2023 Carolinas Resource Plan

DUKE ENERGY®

BUILDING A SMARTER ENERGY FUTURE®

Docket No. E-100, Sub 190

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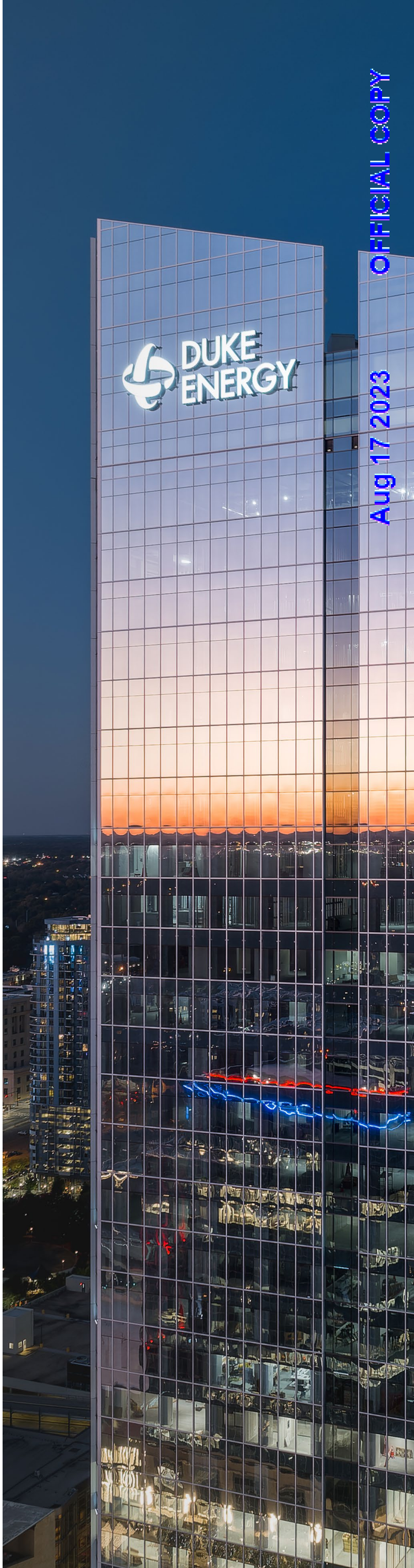
Executive Summary

For over a century, Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and together with DEC, "Duke Energy" or the "Companies") have proudly served residential customers, communities, and commercial, industrial and governmental enterprises across North Carolina and South Carolina (collectively, the "Carolinas"). As public utility subsidiaries of Duke Energy Corporation, one of the largest investor-owned utilities in the country, the combined Companies own and operate approximately 35,000 megawatts ("MW") of diverse electric generating capacity in a 53,200 square-mile service territory.[1] The Companies' robust, diverse and increasingly clean electric systems serving 4.5 million retail customers[2] create a competitive advantage for the Carolinas, driving economic growth and investment. Building on a diverse, cost-competitive resource mix, reliable electric service from an increasingly clean and renewable-fueled energy supply, the Companies actively work with regional, state and local authorities to support economic development opportunities and long-term vitality. In 2022 alone, the Companies helped secure over $3.8 billion in capital investments and over 4,700 jobs to South Carolina and over $13 billion in capital investments and over 17,000 jobs to North Carolina.[3]

1 Appendix B (DEC and DEP System Information) provides detailed information about the DEC and DEP systems. DEC serves 2.8 million customers across a 24,000 square-mile service area in North Carolina and South Carolina. DEP serves 1.7 million customers across a 29,000 square-mile service area in North Carolina and South Carolina.

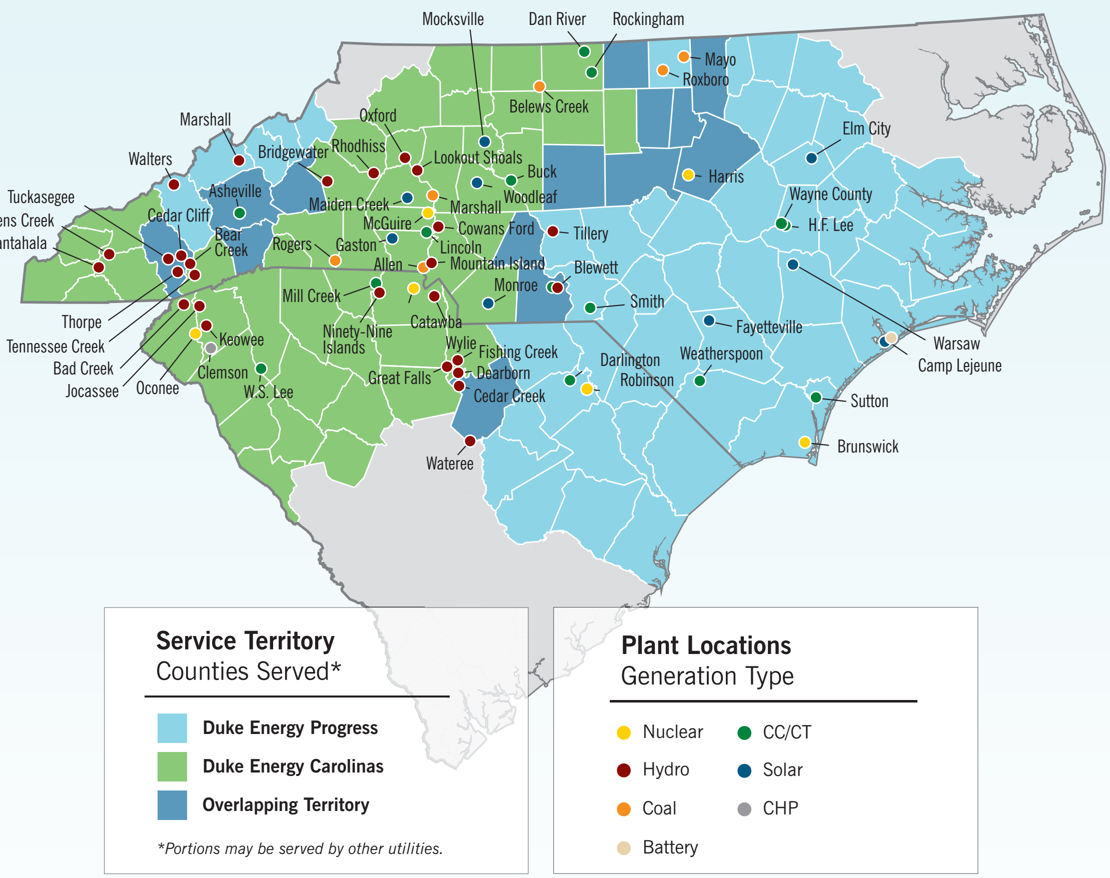
2 820,000 retail customers in SC and 3.66 million retail customers in NC.

3 Duke Energy 2022 Impact Report, available at https://p-cd.duke-energy.com/-/media/pdfs/our-company/esg/2022-impact-report.pdf.



The Companies each operate as dual-state utility systems serving customers across both states (illustrated in Figure 1) and are subject to regulatory oversight by both the North Carolina Utilities Commission ("NCUC") and the Public Service Commission of South Carolina ("PSCSC," and together with NCUC, the "Commissions"). As such, DEC and DEP are submitting this combined Carolinas Resource Plan (the "Plan" or "the Resource Plan") pursuant to the laws and orders of both North Carolina and South Carolina, and have developed a single, unified quantitative integrated resource planning analysis applicable to the dual-state systems.[4] The Plan also includes separate South Carolina and North Carolina Chapters that highlight and explain the ways in which the legal requirements and policy considerations of each state are satisfied by this filing, as well as other state-specific information.

Figure 1: DEC and DEP Utility Systems



4 Data depicted in this Executive Summary is for the combined DEC and DEP system. Planning information and data is separately provided for DEC and DEP in Chapter 3 (Portfolios) and/or Appendix C (Quantitative Analysis).

Plan Overview: Solutions for a Changing Energy Landscape

System-Wide Plan for the Carolinas

The Companies have delivered on efficiencies of the dual-state systems (shown in Figure 1) to benefit residents and businesses in both states by:

- Leveraging significant generation diversity and scale through strategic siting and joint dispatch of the generation fleets.
- Continuing strong nuclear and pumped storage hydro performance.
- Reducing environmental risks and mitigating fuel supply and price volatility by retiring coal units and integrating increasingly clean resources.
- Implementing dynamic dispatch and other advanced fuel management practices.
- Advancing customer programs, demand-side resource control capabilities and renewables as supported by customers and stakeholders.
- Planning and improving grid resilience and power supply reliability through additions and upgrades to the transmission system.

Strategic and constructive regulatory actions in both states, spanning decades, have facilitated the policy alignment necessary to prudently maintain and improve the large and diverse dual-state systems. The Companies' further investments in the dual-state systems under the oversight of both Commissions will continue to provide for an affordable and reliable electric supply, which, in turn, attracts substantial economic development and growth for both states.

Against this backdrop, today's energy landscape in the Carolinas and across the nation is in the midst of profound transformation as outlined in Chapter 1 (Planning for a Changing Energy Landscape). In this period of energy transition, the Companies must build upon the strength of the dual-state system to advance solutions, while prudently managing risks and uncertainties to ensure the Companies' electric systems continue to meet the resource adequacy and reliability needs of all Duke Energy customers in the Carolinas. In the last year, the Carolinas region specifically has experienced dramatic changes. Significant economic development wins have occurred across both states, new residential customers continue to migrate to the Carolinas, and the transition to electric transportation by residential and non-residential customers alike is accelerating. The Carolinas are experiencing significant growth and the Carolinas Resource Plan accounts for these recent, impactful developments as discussed in Appendix D (Electric Load Forecast).

