experience informs planning to mitigate reliability risks.[14] Weather extremes, particularly wide-spread and prolonged cold and heat patterns, increase customer demand and place added stress on the electric system's infrastructure. The events of Winter Storm Elliott across the utility industry generally, and the Companies' experience of emergency load curtailments on December 24 specifically, underscore the importance of planning for reliability and resiliency during the energy transition. In addition to incorporating observations and data from Winter Storm Elliott into the 2023 Resource Adequacy Study, the Companies' real-world experience with extreme weather in December 2022 is reflected in the SERVM Reliability Verification analysis performed by the Companies on each of the base portfolios.

As President and Chief Executive Officer of NERC, James Robb recently noted in his June 1, 2023 testimony before the United States Senate, the country's bulk power system is at an "inflection point" with risk to customers steadily increasing as a result of the rapid energy transformation that is currently underway throughout the country.[15] To meet this challenge, the Companies are building solutions around three governing principles raised by Mr. Robb that must be addressed to preserve grid reliability: 1) adopting an orderly pace for the energy transition, 2) replacing retiring generation with resources that provide both sufficient energy and essential characteristics for stable grid operation (including flexibility, voltage support, frequency response, and dispatchability), and 3) shifting planning focus to address the impact of inverter based resources and distributed energy resources.[16] During this critical execution period, considerations of pace, resource adequacy and diversity of supply- and demand-side resources are all critically important to ensure that the energy transition is an orderly one, with operational reliability and system resiliency maintained as the highest priority in the face of a changing energy landscape.

Planning for a Balanced Mix of Resources to Maintain or Improve System Reliability

As discussed in the Executive Summary and Appendix M (Reliability and Operational Resilience), economic, technological and regulatory drivers are rapidly reshaping the demand for electricity, and the mix of generating resources expected to serve those demands. As shown in Figure NC-1 above, the Carolinas Resource Plan projects significant load growth in the Carolinas due to economic growth, population growth and increasing electrification (e.g., transportation electrification), at the same time

[13] Carbon Plan Order at 9.

[14] See Carbon Plan Order at 56 (directing "Duke to work with the Public Staff in leveraging actual operational experience to continue to plan for the future, mitigate foreseeable risk and prepare for the challenges ahead").

[15] "The Reliability and Resiliency of Electric Service in the United States in Light of Recent Reliability Assessments and Alerts," Testimony of James B. Robb, President and CEO of NERC, before the United States Senate Committee on Energy and Natural Resources (June 1, 2023), *available at* energy.senate.gov/services/files/D47C2B83-A0A7-4E0B-ABF2-9574D9990C11.

[16] Id.

as the utility industry is exiting coal in response to mounting pressures that threaten the long-term reliability of existing coal generators. As such, the Plan has been developed to reliably meet the energy and capacity needs created by increasing electricity demand and the orderly retirement of the Companies' remaining coal units in North Carolina through a variety of strategies.

First, the Companies have adopted a "replace before retire" approach whereby aging units will be replaced by new generating units before they are retired. This approach ensures there are no gaps in the Companies' ability to reliably meet growing energy needs, while also recognizing the need to maintain a deliberate pace for replacing coal units in order to limit the potential of significant cost and fuel security risk exposure as the industry exits coal. Second, the Companies are planning to replace those aging resources with a diverse set of new resources that include new hydrogen-capable dispatchable combined cycle ("CC") and combustion turbine ("CT") generation, increasing reliance on renewables such as wind and solar along with pumped storage hydro and battery energy storage to support integration of these resources, as well as relying upon breakthrough technologies such as new advanced nuclear small modular reactors ("SMRs") and offshore wind in the long-term to provide significant carbon-free baseload energy to the system. Prudent planning, purposeful execution and continued operational excellence will enable the Companies to maintain or improve upon the reliability of the grid as new resources are added and aging units are retired.

Planning for Interim Target Through Continued Orderly Energy Transition Requires Balancing Executability, Reliability and Costs

HB 951 establishes an orderly framework under which the Carbon Plan is reviewed every two years and "may be adjusted as necessary in the determination of the Commission and the electric public utilities."[17] In approving the initial Carbon Plan, the Commission pursued a balanced approach[18] and explained that its initial Carbon Plan established a series of "reasonable steps" and "no regrets" actions in furtherance of achieving the State's emissions reduction mandates. The Commission also determined that it was not necessary or appropriate at that time to prescribe a single portfolio as the definitive least-cost, long-term energy transition path for North Carolina.[19] As the Companies embark on execution of the initial Carbon Plan, the Commission directed the Companies to continue to pursue compliance with the Interim Target, including modeling portfolios that would achieve the 70% emissions reduction target by 2030.[20]

Consistent with the Carbon Plan Order's directives, the Companies have diligently begun executing the near-term actions approved by the Commission, as detailed in Chapter 4, and have again presented multiple Pathways that would, if feasible, achieve the Interim Target in 2030 or beyond 2030. As explained in Chapter 2, the Carolinas Resource Plan is designed around three Energy

[17] N.C.G.S. § 62-110.9(1).

[18] Carbon Plan Order at 8 (" the Commission has endeavored to balance the need for action in the immediate term against the deferral of actions when doing so is in the best interest of customers and the reliable operation of the electric system").

[19] Carbon Plan Order at 19, 25.

[20] Carbon Plan Order at 19.

Transition Pathways (2030, 2033 and 2035) and Core Portfolios within each Pathway that leverage significant demand-side and Grid Edge resources to shrink the challenge and then identify differing near-term actions required to enable the orderly retirement of the Companies' remaining coal units in North Carolina and achieve the Interim Target on the path to carbon neutrality. Importantly, each Pathway requires a different pace, scope and scale of near-term development activities across varying technologies to achieve the Interim Target. The 13 additional Variant Portfolios, 10 Sensitivity Analysis Portfolios and robust quantitative and qualitative comparisons and analyses of the three Core Portfolios across planning objectives presented in Chapter 3 and Appendix C as well as the entire Carolinas Resource Plan demonstrate that the magnitude of the Carolinas' energy transition challenge has increased drastically over the past 12–18 months, chiefly due to incremental load growth and increased resource adequacy needs over the previous plan. Accordingly, consistent with these analyses and the Commission's authority and discretion to determine optimal timing and generation and resource-mix to achieve the least-cost path to compliance with HB 951's carbon emission reduction goals, the Companies have presented near-term actions in this first update to the Carbon Plan that align with Energy Transition Pathway 3 ("Pathway 3") and recommended Core Portfolio P3 Base.

As explained in Chapter 3, Pathway 3 represents, at this snapshot in time, the most reasonable, least-cost planning Pathway and the associated near-term actions are the reasonable steps required to achieve the Interim Target on the path towards carbon neutrality. The Companies support this determination for the following reasons:

1) Pathway 3 pursues all reasonable steps on the least cost path towards achieving the interim target and carbon neutrality.

2) Pathway 3 is the most reasonable, least-cost, least-risk plan for achieving the orderly energy transition of the Companies' dual-state systems.

3) Pathway 3 relies upon breakthrough SMR in the mid-2030s, which HB 951 recognizes would authorize extending the Interim Target compliance date.

4) Pathway 3 keeps the Companies squarely on the path towards achieving carbon neutrality by 2050.

Pathway 3 Pursues All Reasonable Steps Towards Achieving the Interim Target

The near-term actions identified in Chapter 4 and further discussed below represent "all reasonable steps" to be executed between now and 2026. The Near-Term Action Plan ("NTAP") Table 4-2 in Chapter 4 and referenced actions in Table NC-2 below shows the significant incremental supply-side procurement and development activities proposed in 2025–2026 relative to the approved 2022 Carbon Plan to achieve the Pathway 3 trajectory for emissions reductions. Highlights of those near-term actions include:

- Annual solar procurement targets will increase by up to 550 megawatts ("MW") per year or, on average, by approximately 50% from 2022–2024 to 2025–2026 for such resources to be in service by 2031.[21]

- Battery energy storage development will increase by approximately 35% from 2022–2024 to 2025–2026 to provide dispatchable storage capacity and grid support with such resources targeted to be in service by 2032.

