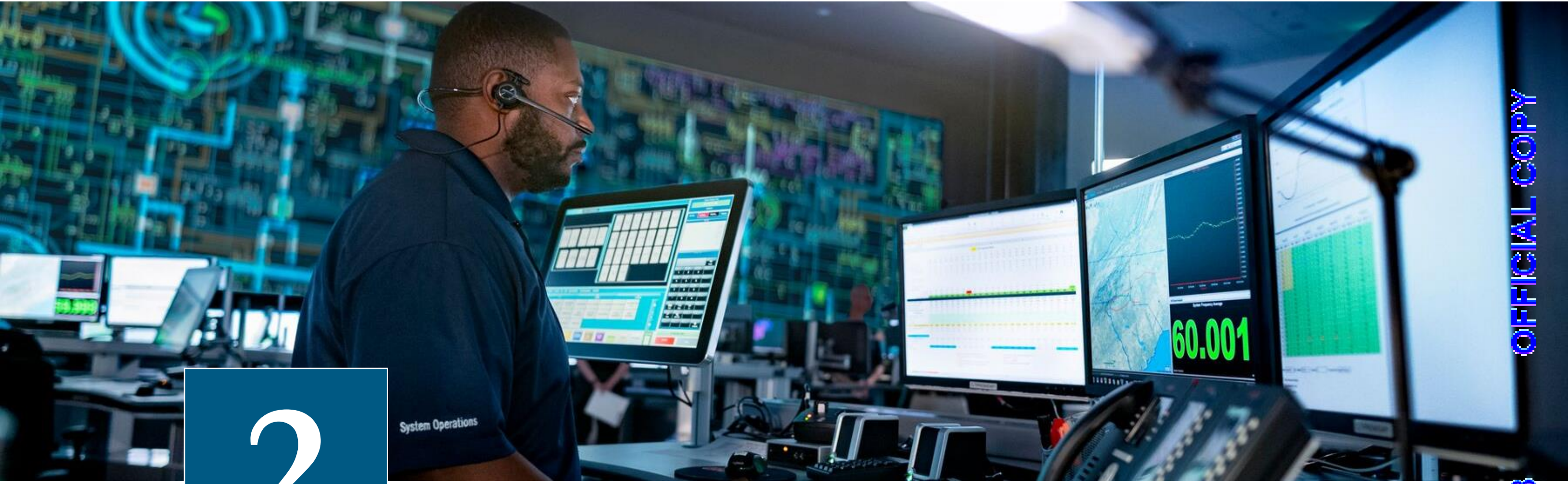


2

Methodology and Key Assumptions

Highlights

- As the energy landscape has changed in significant ways, it is essential that the Companies balance a broader set of long-term resource planning objectives that advance solutions for these changes, while prudently managing risks and uncertainties for an orderly transition of the Companies' electric systems to meet the resource adequacy and reliability needs of customers and communities.

- The core focus of the Carolinas Resource Plan analysis is to identify the most reasonable, least cost plan for the Carolinas through development of resource portfolio options that maintain affordability and reliability along the Companies' path to carbon neutrality by 2050 for the Carolinas system.

- The Companies developed 33 portfolios to explore a wide range of potential demand-side and supply-side resource selections to inform the most reasonable, least cost transition plan for the evolving energy landscape. The modeling approach and analytical framework consists of three Pathways that represent the pace of energy transition and three related Core Portfolios that incorporate the base planning assumptions for each of the three Pathways. A total of 23 Portfolio Variants and Sensitivity Analysis Portfolios were modeled against the Core Portfolios that evaluate a variety of changes to base planning assumptions. Finally, seven Supplemental Portfolios were developed for informational purposes to explore no constraints on carbon dioxide emissions and the potential impact of proposed Environmental Protection Agency Greenhouse Gas rules.

- Production cost sensitivity analyses were performed to examine the robustness of portfolio cost and performance with respect to variability and uncertainty in resource cost, fuel commodity price, and pace of transition.

This Chapter provides an overview of the planning objectives and analytical process utilized to develop the Carolinas Resource Plan (the "Plan" or "the Resource Plan") as well as a summary of key assumptions and inputs to the modeling framework. Growing customer demand and the retirement of aging coal facilities require adoption of a new portfolio of demand-side programs and integration of supply-side resource options over the planning horizon to meet customer's energy adequacy and reliability needs, with an increasingly clean resource portfolio, while also maintaining affordability for customers. At its core, the modeling process is structured to develop and analyze portfolio options that, first and foremost, maintain robust power system reliability while simultaneously implementing cleaner energy resources through hydrogen-capable natural gas resources, advanced nuclear and renewables and integrating energy storage and demand-side tools for increased operational flexibility.

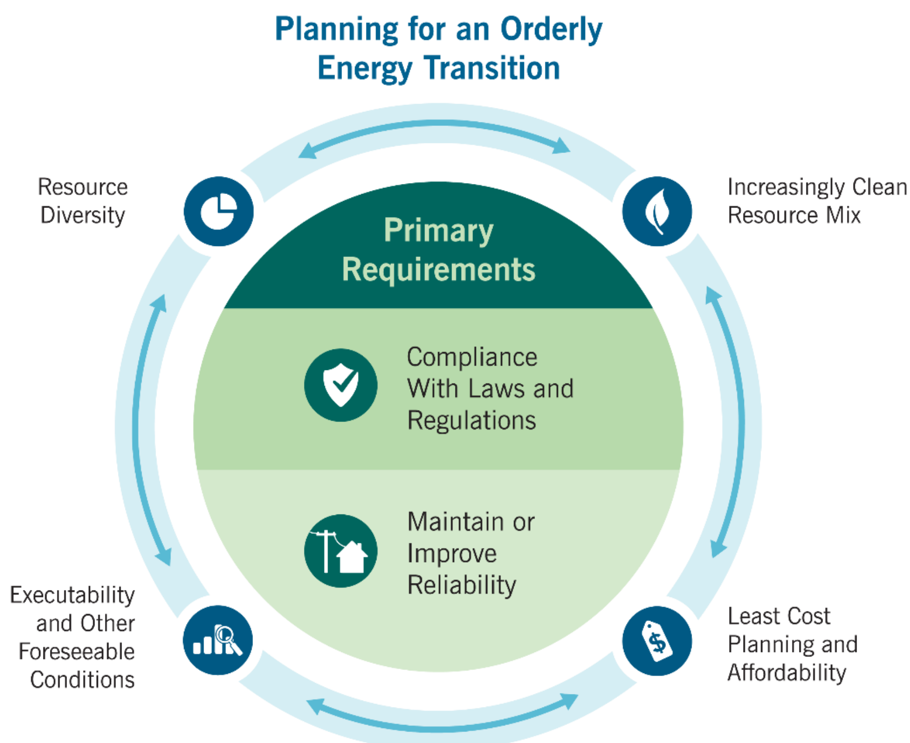
This Chapter discusses the EnCompass modeling tool and modeling framework used for coal retirement analysis, the preliminary resource identification in the capacity expansion model and the detailed, hourly production cost modeling in development of the Carolinas Resource Plan. This Chapter also highlights the primary steps involved in the modeling process and many of the key inputs and assumptions relied upon in the development of the portfolios presented in the Plan. Additional detail is provided in Appendix C (Quantitative Analysis), as well as in other appendices in the Carolinas Resource Plan referenced herein.

Of note, the inputs, assumptions and modeling framework utilized to develop the Plan represent a snapshot in time as of 2023 and are subject to change in future Plan updates, given the extremely dynamic nature of the energy industry as a whole, as well as the changing dynamics of various resource supply chains both domestically and globally. Fundamentally, the planning process must rely upon reasonable inputs and assumptions that are appropriate and available at the time the modeling is undertaken, recognizing that project-specific technology performance characteristics, costs and transmission requirements will only be fully known and available during Plan execution when specific projects are actually sited and developed. This means that supply and demand-side resources included in planning analytics are necessarily generic, a representative sample of the wide range of potential unit sizes, configurations or specific technologies that may be deployed. Plan execution is further discussed in Chapter 4 (Execution Plan).

Resource Planning Objectives for an Orderly Energy Transition

In this evolving and uncertain changing energy landscape described in Chapter 1 (Planning for a Changing Energy Landscape), Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and together with DEC, "Duke Energy" or the "Companies") must broaden planning objectives to consider the interdependencies and risks of meeting load growth and reliability needs as part of an orderly energy transition, retiring coal plants and replacing these resources with an equally reliable, diverse and increasingly clean set of resources (shown below in Figure 2-1). The Plan must comply with applicable planning, environmental and other laws and regulations that govern plan inputs and outputs, while ensuring reliability is continuously maintained or improved for customers — these are non-negotiable. However, the Companies' planning objectives must also balance risks and timing of an orderly energy transition as the industry exits dispatchable coal resources and replaces this capacity with increasingly clean resources. This must be done by ensuring resource diversity to mitigate fuel and technology risks, applying least-cost planning principles and considering affordability for customers, and accounting for plan execution in the face of changing conditions, such as evolving policies and technology advancements. Planning objectives must consider risks associated both with a too-rapid transition and the potential for inadequate capacity and energy replacement *and* the cost and fuel security risks of too slow a transition away from coal.

Figure 2-1: Long-Term Resource Planning Objectives



The long-term resource plan encompasses integrated and interdependent electric, fuel supply and transmission systems; therefore, changes to single inputs or variables may cascade through the resulting plan, influencing the degree to which specific planning objectives are met, and thus creating the need to balance risks and timing across objectives. Chapter 3 (Portfolios) describes the resulting Plan portfolios and how they compare across metrics related to these planning objectives.

Complying with Applicable Laws and Regulations

A primary objective of long-term resource planning includes compliance with current applicable state and federal requirements, which entails translating these requirements into planning inputs and verifying that planning outputs meet any applicable requirements. DEC's and DEP's dual-state electricity systems serving North Carolina and South Carolina (that is, North Carolina customers are served, in part, by South Carolina-sited resources and South Carolina customers are served, in part, by North Carolina-sited resources) requires that resource plans must adhere to the laws and regulations of both states. Therefore, the Plan adheres to the statutory, regulatory and policy requirements of both states, as discussed in more detail in the Chapter SC (The Most Reasonable and Prudent Resource Plan for South Carolina's Future) and Chapter NC (2023-2024 CPIRP Update).

The Plan must comply with several environmental laws and regulations set by the United States Environmental Protection Agency ("EPA") and state agencies. Other agencies have further regulations regarding operations and reliability such as, Federal Energy Regulatory Commission, North American Electric Reliability Corporation ("NERC"), SERC Reliability Corporation and Nuclear Regulatory Commission, among others.[1]

Maintaining or Improving Reliability

System reliability and adequacy of resources to serve customer demand is a primary obligation of the Companies along with meeting specific NERC reliability requirements in system planning and operations. Customers expect the Companies to meet their energy needs reliably at all times of day and during all seasons of the year, and that the Companies are planning for the total needs of the electric systems now and into the future for both normal and extreme weather conditions. The outage events of Winter Storm Elliott, along with previous summer heat waves and winter storm events that preceded outages in other regions of the country, reinforce the central importance of system reliability to customers and businesses. A primary objective of long-term resource planning is to maintain adequate reserves to serve customers through peak demand periods, and meet capacity needs essential for economic growth and development in the Carolinas. In addition, there must be adequate system flexibility to serve customer demand that varies by year, by season, by day and by minute.

The 2023 Resource Adequacy Study (Attachment I) defines the long-term planning reserve margin needed to meet resource adequacy at seasonal demand peaks. Reliability Verification modeling further tests system needs by taking into consideration a given portfolio's ability to meet varying winter demand patterns, including those experienced during major winter events as recently as Winter Storm Elliott in 2022. Appendix M (Reliability and Operational Resilience) provides further context on maintaining reliability during an orderly energy transition as the resource mix changes for both the Companies' operating areas and neighboring operating areas alike, to include more variable energy resources. These changes also highlight the need for additional dispatchable resources to maintain system reliability and energy adequacy.

[1] Each of these entities develops policies and regulations that have a direct bearing on the inputs, analysis and results of the planning process. Examples of such requirements include NC HB 589, SC Act 236 and SC Act 62 programs that set targets for the addition of renewable resources, and NC HB 951 that sets targets for carbon dioxide emissions reductions. A cross reference table with these requirements is provided in Appendix N (Cross Reference).

