Docket No. E-100, Sub 179

CAROLINAS

CARBON PLAN

DUKE ENERGY®

BUILDING A **SMARTER** ENERGY FUTURE®

ACCEPTED FOR PROCESSING - 2022 May 17 12:08 PM - SCPSC - ND-2022-4-E - Page 1 of 32

EXECUTIVE SUMMARY

CHAPTER 1	Introduction and Background
CHAPTER 2	Methodology and Key Assumptions
CHAPTER 3	Portfolios
CHAPTER 4	Execution Plan
APPENDIX A	Carbon Baseline and Accounting
APPENDIX B	Stakeholder Engagement
APPENDIX C	System Overview
APPENDIX D	DEC – DEP Owned Generation
APPENDIX E	Quantitative Analysis
APPENDIX F	Electric Load Forecast
APPENDIX G	Grid Edge and Customer Programs
APPENDIX H	Screening of Generation Alternatives
APPENDIX I	Solar
APPENDIX J	Wind
APPENDIX K	Energy Storage
APPENDIX L	Nuclear
APPENDIX M	Natural Gas
APPENDIX N	Fuel Supply
APPENDIX O	Low-Carbon Fuels and Hydrogen
APPENDIX P	Transmission System Planning and Grid Transformation
APPENDIX Q	Reliability and Operational Resilience Considerations
APPENDIX R	Consolidated System Operations
APPENDIX S	Integrated System and Operations Planning (ISOP)
APPENDIX T	Cross Reference
ATTACHMENT I	DEC Resource Adequacy Study
ATTACHMENT II	DEP Resource Adequacy Study
ATTACHMENT III	DEC and DEP ELCC Study
ATTACHMENT IV	Duke Energy NC EE and DSM Market Potential Study

ACCEPTED FOR PROCESSING - 2022 May 17 12:08 PM - SCPSC - ND-2022-4-E - Page 2 of 32

ACCEPTED FOR PROCESSING - 2022 May 17 12:08 PM - SCPSC - ND-2022-4-E - Page 3 of 32

Executive Summary

The Carolinas Carbon Plan (the "Carbon Plan" or the "Plan") represents the next major step on the continued energy transition of the Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and, together with DEC, "Duke Energy" or the "Companies") systems. The Companies' continued transition, which relies on a diverse portfolio of technologies with lower carbon intensity, is prudent and necessary to reduce exposure to diminishing coal supply and associated regulatory risks, provides for continued reliability, and ensures continued access to capital at reasonable rates for the benefit of customers. Furthermore, the energy transition is supported by a broad range of the Companies' customers and, when combined with continued affordable and competitive rates, will play a crucial role in retaining existing businesses and attracting new economic development to North Carolina and South Carolina (together, the "Carolinas").

This Plan is built on the foundation of decades of reasonable and prudent utility planning practices and decisions that have been jointly overseen by the North Carolina Utilities Commission ("NCUC" or the "Commission") and the Public Service Commission of South Carolina ("PSCSC"). This dual-state approach to least-cost resource planning has benefited customers in the Companies' service territory across the Carolinas through the provision of reliable and affordable electric service with a decreasing carbon intensity. DEC and DEP have a combined carbon dioxide ("CO_2") emission rate that is lower than the national average among all privately held and investor-owned utilities.[1]

Utilizing well-established planning principles honed through decades of integrated resource planning processes overseen by the NCUC and the PSCSC, the Companies' proposed Carbon Plan assesses a range of portfolios that will facilitate continued modernization of the Companies' systems spanning the Carolinas and result in further CO_2 reductions through a prudent, orderly, and cost-effective energy system transition.

For over a century, Duke Energy has provided affordable, reliable, and increasingly cleaner energy for its customers and communities in the Carolinas.[2] Facilitated in part by the Joint Dispatch

[1] MJ Bradley "Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States". July 2021 (www.mjbradley.com).

[2] Duke Energy's Carolinas operations include DEC and DEP service territories. *See* Appendix C (System Overview) for additional information.

ACCEPTED FOR PROCESSING - 2022 May 17 12:08 PM - SCPSC - ND-2022-4-E - Page 4 of 32

Agreement ("JDA"),[3] the Companies' 4.4 million customers in the Carolinas benefit from a diverse and reliable mix of resources and already receive more than half of their energy from nuclear, hydroelectric and solar, making Duke Energy a national leader in carbon-free generation. The dual-state systems provide customers with an expansive portfolio of energy efficiency, demand-side management, and advanced grid technology programs reducing or modifying load to complement the Companies' supply-side generating resources used to reliably serve customer capacity and energy needs. Combined with a very large geographic footprint, the dual-state systems have delivered tremendous economies of scale to customers in the Carolinas, creating competitive advantages for the states' economies and fueling job creation through reliable supply of electricity at rates consistently below the national average.

Duke Energy's CO_2 emissions reductions trajectory represents reasonable and prudent planning for the benefit of customers and aligns with a fundamental energy transformation that is in progress across the U.S. and is changing how energy is produced, delivered and used, as discussed in Chapter 1 (Introduction and Background). Customers, businesses, and communities are expressing a strong desire for emissions-free energy, and many have adopted specific energy-related goals. There is also growing momentum across the country for clean energy through a variety of policies advanced by the federal government, states and communities. Infrastructure investors are also increasingly making decisions based on a company's environmental, social and governance ("ESG") measures, including their CO_2 emissions. Clean energy technologies are advancing and are becoming increasingly cost-effective over time. Finally, reliance on a diminishing coal supply chain with limited transportation flexibility puts additional pressure on aging coal resources. Given all these factors, the Carbon Plan represents prudent long-term electric resource planning that complies with current law and practice with respect to least-cost planning for generation and allows the Companies to further advance the energy transition that is already underway.

North Carolina Session Law 2021-165 ("HB 951") was signed into law on October 13, 2021, and provides a crucial policy framework for the Companies regarding the continued orderly implementation of the energy transition. HB 951 was supported by overwhelming bipartisan majorities in the North Carolina General Assembly and then executed by Governor Roy Cooper. The strong bipartisan support of HB 951 affirms that continuation of the energy transition that Duke Energy has been pursuing under the oversight of the NCUC and PSCSC is sound and prudent energy policy.

Overview of Carbon Plan

The Companies' proposed Plan presents for the Commission's consideration two pathways consisting of four discrete portfolios, all of which further the transition of the Companies' energy systems and achieve the CO_2 emissions reductions targets established under HB 951. The Plan assesses each of the portfolios against four core Carbon Plan objectives (CO_2 reduction, affordability, reliability and executability), all of which are grounded in prudent utility planning and operation.

[3] The Joint Dispatch Agreement provides for combined operational control of DEC's and DEP's respective generating facilities to facilitate the sharing of non-firm economic energy between the two utilities.

ACCEPTED FOR PROCESSING - 2022 May 17 12:08 PM - SCPSC - ND-2022-4-E - Page 5 of 32

As is described in greater detail below, the Plan identifies - and seeks Commission approval of - the reasonable and necessary steps needed in the near term to further the energy transition, and also identifies further actions needed over the intermediate term and key signposts to be monitored over the longer term. The Companies' proposed near-term activities are reflective of a measured, balanced and "all-of-the-above" approach to the energy transition. This approach is built on the bedrock of aggressive, nation-leading goals to continue to "shrink the challenge" of an energy transition by first reducing or modifying energy usage on the system at the customer level, along with plans to evolve customer programs to provide greater access to a zero-emitting energy supply, cutting-edge rate designs to encourage customers to change their load profiles in ways that better support use of carbon-free resources, and implementation of "Grid Edge" technologies that enable Duke Energy to manage the electric system in ways that lower carbon emissions while maintaining reliability.

Under the Plan, the remaining customer demand is then projected to be served through substantial, diversified investments in both technologies mature to the Carolinas and technologies that would be new to the Carolinas' energy system, along with transmission grid investments needed to reliably integrate these new resources onto the Carolinas system. Mature technologies in the Companies' Plan include solar, pumped storage hydro and dispatchable natural gas units, while technologies new to the Carolinas include onshore wind and offshore wind, large-scale battery storage and small modular reactor ("SMR") and advanced nuclear technologies. The Plan outlines near-term development and procurement needed in 2022-2024 to bring projects into service in the period of 2026-2029, along with development activities necessary for longer lead-time resources to remain on track to come online between 2030-2034 (consistent with the target dates reflected in the various portfolios). In summary, the Plan not only provides a modeled planning view of potential portfolios, but also overlays key execution recommendations and considerations that should guide the Commission's assessment of the Plan, including the timing of the Commission's decisions and the ways in which the iterative Carbon Plan process will evolve over the coming years under the oversight of the Commission and the PSCSC.

The Plan is organized in the following chapters, with further detailed information available in appendices.[4]

- **Chapter 1:** Introduction and Background
- **Chapter 2:** Methodology and Key Assumptions
- **Chapter 3:** Portfolios
- **Chapter 4:** Execution Plan

A Plan for the Carolinas' Systems

Under the oversight of the Commission and the PSCSC, the Companies have already made substantial progress in the energy transition, as evidenced by the retirement of 34 coal units in both

[4] For the benefit of the Commission, the Companies identified where in the Carbon Plan the Companies have addressed specific Commission requirements or expectations set forth in various Commission orders in Appendix T (Cross-Reference).

ACCEPTED FOR PROCESSING - 2022 May 17 12:08 PM - SCPSC - ND-2022-4-E - Page 6 of 32

states, totaling 4,200 megawatts ("MW") over the past 11 years, all through the existing regulatory and legal structures. This transition has been achieved and facilitated by alignment between the states in support of cleaner energy resources through portfolio diversification. Through a series of strategic and constructive regulatory actions spanning decades, the Commission and PSCSC jointly enabled the Companies to operate and grow the dual-state systems to meet the needs of customers in both states. The Companies' dual-state systems have delivered tremendous economies of scale, resiliency, and savings to customers and communities in both states, creating competitive advantages for both states' economies and fueling job creation through the reliable and safe supply of electricity at rates consistently below the nation's average.

It is through this lens that the Companies view the emissions reductions targeted in HB 951. The targets established under HB 951 represent a formalization of the Companies' continued orderly transition away from continued reliance on emission-intensive resources, but also, an opportunity for the Commission and the PSCSC to apply least-cost planning principles to drive the energy transition of the Carolinas – all for the benefit of Duke Energy's customers.