- Onshore wind, a new-to-the-Carolinas resource that will require significant initial development activities to achieve successful execution, will be targeted for 1,200 MW additions by 2033, placing up to eight projects into service in the 2031–2033 timeframe.

- New hydrogen-capable CC and CT capacity additions to meet projected load growth, provide system flexibility and ensure reliability are increasing from 2,000 MW (3 units) to be in service by 2029 to 5,780 MW by 2032 (7 units) to enable the continued orderly retirement of 4,400 MW of coal unit capacity also by 2032.

Pathway 3's significantly accelerated scope and pace of execution for interconnecting these supply-side resources reflect an aggressive, but reasonable execution plan for transitioning the Companies' generating fleets towards carbon neutrality, as further discussed in Chapter 3. The Companies are also taking significant steps to develop Bad Creek II and to progress advanced nuclear SMRs towards commercial operation in the mid-2030s, while also taking a prudent approach to evaluating the need for offshore wind, which was not selected during the Base Planning period in Core Portfolio P3 Base but may become part of the most reasonable, least cost plan for the future in the mid-2030s or beyond as discussed further below.

Pathway 3 also reflects aggressive but reasonable planning in all other parts of the Companies' business. As described in Chapter 4 and Appendix H, the Companies continue to identify and execute all cost-effective opportunities to "shrink the challenge" through aggressively pursuing Grid Edge and customer programs and expanding the Companies' energy efficiency and demand response options. This includes targeting an incremental annual reduction of at least 1% of each year's eligible retail sales to be achieved through utility-sponsored energy efficiency, while also designing innovative new rate designs and customer programs that provide customers tools to better manage their electric energy usage and bills. The Companies are also transforming the Carolinas energy delivery system through maintaining and strategically improving the transmission system to interconnect new generating resources while also increasingly relying upon integrated transmission and distribution system operations to maximize the value of the grid for customers, as discussed in Appendix L (Transmission System Planning and Grid Transformation) and Appendix G. As highlighted above and addressed in Chapter 4, the Companies are also pursuing potential merger of DEC and DEP by January 1, 2027, subject to completion of cost-benefit analyses, engagement with stakeholders and

[21] This target assumes continued successful strategic transmission additions can be achieved via the RZEP 2.0 projects planned for inclusion in the 2024 Local Transmission Plan as discussed in Appendix L (Transmission System Planning and Grid Transformation).

obtaining required regulatory approvals. The Companies believe a merged DEC and DEP is an important enabler for the energy transition, allowing for the achievement of aggregate systems efficiencies for customers and harmonizing future resource costs across DEC and DEP, while also having the additional benefit of providing a long-term solution to rate differences.[22] The totality of these planned near-term activities and comprehensive efforts to progress the energy transition under the oversight of the Commission and the PSCSC represent the next reasonable steps that the Commission should direct under N.C.G.S. § 62-110.9

Pathway 3 is the Most Reasonable, Least Cost, Least Risk Plan for Executing the Carolinas' Orderly Energy Transition

Based upon the totality of the Carolinas Resource Plan, Pathway 3 presents the most reasonable, least cost and least risk Pathway to reliably transition the system and to prudently plan for the needs of customers, as compared to Pathways 1 and 2.

The Companies' Portfolio comparison and analysis presented in Chapter 3 demonstrates that pursuing Pathway 1 would require much more accelerated, more expensive and, in certain cases, infeasible actions to develop, procure permit, construct and interconnect the levels of new gas hydrogen-capable CCs and CTs, solar, wind and batteries required. Attempting to execute Energy Transition Pathway 1, modeled using substantially aggressive Core Portfolio P1 Base assumptions described in Chapter 2, would require the Companies to site, permit, construct and interconnect almost twice as many projects by 2030 as P2 Base and P3 Base. P1 Base adds nearly 28,000 MW of nameplate resources by 2033 — including over 6,100 MW of batteries and nearly 2,400 MW of offshore wind — well in excess of even the Companies' "high resource availability" case and the equivalent to 64% of today's current combined system. This rate of resource additions, including associated transmission needs, exceeds the Companies' expectations regarding what is reasonable to support across the entire project lifecycle and supporting supply chains — development, construction and commissioning — making P1 Base unattainable. Simply put, the recent significant load growth, increased resource adequacy needs and other recent changes to the Carolinas energy landscape have materially increased the magnitude of the energy transition challenge to the point where 2030 is no longer attainable while maintaining or improving reliability, and pursuing it further is not in the best interest of customers.

Pathway 3 also presents the least cost, least risk planning Pathway compared to Pathway 2. As Chapter 3 highlights, Pathway 2 requires much more accelerated battery energy storage additions by 2033 (an increase of 2,600 MW or 75% over the batteries in P3) and is projected to cost approximately $4 billion more by 2038 and $5 billion by 2050 than Pathway 3.[23] On an overall nameplate MW basis, P2 Base adds over 4,200 MW more than P3 Base through 2033. This means Pathway 2 requires an increased and concentrated level of major project activity to accomplish over Pathway 3 — particularly 1,600 MW of offshore wind and 5,000 MW of batteries by 2033 — considering siting, permitting and

[22] Carbon Plan Order at 131.

[23] Calculation is based on a comparison of the PVRRs of the Core Portfolios under the two Pathways. See Chapter 3 (Portfolios) at Figure 3-8.

construction needs, and supply chain and labor availability for both the resources and related transmission.

The executability risks for Pathway 2 are materially greater in the early 2030s than Pathway 3 due to the significantly greater number of projects that need to be placed into service to achieve a 2033 Interim Target. For example, Core Portfolio P2 Base assumes installed battery energy storage capacity increases from 1.1 gigawatts ("GW") by 2030 to 5.7 GW by 2033, which equates to 56 100 MW projects and is over two times the battery energy storage increase during this period assumed in Core Portfolio P3 Base, thus making P2 Base's concentrated level of resource additions highly challenging to execute. These challenges include, but are not limited to, constraints in global supply chains, local labor availability and required permitting activities. Additionally, the Companies must prioritize reliability and compliance with NERC standards when managing significantly higher rates of project-related transmission outages — ensuing prudent system maintenance and asset management to meet the Commission's directive to "not alter, delay or modify any scheduled maintenance, asset management operations or upgrades on its system."[24]

Finally, Pathway 2 also assumes the addition of 1,600 MW of offshore wind by 2033, during a period of significant coal unit retirement and resource additions.[25] As discussed further below, the Companies plan to evaluate the need for offshore wind in the mid- to late 2030s and will update the Commission in the next biennial CPIRP in 2025, or sooner based on resource needs and market conditions, as provided for under HB 951's "check and adjust" framework.