Conducting Risk Adjusted Planning and Considering Consumer Affordability

Like reliability, cost-competitive rates and consumer affordability are important for the vitality and growth of the Carolinas. The long-term planning process must follow least-cost planning principles including, but not limited to:

- Accounting for land, capital, fuel and operations and maintenance costs that vary by resource type.
- Appropriately balancing risks and uncertainties regarding future fixed and variable costs.
- Integrating potential tax incentives from the Inflation Reduction Act of 2022 ("IRA").
- Considering both cumulative long-term costs expressed in present value terms and forecasted customer bill impacts at future snapshots in time.

Aggregate resource cost impacts must be balanced with legal and regulatory compliance requirements, reliability standards for keeping the lights on at all times and during all seasons of the year and the significant risks from the pace of energy transitions — too fast a transition causing potential reliability gaps if adequate replacement resources are not in place prior to retirement, and too slow a transition out of coal resulting in significant exposure to coal availability, price volatility, operational risks, as well as exposure to proposed and future federal environmental regulations facing the coal industry as discussed below.

Planning for Increasingly Clean Resource Mix

The Companies must plan to balance risks associated with load growth while planning for and executing an orderly transition from coal and reduced reliance on gas over time. The appropriate pacing of retiring and replacing (including repurposing sites where feasible) over 8,400 megawatts ("MW") of coal by 2035 mitigates fuel security and cost risks of the wholesale industry exit from coal while significantly contributing to required emissions reductions. The Companies have had a corporate commitment to clean energy for well over a decade, aligning with, and in response to, the clean energy goals of many of the customers currently served by the Companies, as well as the clean energy goals of industries and businesses looking to expand into the Carolinas.[2] Historical and evolving regulatory requirements and policy drivers, including the EPA Clean Air Act ("CAA") Section 111 Proposed Rule, indicate that utilities should be planning for an increasingly clean resource mix. This objective must be balanced with the need to maintain or improve reliability for customers. As discussed previously, timely commissioning of equally reliable replacement resources and the certainty of regulatory decisions to enable those replacements is essential to managing operational risk. If this resource replacement is executed in a balanced way, it can facilitate resource diversity in power supply.

[2] 2022 Duke Energy Impact Report.

Resource Diversity to Mitigate Fuel and Technology Risks, Enhance Reliability

A diverse portfolio of power supply resources is a planning objective that allows the Companies the ability to hedge risks and costs and take advantage of complementary technologies to optimize the system across economics, system reliability and environmental attributes. An orderly energy transition will require a diverse array of tools in the toolbox — an “all of the above approach.” Having more tools in the toolbox to operate the system increases operational flexibility, as well as complexity for system operators that will require a glide path of operational experience as new technologies are integrated into the system at scale. Ultimately, a balanced and diverse resource mix prudently manages technology and fuel risks across the portfolio and provides for operational flexibility.

Accounting for Plan Execution and Foreseeable Conditions in the Planning Environment

While planning and forecasting never has perfect foresight, it can consider realities experienced “on the ground” through execution or account for reasonably foreseeable conditions. Many examples have already been highlighted in Chapter 1 — industry exit from coal, environmental regulations making fossil generation increasingly uneconomic and industries that are seeking to locate and expand in the Carolinas who are prioritizing access to increasingly clean energy as an important criterion of their siting process[3]. Other factors impacting generation project lead times and costs include supply chain and workforce challenges, requirements and challenges for siting and permitting and considering significant infrastructure dependencies such as transmission or fuel supply needs. This is a broad area that must be balanced with other planning objectives to inform plan executability and account for realistic conditions in the planning environment.

Analytical Framework

This section describes the development of the Energy Transition Pathways and portfolios evaluated in developing the Carolinas Resource Plan. The Companies developed 26 portfolios to explore a wide range of potential demand-side and supply-side resource selections to inform the most reasonable, least cost transition plan for the evolving energy landscape. The modeling approach and analytical framework consists of three Pathways that each represent a different pace of energy transition and three related Core Portfolios that incorporate the base planning assumptions for each of the three Pathways. A total of 23 Portfolio Variants and Sensitivity Analysis Portfolios were modeled against the Core Portfolios that evaluate a variety of changes to base planning assumptions. Finally, seven Supplemental Portfolios were developed for informational purposes to explore no constraints on CO_2 emissions and the potential impact of EPA Clean Air Act Section 111 regulating GHG gas from fossil-based resources (“EPA CAA Section 111 Proposed Rule”). Production cost sensitivity analyses were

[3] Publicly traded commercial and/or industrial enterprises are increasingly incorporating goals to “decarbonize” their supply chains by reducing Scope 2 and 3 emissions. As providers of an essential input, electricity, the Companies are considered “suppliers” and the Companies’ GHG emissions are accounted for in customers’ Scope 2 GHG inventory because they are a result of the organization’s energy use. Enabling a potential or existing customer to reach a Scope 2 emissions goal, increases the likelihood of initial site selection and expanding operations at a site.

also performed to examine the robustness of portfolio cost and performance with respect to variability and uncertainty in resource cost, fuel commodity price, and pace of transition.

Pathway and Portfolio Development

In consideration of achieving long-term resource planning objectives, particularly the non-negotiable requirements to comply with laws and regulations and to maintain or improve reliability for customers while meeting significant new resource needs due to growth, the pace of the energy transition and the timing of the availability and amounts of equally reliable resources to replace retiring coal emerged as central to portfolio development. As presented in Figure 2-2 below, the Companies developed the following energy transition Pathways and related portfolios to evaluate the most reasonable, least cost transition path and timing to achieve interim CO_2 emissions reductions targets.[4]

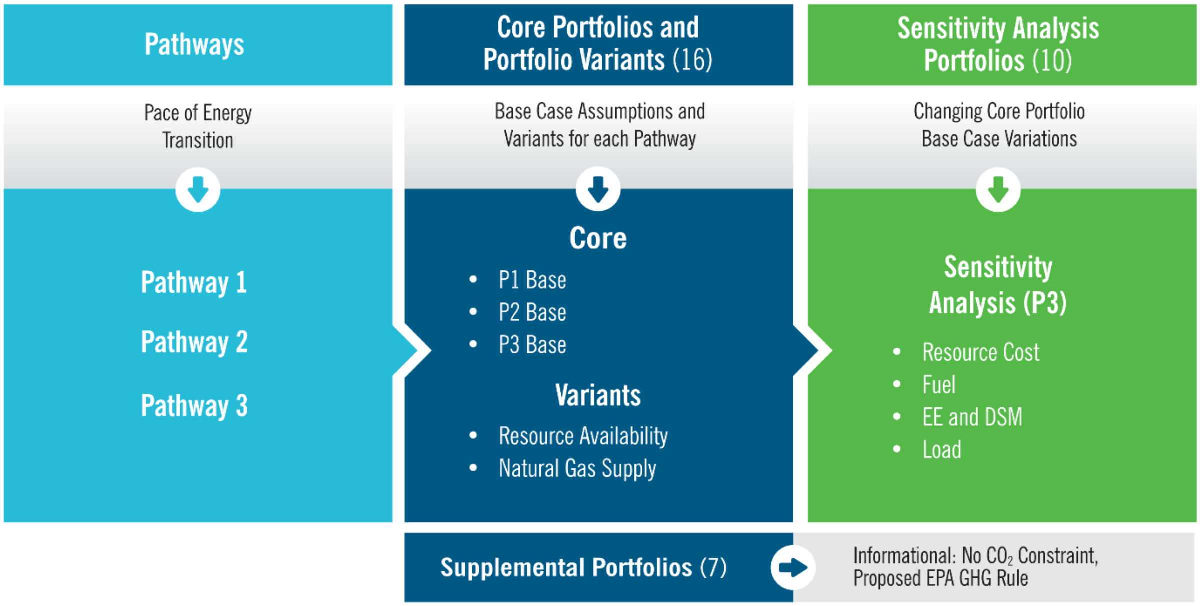
Of important note, all portfolios were developed using established least-cost planning principles and are designed to meet the resource planning requirements and objectives of both states and the North Carolina Utilities Commission and the Public Service Commission of South Carolina (together, the "Commissions") during the Base Planning Period.[5] The Pathways and Portfolios lead to an orderly energy transition to meet load growth, exit coal, reduce emissions and achieve carbon neutrality over the long-term planning horizon by 2050, comply with North Carolina and South Carolina law and align with many government, community, customer, supplier and equity investor stakeholder expectations. Specifically, the Carolinas Resource Plan modeling ensures the selection of the most reasonable, least cost portfolio of resources while achieving the associated energy transition Pathway towards carbon neutrality and maintaining resource adequacy and system reliability.

The methods and models used to develop portfolios and perform production cost analysis are described later in this Chapter.

[4] CO_2 emissions reduction target: North Carolina Session Law 2021-165 ("HB 951") — 70% CO_2 emissions reductions interim target and 2050 carbon neutrality.

[5] The Base Planning Period is the 15-year resource planning horizon that meets North Carolina and South Carolina long-term planning requirements.

Figure 2-2: Energy Transition Pathways and 26 Portfolios in Plan



Energy Transition Pathways and Core Portfolios

As previously discussed, the three Pathways and related Core Portfolios represent different approaches to the pace of the continued energy transition. The pace of transition is a critical planning consideration with implications for all planning objectives described above. Declining reliance on fossil fuels and associated CO_2 emissions are a characteristic of the transition, and the Companies employed several different levels of constraints on CO_2 emissions in their modeling to evaluate different transition paces, with more stringent constraints causing the model to deploy lower-CO_2 and fossil fuel-free resources in larger quantities earlier in the planning period, and less stringent constraints resulting in a more moderate pace. The three Pathways include an interim CO_2 emissions reduction target of 70% from a 2005 baseline, with that target reached in a different year in each, while all three Pathways reach carbon neutrality by 2050.

Pathway 1 represents the most aggressive pace of energy transition, requiring highly aggressive execution assumptions related to resource availability in both timing and amounts, at a higher cost and with increased reliability risk to achieve a 70% CO_2 reduction by 2030. Pathway 2 reaches the interim target by 2033, enabled by the availability of 1,600 MW of offshore wind and all supporting transmission infrastructure by the beginning of that year. Finally, Pathway 3 reaches the interim target by 2035, the year by which the Companies are planning for the first advanced nuclear units to be deployed. Pathway 3 relies on two small modular reactors ("SMR") totaling 600 MW to achieve the interim target. Further discussion of timelines for deployment of advanced nuclear can be found in Appendix J (Nuclear).

Three Core Portfolios have been developed using base planning assumptions across the three Pathways, which are further discussed below. Each Core Portfolio is designed to achieve the pace of energy transition that is consistent with the Pathway under which that portfolio was developed. Modeling inputs and assumptions are consistent across the Core Portfolios, with the exception of the resource availability assumptions used to develop P1 Base, the Core Portfolio corresponding to Pathway 1. P1 Base, which targets 70% CO_2 emissions reductions by 2030, requires higher resource availability than the amounts used to develop the high resource availability Portfolio Variants as described below.

Portfolio Variants and Sensitivity Analysis Portfolios

As discussed above, the Companies developed a framework that explores a wide range of potential approaches to achieving an executable energy transition that balances the planning objectives and requirements of both states. These consist of three Core Portfolios and 13 Portfolio Variants, each of which is derived from one of the Core Portfolios. The Companies developed the Portfolio Variants by changing one or more inputs or assumptions to the capacity expansion model (described below) and allowing the model to select a different mix of resources. The Portfolio Variants evaluated the significance of specific variables in resource selection and provide a thorough assessment of the risks and potential opportunities that could be realized in the future as events unfold. In addition to the extensive portfolio analysis, the Companies created 10 additional Sensitivity Analysis Portfolios derived from the P3 Base in which certain additional inputs or assumptions were changed beyond those used to create the Portfolio Variants.

