STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 179

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of: Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plan and Carbon Plan	)))))))	**DIRECT TESTIMONY OF GLEN SNIDER, BOBBY McMURRY, MICHAEL QUINTO AND MATT KALEMBA FOR DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC**

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Q. MR. SNIDER, PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION WITH DUKE ENERGY CORPORATION.

A. My name is Glen A. Snider, and my business address is 526 South Church Street, Charlotte, North Carolina, 28202. I am the Managing Director of Carolinas Integrated Resource Planning and Analytics for Duke Energy Corporation.

Q. BEFORE INTRODUCING YOURSELF FURTHER, WOULD YOU PLEASE INTRODUCE THE PANEL.

A. Yes. I am appearing on behalf of Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and together with DEC, the "Companies" or "Duke Energy") together with Bobby McMurry, Michael Quinto, and Matt Kalemba on the "Modeling and Near-Term Actions Panel." Witnesses McMurry, Quinto, and Kalemba will introduce themselves.

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL BACKGROUND.

A. My educational background includes a Bachelor of Science in mathematics and a Bachelor of Science in economics from Illinois State University.

Q. PLEASE DESCRIBE YOUR BUSINESS BACKGROUND AND PROFESSIONAL QUALIFICATIONS.

A. With respect to professional experience, I have been in the utility industry for over thirty years. I started my career in 1989 as an associate analyst with the Illinois Department of Energy and Natural Resources, responsible for assisting in the review of Illinois utilities' integrated resource plans. In 1992, I accepted a planning analyst job with Florida Power Corporation and for the past twenty years have held various management positions within the utility industry. These positions have included managing the Risk Analytics group for Progress Ventures and the Wholesale Transaction Structuring group for ArcLight Energy Marketing. Immediately prior to the merger of Duke Energy and Progress Energy, I was Manager of Resource Planning for Progress Energy Carolinas. I am currently the Managing Director of Integrated Resource Planning and Analytics for Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) and have had the privilege to lead this team for the past ten years.

Q. WHAT ARE YOUR RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. I am responsible for the supervision of the Integrated Resource Plans ("IRPs") for both DEC and DEP. In addition to the production of the IRPs, I have responsibility for overseeing the analytic functions related to resource planning related issues for the Carolinas region. Examples of such analytic functions include, but are not limited to, unit retirement analyses, the analytical support for applications for certificates of public convenience and necessity for new generation, and analyses required to support the Companies' avoided cost calculations that are used in the Commission's biennial avoided cost rate proceedings.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?

A. Yes. I have testified before the Commission on numerous occasions including prior IRP proceedings, technical conferences, certificate proceedings, avoided cost proceedings and various other matters involving resource planning related issues.

Q. MR. McMURRY, PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION WITH DUKE ENERGY CORPORATION.

A. My name is Robert A. (Bobby) McMurry, and my business address is 526 South Church Street, Charlotte, North Carolina, 28202. I am the Managing Director of Resource Planning Strategy and Analytics for Duke Energy Business Services, LLC.

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL QUALIFICATIONS.

A. My educational background includes a Bachelor of Science in Engineering from the University of North Carolina at Charlotte. I am also a registered Professional Engineer in North Carolina and South Carolina.

Q. PLEASE DESCRIBE YOUR BUSINESS BACKGROUND AND EXPERIENCE.

A. I began my career at Duke Power Company (now known as DEC) in 1982 and have had a variety of responsibilities for DEC in areas of structural design, environmental strategy, allowance management, integrated resource planning and modeling. I assumed my current position as Managing Director, Resource Planning Strategy and Analytics in 2012.

Q. WHAT ARE YOUR RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. As Managing Director of Resource Planning Strategy and Analytics, I have the primary responsibility to lead the team that performs the modeling and analytics to support integrated resource planning for each of Duke Energy's regulated utilities, including DEC and DEP. My team is responsible for the modeling performed by the Companies in support of the Carolinas Carbon Plan ("Carbon Plan" or the "Plan").

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?

A. Yes. I have testified before the Commission in prior IRP hearings in Docket No. E-100, Sub 118 and Docket No. E-100, Sub 124.

Q. MR. QUINTO, PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION WITH DUKE ENERGY CORPORATION.

A. My name is Michael T. (Mike) Quinto, and my business address is 526 South Church Street, Charlotte, North Carolina 28202. I am a Lead Engineer on the Carolinas Integrated Resource Planning and Analytics team for the Companies.

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL QUALIFICATIONS.

A. I received a Bachelor of Science in Mechanical Engineering from the University of Cincinnati in 2014. I am a registered Professional Engineer in North Carolina.

Q. PLEASE DESCRIBE YOUR BUSINESS BACKGROUND AND EXPERIENCE.

A. I started my career with Duke Energy in 2011 as part of the engineering co-op program. I was hired by Duke Energy in 2014 as a full-time employee following completion of my engineering degree. Since then, I have served in a variety of engineering roles in Integrated Resource Planning and Modeling in Enterprise Strategy and Planning and in Business Performance in Renewables and Regulated Energy and Operations Support.

Q. WHAT ARE YOUR RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. In my current position I provide direction and support for IRP modeling and perform financial analytics to support the DEC and DEP IRPs and the Carbon Plan.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?

A. No. I have not previously testified before the Commission. I did, however, present to the Commission as part of a technical panel on coal retirements in the Companies' 2020 IRP proceeding in Docket No. E-100, Sub 165.

Q. TURNING NOW TO YOU, MR. KALEMBA, PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION WITH DUKE ENERGY CORPORATION.

A. My name is Matthew (Matt) Kalemba, and my business address is 526 South Church Street, Charlotte, North Carolina, 28202. I am the Director of Distributed Energy Technologies ("DET") Planning and Forecasting for Duke Energy.

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL QUALIFICATIONS.

A. I received a Bachelor of Science in Chemical Engineering from North Carolina State University in 2000 and a Master of Business Administration from Lake Forest Graduate School of Management in Chicago in 2012.

Q. PLEASE DESCRIBE YOUR BUSINESS BACKGROUND AND EXPERIENCE.

A. From 2000 to 2014 I held various roles in the petroleum refining and petrochemical industry including process engineering, feedstock and supply chain management, and short-term, mid-term, and long-term strategy development. I joined Duke Energy in 2014 as an analyst in the Carolinas Integrated Resource Planning team and became Director of DET Planning and Forecasting in March of 2020.

Q. WHAT ARE YOUR RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. As Director of DET Planning and Forecasting, I have the primary responsibility for leading the team that develops the long-term forecast for distributed energy resources ("DER") for each of Duke Energy's regulated utilities, including DEC and DEP. This includes developing rooftop solar and electric vehicle ("EV") forecasts that are used as load modifiers in the Companies' load forecasts, as well as developing the utility-scale solar forecasts for each jurisdiction. My team is also responsible for creating the energy profiles for solar and wind resources, as well as the load profiles for EVs. Finally, I support the development of planning assumptions regarding battery storage.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?

A. Yes. I testified in 2017 as DEC's lead technical witness supporting DEC's application for approval to construct a 400 megawatt ("MW") natural gas combustion turbine ("CT") electric generating facility in Lincoln County (Docket No. E-7, Sub 1134). I also testified before the Public Service Commission of South Carolina ("PSCSC") in the Companies' 2020 IRP proceeding.

Q. IS THE PANEL SPONSORING ANY EXHIBITS IN YOUR DIRECT TESTIMONY?

A. Yes. We are sponsoring the following exhibits, which are described below.

- **Modeling and Near-Term Actions Panel Exhibit 1** provides an overview of the key inputs and assumptions used to develop the supplemental portfolio analysis discussed in Section III, below.
- **Modeling and Near-Term Actions Panel Exhibit 2** provides graphics and figures presented in our testimony in a larger, more readable format.
- **Modeling and Near-Term Actions Panel Exhibits 3-10** provide data request responses that are referenced throughout the testimony.

Q. MR. SNIDER, ON BEHALF OF THE PANEL, PLEASE BRIEFLY SUMMARIZE YOUR JOINT TESTIMONY.

A. Our joint testimony addresses the following:

Carbon Plan Objectives and Proposed Near-Term Actions

1) Highlights how the Companies three-pronged planning framework supports the need for an "all-of-the-above" approach that includes a diverse mix of both demand and supply-side resources to achieve the Carolinas energy transition and carbon reduction targets set out in Session Law 2021-165 ("HB 951") in an economic and executable manner while maintaining or improving system energy adequacy and reliability.

2) Describes how the results of the Carbon Plan modeling and analysis together with the results of the supplemental portfolio analysis support the Companies' proposed near-term actions, which, if approved by the Commission, will enable Duke Energy to make immediate progress towards the Carolinas energy transition and continued carbon dioxide ("CO_2") emissions reduction while pursuing necessary development activities to advance long lead-time resources (offshore wind, small modular reactor nuclear ("SMR"), and pumped storage

hydro at Bad Creek) and to keep all options available in advance of the 2024 Carbon Plan update.

3) Explains that the near-term actions identified in Carbon Plan Executive Summary Table 3 and replicated in Bowman Exhibit 3 are generally consistent with all pathways and portfolios and will result in direct, decisive and immediate action in the near-term, while affording the Commission discretion and flexibility to determine the optimal timing and mix of additional resources required for prudent resource planning and to meet HB 951's energy transition targets in future Carbon Plan biennial update proceedings.