Reliance on Advanced Nuclear SMRs to Achieve Interim Target

Pathway 3 relies on adding two advanced nuclear SMRs that are planned to achieve commercial operation by the beginning of 2035 to achieve the Interim Target. These breakthrough nuclear technologies are not anticipated to be available for deployment by the Companies until the mid-2030s and HB 951 provides the Commission discretion to adjust the timing of achieving the Interim Target on the Pathway to carbon neutrality where it authorizes construction of a nuclear facility or wind energy facility that would require additional time for completion.[26] As explained in Chapter 3, the Companies' recommended P3 Base portfolio as well as each of the Variant Portfolios and delayed nuclear sensitivity portfolio identify the need for SMRs as soon as they become available to be selected by the model. Subject to continued development work, including obtaining pre-requisite Nuclear Regulatory Commission permitting approvals, the Companies plan to seek Commission authorization to construct these advanced nuclear units in the intermediate term beyond 2026. In the near-term, as further discussed below and in Appendix J (Nuclear), the Companies plan to continue initial development work for bringing SMRs 1 and 2 online by 2035, as prudent and reasonable steps on the most reasonable, least-cost Energy Transition Pathway for the Carolinas. The important role advanced

[24] Carbon Plan Order at 134 (Ordering Paragraph No. 36). See Appendix L (Transmission System Planning and Grid Transformation).

[25] Chapter 3, Figure 3-6, Table 3-7 and Figure 3-14.

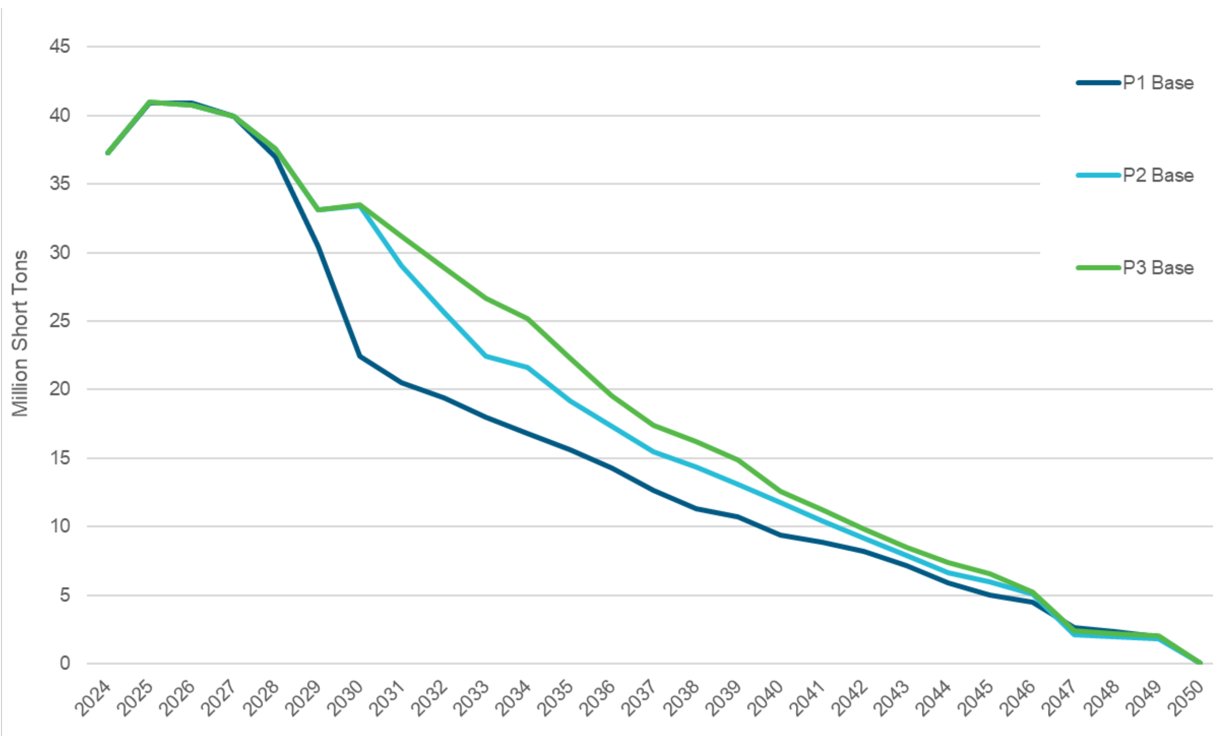
[26] N.C.G.S. § 62-110.9(4).

nuclear will play in the Carolinas' energy transition supports planning to execute Pathway 3 at this time.

Pathway 3 Keeps Duke Energy Squarely on the Path to Achieving Carbon Neutrality

As highlighted in Chapter 3, it is important to recognize that Pathway 3 is aggressive in execution planning requirements, while keeping the Companies squarely on the path to achieving carbon neutrality by 2050. As highlighted in Figure NC-2 below, carbon emission reductions under Pathways 2 and 3 largely converge by the end of the Base Planning Period in 2038 and all three Pathways converge by the mid-2040s on the path to carbon neutrality in 2050.

Figure NC-2: Annual CO_2 Emissions by Core Portfolio, Combined Carolinas System



In this critical execution period where the Companies must reliably replace coal, integrate increasingly clean resources, while meeting significant forecasted demand growth, these factors together support pursuing Pathway 3 as the near-term least cost path to meet HB 951's carbon emission reduction goals. Looking ahead, the Commission will also have the opportunity to continue to oversee, review and adjust the Companies' progression of this Pathway through the biennial CPIRP based on execution progress and active monitoring of execution risks and signposts — such as timely siting and permitting, supply chain conditions, load growth, changes in policy, technology developments and evolving market conditions — as outlined in Chapter 4.

New Supply-Side Resources Proposed for Selection in 2023-2024 CPIRP

The Commission's initial Carbon Plan Order approved a series of near-term actions as the initial "reasonable steps" that the Companies were authorized to pursue under the HB 951 framework of "selecting" resources to achieve HB 951's planning objectives.[27] As presented in Chapter 4, the Companies have developed an updated Execution Plan that extends the Companies' proposed near-term actions through 2026, which aligns with the end of the next CPIRP planning cycle. The Companies continue to support all supply-side resources selected by the Commission for development and procurement in the 2022 Carbon Plan Order as needed to continue to progress the energy transition over the Base Planning Period. These previously selected resources as well as the new incremental supply-side resources identified below in Table NC-1 that are targeted for execution in 2025–2026 are supported by the Companies' modeling presented in Chapter 3 and optimized for execution planning as presented in Chapter 4 to meet demand growth while remaining on a reliable, least cost path to achieving HB 951's carbon dioxide emissions reductions targets.

[27] Carbon Plan Order at 19, 25 citing N.C.G.S. § 62-110.9(1). Proposed Rule R8-60A(d)(7) now also requires the Companies to identify proposed supply-side resources for selection as needed to progress the least cost energy transition path to achieve the Interim Target and plan for carbon neutrality over the long-term.

Table NC-1: Reconciliation of 2022 Carbon Plan and 2023-2024 CPIRP Proposal – New Supply-Side Resources for Execution[28]

Resource MW amounts	2022 Selection	CPIRP	Additional to 2022 CP	2023 NTAP Progress	CPIRP Proposed Near-Term Actions 2024–2026
Solar	3,100	6,000 by 2031	2,700 to 3,150	- 2022 SP: 964.7[1] - 2023 SP/SPS: 1,435[1] - Continue RZEP 1.0 projects	- Continue RZEP 1.0 projects and advance RZEP 2.0 projects.[2] - 2024 Procurement: 1435 - 2025–2026 Procurement: target 2,700 to 3,150
Battery Storage[3]	1,600	2,700 by 2031	1,100	- Stand-alone: progressing development on 1000[4] - 2023 Solar RFP targeting 260 SPS	- 2024 to 2026: Develop 650 stand-alone, target procurement of 790 of SPS (450 SPS incremental to 2022 Carbon Plan)
Onshore Wind	0	1,200 by 2033	1,200	- Carolinas site screening evaluation	- Site feasibility and development for Definitive Interconnection System Impact Study ("DISIS") and 2031–2033 in-service, respectively[5] - 300 for 2025 DISIS - 450 for 2026 DISIS - 450 for 2027 DISIS
CT[6]	800	1,700 by 2031	900	- Generator Replacement Request ("GRR") - Pre-Certificate of Public Convenience and Need ("CPCN") for 2 CTs (2029)	- 2024: CPCN for 2 CTs (2029) - 2025: CPCN for 1 CT (2030) - 2026: CPCN for 1 CT (2032)
CC[6]	1,200	4,080 by 2032	2,880	- GRR - Pre-CPCN for 1 CC in-service beginning of year 2029	- 2024: CPCN for 1 CC (2029) - 2025: CPCN for 2 CCs (2030, 2031)
Pumped Storage Hydro	0	1,700 by 2034[7]	1,700	- Entered 2022 queue - Issued major equipment RFP - Initial construction estimates - Continued Federal Energy Regulatory Commission ("FERC") license activities	- 2024: SC Certificate of Environmental Compatibility and Public Convenience and Necessity ("CECPCN") - 2025 and 2026: File NC Out of State CPCN, file final FERC application

Note 1 : 2022 and 2023 Solar Procurements includes residual quantities from previous procurements.