Supplemental Portfolios

Additional analysis was completed for informational purposes to address specific regulatory needs or informational needs. A Supplemental Portfolio that does not specify a CO_2 target was completed to address the South Carolina 2020 IRP order[6], with two additional Portfolio Variants to evaluate the impact of solar project ownership and South Carolina IRP ordered battery price forecasts and natural gas fuel curve (described further below) also performed.[7] Additionally, two Supplemental Portfolios that evaluate the potential impact of new proposed regulations from the EPA CAA Section 111 Proposed Rule were completed, as described further below. As these rules have only been proposed, these Supplemental Portfolios are only for informational purposes. Finally, two additional portfolios were developed to understand the impact of high and low levels of Energy Efficiency/Demand-side Management ("EE/DSM") based on changes in fuel costs and more or less restrictive CO_2 constraints.

[6] Order Accepting 2022 Integrated Resource Plan Updates, at 9, Docket Nos. 2019-224-E, 2019-225-E, 2021-8-E, and 2021-10-E (Mar. 22, 2023).

[7] Executing on a resource plan with no specified CO_2 emissions reduction target would require the Companies to violate state law that applies to their dual-state operations, and therefore portfolios without specified reduction constraints are included in this filing as Supplemental Portfolios for informational purposes only.

Portfolio Matrix

This framework of extensive portfolio development analysis paired with additional production cost analytics allowed for a robust evaluation of the risks, uncertainties and potential tradeoffs relative to the planning objectives described above. The evaluation of modeling results across the Core Portfolios is described in Chapter 3 and more detailed information on Portfolio Variants, Sensitivity Analysis Portfolios and Supplemental Portfolios is in Appendix C.

The Companies changed assumptions across the following variables to develop the Portfolio Variants:

- **Resource Availability** – Existing generating assets cannot be retired until equally reliable replacement resources are connected to the system so that system reliability can be maintained or improved. In addition to supporting planned retirement of existing assets, new resources are needed to support rapid economic growth in the Carolinas while simultaneously reducing dependence on fossil fuels and associated emissions. For these reasons, the pace at which new resources can be deployed will be an important determinant in the Companies' ability to successfully execute the Carolinas Resource Plan. Recent supply chain challenges and competing demands across the country and world, combined with the potential for siting, permitting and interconnection challenges, create considerable uncertainty regarding the volumes of new resources that will be available in the Carolinas over the coming years. Thus, the Companies developed Portfolio Variants assuming availability both above and below the base case levels assumed in the primary portfolios.

- **Natural Gas Supply** – Future supply of natural gas to the Carolinas remains an important factor in resource planning. At the time the Companies finalized inputs for the Carolinas Resource Plan analytics, Mountain Valley Pipeline ("MVP") was not in service. Given the uncertainty the uncertainty around MVP coming into service and the timing, the Companies developed the base portfolios assuming that additional natural gas supply would only be available from the Gulf Coast region and that Appalachian gas would not become available in the Carolinas. To capture the benefits of a diversified natural gas supply from the Appalachia region to the Carolinas, which would supplement existing Gulf Coast supply and support reliable growth and replacement capacity, the Companies developed Portfolio Variants to evaluate how the completion of the MVP could affect the Resource Plan. Similarly, the Companies also developed portfolios to evaluate the potential implications of natural gas availability below the volumes assumed in the base portfolios.

The Companies used alternate assumptions for the following variables to develop the Sensitivity Analysis Portfolios:

- **Resource Cost** – Not only must new resources be available, but they must be available at reasonable costs. The Companies developed Sensitivity Analysis Portfolios that evaluate the potential resource selection changes resulting from resource costs above and below base case assumptions on the Carolinas Resource Plan.

- **Fuel Commodity Price** – In addition to the gas supply Portfolio Variant described above, the Companies developed Sensitivity Analysis Portfolios to evaluate potential resource selection changes resulting from natural gas commodity prices above and below the base case forecast. In contrast to the gas supply analysis, fuel delivery charge (gas transmission) assumptions were held constant for these cases, which were intended to test the impacts of high and low commodity price environments only.

- **Energy Efficiency and Demand Response Achievement** – Duke Energy continues to pursue aggressive targets for utility-offered energy efficiency ("UEE")[8] and demand response ("DR") programs that entail considerable execution challenges as described in Appendix H (Grid Edge and Customer Programs). The Companies developed Sensitivity Analysis Portfolios assuming both lower and higher levels of UEE and DR savings than assumed in the primary portfolios to evaluate the potential impacts on the Carolinas Resource Plan.

- **Load** – As explained in Appendix D (Electric Load Forecast), the load forecast in the Carolinas Resource Plan analysis represents a considerable increase over that which the Companies used to develop prior resource plans. In addition to the base forecast, the Companies developed Sensitivity Analysis Portfolios assuming even higher and somewhat lower load than reflected in the base forecast, to evaluate the potential impacts of factors such as more rapid transportation electrification or economic retrenchment. Portfolios developed using different load forecasts are not directly comparable to one another because they are based on fundamentally different customer energy and peak demand requirements which requires different resource portfolios to maintain reliability and serve load in all hours throughout the planning horizon. The alternate load portfolios, however, do provide important insight to the risks and resource differences associated with material variance between actual future load and forecasted load.

The Companies developed Supplemental Portfolios by changing assumptions for the following variables for informational purposes only:

- **Proposed Greenhouse Gas Rules** – Near the conclusion of the stakeholder engagement period and finalization of modeling inputs, the EPA issued proposed

[8] Note that UEE specifically refers to the Companies' approved utility-sponsored programs where participants actively take part in demand response ("DR") and conservation measures offered under the EE/DSM riders within their service territory. Naturally occurring energy efficiency recognizes load reductions resulting from customers adopting efficiency improvements not associated with utility-sponsored programs. Appendix H (Grid Edge and Customer Programs) details the Companies' ongoing efforts to identify opportunities to expand the reach of UEE programs. Within this document, UEE and energy efficiency ("EE") terms may be used interchangeably to refer to approved utility programs unless otherwise noted.

regulations under Section 111 of the Clean Air Act. The EPA CAA Section 111 Proposed Rule addresses GHG emissions from existing coal plants and from new and existing natural gas plants. The Companies recognize the significance and potential impacts of these proposed rules, as well as the complex and lengthy period ahead as the proposed regulations are carefully considered. 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. In light of the potential significant impacts to the resource portfolios and costs, the Companies did perform preliminary modeling of two Supplemental Portfolios to evaluate the potential impacts of the EPA's proposed regulations on resource selection to help inform the Commissions. Because there is considerable uncertainty regarding the costs and timing of compliance mechanisms for the proposed rules, and the final form of the rules themselves, these portfolios are included for informational purposes only.

- **No CO_2 Reduction Constraint** – The Companies developed a Supplemental Portfolio that includes no constraints on natural gas utilization and associated CO_2 emissions. Executing on a resource plan with no specified CO_2 emissions reduction target would require the Companies to violate state law that applies to their dual-state operations. Additionally, the resulting portfolio lacks resource diversity as a core planning objective called for in both states' Integrated Resource Plan rules and would result in customer exposure to gas availability, price volatility as well as proposed and future regulatory compliance risks. Therefore, portfolios developed without specified CO_2 targets, including an economic coal retirement schedule developed without CO_2 emissions reductions constraints, are included in this filing for informational purposes only.

- **Natural Gas Pricing and Low Battery Costs** – This portfolio utilizes specific natural gas and battery price assumptions as directed in previous South Carolina IRP Orders. These assumptions include the use of NREL ATB "Low" battery costs forecast for batteries and the use of a natural gas price forecast that relies on market prices for eighteen months before transitioning over eighteen months to the average of at least two fundamentals-based forecasts. This portfolio is also included for informational purposes only against the Supplemental Portfolio that has no CO_2 constraint.

- **Solar PPA** – The Companies developed a Supplemental Portfolio to evaluate the impact of solar project ownership structure on resource selection. This portfolio includes the assumption that all new solar is procured via purchase power agreement. This portfolio is also included for informational purposes only against the Supplemental Portfolio that has no CO_2 constraint, because the specifics of project ownership and procurement are outside of the scope of resource planning, which is based on generic unit assumptions.

- **EE / DSM** – The Companies developed two additional Supplemental Portfolios to assess the impact to resource selection with varying EE and DSM forecasts, fuel prices and carbon constraints. Importantly, this South Carolina-ordered IRP requirement addresses how high forecasts of EE and DSM might impact resources selected in a high fuel price scenario with more restrictive carbon emissions constraints and conversely, how low EE and DSM might impact resources selected in a lower fuel price scenario with less restrictive, or in this case, no carbon emissions constraints. These Supplemental Portfolios are being provided for informational purposes only.

In addition to the portfolios described above, the Companies performed production cost sensitivity analysis against the Core Portfolios to examine the robustness of portfolio cost and performance with respect to variability and uncertainty in additional inputs. For the sensitivity analysis step, the Companies tested variations in resource cost and fuel prices across the different paces of energy transition represented by the Core Portfolios. This analysis is described in greater detail in the Performance Sensitivity Analysis section later in this Chapter and in Appendix C. Additional information on the Portfolios is shown below in Table 2-1.

Table 2-1: Carolinas Resource Plan Portfolio Matrix

Portfolio	CO_2 Constraint	Resource Availability	Gas Supply	Supply-Side Resource Costs	Fuel Commodity Price	Load	EE	DSM
Pathway 1								
P1 Base	70% reduction by 2030 Carbon-neutral by 2050	High+	Gulf Coast Only	High+	Base	Base	Base	Base
P1 Belews Creek Gas		High+ Belews Creek 100% Gas		High+	Base	Base	Base	Base
Pathway 2								
P2 Base	70% reduction by 2033 Carbon-neutral by 2050	Base	Gulf Coast Only	Base	Base	Base	Base	Base
P2 High Availability		High for All Resources		Base	Base	Base	Base	Base
P2 Low Solar		Limited Solar		Base	Base	Base	Base	Base
P2 Low Onshore		Limited Onshore Wind		Base	Base	Base	Base	Base
P2 Limited Gas		Maximum 2 CTs		Base	Base	Base	Base	Base
P2 MVP		Base	Appalachia + Gulf Coast	Base	Base	Base	Base	Base
Pathway 3								
P3 Base	70% reduction by 2035 Carbon-neutral by 2050	Base	Gulf Coast Only	Base	Base	Base	Base	Base
P3 High Availability		High for All Resources		Base	Base	Base	Base	Base
P3 Low Solar		Limited Solar		Base	Base	Base	Base	Base
P3 Low Onshore		Limited Onshore Wind		Base	Base	Base	Base	Base
P3 OSW in '37		Offshore Wind Added in 2037		Base	Base	Base	Base	Base
P3 SMR Delay		Advanced Nuclear Delayed to 2037		Base	Base	Base	Base	Base
P3 Limited Gas		Maximum 2 CTs		Base	Base	Base	Base	Base
P3 MVP		Base	Appalachia + Gulf Coast	Base	Base	Base	Base	Base

Portfolio	CO_2 Constraint	Resource Availability	Gas Supply	Supply-Side Resource Costs	Fuel Commodity Price	Load	EE	DSM
Portfolio Sensitivity Analysis								
P3 High Resource Cost	70% reduction by 2035 Carbon-neutral by 2050	Base	Gulf Coast Only	High	Base	Base	Base	Base
P3 Low Resource Cost				Low	Base	Base	Base	Base
P3 High Fuel				Base	High	Base	Base	Base
P3 Low Fuel				Base	Low	Base	Base	Base
P3 High Load				Base	Base	High	Base	Base
P3 Low Load				Base	Base	Low	Base	Base
P3 High EE				Base	Base	Base	High	Base
P3 Low EE				Base	Base	Base	Low	Base
P3 High DSM				Base	Base	Base	Base	High
P3 Low DSM				Base	Base	Base	Base	Low
Supplemental Portfolio Analysis								
SP EPA 111 CF	70% reduction by 2035 Carbon-neutral by 2050 EPA 111 - Capacity Factor	Base+	Gulf Coast Only	Base	Base	Base	Base	Base
SP EPA 111 H_2	70% reduction by 2035 Carbon-neutral by 2050 EPA 111 - Hydrogen	Base		Base	Base	Base	Base	Base
SP SC No CO_2 Constraint	No Constraint	Base		Base	Base	Base	Base	Base
SP SC Battery and Gas Cost				Low Bat	SC	Base	Base	Base
SP Low EE, DSM, Fuel, No CO_2				Base	Low	Base	Low	Low
SP SC PV PPA		Solar as PPA		Base	Base	Base	Base	Base
SP High EE, DSM, Fuel, CO_2	70% reduction by 2030 Carbon-neutral by 2050	Base		Base	High	Base	High	High

Note : High+ Portfolio requires highly aggressive resource availability assumptions.