Duke Energy acknowledges that the PSCSC is not bound by North Carolina law and recognizes that further proceedings before the PSCSC will be required subsequent to the Commission decision in this proceeding. As this Commission aptly stated, "engagement with the PSCSC to consider and examine the benefits of continued system-wide planning and operation for Duke Energy's customers in both states, in a manner that is consistent with applicable South Carolina law and [North Carolina] law and respectful of the jurisdiction and sovereignty of each state could be worth exploring."[5] If differences in state energy policy do not allow for alignment and system-wide planning, then the Companies may need to plan and operate as two different systems, which could result in ultimate separation of the utilities. This approach could increase costs and will, in general, make the energy transition less efficient.

Continuation of the dual-state planning for each system is in the best interests of customers and ultimately the economic development interests of both states. As the Commission has confirmed: "the DEP and DEC systems, each of which operates as a single integrated system across the Carolinas, for many generations have provided reliable, efficient, and affordable electricity to the residents of both states."[6] The Companies believe that continuation of the current well-planned and integrated single-system approach for each utility remains in the best interests of customers and will seek to achieve alignment by continuing to actively encourage South Carolina stakeholder participation in the energy transition planning process and then ultimately through the established regulatory processes, including primarily the comprehensive 2023 South Carolina Integrated Resource Plan ("IRP") review process required by South Carolina law. Further details regarding state alignment are discussed in Chapter 1 (Introduction and Background) and further timing details are described in Chapter 4 (Execution Plan).

[5] *Order Accepting Withdrawal of Petition for Joint Proceeding*, Docket Nos. E-2, Sub 1259 & E-7, Sub 1283, at 2 (February 1, 2022).

[6] *Id.*

ACCEPTED FOR PROCESSING - 2022 May 17 12:08 PM - SCPSC - ND-2022-4-E - Page 7 of 32

Stakeholder Engagement

The Carbon Plan is informed by diverse stakeholder engagement, occurring before and after HB 951 became law. Duke Energy has engaged with stakeholders in North Carolina and South Carolina across a broad array of the Companies' operation and planning processes for a number of years, including with respect to energy efficiency and demand-side management ("EE/DSM"), IRPs, Integrated System & Operations Planning ("ISOP"), affordability, rate design, solar net metering, generator interconnection and a variety of other topics. In particular, the Plan is informed by the collaborative work of the recent 2020 IRP process,[7] the 2019 State Clean Energy Plan ("CEP")[8] process in North Carolina, as well as the Carbon Plan-specific stakeholder process that has occurred in the months leading up to this filing as directed and overseen by the Commission.[9] Through the Carbon Plan-specific stakeholder process,[10] Duke Energy actively engaged stakeholders across the Carolinas through three primary virtual stakeholder meetings, coordinating with over 500 participants from stakeholder groups, such as customer and consumer advocacy groups, community leaders and advocates, renewable energy developers, environmental interests and academia. In addition to the primary stakeholder meetings, multiple subgroup sessions were conducted based on specific technical or interest areas. Details of these activities, which were facilitated by an independent entity, the Great Plains Institute, can be found on Duke Energy's website.[11]

Stakeholder feedback directly influenced both the stakeholder process itself and the development of the Plan in a variety of ways, as illustrated in Figure 1 below. Stakeholder feedback also influenced Plan assumptions and execution considerations, such as the importance of timely and adequate grid investments to achieve Plan targets, navigating future regulatory uncertainty and risk management. Stakeholder feedback regarding community impacts of the energy transition in terms of environmental justice, local economies and employment will be used to inform execution decisions.

---

[7] Duke Energy, Integrated Resource Planning, https://www.duke-energy.com/irp (last visited May 3, 2022).

[8] In October 2019, Governor Roy Cooper issued the CEP, establishing goals for electric sector carbon reductions and regulatory modernization. This launched a 16-month stakeholder process aimed at developing recommendations supporting the CEP objectives. *See* N.C. Dept. Env. Quality, Clean Energy Plan, https://deq.nc.gov/energy-climate/climate-change/nc-climate-change-interagency-council/climate-change-clean-energy-plans-and-progress/clean-energy-plan (last visited May 3, 2022).

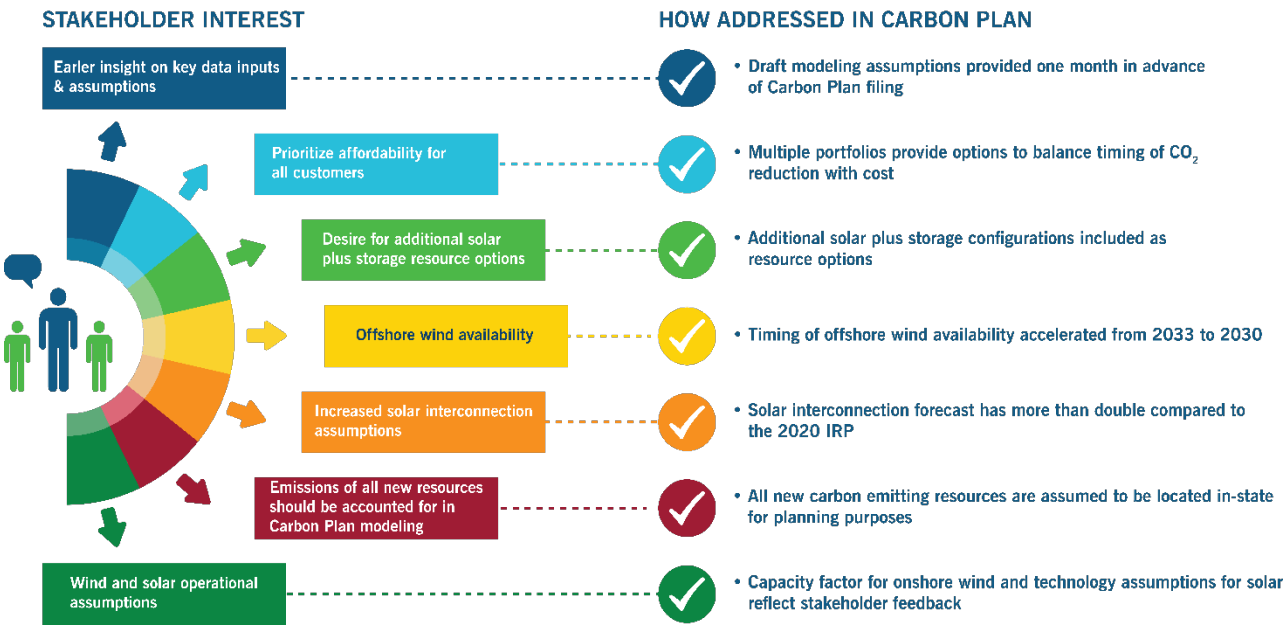
[9] *See* Appendix B (Stakeholder Engagement) for additional information regarding the stakeholder process, stakeholder forums, and the North Carolina CEP.

[10] *Order Requiring Filing of Carbon Plan and Establishing Procedural Deadlines*, Docket No. E-100, Sub 179 (November 19, 2022) ("Carbon Plan Procedural Order").

[11] *See* Duke Energy, Carolinas Carbon Plan, www.duke-energy.com/CarolinasCarbonPlan (last visited May 2, 2022).

ACCEPTED FOR PROCESSING - 2022 May 17 12:08 PM - SCPSC - ND-2022-4-E - Page 8 of 32

Figure 1: Incorporation of Stakeholder Feedback



Specific stakeholder input to the Plan is included throughout the main body and subject matter appendices of the Plan. As of the date of this filing, Duke Energy has made available the final Carbon Plan modeling datasets, which will allow intervenors[12] to assess all aspects of the Companies' modeling analysis. Duke Energy also looks forward to participating in a series of upcoming public hearings across the State that are scheduled in the coming months.[13] Finally, the Companies anticipate substantial engagement with intervenors post-filing as directed by the Commission in its April 1, 2022 *Order Establishing Additional Procedures and Requiring Issues Report*. Additional detail on the Companies' stakeholder engagement efforts is provided in Appendix B (Stakeholder Engagement).

Planning Requirements Under HB 951

HB 951 establishes three primary requirements, all of which must be satisfied in the plan developed by the Commission to achieve the targeted CO_2 reductions. The first requirement is that the Commission must comply with current law and practice with respect to least-cost planning for generation.[14] The second requirement is that any generation and resource changes must maintain or

[12] As described in the Companies' April 5, 2022 letter in this docket and the cover letter for this filing, access to the modeling data will be made available upon request to intervenors whose participation in this docket has been approved by order of the Commission and who have submitted an executed confidentiality agreement to the Companies.

[13] *Order Scheduling Public Hearings and Requiring Public Notice Pursuant to House Bill 951*, Docket No. E-100, Sub 179 (March 9, 2022) ("Order on Public Hearings").

[14] HB 951, Section 1(2).

ACCEPTED FOR PROCESSING - 2022 May 17 12:08 PM - SCPSC - ND-2022-4-E - Page 9 of 32

improve upon the adequacy and reliability of the existing grid.[15] The third requirement is that any new generation facilities or other resources selected by the Commission in order to achieve the CO_2 emissions reduction goals for electric public utilities must be owned and recovered on a cost of service basis by the applicable electric public utility, except in the case of energy efficiency measures and demand-side management, for which existing law applies, and in the case of solar generation, which is to be allocated according to the specified percentages.[16]

Defining the Baseline for CO_2 Emissions Reduction

Section 1 of HB 951 directs the Commission to take all reasonable steps to achieve two emissions reductions targets: (1) a 70% reduction in CO_2 emissions from electric generating facilities owned or operated by electric public utilities in North Carolina by 2030 from 2005 levels and (2) carbon neutrality by 2050, and further provides that the timing of achievement of the interim 70% reductions target may be adjusted based upon certain factors.[17] To achieve these CO_2 emissions reductions targets over the interim and long term, the Commission is tasked with developing a Carbon Plan, which "may, at a minimum, consider power generation, transmission and distribution, grid modernization, storage, energy efficiency measures, demand-side management, and the latest technological breakthroughs[.]"[18]

As recognized by the Commission's initial Procedural Order, a prerequisite to development of pathways to meeting these targets is a clear understanding of the baseline for measuring progress toward meeting the goals.[19,20] The CO_2 emissions baseline and progression to achieve the interim 70% interim reduction target are shown below in Figure 2 and explained in more detail in Appendix A (Carbon Baseline and Accounting). Importantly, while HB 951 defines and allows for carbon neutrality by 2050 through the use of offsets,[21] the Plan does not currently assume utilizing offsets.

[15] *Id.* Section 1(3).

[16] *Id.* Section 1(2).

[17] *Id.* Section 1(4).