Review of Carbon Plan Modeling Approach

4) Explains that the Carbon Plan for energy transition of its dual-state Carolinas systems was developed through a sophisticated and comprehensive analytical process using a suite of advanced technical models and was presented in an unprecedented level of detail and transparency to ensure that the resulting portfolios and the proposed near-term actions support all four core Carbon Plan energy transition objectives: CO_2 reductions, affordability, reliability, and executability.

5) Reemphasizes that the Carbon Plan pathways and portfolios for energy transition are designed to evaluate the full range of options available to the Commission to set the pace of the energy transition and the Commission's discretion to consider all resources available to meet the interim 70% CO_2 emissions reduction target under the core Carbon Plan objectives.

6) Requests the Commission find that the Carbon Plan was developed based upon reasonable inputs, assumptions and methods at the snapshot in time in which the Plan was developed and further find the associated results are reasonable for planning purposes for energy transition and supports Commission approval of the near-term actions identified in Carbon Plan Executive Summary Table 3 and also replicated in Bowman Exhibit 3. The Companies believe that it is not necessary, or likely possible. for the Commission to resolve every disputed issue related to the complex modeling assumptions. The Companies believe that, while there are uncertainties inherent in this process, the modeling assumptions are reasonable and support the near-term action plan presented for approval in this initial Carbon Plan proceeding. Approval of the near-term action plan will allow the Commission to retain discretion to consider all available options in future Carbon Plan biennial update proceedings as the energy transition continues.

Supplemental Modeling Portfolios

7) Explains that through consultation with the Public Staff and taking into consideration recommendations from other intervenors, as well as extensive effort by Duke Energy, the Companies have performed Supplemental Portfolio Modeling as discussed in Section III and further detailed in Modeling and Near-Term Actions Panel Exhibit 1. The supplemental modeling incorporates a number of different resource planning assumptions to assess the reasonableness of the Companies' proposed near -term activities.

8) Demonstrates that the supplemental portfolios (SP5 and SP6) validate near-term actions presented in the Carbon Plan for Commission approval are reasonable.

Update on Near-Term Solar Procurement

9) Describes the Companies plans for procuring the CPRE Program Remainder MW (441 MW) as part of the 2022 Solar Procurement to close out the CPRE Program under Session Law 2017-192 ("HB 589"). This final procurement under the CPRE Program increases the total procurement volume of solar resources to be procured via the 2022 Solar Procurement to approximately 1,200 MW.

Responses to Recommendations and Criticisms of Carbon Plan Modeling

10) Reintroduces 2005 CO_2 emissions baseline accounting method, as supported by the Public Staff and the NC Department of Environmental Quality, and requests the Commission approve this method as appropriate for tracking future CO_2 emissions to gauge progress toward HB 951 targets.

11) Explains that all steps in the complete Carbon Plan analytical process are reasonable and necessary to analyze the core Carbon Plan objectives and further explains how no single model can address the multiple objectives of an orderly energy transition outlined in HB 951.

12) Describes how the reserve margin and effective load carrying capability ("ELCC") assumptions used in developing the Carbon Plan portfolios are based on comprehensive studies conducted by Astrapé Consulting for the Companies and provide reasonable reserves and capacity value estimates for use in capacity expansion modeling. These metrics, when coupled with the reliability validation step in the modeling process, ensure the Companies' Carbon Plan portfolios maintain or improve system reliability as required for prudent resource planning and by HB 951.

13) Highlights the Carbon Plan's aggressive commitment to pursue offerings that encourage energy efficiency ("EE"), demand response, and other innovative Grid Edge customer programs to "shrink the challenge" of the energy transition.

Discusses why the Companies' achievable assumption of 1% of eligible retail load is appropriate and the significantly more aggressive EE assumptions advocated for by some Intervenors are not reasonable or appropriate for inclusion in the Plan.

14) Explains how the net energy metering solar ("NEM") and electric vehicle forecasts were developed, and how those forecasts are reasonable for Carbon Plan modeling purposes and will be updated in future iterations of the Carbon Plan.

15) Reiterates that the reasonable coal unit retirement dates used in the Carbon Plan analysis are informed by capacity expansion modeling results and consideration of several real-world system constraints that are not captured in modeling and support a balanced approach to achieving the core Carbon Plan objectives and an orderly energy transition.

16) Explains that the resource capital cost forecasts used in the Carbon Plan analysis were developed to reflect the Companies' expected unit configurations and operating conditions in the Carolinas and are therefore the most appropriate planning estimates for this purpose.

17) Agrees with recommendations regarding the inclusion of revised solar paired with storage ("SPS") dispatch modeling and additional SPS configurations as included in SP5 and SP6 Supplemental Portfolio analysis may be reasonable to include in future Carbon Plan modeling but cautions that significant increases in model processing time caused by these updates is not sustainable.

18) Identifies that further study of various aspects of SPS assets is required to ensure actual operations of solar paired with battery storage match modeling assumptions for this resource. Further study areas include additional ELCC analysis, review of battery storage charging source options (DC solar charging, DC solar and grid charging, and AC-tied grid charging), transmission implications of various configurations, development of third-party storage commercial contract terms and conditions that replicate the operational characteristics as well as qualitative benefits and risks of similar Company owned assets over the life of the Contract.

19) Rebuts critiques that the Companies' solar interconnection assumptions are arbitrary and overly conservative and explains that the assumptions reflect the impacts of queue reform, the potential for larger solar projects to interconnect, and the development of Red Zone Transmission Expansion Plan ("RZEP"). Demonstrates that the Companies' solar interconnection assumptions are aggressive when compared to peer utility resource plans as well as the Companies' own historic interconnection rates.

20) Rebuts critiques regarding the reasonableness of the Companies' natural gas

commodity price forecast and longer-term hydrogen fuel cost assumptions and demonstrates both that Duke Energy's assumptions are reasonable for planning purposes and that Supplemental Portfolio Modeling still selects the need for new natural gas resources in the near-term if these inputs are changed as recommended by the Public Staff.

Review of Intervenor-Sponsored Alternate Modeling and Portfolios

21) Describes how intervenors sponsoring alternate planning analyses failed to maintain technical objectivity, using outcome-oriented assumptions and methods that result in portfolios that unduly favor certain resources, lack prudent diversification of risks, and do not appropriately balance the core Carbon Plan objectives.

22) Explains that intervenors' analyses are incomplete, lacking any focused validation of economics and reliability, which is critical for any plan that envisions a continued transition to greater reliance on variable energy and energy-limited resources and importantly are not compliant with HB 951.

23) Rebuts intervenors' suggested modifications to the Companies' proposed near-term actions as they are based on flawed and incomplete analysis and would increase the risk of failure to achieve the goals set out in HB 951.

Recommendations for Future Carbon Plan Modeling

24) Recognizes that additional engagement with the Public Staff and other stakeholders on Carbon Plan modeling is appropriate in advance of the 2024 Carbon Plan update.

I. INTRODUCTION AND PURPOSE

(A) Carbon Plan is designed to Achieve Core Objectives of CO_2 reductions, Affordability, Reliability, and Executability.

Q. PLEASE DESCRIBE THE CORE OBJECTIVES OF THE CARBON PLAN.

A. As described by witness Kendal C. Bowman, in developing the Carbon Plan for an orderly energy transition of the Companies' Carolinas systems, Duke Energy sought to balance four core planning objectives in pursuing all reasonable steps towards achieving the requirements of HB 951: CO_2 reductions, affordability, reliability, and executability. As described throughout the Carbon Plan, and in more detail throughout this testimony, the Carbon Plan modeling framework was developed to achieve the energy transition and the CO_2 reduction targets outlined in HB 951 in the least cost manner for customers while ensuring system reliability is maintained or improved, and that the portfolios could be executed by the Companies subject to mitigation of varying execution risk factors described in the Plan.

Q. PLEASE DESCRIBE FURTHER THE MODELING APPROACH UTILIZED TO CREATE THE CARBON PLAN AND TO ACHIEVE THE FOUR CORE OBJECTIVES.

A. The Carbon Plan was developed with stakeholder input using a robust modeling analysis framework, with intentional focus on achieving the core objectives described above, and ultimately serving to inform the Commission's determination of near-term actions required to pursue the least-cost pathway to achieve compliance with HB 951's CO_2 emission reductions targets while maintaining or improving system reliability. To analyze these objectives, the Carbon Plan utilizes a comprehensive set of modeling tools within an analysis framework designed to fully assess the operational, economic, and reliability implications of resources within a set of planning portfolios. A summary of the modeling tools, inputs and results is presented in Chapter 2 (Methodology and Key Assumptions) and Chapter 3 (Portfolios) of the Plan, with a detailed description provided in Appendix E (Quantitative Analysis). Importantly, the Carbon Plan also places much greater focus on near-term and longer-term executability than past integrated resource planning analyses to inform the Commission's determination of resources to be selected to meet HB 951 requirements.[1]

Q. AS EXPLAINED IN THE CARBON PLAN, THE MODELING ANALYSIS IS BASED ON A SNAPSHOT IN TIME. COULD YOU PROVIDE SOME EXAMPLES OF EXTERNAL FACTORS THAT HAVE CHANGED SINCE THE COMPANIES DEVELOPED THE CARBON PLAN?