Note : Base+ Offshore wind availability was accelerated relative to the base assumptions and an additional CC was made available.

Analytical Process – Overview

The analytical process used to develop the Carolinas Resource Plan involves several important steps as illustrated in Figure 2-3 below. Each step in the process summarized in Figure 2-3 (Modeling Software and Development of Modeling Assumptions, Portfolio Development, Production Cost, Reliability Verification and Performance Analysis) is described in greater detail in the following sections of this Chapter and in Appendix C.

Figure 2-3: Carolinas Resource Plan Analytical Process Flow Chart

Modeling Software and Development of Modeling Assumptions

This section outlines key inputs to the Carolinas Resource Plan modeling process. These inputs include, but are not limited to, updates to the Companies' load forecasts, including impacts of UEE program savings, new rate offerings, voltage control programs and other customer demand-side programs along with numerous existing and new supply-side technology modeling input data. Key reliability requirements used in the portfolio development and analysis process include planning reserve margin, Effective Load Carrying Capability ("ELCC") values for renewables and energy storage resources and operational reserve requirements. As previously noted, the inputs, assumptions, and modeling framework utilized to develop the Plan represent a snapshot in time as of 2023 and are subject to change in future Plan updates.

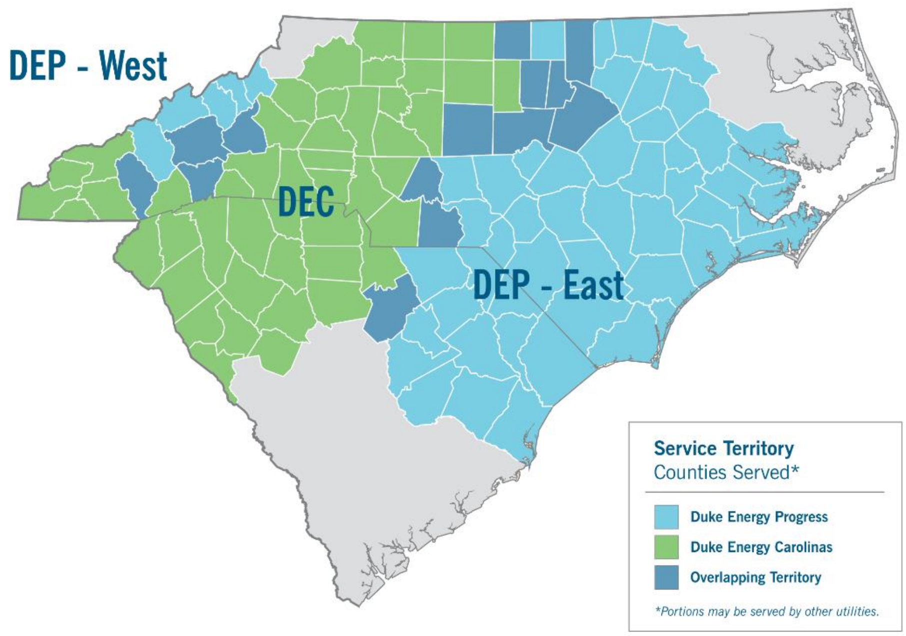
Modeling Software

The Companies utilized the EnCompass capacity expansion and production cost simulation software package ("EnCompass"), licensed through Anchor Power Solutions, as the primary modeling tool for the development and analysis of the Plan Portfolios. The capacity expansion model and the production cost model are separate modules within EnCompass, as described in this section and Appendix C. In addition to these primary tools, the Companies utilized more granular reliability modeling tools as part of the overall modeling process as described below. These additional tools ensure consumer affordability and system reliability as the system transitions to larger levels of zero-carbon variable energy resources.

DEC & DEP System Configuration

In capacity expansion and production cost modeling of the Carolinas system, DEC and DEP remain two separate utilities and legal entities, operating across three areas (DEP-West, DEC and DEP-East, as depicted below in Figure 2-4), each with its own load, resources and transmission limits between them. DEC and DEP continue to utilize joint dispatch, which allows for the utilities to optimize the dispatch of the system to provide cost savings to customers.

Figure 2-4: DEC and DEP Service Territories and Balancing Authorities



The resource planning analytics assume the implementation of a “Consolidated System Operations” model where the NERC Balancing Authority (“BA”), Transmission Service Provider and Transmission Operator functions are consolidated for DEC and DEP. This consolidated approach allows for economically dispatching the system, and furthermore, allows for optimization of meeting operating services requirements, such as balancing and regulating reserves. In the current operations of the DEC and DEP systems, each utility must meet its own operating requirements with its own units to meet the system operational needs of its BA area. The Consolidated System Operations model allows the collective operating requirements to be aggregated at the combined system level, which improves efficiency by allowing the requirement to be met by resources from either company as compared with the separate BA scenario. The two utilities do, however, retain responsibility for independently committing resources for meeting forecasted demand and maintaining long-term capacity planning requirements in the modeling. As further discussed in Chapter 4, the Companies are planning for Consolidated System Operations as part of the planned merger of DEC and DEP, which could be completed by January 2027.

Reliability Requirements

Ensuring reliability necessarily comes first in the modeling process. As previously noted, key reliability inputs needed in the Carolinas Resource Plan modeling include planning reserve margins, ELCC values and operational reserve requirements. These inputs are foundational resource planning components that ensure the Companies are maintaining or improving upon the adequacy and reliability of the existing grid as further described below.

Planning Reserve Margin

DEC and DEP retained Astrapé Consulting[9] to conduct a new resource adequacy study to support development of the Companies' Carolinas Resource Plan. The study included updates to all inputs including impacts on cold weather load response and unit outage performance experienced during Winter Storm Elliott in December 2022. Based on results of the new study, the Companies utilized a 22% minimum winter planning reserve margin in developing the Carolinas Resource Plan portfolios. As described in more detail in Appendix C and in the 2023 Resource Adequacy Study report, included as Attachment I to the Carolinas Resource Plan, the planning reserve margin is based on achieving the widely accepted industry threshold of one event-day in 10-year loss of load expectation ("LOLE") and reflects an increase over the prior planning reserve margin criterion. Also, as described later in this Chapter and in Appendix C, the Carolinas Resource Plan analytical process includes a Reliability Verification step to ensure that the LOLE threshold is maintained for each portfolio and, if required, adds additional capacity to keep the portfolio at the threshold.

Effective Load Carrying Capacity

In developing the Carolinas Resource Plan, results from recent ELCC studies were used to estimate the reliability capacity value attributable to variable energy and energy-limited resources such as solar, wind and storage resources. ELCC can be thought of as a measure of the reliability equivalence for intermittent renewable and energy-limited storage resources being added to an existing generation portfolio.

Solar and storage ELCC values were based on the 2022 ELCC study conducted by Astrapé Consulting using the SERVM[10] model. The Companies also retained Astrapé to conduct a new 2023 ELCC study to determine appropriate reliability capacity values for onshore and offshore wind resources. ELCC is further described in Appendix C and in the 2022 and 2023 ELCC study reports provided as Attachments II and III to the Carolinas Resource Plan.

Operational Reserve Requirements

The Companies include operational reserve requirements in the expansion plan modeling process to capture the variance in load and renewables due to forecast error, intra-hour volatility and system ramping needs. The operational reserve model was developed by Duke Energy, based at a high level

[9] Astrapé Consulting is an energy consulting firm with expertise in resource adequacy and integrated resource planning. Astrapé has conducted several Resource Adequacy Studies and Effective Load Carrying Capability Studies for DEC and DEP in recent years.

[10] The Strategic Energy & Risk Valuation Model ("SERVM") is a state-of-the-art reliability and hourly production cost simulation tool managed by Astrapé Consulting which provides consulting services and/or licenses the model to its users.

on a planning and reliability tool developed by the Electric Power Research Institute ("EPRI"),[11] and is used to calculate hourly operational reserves required to ensure that the Companies will have sufficient flexible resources available to mitigate the risk of load and renewable output uncertainty.

Operational reserve requirements are heavily influenced by the level of intermittent resources on the system. Operational reserve requirements are used in both the capacity expansion process for the development of portfolios and in the production cost modeling for the detailed operations of the system. Operational reserve requirements are also included when conducting the additional portfolio Reliability Verification for each portfolio influenced by the selected levels of solar and wind capacity in each portfolio.

Electric Load Forecast

Key inputs and assumptions used within the modeling framework include assumptions regarding the Companies' peak demand and annual energy load forecast inclusive of significant demand-side factors impacting the forecast. This section provides an overview of these demand-side assumptions impacting the Carolinas Resource Plan. More detail is contained in Appendix D and Appendix H. A summary of several of the key assumptions in this area is shown below.

The Carolinas Resource Plan utilizes an electric load forecast projection through 2050 of the yearly energy and seasonal peak demands of the customer base within the DEC and DEP service areas. The econometric process to derive the retail load forecast is described in detail in Appendix D. Tables 2-2 through Table 2-6 below provide an overview of the base planning assumptions over the Base Planning Period in the Carolinas Resource Plan for this important topline parameter. The tables provide the components of the net load forecast and the compound annual growth rates ("CAGR") for these components for the DEC and DEP annual energy and peak winter load requirements.

[11] EPRI's Dynamic Assessment and Determination of Operating Reserve ("DynADOR") tool is a standalone application used to determine operating reserve requirements. *See* EPRI, Program 173: Bulk Integration of Renewables and Distributed Energy Resources, Dynamic Reserve Determination Tool. https://www.epri.com/research/programs/067417/results/3002020168. The Companies developed their methodology based on the DynADOR tool with some modifications, including to generate reserves for a multi-year planning horizon.

Table 2-2: Forecasted Energy Sales – System Obligation at Generator – DEC [GWh]

Year	Gross Retail Sales	Energy Efficiency	Rooftop Solar	Electric Vehicles	Voltage Control (IVVC)	CPP/ PTR	Net Retail Sales at Meter	Line Loss + CO Use	Gross Retail at Gen	Wholesale	System Obligation at Gen
2024	82,844	(814)	(159)	96	(49)	(2)	81,917	5,345	87,262	8,505	95,767
2025	83,613	(1,342)	(267)	201	(234)	(3)	81,969	5,348	87,318	8,539	95,857
2026	84,596	(1,868)	(381)	358	(318)	(4)	82,382	5,375	87,757	8,594	96,351
2027	86,053	(2,388)	(483)	584	(337)	(6)	83,424	5,442	88,865	8,651	97,516
2028	87,997	(2,916)	(575)	902	(353)	(8)	85,048	5,546	90,594	8,721	99,315
2029	89,813	(3,446)	(670)	1,319	(356)	(10)	86,650	5,649	92,299	8,770	101,069
2030	91,337	(3,969)	(771)	1,845	(359)	(12)	88,070	5,741	93,811	8,830	102,640
2031	92,907	(4,469)	(878)	2,475	(362)	(14)	89,658	5,843	95,501	8,893	104,393
2032	94,470	(4,931)	(989)	3,207	(366)	(17)	91,374	5,953	97,327	8,967	106,293
2033	95,974	(5,252)	(1,096)	3,984	(369)	(19)	93,223	6,072	99,295	9,016	108,310
2034	96,875	(5,451)	(1,199)	4,809	(373)	(21)	94,640	6,163	100,803	9,073	109,876
2035	97,896	(5,602)	(1,281)	5,665	(379)	(22)	96,276	6,268	102,544	9,129	111,672
2036	98,917	(5,695)	(1,348)	6,545	(384)	(24)	98,010	6,379	104,390	9,195	113,584
2037	99,902	(5,726)	(1,413)	7,381	(390)	(25)	99,729	6,490	106,219	9,236	115,455
2038	101,056	(5,616)	(1,484)	8,221	(396)	(26)	101,756	6,620	108,376	9,289	117,664
CAGR	1.4%	14.8%	17.3%	37.4%	16.0%	21.7%	1.6%	1.5%	1.6%	0.6%	1.5%

Within the DEC service territory, the following programs will have a significant impact on net retail load over the initial 15-year time horizon:

- **Utility Energy Efficiency**: UEE is forecasted to achieve a robust CAGR of 14.8% over the 15-year Base Planning Period, peaking at approximately 5.7% of gross retail sales by the year 2038. UEE savings reflect an incremental annual reduction of at least 1% of each year's eligible retail sales. It is important to note that this 1% annual target is based on an aspirational goal emerging from the Company's ongoing engagement with the Carolinas EE/DSM Collaborative, which consists of both Duke Energy experts and a broad range of external stakeholders.