Note 2 : RZEP 2.0 subject to local transmission planning process. See Appendix L (Transmission System Planning and Grid Transformation).

Note 3 : Battery Storage amount includes stand-alone battery development and SPS amounts. Annual targets may be adjusted during development.

Note 4 : Includes stand-alone storage resources currently in advanced development.

Note 5 : The exact amounts, models, configurations, and timing of CTs and CCs will depend on specific system needs and optimizing for execution.

Note 6 : To achieve in-service capacities for onshore wind, the Companies will target higher development quantities to account for assumed levels of project attrition.

Note 7 : Bad Creek II Pumped Storage Hydro is projected to come into service by mid-2033; for planning purposes, the modeling reflects this resource coming into all resource portfolios at beginning of year 2034.

[28] See Chapter 4 (Execution Plan) and Table 4-2: Supply-Side Near-Term Actions Plan 2023 to 2026 for additional detail on near-term actions.

In addition to the resources selected by the Commission as needed in the initial 2022 Carbon Plan for development and procurement in 2022–2024, Table NC-1 identifies the need for significant additional solar, battery energy storage, as well as new hydrogen-capable CT and CC gas capacity to be developed in 2025–2026 as summarized below:

- **Major Solar Procurements Underway:** The Companies have made progress advancing the solar and SPS resources selected by the Commission, procuring 965 MW targeted to come online in 2026–2027[29] in the now-completed 2022 SP and targeting procurement of 1,435 MW of new solar and SPS resources in the now-open 2023 Solar Request for Proposal ("RFP").[30] The NTAP outlines additional solar and SPS procurements through 2026 to procure 1,435 MW in 2024 and then up to 3,150 MW in 2025–2026. This higher solar procurement target for 2025–2026 (1,575 MW annually) assumes NCTPC approval of the RZEP 2.0 projects in 2024 to allow such projects to more efficiently interconnect by 2031.

- **Initial Hydrogen-Capable Gas Turbine CPCNs Planned for 2023–2024:** The Companies are executing on the new hydrogen-capable CT and CC gas capacity selected by the Commission in 2022, finalizing applications for authorization to construct hydrogen-capable gas assets, including DEC planning a grouping of two 450 MW CTs that will replace retiring capacity at Marshall Station (900 MW total) and a 1,360 MW CC at Person County Energy Complex.

- **Significant Interconnection, Development Work and Regulatory Approvals Planned in 2024–2026:** The NTAP provides plans for interconnection studies and asset authorizations for the additional capacity needed beyond the amounts identified in the 2022 Carbon Plan to meet new demand growth and replace coal units planned for retirement. The NTAP also identifies the need for 2,900 MW of additional solar and SPS resources, as well as two additional CC units and three additional CTs for procurement and development in 2025–2026.

- **Jumpstarting the Onshore Wind Market:** The Companies' NTAP identifies significant onshore wind as needed by 2033 — a resource with limited deployment in the Carolinas. To meet this need and supported by the completed stakeholder engagement and third-party siting and feasibility evaluation, the Companies are proposing aggressively commencing development in 2024 to jumpstart the market in the Carolinas and to achieve 1,200 MW (8 projects modeled in 150 MW blocks) by 2033. As highlighted in Appendix I (Renewables and Energy Storage), this emerging market for onshore wind will become clearer over the next few years as the Companies (and the Commission through selecting this resource) commit to proceed with robust development necessary to achieve the Interim Target.

[29] 2022 Solar Procurement included 343 MW of utility-owned solar and 622 MW of purchased power agreements ("PPA"), 286 MW of which are CPRE PPAs and are expected to complete the interconnection study process in early 2024.

[30] Order Accepting Proposed 2023 Solar Procurement Request for Proposal, Docket Nos. E-2, SUB 1317 and E-7, Sub 1290 (July 26, 2023).

- **Selecting Bad Creek II:** The Companies request the Commission select Bad Creek II as needed to successfully execute the Carolinas Resource Plan. As further discussed in Appendix I, pumped storage hydro is a proven technology that provides valuable operational flexibility benefits to the system. Once completed and placed into service, Bad Creek II will provide an additional approximately 1,700 MW of dispatchable long-duration storage capacity that will be increasingly critical as the Companies plan for the integration of increasing variable energy resources over the next decade. Chapter 4, Figure 4-8 presents planned near-term and intermediate term actions for the continued development and regulatory approval process for placing Bad Creek II into service on its target schedule by 2033. Today, Bad Creek II is progressing in 2022 DISIS as identified in Appendix L and DEC is progressing initial development work for the project. Recognizing the significant near-term activities to execute Bad Creek II, including signing an Interconnection Agreement in 2024 and seeking regulatory approvals to construct the Facility in 2024–2025, the Companies request the Commission select Bad Creek II as part of this updated NTAP of near-term resources that are definitively needed to achieve the goals of HB 951.

In total, the 2023–2026 NTAP proposes 17,380 MW of new capacity for development and procurement including 10,680 MW incremental to the capacity selected by the Commission in the initial Carbon Plan. The resource additions represented in the NTAP are essential to maintain reliability while supporting the economic development and population growth of the Carolinas and to provide flexibility to accommodate additional growth. There has recently been a significant uptick in large businesses indicating interest in adding or expanding operations and employment in the service territory and there is potential for those trends to persist in the coming months and years. The Companies support these capacity additions, subject to future Commission oversight and review in certificate, rate case and other proceedings (as applicable), as prudent and in the best interest of customers and ask the Commission to select these supply-side resources as necessary to execute the CPIRP.

Update on Initial Development Activities for Long Lead-Time Resources and Plans for Future Development

In addition to selecting supply-side resources that the Commission determined were necessary to meet the Carbon Plan requirements, the Commission's initial Carbon Plan also directed further study and/or authorized the Companies to incur costs to conduct preliminary or initial development work to progress longer-lead time advanced nuclear, pumped storage hydro, and offshore wind resources to ensure that these resources remain available options for the Companies' customers for purposes of Carbon Plan execution.[31] Specifically, the Carbon Plan Order provided requested assurances of future recoverability of costs for advanced nuclear development pursuant to N.C.G.S. § 62-110.7 and for pumped storage hydro and offshore wind pursuant to the Commission's general authority under the

[31] Carbon Plan Order at 133 (Ordering Paragraph Nos. 24–25).

Public Utilities Act.[32] These important Commission authorizations have allowed the Companies to both further analyze and to progress initial development of these resources that could be central components of the Companies' most reasonable, least cost path to achieving HB 951's targets. In Appendix I for Bad Creek II and wind and Appendix J for advanced nuclear, the Companies have provided detailed status updates on activities leading up to this filing and identified future activities and related planned expenditures through 2026. Also, as presented in Chapter 4, the Companies have developed an updated Execution Plan for these resources extending near-term development actions through 2026, which aligns with the end of the next CPIRP planning cycle.