A. Yes. Resource planning analyses rely heavily upon inputs, assumptions and forecasts about future conditions that are based on a "snapshot in time" at the time the plan is developed. The Carbon Plan reflects cost inputs and assumptions that were available in late 2021 through spring 2022, as discussed

[1] *See* Carbon Plan Chapter 4 (addressing Execution Plan).

in Chapter 2 and many of the Appendices to the Carbon Plan.[2] Since the Carbon Plan was developed, economic conditions and other external factors have changed. For example, renewable resource, battery storage and natural gas capital cost and commodity cost input assumptions in the Plan were developed at a point in time prior to spikes in domestic inflation and prior to many of the geopolitical issues that are placing varying levels of upward pressure on actual market costs for resources in the Plan (compared to the point in time when Plan inputs were developed). Conversely, as mentioned by Witness Bowman, President Biden recently signed into law the Inflation Reduction Act of 2022 ("IRA"), which includes clean energy tax incentives that will help to offset these cost increases.

Another example of an important input into the planning process is the underlying forecasts for customer annual energy requirements and seasonal peak demand needs. Several factors influence these forecasts including the overall state of the economy, the rate of residential, commercial, and industry migration to the Carolinas, consumer adoption rates for rooftop solar, energy efficiency programs, and EVs, along with several other factors. Many of these factors have evolving headwinds and tailwinds that will result in changes to the energy and peak demand forecasts and will be captured in future Carbon Plan updates.

[2] Carbon Plan Chapter 2 at 1.

Q. PLEASE EXPLAIN HOW THE CARBON PLAN AND THE ASSOCIATED NEAR-TERM ACTIONS PRESENTED IN THE EXECUTION PLAN ACCOUNT FOR CHANGING MARKET CONDITIONS, INPUTS AND ASSUMPTIONS, AND HOW THE COMMISSION SHOULD VIEW SUCH CHANGES?

A. First, as described in Chapter 3 and Appendix E, the modeling process involves significant sensitivity analysis on many input variables to test the robustness of the Plan under various changes or sensitivities to inputs. Second, as described later in this testimony, the Companies conducted additional analysis to further test the robustness of the Plan's outcomes based on feedback from the Public Staff. Third, as called for by HB 951, the Plan will be updated on a bi-annual basis with an initial Plan update to be filed in 2024. Fourth, the near-term actions outlined in the Carbon Plan Executive Summary Table 3 will result in several new dockets before the Commission that will involve updated, detailed analysis that is beyond the scope of a long-range plan and will help to inform the 2024 Carbon Plan update filing that will be made with the Commission.

Based on this comprehensive base planning analysis, sensitivity analysis and supplemental modeling analysis conducted throughout this proceeding, the Companies' proposed near-term actions represent the "reasonable steps"[3] contemplated by HB 951 to decisively move forward in this next major phase of the energy transition and should be approved by the

[3] *See* G.S. § 62.110.9.

Commission. The Companies also emphasize for the Commission that the planning process and subsequent execution processes are dynamic in nature. As such, the volume and nature of future resource additions, beyond those identified in the near-term action plan, will be adjusted based on initial procurement activities and updated analysis that will be presented in the 2024 Carbon Plan update. Finally, given the dynamic nature of almost every aspect of the Carbon Plan, one of the largest potential barriers to establishing the most prudent and reasonable least cost pathway to accomplish an orderly Carolinas energy transition and to meet HB 951's goals may be the perpetual desire for additional analysis and planning prior to execution. In the alternative, robust planning informed and updated by robust execution in a sequential and complementary manner will best serve to balance the core objectives discussed above and to achieve the emissions reductions targets envisioned in HB 951.

(B) <u>The Companies' Carbon Plan Modeling is Reasonable for Planning Purposes and Supports Commission Approval of the Near-Term Actions Identified in the Execution Plan.</u>

Q. MR. SNIDER, PLEASE EXPLAIN THE HIGH-LEVEL CONCLUSIONS RESULTING FROM THE COMPANIES' MODELING ANALYSIS.

A. The Companies' Carbon Plan modeling identifies the need for a diverse mix of demand-side programs and supply-side low carbon and zero-carbon resources. As described by Witnesses Lon Huber and Tim Duff ("Grid Edge Panel"), the Plan starts with an aggressive commitment to pursue offerings that encourage energy efficiency, demand response, and other innovative customer programs to first reduce the need for supply-side resources. On the supply side, the Plan identifies the need for a broad mix of zero-carbon resources, storage resources, and a limited amount of hydrogen-capable natural gas resources to maintain system reliability. This "all-of-the-above" approach is supported by the Companies' modeling, prudent utility planning, and provides customers with a diverse mix of resources that achieves carbon reduction targets in an economic and executable manner while maintaining system energy adequacy and reliability pursuant to the requirements of HB 951. Furthermore, in addition to reducing quantitative risk factors identified within the planning framework, a portfolio with a broad mix of customer offerings and supply-side resources also helps to diversify qualitative or unforeseen risks that may arise over the planning horizon but that cannot be fully modelled at a single point in time.

Q. WHAT ARE THE COMPANIES ULTIMATELY SEEKING FROM THE COMMISSION IN THIS PROCEEDING?

A. Witness Bowman reintroduces the Companies' request for relief in their entirety, and I would like to highlight a few key aspects of those requests that are specifically supported by this Panel's testimony. HB 951 directs the Commission to develop a plan to take all reasonable steps to achieve a 70% interim CO_2 emissions reduction target and carbon neutrality by the year 2050.[4] To execute on the Companies' energy transition targets, and meet HB 951's goals, the Companies request that the Commission approve the Companies' proposed Carbon Plan in its entirety, which includes a defined set of near-term

[4] G.S. § 62-110.9.

procurement and development activities that support the portfolios identified in the Plan while allowing for flexibility over time. As explained in the Carbon Plan itself, approving a single portfolio would be premature at this time before more information is gathered regarding the long lead-time supply-side resources—offshore wind, SMR and pumped storage hydro—that are projected to be needed to execute the least cost path to achieving the HB 951 goals. To enable the Companies to begin executing the Carbon Plan and advancing the energy transition while retaining discretion to continue to assess the least cost pathway in future Carbon Plan updates, the Commission should approve moving forward with the Companies' proposed near-term actions outlined in "Table 3: Supply-Side Resources Requiring Actions in Near-Term" presented in the Carbon Plan[5] and also replicated in Bowman Exhibit 3.

The Companies specifically request the Commission affirm that the Companies' Carbon Plan modeling across all portfolios is reasonable for planning purposes and presents a reasonable plan for achieving HB 951's authorized CO_2 emissions reductions targets in a manner consistent with HB 951's requirements and prudent utility planning. At the time the 2024 Carbon Plan update is filed, the Companies will present updated modeling and more refined information that the Commission can consider to evolve this initial Carbon Plan and to make further key decisions regarding resource selections with respect to both the interim and long-term targets.

[5] Carbon Plan Executive Summary at 23.

Finally, the Commission should approve the Companies' methodologies outlined in Appendix A (Carbon Baseline and Accounting) for tracking achievement of HB 951's CO_2 emissions reductions targets and confirm the Commission's accounting requirements for emissions from new out-of-state resources selected by the Commission (if any) as addressed later in our joint testimony.

Q. DOES THE COMPANIES' CARBON PLAN MODELING ANALYSIS SUPPORT THE ACHIEVEMENT OF CARBON PLAN OBJECTIVES UNDER HB 951?

A. Yes.

Q. IN ADDITION TO THE ANALYSIS PRESENTED IN THE CARBON PLAN, ARE THE COMPANIES SPONSORING ADDITIONAL MODELING ANALYSIS?

A. Yes. The Companies provide additional detail below in Section III (Supplemental Modeling Portfolios) regarding the supplemental modeling analysis and alternative SP5 and SP6 ("together the "Supplemental Portfolios") developed over the past few weeks after collaborative discussion with the Public Staff and review of intervenor comments. The key inputs and assumptions used to develop this analysis are addressed in detail in Modeling and Near-Term Actions Panel Exhibit 1.

Q. DOES THE COMPANIES' RECENT SUPPLEMENTAL MODELING PERFORMED AT THE RECOMMENDATION OF THE PUBLIC STAFF

FURTHER SUPPORT THE NEAR-TERM ACTIONS PREVIOUSLY DISCUSSED?

A. Yes. While the Companies do not necessarily fully support all of the Public Staff's supplemental modeling adjustments (as described later in this testimony), the results of the supplemental modeling analysis validate the Companies' proposed near-term (2022-2024) actions for supply-side resources presented in Table 3 of the Executive Summary.[6] Informed by this supplemental modeling analysis, the Companies affirm the recommended near-term actions and request that the Commission approve the near-term supply-side development and procurement activities and select the resources presented in Table 3 of Executive Summary under the framework of HB 951.

[6] Carbon Plan Executive Summary at 23.

Q. DOES THE COMPANIES' ADDITIONAL MODELING ALSO SUPPORT THE COMPANIES' REQUEST FOR COMMISSION APPROVAL OF THE DECISION TO INCUR EXPENDITURES FOR THE NEAR-TERM DEVELOPMENT ACTIVITIES FOR OFFSHORE WIND, SMR, AND BAD CREEK II?