  The cumulative UEE savings shown in Table 2-2 are net of the roll-off, or decay, of historical savings associated with the measure lives of previously achieved program savings. To be clear, this does not mean the savings associated with those earlier measures have ended. Once roll-off occurs, the Companies account for these historical savings as a part of the load forecast rather than showing those savings in the UEE forecast. This forecast only represents the incremental savings directly attributed to utility-sponsored programs above and beyond any naturally occurring or policy-driven savings. Within the load forecast modeling framework, naturally occurring efficiency trends replace the rolled off UEE savings, continuing to reduce forecasted load on an enduring basis.

  Achievement of annual savings of this magnitude over the full timeline of this Plan will require substantial customer participation and regulatory support as further discussed in Appendix H. Duke Energy will continue extensive engagement with the EE/DSM Collaborative and other stakeholders in pursuit of these aggressive goals.

- **Rooftop Solar**: Utilizing Rooftop Solar ("RS") rates first approved in the Carolinas in 2022, behind-the-meter solar is assumed to achieve a 17.3% CAGR over the next 15 years. The Companies continue to work with stakeholders to develop new rate designs and complementary programs that are discussed further in Appendix H.

- **Electric Vehicles**: Within DEC, electric vehicles ("EVs") are projected to grow from roughly 0.6% of the total vehicle fleet today to 25.6% by 2035, achieving the highest CAGR of any of the components listed in Table 2-2 at 37.4%. Appendix D provides further detail regarding the net impact of EVs in DEC.

- **Integrated Volt-Var Control**: Integrated Volt-Var Control ("IVVC") has been modeled to achieve a rollout across 96% of eligible circuits in DEC's service territory over a multi-year timeframe. IVVC has two modes of operation — Peak-Shaving mode, which is counted as a firm capacity resource and Conservation Voltage Reduction ("CVR") mode, which reduces gross retail load. The Peak-Shaving and CVR modes of operation will be managed by a centralized Distribution Management System ("DMS"). CVR mode will eventually support voltage reduction and energy conservation on a year-round basis across 90% of the hours in the year, as opposed to Peak-Shaving mode which will reduce demand during the remaining peak 10% of hours as a firm capacity resource (similar to DR programs). IVVC CVR mode is projected to achieve a CAGR of 16.0% through 2038.

- **Critical Peak Pricing/Peak Time Rebate**: Described in further detail in Appendix D and Appendix H, the approved Critical Peak Pricing ("CPP") rate rider is a dynamic overlay option for DEC's electric service, including both its existing flat volumetric rates, as well as its existing and proposed time-of-use rates. This time variant pricing option allows DEC to call critical events up to 20 times per year ("20 CP") based on system conditions, such as when there is expected to be extreme temperatures, high energy usage, high market energy costs or major generation or transmission outages. Peak Time Rebate ("PTR") is another structure that is added to a base rate plan that rewards customers who consume lower than usual energy during peak hours. The rebate structure for PTR has not yet been approved but is modeled within the DEC Load Forecast. CPP/PTR achieves a 21.7% CAGR in DEC although the greatest measurable impact will be upon peak capacity described in further detail below.

Table 2-3: Forecasted Energy Sales – System Obligation at Generator – DEP (GWh)

Year	Gross Retail Sales	Energy Efficiency	Rooftop Solar	Electric Vehicles	Voltage Control (IVVC)	CPP/ PTR	Net Retail Sales At Meter	Line Loss + CO Use	Gross Retail at Gen	Wholesale	System Obligation at Gen
2024	45,659	(425)	(117)	61	0	(1)	45,176	2,237	47,413	18,022	65,435
2025	46,432	(700)	(191)	127	(39)	(2)	45,627	2,258	47,886	18,895	66,781
2026	47,129	(983)	(268)	225	(398)	(3)	45,702	2,262	47,963	19,369	67,333
2027	47,706	(1,273)	(335)	366	(402)	(5)	46,058	2,279	48,337	19,579	67,915
2028	48,568	(1,555)	(391)	564	(406)	(6)	46,774	2,313	49,087	19,793	68,880
2029	49,463	(1,825)	(449)	821	(409)	(8)	47,592	2,352	49,944	19,984	69,928
2030	50,323	(2,086)	(512)	1,145	(413)	(10)	48,446	2,392	50,839	20,191	71,029
2031	50,881	(2,330)	(579)	1,528	(417)	(12)	49,072	2,422	51,494	20,411	71,905
2032	51,320	(2,550)	(651)	1,971	(420)	(14)	49,657	2,450	52,107	20,670	72,777
2033	51,768	(2,693)	(719)	2,438	(424)	(15)	50,355	2,484	52,839	20,794	73,633
2034	52,138	(2,780)	(785)	2,930	(428)	(17)	51,058	2,517	53,575	20,923	74,498
2035	52,578	(2,861)	(837)	3,438	(432)	(18)	51,868	2,556	54,424	21,055	75,479
2036	53,081	(2,928)	(879)	3,958	(438)	(19)	52,774	2,598	55,373	21,193	76,566
2037	53,496	(2,971)	(920)	4,451	(444)	(20)	53,591	2,637	56,228	21,335	77,563
2038	53,962	(2,964)	(966)	4,946	(451)	(21)	54,505	2,681	57,186	21,482	78,668
CAGR	1.2%	14.9%	16.3%	36.9%	20.6%	21.9%	1.3%	1.3%	1.3%	1.3%	1.3%

Within the DEP service territory, the following programs will have a significant impact on net retail load over the initial 15-year time horizon:

- **Utility Energy Efficiency**: UEE is forecasted to achieve a robust CAGR of 14.9% over the 15-year Base Planning Period, peaking at approximately 5.5% of gross retail sales by the year 2038. UEE savings reflect an incremental annual reduction of at least 1% of each year's eligible retail sales. As previously noted for DEC, achievement of annual savings of this magnitude over the full timeline of this Plan will require substantial customer participation and regulatory support as further discussed in Appendix H.

- **Rooftop Solar**: Utilizing RS rates approved in the Carolinas as of January 1, 2022, behind-the-meter solar is assumed to achieve a 16.3% CAGR. The Companies continue to work with stakeholders to develop new rate designs and complementary programs that are discussed further in Appendix H.

- **Electric Vehicles**: Within DEP, EVs are projected to grow from roughly 0.7% of the total vehicle fleet today to 26.4% in 2035, achieving the highest CAGR of any of the components listed above at 36.9%. Appendix D provides further detail regarding the net impact of EVs in DEP.

- **Integrated Volt-Var Control**: In contrast to DEC, DEP has completed the circuit-level upgrades required to fully implement IVVC through the legacy Distribution System Demand Response ("DSDR") peak-shaving program, which accomplished the program goal of upgrading 97% of eligible circuits by July 2014. Therefore, the only IVVC program upgrade required in DEP is to implement CVR mode through a centralized DMS to control voltage by circuit. CVR mode will be fully operational by 2025 and will support voltage reduction and energy conservation on a year-round basis across 90% of the hours in the year while the already functioning DSDR Peak-Shaving mode will continue to clip demand during the 10% of hours classified as peak. IVVC CVR mode is projected to achieve a CAGR of 20.6% from 2025 through 2038.

- **Critical Peak Pricing/Peak Time Rebate**: Similar to DEC, the approved CPP rate rider is a dynamic overlay option for DEP's electric service, including both its existing flat volumetric rates, as well as its existing and newly proposed time-of-use rates. This time variant pricing option allows DEP to call critical events up to 20 times per year ("20 CP") based on system conditions, such as when there is expected to be extreme temperatures, high energy usage, high market energy costs or major generation or transmission outages. The rebate structure for PTR has not yet been approved but is modeled within the DEP Load Forecast. CPP/PTR achieve a 21.9% CAGR in DEP although the greatest measurable impact will be upon peak capacity described in further detail below.

Lastly, Table 2-4 below provides forecasted energy sales for the Combined Carolinas system

Table 2-4: Forecasted Energy Sales – System Obligation at Generator – Combined Carolinas System (DEC/DEP) (GWh)

Year	Gross Retail Sales	Energy Efficiency	Rooftop Solar	Electric Vehicles	Voltage Control (IVVC)	CPP/ PTR	Net Retail Sales At Meter	Line Loss + CO Use	Gross Retail at Gen	Wholesale	System Obligation at Gen
2024	128,503	(1,239)	(276)	157	(49)	(3)	127,093	7,582	134,675	26,527	161,202
2025	130,045	(2,042)	(457)	329	(273)	(5)	127,597	7,606	135,203	27,434	162,637
2026	131,725	(2,851)	(648)	583	(716)	(7)	128,084	7,637	135,721	27,963	163,684
2027	133,759	(3,661)	(818)	950	(739)	(10)	129,481	7,721	137,202	28,229	165,432
2028	136,564	(4,470)	(966)	1,466	(758)	(14)	131,822	7,859	139,681	28,514	168,195
2029	139,276	(5,271)	(1,119)	2,140	(765)	(18)	134,242	8,001	142,243	28,754	170,997
2030	141,659	(6,055)	(1,284)	2,990	(772)	(22)	136,516	8,133	144,649	29,020	173,670
2031	143,789	(6,800)	(1,457)	4,003	(779)	(26)	138,730	8,265	146,995	29,304	176,298
2032	145,790	(7,481)	(1,640)	5,178	(786)	(30)	141,030	8,403	149,433	29,636	179,070
2033	147,742	(7,944)	(1,815)	6,422	(793)	(34)	143,578	8,556	152,133	29,810	181,944
2034	149,013	(8,232)	(1,984)	7,740	(801)	(38)	145,699	8,680	154,379	29,996	184,374
2035	150,474	(8,463)	(2,119)	9,103	(811)	(41)	148,144	8,824	156,967	30,184	187,151
2036	151,997	(8,623)	(2,228)	10,504	(823)	(43)	150,785	8,978	159,763	30,387	190,150
2037	153,398	(8,698)	(2,333)	11,831	(834)	(45)	153,320	9,127	162,447	30,572	193,018
2038	155,018	(8,580)	(2,450)	13,167	(847)	(46)	156,261	9,301	165,562	30,771	196,333
CAGR	1.3%	14.8%	16.9%	37.2%	22.5%	21.8%	1.5%	1.5%	1.5%	1.1%	1.4%

Table 2-5: DEC Winter Peaks – Impacts of Program (MW)

Year	Gross Retail Peak	UEE/RS/ CPP/PTR	Electric Vehicles	Net Retail Peak	Line Loss / CO Use	Retail Peak at Gen	Wholesale	System Peak at Gen
2024	14,806	(116)	3	14,693	936	15,629	1,881	17,510
2025	14,899	(222)	6	14,683	948	15,631	1,895	17,527
2026	15,092	(339)	12	14,766	957	15,722	1,909	17,631
2027	15,394	(460)	20	14,953	953	15,907	1,926	17,832
2028	15,841	(627)	32	15,246	941	16,188	1,941	18,129
2029	16,234	(688)	60	15,606	978	16,584	1,906	18,490
2030	16,530	(803)	89	15,817	991	16,808	1,910	18,718
2031	16,930	(913)	127	16,144	1,009	17,153	1,923	19,076
2032	17,321	(1,015)	173	16,478	1,029	17,507	1,940	19,448
2033	17,698	(1,092)	228	16,834	1,006	17,840	1,948	19,788
2034	17,884	(1,151)	288	17,021	1,020	18,041	1,965	20,006
2035	18,101	(1,198)	354	17,257	1,053	18,310	1,989	20,299
2036	18,309	(1,233)	424	17,500	1,071	18,571	1,996	20,568
2037	18,557	(1,252)	497	17,802	1,095	18,897	2,013	20,910
2038	18,802	(1,255)	572	18,119	1,099	19,218	2,037	21,255
CAGR	1.7%	18.5%	47.0%	1.5%	1.1%	1.5%	0.6%	1.4%