Table NC-2 below shows resources previously identified as approved for initial development spend in the 2022 Carbon Plan with the addition of onshore wind development requirements defined as an outcome of the Commission's directed stakeholder engagement and feasibility efforts as described above.[33] The table provides requested development expenditure authorization and related activities through 2026.

Table NC-2: Reconciliation of 2022 Carbon Plan and 2023-2024 CPIRP Proposal – Development Activities

Resource	2022 MW Amount	2022 $ Authorized	CPIRP $ Requested Authorization	CPIRP Proposed Near-Term Actions 2024–2026
Onshore Wind	0	Directed Stakeholder Engagement	$64.5M for development of three annual tranches through 2026 to achieve 1,200 MW in-service by 2033	- Site feasibility and development for DISIS and 2031–2033 in-service, respectively - 300 MW for 2025 DISIS - 450 MW for 2026 DISIS - 450 MW for 2027 DISIS
Pumped Storage Hydro	1,700	$40M[1]	$165M from 2023 through 2026	- 2024: File for SC CECPCN - 2025 and 2026: File NC Out of State CPCN (N.C.G.S. § 62-110.6), file final FERC application

[32] Carbon Plan Order at 29 ("[T]he Commission concludes that where it approves a request from Duke to incur initial project development costs for purposes of execution of the Carbon Plan, the Commission's approval constitutes reasonable assurance of recoverability in a future cost recovery proceeding, even if the resource is ultimately not selected by the Commission for the Carbon Plan. However, any such approval does not amount to the approval of the reasonableness or prudence of specific project development activities or the recoverability of specific items of cost.").

[33] Appendix I (Renewables and Energy Storage) provides information gleaned from the extensive onshore wind stakeholder and feasibility work conducted since the 2022 Carbon Plan, as directed in Carbon Plan Order at 92 and 133.

Resource	2022 MW Amount	2022 $ Authorized	CPIRP $ Requested Authorization	CPIRP Proposed Near-Term Actions 2024–2026
Advanced Nuclear	600	$75M[2]	$75M through 2024 plus additional $365M through 2026	- Site 1 – 2023 to 2026: Choose reactor technology, submit early site permit (“ESP”), develop construction permit/license application, contract with reactor vendor, and order long-lead equipment. - Site 2 – 2025 to 2026: Develop and submit ESP, begin construction permit/license application.
Offshore Wind	0	Wind Energy Area (“WEA”) Evaluation	Evaluate potential resource need in Base Planning Period (2033 or later)	- Continue partnership with NC State Energy Office to pursue IIJA funding. - Actively monitor United States market and supply chain development to inform optionality. - Continue to evaluate potential earlier resource need (0 to 1,600 MW) and make recommendation on offshore wind RFP in 2025 or sooner based on the market conditions and need.

Note 1 : Projected costs through 2024 are $30.7M.
Note 2 : Projected costs through 2024 are $74.9M.

Bad Creek II Pumped Storage Hydro

As discussed earlier, the Companies are proposing the selection of Bad Creek II under HB 951 as part of the updated 2023 NTAP as definitively needed and part of the most reasonable, least cost path to successfully execute the Carolinas Resource Plan. To continue development in the near-term, DEC has identified $165 million in expected development costs through 2026.[34] Pumped storage hydro is verified in all portfolios and, as the Commission noted, is a “unique and valuable system resource”[35] that is proven through DEC’s extensive experience with operations, maintenance, and integration of pumped storage hydro into system operations to increase flexibility, particularly as increasing amounts of solar have come onto the system.

Advanced Nuclear Small Modular Reactors

Portfolio analysis demonstrates that the most reasonable, least cost energy transition pathway for the Carolinas in all cases requires advanced nuclear, as it is the only zero-carbon baseload resource currently available. Although advanced nuclear makes up a relatively small portion of the incremental capacity additions prior to 2038, nuclear is fundamental to the energy transition and over two-thirds of the Companies’ energy mix and over a quarter of the capacity mix by 2050 is obtained from nuclear resources in all Core Portfolios. As directed by the Commission, Appendix J provides an update on

[34] See Appendix I (Renewables and Energy Storage) for additional details.

[35] Carbon Plan Order at 97.

the industry developments,[36] and the Companies continue on a close follower path to the first-of-a-kind projects for SMRs that leverage similar technology of today's large light-water reactors, use the same fuel type, have a similar labor skill-base to maintain and operate, and have proven supply chains. The near-term actions and execution plan demonstrate the plan for the initial required SMR site development and support the need for $365 million in expected development cost expenditures for the 2025–2026 timeframe, with construction on the first site beginning in the intermediate-term after the next CPIRP update in 2025.

Onshore and Offshore Wind

Wind is necessary to meet the need for a diverse mix of resources, is complementary to solar and is an important zero-carbon resource in achieving emissions reductions, and onshore wind is selected in all three Energy Transition Pathways. Wind along with nuclear was identified in HB 951 as resources that may require additional time for completion based on several factors when providing for Commission discretion on timing of Interim Target compliance.[37] As highlighted in Appendix I, the Commission-directed stakeholder engagement and feasibility efforts supported the Companies development plan to target development of 1,200 MW of onshore wind projects in the near-term (2024–2026) in order to enter into DISIS for timely operation to contribute to achieving the Interim Target in the mid-2030s. As further described in Appendix I, this development work requires expected development cost of approximately $65 million through 2026 to advance development partnerships, secure site control and conduct required environmental and permitting activities.

Like onshore wind, offshore wind is a complementary operational profile to solar and provides significant contribution to a diverse set of generating resources and carbon dioxide emissions reductions. As explained in Chapter 3, Core Portfolio P3 Base selected offshore wind in the 2040s; however, offshore wind was selected in the 2030s by several Pathway 3 portfolios developed to test the impacts of reduced or delayed availability for other resource types (see Table NC-3 below).

Table NC-3: Offshore Wind in Pathway 3 Portfolios

Pathway 3 Portfolios	Offshore Wind
Delayed Nuclear	1,600 MW by 2035
Low Onshore Wind	800 MW by 2034
Low Solar	800 MW by 2034
Limited Gas Supply	800 MW by 2034
High Resource Costs	800 MW by 2033
MVP	800 MW by 2034
Low Gas Prices	800 MW by 2033
High Load	1,600 MW by 2034
Low EE	800 MW by 2034

[36] Carbon Plan Order at 95–96.

[37] N.C.G.S. § 62-110.9(4) (recognizing the potential for "technical, legal, logistical or other factors beyond the control of the electric public utility" to impact the development timeline for wind energy).

This variability in the selection of offshore wind across the portfolios illustrates the challenge of achieving the Interim Target by 2035 and the potential earlier need for offshore wind if there are further increases in load through growth and economic development, significant shortfalls in resources contributing to the Interim Target, less contribution to load reduction from Grid Edge and customer programs or other significant changes to base planning assumptions. This analysis supports the importance and prudency in maintaining the option to add offshore wind as part of the most reasonable, least cost plan in the future, considering that it is needed to meet load growth and achieve long-term carbon neutrality in all Pathways and has value as a relatively higher capacity factor complement to solar generation.