The Carolinas Resource Plan is designed to reliably meet current and future customers' energy needs over the next 15 years, while also planning for the Companies' longer-term energy transition to achieve carbon neutrality by 2050. To meet customers' needs and navigate the complex and dynamic energy landscape of the future, the Plan presents three Energy Transition Pathways and a robust portfolio of sensitivity analyses to inform the pace and "all of the above" approach to prudently retiring as well as replacing 8,400 MW of coal-fired generating capacity — including repurposing sites where feasible — with equally reliable resources to meet customer needs of the future (see Chapter 2 (Methodology and Key Assumptions)). Based on detailed modeling and analysis designed to meet the planning objectives and requirements of both states, the Plan also presents detailed near-term actions consistent with a recommended portfolio that will be executed between now and 2026 on the most reasonable, least cost path to achieving an orderly transition of the Companies' generating fleets.

As supported in Chapter 3 (Portfolios), the Companies' recommended portfolio achieves 70% carbon-dioxide (CO_2) emissions reductions from 2005 levels by 2035[5] — and mitigates coal exposure risk as explained in Appendix F (Coal Retirement Analysis) — by retiring all coal-fired generation by that date and replacing this capacity with significant new solar, wind, battery energy storage, pumped storage hydro, hydrogen-capable natural gas resources, and nuclear small modular reactors ("SMRs"). The Plan also expands the Companies' energy efficiency and demand response options, which are the most successful in the region, to continue shrinking the challenges of the transition out of coal and offer customers tools to better manage their electric energy usage and bills. As detailed in Chapter 4 (Execution Plan), successful execution of the proposed near-term actions between now and 2026 and continued action to support the recommended portfolio will require prudent and intentional planning and timely regulatory approvals to meet growing customer needs, enable retirement of coal generation resources in an orderly manner and ensure reliability is maintained or improved for the Carolinas.

Planning Impacts of a Changing Energy Landscape

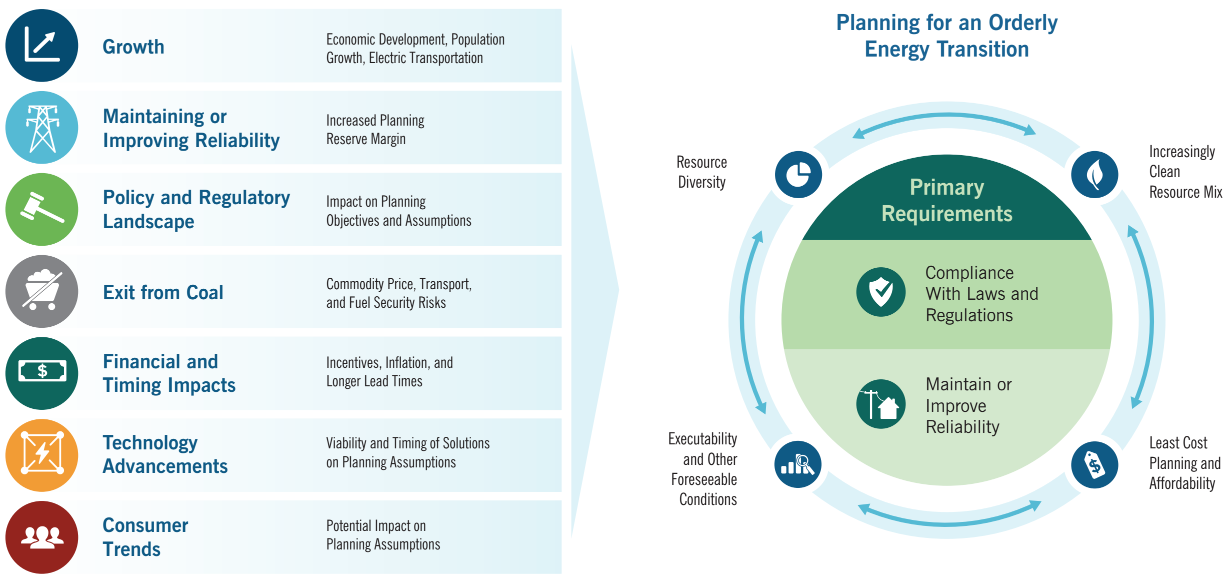
In the intervening months since the most recent resource plans were developed and decided in both North Carolina and South Carolina,[6] substantial changes to the energy landscape have introduced impacts to the Companies' resource plans, as shown in Figure 2 and described in Chapter 1. The Companies are experiencing significant new load growth stemming from favorable economic development, residential population growth across the Carolinas and the increasing adoption of electric vehicles ("EV") through initiatives and policies that are advancing transportation electrification. Additionally, evolving reliability imperatives including but not limited to lack of available market purchases and the need for higher reserve margins, particularly in extreme winter weather, are increasing capacity needs. At the same time growth and reliability needs are increasing, the Companies are planning for an orderly transition out of coal-fired generation to mitigate commodity price, transportation and fuel security risks related to ongoing industry exit from coal. Other changes in the energy landscape include the passage of significant federal legislation, including the Inflation Reduction Act of 2022 ("IRA") and the Infrastructure Investment and Jobs Act ("IIJA"), new proposed environmental regulations, and a dynamic macro-economic and inflationary environment impacting supply chain and resource costs. Finally, the viability and timing of technology advancements along with growth in customers' desire for more renewables and the ability to optimize energy usage, are informing planning assumptions, in addition to carefully balancing the operating characteristics of renewable energy and resources that are complementary to them.

As the energy landscape continues to change in significant ways, it is essential that the Companies balance a broader set of long-term resource planning objectives (shown in Figure 2) that advance solutions for a changing energy landscape, while prudently managing risks and uncertainties for an orderly transition of the Companies' electric systems to meet the reliability and affordability needs of customers and communities.

5 Carbon dioxide emissions reductions targets are defined for the Companies' North Carolina generating facilities.

6 Order Adopting Initial Carbon Plan and Providing Direction for Future Planning, NCUC Docket No. E-100, Sub 179 (Dec. 30, 2022); Order Accepting 2022 Integrated Resource Plan Updates, PSCSC Order No. 2023-189, Docket Nos. 2019-224-E, 2019-225-E, 2021-8-E and 2021-10-E (Mar. 22, 2023).

Figure 2: Changing Energy Landscape Shaping Resource Plan and Planning Objectives



Increased Planning Needs for the Carolinas

As introduced above, in the intervening months since the Commissions considered previous resource plan filings, the Carolinas have seen unprecedented growth in economic development, and Duke Energy has played a critical role in the successful recruitment of these highly competitive projects to the service area. These projects include large industrial projects, such as high-tech and power intensive manufacturing projects that require power supply reliability, affordability and sustainably-sourced power. For example, recent additions to the Carolinas service territory are companies such as Wolfspeed silicon carbide material manufacturing, VinFast and Toyota manufacturing plants in North Carolina and the AESC battery production plant as well as the expansion of the BMW manufacturing plants for EV production and battery assembly in South Carolina. The size, scale and speed of economic development projects have dramatically increased over the past two years. In addition to emerging EV-related manufacturing, the Carolinas are experiencing the ongoing growth in energy needs to support cloud-based and artificial intelligence computing services upon which many customers and businesses depend. In addition, the Plan reflects an acceleration in the projected adoption of EVs by both residential and commercial customers. Finally, the population of the Carolinas continues to increase which results in further upward pressure on energy demand. To illustrate the magnitude of the projected load growth, the Companies currently project that by 2038, the annual amount of energy consumed on its system will have increased by approximately 35,000 gigawatt hours ("GWh") compared to 2024, which is greater than the total amount of electric retail sales in the states Delaware, Maine and New

Hampshire combined.[7] More detailed information on the impacts of the Carolinas' growing economic development environment, increasing population and expanding EV adoption is found in Appendix D.

In summary, the combined effect of these developments and projected trends has resulted in a significant increase in the load forecast that drives material changes in the Companies' Plan relative to prior plans. Chapter 3 and Appendix C (Quantitative Analysis) also discuss the importance of high load sensitivity analysis provided in this plan and the need to closely monitor economic development activities leading into future resource plans to ensure energy infrastructure additions in the Carolinas keep pace with the needs of an expanding business environment in the Companies' dual-state service territories.

Maintaining or Improving Reliability

The Companies must ensure ongoing system reliability, compliance with state law and meeting mandatory North American Electric Reliability Corporation ("NERC") Reliability Standards during the ongoing energy transition consistent with prudent utility planning, as well as the expectations of the residents, businesses and industries served in the Companies' dual-state systems. As the Carolinas' energy needs increase due to factors previously discussed, resource adequacy to ensure reliability in all seasons, particularly in extreme cold, must keep pace. The Companies maintain a minimum physical reserve margin to ensure reliability during unexpected conditions related to extreme weather.

In the Carolinas, the Companies have long maintained the reliability of the grid by relying upon steady baseload nuclear generation plus dispatchable generation resources, such as coal, natural gas, and hydropower. As the nation's energy industry transitions out of coal, the Companies must preserve reliable electric utility service by ensuring that an adequate dispatchable capacity and energy supply are available prior to retiring coal units. When integrated across the grid with storage at scale, renewables, such as wind and solar, can provide additional grid reliability and serve to mitigate fuel cost volatility and reduce the Companies' reliance on fuel supply chains. However, given the seasonal, day-to-day, and week-to-week uncertainties in the availability of renewable energy, dispatchable generation resources remain critical for balancing the supply of electricity with the demand for electricity at all times. Dispatchable generation resources provide essential flexibility to the grid when renewable output is high and offer a necessary backup source of energy and capacity when renewable output is low. Thus, the combination of increases in electricity demand discussed above and the operational impacts from an increase in variable renewable generation necessitate additional dispatchable generation resources to meet the Carolinas' system requirements under all system conditions, as further discussed in Appendix M (Reliability and Operational Resilience).