A. Yes. In the Carbon Plan, the Companies request Commission approval of the decision to incur expenditures related to the near-term development work to support the future availability of offshore wind, SMR, and new pumped storage hydro at Bad Creek to ensure that these resources are available options for the Companies' customers on the timelines identified in the portfolios if selected in future Carbon Plan updates.[7] Additional details on how the supplemental modeling portfolios impact the need for, and timing of, these resources are addressed in Exhibit 1. Witnesses Regis Repko, Steve Immel, Chris Nolan, and Clift Pompee ("Long Lead-Time Resources Panel") provide additional detail on these resources and the Companies' near-term development activities.

Q. DO YOU HAVE ANY FINAL INTRODUCTORY COMMENTS?

A. Yes. As we highlight above, the Carbon Plan has been developed based upon reasonable inputs and assumptions about future costs and resource availability as of the time that the Plan was developed. Today, the Companies continue to support these near-term development and procurement activities as the initial reasonable and prudent steps in executing the Carbon Plan.

[7] Carbon Plan Executive Summary at 27-28.

Looking ahead, approximately 12-15 months after the Carbon Plan is approved, the Companies will begin developing modeling assumptions to create the 2024 Carbon Plan update. A number of key developments over that period will be influential in updating the Plan. Such developments will provide more clarity on market cost and availability of resources critical to the energy transition. Results from the 2022 Solar Procurement Program and 2023 procurement activities, implementation of the IRA, more detail on specific transmission expansion plans to support renewable energy deployment, progress on offshore wind supply-chain constraints and the SMR licensing process, along with many other future developments will influence the 2024 update. Given the dynamic nature of the energy landscape, we urge the Commission to remain focused on the steps necessary today to support the achievement of the emissions reduction targets while retaining discretion to evolve the Plan and preserving all options needed to achieve an orderly energy transition and HB 951's objectives with an eye toward the informed future refinements to be made in the not-so-distant future.

II. CARBON PLAN MODELING APPROACH

(A) The Carbon Plan Provides Unprecedented Detail on Modeling Methodology and Key Assumptions, Portfolio Development and Carbon Plan Pathways, as Well as Detailed Quantitative Analysis.

Q. MR. QUINTO, HOW DOES THE CARBON PLAN DIFFER FROM PAST IRPs IN TERMS OF OBJECTIVES, SCOPE, AND LEVEL OF DETAIL?

A. Traditional integrated resource planning includes, at a minimum, the development of a forecast of native load requirements and comprehensive analysis of resource options to satisfy these load requirements over the planning horizon. An IRP typically spans a 15-year planning horizon and seeks to present a resource plan that meets least cost planning criteria while maintaining reliability and complying with applicable state and federal laws.

The Carbon Plan presented by the Companies expands on the objective, scope, and level of detail in a typical IRP in many respects. As required by HB 951, a Carbon Plan must maintain or improve the reliability of the system, while meeting specified CO_2 emissions reductions targets. HB 951 introduces a new planning paradigm to achieve a targeted reduction of 70% CO_2 emissions from electric generating facilities owned or operated by the Companies in North Carolina from a 2005 baseline while also planning over a much longer horizon to achieve carbon neutrality by 2050.

Similar to traditional IRPs, the achievement of these targets in the Carbon Plan employs the IRP's standard of least cost planning. The Carbon Plan provides extensive details on modeling methodology and key assumptions

(Carbon Plan Chapter 2), Portfolio Development and Carbon Plan Pathways (Carbon Plan Chapter 3) as well as detailed quantitative analysis (Carbon Plan Appendix E) used to develop the Carbon Plan portfolios and sensitivities and to assess the portfolios under key Carbon Plan objectives (affordability, CO_2 reductions, reliability, and execution risk).

Importantly, the Carbon Plan's enhanced focus on executability as a core objective is of paramount importance to the success of the Plan's portfolios in terms of meeting HB 951 targets and accomplishing an orderly energy transition of the Companies' Carolinas systems. Assumptions in many aspects of the Carbon Plan, including timing of new technologies, adoption of demand-side measures, and ability to retire more carbon-intensive and aging coal-fired generation and to interconnect new resources, all while maintaining a highly reliable system, must be aggressive enough to meet the required carbon reductions while remaining executable. Indeed, the Public Staff likewise recognizes executability as the crucial component to a candidate resource plan:

> "Execution risks will likely pose the most significant challenge to achieving the CO_2 reduction goals in Section 110.9, and should, therefore, be given substantial attention by the Commission."[8]

To assure executability of the Plan, the Execution Plan (Chapter 4) provides the Commission unprecedented detail on the Companies' execution plans, including near-term supply-side development and procurement activities to achieve the interim emissions reduction targets and ensure that selected and

[8] Public Staff Comments at 12.

long lead-time resources are available options for the Companies' customers on the timelines identified within the portfolios if selected in future Carbon Plan updates. Importantly, HB 951 also evolves the traditional IRP paradigm by providing the Commission express direction and authority to select new resources as part of the Carbon Plan to achieve HB 951's authorized CO_2 emission reduction goals.

Q. PLEASE EXPLAIN THE RATIONALE BEHIND THE PATHWAYS AND PORTFOLIOS PRESENTED IN THE CARBON PLAN.

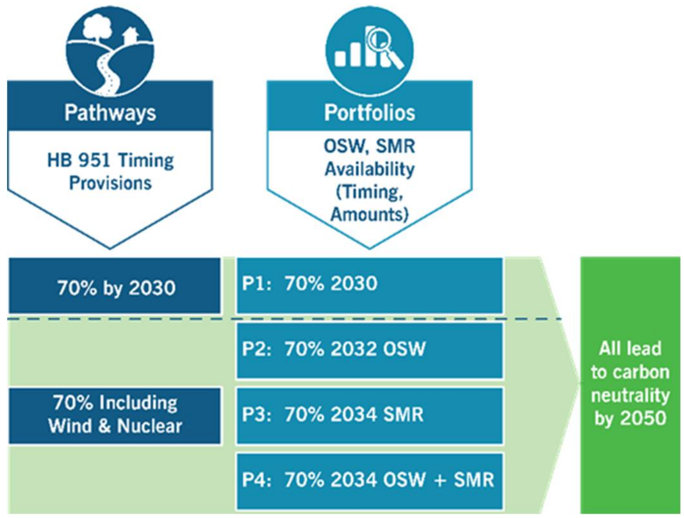
A. In the Carbon Plan, the Companies present two pathways composed of four portfolios to present least cost paths to meeting the interim CO_2 reduction targets and to progress towards carbon neutrality in 2050. These pathways and portfolios, presented below and in Chapter 2 of the Carbon Plan, recognize that HB 951 affords the Commission flexibility, i.e., "retain[ing] discretion," in determining optimal timing of resources to achieve the least cost path in compliance with the CO_2 reduction goals, including discretion in achieving the reduction goals by the authorized date, especially in the event the Commission authorizes the construction of a nuclear or wind energy facility.

Considering the discretion afforded to the Commission regarding the interim target,[9] it is important to explore and understand the material impacts

[9] As directed by the Commission in its *Order Scheduling Expert Witness Hearing, Requiring Filing of Testimony, and Establishing Discovery Guidelines* ("Order Scheduling Expert Witness Hearing"), the Companies will address legal issues related to the application of HB951's extension period in comments to be filed on September 9, 2022.

on carbon reductions relative to cost and timing of implementing nuclear and wind energy facilities, especially offshore wind energy facilities with the potential to supply large amounts of zero-carbon energy. The optimal timing of achieving the CO_2 reduction goals in these cases is therefore dependent on the availability of these resources to contribute to the 70% interim target. For this reason, the Companies present two pathways, as show in Figure 1, one achieving the interim reduction targets by 2030, utilizing the available technology at that time, and the other achieving the interim reductions target once additional nuclear and offshore wind resources would be available for deployment at scale.

Figure 1: Summary of Carbon Plan Proposed Pathways and Portfolios[10]



As further detailed in Carbon Plan Chapter 2, Portfolio 1 follows the first pathway, achieving the interim reduction targets by 2030. Portfolios 2, 3 and 4 follow the second pathway and achieve the targets by 2032 or 2034.

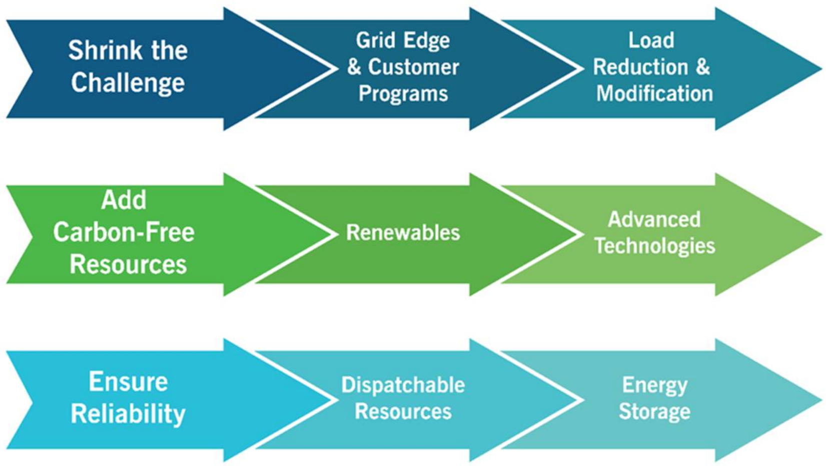
Importantly, regardless of the timeframe for achieving the interim reductions targets, each of the portfolios keeps the Companies on the longer-term path to achieving carbon neutrality by 2050, albeit at differing projected costs and levels of execution risk. For the purposes of modeling, the Companies planned to an "absolute" zero CO_2 emissions target rather than assuming carbon offsets are used to meet the carbon neutrality goal. To achieve this longer-term objective, the Carbon Plan uses emerging technologies in the latter parts of the Plan as placeholders for advanced technologies or more cost effectively utilizing carbon offsets that might be needed in achieving the 2050 target.