[18] *Id.* Section 1(1).

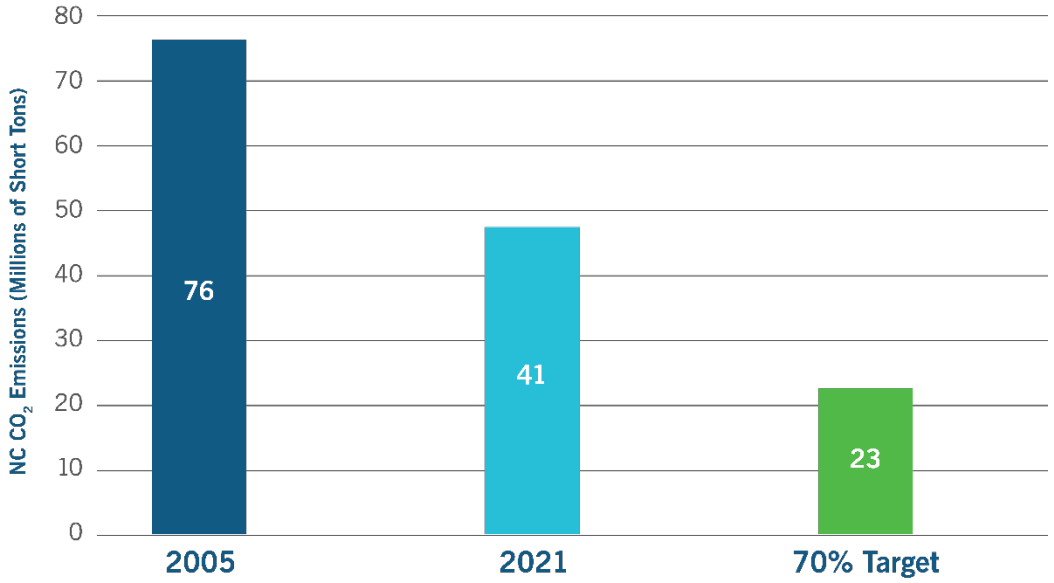
[19] Carbon Plan Procedural Order, at 3.

[20] *See* Appendix A (Carbon Baseline and Accounting) for specific methodologies for CO_2 emissions baseline calculation and CO_2 emissions accounting, along with key definitions for carbon neutrality and offsets.

[21] HB 951, Section 1.

ACCEPTED FOR PROCESSING - 2022 May 17 12:08 PM - SCPSC - ND-2022-4-E - Page 10 of 32

Figure 2: North Carolina CO_2 Emissions Baseline, Progress and 70% Reduction Target



HB 951 establishes CO_2 emissions reductions targets for Duke Energy's electric generating facilities located in North Carolina. In light of Duke Energy's dual-state systems, stakeholders expressed concerns regarding a strategy that involves use of CO_2-emitting resources located outside of North Carolina.

First and foremost, the Companies are committed to systemwide CO_2 emissions reductions, targeting carbon neutrality for their entire system by 2050. Second, the Companies affirmed during the stakeholder process that, for modeling purposes, they would assume that any new CO_2-emitting resources selected in the model would be sited in North Carolina.

However, consistent with past practice, in most cases, the selection and siting of new resources will occur after completion of the modeling process (with such modeling results, including any modifications ultimately required by the Commission, informing the procurement process). This approach will ensure that the most cost-effective resources are selected for the benefit of customers, taking into account a range of site-specific and other factors that are not practical for inclusion in the modeling process.

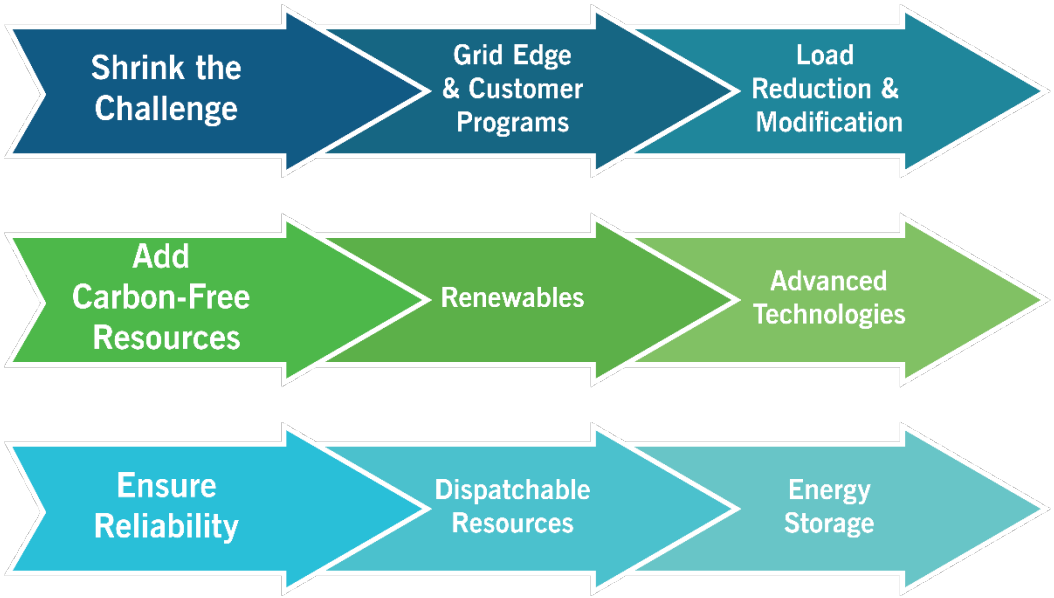
Therefore, the Companies request Commission confirmation with respect to two issues concerning CO_2 emissions accounting under HB 951. First, the Companies request Commission approval of the methodologies outlined in Appendix A (Carbon Baseline and Accounting) for tracking achievement of HB 951's CO_2 emissions reductions targets. Second, the Companies request that the Commission determine whether CO_2 emissions from out-of-state generating resources ultimately selected to be part of the Plan should be accounted as if such emissions occurred in the State. Once again, for modeling purposes, the Companies assumed all new selected resources would be sited in North Carolina.

ACCEPTED FOR PROCESSING - 2022 May 17 12:08 PM - SCPSC - ND-2022-4-E - Page 11 of 32

Carbon Plan Illustrates Pathways to 70% CO_2 Emissions Reductions

The Companies intend to take a multipronged approach to maintaining affordable and reliable service while also meeting CO_2 emissions reduction targets. As depicted in Figure 3 below, the Companies first plan to "shrink the challenge" by reducing energy requirements and modifying load patterns through grid edge and customer programs[22] allowing more tools to respond to fluctuating energy supply and demand. The second and third prongs focus on development of diverse portfolios of carbon-free and flexible, dispatchable energy supply sources to facilitate CO_2 emissions reductions while maintaining reliable energy service.[23] Supply resource diversity provides flexibility and mitigates the risk over reliance on any one technology to meet reliability and resilience requirements as the energy transition evolves how the Companies operate the grid.

Figure 3: Three-Pronged Approach to Planning



Two Pathways to 70% CO_2 Emissions Reductions

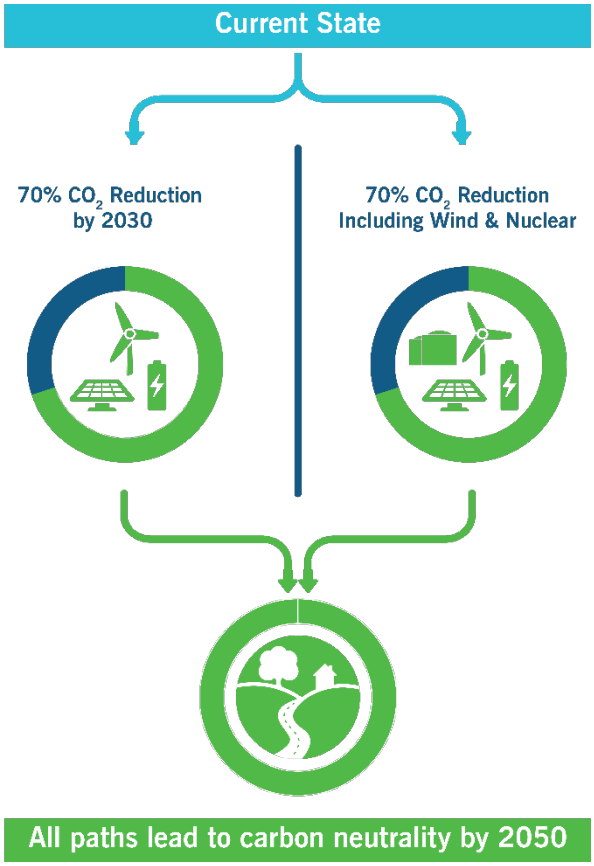
The Plan explores the risks and benefits of two pathways for achieving the interim 70% reduction target, with both pathways resulting in carbon neutrality of the systems by 2050. As shown in Figure 4 below, one pathway achieves the 70% target by 2030 and the second pathway achieves the 70% target by 2034 through reliance on offshore wind and/or nuclear SMR generation technologies as is contemplated by HB 951.

[22] *See* Appendix G (Grid Edge and Customer Programs) for additional information.

[23] *See* Appendix I (Solar), Appendix J (Wind), Appendix K (Energy Storage), Appendix L (Nuclear), Appendix M (Natural Gas), Appendix N (Fuel Supply) and Appendix O (Low-Carbon Fuels and Hydrogen) for additional information.

ACCEPTED FOR PROCESSING - 2022 May 17 12:08 PM - SCPSC - ND-2022-4-E - Page 12 of 32

Figure 4: Two Pathways to Carbon Neutrality



Defining Portfolios Within Each of the Two Pathways

The Companies have developed four portfolio options within the two pathways: Portfolio 1 achieves 70% CO_2 emissions reductions by 2030, and Portfolios 2-4 achieve the 70% reduction target between 2032 and 2034 relying on offshore wind and/or nuclear SMR generation technologies. The latter three portfolios are predicated on the flexibility and discretion provided to the Commission in HB 951 to determine the optimal timing and generation and resource mix to achieve the least-cost path to HB 951's CO_2 emissions reductions targets. Specifically, HB 951 provides that the Commission has "discretion in achieving the authorized carbon reduction goals by the dates specified in order to allow for implementation of solutions that would have a more significant and material impact on carbon reduction" and pursuant to this discretion may approve a Carbon Plan that targets completion two years after the specified dates.[24] In addition, the Commission may approve a Carbon Plan that achieves the target after the specified dates "in the event the Commission authorizes construction of a nuclear facility or wind energy facility that would require additional time for completion due to technical, legal, logistical or other factors beyond the control of the electric public utility, or in the event

[24] HB 951, Section 1(4).