As directed by the Commission, the Companies conducted a study of WEAs detailed in Appendix I. As further described in Appendix I, offshore wind is a new and emerging market in the United States and recent events bring into greater focus the immature domestic supply chain and inflationary challenges that have impacted this technology's costs and in-flight development activities.[38] Considering the Portfolio analysis results discussed above, the Companies propose additional monitoring of the market while keeping important no-regrets transmission-related activities underway in the near-term as reasonable steps. These proposed actions protect customers from significant near-term financial commitments as this developing domestic market matures and allows the Companies and the Commission to evaluate the deployment of scaled projects and any accrued operational experience in the U.S. Atlantic in the coming months. The Companies will continue to evaluate the option for offshore wind to meet system needs in the mid-2030s given the potential for future adjustments to the Companies' planning assumptions and make a recommendation on an RFP in 2025 or sooner based on both market conditions and any change in resource need.

Finally, the Companies note that with any long lead-time resource that results in a large, multi-year construction project, the recovery of the Companies' financing costs during the construction period is an important consideration to ensure strong credit ratings to facilitate the lowest possible financing costs for customers.

Critical Role of Optimizing Existing Resources in Energy Transition

An important component of the Execution Plan detailed in Chapter 4 is continuing to optimize existing low-carbon dispatchable and zero-carbon emitting baseload resources to provide the most value out of existing investments for customers and optimize their contribution to the energy transition. As described in Appendix J, existing nuclear provides 83% of all zero-carbon generation produced enterprise-wide; therefore, extending the operational lives of existing units through Subsequent License Renewals ("SLRs") and pursuing cost-effective power uprates ("PURs"), measurement uncertainty recapture projects ("MURs") and 24-month fuel cycle extensions that increase zero-carbon

[38] Commercial scale offshore wind in the U.S. is at an early stage with only 42 MW generating power in operation, and as of May 31, 2022, there were approximately 17 GW of offshore purchase power agreements (EIA Offshore Wind Market Report: 2022 Edition), with some cancellations during 2023 in the northeast United States, *available at* https://www.energy.gov/eere/wind/articles/offshore-wind-market-report-2022-edition.

baseload output of these facilities over the next decade are essential to the energy transition. Appendix J provides a schedule detailing plans for SLR of the existing fleet through the late 2030s as required by the Carbon Plan Order[39] and provides a summary table of planned PUR, MUR and 24-month fuel cycle extension projects with estimated in-service dates, costs and associated activities included in the Execution Plan in Chapter 4. Additional detail on the cost effectiveness of the PURs and MUR projects are addressed in Appendix C.

The Commission's Carbon Plan Order acknowledged that existing gas resources will need to operate with more flexibility as increased levels of renewables and storage on the system in order to maintain reliability and specifically directed the Companies to pursue expansion of flexibility of their existing natural gas fleet, targeting specific projects or regions that would benefit most from flexibility projects, with a specific focus on identifying least cost flexibility expansion projects that will improve or maintain system operability and reliability.[40] The Companies have identified targeted and cost effective flexibility expansion projects at seven existing DEC and DEP CC power blocks that are estimated to increase winter capacity by up to 251 MW, targeting in-service year range of 2025–2028. These projects are summarized in Appendix K (Natural Gas, Low-Carbon Fuels and Hydrogen) and associated activities are included in the Execution Plan in Chapter 4.

Planning for Orderly Coal Unit Retirements

The Commission's Carbon Plan Order recognized the magnitude of the challenge the Companies face in the next decade to retire 8,400 MW of coal capacity by the end of 2035 and found that the Companies are taking reasonable steps to meet this challenge.[41] The Carbon Plan Order also emphasized that the Companies' coal retirement plan must continue to take a holistic approach and focus on maintaining operational flexibility and reliability as an overly prescriptive approach would not be prudent.[42] While recognizing the need for flexibility, the Commission also required the Companies to show substantial justification for any delays to the retirements of the Companies' coal facilities as presented in their 2022 Carbon Plan.[43]

The Companies have retired over 35 coal units — totaling 4,400 MW — in the last decade and the remaining coal units on the Companies' system continue to provide necessary, dispatchable power to ensure reliability during the energy transition. As a result of the substantial increase in the Companies' load forecast in the past 12–18 months, as detailed in Appendix D, planning for equally reliable replacement resources and critically assessing the most prudent retirement dates for these remaining coal units is even more critical today. Due to the changing energy landscape addressed in Chapter 1 and informed by the Companies' updated coal retirement analysis presented in Appendix F (Coal Retirement Analysis), the Carolinas Resource Plan results in limited delays of the coal retirement schedule for some units that the Companies presented and the Commission approved in the 2022

[39] Carbon Plan Order at 67, 132 (Ordering Paragraph No. 12).

[40] Carbon Plan Order at 69, 132 (Ordering Paragraph No. 14).

[41] Carbon Plan Order at 64.

[42] Carbon Plan Order at 64–65.

[43] Carbon Plan Order at 65.

Carbon Plan. The Coal Retirement Study presented in Appendix F provides a comprehensive analysis of the update planned coal unit retirement strategy, which identifies the most reasonable and appropriate retirement schedule to retire aging coal units and to ensure reliability is maintained by executing a "replace before retire" approach as further addressed in Chapter 4.

The updated Carolinas Resource Plan and Coal Retirement Analysis supports the Companies' plans to retire all remaining units operating in North Carolina by the end of 2035. Due to the substantial increase in the load forecast, however, certain previously planned accelerated coal unit retirements were re-evaluated based on the system's need to reliably serve this increase in load until additional, equally reliable replacement resources can come online. Table NC-4 below shows the proposed, updated retirement dates for the Companies coal-fired units.

Table NC-4: Coal Unit Retirement Schedule Comparison (Retired by Jan 1)

Units	2022 Carbon Plan	2023 Resource Plan – P3
Allen 1 & 5	2024	2025[1]
Cliffside 5	2026	2031
Cliffside 6	2049	2049[2]
Marshall 1 & 2	2029	2029
Marshall 3 & 4	2033	2032
Belews Creek 1 & 2	2036	2036
Mayo	2029	2031
Roxboro 1 & 2	2029	2029
Roxboro 3 & 4	2028-2034	2034

Note 1 : Allen 1 & 5 retirements are planned by December 31, 2024. The 2022 Carbon Plan assumed these units were planned to be retired by January 1, 2024. These unit retirements have been extended to support the system with additional capacity as a result of load forecast and planning reserve margin targets increases in the Carolinas Resource Plan.
Note 2 : Cliffside 6 is assumed to continue operating on 100% on natural gas beyond 2035 and was not included in the coal retirement analysis for the Carolinas Resource Plan.

The limited delays to the coal retirement schedule from the 2022 Carbon Plan to the Resource Plan are primarily the result of increases in load forecast and planning reserve margin. The tremendous growth for the Carolinas, resulting from the continued customer and business migration to the region, requires certain of the Companies' coal units to remain online longer until additional replacement resources can be built. Also, as neighboring utilities' systems begin to look more like the Companies' with winter morning peaks, the Companies can rely less on neighbors for assistance, especially considering that those neighbors are also undergoing a transition to less carbon-intensive generation. While the later coal unit retirement dates result in some coal capacity being online slightly longer than initially projected in the 2022 Carbon Plan, it does not necessarily mean the energy mix from coal will increase. For example, these coal units will continue to be used only on a limited basis at peak times to maintain system reliability while the Companies continue to add replacement resources along the way.[44] Overall, the long-term dates for coal retirements in the 2030s remained largely the same as the Companies work to deploy the energy transition at an accelerated, reliable pace.

In addition to completing the comprehensive coal retirement analysis presented in Appendix F, the Companies also completed an analysis of converting the Belews Creek facility to operate 100% on natural gas. This Portfolio Variant assumes Belews Creek is converted to operate exclusively on natural gas beginning in 2030 to help meet the Interim Target and extending the life of the asset through 2040 as a bridge until the Companies could bring fully hydrogen-fired CT or CC generating units, or other potential replacement resources, online. Ultimately, this assumed conversion did not result in a least cost option as further discussed in Chapter 3 and Appendix C.