[10] Carbon Plan Chapter 2 at 3 (Figure 2-2).

Q. PLEASE DESCRIBE THE APPROACH THE COMPANIES USED TO DEVELOP THE CARBON PLAN PORTFOLIOS AND ACHIEVE THE HB 951 REQUIREMENTS.

A. To achieve HB 951's CO_2 emission reduction requirement and balancing the four core objectives discussed above, the Companies approached developing the Carbon Plan using the three-pronged approach illustrated in Figure 2 below:

Figure 2: Three-Pronged Approach to Planning[11]



The first prong is to "shrink the challenge" for energy transition, which represents the Carbon Plan's focus on reducing the amount of load the Companies must serve. Every incremental megawatt-hour of load the Companies need to serve presents the potential to have to serve that load with incremental cost or CO_2 emissions. To the extent that grid edge and customer programs can reliably and cost effectively be utilized to manage fluctuating energy supply and demand and reduce system annual energy and peak-demand

[11] Carbon Plan Chapter 2 at 2 (Figure 2-1).

requirements to ensure reliability of the system, the Companies plan to prioritize deployment and usage of such resources.

The second prong is the addition and utilization of zero-carbon emitting resources to replace retiring coal generation and meet new load. This step begins with the ability to leverage zero-carbon renewable resources that are currently available today. This includes continuing to programmatically add significant solar to the system over time, while integrating available onshore wind resources, and maintaining the existing renewable resources on the system, such as the Companies' expansive portfolio of hydroelectric facilities. In the mid-term to long-term, this means continuing development activities of emerging renewable and other zero-carbon resources while pursuing subsequent license renewals ("SLR") for the Companies' existing nuclear fleet. These emerging resources include offshore wind, a technology that is well established in other parts of the world, such as Europe, but would be new-to-the Carolinas and has not been deployed at large scale in the United States; small modular and advanced nuclear reactors, both currently under development in North America and abroad; and use of green hydrogen, produced from zero-carbon resources such as renewables or nuclear power, that does not emit CO_2 when used in combustion for power generation. Finally, maintaining the Companies' existing fleet is critical to achieving the emissions reduction targets through 2050, while the remainder of the fleet transitions.

Continuing to pursue the wide range of advanced technologies is prudent given the risk that not all of these resources will be technically or economically viable. The combination of leveraging currently available renewable resources, while continuing to develop the technologies that could further transform the energy system is crucial to achieving a least cost path to carbon neutrality by 2050.

The third prong is ensuring reliability of the system. While presented last here, maintaining or improving reliability of the system represents a minimum standard of any portfolio and is given special recognition and attention in the law: in developing the Carbon Plan, the Commission must "[e]nsure any generation and resource changes maintain or improve upon the adequacy and reliability of the existing grid."[12] Recognizing the fundamental importance of this issue, the Carbon Plan modeling robustly assesses potential reliability risks in developing the portfolios and Carbon Plan Appendix Q (Reliability and Operational Resilience Considerations) addresses how the Companies are planning to meet the evolving challenges of a transitioning resource mix and grid. Witnesses Sam Holeman and Sammy Roberts (the "Reliability Panel") also address this core Carbon Plan objective in more detail from an operator's perspective. While these objectives are part of the Carbon Plan, they are also consistent with reasonable and prudent resource planning.

As the Companies pursue more variable energy renewable resources on the system, they must ensure the integration and operation of these resources does not sacrifice reliably meeting customers' energy needs. The pursuit of the

[12] N.C. Gen. Stat. § 62-110.9(3).

first prong may be able to help preserve reliability through flexibility of net load on the system, but the reliable operation of the grid every minute and in all hours of the year will require dispatchable and flexible resources, such as CCs and CTs, to complement the variability in output of renewables and backstop these resources in the event they are unavailable. Into the future, as energy storage deployment on the system continues to grow, and additional forms of energy storage, such as batteries, pumped storage hydro, and chemical storage such as hydrogen production, become available to the system, these resources could continue to offset the utilization of natural gas in flexible, dispatchable peaking resources to maintain reliability, but energy storage of all forms will require rigorous analysis to ensure reliability can be preserved in such cases.

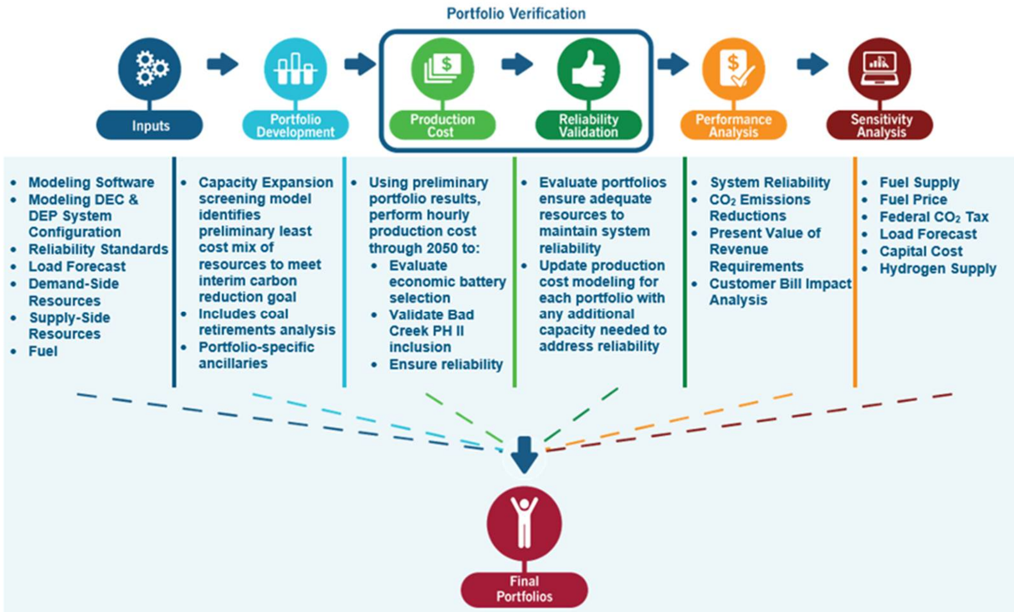
In summary, the Companies' three-pronged approach to energy transition and developing the Carbon Plan prioritizes the role of grid edge and customer programs to be part of achieving the reduction goals, while offsetting more carbon-intensive resources on the system today through additions of renewables and advanced technologies in the future, all while maintaining or improving on the reliability of the system.

Q. PLEASE PROVIDE A BRIEF SUMMARY OF EACH OF THE STEPS IN THE MODELING PROCESS USED TO DEVELOP THE CARBON PLAN.

A. The Carbon Plan provides the Commission and interested parties with unprecedented detail and insight into the Companies' modeling and portfolio development process in Chapters 2 and 3, as well as in Appendix E. The Carbon

Plan utilizes sophisticated modeling and planning techniques, including the EnCompass modeling platform and a suite of portfolio verification and reliability validation modeling tools. Each of these modeling steps is explained in Appendix E and is essential to a complete Carbon Plan analysis that develops least cost pathways to achieving CO_2 emissions reduction targets while ensuring prudent planning for a reliable system. Figure 3 below, presents the analytical process followed in the development of the Carbon Plan portfolios and analysis.

Figure 3: Carbon Plan Analytical Process Flow Chart[13]



Appendix E provides substantial additional detail on the modeling software and assumptions of the system, load, resources and other inputs used in the Carbon Plan modeling, but a high-level summary of the Carbon Plan Analytical Process follows here.

Portfolios were initially developed using the capacity expansion model within EnCompass, an economic resource selection screening model. As described in Appendix E, the EnCompass capacity expansion tool must simplify the optimization problem in order to solve it in a reasonable time period including the variety of load shapes the tool considers during the capacity expansion planning process. The model was also used to endogenously determine economic coal unit retirements with the co-optimization of resources

[13] Carbon Plan Chapter 2 at 5 (Figure 2-3). Figure 3 is also replicated in Modeling and Near-Term Actions Panel Exhibit 2.

and to identify the least cost portfolios of incremental resources to meet system load requirements and CO_2 emissions reductions targets. This initial evaluation of all resource options to identify resources that most economically meet the needs of the system requires simplified simulations of the system to assess potential resource combinations in a workable timeframe.

Following the initial capacity expansion screening step, the Companies performed additional modeling and analysis to ensure the appropriate selection of resources to meet economic, reliability and CO_2 emissions reductions objectives. This modeling analysis, described as the "Portfolio Verification step" in Appendix E,[14] was performed within the Companies' standard IRP production cost model, EnCompass, and in the Strategic Energy & Risk Valuation Model ("SERVM").[15] SERVM is widely utilized in the utility industry to assess reliability standards and quantify the reliability requirements for large, complex power systems including determining planning reserve margin requirements and effective load carrying capability ("ELCC") or capacity values.