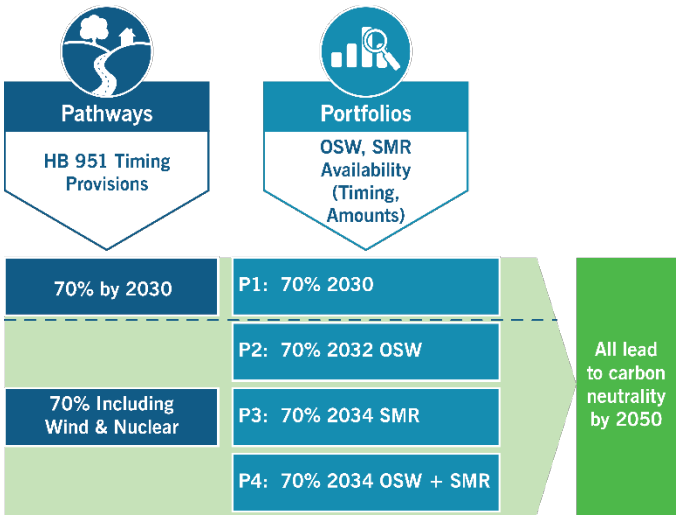
ACCEPTED FOR PROCESSING - 2022 May 17 12:08 PM - SCPSC - ND-2022-4-E - Page 13 of 32

necessary to maintain the adequacy and reliability of the existing grid."[25] Therefore, the latter three portfolios rely on offshore wind and/or SMR to achieve 70% CO_2 emissions reductions to provide optionality for the Commission consistent with intent of the General Assembly, with all portfolios achieving the 70% interim target by 2034 and carbon neutrality by 2050.

Finally, each of the four portfolios was developed based on the key planning parameter of access to firm transportation for lower-cost natural gas from the Appalachia region. Recognizing the potential uncertainty in interstate pipeline availability, the Plan also includes an alternate fuel supply case sensitivity analyses for each of the portfolios to assess the impact on the portfolios should access to Appalachian gas not be achieved. The availability of firm transportation of natural gas to fuel existing natural gas generation resources and new flexible natural gas resources is critical to operate a reliable system, facilitate coal retirements (thereby reducing exposure to a deteriorating coal supply chain), and to integrate and reliably back-stand high levels of intermittent renewable resources on the system.[26] Importantly, the alternate fuel supply case evaluated for each portfolio should be understood as a future "pivot point." That is, the alternate fuel supply cases assess the future resource mix in the event that the Companies are not able to access new Appalachian natural gas, in which scenario the Companies would "pivot" to pursue the resources identified in the alternate case. The Companies' proposed near-term activities allow appropriate flexibility to accommodate such a pivot without material impact.

Figure 5 below illustrates the progression from the two pathways through to the four portfolios.

Figure 5: Pathways and Portfolios to 70% CO_2 Emissions Reductions



[25] *Id.*
[26] *See* Appendix N (Fuel Supply) for additional information.

ACCEPTED FOR PROCESSING - 2022 May 17 12:08 PM - SCPSC - ND-2022-4-E - Page 14 of 32

Portfolio Results

Each portfolio presents a road map to transition away from continued reliance on emissions intensive resources via orderly retirement of coal facilities and prudent, planned additions of a diverse mix of low-carbon and emissions-free resources, all while keeping a keen eye on reliability and affordability. All portfolios assume acceleration of renewable technologies including solar, onshore and offshore wind, greater integration of battery and pumped storage hydro, expanded energy efficiency and demand response and deployment of new zero-emitting load-following resources such as nuclear SMRs, as well as hydrogen solutions in the longer term to achieve carbon neutrality by 2050. All resource types identified in each of the portfolios are likely to be needed either to achieve the interim 70% CO_2 emissions reduction targets or carbon neutrality over the longer term. The primary difference among the four portfolios largely relates to the pace of deployment.

Chapter 2 (Methodology and Key Assumptions) details the portfolio modeling inputs and assumptions, Chapter 3 (Portfolios) presents detailed information on the core Carbon Plan objectives and modeling outputs for each of the four portfolios (and corresponding alternate fuel case portfolios) included in the Plan, in addition to sensitivities of varying natural gas supply and prices, as well as technology capital costs for specific portfolios. Appendix E (Quantitative Analysis) provides additional modeling result details, including corresponding portfolios for the alternate fuel supply cases.

The following is a summary description of the four portfolios:

- **Portfolio 1: "70% by 2030" –** Portfolio 1 targets achieving the 70% CO_2 emissions reductions by 2030. To meet this aggressive target, P1 requires 800 MW (one 800 MW block) of offshore wind to be placed in service by year-end 2029, new solar interconnections ramping up to 1,800 MW/year by year-end 2028 (approximately 2.5 times the maximum amount interconnected in any previous year) and the addition of nearly 1,800 MW of new battery energy storage capacity (including batteries paired with solar), up from only 13 MW in service today. Portfolio 1 also plans for a slightly accelerated retirement of Roxboro Units 3-4 (1,409 MW) with all other coal retirements consistent across the portfolios.

- **Portfolio 2: "70% by 2032 OSW" –** Portfolio 2 aggressively deploys two 800 MW blocks of offshore wind, the first in 2029 and the second in 2031, to achieve the 70% interim target by 2032. As described in greater detail in Appendix P (Transmission Planning and Grid Transformation), connecting the second block of offshore wind requires extensive additional transmission upgrades. Importantly, Portfolio 2 extends the timeframe for achieving the 70% interim target relative to P1, allowing time to construct needed additional transmission, enabling greater contributions from grid edge resources and customer programs, and a slightly less aggressive pace of new solar and energy storage additions. Portfolio 2 plans for the same coal unit retirement schedule as Portfolio 1, except that Roxboro Units 3-4 (1,409 MW) are proposed to be retired by 2032.

- **Portfolio 3: "70% by 2034 SMR" –** Portfolio 3 targets the achievement of 70% CO_2 emissions reductions by 2034 with new nuclear. It is the only portfolio that does not include the deployment of offshore wind. By extending the 70% interim target timeframe to 2034, this portfolio allows the

ACCEPTED FOR PROCESSING - 2022 May 17 12:08 PM - SCPSC - ND-2022-4-E - Page 15 of 32

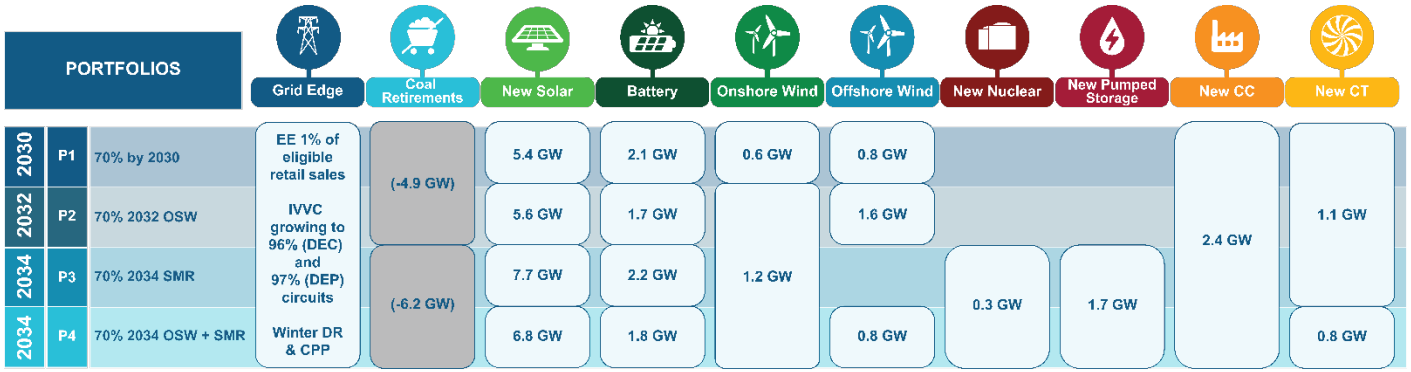
first new nuclear unit (285 MW SMR), deployed in 2032, to contribute toward achieving the 70% interim target. Portfolio 3 extends the timeframe for achieving the 70% interim target relative to P1 and P2, allowing additional time for deployment of solar, wind, battery, pumped storage hydro and grid edge resources to contribute to meeting the interim target. Portfolio 3 plans for the same coal unit retirement schedule as Portfolios 1 and 2, except for Roxboro Units 3-4 (1,409 MW) which are retired by 2034 in this portfolio.

- **Portfolio 4: "70% by 2034 OSW+SMR" –** Portfolio 4 deploys both offshore wind and new nuclear resources to achieve the 70% interim target by 2034. To meet this target, 285 MW (one unit) of nuclear SMR and 800 MW (one 800 MW block) of offshore wind are added in the early 2030s. The extended timeframe allows for greater contributions from grid edge resources, as well as additional time to build out required solar, onshore wind, battery and pumped storage hydro capacity. Portfolio 4 plans for the same coal unit retirement schedule as Portfolios 1 and 2, except for Roxboro Units 3-4 (1,409 MW) which are retired by 2034 in this Portfolio.

The following figures below present two distinct "snapshots" at two different points in time of the projected future resource mix under each of the four portfolios: Figure 6 provides a snapshot of the projected resource mix additions in the year in which 70% CO_2 emissions reductions are achieved (which varies across the four portfolios as discussed above) and Figure 7 provides a snapshot of the projected resource mix in 2035. By comparing and contrasting the portfolios, these figures, along with Table 1, illustrate how different mixes of resource types influence the pace and cost of the Companies' Carolinas' energy transition that supports ongoing reliable and affordable service while enabling future economic development in the Carolinas.