Recognizing these critical considerations and based on the Companies' operational experience and resource-specific data, the 2023 Resource Adequacy Study[8] demonstrates the need for a 22% planning reserve margin for DEC and DEP on a combined basis. 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 recognizes that neighboring systems have shifted towards winter planning for ensuring resource adequacy and are also retiring dispatchable resources, making

7 US Electricity Profile 2021 – U.S. Energy Information Administration (EIA), available at https://www.eia.gov/electricity/state/.

8 See Attachment I (2023 Resource Adequacy Study for Duke Energy Carolinas & Duke Energy Progress) for details.

capacity during extreme winter weather increasingly constrained across the entire region. As with prior studies, this reserve margin increase assumes a combined view of the Companies, and a 22% reserve margin is consistent with peer operators across the region.

Executing an Orderly Energy Transition as the Industry Exits Coal

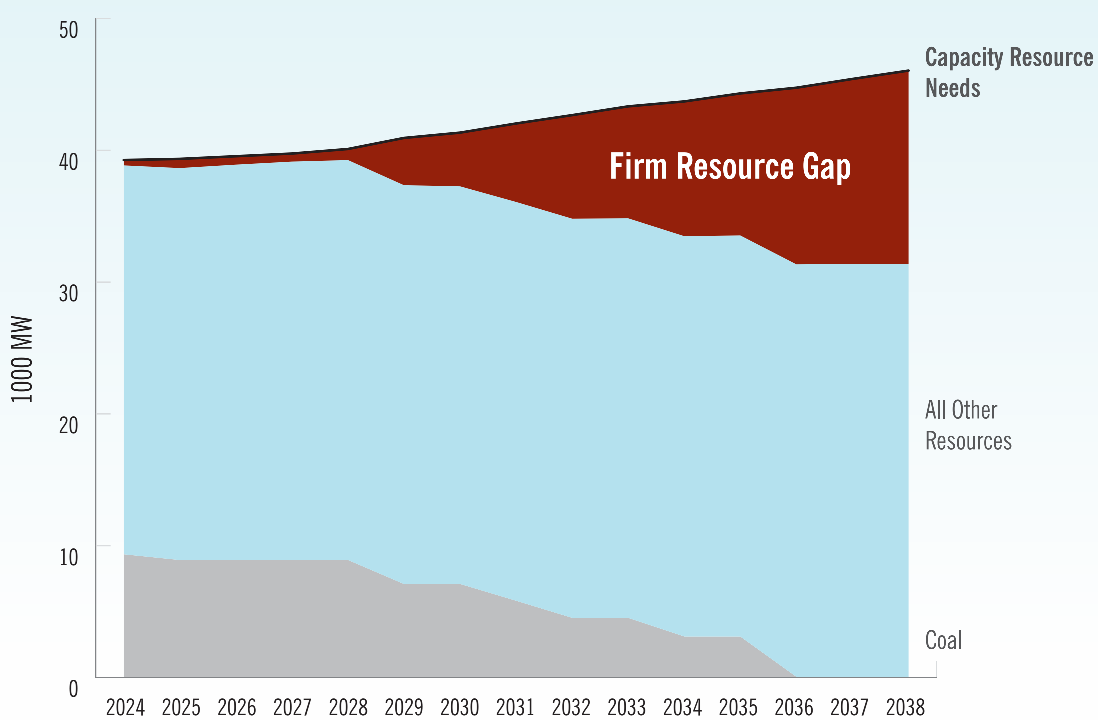
Coal-fired generation in the Carolinas has contributed to reliable and low-cost operations for decades, and the remaining coal resources on the system continue to provide critical, dispatchable power to ensure reliability today (particularly during extreme weather). However, as these units near the end of their planned operating lives, reliably operating and maintaining coal-fired generation resources is increasingly challenged by several risks and uncertainties as discussed in more detail in Chapter 1 and Appendix F. These internal and external challenges create future risks for coal supply assurance and ultimately increase reliability and affordability risks for customers.

The planning implications of the industry's exit from coal are that the Companies must set achievable target schedules for coal unit retirements that are contingent upon the commercial operation of new, equally reliable replacement resources prior to retirement — "replace before retire." Not only must replacement resources be equally or more reliable than the resources they replace, but they must also be diverse, operationally flexible and increasingly clean to meet emissions reductions targets and increasingly stringent environmental regulations.

The Magnitude of Energy Transition Challenge has Rapidly Increased

The cumulative impact of the changing energy landscape described above has resulted in a material

Figure 3: DEC and DEP Joint Winter Capacity Resource Needs



increase in aggregate capacity resource needs through this Base Planning Period[9] as compared to previous resource plans. Figure 3 shows the growing need for reliable winter capacity resources to meet winter peak demand inclusive of an appropriate reserve margin previously mentioned and detailed in the load forecast (Appendix D) and the 2023 Resource Adequacy Study. As depicted in Figure 3, over 15,000 MW of dependable winter capacity additions will be needed over the Base Planning Period to meet this growing customer demand, while also replacing retiring coal units with a diverse mix of equally reliable replacement resources.

The unprecedented magnitude of the required resource needs coupled with challenging and dynamic global supply-chains, evolving state and federal energy policies and regulations, as well as changing local, state and federal permitting and siting regulations will present significant challenges in this critical execution period of the energy transition (see Figure 8 further below). Furthermore, while the Plan outlines a specific set of forecasted resources over this planning horizon based upon general input assumptions and market conditions at the time the plan was developed, it will be important to maintain flexibility during execution, checking and adjusting to changing market conditions and project specific realities as new resources are being developed and brought into service. In addition to executing the Resource Plan, the Companies continually evaluate emerging opportunities to pursue prudent incremental supply-side and Grid Edge[10] projects that can meet growing customer needs while conforming with long-term planning objectives outlined in Chapter 2.

Reducing Demand and Optimizing Load Through Grid Edge and Customer Program Solutions

Critical to achieving the energy transition in a timely manner is the Companies' ability to reduce or optimize load through Grid Edge and customer programs, which include energy efficiency and demand-side management programs, new innovative rate designs, voltage control efforts, renewable energy programs, behind-the-meter generation and storage, and electric transportation programs. Collectively, these programs enable the Companies to "shrink the challenge" of meeting growing load in the Carolinas while maintaining affordability and reliability for customers. As discussed in more detail in Appendix H (Grid Edge and Customer Programs), the Companies offer several programs that assist customers in managing their electric energy usage, which adds value to the grid and helps reduce customers' electric energy bills. Energy efficiency programs in particular can help customers reduce their energy usage, thereby helping to reduce energy bills. Increasing interest from stakeholders in expanding these options — so that everyone can participate in the transition — has resulted in new programs being proposed and approved, and the Companies continue to engage with stakeholders to discuss further expansion of offerings that help customers save energy.

To plan for the important role that Grid Edge and customer program resources will play, and consistent with prior directives from the NCUC and PSCSC, the Companies have modeled low, base and high cases of energy efficiency savings and have integrated new demand-side management programs into their load forecasts. With the growing load attributable to transportation electrification, population growth and economic development, the implementation of

9 The Base Planning Period is the 15-year resource planning horizon, which meets North Carolina and South Carolina long-term planning requirements.

10 As further described in Appendix H (Grid Edge and Customer Programs), Grid Edge resources refer to technologies, programs and investments at the edge of the electricity network or grid, where the Companies' electricity reaches customers' homes and businesses. These technologies and resources can be used to manage parts of the electric system and reduce, shape or optimize energy loads.

the Companies' proposed Grid Edge enablers are designed to meet customer expectations for options to manage their bills effectively while also playing an important part in the energy transition that is vital to economic development in the Carolinas. Appendix H further describes Grid Edge programs and enablers, how transportation electrification will present challenges and new opportunities, and how recent federal legislation will assist with "shrinking the challenge" by incenting new energy efficiency investments.

Incorporating Federal Funds to Directly Benefit Customers

To reduce the cost impacts of the energy transition, the Companies are seeking to leverage funding resulting from major recent federal legislation. New investment grants and tax credits available for resources in the Plan will help ensure a more affordable energy transition. These funds directly benefit customers — they bring down the costs of projects and resources and those benefits are realized in customers' bills.

The passage of the IRA and IIJA provides a unique opportunity to capture historic time-bound production, tax, investment and programmatic incentives that directly benefit customers.[11] The IRA provides for extended clean energy production and investment tax credits that are aimed at assisting customers with the transition to clean energy, along with $67 billion in additional clean energy grants[12]. IRA clean energy production and tax credits for solar, wind, nuclear, pumped storage hydro and hydrogen are incorporated into Plan input assumptions, described in detail in Chapter 2. The Companies are also currently working with the pertinent state and federal agencies to define the scope of the opportunities, and they intend to guide customers on accessing funds that will drive down the costs of investing in energy efficient improvements. The IRA is also providing significant investment incentives for clean hydrogen production, and the IIJA allocated $8 billion for the United States Department of Energy ("DOE") to develop regional Hydrogen Hubs.[13] Duke Energy is one of five utilities participating in the Southeast Hydrogen Hub funding application. Additionally, the IIJA provides for $65 billion in transmission and grid investment and over $7 billion in EV charging investment.[14] The Companies are aggressively pursuing federal funds under the IIJA that support grid resilience, long duration energy storage and hydroelectric production incentives that could be used at the Bad Creek pumped hydro station in South Carolina.

Integrated Resource Planning Process

Stakeholder Engagement

Stakeholder engagement is central to how Duke Energy does business, and the Companies have facilitated or participated in engagements across a wide range of regulatory and technical matters. In developing this Carolinas Resource Plan, the Companies built on the collaborative engagement with stakeholders representing both South Carolina and North Carolina in support of the 2020

11 United States Congress: Infrastructure Investment and Jobs Act ("IIJA") became law in November 2021, Inflation Reduction Act of 2022 ("IRA") became law in August 2022.

12 The White House, Building a Clean Energy Economy: A Guidebook to the Inflation Reduction Act's Investments in Clean Energy and Climate Action, Version 2, January 2023, available at https://www.whitehouse.gov/wp-content/uploads/2022/12/Inflation-Reduction-Act-Guidebook.pdf.