The Portfolio Verification step includes production cost modeling to confirm economic selection of resources by the capacity expansion model. Due to the simplified simulations used in capacity expansion modeling, the capacity expansion model alone cannot evaluate in-depth economic operation of

[14] Carbon Plan Appendix E at 57-71.
[15] SERVM is a state-of-the-art reliability and hourly production cost simulation tool managed by Astrapé Consulting who provides consulting services and/or licenses the model to its users.

resources to ensure economic resource selection, especially in the case of energy-limited resources such as storage. The production cost model is used for a more detailed and realistic simulation of the system to more accurately account for the cost to operate the system with these resources. This concept is discussed in further detail in Appendix E.[16]

The Portfolio Verification step also includes enhanced reliability validation modeling and analysis using both SERVM and EnCompass. This analysis is especially important for portfolios with high reliance on variable energy and energy-limited resources, which presents risks that planning reserve margins alone do not adequately address, especially in severe weather events.

Finally, CO_2 and affordability analyses, including present value of revenue requirement ("PVRR") and customer bill impacts, are conducted for these portfolios to verify that each portfolio meets CO_2 reduction targets and to allow comparison of costs across portfolios. Additionally, sensitivity analyses are performed to test the robustness of the Carbon Plan portfolios in terms of resource selection, portfolio cost, and emissions reduction assurance against a host of uncertainties that could present challenges to achieving the Carbon Plan objectives.

Q. PLEASE PROVIDE A SUMMARY OF EACH OF THE STEPS PERFORMED IN THE PORTFOLIO VERIFICATION ANALYSIS.

[16] Carbon Plan Appendix E at 57-60.

A. As described in Appendix E, the Portfolio Verification analysis consisted of the following steps:

- **Battery-CT Optimization –** To quickly assess a wide range of resource options, the capacity expansion resource screening model makes necessary simplifications in hourly loads and system operations to find potential least cost resource portfolios to minimize the cost of the system. Due to these simplifications, especially for load, resources are evaluated against load shapes that are an amalgamation of peak, average and low load conditions for computational efficiency. This simplification has the unfortunate side effect of stretching the load shape in a way that does not reflect actual hourly needs on the system, which results in the capacity expansion model over-valuing short-duration energy storage. This concept is discussed at length in Appendix E.[17] Because the capacity expansion model over-ascribes value to energy storage resources, it is important to use additional analysis to verify that if a portion of the energy storage included in the initial capacity expansion results is economic relative to other peaking resources, in this case CTs. To do this, the Companies ran the initial expansion plan through the detailed production cost model, which more accurately and thoroughly simulates hourly load shapes as well as the hourly operation of the system, dispatching economically among all units of the resource

[17] Carbon Plan Appendix E at 57-58.

portfolio in every hour of every day of the planning horizon. This gives the Companies a more accurate reflection of actual production cost impacts of these resources on the system. In this step, the Companies replaced approximately 35% of the batteries selected by the capacity expansion model with CTs and re-ran the detailed production cost model with the adjusted resource mix. Removing batteries and adding CTs typically increases modeled production costs, but because CTs are lower capital cost ($/kW) to build than batteries this adjustment reduces total capital costs of the portfolio. As long as the capital cost savings are more than enough to offset the production cost increase and CO2 reduction targets can still be met, the CTs are the more cost-effective resource. This process revealed that 1,600 to 2,000 MW of batteries should be replaced with CTs to improve the economics of Portfolios 1-4.

- **Bad Creek Powerhouse II Validation –** Due to the limitations of the capacity model in evaluating energy storage, as discussed in the Battery-CT Optimization step, the Companies performed additional comparative economic analysis of this long-duration storage to confirm Bad Creek II as an economic inclusion in the portfolios. In the initial development of portfolios, Bad Creek II was prescribed into each of the portfolios. To confirm the inclusion was economic, the Companies compared the project's cost effectiveness to other longer-duration storage options.

Similar to the Battery-CT economic evaluation, the Companies ran the detailed production cost model including Bad Creek II and then replaced the project with the equivalent amount of 8-hr lithium-ion batteries and ran the detailed production cost model again. The differences in production cost and new project costs were compared and it was confirmed that the inclusion of Bad Creek II was economic. The analysis was performed for Portfolios 1 and 4, and the Bad Creek II expansion project was economic by $200 to $350 MM over the planning horizon.

- **Resource Adequacy and Reliability Verification** – Additional modeling was performed, using both the EnCompass production cost model and SERVM, to ensure that each portfolio would maintain the reliability of the system. The SERVM model was used to verify that the portfolios maintain resource adequacy in 2030 and 2035 as the system undergoes significant changes, while the production cost model was used to verify that portfolios could reliably meet the energy and CO_2 reduction requirements through 2050.

The continuing transition to greater reliance on variable energy and energy limited resources makes it increasingly critical to supplement the static reserve margin requirement and resource-specific ELCC values used in the capacity expansion model with more sophisticated tools. As mentioned previously, SERVM is the state-of-the-art production cost model used to develop the Companies' planning reserve margins, quantifying the performance of resource portfolios across 41 weather years and a range of forced outage scenarios to ensure the portfolio can maintain the industry standard one day in 10-year loss of load expectation ("LOLE"), which equates to an LOLE of 0.1 event-days/year. The Carbon Plan portfolios, including adjustments resulting from the economic Battery-CT and Bad Creek II evaluations, were loaded into SERVM and run through this wide range of weather and forced outage simulations to measure LOLE and ensure the reliability benchmark was met. In cases where the reliability benchmark was not met, the Companies added "reliability CTs" to the portfolios until the LOLE benchmark was met, indicating that the newly adjusted portfolio could maintain system reliability.[18]

Finally, with any necessary reliability CTs added to the portfolios, the Companies ran the detailed production cost model again to ensure that hourly load throughout the planning horizon could be served while meeting CO_2 reduction targets. As a result of this step, the Companies found that each of the portfolios failed to provide adequate zero-carbon energy near the end of the planning period (2047 and later), so additional zero-carbon generating resources were added to eliminate

[18] No additional reliability CTs were needed to maintain reliability in 2030 and 2035 for Portfolios 1-4. The same resource adequacy and LOLE assessments were run for the Alternate Fuel Supply Sensitivity Portfolios and resulted in the need for additional CT resources in some portfolios to ensure resource adequacy in 2035.

energy-not-served identified by the model. The verification resulted in the addition of 900 to 1,100 MW of nuclear SMR to fill the energy gap.[19]

These additional modeling steps are enhancements to the overall modeling framework and are critical to ensure cost effective and reliable portfolios as required by HB 951.

Q. PLEASE EXPLAIN HOW THE COMPANIES ACCOUNTED FOR "NEIGHBOR ASSISTANCE" WHEN ASSESSING PORTFOLIO RELIABILITY.

A. As discussed in more detail in Appendix E, the Companies utilized modeling data from the 2020 Resource Adequacy Study to develop an island case LOLE target that would correspond to achieving a 0.1 LOLE on an interconnected system basis. The corresponding island case LOLE was determined to be 0.253 event-days per year.[20] Thus, the Carbon Plan portfolios were run as island scenarios with the LOLE compared to 0.253 event-days per year, corresponding to 0.1 LOLE on an interconnected basis. Said another way, "neighbor assistance" meaning the ability to rely upon non-firm energy imported from neighboring balancing authorities ("BAs") adds to system reliability by

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[19] It was later discovered that the excessive energy not served identified by the production cost model was due, in part, to a modeling bug associated with modeling new nuclear units in EnCompass. The Supplemental Portfolio analysis implements a resolution that no longer requires additional resources to meet energy needs in this step. More details on this resolution are included in Modeling and Near-Term Actions Panel Exhibit 1.

[20] Carbon Plan Appendix E at 63.

reducing expected event days in a ten-year period from 2.53 to the industry standard of only 1 event-day in a ten-year period.

This level of reliability benefit from neighboring BAs was held constant during the reliability validation step. However, as discussed in more detail in the Reliability Panel's testimony, future market assistance for reliability planning purposes is highly speculative due to the uncertainty in the pace of neighboring utilities' transition to variable energy and energy limited resources to achieve CO_2 reduction targets. As neighboring systems similarly transition to higher amounts of renewables and storage, neighbors' LOLE risk may similarly shift to the winter months as it has for DEC and DEP. This likely future scenario could lower the diversity in load and resources with neighboring systems resulting in a lower amount of capacity reserves available during winter peak periods. Rather than speculate and build out an assistance area for 2030 and 2035 in SERVM, the Companies assumed that the level of market assistance would neither improve nor decline from the level of assistance modeled in the 2020 Resource Adequacy Study.[21]

Contrary to the position of some intervenors, the Companies believe that this assumption may actually *overestimate* our ability to rely on neighbors in the next decade; however, this simplifying assumption was undertaken to facilitate the LOLE validation step providing a general representation of how the transition of the Companies' system could impact resource adequacy. This

[21] Carbon Plan Attachment I (DEC) and Attachment II (DEP).

approach allows the Companies to observe how reliability of the system changes with resource transition across time without speculation about future market assistance.