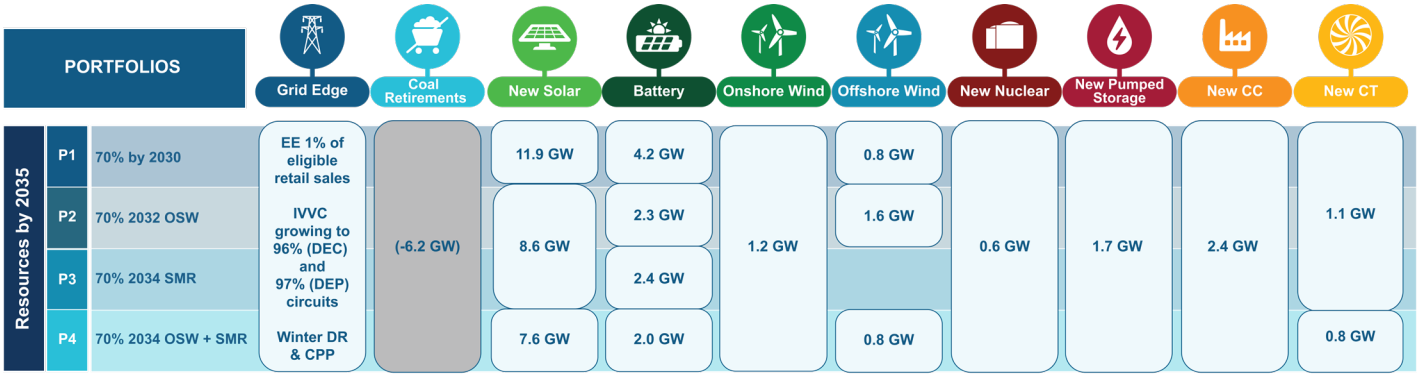
ACCEPTED FOR PROCESSING - 2022 May 17 12:08 PM - SCPSC - ND-2022-4-E - Page 16 of 32

Figure 6: 70% Portfolio Snapshot at the Time of Achievement of Interim 70% Target (date of achievement varies across portfolios)



Note 1: Gray blocks denote coal retirements, which are dependent on addition of resources shown.
Note 2: Remaining coal planned to be retired by year end 2035.
Note 3: New Solar includes solar + storage, excludes projects related to pre-existing programs such as HB 589 and Green Source Advantage.
Note 4: Capacities as of beginning of the target year of 70% reduction.
Note 5: IVVC = Integrated Volt/Var Control.
Note 6: CPP = Critical Peak Pricing.
Note 7: Battery includes batteries paired with solar.

Figure 7: Portfolio Snapshot in 2035



Note 1: Gray blocks denote coal retirements, which are dependent on addition of resources shown.
Note 2: Remaining coal planned to be retired by year end 2035.
Note 3: New Solar includes solar + storage, excludes projects related to pre-existing programs such as HB 589 and Green Source Advantage.
Note 4: Capacities as of beginning of 2035.
Note 5: IVVC = Integrated Volt/Var Control.
Note 6: CPP = Critical Peak Pricing.
Note 7: Battery includes batteries paired with solar.

ACCEPTED FOR PROCESSING - 2022 May 17 12:08 PM - SCPSC - ND-2022-4-E - Page 17 of 32

As explained above, the Companies assessed each of the portfolios against four core Carbon Plan objectives - CO_2 reduction, affordability, reliability and executability. A summary of the results of the evaluation is provided in Table 1 below. As part of the evaluation, the Companies assessed the risk to achieving 70% CO_2 reduction by target year of each portfolio based on the complexity of execution associated with each portfolio in light of the technologies utilized and, importantly, the pace of deployment. The more a portfolio relies on technologies new to the Carolinas and the more substantial the pace and scale of deployment and dependence on constrained supply chains, the higher the risk of achieving 70% CO_2 reductions by the target year. The appendices for each resource type provide further background regarding such considerations. As shown in Table 1, portfolios with a more rapid progression toward 70% CO_2 reduction are projected to have greater impacts on customer costs. Further details regarding the core Carbon Plan objectives and the related quantitative analysis are provided in Chapter 3 (Portfolios).

ACCEPTED FOR PROCESSING - 2022 May 17 12:08 PM - SCPSC - ND-2022-4-E - Page 18 of 32

Table 1: DEC/DEP Combined System Portfolio Results Table

CARBON PLAN PORTFOLIOS	P1		P2		P3		P4	
RESOURCES [MW] START OF YEAR (2030 | 2035)								
Total Contribution from Grid Edge & Customer Programs[1]	3,486	4,230	3,486	4,230	3,486	4,230	3,486	4,230
Total System Solar[2, 3]	12,307	18,829	10,432	15,604	10,657	15,604	10,357	14,554
Incremental System Solar (excludes projects in development)[2]	5,400	11,850	3,525	8,625	3,750	8,625	3,450	7,575
Incremental Onshore Wind[2]	600	1,200	600	1,200	600	1,200	600	1,200
Incremental Offshore Wind[2]	800	800	800	1,600	0	0	0	800
Incremental SMR Capacity[2]	0	570	0	570	0	570	0	570
Incremental Energy Storage[2, 4]	2,067	5,671	1,092	3,815	1,030	3,852	917	3,477
Incremental Gas (CC)[2, 5]	2,430	2,430	2,430	2,430	2,430	2,430	2,430	2,430
Incremental Gas (CT)[2, 5]	1,128	1,128	0	1,128	0	1,128	0	752
Remaining Dual Fuel Coal Capacity[2, 6]	4,387	3,069	4,387	3,069	4,387	3,069	4,387	3,069
Early Coal Retirements	*Subcritical by 2030; MSS 3&4 in 2032*		*Subcritical by 2030 except Rox 3&4 in 2031; MSS 3&4 in 2032*		*Subcritical by 2030 except Rox 3&4 in 2033; MSS 3&4 in 2032*		*Subcritical by 2030 except Rox 3&4 in 2033; MSS 3&4 in 2032*	
Total Coal Retirements [MW] by End of 2035	8,445		8,445		8,445		8,445	
COST & AFFORDABILITY (2030 | 2035)								
Average Monthly Residential Bill Impact for a Household Using 1000kWh (DEP) [$/month]	$35	$45	$29	$45	$19	$31	$18	$34
Average Monthly Residential Bill Impact for a Household Using 1000kWh (DEC) [$/month]	$8	$33	$5	$30	$7	$29	$5	$28
Present Value Revenue Requirement (PVRR) through 2050 (DEP/DEC Combined System) [$B]	$101		$99		$95		$96	
PVRR through 2050 (DEP) [$B]	$42		$42		$38		$39	
PVRR through 2050 (DEC) [$B]	$59		$56		$57		$56	
CO_2 EMISSIONS IMPACT (2030 | 2035)								
NC CO_2 Reduction[8]	71%	80%	66%	77%	65%	74%	64%	74%
System CO_2 Reduction[9]	70%	78%	65%	76%	63%	72%	63%	72%
Year in which 70% NC CO_2 Reduction Achieved	2030		2032		2034		2034	
RELIABILITY & FLEXIBILITY (2030 | 2035)								
95th Percentile Expected Net Load Ramp [MW/hr][9]	6,604	10,803	5,341	8,621	5,506	8,656	5,296	7,922
Average CC Starts per Unit per Year	53	99	35	77	34	75	29	67
EXECUTABILITY								
Annual Solar Additions Reached to Achieve 70% (MW/yr | vs. Historical Maximum)[2, 10]	1,800	2.4X	1,350	1.8X	1,350	1.8X	1,350	1.8X
Cumulative Additions of New-to-the-Carolinas Resource Types [MW] (2030 | 2035)[2, 11]	3,140	6,480	2,170	5,380	1,270	3,820	1,150	4,210
Overall Level of Risk to Achieving 70% CO_2 Reduction by Target Year								

1. Contribution of UEE/DR (including Integrated Volt-Var Control (IVVC), Critical Peak Pricing (CPP) and Peak Time Rebate (PTR)) in 2030/2035 to peak winter planning hour.
2. Nameplate capacity.
3. Total solar nameplate capacity includes 1,453 MW in DEC and 3,561 MW in DEP projected in service by January 1, 2023.
4. Includes 4-hr and 6-hr grid-tied battery energy storage, battery energy storage at solar-plus-storage sites and pumped storage hydro.
5. New natural gas facilities will be capable of burning carbon-free hydrogen in the future; hydrogen blending assumed to begin in 2035.
6. Remaining coal units are capable of co-firing on natural gas.
7. Combined North Carolina-specific DEC/DEP System CO_2 Reductions from 2005 baseline.
8. Combined DEC/DEP System CO_2 Reductions from 2005 baseline.
9. Average of 95th percentile day across 40 weather years. Net load ramp = hourly change in load net of renewable generation as indicator of fleet flexibility challenges.
10. Annual solar additions represent annual amount [MW] required beginning in 2028 to reach 70%; maximum annual total DEP/DEC solar additions to date have been 750 MW.
11. New-to-the-Carolinas includes onshore wind, offshore wind, battery energy storage, and SMR

ACCEPTED FOR PROCESSING - 2022 May 17 12:08 PM - SCPSC - ND-2022-4-E - Page 19 of 32

Planning for Coal Retirements

Under the oversight of the Commission and the PSCSC, the Companies have already made substantial progress in executing a planned, orderly emissions reduction trajectory over the past 11 years. Indeed, analyzing the need for and timing of coal-fired generating unit retirements are core components of the resource planning process, as evidenced by the retirement of 34 coal units totaling 4,200 MW since 2010. Orderly, planned retirement of such significant capacity resources across all portfolios mitigates fuel security and operational risks for customers and contributes significantly to CO_2 emissions reductions. The Companies' remaining coal units continue to provide year-round dispatchability that is especially critical during high load winter conditions and must be replaced by equally reliable resources.

The Companies utilized the enhanced modeling capability offered by EnCompass's capacity expansion model to perform coal unit retirement analysis within the Portfolio Development step.[27] As shown in Table 2 below, the projected coal unit retirement dates are substantially identical across all four portfolios, with the exception of Roxboro Units 3 and 4, with retirement of those units effective 2028 in P1, 2032 in P2 and 2034 in P3 and P4.

In all portfolios, the remaining coal-capable units that continue to operate beyond these planned retirement dates will be dual-fuel units operating primarily on lower-carbon natural gas. In all Portfolios, by the end of 2035, over 8,400 MW of coal capacity, representing approximately 20% of the winter capacity requirement for the combined system, would retire. Importantly, the timing of actual retirements will ultimately be driven by the ability to place in service the necessary replacement resources and access to fuel supply. Decisive action is needed to achieve those outcomes as further described in the Execution Plan. By the end of 2035, and in order to maintain system reliability during peak periods, the only remaining unit would be Cliffside Unit 6, which would operate through the remainder of its economic life (through 2048) fueled by low-carbon natural gas. Table 2 summarizes the projected coal retirement dates across all four portfolios.