13 See Appendix K (Natural Gas, Low-Carbon Fuels and Hydrogen) for more information on recent federal actions on natural gas and hydrogen.

14 The White House, Fact Sheet: The Bipartisan Infrastructure Deal, November 2021, available at https://www.whitehouse.gov/briefing-room/statements-releases/2021/11/06/fact-sheet-the-bipartisan-infrastructure-deal.

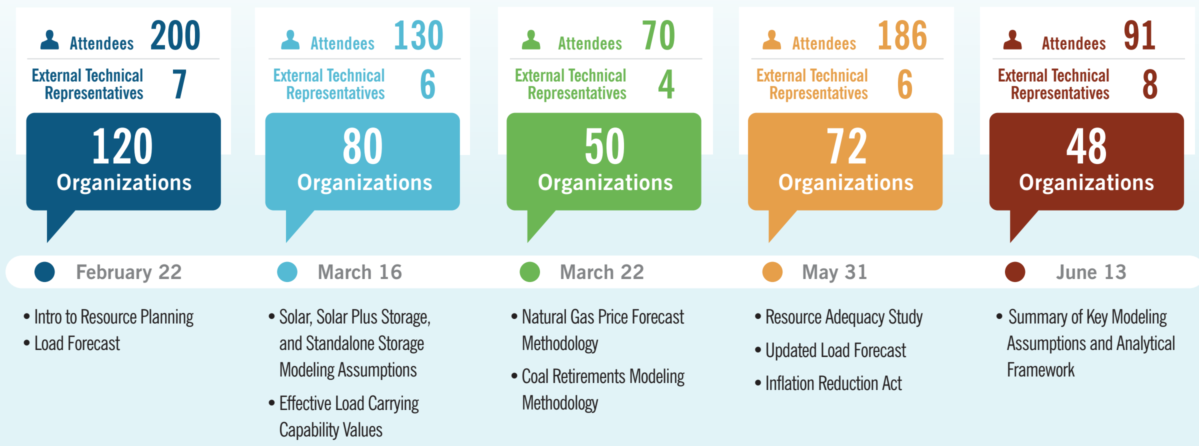


Figure 4: Technical Stakeholder Meetings, Topics, and Participation

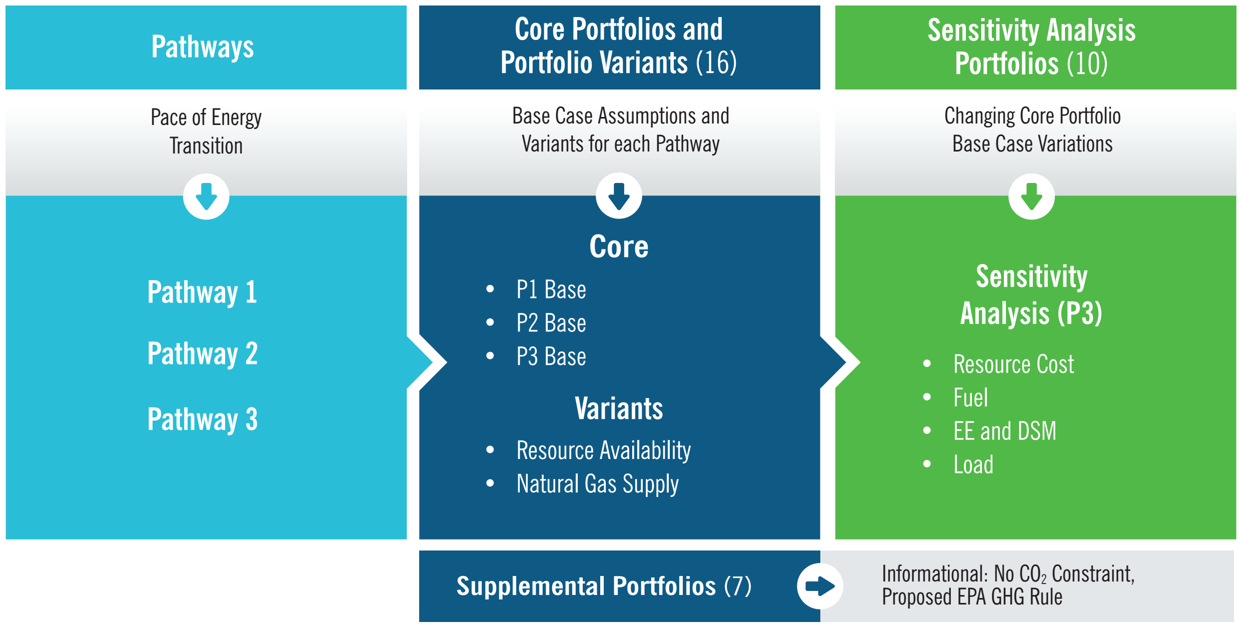
Integrated Resource Plan ("IRP") process and initial 2022 proposed Carbon Plan filed in North Carolina, particularly given the nature of the dual-state system. As the focus of this stakeholder engagement was to obtain feedback on the Companies' modeling assumptions and inputs, meetings were structured to ensure engaged discussion on a significant number of complex technical topics. To enhance the focus on these more technical aspects of the Resource Plan development process, stakeholders from varying backgrounds participated in topical meetings as Technical Representatives to ensure deeper and more informative discussion. In each of these sessions, the Technical Representatives presented their perspectives to a diverse group of attendees that included customers, environmental advocates, community leaders, renewable energy developers and other industry representatives. The Companies also dedicated time in each meeting to address state-specific topics outside of the technical process.[15] Figure 4 shows the dates of the Technical Stakeholder Meetings, gives an overview of the topics discussed and provides detail on the number of stakeholders participating.

Modeling Approach to Achieving an Orderly Energy Transition

The Companies' modeling approach is designed to determine the most reasonable, least cost path to achieving an orderly energy transition that maintains or improves system reliability, prudently manages risks and uncertainties and ensures the Companies can meet the energy needs of customers over the Base Planning Period. To accomplish this objective, the Companies have developed three Energy Transition Planning Pathways to inform the pace of and optimal execution approach to the Carolinas' energy transition in the near-term on the path to achieving carbon neutrality by 2050 — Pathway 1 evaluates the resources needed to achieve 70% CO_2 emissions reductions from 2005 levels by 2030; Pathway 2 evaluates the resources needed to achieve 70% CO_2 emissions reductions from

15 The participation and/or input of stakeholders during these sessions does not imply, suggest, signify or in any way reflect their position or endorsement concerning the topics discussed during the stakeholder meetings. The structure of stakeholder meetings and vehicles for providing feedback to the Companies are discussed in more detail in Appendix A (Stakeholder Engagement).

Figure 5: Energy Transition Pathways and Portfolios Presented in the Plan



2005 levels by 2033; and Pathway 3 evaluates the resources needed to achieve 70% CO_2 emissions reductions from 2005 levels by 2035. Within these Energy Transition Pathways, the Companies have modeled three Core Portfolios (P1 Base, P2 Base and P3 Base) using base planning assumptions.

In addition to the three Core Portfolios, 13 additional Portfolio Variants as well as 10 Sensitivity Analysis Portfolios incorporated adjustments to key planning assumptions as shown in Figure 5. The Portfolio Variants were developed by changing one or more key inputs or assumptions and allowing the model to select a different mix of resources and provide an assessment of the risks and potential benefits that could be realized in the future as events unfold related to specific resource availability or natural gas supply. The Companies also created additional Sensitivity Analysis Portfolios derived from the P3 Base in which certain inputs or assumptions were changed beyond those used to create the Portfolio Variants to evaluate model sensitivities to changes in variables such as resource costs, load and levels of energy efficiency and demand-side contribution.

In total, the Companies have analyzed over 30 portfolios in developing the Plan, with a primary focus on developing the three Core Portfolios that rely upon base planning assumptions to develop resource plans under each Pathway. Based on detailed modeling analysis described in Chapter 2, Appendix C and Appendix F, the Companies have identified the most economic coal retirement schedule as well as the future resource mix under each of the Core Portfolios needed to reliably "replace before retiring" the Companies' coal units during the Base Planning Period through 2038.

Modeling Supplemental Portfolios

No Carbon Constraints

As required by the PSCSC,[16] the Companies modeled Supplemental Portfolios without CO_2 reduction constraints (Base Case and a Portfolio Variant). While the Companies performed a "No Carbon Constraints" modeling exercise, it is not a viable pathway as it does not comply with applicable laws and requirements and, therefore cannot be the most reasonable and prudent means of meeting the Companies' resource planning requirements. As such, these Supplemental Portfolios are included in Chapter 3 for informational purposes only.

Proposed Environmental Protection Agency Environmental Regulations

Near the conclusion of the stakeholder engagement period and finalization of modeling inputs, the U.S. Environmental Protection Agency ("EPA") issued proposed regulations under Section 111 of the Clean Air Act ("CAA"). The EPA CAA Section 111 Proposed Rule addresses greenhouse gas ("GHG") emissions from existing coal plants and from new and existing natural gas plants. The Companies recognize the significance and potential impacts of the EPA CAA Section 111 Proposed Rule, as well as the complex and lengthy period ahead as the proposed regulations are carefully considered. At the time of this filing, the Companies just recently submitted their comments on the EPA CAA Section 111 Proposed Rule to the EPA.[17]

At this time, the Companies did not include the proposed rules in base planning assumptions, as the EPA CAA Section 111 Proposed Rule is still being interpreted, clarified and commented on and may change prior to ultimate implementation. However, given the potential broad implications of this rule, the Companies did evaluate Supplemental Portfolios around these rules as proposed to help inform the Commissions, noting that these sensitivities have considerable uncertainty regarding future hydrogen production and infrastructure costs and timing (details in Chapter 3 and Appendix C). During Resource Plan proceedings with the Commissions, the Companies will monitor progress of these proposed regulations as they relate to long-term planning assumptions and communicate any relevant developments.