Table 2-6: DEP Winter Peaks – Impacts of Programs (MW)

Year	Gross Retail Peak	UEE/RS/ CPP/PTR	Electric Vehicles	Net Retail Peak	Line Loss / CO Use	Retail Peak at Gen	Wholesale	System Peak at Gen
2024	9,836	(44)	1	9,793	440	10,234	3,931	14,164
2025	9,928	(72)	3	9,859	443	10,302	4,114	14,416
2026	9,922	(103)	6	9,826	446	10,272	4,170	14,441
2027	10,028	(142)	10	9,896	445	10,341	4,222	14,563
2028	10,191	(178)	16	10,028	457	10,486	4,248	14,734
2029	10,483	(218)	25	10,289	466	10,756	4,300	15,055
2030	10,567	(260)	37	10,344	473	10,817	4,343	15,160
2031	10,760	(303)	53	10,510	475	10,985	4,385	15,370
2032	10,886	(344)	73	10,616	477	11,092	4,420	15,512
2033	11,074	(381)	97	10,790	484	11,274	4,446	15,721
2034	11,146	(413)	123	10,856	491	11,348	4,473	15,821
2035	11,323	(442)	152	11,033	495	11,528	4,501	16,030
2036	11,355	(465)	183	11,072	501	11,573	4,529	16,102
2037	11,516	(488)	215	11,243	500	11,743	4,558	16,301
2038	11,634	(500)	248	11,382	502	11,884	4,588	16,472
CAGR	1.2%	18.9%	45.0%	1.1%	0.9%	1.1%	1.1%	1.1%

Demand-Side Management

DSM contains three components: customer-sited DR, circuits-focused peak shaving (IVVC Peak Shaving mode) and peak shifting via CPP and PTR rate programs. All share similarities in that DEC/DEP system operators initiate DSM events to reduce system load during winter and summer peaks. DR and IVVC peak shaving are similar in that they are counted as capacity while CPP/PTR sends price signals to participating customers to avoid usage during peak times, therefore reducing aggregate peak demand on the system. DSM programs are explained in further detail below and in Appendix H.

Demand Response

In addition to the programs shown in the previous tables that reduce the load forecast, controllable DR customer programs also serve a very important role in meeting system peak demand requirements. When winter and summer peak loads occur, system operators can initiate DR events to lower customer energy consumption and quickly reduce the stresses on the system that can occur during these high demand periods. Mechanical DR programs send signals directly to customer equipment, such as thermostats and water heaters, to immediately lower energy usage. Alternatively, large commercial and industrial customers can participate in customized manual DR programs where Duke Energy will communicate the request to reduce load during high system demand periods. Employees of those firms comply by flexibly choosing what load to reduce to meet their previously agreed upon demand reduction commitments. Mechanical and manual DR customers are compensated monthly for opting-in to these programs in return for their commitment to reducing consumption during peak periods.

DR capacity is modeled as a controllable peaking resource similar to traditional generation and contributes equally to capacity planning reserve margins. Effective utilization of DR programs can decrease the runtime of older, more expensive generation and avoid or defer the need for new supply-side peaking resources.

Table 2-7 below summarizes the peak winter capacities of mechanical and manual DR programs in the Carolinas Resource Plan throughout time.

Table 2-7: Mechanical and Manual Demand Response, Winter (MW)

	DEC	DEP
2025	574	234
2030	682	369
2035	740	525

Critical Peak Pricing and Peak Time Rebate

The Carolinas Resource Plan also includes the projected impacts of peak reduction pricing programs, including CPP and PTR programs. These programs were also identified in the Companies' 2020

Winter Peak Study as a means to reduce peak winter demand using new voluntary customer rates structures. CPP and PTR programs are designed to send price signals to customers who opt-in to the program to encourage them to reduce load during peak periods in exchange for bill rebates or other favorable rate structures. The impacts of CPP and PTR are built into the load forecast to capture anticipated changes in customer load shape with the reductions at system peak summarized in Table 2-8 below.

Table 2-8: Critical Peak Pricing Demand Response, Winter (MW)

	DEC	DEP
2025	50	29
2030	133	132
2035	249	247

Integrated Volt-VAR Control – Peak Shaving Mode

As previously described, IVVC is a voltage reduction and peak-shaving program that operates at the circuit level using a centralized DMS. System operators utilize the CVR mode of IVVC for 90% of the hours of the year that are non-peak by adjusting voltage across eligible circuits utilizing the DMS. During winter and summer peak hours, which account for 10% of the year, CVR is turned off and Peak Shaving mode is turned on. This mode operates the same way as DR, but instead of reducing load by individual customer, it reduces voltage at the circuit level at carefully calibrated levels. This mode has existed in DEP as the DSDR program since 2014 and has been installed on 97% of eligible circuits. DEC is upgrading circuits in phases with the goal of implementing IVVC across 96% of eligible circuits over several years.

Below in Table 2-9 are the peak load reduction projections of the program from 2025–2035.

Table 2-9: IVVC Peak Shaving Capacity, Winter (MW)

	DEC	DEP
2025	129	146
2030	199	152
2035	210	160

Supply-Side Resources

Growing customer demand and the retirement of aging coal facilities require adoption of a new portfolio of demand-side and supply-side resource options over the planning horizon to meet customer adequacy and reliability needs, while also maintaining affordability for customers. Supply-side options considered in developing the Carolinas Resource Plan include cleaner energy resources through renewables, energy storage, advanced nuclear and hydrogen-capable natural gas resources. The Companies considered a diverse range of baseload, peaking/intermediate, variable energy and energy storage technologies in developing the Carolinas Resource Plan. Appendix E (Screening of Generation Alternatives) describes the technical and economic screening of resources that was conducted prior to performing the detailed Carolinas Resource Plan modeling and analysis. This section provides an overview of the input assumptions associated with the selectable supply-side resources made available in the EnCompass capacity expansion modeling phase.

Figure 2-5 below summarizes the key base assumptions for selectable resources included in the capacity expansion modeling. Refer to Appendix C for the more aggressive modeling assumptions used to develop portfolio P1 (70% carbon reduction by 2030). Further details regarding model input assumptions for selectable resources are provided in this section with additional information also provided in the related appendices. As previously noted, input assumptions, such as project capital costs and transmission interconnection costs for each resource type, are generic values as site-specific costs for any given resource will only be known as projects are sited during execution of the Plan.

Figure 2-5: Key Assumptions for Selectable Supply-Side Resources

Solar

- Solar interconnection potential is 1,350 MW/year starting in 2028 and increasing to 1,575 MW/year starting 2031
- Bifacial panels, single-axis tracking
- Three configurations of solar paired with storage

Storage

- Up to 2,200 MW stand-alone batteries per year per utility available for selection in all portfolios beginning 2027, no cumulative ceiling
- 1,680 MW Bad Creek II long-duration pumped storage hydro evaluated for inclusion in 2034

Advanced Nuclear

- First two SMRs (300 MW each) available beginning 2035 and additional SMRs available thereafter
- Advanced Reactors with integrated energy storage available beginning 2038

Wind

Onshore Wind

- 19.2% capacity factor (DEC)
- 26.6% capacity factor (DEP)
- Up to 300 MW/year starting 2031, increasing to 450 MW/year starting in 2032, and up to 2,250 MW total available for selection in all Portfolios (600 MW on DEC system and 1,650 MW on DEP system)

Offshore Wind

- Approximately 40-41% capacity factor
- First 800 MW block available for selection beginning 2032, additional available beginning 2033, and up to 7,200 MW through the planning period

Gas[12]
• Market-based natural gas commodity prices are utilized for the first five years; transition from market-based to fundamentals-based prices over next three years; use of full fundamentals-based pricing beginning in year nine • Limited natural gas supply (limit of three new combined cycles ("CCs") up to approximately 4,100 MW) • Up to 2,125 MW of new combustion turbine ("CT") capacity per year per utility available for selection in all portfolios, no cumulative ceiling
Hydrogen
• Clean hydrogen blended into natural gas supply to all existing gas units (CC, CT, and natural gas co-fired coal units) starting in 2035 and growing over time • Clean hydrogen market assumed available by 2040 • All new CTs selected after 2039 are assumed to be operated on 100% hydrogen • All new CTs and CCs added to the portfolios operate on hydrogen in 2050

Modeling Inputs and Assumptions for Selectable Supply-Side Resources

Solar and Solar Paired with Storage

Technology Description

Based on prior stakeholder feedback, the Companies assumed that all future solar would reflect projects with bifacial panels, single-axis tracking capability and operating at an annual capacity factor of approximately 27%. Pairing storage with solar can further increase the energy value of solar. The Companies allowed the storage that is paired with solar to utilize the facility's interconnection to charge the battery directly from the grid, if optimal to do so for the system. Based on stakeholder feedback, the Companies included three options for solar paired with battery storage as shown in Table 2-10 below.

Table 2-10: Solar Paired with Battery Storage, Plan Modeling Options

	Option 1	Option 2	Option 3
Solar Capacity	75 MW	75 MW	75 MW
Storage Capacity	20 MW	40 MW	60 MW
Duration	4-hour	4-hour	4-hour

[12] For modeling purposes all CO_2 emissions from new resources count against the CO_2 emissions reductions targets as if the generator was located in North Carolina. Actual siting will be determined at time of execution and reflected in the modeling appropriately at that time.

Technology Cost

The technology costs for solar and solar paired with storage are provided in Table 2-11 below. The Companies based solar and solar paired with storage costs on estimates from the Guidehouse tools[13] specific to the Carolinas with input from the 2022 solar procurement analysis.

Table 2-11: Technology Cost of Solar and Solar Paired with Storage

Technology	Overnight Cost (2023 $/kW)
Solar PV SAT	$1,850
Solar PV SAT + 20 MW/4-Hour Li-Ion Storage	$2,550

Transmission Cost

Table 2-12 below provides the transmission costs for solar and solar paired with storage resources used in the capacity expansion model factored into the selection of resources.

Table 2-12: Transmission Cost of Solar and Solar Paired with Storage

	Transmission Overnight Cost (2023 $/W)	
	DEC	DEP
Solar and Solar Paired with Storage	$0.35	$0.21

Resource Availability

Table 2-13 below shows the solar interconnection limits used for the base assumptions.

[13] Guidehouse creates these tools based on market estimates of the technologies to determine current installation costs as well as expected costs for the next ten years for each technology. The costs are validated against other industry reports and engineering studies.

Table 2-13: Maximum Solar (MW) Available for Selection Annually[14]

Maximum Solar (MW)			
2028	2029	2030	2031+
1,350	1,350	1,350	1,575

Appendix I (Renewables and Energy Storage) explains the Companies' modeling approach for assumed future solar interconnections in further detail.

Energy Storage

Technology Description

Energy storage will play a critical role in the low-carbon future of the power system. Energy storage does not create CO_2 emissions when discharging and can be charged from zero-carbon resources including nuclear, solar, wind and hydro power. Energy storage also provides the system benefit of allowing excess zero-carbon power to be stored for later use instead of curtailed. The dispatchable nature of energy storage allows this energy to be injected back into the grid when it is needed most, offsetting higher cost, carbon intensive generation.

Table 2-14 below reflects the various configurations of stand-alone battery energy storage that were modeled in EnCompass.

Table 2-14: Standalone Battery Storage, Plan Modeling Options

	Option 1	Option 2	Option 3
Storage Power Capacity (MW)	100 MW	100 MW	100 MW
Storage Duration Capacity (MWh)	400 MWh	600 MWh	800 MWh
Full Load Discharge Duration (hours)	4 hours	6 hours	8 hours

Additionally, the Companies modeled an expansion of the Bad Creek Pumped Storage Hydro Station ("Bad Creek II"), which provides an additional 1,680 MW long-duration storage resource in the Carolinas Resource Plan. Since this is not a generic unit technology, overnight capital costs are not included in the table below. The final type of energy storage modeled in the Carolinas Resource Plan is the integrated storage of advanced reactors ("AR"). This integrated storage option allows for thermal energy to be stored from the nuclear reactor and released to supplement generation in times of peak

[14] The general convention used in the Companies' Carolinas Resource Plan is that resources are available for selection or retired on a beginning-of-year ("BOY") basis. The years in the table refer to solar available to be selected into the portfolio at the start of the calendar year. For example, 1,350 MW of solar is available for selection by the model at the start of 2028, 2029 and 2030, increasing to 1,575 MW in 2031 and beyond. In execution, resources may be added throughout the year prior, but for modeling and planning purposes, the Plan only plans on resources for meeting energy and capacity needs on a full year basis.

demand. This storage configuration allows for the consistent operation of the nuclear plant, while changing the output of the overall facility. Furthermore, integrated thermal storage has a very high round trip efficiency compared to the other storage options.