Table 2: Projected Coal Unit Retirements (effective by January 1 of year shown)

Unit[1]	Utility	Winter Capacity (MW)	Effective Year (Jan 1)
Allen 1[2]	**DEC**	167	2024
Allen 5[2]	**DEC**	259	2024
Belews Creek 1	**DEC**	1,110	2036
Belews Creek 2	**DEC**	1,110	2036
Cliffside 5	**DEC**	546	2026
Marshall 1	**DEC**	380	2029
Marshall 2	**DEC**	380	2029
Marshall 3	**DEC**	658	2033

[27] Appendix E (Quantitative Analysis) includes a detailed description of endogenous coal retirement analysis.

ACCEPTED FOR PROCESSING - 2022 May 17 12:08 PM - SCPSC - ND-2022-4-E - Page 20 of 32

Unit[1]	Utility	Winter Capacity (MW)	Effective Year (Jan 1)
Marshall 4	**DEC**	660	2033
Mayo 1	**DEP**	713	2029
Roxboro 1	**DEP**	380	2029
Roxboro 2	**DEP**	673	2029
Roxboro 3	**DEP**	698	2028-2034[3]
Roxboro 4	**DEP**	711	2028-2034[3]

[1]Cliffside 6 is assumed to cease coal operations by the beginning of 2036 and was not included in the Carbon Plan's Coal Retirement Analysis because the unit is capable of operating 100% on natural gas.
[2]Allen 1 & 5 retirements are planned by 2024 and were not re-optimized in the Carbon Plan's Coal Retirement Analysis.
[3]Retirement year for Roxboro units 3 and 4 vary by portfolio, with retirement of those units effective 2028 in P1, 2032 in P2 and 2034 in P3 and P4.

Although the current coal units provide valuable capacity to maintain reliability through winter weather events, coal generation is a progressively small contributor to system energy needs and the average age of the Companies' remaining coal assets is now nearly 50 years. Operational risks of continued coal operation will only increase over time as these older units are called upon to run even more infrequently. In addition, coal supply chains continue to deteriorate, further increasing risk of continued coal operations for customers.[28] HB 951 recognized the importance of coal retirements to meet CO_2 emissions reductions targets by including provisions to facilitate securitization of subcritical coal assets that are retired early.[29] As the Companies continue the transition to cleaner energy sources, Duke Energy will engage and assist communities that experience adverse economic effects from fossil fuel plant closures, as well as consider locating replacement generation within those communities when feasible.

Grid Investments and Operational Flexibility Key to Energy Transition

Grid investments and operational flexibility are critically important to both the pace and the reliability of the energy transition. The Companies and stakeholders agree on the importance of timely and prudent transmission and distribution investments in both the near term and long term to enable the interconnection of an unprecedented amount of solar, storage and wind resources. Grid investments required for coal retirements and the additions of other new resources such as nuclear, flexible natural gas and energy storage are also critical to support grid stability. Additionally, efficient system operation optimizes costs for customers and creates operational flexibility to strengthen reliability consistent with the least cost and reliability provisions of HB 951.[30]

With respect to the transmission investments, the Companies are evaluating all potential options to leverage transmission planning to meet the Plan targets, including through the potential for proactive

[28] *See id.* for additional information on coal fuel supply.

[29] HB 951, Section 5.

[30] *Id.* Section 1.

ACCEPTED FOR PROCESSING - 2022 May 17 12:08 PM - SCPSC - ND-2022-4-E - Page 21 of 32

transmission investments.[31] As identified in Chapter 4 (Execution Plan) and further discussed in Appendix P (Transmission Planning and Grid Transformation), the Companies are already engaging through the North Carolina Transmission Planning Collaborative ("NCTPC") to advance consideration of transmission projects in the near term that have been identified as needed to facilitate more solar interconnections and achieve targeted carbon reductions in a least cost manner while maintaining reliability. In addition, the Companies are exploring options for accelerating interconnection construction timelines.[32]

With respect to the distribution grid, the Companies are developing and implementing necessary changes to the distribution system to improve resiliency and to allow for dynamic power flows associated with evolving customer trends such as increased adoption of rooftop solar, electric vehicle charging, home battery systems and other innovative customer programs and rate designs. Distribution grid control enhancement investments are foundational across all portfolios, improving flexibility to accommodate increasing levels of distribution-connected renewable resources while developing a more sustainable and efficient grid. The Companies continue to develop ISOP tools and processes to identify and prioritize future grid investment opportunities that can combine benefits of non-traditional solutions such as energy storage, innovative rate designs and customer programs to minimize total costs across distribution, transmission and generation.[33]

Finally, the grid operates as a holistic, interconnected system and various factors can cause rippling effects to grid operations as the resource mix changes and the system relies on higher levels of weather-dependent intermittent resources. Having flexibility through system operations and availability of fast-responding dispatchable resources is necessary to maintain all federally mandated NERC reliability standards and to maximize fuel and resource cost-effectiveness for customers. To that end, the Companies are pursuing consolidating DEC and DEP system operations to build upon the reliability and fuel efficiency benefits of the existing JDA.[34] Customers in North Carolina and South Carolina will benefit from flexibility, production cost savings, and simplification through a consolidated DEC and DEP system operations function. As discussed previously, the retirement of substantial coal units and integration of unprecedented amounts of intermittent renewables will require new flexible natural gas resources to balance the system during this energy transition,[35] a need underscored by NERC leadership.[36] The combination of consolidating system operations and implementing flexible dispatchable resources simultaneously manages costs and ensures reliability for customers.

---

[31] *See* Appendix P (Transmission System Planning and Grid Transformation) for additional information.

[32] *See* Appendix I (Solar) for additional information.

[33] *See* Appendix S (Integrated System and Operations Planning) for additional information.

[34] *See* Appendix R (Consolidated System Operations) for additional information.

[35] *See* Appendix Q (Reliability and Operational Resilience Considerations) and Appendix M (Natural Gas) for additional information.

[36] James B. Robb & Mark Lauby, *3-D Grid Transformation: Mitigating the Risks,* Pub. Utils. Fortnightly, at 5 *available at* https://www.fortnightly.com/3-d-grid-transformation-mitigating-risks ("We must invest to maintain (and improve) the natural gas system's ability to meet the balancing and synchronization needed to assure reliability of the power sector").

ACCEPTED FOR PROCESSING - 2022 May 17 12:08 PM - SCPSC - ND-2022-4-E - Page 22 of 32

Customer Financial Impacts

The Companies are committed to the continued provision of affordable electricity for residents, businesses, industries, and communities in the Carolinas. Seeking the appropriate pace of technology adoption to achieve CO_2 emissions reductions targets requires careful balancing of a variety of factors, including affordability. Throughout the Carbon Plan stakeholder process, stakeholders consistently reinforced the importance of mitigating cost impacts on customers and communities. While the Plan forecasts incremental system revenue requirements and system residential bill impact differences associated with each of the Plan portfolios, the projected cost impacts will change over time with evolving market conditions and policy mandates. Cost and bill impacts presented are associated with incremental resource retirements and additions identified in the Plan and as such do not include potential efficiencies, offsets, or costs in other parts of the business. Factors such as changing cost of capital, inflation, and changes in other costs will also influence future energy costs and will be incorporated in future Plan updates and forecasts as market conditions evolve. Finally, future cost of service allocators and rate design will impact how these costs are spread among the customer classes and, therefore, ultimate customer bill impacts.

The Companies have identified several additional strategies to manage costs during the energy transition. The Companies' Execution Plan outlined in Chapter 4 (Execution Plan) ensures the use of competitive procurements and other practices to ensure that the most cost-effective solutions are identified for the benefit of customers. This diligence includes market exploration to determine availability of cost-effective generating facilities and other resources for purchase and for third-party engineering, procurement, and construction efficiencies for both turnkey projects and component activities of projects. The Companies will pursue Infrastructure Investment and Jobs Act ("IIJA") opportunities to seek funding alternatives to benefit customers where feasible.[37] On a related note, the Low Income and Affordability Collaborative[38] has undertaken important work to address affordability of electric service for low-income customers. Finally, the EE/DSM Collaborative continues to seek cost-effective programs to reduce energy usage and modify load, resulting in customer and system savings.

When developing the portfolios, the Companies applied least cost planning principles to achieve CO_2 reductions within specified constraints that reflect the availability and maturity of new resources. All portfolios utilize the most economic coal unit retirement date assumption, rather than relying on the depreciable lives of the coal units. The variation in timing of retirements and pace of new resource additions results in variations in incremental costs and customer bill impacts as shown in Figure 8 below. More specifically, due to the accelerated timeline for achievement of the interim target, Portfolio

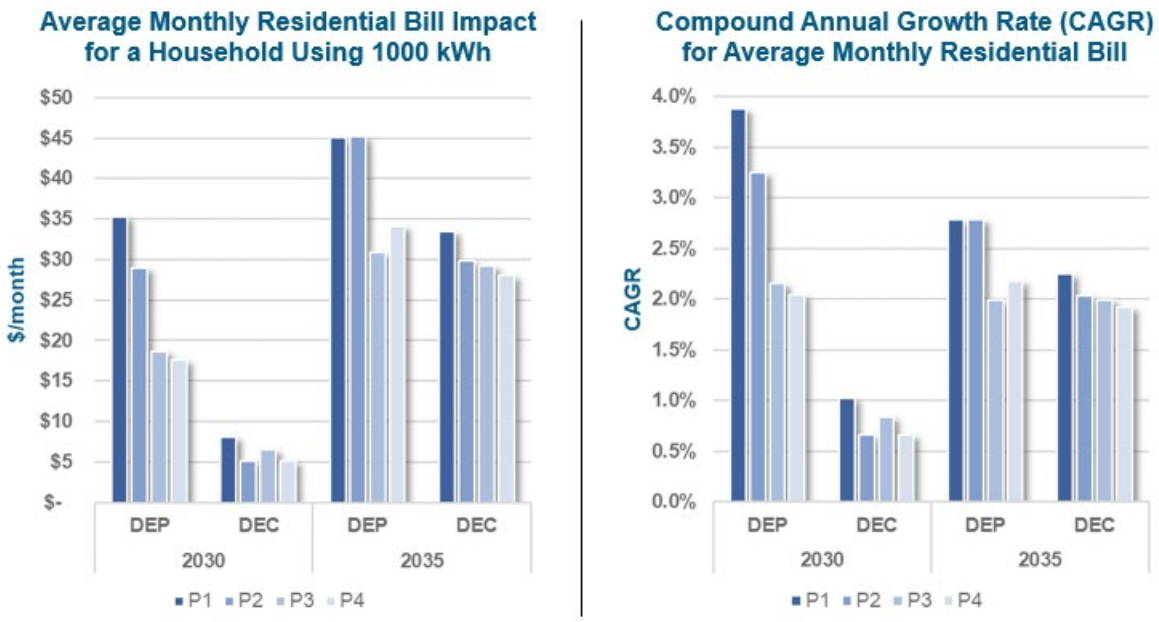
[37] *See Comments of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC*, Docket No. M-100, Sub 164 (March 15, 2022) and *Reply Comments of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC*, Docket No. M-100, Sub 164 (April 14, 2022) (explaining Companies' plans to identify opportunities to use IIJA-related funds to offset customer costs).