Update on Transmission System Planning and Grid Transformation

The Commission's initial Carbon Plan Order emphasized the importance of a coordinated transmission planning process to ensure that the Carbon Plan could be executed and that new generator interconnections would not negatively impact the adequacy and reliability of the existing grid in the Carolinas.[45] As Appendix L explains, the Companies manage the adequacy and reliability of their transmission systems and interconnections with neighboring entities through both internal analysis and participation in local and regional planning processes and regional reliability groups. This involves a detailed annual screening that looks 10 years ahead using methods that comply with SERC Reliability Corporation policy and NERC Reliability Standards to identify the need for future transmission system expansion and upgrades.

The system impacts of prospective generator interconnections are studied in accordance with the FERC Large and Small Generator Interconnection Procedures in the Open Access Transmission Tariff ("OATT") and related North Carolina and South Carolina state interconnection procedures. These studies evaluate the location, MW of interconnection requested, resource/load characteristics and other clustered queue requests to ensure no negative impact on the grid. Appendix L describes the ongoing successful execution of the new system-wide cluster study framework in the Carolinas as well as recent developments including the FERC's issuance of Order No. 2023 directing cluster study reforms to its generator interconnection procedures.

The initial Carbon Plan Order directed the Companies to work with stakeholders to coordinate the timing, cost and scheduling of new Carbon Plan-compliant generation system resources.[46] All 14 RZEP 1.0 projects acknowledged as needed in the initial Carbon Plan Order are on or ahead of the original planned in-service date schedule. The aggregate cost estimates for the projects have increased from $554 million to $576 million. An additional project — the Camden-Camden Dupont 115 kV upgrade— has also been included in the 2023 Local Transmission Plan based on an updated summer 2022 assessment of the 2022 Definitive Interconnection System Impact Study ("DISIS")

[44] Carbon Plan Order at 60, n.11.

[45] Carbon Plan Order at 123.

[46] Carbon Plan Order at 123.

Phase 1 study results. Table L-8 in Appendix L provides updated cost estimates for each RZEP 1.0 project along with planned in-service dates by project.

In this CPIRP update, the Companies seek Commission acknowledgement of the need for a second phase of RZEP projects ("RZEP 2.0"), similar to the request made for RZEP 1.0 in the initial Carbon Plan. RZEP 2.0 consists of three DEC and three DEP lines located in both North Carolina and South Carolina with projected in-service dates in approximately 2029 and 2030, as identified in Table L-7 of Appendix L. As explained in Appendix L and Chapter 4, these projects will be necessary to support solar procurements targeting approximately up to 3,150 MW of solar and SPS in 2025 and 2026 to achieve commercial operation of such resources in 2029–2031.

The initial Carbon Plan also required the Companies to provide an update on plans for NCTPC revisions to the local planning process, and Appendix L provides a comprehensive update on these efforts.[47] In summary, in coordination with the NCTPC Oversight Steering Committee, the Companies established a plan for revising Attachment N-1 of the OATT to change its name to the Carolinas Transmission Planning Collaborative to reflect its dual-state applicability, as well as other changes to the local planning process to increase transparency and opportunities for engagement and coordination with stakeholders, as well as to create a new planning process geared toward studying and developing strategic, multi-value transmission projects. A high-level presentation of these plans was presented at the Transmission Advisory Group stakeholder group of the NCTPC in March 2023 and a more detailed presentation was presented in June 2023. The Companies expect feedback from stakeholders in August 2023 and plan to file proposed revisions to Attachment N-1 with FERC in the October/November 2023 time frame.

Update on Grid Edge and Customer Programs

The Commission's initial Carbon Plan Order recognized the continued importance of expanding Grid Edge resources and customer programs as a key component of the Companies' strategy to "shrink the challenge" of reliably transitioning the Companies' system to reduce carbon emissions while meeting load growth, and ultimately reaching carbon neutrality. Specifically, the Commission's initial Carbon Plan order acknowledged the central role of Grid Edge resources and customer programs while also providing the Companies with direction for the 2023 Plan related to utility EE,[48] updates to the DSM/EE Mechanism,[49] transportation electrification,[50] new regulatory mechanisms such as rapid prototyping [51] and rate design.[52] The role of EE and Grid Edge technologies is as important as ever in the current changing energy landscape and the Companies have filed for approval of a number of new customer programs, initiated new proceedings and are actively working with stakeholders where appropriate to meet all of these requirements. The Companies are also actively looking for ways to

[47] Carbon Plan Order at 120–121.

[48] Carbon Plan Order at 104-06, Ordering Paragraph No. 28.

[49] Carbon Plan Order at 109-110, Ordering Paragraph No. 31.

[50] Carbon Plan Order at 108.

[51] Carbon Plan Order at 110, Ordering Paragraph No. 32.

[52] Carbon Plan Order at 113.

reduce the cost impacts of the energy transition by seeking to leverage funding resulting from major, recent federal legislation such as the IRA and IIJA to bring down the costs of projects and resources with the benefits ultimately being realized in customers' bills. Appendix H provides greater detail on the Companies' actions since the initial Carbon Plan and Table 4-16 in Chapter 4 provides an overview of near- and intermediate-term actions the Companies plan to take related to EE, demand response, rapid prototyping, transportation electrification, rate design and voltage optimization. The Companies are requesting that the Commission approve its plans to continue both advancing Grid Edge and customer programs and engaging with stakeholders on updating the underlying determination of the utility system benefits in the Companies' upcoming EE/DSM Cost Recovery Mechanism proposal.

Engagement Plans for Impacted Communities

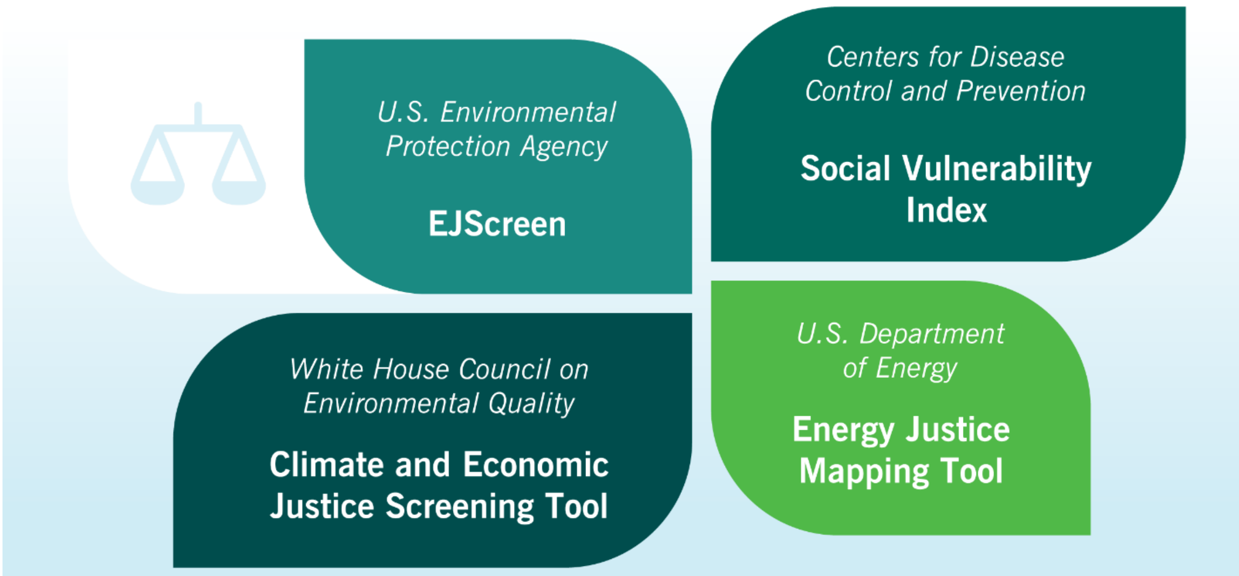
The Carbon Plan Order directed the Companies to continue to develop targeted engagement plans for impacted communities and to report on these Plans and ensuing engagement with stakeholders in this initial CPIRP filing.[53] As highlighted in the Executive Summary, stakeholder engagement is central to how Duke Energy does business, and the Companies have invested significant resources and focus in planning and responsibly executing the energy transition to develop environmental justice ("EJ") engagement plans as well as to prioritize working with impacted communities in Duke Energy's service territories.