Integrated Resource Planning Results

Planning for Coal Unit Retirements

The Companies have already made substantial progress in executing a planned, orderly coal unit retirement strategy, as evidenced by the 35 coal units totaling 4,400 MW that have been retired from service since 2011. Today, the Companies' remaining 15 coal units are all located in North Carolina (while serving customers in both states), representing approximately 20% of the winter capacity requirement for the combined system, and have been in service for an average of 50 years. In response to directives by both the PSCSC and the NCUC to analyze the need for and timing of coal-fired generating unit retirements in this updated 2023 resource planning process, the Companies

16 Order No. 2023-189 at 7–8, Docket Nos. 2019-224-E, 2019-225-E, 2021-8-E and 2021-10-E (Mar. 22, 2023).

17 Comments of Duke Energy, EPA New Source Performance Standards For Greenhouse Gas Emissions From New, Modified, And Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines For Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; And Repeal Of The Affordable Clean Energy Rule, Docket ID No. EPA-HQ-OAR-2023-0072, 88 Fed. Reg. 33,240 (May 23, 2023), submitted on regulations.gov, Aug. 8, 2023.

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

		Capacity (MW)	Pathway 1	Pathway 2	Pathway 3
DEC	Allen 1 & 5[1]	426	2025	2025	2025
	Cliffside 5	546	2029	2031	2031
	Cliffside 6[2]	849	2049	2049	2049
	Marshall 1 & 2	760	2029	2029	2029
	Marshall 3 & 4	1,318	2034	2032	2032
	Belews Creek 1 & 2	2,220	2030	2036	2036
DEP	Mayo	713	2029	2031	2031
	Roxboro 1 & 2	1,053	2029	2029	2029
	Roxboro 3 & 4	1,409	2030	2033	2034

Note 1: Allen 1 & 5 retirements are planned by December 31, 2024. Retirements were not included in the Coal Retirement Analysis due to near term planned retirement dates.

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.

utilized the enhanced modeling capability offered by EnCompass' capacity expansion model to perform coal unit retirement analysis within the Portfolio Development step. Appendix C and Appendix F provide a detailed description of the coal retirement analysis.

As shown in Table 1, the Plan's projected coal unit retirement dates are substantially similar between Pathways 2 and 3, with only Roxboro 3 and 4 differing by one year between the two pathways. Pathway 1 reflects accelerated coal retirements for most units relative to Pathways 2 and 3 based on the significant incremental capacity that would need to be added to achieve Pathway 1's target emissions reduction date. Previous IRPs reflected the opportunity to accelerate certain unit retirement dates based on load forecast projections and projected capacity needs that are fundamentally different from the system's demands and resource needs that the Companies are planning for today. While the Companies are still planning for the orderly retirement and replacement of over 8,400 MW of coal capacity by the end of 2035, due to the changing energy landscape described above, more accelerated unit retirements have been re-evaluated based on the systems need for capacity until additional reliable replacement resources can come online. In order to leverage existing infrastructure to maintain system reliability through the transition of the fleet beyond the Base Planning Period, the only remaining coal unit after 2035 is Cliffside Unit 6, which is planned to cease burning coal and operate through the remainder of its useful life (to 2049) fueled by natural gas. Table 1 summarizes the projected coal retirement dates across all three pathways portfolios.

Importantly, 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 dispatchable and reliable resources. Therefore, 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 Chapter 4 and Appendix F. To plan for an orderly energy transition from coal-fired generation that ensures and improves upon reliability for customers, the projected retirement timelines for existing coal units will remain inextricably linked to the timeline for commercial operation dates of replacement resources needed to ensure reliability. Delays in the completion of equally reliable replacement resources will cause the Companies to revise the coal unit retirement schedules as needed to ensure reliability, while considering the significant fuel cost and reliability risks of a delayed exit from coal.

Outside of the IRP cases before the Commissions, the Companies will continue to engage with stakeholders throughout the process of planning and constructing new generation resources and other infrastructure that meets the needs of its customers and fulfills regulatory and legislative requirements. The Companies recognize the importance of multiple perspectives and are committed to ensuring that customers and local communities are engaged. As the Companies continue in the transition to cleaner energy sources, Duke Energy will continue to 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.

Planning to Meet Future Resources Needs and Pace of Energy Transition

Building on the modeling approach and coal retirement analysis discussed above, Figure 6 below presents "snapshots" at different points in time under each of the Energy Transition Pathways' Core Portfolios (P1 Base, P2 Base and P3 Base), illustrating model-selected resource additions through 2030, 2033, 2035 and 2038. By comparing the portfolios, these figures illustrate how different mixes of resource types influence the pace of the Companies' Carolinas' energy transition that supports ongoing reliable and affordable service while enabling future economic development and load growth in the Carolinas.

Pathways Align on Increased Need and Essential Energy Transition Elements

Given the increase in projected customer demand for energy, all Core Portfolios show an increase in overall resource needs relative to prior resource plans. All Core Portfolios leverage the Companies' existing system resources by further extending the lives of the 11 baseload nuclear plants, improving the flexibility of the existing natural gas fleet, and extending the license of Bad Creek and essentially doubling the capacity of the Bad Creek site ("Bad Creek II"). Additionally, included in each of the portfolios are identical forecasts for the impacts of Grid Edge programs, such as energy efficiency programs and new rate offerings that will help "shrink the challenge" of the energy transition by reducing energy and peak demand needs on the system while providing customers additional options to control their energy usage and bills. In addition to significantly expanding renewable capacity and extending the lives of existing nuclear units, all portfolios rely on adding breakthrough advanced nuclear SMRs as fundamental to the energy transition and baseload and dispatchable hydrogen-capable gas resources to provide capacity and to ensure power supply reliability for customers every hour of every day, through all types of weather. Offshore wind is not identified as needed under recommended Core Portfolio P3 Base through 2038; however, it is identified in several Pathway 3 Portfolio Variants and Sensitivity Analysis Portfolios by 2035, demonstrating that offshore wind could become a future potential option for Pathway 3 in the Base Planning Period.

Figure 6: Incremental Resource Additions for Core Portfolios by 2030, 2033, 2035, and 2038

<table>
<tr><th>By January 1 2030</th><th>Grid Edge</th><th>Coal Retirements</th><th>Solar</th><th>Battery</th><th>CT</th><th>CC</th><th>Onshore Wind</th><th>Pumped Storage Hydro</th><th>Advanced Nuclear</th><th>Offshore Wind</th></tr>
<tr><td>P1 Base</td><td>EE at least 1% of eligible retail sales</td><td>(-7.1 GW)</td><td>6.6 GW</td><td>5.1 GW</td><td>1.7 GW</td><td>2.7 GW</td><td>0.3 GW</td><td></td><td></td><td>1.6 GW</td></tr>
<tr><td>P2 Base</td><td>IVVC growing to 96% (DEC) & 97% (DEP) circuits</td><td rowspan="2">(-2.2 GW)</td><td rowspan="2">4.1 GW</td><td>0.9 GW</td><td rowspan="2">2.1 GW</td><td rowspan="2">1.4 GW</td><td></td><td></td><td></td><td></td></tr>
<tr><td>P3 Base</td><td>Winter DR & CPP</td><td>0.7 GW</td><td></td><td></td><td></td><td></td></tr>
</table>

<table>
<tr><th>By January 1 2033</th><th>Grid Edge</th><th>Coal Retirements</th><th>Solar</th><th>Battery</th><th>CT</th><th>CC</th><th>Onshore Wind</th><th>Pumped Storage Hydro</th><th>Advanced Nuclear</th><th>Offshore Wind</th></tr>
<tr><td>P1 Base</td><td>EE at least 1% of eligible retail sales</td><td>(-7.1 GW)</td><td>13.4 GW</td><td rowspan="2">6.1 GW</td><td>2.6 GW</td><td>2.7 GW</td><td>1.5 GW</td><td></td><td></td><td>2.4 GW</td></tr>
<tr><td>P2 Base</td><td>IVVC growing to 96% (DEC) & 97% (DEP) circuits</td><td>(-6.2 GW)</td><td rowspan="2">8.8 GW</td><td rowspan="2">2.1 GW</td><td rowspan="2">4.1 GW</td><td rowspan="2">1.2 GW</td><td></td><td></td><td>1.6 GW</td></tr>
<tr><td>P3 Base</td><td>Winter DR & CPP</td><td>(-4.8 GW)</td><td>3.4 GW</td><td></td><td></td><td></td></tr>
</table>

<table>
<tr><th>By January 1 2035</th><th>Grid Edge</th><th>Coal Retirements</th><th>Solar</th><th>Battery</th><th>CT</th><th>CC</th><th>Onshore Wind</th><th>Pumped Storage Hydro</th><th>Advanced Nuclear</th><th>Offshore Wind</th></tr>
<tr><td>P1 Base</td><td>EE at least 1% of eligible retail sales</td><td>(-8.4 GW)</td><td>14.9 GW</td><td>6.1 GW</td><td>2.6 GW</td><td>2.7 GW</td><td>2.3 GW</td><td rowspan="3">1.7 GW</td><td rowspan="3">0.6 GW</td><td>2.4 GW</td></tr>
<tr><td>P2 Base</td><td>IVVC growing to 96% (DEC) & 97% (DEP) circuits</td><td rowspan="2">(-6.2 GW)</td><td>11.8 GW</td><td>6.7 GW</td><td rowspan="2">2.1 GW</td><td rowspan="2">4.1 GW</td><td>1.7 GW</td><td>1.6 GW</td></tr>
<tr><td>P3 Base</td><td>Winter DR & CPP</td><td>11.9 GW</td><td>4.3 GW</td><td>2.1 GW</td><td>0-1.6 GW</td></tr>
</table>

<table>
<tr><th>By January 1 2038</th><th>Grid Edge</th><th>Coal Retirements</th><th>Solar</th><th>Battery</th><th>CT</th><th>CC</th><th>Onshore Wind</th><th>Pumped Storage Hydro</th><th>Advanced Nuclear</th><th>Offshore Wind</th></tr>
<tr><td>P1 Base</td><td>EE at least 1% of eligible retail sales</td><td rowspan="3">(-8.4 GW)</td><td>15.8 GW</td><td>6.1 GW</td><td>2.6 GW</td><td>2.7 GW</td><td>2.3 GW</td><td rowspan="3">1.7 GW</td><td>3.0 GW</td><td>2.4 GW</td></tr>
<tr><td>P2 Base</td><td>IVVC growing to 96% (DEC) & 97% (DEP) circuits</td><td>14.1 GW</td><td>7.0 GW</td><td>2.1 GW</td><td rowspan="2">4.1 GW</td><td>2.1 GW</td><td rowspan="2">2.4 GW</td><td>1.6 GW</td></tr>
<tr><td>P3 Base</td><td>Winter DR & CPP</td><td>14.6 GW</td><td>6.0 GW</td><td>3.0 GW</td><td>2.3 GW</td><td>0-1.6 GW</td></tr>
</table>

Note 1: Coal retirements are dependent on addition of resources shown.