[38] *Order Accepting Stipulations, Granting Partial Rate Increase and Requiring Customer Notice,* Docket Nos. E-2, Sub 1219 & Sub 1193 (April 16, 2021); *Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice,* Docket Nos. E-7, Sub 1213, Sub 1214, and Sub 1187 (March 31, 2021).

ACCEPTED FOR PROCESSING - 2022 May 17 12:08 PM - SCPSC - ND-2022-4-E - Page 23 of 32

1 has the most substantial bill impact by 2030. By 2035, the bill impact differences between P1 and P2 narrow but P3 and P4 continue to have a smaller bill impact relative to P1 and P2.

Figure 8: Intermediate-Term Residential Bill Impact by Portfolio



The Companies recognize the potential for further rate disparity across DEC and DEP, principally driven by optimal location of new generation and transmission investments required to meet CO_2 reduction targets. As discussed in Appendix R (Consolidated System Operations), the Companies will continue to evaluate potential solutions for the rate disparities, including whether a full merger of the DEC and DEP utilities is in the best long-term interests of our customers.

New Carbon Plan Execution Planning Framework

The Execution Plan in Chapter 4 (Execution Plan) provides a detailed summary of the steps the Companies will take, as well as key enablers needed to deliver Plan results. In addition, the Execution Plan identifies key "signposts" the Companies will monitor during execution to navigate Plan uncertainty.

The Execution Plan represents an evolution from the short-term action plan framework presented in past IRPs to a more detailed and comprehensive assessment of near-term actions, intermediate-term actions and long-term planning, with associated risk and signpost monitoring. Near-term actions are those activities in the 2022-2024 time frame needed to advance the Plan components across all portfolios and involves an all-of-the-above approach involving Grid Edge initiatives to shrink the challenge, optimizing existing assets (including through the continued, disciplined pursuit of Subsequent License Renewals ("SLR") for the Companies' existing nuclear fleet, which is a

ACCEPTED FOR PROCESSING - 2022 May 17 12:08 PM - SCPSC - ND-2022-4-E - Page 24 of 32

foundational need for the energy transition), pursuit of consolidated system operations and development and procurement activities for new supply-side resources.

With respect to supply-side resource, Table 3 below summarizes the near-term procurement and development activities proposed by the Companies for approval, which are prudent and orderly steps that support optionality beneficial to all portfolios.

ACCEPTED FOR PROCESSING - 2022 May 17 12:08 PM - SCPSC - ND-2022-4-E - Page 25 of 32

Table 3: Supply-Side Resources Requiring Actions in Near-Term

Resource	Amount	Proposed Near-Term Actions
Proposed Resource Selections: In-Service through 2029		
Carbon Plan Solar	3,100 MW	• Begin Public Policy Transmission projects in 2022[6] • Procure 3,100 MW of new solar 2022-2024 with targeted in service in 2026-2028, of which a portion is assumed to include paired storage
Battery Storage	1,600 MW	• Conduct development and begin procurement activities for 1,000 MW stand-alone storage and procure 600 MW storage paired with solar
Onshore Wind	600 MW	• Engage wind development community in preparation for procurement activities • Procure 600 MW in 2023-2024
New CT[1]	800 MW	• Submit CPCN for 2 CTs totaling 800 MW in 2023
New CC[2]	1,200 MW	• Submit first CPCN for 1,200 MW in 2023 • Evaluate options for additional gas generation pending determination of gas availability
Proposed Resource Development: Options for 70% Interim Target		
Offshore Wind[3]	800 MW	• Secure lease • Initiate development and permitting activities for 800 MW[7] • Conduct interconnection study • Initiate preliminary routing, right-of-way acquisition for transmission
New Nuclear[4]	570 MW	• Begin new nuclear early site permit ("ESP") for one site • Begin development activities for the first of two SMR units
Pumped Storage Hydro[5]	1,700 MW	• Conduct feasibility study for 1,700 MW • Develop EPC strategy • Continued development of FERC Application for Bad Creek relicensing

Note 1: CPCN for two CTs (800 MW) estimated for in-service 2027-2028
Note 2: CPCN for one CC (1,200 MW) estimated for in-service 2027-2028, CPCN for second CC (1,200 MW) will be evaluated for submittal in 2024 with estimated in-service 2030 as fuel supply is determined.
Note 3: Retaining optionality through early development activities, in-service date assumption dependent upon portfolio.
Note 4: New nuclear capacity represents first two SMR units, planned in-service date through 2034.
Note 5: Pumped storage hydro capacity represents second powerhouse at Bad Creek, planned in-service 2033.
Note 6: Projects subject to North Carolina Transmission Planning Collaborative ("NCTPC") approval.
Note 7: Federal regulations require the lessee to submit in the preliminary term of 12 months: (i) a Site Assessment Plan ("SAP"); or ii) a combined SAP and Commercial Operation Plan.

ACCEPTED FOR PROCESSING - 2022 May 17 12:08 PM - SCPSC - ND-2022-4-E - Page 26 of 32

As shown in Table 3 above and detailed further in Chapter 4 (Execution Plan), the Companies propose to implement substantial procurement and development activities for new supply-side resources in the near-term (2022-2024). These activities include the targeted procurement of 3,100 MW of solar to be in-service 2026-2028 (660 MW of which is assumed to include paired storage), along with the commencement of necessary transmission projects (pending NCTPC approval). The Companies will also seek to procure 600 MW of onshore wind and initiate development activities for 1,000 MW of batteries. With respect to natural gas, the Companies will need to begin developing 800 MW of CTs (two units at single site) and 1,200 MW of CCs (one unit) during the near term, which will also require subsequent CPCN proceedings projected to occur prior to the next biennial Carbon Plan update. In this respect, the Companies' near-term Execution Plan recognizes the importance of siting new natural gas at the Companies' retiring coal unit sites and also recognizes that prudent and least-cost development of new natural gas resources will be informed by future accessibility of Appalachian gas and provides a flexible path and pivot point by 2024 if firm transportation is not obtained. The Companies believe that it is appropriate for these resources to be deemed selected at this time for purposes of HB 951, Section 1.(2), in all cases subject to the obligation to obtain a CPCN (where applicable) and to keep the Commission apprised of material changes in assumed pricing or schedule.

In all cases, the Companies will leverage its procurement expertise to drive down costs for customers, in part, by identifying optimal resource locations in North Carolina or South Carolina. This procurement process will also ensure alignment between the costs assumed for modeling purposes and the actual prices delivered by the market and will provide substantial opportunities to "check and adjust" procurement activities as more refined and updated information is gathered and through further engagement with the Commission and the PSCSC in CPCN proceedings and other regulatory processes and updates.

Finally, the near-term activities include substantial development work on three longer lead time resources - offshore wind, SMR and new pumped storage hydro - all of which are likely to be needed either to achieve the interim 70% CO_2 emissions reductions target or carbon neutrality over the longer term. Such development work is needed both to gather information to provide a more refined cost estimate to the Commission in the 2024 Carbon Plan update, as well as to be positioned to implement such resources on a timeline consistent with the portfolios. As is explained in more detail in Chapter 4 (Execution Plan) and the applicable appendices, if the Companies do not undertake development activities in the near term for these long lead-time resources, such resources will not be available on the timelines contemplated by the portfolios. Finally, the Companies believe that it is reasonable for the Commission to approve these development activities as reasonable steps under the Carbon Plan, as well as the related accounting requests, for the reasons more fully described in Chapter 4 (Execution Plan). The Companies are not at this time requesting selection of these resources for purposes of HB 951, Section 1.(2), since such selection would be premature at this time before the Companies have detailed proposals with more defined cost estimates, projected construction timelines, *etc*. The Commission will be able to more fully consider the potential selection of these resources in future regulatory proceedings (such as the 2024 biennial Carbon Plan update) in which the Commission can consider in more detail the specific resource proposal and all related issues (*e.g.,* necessary cost recovery mechanisms).

ACCEPTED FOR PROCESSING - 2022 May 17 12:08 PM - SCPSC - ND-2022-4-E - Page 27 of 32

Intermediate-term actions reflect activities in the planning period beyond 2022 to 2024 to achieve the interim 70% CO_2 emissions reductions target. For this planning period, the Companies present an intermediate-level of detail on business planning and regulatory execution strategy. Finally, long-term actions refer to those planning activities that support the 2050 carbon neutrality target. In this long-term planning period, the Plan presents a very high-level business planning and regulatory execution strategy, with long-term signpost monitoring.

Developing an Executable Plan to Advance the Energy Transition

The Companies' proposed Carbon Plan provides for the Commission a critical snapshot in time of four options for continuing the energy transition in the Carolinas, including further substantial progress in CO_2 emissions reductions that are consistent with prudent utility planning and the targets established under HB 951.

As described in more detail in Chapter 2 (Methodology and Key Assumptions) and Appendix G (Grid Edge and Customer Programs), the Companies' Carbon Plan modeling assumes nation-leading amounts of EE and DSM (targeting 4,230 MW of contribution by 2035 in all scenarios). These higher levels of EE and other demand-side options are not supported by current evaluation frameworks. Achieving the aggressive level of demand-side program growth assumed in the Carbon Plan will require changes to current cost/benefit processes to reflect their value on par with the cost of carbon-free supply-side alternatives such as wind, solar paired with storage or SMRs. To this end, after the conclusion of this proceeding, the Companies will proceed to propose appropriate changes to the derivation of utility system benefits as defined in the Companies' approved EE/DSM Cost Recovery Mechanism. These processes must necessarily follow this initial development of the Carbon Plan, but, once again for the sake of clarity, this Carbon Plan rests upon an assumption of substantial growth of EE/DSM.