Technology Cost

The technology costs for energy storage are provided in Table 2-15 below. Battery storage costs were based on estimates from the Guidehouse tool with modifications based on recent trends in lithium carbonate pricing. As noted in the Advanced Nuclear section below, advanced nuclear with integrated storage technology costs were based on input from EPRI, information from vendors and other engineering studies.

Table 2-15: Technology Cost of Energy Storage

Technology	Overnight Cost (2023 $/kW)
4-Hour Li-Ion Storage	$2,250
6-Hour Li-Ion Storage	$3,300
8-Hour Li-Ion Storage	$4,200

Transmission Cost

Table 2-16 below provides the transmission costs for energy storage resources used in the capacity expansion model. Battery storage is assumed to be placed at existing coal retirement sites with zero transmission system upgrade costs or at other locations on the grid as to not negatively impact the transmission system. Transmission costs associated with advanced nuclear with integrated storage are provided in the Advanced Nuclear section below.

Table 2-16: Transmission Cost of Energy Storage

	Transmission Overnight Cost (2023 $/W)	
	DEC	DEP
Battery Storage	$0.0	$0.0
Bad Creek II Pumped Storage	$0.37	N/A

Resource Availability

The Companies assumed interconnection potential for battery energy storage to be 2,200 MW per year per utility with no cumulative ceiling.

Advanced Nuclear

Technology Description

In addition to the zero-carbon energy already provided by the current nuclear fleet, next generation nuclear can provide significant operational flexibility that will be needed to support increased deployment of renewable energy resources. As shown in Table 2-17 below, the Companies considered two types of advanced nuclear plants in development of the Carolinas Resource Plan which included SMRs and ARs. SMRs are water-cooled reactors where ARs are non-water-cooled (e.g., molten salt, liquid metal, or high-temperature gas).

Table 2-17: Advanced Nuclear Modeled in the Carolinas Resource Plan

Definitions	
Small Modular Reactors	• Light water-cooled, the same technology utilized by today's current commercial fleet • Proven technology and furthest along from a licensing standpoint • Typically, 300 megawatts electric ("MWe") or less
Advanced Reactors	• Non-water-cooled – molten salt, helium gas, liquid sodium • Higher efficiency, cycling ability and integrated storage • Integrates well with variable renewable power • Can be 50 MWe up to 1,200 MWe, typically 350 MWe or less

Technology Cost

The technology costs of advanced nuclear reactors are provided in Table 2-18 below. Advanced nuclear reactor costs were based on EPRI analysis and reports, information from vendors, and other engineering studies.

Table 2-18: Technology Cost of Advanced Nuclear Reactors

Technology	Overnight Cost (2023 $/kW)
Generic Small Modular Reactor	$6,450
Generic Advanced Reactor with Thermal Storage	$6,850

Transmission Cost

Table 2-19 below provides the transmission costs for advanced nuclear reactors used in the capacity expansion model.

Table 2-19: Transmission Cost of Advanced Nuclear Reactors

	Transmission Overnight Cost (2023 $/W)	
	DEC	DEP
Advanced Nuclear Reactors	$0.45	$0.22

Resource Availability

Carolinas Resource Plan base modeling assumes the first two 300 MW SMR blocks are available beginning 2035 with additional 300 MW blocks available thereafter. Modeling also assumes 450 MW AR blocks (300 MW nuclear/150 MW storage) are available beginning in 2038.[15]

Wind

Technology Description

Onshore and offshore wind technologies are mature, scalable and increasingly cost-effective zero-carbon resources. Both onshore and offshore wind turbines generally operate by harnessing wind with large turbine blades that spin and turn a generator that converts the rotational energy into electrical energy. Multiple wind turbines installed and connected form a wind farm, which can add up to hundreds of MW to the system. Similar to solar, onshore and offshore wind resources are variable energy resources with their output being dependent on weather conditions.

Technology Cost

The technology costs for wind resources are provided in Table 2-20 below. Onshore wind technology costs are based on estimates from the Guidehouse tool specific to the Carolinas. Offshore wind costs were obtained through a NCUC-required analysis of the Wind Energy Areas off the North Carolina Coast. This analysis was conducted in an unbiased manner through a non-binding request for information process conducted by DNV Energy with interested developers. The Companies then took the anonymized data received from DNV Energy to create a generic profile that was used for modeling purposes.

Table 2-20: Technology Cost of Wind

Technology	Overnight Cost (2023 $/kW)
Onshore Wind	$2,150
Offshore Wind	$4,150 - $4,850

[15] See Appendix J (Nuclear) for further information.

Transmission Cost

Table 2-21 below provides the transmission costs for wind resources used in the capacity expansion model.

Table 2-21: Transmission Cost of Wind

	Transmission Overnight Cost [2023 $/W]	
	DEC	DEP
Onshore Wind	$0.27	$0.16
Offshore Wind 800 MW	-	$0.48
Offshore Wind 1,600 MW	-	$0.84
Offshore Wind 2,400 MW	-	$0.65

Resource Availability

Appendix I provides a detailed discussion of the development timeline and process to site onshore and offshore wind energy projects. For onshore wind, the Carolinas Resource Plan base modeling assumed that the annual amount that could be selected between DEC and DEP was 300 MW/year beginning 2031, increasing to 450 MW/year starting in 2032, and up to a total volume of 600 MW on the DEC system and 1,650 MW on the DEP system (2,250 MW cumulative limit).

For offshore wind, the base modeling allowed selection of three 800 MW offshore wind blocks (January 1, 2032, January 1, 2033, and January 1, 2034) with additional offshore wind assumed to be available beginning 2040 for a total of 7,200 MW through the planning period.

Simple Cycle Combustion Turbines and Combined Cycle Power Blocks

Technology Description

New simple cycle CTs and CC power blocks with the future capability to use hydrogen fuel will play a critically important role into the future, given the system’s growing need for reliability resources that are both dispatchable and capable of operating for extended periods of time as required to support and back stand the integration of variable energy renewable resources, and to enable the retirement of older less-efficient coal units by equally providing reliability. Over the planning horizon, future gas generation is projected to operate less often than fossil-fueled plants do today but will serve an important role in providing firm dispatchable capacity as the industry transitions to additional levels of intermittent renewable resources and energy limited storage resources. Based on modeled fuel supply constraints, the Companies limited the amount of new CC capacity able to be selected in the Carolinas Resource Plan modeling. The exact model of CT chosen during Plan execution, whether in simple-cycle or CC configuration, will depend on the specific needs of the system at the time of development. For modeling purposes, the Companies’ Carolinas Resource Plan considers advanced class peakers and CCs. These new CC and CT assets are expected to be hydrogen- (or other carbon-neutral fuel) capable when they begin operation and suitable for increased hydrogen burning capability, eventually up to 100%. Hydrogen blending with natural gas and eventually 100% hydrogen use will reduce the exposure of those resources to regulatory risk and lower the carbon footprint of any future CTs and CCs as further described in Appendix K (Natural Gas, Low-Carbon Fuels and Hydrogen).

Technology Cost

The technology costs for CTs and CCs are provided in Table 2-22 below. CT and CC costs are provided as a range based on Burns & McDonnell estimates since cost estimates for specific turbine configurations for the Carolinas are proprietary.

Table 2-22: Technology Cost of CTs and CCs

Technology	Overnight Cost (2023 $/kW)
Multi-Unit Combustion Turbine	$750 – $900
2x1 Combined Cycle	$800 – $1,250

Transmission Cost

Table 2-23 below provides the transmission costs for CT and CC resources used in the capacity expansion model.

Table 2-23: Transmission Cost of CTs and CCs

	Transmission Overnight Cost (2023 $/W)	
	DEC	DEP
Natural Gas CCs and CTs	$0.45	$0.22

Resource Availability

- Base portfolios assumed a limited amount of firm transportation capacity to transport gas supply to the Carolinas and were constrained to allow the model to select up to three new CC facilities or ~4,100 MW of new CC capacity.
- Hydrogen capable simple-cycle CT capacity additions were modeled with sufficient ultra-low sulfur fuel oil backup eliminating the need for interstate firm gas delivery. The modeling allowed up to 2,125 MW of new CT capacity per year per utility for selection in base portfolios with no cumulative ceiling.
- Appendix K provides additional details on the CC and CT combustion technology and assumptions used in the modeling.

Hydrogen

Technology Description

The Companies' existing CT and CC generation fleet was designed to operate by utilizing natural gas or fuel oil. Hydrogen and hydrogen-based fuels are emerging zero-carbon or low-carbon emissions fuels that offer an alternative to fossil fuels. When utilized in an appropriate generating asset, hydrogen can be a zero-emitting load-following resource, enabling the support of more grid-connected renewable resources. With some modifications to the CTs and the development of a robust supply chain, hydrogen could replace existing fossil fuels in power generation.

Technology Cost

100% hydrogen capable turbines are a developing technology, and cost estimates for retrofits and new hydrogen capable units are not available from original equipment manufacturers ("OEMs") at this time. Duke Energy developed cost estimates for use in the Carolinas Resource Plan modeling based on discussions with third-party OEMs.

Resource Availability

Hydrogen is assumed to be blended into the natural gas pipeline and burned in all-natural gas burning units (CCs, CTs and natural gas co-fired coal units) as follows:

- 0.33% by heat content (~1% by volume) starting in 2035
- 0.66% by heat content (~2% by volume) starting in 2038
- 1.00% by heat content (~3% by volume) starting in 2041

Any new peakers selected in the 2040s are treated as 100% hydrogen fueled. Some, but not all existing CT and CC units on the system in 2050, as well as all new CTs and CCs added to the portfolios, operate exclusively on hydrogen in 2050. Appendix K provides additional details on future hydrogen use considerations.

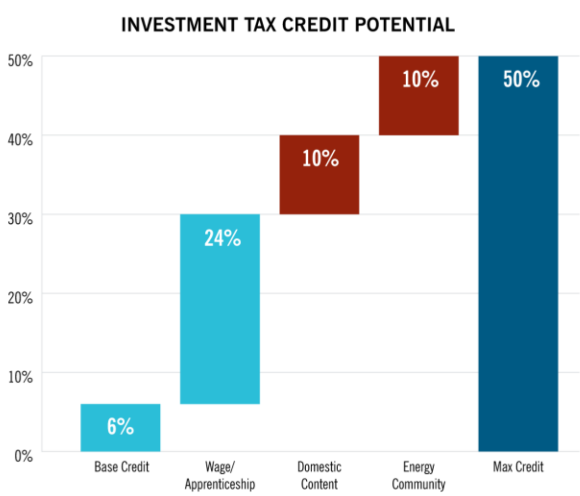
Inflation Reduction Act of 2022

The IRA, signed into law on August 16, 2022, makes the single largest investment in climate and energy in American history (Department of Energy, IRA). For Duke Energy, the IRA will primarily provide tax incentives including tax credits in the form of Production Tax Credits ("PTC") and Investment Tax Credits ("ITC"). The IRA consists of a base credit and bonus credits based on meeting certain criteria. PTCs are a 10-year, inflation adjusted United States federal income tax credit for each kilowatt-hour ("kWh") of electricity generated. ITCs are a United States federal income tax credit based on a percentage of the capital investment and can be taken immediately upon facility completion.