Q. PLEASE EXPLAIN WHETHER ANY CONSTRAINTS WERE PLACED ON MODEL SELECTION OF RESOURCES AND WHY THESE ARE CONSISTENT WITH REASONABLE AND PRUDENT RESOURCE PLANNING AS WELL AS HB 951 OBJECTIVES.

A. Models are simplified representations of real-world operations over time, and therefore it is necessary to implement certain constraints so that the modeled system better reflects real-world conditions. In resource planning, constraints are necessary to develop portfolios that can reasonably be expected to deliver desired outcomes and actually be executable in the real world. Some examples of constraints used in the Carbon Plan analysis include planning reserve margin requirements, caps on CO_2 emissions, and limits on the timing and pace of the addition of new resources. Without these constraints, model-selected resource portfolios may not maintain system reliability, may not achieve CO_2 emissions reduction targets, or may call for the addition of new resources faster than they can be procured, constructed or interconnected in the real world. It is prudent to minimize the disconnect between model results and reality to avoid a disorderly transition or "unexecutable" expectations for transitioning of the fleet.

In summary, the constraints used in the Carbon Plan analysis, as discussed later in this testimony, are reasonable for planning purposes to create a realistic representation of cost and resources required to maintain reliability as we exit coal generation and also achieve HB 951's CO_2 emissions reductions targets.

Q. PLEASE BRIEFLY REINTRODUCE THE COMPANIES' MASS CAP APPROACH TO MODELING EMISSION REDUCTIONS.

A. To develop the preliminary selection of resources in the Carbon Plan, the Companies used the capacity expansion model with a mass cap constraint. This modeling technique puts a limit on the amount of CO_2 a candidate resource portfolio is allowed to emit through the economical simulation of system operations. Using this approach, the model must select resources, which, when integrated in the portfolio, result in CO_2 emissions that are less than the specified limit. Annual CO_2 limits are decreased along a linear reduction trajectory between 2025 and the 70% interim target year. Thereafter the limit continues to be reduced along a linear trajectory between the 70% interim year and 2050 when net zero emissions is achieved. This approach necessitates the addition of resources throughout the planning horizon rather than waiting until the compliance target years to add in significant amounts of zero-carbon resources. Importantly, this also creates a more systematic, orderly and executable transition given the significant challenges and risks associated with clustering all resource additions in the plan into short windows just prior to target reduction dates. Additional details are provided in Appendix E.[22]

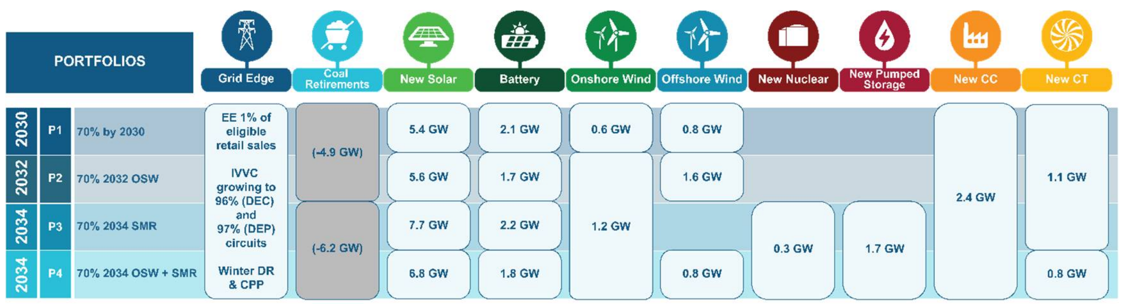
[22] Carbon Plan Appendix E at 5-6.

(B) Portfolio Recap: Carbon Plan Modeling Produces Reasonable Pathways and Portfolios that Achieve HB 951 Goals and Balance Core Carbon Plan Objectives.

Q. PLEASE REINTRODUCE THE FOUR CARBON PLAN PORTFOLIOS RESULTING FROM THE MODELING ANALYSIS DISCUSSED ABOVE.

A. Chapter 3 of the Carbon Plan provides a detailed discussion of the four Carbon Plan portfolios, the results of which are presented in Figure 4 and Figure 5.

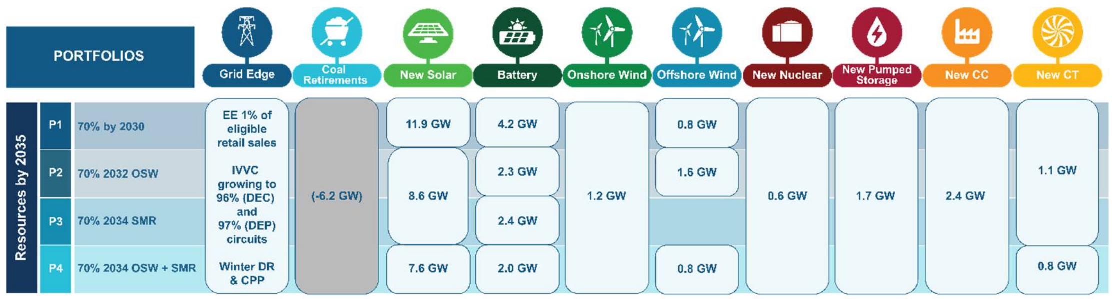
Figure 4: Portfolio Snapshot to Achieve 70% Interim Target (2030-2034)[23]



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

[23] Carbon Plan Chapter 3 at 3 (Figure 3-1). Figure 4 is also replicated in Modeling and Near-Term Actions Panel Exhibit 2.

Figure 5: Portfolio Snapshot in 2035[24]



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

Each portfolio is designed to evaluate a different pace for achieving the interim 70% CO_2 emissions reduction target, including the costs and resources available in the timeframe contemplated. Portfolio 1 contemplates 70% CO_2 emissions reduction by 2030, and therefore is largely limited to currently available resource types, with the first 800 MW block of offshore wind coming online by the end of 2029. Portfolio 2 delays 70% CO_2 emissions reduction to 2032, allowing time for a second 800 MW block of offshore wind to be deployed to contribute to the interim target. Portfolio 3 and Portfolio 4 achieve 70% CO_2 emissions reduction in 2034, incorporating the first SMR on the system to do so. Portfolio 3 represents a path that does not include offshore wind, while Portfolio 4 presents a hybrid approach, using both offshore wind and SMR to achieve the interim target. All portfolios achieve carbon neutrality by 2050. Taken together, the portfolios provide a broad set of options across which

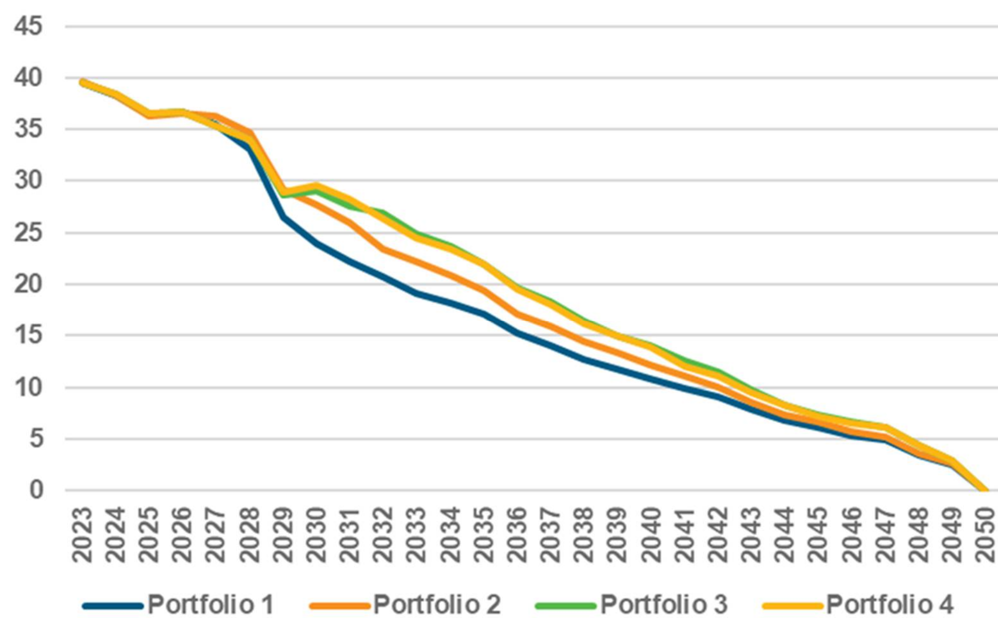
[24] Carbon Plan Chapter 3 at 3 (Figure 3-2). Figure 5 is also replicated in Modeling and Near-Term Actions Panel Exhibit 2.

tradeoffs can be weighed with respect to emissions reductions, costs, portfolio diversity and execution risks, *etc*.

Q. PLEASE SUMMARIZE KEY TAKEAWAYS FROM THE CARBON PLAN PORTFOLIO EVALUATION.

A. The results of the analysis are discussed at length in Chapter 3 of the Carbon Plan. As illustrated in Figure 6 below, all portfolios achieve carbon neutrality by 2050. The primary differentiator across portfolios is the pace of the energy transition, which creates differences in relative costs and risks to successful plan execution.