As the Commission and intervenors consider this Carbon Plan, a number of key "lenses" should be applied:

- First, it is important to understand the difference in the purpose and intent of long-term planning versus plan execution. Long-term planning is, by nature, dependent on numerous modeling inputs and assumptions about future conditions that are based on a "snapshot in time" at the time the plan is developed. Based on the Companies' experience with prior IRPs, there will undoubtedly be some amount of disagreement from intervenors regarding certain key assumptions utilized in the Companies' modeling, though the Companies have sought to the greatest extent possible through the stakeholder process and past IRPs and Commission decisions to narrow the range of disputes. However, while that long-term view is crucial, Carbon Plan implementation will be equally (if not more so) guided by the real-world execution activities, which the Companies have described in Chapter 4 (Execution Plan). It may not be necessary for the Commission to resolve each and every dispute concerning modeling assumptions, when the outcome of such disputes do not fundamentally alter the activities needed in the near term.

ACCEPTED FOR PROCESSING - 2022 May 17 12:08 PM - SCPSC - ND-2022-4-E - Page 28 of 32

- Second and relatedly, it is important to consider how the Carbon Plan will develop over time through the iterative process contemplated by HB 951 and through the coordinated input of the PSCSC. This initial Carbon Plan proceeding is certainly a crucial first step in the continued energy transition. But it is obviously not the final step. The next two-year period following the Commission's decision in this proceeding will offer substantially greater clarity and precision regarding a range of issues that will significantly impact the longer-term trajectory of the Carbon Plan. A crucial near-term post-2022 factor will be the PSCSC's review of the Carbon Plan in the 2023 IRP, which will provide important direction for further development of the Carbon Plan for the Companies' combined Carolinas systems. In addition, there is a wide range of other crucial information that will be gathered between now and the 2024 biennial Carbon Plan update as the Companies begin to execute the Carbon Plan. That information includes, but is not limited to, more refined cost estimates and timelines for technologies new to the Carolinas, the availability of pipeline capacity to source gas supply from Appalachia, more clarity on the longer-term state of supply chain challenges, more detailed market information gathered from procurement activities, and better estimates on timelines for long lead time grid transmission upgrades. In addition, numerous follow-on regulatory processes will be required prior to the next Carbon Plan biennial proceeding, including numerous CPCN proceedings for resources selected by the Commission in its initial plan and docketed proceedings regarding EE/DSM and customer programs. Such CPCN proceedings and other regulatory processes will provide ample opportunities for the Commission to assess more detailed market information, refined cost estimates and updated schedules to ensure alignment with the approved Carbon Plan trajectory. And future EE/DSM and customer program dockets will provide opportunities to build on the Carbon Plan through implementation of customer-facing programs and initiatives.

- Third, it is important to consider the execution plan over both the intermediate horizon and the long-term horizon contemplated by HB 951. While there are some important distinctions regarding pace in the various portfolios on the trajectory toward 70% CO_2 emissions reductions, those differences substantially diminish by 2035 and effectively disappear over the longer-term trajectory toward carbon neutrality in 2050. Stated differently, there will likely be some differences of perspective in this proceeding regarding the pace of implementation and technology focus in the short term; but, over the longer term, the energy transition undoubtedly will require a diversified all-of-the-above strategy including new and emerging technologies. Therefore, the near-term Execution Plan reflects a disciplined pursuit of a range of solutions, including near-term procurements and development of longer-lead time resources, some of which are new to the Carolinas resources (Onshore and Offshore Wind and SMR) and others of which are not (pumped hydro expansion). All such long-lead time resources (and more) will potentially ultimately be needed on the pathway to 2050 and therefore initial development work in the near term is beneficial in all future scenarios.

In summary, the near-term supply-side activities and enabling transmission represent the "reasonable steps" that are proposed by the Companies to continue the energy transition through 2024, at which point the Commission will have a further opportunity to "check and adjust" the strategy with the benefit of substantial additional and more refined information. As explained above and further throughout this

ACCEPTED FOR PROCESSING - 2022 May 17 12:08 PM - SCPSC - ND-2022-4-E - Page 29 of 32

Plan, execution will be critical both with respect to the ability to achieve timelines assumed in the modeling but also with respect to providing the Commission a more refined Plan in the future. Over the next few years, timelines and costs assumed in the modeling will either be validated or challenged by the real-world execution path and such information will be used to refine strategies and improve benefits for customers.

To be clear, the near-term supply-side activities proposed by the Companies are meaningful and varied and will leverage all available demand- and supply-side resources to accelerate the energy transition. The Companies are proposing definitive next steps with respect to the procurement of solar, batteries, onshore wind, and transmission upgrades. The Companies are also proposing for Commission approval definitive but preliminary steps with respect to the development of CTs, CCs, offshore wind, nuclear and pumped hydro - in all of those cases, the Commission will have further opportunity to review and assess such resources either through subsequent regulatory processes (*i.e.,* a CPCN proceeding) or the next biennial Carbon Plan process.

The Companies request that the Commission approve the Companies' proposed Carbon Plan in its entirety, which includes both a defined set of near-term procurement and development activities and four primary portfolios that allow for flexibility over time, instead of approving a single portfolio which would be premature at this time before more information is gathered regarding the longer-lead time supply side resources. Stated differently, the Companies believe that the Commission should approve the proposed near-term activities and further affirm that the Companies' Carbon Plan modeling across all portfolios is reasonable for planning purposes and presents a reasonable plan for achieving HB 951's authorized CO_2 emissions reductions targets in a manner consistent with HB 951's requirements and prudent utility planning. At the time the 2024 Carbon Plan update is filed, the Companies will have more refined information that the Commission can consider in updating the Carbon Plan and making further key decisions regarding resource selections with respect to both the interim and long-term targets.

Achievement of the energy transition, particularly over the long term, will likely require breakthrough technologies, as is contemplated by HB 951. The Companies are engaged throughout the industry in monitoring and assessing potential breakthrough technologies that have the greatest potential for benefit to customers. Ultimately, it may be prudent for the Commission to approve and the Companies to pursue one or more such breakthrough technologies in order to facilitate and even hasten industry and technology evolution. Such initiatives could be particularly beneficial where the Companies are able to leverage partnerships and external funding for the benefit of customers and gain experience in real-world operation on a small scale before large-scale deployment. The Companies are currently evaluating a number of such opportunities involving long-duration storage and hydrogen production, storage, transportation and generation.

Going forward, the Companies will remain laser focused on both reliability and affordability. Specifically, as the Companies gather more information and increasing amounts of new resources are added to the system, the Companies will continually reassess whether the existing reliability of the system is being maintained or improved as is required under HB 951. The projected retirement timelines for existing coal units will remain inextricably linked to the timeline for completion of

ACCEPTED FOR PROCESSING - 2022 May 17 12:08 PM - SCPSC - ND-2022-4-E - Page 30 of 32

replacement resources needed to ensure reliability - delays in the completion of replacements will necessarily cause the Companies to readjust schedules as needed to ensure reliability. Similarly, the strategy over time will be adjusted to the extent that cost impacts over time materially diverge from projected impacts.

Closing and Summary of Requests to Commission

The Plan proposed herein 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. Duke Energy looks forward to continued engagement and collaboration regarding the Plan in this proceeding with Public Staff and intervenors and to further engagement with regulators and stakeholders in the future as the Plan evolves.

The Companies request that the Commission adopt the Companies' proposed Plan and make the following specific findings:

- Affirm that the Companies' Carbon Plan modeling is reasonable for planning purposes and presents a reasonable plan for achieving HB 951's authorized CO_2 emissions reductions targets in a manner consistent with HB 951's requirements and prudent utility planning;
- Approve the near-term supply-side development and procurement activities identified above in Table 3, including by
    - Deeming the following resources as being selected in this initial Carbon Plan for purposes of HB 951, Section 1.(2), in all cases subject to the obligation to obtain a CPCN (where applicable) and to keep the Commission apprised of material changes in assumed pricing or schedule:
        - 3,100 MW of solar generation (including 750 MW requested to be procured through the 2022 Solar Procurement Program), of which a substantial portion is assumed to include paired storage;
        - 1,600 MW of battery storage (1,000 MW stand-alone storage, 600 MW storage paired with solar);
        - 600 MW of onshore wind;
        - 800 MW of CTs; and
        - 1,200 MW of CC
    - Approving the Companies' plans to pursue initial development activities to support the future availability of offshore wind, SMRs and new pumped storage hydro at Bad Creek

ACCEPTED FOR PROCESSING - 2022 May 17 12:08 PM - SCPSC - ND-2022-4-E - Page 31 of 32

to ensure that these resources are available options for the Companies' customers on the timelines identified the portfolios if selected in future Carbon Plan updates;

- Making the following additional determinations with respect to the project development activities summarized in Table 3:
    - Engaging in initial project development activities for these resources is a reasonable and prudent step in executing the Carbon Plan to enable potential selection of these generating facilities in the future;
    - To the extent not already authorized under applicable accounting rules, that the Companies are authorized to defer associated project development costs for recovery in a future rate case (including a return on the unamortized balance at the applicable Companies then authorized, net-of-tax, weighted average cost of capital), subject to the Commission's review of the reasonableness and prudence of specific costs incurred in such future proceeding; and
    - That in the event the long lead time resources are ultimately determined not to be necessary to achieve the energy transition and the CO_2 emission reduction targets of HB 951, such project development costs will be recoverable through base rates over a period of time to be determined by the Commission at the appropriate time.

- Approve the Companies' proposed actions with respect to existing supply-side resources, including through expanding flexibility of the existing gas fleet and continued disciplined pursuit of SLRs for the Companies' existing nuclear fleet;
- Approve the Companies' plans to advance Grid Edge and Customer Programs and to update the underlying the determination of the utility system benefits in the Companies' approved EE/DSM Cost Recovery Mechanism;
- Acknowledge that HB 951 establishes new public policy goals requiring new generation and other resources that will necessarily inform the Companies' transmission system planning processes as outlined in the Open Access Transmission Tariff and direct the Companies to continue to study future transmission needs to reliably implement the Carbon Plan through the North Carolina Transmission Planning Collaborative and other appropriate forums;
- Approve the Companies methodologies outlined in Appendix A (Carbon Baseline and Accounting) for tracking achievement of HB 951's CO_2 emissions reductions targets and confirm the Commission's accounting requirements for emissions from new out-of-state resources selected by the Commission (if any) as described above;

- Affirm that the first biennial Carbon Plan update proceeding should be held in 2024 and that the Companies' next biennial IRPs will be held in abeyance to 2024 to align with the Carbon Plan update, as further discussed in Chapter 4 (Execution Plan); and

- Direct the Companies and Public Staff to develop and propose for comment by January 31, 2023, revisions to the Commission's IRP Rule R8-60 and related rules for certificating new generating facilities to support execution of the Carbon Plan.

ACCEPTED FOR PROCESSING - 2022 May 17 12:08 PM - SCPSC - ND-2022-4-E - Page 32 of 32