Both the PTC and ITC are allocated in base and bonus amounts if certain criteria are met. As seen in Figure 2-6 below, the base credit for investing in a zero-carbon emitting resource is 6% for ITC and $6/MWh (2025) for PTC.[16] There are three levels of bonuses that can be added by meeting certain criteria for projects greater than 5 MW: 1) Wage and Apprenticeship, 2) Domestic Content and 3) Energy Communities. Meeting one of these three criteria can increase base ITC by 24% to a total of 30% or can increase base PTC by $24/MWh to a total of $30/MWh. Meeting two of the three criteria can increase base ITC by an additional 10% or base PTC by an additional $3/MWh (PTC is increased by a 10% adder). Meeting all three of these criteria can increase base ITC by an additional 10% or base PTC by another $3/MWh (PTC is increased by another 10% adder). Potential maximum credit if all bonus criteria is met is 50% for ITC and $36/MWh (2025) for PTC.

Plan modeling assumes that the Companies can meet wage and apprenticeship guidelines for its resource plan modeling, so the baseline for all eligible projects will be 30% ITC or $30/MWh PTC (2025). No domestic content will be assumed in modeling since the bonus is based on very project-specific guidelines about portions of projects manufactured in the US, and the Companies will require more clarification from the Treasury on its application. Energy community bonuses are based on siting projects on retired coal generation sites or closed mined sites, brownfield sites or statistical area categories with historical employment in fossil areas and high unemployment. The Companies have preliminarily identified retired coal sites where it may be feasible to site energy storage, and work is ongoing to assess other potential energy community areas.

Figure 2-6: Inflation Reduction Act of 2022



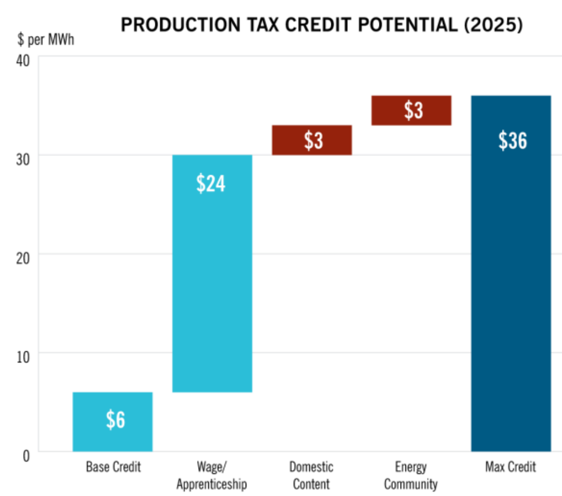


Table 2-24 below shows which ITC and PTC assumptions, including where applicable bonus incentives created in the IRA, are included in Plan modeling. These assumptions will be modified based on site and project specific criteria during procurement.

[16] PTC values are indicative based on inflation assumptions.

Plan modeling also assumes that all projects eligible for IRA will qualify for 5-year modified accelerated cost recovery system ("MACRS"). In addition, the Companies' modeling assumes that the credits for IRA Sections 45Y and 48E shown below in Table 2-24 do not phase out during the resource plan study period which ends in 2050. The IRA states that credits will phase out the later of "the year after 2032" or when the electric power sector GHG emission achieves a 75% reduction of 2022 levels.[17] From review of studies from Rhodium, REPEAT, Resources for the Future, Energy Innovation and other recent IRPs, Duke Energy has determined that the 75% reduction from 2022 levels will not be reached until the mid-2040s at the earliest. With uncertainty in the date in which the energy sectors GHG emissions achieve 75% reduction and safe harbor provision extending the availability for tax credit eligibility, the Plan assumes no phase out of IRA credits over the planning horizon.

Plan modeling assumes that stand-alone solar, wind and advanced nuclear will receive PTCs and standalone storage and pumped storage will receive ITCs. 60% of new stand-alone batteries are assumed to be sited at retired coal sites and will receive the Energy Community bonus. Solar paired with storage and Advanced Nuclear (with integrated thermal storage) will receive PTC on the generating portion and ITC on the storage portions of the project. Finally, it is assumed that hydrogen commodity prices used in the Plan reflect the $3 kg/hydrogen PTC that is produced by a carbon neutral source.

Table 2-24: Carolinas Resource Plan Modeling Assumptions

Generation Alternatives	IRA Incentives Modeled in Resource Plan	Incentive Phase Out
Standalone Solar (45Y) Onshore Wind (45Y) Offshore Wind (45Y) Advanced Nuclear (45Y)	PTC for 10 Years 5 Year MACRS	No Credit Phase Out During Study Period
Standalone Storage (48E)	40% of MW @ 30% ITC 60% of MW @ 40% ITC 98.5% Project Eligibility 5 Year MACRS	No Credit Phase Out During Study Period
Solar Paired with Storage (45Y+48E) Advanced Nuclear (45Y+48E)	PTC for 10 Years (Solar/Nuclear) 30% ITC (Storage) 98.5% Project Eligibility 5 Year MACRS	No Credit Phase Out During Study Period
Pumped Storage (48E)	30% ITC 98.5% Project Eligibility 5 Year MACRS	No Credit Phase Out During Study Period
Hydrogen (45V)	$3/kg PTC for 10 Years	End Year After 2032 if not yet under construction

[17] A 75% reduction in GHG emissions from 2022 levels corresponds to an approximate 83% reduction in GHG emissions from 2005 levels.

The Companies will continue to monitor and refine their assumptions as more Treasury Guidance is given and will maximize benefits to its customers. These credits will pass directly to customers and will lower the cost of the energy transition to customers.

Infrastructure Investment and Jobs Act

Both the IRA and Infrastructure Investment and Jobs Act (“IIJA”) represent historic opportunities to invest in clean, innovative and resilient energy infrastructure. Duke Energy has implemented a rigorous prioritization methodology with specific criteria developed by the Companies to identify IIJA programs that align with the Companies’ objectives of providing reliable and affordable energy to their customers. This framework has allowed the Companies to focus their efforts on pursuing programs that will yield the greatest results while identifying lower priority programs that Duke Energy will continue to monitor for further developments or alignment with future initiatives. The Companies aggressive pursuit of federal funds under IIJA programs that have been identified as high priority has resulted in Duke Energy submitting 17 IIJA-funded applications that will reduce the cost of developing and deploying clean energy technologies and grid improvements, including:

- Advancing the production, storage, transport and delivery of hydrogen as part of the Southeast Hydrogen Hub Coalition;
- Demonstrating an emergent long duration energy storage technology in North Carolina which will benefit both North Carolina and South Carolina;
- Improving grid resilience and reliability and deploying smart grid technologies to integrate more renewables, batteries, EVs and other Grid Edge technologies; and
- Incentivizing more efficient hydropower capability in the Carolinas.

The Companies will incorporate any cost savings associated with IIJA initiatives as appropriate in future Plan updates.

Portfolio Development

As previously described, the Plan must maintain or improve reliability, account for customer affordability and least cost, while also complying with existing state and federal laws and regulations including the Companies’ dual-state system obligations to reduce reliance on fossil fuel resources and achieve CO_2 emissions reductions targets through the retirement of coal units in North Carolina and implementation of an increasingly clean set of resources. To achieve this, the capacity expansion model is used to optimize portfolio resources to meet customer energy and peak demand needs, maintain or improve reliability, as well as achieve carbon reductions targets over the planning horizon in a least-cost manner. The model seeks to develop a portfolio of resources that will minimize overall system costs inclusive of capital costs for new resources as well as ongoing operation, maintenance and fuel costs. Capacity expansion examines numerous permutations of possible resource options that meet system reliability and carbon emissions reductions targets for each portfolio. Given the vast number of resource options examined in this phase of the analysis, the capacity expansion screening model uses a simplified, average representation of hourly system demand to screen for the optimal resource portfolio.

The Companies first perform coal unit retirement analysis endogenously within capacity expansion. The endogenous evaluation was, in part, based on prior stakeholder feedback, as well as the enhanced modeling capability offered by EnCompass. The projected ongoing capital and operating and maintenance coal unit expenses were estimated using the capacity factors from the initial expansion plan analysis. After inputting these expenses into the model, capacity expansion selected the coal unit retirements as a part of the resource mix while minimizing cost and meeting the CO_2 emissions reductions targets. Final retirement dates are then established based on the ability to execute replacement resources and transmission upgrades necessary to ensure or improve reliability and other qualitative planning considerations. The retirement selection process is explained in more detail in Appendix F (Coal Retirement Analysis).

With the coal retirement dates established, resource portfolios are then optimized in the capacity expansion model utilizing the final retirements established in the coal retirement analysis for each pathway. These preliminary portfolios are then ready to be evaluated for detailed operations and reliability analysis within the production cost model.

Production Cost

The portfolio of resources developed using the capacity expansion model is then evaluated in the production cost model. This model uses detailed, chronological, hourly granularity over the planning horizon to simulate the commitment and dispatch of system resources to meet the weather normal hourly load requirements of the system consistent with least-cost system operations. This level of detailed analysis allows for modeling resources with specified generation profiles or other detailed operating characteristics. The detailed hourly production cost model is also utilized for sensitivity analyses of selected portfolios. Completion of this step produces preliminary portfolios that satisfy portfolio objectives subject to a final step required to ensure that the portfolios maintain power system reliability. The results from the production cost runs are the basis for the economic and rate impact analysis, and verification that carbon emissions reductions targets, reserve margins and Joint Dispatch Agreement transfer limits are met. Finally, a check on system operation and reliability is performed using results from the production cost analysis to ensure there are adequate resources and energy to serve customer load in all hours.

The Bad Creek II second pumped storage hydro powerhouse was included in all portfolios in 2034. This proven resource provides critical net dependable capacity during peak periods to meet growing customer demand in the region while diversifying reliance on constrained dispatchable resources such as natural gas and battery energy storage. Furthermore, as the Companies execute on the energy transition, longer-duration storage will provide essential system flexibility and balancing capabilities required for efficient and reliable day-to-day operations of the grid. The Companies have a long operating history with pumped storage and a second powerhouse at Bad Creek would be an addition of a demonstrated technology that can provide over 10 hours of storage. To assure competitiveness, two alternative cases for Bad Creek II powerhouse were evaluated. One case with Bad Creek II excluded from the modeling and a second case where the model was allowed to economically select Bad Creek II. In the first case, including Bad Creek II proved to be a more economical solution than not including the unit. The second case, where Bad Creek II was allowed to be selected or not selected by the model, the unit was selected. The results of these cases verified the inclusion of Bad Creek II in all portfolios. Detailed results of the analysis are discussed in Appendix C.

Reliability Verification

Initial reserve margin and ELCC values are dependent on many factors including the system peak demand and load shape to be served, the existing resource mix, as well as the expected adoption level of different renewable and energy storage resource technologies. The capacity expansion model introduces changes in the resource mix which can impact ELCC values, LOLE and operational reserve requirements. Since it is not practical to determine these values for infinite combinations of resources, nor are such inputs easily integrated into the resource planning models, the Companies conducted additional reliability modeling within SERVM, the model used to calculate LOLE, reserve margins and ELCC values, for the base portfolios for study years 2033 and 2038. This verification step ensures that reliability is maintained with the portfolios' particular set of resources identified in the capacity expansion model. Additional dispatchable resources are added in this step if additional firm capacity is needed to maintain system reliability. Results of this Reliability Verification step produce the final portfolios evaluated in the Performance Analysis step discussed in the next section. Appendix C addresses the LOLE verification process in greater detail.

Performance Analysis

The final portfolios from the production cost analysis with any additional resources required for reliability are then evaluated for cost, both in terms of present value of revenue requirements and estimated customer bill impacts, as well as for carbon emissions reductions over the planning horizon. The customer bill impacts incorporate system fuel, operating and maintenance and capital expenditures of new resources for each portfolio projected through 2033 and 2038. Chapter 3 includes analysis of portfolio performance against the core Carolinas Resource Plan objectives with additional detail provided in Appendix C.

Performance Sensitivity Analysis

In addition to the Core Portfolios, Portfolio Variants and Sensitivity Analysis Portfolios described earlier in this Chapter, the Companies performed additional sensitivity analysis to evaluate the robustness of portfolio performance results with respect to variability in certain input variables. For the sensitivity analysis step, the Companies tested variations in resource cost and fuel price across three different levels of carbon constraints. The Companies kept the portfolios fixed for this analysis. Figure 2-7 below shows the sensitivity analysis cases that were conducted. Refer to Chapter 3 and Appendix C for further detail regarding the sensitivity analyses and results.

Figure 2-7: Performance Sensitivity Analysis Cases