Note 2: New Solar includes solar paired with storage, excludes projects currently in advanced development.

Note 3: IVVC = Integrated Volt/VAR Control.

Note 4: CPP = Critical Peak Pricing.

Note 5: Battery includes batteries paired with solar.

Note 6: Offshore wind was not selected in P3 Base in the Base Planning Period however may be an option depending on resource need and market conditions.

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.

Energy Transition Pace Through Next Decade is Key Pathway Differentiator

Each Pathway requires a different pace, scope and scale of near-term development activities across varying technologies to achieve plan objectives and meet new load growth and capacity needs. As the figures above show, P1 Base requires an unattainable level of resource additions and associated transmission capacity to be permitted, constructed and in service by 2030, including 1,600 MW of offshore wind, two new hydrogen-capable combined-cycle generators (2,720 MW), 6,600 MW of new solar (an average of 2,200 MW interconnected per year from 2027 to 2029 in addition to the 3,000 MW already in advanced development) and over 5,300 MW of new battery energy storage (including nearly 300 MW currently in advanced development). P2 Base represents very aggressive deployments of new resources, requiring 1,600 MW of offshore wind and associated transmission, and 6,300 MW of batteries (including projects in advanced development) to achieve 70% CO2 emissions reduction by 2033. P3 Base also includes an aggressive level of resource additions, but with lower execution risks and lower costs relative to P2 Base due to requiring 2,600 MW less batteries by 2033 and allowing time for lower cost clean resources to meet the energy needs that are supplied by offshore Wind in P2 Base. P3 Base represents an ambitious plan requiring approximately 25 to 30 major generation projects each year from 2030 to 2035, yet reasonably balances the pace of energy transition with the need to reliably and cost-effectively serve growing customer needs in the Carolinas, reaching 70% CO2 emissions reduction by 2035. P3 Base also represents PVRR savings of nearly $5 billion relative to P2 Base by 2050. Despite differences in pace, all Core Portfolios begin to converge by the end of the Base Planning Period and result in very similar energy and capacity mixes over the long-term through 2050.

Portfolio Evaluation

To determine the optimal timing and generation and resource mix that achieves the most reasonable, least cost energy transition path, the Companies have evaluated the Core Portfolios and PortfolioVariants against metrics related to long-term planning objectives that are grounded in the resource planning requirements of both South Carolina and North Carolina, as further discussed in Chapter 2. Table 2 summarizes the Core Portfolios in the context of these planning objectives with detailed analysis and results included in Chapter 3.

As highlighted in Table 2, the Companies have considered both the complexity of execution associated with each pathway in light of the technologies utilized and, importantly, the pace of technology deployment. The more substantial the pace and scale of deployment required for a Pathway, and the greater the dependence on constrained supply chains, the higher the execution risks are to meeting planned coal unit retirement dates and reliably progressing the energy transition to bring new capacity and energy resources online during the Base Planning Period. The appendices for each resource type provide further background regarding such executability risks and considerations.[18] Table 2 also highlights that pursuing a more rapid Energy Transition Pathway is projected to have greater impacts on customer costs. Further details regarding the core long-term planning objectives and the related quantitative analysis are provided in Chapter 3 and Appendix C.

18 See Appendix I (Renewables and Energy Storage), Appendix J (Nuclear) and Appendix K (Natural Gas, Low-Carbon Fuels, and Hydrogen) for additional information.

Table 2: Portfolio Results

CAROLINAS RESOURCE PLAN PORTFOLIOS	P1 Base		P2 Base		P3 Base	
DEC/DEP COMBINED SYSTEM RESOURCES [NAMEPLATE MW] START OF YEAR	**2033**	**2038**	**2033**	**2038**	**2033**	**2038**
Total Contribution from Grid Edge & Customer Programs[1]	2,087	2,536	2,087	2,536	2,087	2,536
Incremental System Solar (excl. ~3,000 MW of projects in dev.)	13,350	15,750	8,775	14,100	8,775	14,625
Incremental Onshore Wind	1,500	2,250	1,200	2,100	1,200	2,250
Incremental Offshore Wind	2,400	2,400	1,600	1,600	0	0
Incremental Advanced Nuclear Capacity	0	3,000	0	2,400	0	2,400
Incremental Energy Storage[2]	6,374	8,054	6,314	8,894	3,694	7,954
Incremental Gas (CC)[3]	2,720	2,720	4,080	4,080	4,080	4,080
Incremental Gas (CT)[3]	2,550	2,550	2,125	2,125	2,125	2,975
Remaining Coal Capacity[4]	2,162	0	3,064	0	4,473	0
Total Coal Retirements [MW] by End of 2035[4]	**8,445**		**8,445**		**8,445**	
PORTFOLIO COST (2033/2038)	**2033**	**2038**	**2033**	**2038**	**2033**	**2038**
Average Monthly Residential Bill Impact for a Household Using 1000kWh (DEP/DEC Combined System) [$/month] 2033 | 2038[5]	$60	$70	$48	$56	$35	$55
Average Monthly Residential Bill Impact for a Household Using 1000kWh (DEP) [$/month] 2033 | 2038[5]	$86	$77	$72	$63	$41	$48
Average Monthly Residential Bill Impact for a Household Using 1000kWh (DEC) [$/month] 2033 | 2038[5]	$41	$65	$32	$51	$30	$59
	2038	**2050**	**2038**	**2050**	**2038**	**2050**
Present Value Revenue Requirement (PVRR) (DEP/DEC Combined System) through 2038 | 2050 [$B]	$76	$139	$69	$124	$66	$119
PVRR (DEP) [$B] through 2038 | 2050	$34	$62	$28	$53	$26	$48
PVRR (DEC) [$B] through 2038 | 2050	$42	$77	$40	$71	$40	$71
INCREASINGLY CLEAN RESOURCE MIX	**2033**	**2038**	**2033**	**2038**	**2033**	**2038**
CO2 Intensity (DEP/DEC Combined) [lbs/MWh]	217	131	267	163	313	182
Year in which 70% CO2 Reduction Achieved	**2030**		**2033**		**2035**	
RELIABILITY & FLEXIBILITY	**2033**	**2038**	**2033**	**2038**	**2033**	**2038**
95th Percentile Expected Net Load Ramp (MW/hr)	12,122	13,581	9,206	12,553	9,201	12,880
Average CC Starts per Unit per Year	86	90	39	64	60	81
ENERGY TRANSITION RISK ASSESSMENT	**2033**	**2038**	**2033**	**2038**	**2033**	**2038**
Cumulative Nameplate MW Additions of Resources with Limited Operational History in the Carolinas[6]	10,274	15,704	9,114	14,994	4,894	12,604
Cumulative Nameplate MW Additions, Combined Carolinas System[7]	31,907	39,737	27,107	38,312	22,887	37,297
Cumulative Nameplate MW Additions as % of Current Combined Carolinas System	73%	91%	62%	88%	53%	86%
Cumulative Capital Dollar Requirement, Combined Carolinas System [$B]	$85	$130	$59	$101	$44	$92
Overall Pathway Risk Related to Cost, Reliability, and Plan Execution						

Note 1: Includes winter peak impact of load modifiers (utility-sponsored energy efficiency, behind-the-meter solar, critical peak pricing), integrated Volt-VAR control (IVVC) and demand response programs.

Note 2: Includes stand-alone storage, paired storage, pumped storage hydro and forecast.

Note 3: New natural gas facilities will be capable of burning zero-carbon hydrogen in the future; hydrogen blending assumed to begin in 2035.

Note 4: Cliffside 6 continues to operate on 100% natural gas.

Note 5: Average retail rate impact across all customer classes applied to representative residential bill.

Note 6: Includes onshore wind, offshore wind, battery energy storage and advanced nuclear.

Note 7: Includes solar and battery projects currently in advanced development.