Development of Environmental Justice Engagement Plans

In North Carolina, Duke Energy's work on EJ builds upon the outreach established in 2022, as the Companies prepared their proposed Carbon Plan filing. In 2022, Duke Energy organized three meetings with EJ-focused stakeholders, with a specific focus on low-income and communities of color, to understand the issues that were important to them. During these meetings the Companies observed a consistent emphasis on the need for local community engagement. In response, the Companies developed regional advisory councils to address the need for and to guide local engagement. Duke Energy also hosted a more broadly focused statewide EJ Council meeting on June 1, 2023. The Companies will use feedback from EJ stakeholders to build engagement plans. These engagement plans will incorporate demographic, socio-economic and existing EPA-permitted facility data from various third-party EJ tracking tools (Figure NC-3 below) that help to identify EJ communities and potential impacts from project activities.

[53] Carbon Plan Order at 135, Ordering Paragraph No. 39.

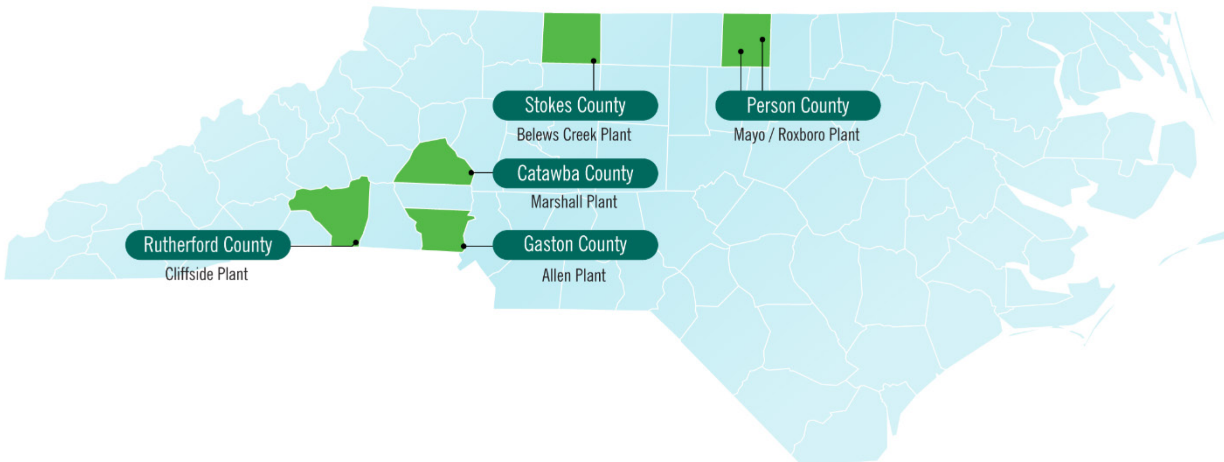
Figure NC-3: Third-Party Mapping Tools



Duke Energy's Work with Impacted Communities

Duke Energy is also continuing to address the impacts of coal plant retirements on the communities it serves. As a result, the Companies' stakeholder engagement plan includes targeted outreach to communities where the Companies have remaining coal facilities. Duke Energy is assisting these communities by identifying ways to mitigate the potential loss of tax base and employment due to expected coal plant retirements. In addition to those directly impacted by coal plant retirements, Duke Energy also includes in its definition of impacted communities those communities directly impacted by large infrastructure projects, transmission lines and substations, and other new generation. The Companies' engagement with impacted communities includes customized strategies tailored to provide meaningful local engagement from those most impacted by a specific project. Engagement efforts are either underway or planned for several impacted communities as shown in Figure NC-4 below.

Figure NC-4: Generation Facilities and Impacted Communities



Additionally, on May 31, 2023 and July 26, 2023, the Companies invited Carolinas Resource Plan stakeholders to receive feedback on EJ work and the Companies' approach to impacted communities. The Companies provided attendees with an overview of Duke Energy's engagement plans and approach to working with impacted communities. The Companies also provided participants an opportunity to ask questions and share feedback and committed to maintaining a dialogue with stakeholders by providing a dedicated email address and phone number, which may be used to communicate with the Companies.

Duke Energy will continue to engage with impacted stakeholders throughout the planning and constructing of new generation resources and other infrastructure projects. The Companies recognize the importance of hearing many perspectives and are committed to ensuring that the customers and communities have a seat at the table.

Parallel Review by South Carolina Commission

As identified in the initial 2022 proposed Carbon Plan[54] and further discussed in Chapter SC, the Carolinas Resource Plan is contemporaneously being filed with the PSCSC pursuant to South Carolina's triennial IRP review statute, which requires the PSCSC to consider the Plan under the South Carolina's IRP statute's balancing factors and, in its discretion, approve the most reasonable and prudent plan to meet the Companies' South Carolina customers' capacity and energy needs.[55] The

[54] See Initial 2022 Proposed Carbon Plan of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC at Chapter 4, Figure 4-3.

[55] See S.C. Code Ann. § 58-37-40(C)(2) (directing PSCSC, in its discretion, to consider whether the utility's IRP appropriately balances seven factors, including affordability and least cost, power supply reliability, diversity of generation supply, amongst others, when determining whether the Companies' IRPs represent the most reasonable and prudent means of meeting the utility's capacity and energy needs). The PSCSC has scheduled an evidentiary hearing on the Companies' SC IRP to commence on April 8, 2024, and must issue a final order approving, modifying, or denying the plan within 300 days of filing (by June 10, 2024).

Commission has previously recognized the continued importance of coordinated dual-state resource planning as the Companies “operate[] as a single integrated system across both North Carolina and South Carolina, [and] for many generations have provided reliable, efficient and affordable electricity to the residents of both states.”[56] To that end, the Companies look forward to continued constructive engagement with this Commission, the PSCSC, the Public Staff, the South Carolina Office of Regulatory Staff, other consumer and customer advocates as well as the many other stakeholders in both North Carolina and South Carolina that seek to better understand and help inform the Companies’ resource planning future for the Carolinas.

Closing and Summary of Requests to Commission

The Carolinas Resource Plan and CPIRP update to the Commission provides a comprehensive and detailed analysis supporting the continued energy transition that is balanced, reasonable and executable and importantly, will ensure reliable electric service for the Companies’ customers at affordable rates over the short and long term. The proposed near-term actions present the reasonable steps required for action in the near-term on the most reasonable, least cost path for the Carolinas to achieve the planning objectives of HB 951. Ultimately, the Companies’ success in executing the Carolinas Resource Plan requires clear direction from the Commission on the most reasonable, least cost path for actions to be completed in the near-term. To that end, the specific authorizations sought by the Companies as part of this CPIRP update are set forth in the Companies’ accompanying Petition. The requested authorizations center on the steps to be taken by the Companies between now and the end of the next CPIRP in 2025–2026 and should be granted for the reasons explained in great detail in this Plan.

[56] Order Accepting Withdrawal of Petition for Joint Proceeding, Docket Nos. E-2, Sub 1283 and E-7, Sub 1259 (Feb. 1, 2022).