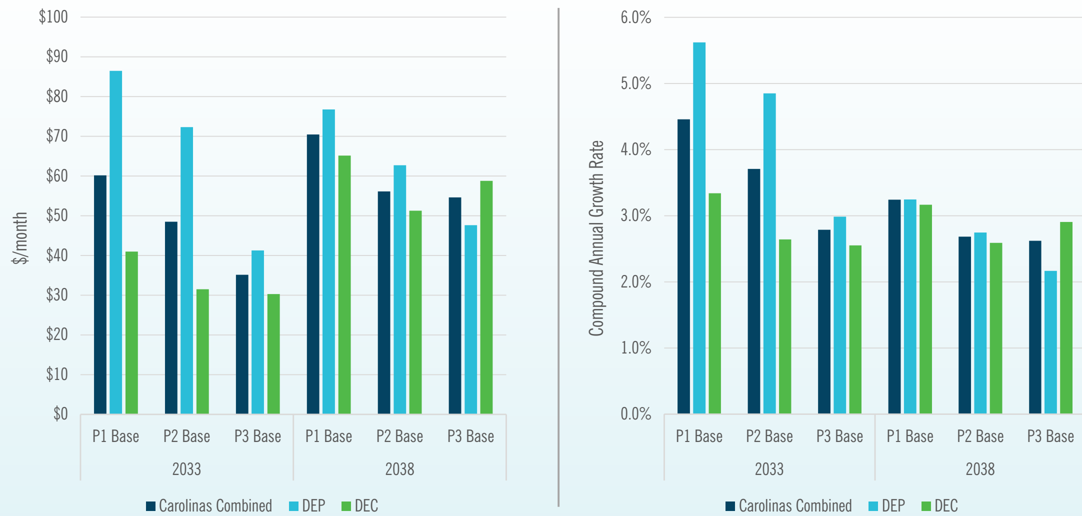
Customer Financial Impacts and Pace of Energy Transition

The Companies are committed to the continued provision of affordable and reliable electricity for residents, businesses, industries, and communities in the Carolinas. Prudently managing the appropriate pace of technology adoption during the energy transition requires careful balancing of a variety of factors, including affordability. In stakeholder engagement in connection with development of the Carolinas Resource Plan, a variety of stakeholders reinforced the importance of mitigating cost impacts on customers and communities. Consistent with past resource planning in both states, the Plan forecasts incremental system revenue requirements and system residential bill impact differences associated with each of the Core Portfolios as more fully discussed in Chapter 3. These analyses are based on the current snapshot in time of this 2023 planning cycle, and it is important to recognize that the projected cost impacts will change over time with evolving market conditions and regulatory policies. This analysis of Portfolio cost and bill impacts is associated with incremental resource retirements and additions identified in the Plan and as such does not include potential efficiencies, offsets, or costs in other parts of the business. Factors such as the 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 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' Plan strategically assesses how best to leverage IRA tax credits and other benefits for customers as described in Chapter 2, while the Companies continue to aggressively pursue IIJA funding opportunities to benefit customers where feasible. Finally, the Energy Efficiency/Demand Side Management Collaborative continues to seek cost-effective programs to reduce energy usage and modify load, resulting in customer and system savings.

In developing the Plan portfolios, the Companies applied least cost planning principles within specified constraints, including the availability and maturity of new resources to achieve varying paces of CO_2 reductions over the Base Planning Period. Each portfolio utilizes the results of the economic coal unit retirement analysis associated with each pathway's assumptions, rather than relying strictly 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 7. More specifically, due to the accelerated timeline, Core Portfolio 1 (which is unattainable as discussed above) has the most substantial bill impact by 2033. Portfolio 2 has an elevated bill impact compared to Portfolio 3 based on earlier emission reductions as a result of the integration of offshore wind in 2032 and 2033. By 2038, the bill impact differences between P2 and P3 narrow but P1 continues to have the most significant bill impact of the core portfolio pathways.

Figure 7: Residential Bill Impact by Portfolio in 2033 and 2038



Cost Mitigation Through Grid Edge Customer Programs and Federal Tax Incentives and Funding

Competitive rates and consumer affordability are critical for the continued vitality and growth of Carolinas. Particularly in this current inflationary environment, costs and affordability are top of mind for customers. As discussed earlier and as described in more detail in Appendix H, the Companies offer Grid Edge energy efficiency and demand-side management programs, as well as new rate designs to empower customers to better manage their energy usage and, in turn, their energy bills. The Plan includes important time-bound incentive opportunities from the IRA in the Plan inputs described in detail in Chapter 2. These IRA savings and rebate opportunities can, in some cases, be combined with utility incentives, maximizing the benefit to customers for energy efficiency investments as further described in Appendix H. Along with additional IIJA funding opportunities, these federal funds directly benefit customers and help offset upward pressure on resource costs due to inflation and supply chain challenges.

Cost Mitigation Through Potential Merger of Duke Energy Carolinas and Duke Energy Progress

In addition to leveraging Grid Edge programs and federal funding to support operations and offset the cost impacts of the energy transition, the Companies have launched a costs/benefits study to evaluate merging DEC and DEP into one operating utility company. While analyses are still preliminary, the Companies believe there are aggregate benefits to customers through a merger and operating as one utility would harmonize future resource costs of this critical energy transition across DEC and DEP as the Resource Plan is implemented. The Companies have projected January 2027 for potential merger completion,[19] pending stakeholder activities and necessary regulatory approvals. This Resource Plan continues to assume two separate utilities; future long-term planning assumptions will be appropriately aligned as a result of how the merger workstream progresses.

19 See example timeline for DEC and DEP merger in Chapter 4 (Execution Plan) Figure 4-4.

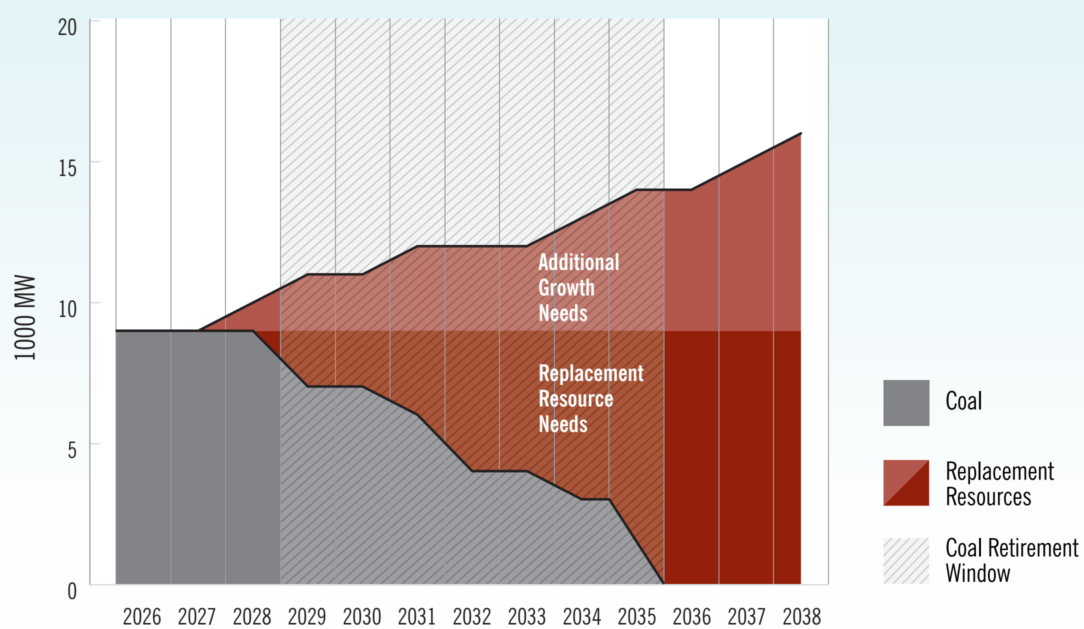
Developing an Executable Plan to Advance an Orderly Energy Transition for the Carolinas

As addressed in more detail in Chapter 4 and the South Carolina and North Carolina Chapters, the Companies are progressing through a critical execution period for their dual-state electric systems; the timing of the commercial operation of the diverse resources replacing coal generation over the next decade is essential to meeting the growing energy needs of customers while maintaining or improving reliability. As shown in Figure 3, over 15,000 MW of dependable winter capacity additions will be needed over the Base Planning Period. Figure 8 presents an alternative view of this need, delineating the impacts of retirement and project load growth on the overall needs.

In light of these immense needs, steady progress to advance the execution of the energy transition must be made in the current 2023–2026 planning period to ensure the Companies can continue meeting planning objectives and mitigate the risks of the changing energy landscape for customers. During this critical energy transition period, the Companies must advance a Carolinas Resource Plan that recognizes and confirms alignment of the policy goals and regulatory requirements of both jurisdictions in which they operate — to accomplish the most reasonable and prudent plan for South Carolina and to present all reasonable steps that the Companies plan to take under regulatory oversight to meet the carbon emission reduction goals and energy transition requirements in North Carolina on the most reasonable, least cost path to carbon neutrality by 2050.

To meet these objectives and advance the energy transition, Chapter 4 presents an Execution Plan for the Carolinas that builds on the initial near-term actions presented and approved by the NCUC in last year's initial 2022 proposed Carbon Plan and evolves the short-term action plan framework

Figure 8: Critical Execution Period in the Energy Transition



presented in past South Carolina IRPs. The Execution Plan (along with certain Appendices to the Plan[20]) provides updates on recent activities over the past year and presents a detailed and comprehensive assessment of executable near-term actions in the years 2023–2026, as well as identifies intermediate-term actions in the years 2027–2032 that will be further considered in future planning periods and considers long-term planning for key risks and signposts over the remainder of the 15-year Base Planning Period through 2038 and longer-term planning horizon through 2050. Table 3 summarizes the near-term actions plan from 2023 through 2026.

Table 3: Supply-Side Near-Term Actions Plan 2023 to 2026[21]

Resource	MW, BOY In-Service	Activities through 2023	Near-Term Actions 2024–2026
Solar	6,000 by 2031	• 2022: 964.7 MW procured • 2023: 1,435 MW targeted to procure	• Continue Red Zone Transmission Expansion Plan ("RZEP") 1.0 projects, advance RZEP 2.0 projects • 2024: target to procure 1,435 MW of solar and SPS • 2025 and 2026: target to procure 2,700 MW to 3,150 MW of solar and SPS
Battery Storage	2,700 by 2031	• Progressing development of 1,000 MW stand-alone • 2023: 260 MW SPS targeted to procure	• 650 MW stand-alone • 790 MW of SPS through procurements
Onshore Wind	1,200 by 2033	• Carolinas site screening evaluation	• Site feasibility studies and siting development engagement for 300, 450 and 450 MW per year, respectively
CT	1,700 by 2032	• Interconnection request and Pre-Certificate of Public Convenience and Need ("CPCN") for 2 CTs total 900 MW (2029)	• 2024: CPCN for 2 CTs (2029) • 2025: CPCN for 1 CT (2030) • 2026: CPCN for 1 CT (2032)
CC	4,080 by 2031	• Interconnection request and Pre-CPCN for 1 CC (2029)	• 2024: CPCN for 1 CC (2029) • 2025: CPCN for 2 CCs (2030, 2031)
Pumped Storage Hydro	1,700 by 2034	• Interconnection request, equipment proposals, and construction estimates • Federal license activities	• 2024: South Carolina Certificate of Environmental Compatibility and Public Convenience and Necessity ("CECPCN") • 2025 and 2026: File North Carolina Out of State CPCN, file federal license application
Advanced Nuclear	600 by 2035	• Evaluating reactor technologies • Developing Early Site Permit ("ESP") for Site 1	• Site 1: Choose reactor technology, submit ESP, develop construction permit/license application, contract with reactor vendor, order long-lead equipment • Site 2: Develop and submit ESP, begin construction permit/license application
Offshore Wind	Evaluate potential need for 2033 or later	• Evaluated 3 Wind Energy Areas ("WEAs") off North Carolina coast • Partnered with NC State Energy Office to pursue IIJA funding	• Continue IIJA funding partnership • Monitor domestic market and supply chain • Evaluate potential earlier resource need (0 to 1,600 MW) and make recommendation for RFP in 2025 or sooner based on the market conditions and need

20 See Appendix I (Renewables and Energy Storage), Appendix J (Nuclear) and Appendix K (Natural Gas, Low-Carbon Fuels, and Hydrogen) for additional information, Appendix L (Transmission System Planning and Grid Transformation).

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

The planned near-term actions presented for execution address development and procurement activities planned through 2026 and identify the actions needed to maintain reliability and meet increased customer demand through substantial, diversified investments in dispatchable natural gas units, pumped storage hydro, advanced SMR nuclear technologies and solar and wind augmented with flexible large-scale battery storage. The Companies' proposed near-term actions are consistent with what is needed to support Core Portfolio P3 Base, which reflects the near-term addition of 5,625 MW of new solar by 2031, 2,700 MW of battery energy storage by 2031, 1,200 MW of onshore wind by 2033 and approximately 4,400 MW of new gas turbine projects placed into service through roughly 2032, as well as continuing development activities necessary to place longer lead-time resources including approximately 1,700 MW at Bad Creek II pumped storage hydro facility coming into service by 2034 and two advanced nuclear SMR resources (600 MW total) to come online by 2035. The Companies believe these planned resource additions, while ambitious to execute on the timelines required by the modeling to enable the orderly retirement of coal units on the planned schedule, reflect a prudent approach in the near term to progress the energy transition that mitigates risks and supports resource diversity, adequacy and reliability for customers.

In addition to progressing execution of this planned portfolio of resources, the Companies are also proposing limited near-term activities to continue early-stage planning and development activities for potential offshore wind generation. As noted earlier, offshore wind is not identified as needed under recommended Core Portfolio P3 Base through the end of the Base Planning Period in 2038; however, it is identified as needed in the long-term to achieve carbon neutrality across all Energy Transition Pathways, and numerous Pathway 3 Portfolio Variants and Sensitivity Analysis Portfolios demonstrate that adding up to 1,600 MW of offshore wind by 2035 could become part of the most reasonable, least cost path for the Carolinas in the future. Accordingly, in order to maintain optionality, it is prudent to continue to actively monitor the United States' offshore wind market and supply chain development (including challenges recently observed in the market) and continue to evaluate the need to develop offshore wind during the Base Planning Period (2033 or later) to plan for a number of potential alternative scenarios where offshore wind may be selected in the Plan. These alternative planning scenarios are further discussed in Chapter 3 and include scenarios involving compliance with EPA CAA Section 111 Proposed Rule, additional growth materializing in the Carolinas, lower Grid Edge and demand-side contributions to load reduction than planned, execution challenges achieving the assumed pace of other zero-carbon resource additions, or the costs of other resources increasing relative to offshore wind costs.

Recognizing that resource planning is an iterative process, both Commissions will have a further opportunity to "check and adjust" in the future as policies evolve, new technological developments occur and more refined information becomes known. 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 in future Plans.

Transforming the Transmission System to Enable Plan Execution

The Plan requires transformation of the Companies' transmission systems in the near-term and the long-term to interconnect the new supply-side resources that will be needed to meet load growth and economically retire significant amounts of coal-fired generation. To meet this challenge while ensuring that the adequacy and reliability of the existing grid is maintained or improved, Duke Energy will utilize both the annual Definitive Interconnection System Impact Study ("DISIS") Cluster Study process and the Federal Energy Regulatory Commission ("FERC") jurisdictional transmission planning process to strengthen the transmission grid over time. The Execution Plan identifies essential transmission grid investments required to plan for coal unit retirements and to reliably integrate these new resources onto the Companies' systems and fully enable the execution of the energy transition. Additional detail on the Companies' transmission system planning process is presented in Appendix L (Transmission System Planning and Grid Transformation).

Demand-Side and Grid Edge Resources in the Execution Plan

Figure 9: Grid Edge and Customer Program Residential Offerings

The supply-side Execution Plan described above is augmented by the Companies' nation-leading and innovative regulatory efforts underway to reduce or modify energy usage on the system at the customer level, to evolve customer programs providing greater access to desired renewable resources, and to encourage customers to change their load profiles in ways that better support system optimization and reliability through novel rate designs and advanced technologies. Additional details on the foundational role of demand-side and Grid Edge resources to the Companies' Resource Plan and related customer offerings (illustrated in Figure 9) is presented in Appendix H.

Hydrogen-Capable Natural Gas for Reliability and Enabling an Orderly Energy Transition

As Duke Energy transitions the generation fleet by retiring more coal units and bringing more variable generation online, dispatchable energy resources will be necessary to maintain most reasonable, least cost and reliable operations. The Companies continue to pursue an “all of the above” strategy that will in the near- and intermediate-term rely on new hydrogen-capable natural gas generation to reliably “replace and retire” coal, meet new load growth and reliably integrate renewables onto the system. Without new dispatchable natural gas units available to serve load, the significant planned retirement of coal generation stations will be delayed. For modeling purposes in this resource planning cycle, the Companies are assuming incremental Gulf Coast gas supply for any new combined cycles in their base case. With passage of the Fiscal Responsibility Act of 2023 addressing permitting for Mountain Valley Pipeline (“MVP”), the Companies believe that MVP and the Southgate extension remain viable options for future fuel supply, further discussed in Appendix K (Natural Gas, Low-Carbon Fuels and Hydrogen).

Many federal actions and investments are indicating that the industry is coalescing around hydrogen as a future potential fuel to lower carbon emissions and also as a way to relieve natural gas supply constraints. Although it is unlikely that the U.S. clean hydrogen supply can match the need for blending hydrogen into the existing natural gas combined-cycle fleet in the near-term, the DOE’s Hydrogen Hub funding and Hydrogen Energy Earthshot as well as the EPA CAA Section 111 Proposed Rule indicate that investment and expansion of the hydrogen supply chain could continue. The Company is taking actions in the near- and intermediate-term to “future-proof” combustion turbine assets so that they are capable of operating as hydrogen-fueled assets. As discussed earlier, this includes partnering with other utilities in six states on a Southeast Hydrogen Hub application to DOE pursuant to the IIJA and a proposed demonstration Hydrogen Project at the Clemson Combined Heat and Power Plant. More details on the Companies’ natural gas supply assumptions and hydrogen planning efforts are discussed in Appendix K.

Constructive Engagement and Timely Regulatory Action are Needed to Enable an Orderly Energy Transition for the Carolinas

Constructive work by the Companies, the Commissions and stakeholders is needed to enable this Carolinas’ energy transition in an orderly way that ensures reliability and considers affordability for customers. Continuing the Companies’ investment in stakeholder engagement is an essential enabler of long-term planning and other interrelated work streams as outlined in Appendix A (Stakeholder Engagement). Through this network of stakeholder engagement and collaboration, the Companies can better navigate the energy transition and keep informed of the risks, interdependencies, market conditions, technology advancements, consumer trends and other signposts of this changing energy landscape to check and adjust along the way. During execution, integrating environmental justice and community impacts into project-related implementation work “on the ground” enables sustainable outcomes.

Successful implementation of an energy transition must also be enabled by timely and constructive regulatory actions across a myriad of workstreams and certainty of investment recovery to pave the way for plan execution, particularly as the Companies monitor and assess the potential for even more substantial load growth resulting from further economic development successes. Support for the prudent near-term actions and continued development of investments into the intermediate-term in the Execution Plan creates timely and meaningful progress in the face of an evolving energy landscape. In this critical execution phase of the energy transition, decisive actions must be taken to advance solutions and that also serve to mitigate risks of inaction — as the Companies plan for an orderly exit from coal over the next several years which includes a future of higher energy demand requiring increasingly clean resources.

This Carolinas Resource Plan manages the risks, opportunities and challenges cited in Chapter 1 and is in the best interest of customers to advance an orderly energy transition. Importantly, this Plan provides supporting analysis as described in Chapters 2 and 3 that leads to important Near-Term Actions and Detailed Execution Plans in Chapter 4 that serves to set an intentional course of reasonable and prudent actions supporting resource improvements, additions and retirements, while always keeping a focus on reliability and affordability for customers. The Companies respectfully assert that their Near-Term Action Plan and Execution Plan associated with the recommended Portfolio are appropriate for approval by NCUC and the PSCSC, and that the Plan provides a reasonable and balanced approach for resource planning purposes that meets the legal requirements and policy goals of the states in which the Companies provide service.