Figure 6: Annual CO_2 Emissions by Portfolio, Combined Carolinas' System (millions of short tons)[25]



The more rapid transition contemplated in Portfolio 1 comes at greater cost ($2 billion more than Portfolio 2 and approximately $6 billion more than Portfolios

[25] Carbon Plan Chapter 3 at 26 (Figure 3-17).

3 and 4 in PVRR terms) and carries more exposure to execution risks associated with a more concentrated portfolio and more aggressive resource deployment in the near-term. As detailed in Chapter 4 and discussed in the next section of this testimony, the Companies' proposed near-term actions represent meaningful and immediate progress toward continued CO_2 emissions reduction while pursuing necessary development activities to advance longer lead-time resources and keep all options available ahead of the 2024 Carbon Plan update.

(C) Execution Plan Provides the Commission and Stakeholders Unprecedented Detail on Companies Near-Term Plans to Execute Carbon Plan, Subject to Requested Approvals and Future Updates.

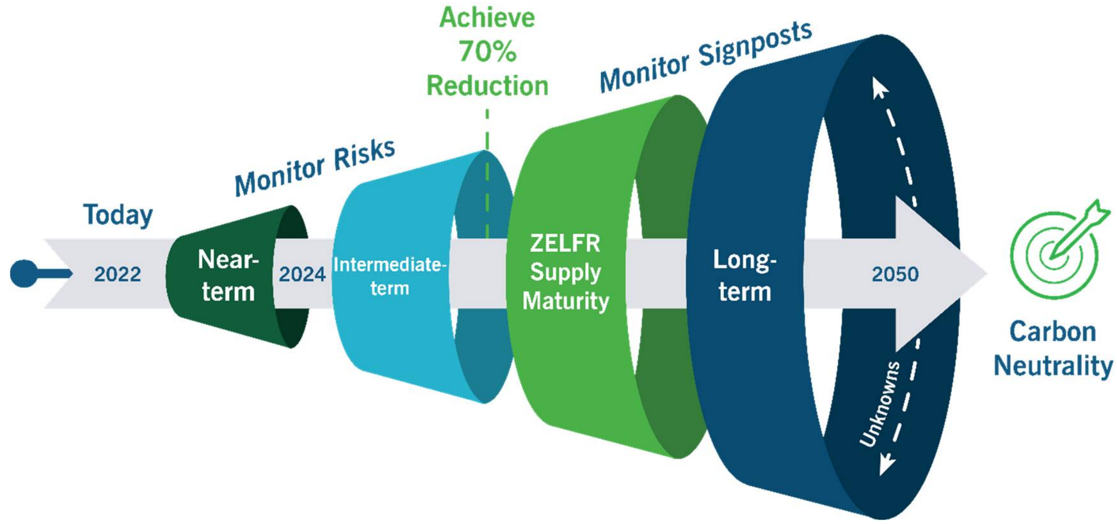
Q. PLEASE DESCRIBE THE EXECUTION PLAN PRESENTED IN THE CARBON PLAN.

A. As highlighted above, executability of the Carbon Plan and our path for energy transition is a core objective and key area of focus for achieving the CO_2 emissions reductions targets set forth in the Carbon Plan. Chapter 4 of the Carbon Plan presents detailed information in the form of a first-of-its-kind "Execution Plan" to inform the Commission and stakeholders on how the Companies are approaching executing the Carbon Plan across multiple time horizons through 2050.

The Execution Plan presents the Commission and stakeholders with an overview of the Companies' near-term, all-of-the-above energy transition strategy for executing the Carbon Plan, as well as intermediate- and longer-term strategies to meet the interim CO_2 emissions reductions target and to achieve carbon neutrality by 2050.[26] Consistent with the Companies' three-pronged approach to developing the Carbon Plan, the Execution Plan details the Companies near- and intermediate-term plans for coal retirements and optimizing existing supply-side resources, development and procurement of new supply-side resources, plans for grid transformation and consolidated customer operations, as well as grid edge and customer programs. The Execution Plan also addresses the Companies' long-term planning approach and signpost monitoring to achieve carbon neutrality by 2050, as illustrated in Figure 7.

[26] Carbon Plan Chapter 4 at 2.

Figure 7: Execution Plan Time Horizons and Navigating Uncertainty[27]



Q. DOES THE EXECUTION PLAN IDENTIFY THE GENERATING FACILITIES AND OTHER RESOURCES THAT THE COMPANIES ARE ASKING THE COMMISSION TO SELECT IN THIS INITIAL CARBON PLAN PROCEEDING FOR PROCUREMENT AND THOSE RESOURCES FOR WHICH THE COMPANIES ARE REQUESTING APPROVAL OF DEVELOPMENT ACTIVITIES IN THE NEAR-TERM?

A. Yes. Table 4-1 of the Execution Plan[28] presents the activities that are required in the near-term and for which the Companies request approval under HB 951. The near-term execution actions identified are generally consistent with all portfolios and have been developed to enable the Commission to direct decisive

[27] Carbon Plan Chapter 4 at 3 (Figure 4-1).
[28] Table 4-1 in the Execution Plan is identical to Table 3 in the Executive Summary. This summary of the Companies' proposed near-term actions is also replicated as Bowman Exhibit 3 for ease of reference.

and immediate action in the near-term, while retaining discretion to determine the optimal timing and least cost path to meeting HB 951's targets in future Carbon Plan update proceedings. Subject to approval by the Commission, these initial development and procurement activities represent the reasonable steps and immediate actions that the Companies will undertake between now and 2024 to execute the Plan. Importantly, as more information is gathered through execution, the Companies will keep the Commission apprised of material developments through future biennial Carbon Plan updates, as well as through seeking resource-specific regulatory approvals (e.g., a CPCN proceeding).

Q. DOES THE EXECUTION PLAN TAKE INTO ACCOUNT THE AVAILABILITY AND PRICE OF POWER SOLD BY THIRD-PARTY ENERGY SUPPLIERS?

A. Yes. To the extent contemplated by HB 951, the Execution Plan takes into account the availability and prices of power sold by third-party energy suppliers. The Execution Plan presents the Companies' general procurement approach and explains that implementation of the Carbon Plan will include a range of procurement methods.[29] For solar and solar paired with storage, regular solicitations will be used to procure controllable purchase power agreements in addition to utility-owned resources. In all cases, the information gained through the procurement process will be used to inform and refine future Carbon Plan analysis and filings. Importantly, the General Assembly in enacting HB 951

[29] Carbon Plan Chapter 4 at 12.

prescribed that any new generation facilities or other resources selected by the Commission in order to achieve the CO_2 emissions reduction goals for electric public utilities must be owned and recovered on a cost of service basis by the applicable electric public utility, except in the case of energy efficiency measures and demand-side management, for which existing law applies, and in the case of solar generation, which is to be allocated according to the specified percentages.[30] As directed by the Commission in its Order Scheduling Expert Witness Hearing, the Companies will address legal issues related to the application of HB 951's ownership requirements in comments to be filed on September 9, 2022.

III. <u>SUPPLEMENTAL MODELING PORTFOLIOS</u>

Q. MR. QUINTO, PLEASE DESCRIBE THE SUPPLEMENTAL MODELING THAT THE COMPANIES PERFORMED AND ARE PRESENTING AS MODELING AND NEAR-TERM ACTIONS PANEL EXHIBIT 1.

A. The Companies have conducted supplemental modeling analysis largely based on recommendations by the Public Staff (but reflective of certain comments of other intervenors as well), to further assess the reasonableness of the Carbon Plan modeling and the Companies' proposed near-term actions for timely achievement of the CO_2 emissions reduction goals. These Supplemental Portfolios are included as Modeling and Near-Term Actions Panel Exhibit 1.

[30] Carbon Plan Execution Plan at 7.

As generally described in the Companies' July 28, 2022, update letter to the Commission, the Companies worked with the Public Staff to identify appropriate and potentially impactful modeling functionality and input assumptions that could be evaluated through supplemental modeling within the very tight regulatory timeline for this proceeding. As explained by the Public Staff, the intent of this supplemental modeling is to validate the proposed near-term actions and the robustness of the Companies' Carbon Plan modeling.[31]

This supplemental analysis looks at the impact of increased modeling functionality, such as allowing the EnCompass model to endogenously dispatch storage resources that are paired with solar and addresses key uncertainties to the overall near-term execution plan, such as fuel supply, both natural gas and hydrogen, and resource technology options and configurations, such as more SPS combinations and multiple CCs and CTs available for the model to select. These modeling revisions and key uncertainties are further discussed in Modeling and Near-Term Actions Panel Exhibit 1.

Q. PLEASE ADDRESS THE SCOPE OF THE COMPANIES' SUPPLEMENTAL MODELING.

A. Through the supplemental modeling, the Companies developed two additional portfolios, each with two fuel supply assumption scenarios. As recommended by the Public Staff, the "primary" natural gas supply assumption for the supplemental modeling analysis is the Public Staff's "no Appalachian gas"

[31] Public Staff Comments at 20-21.

assumption, whereas the "limited Appalachian gas" assumption is considered the "alternate" fuel supply scenario. As shown below in Table 1, SP5 represents the no Appalachian gas supply scenario and targets a 2032 interim 70% compliance year, and Supplemental Portfolio 5 with Alternate Fuel ("$SP5_A$") represents a fuel supply scenario which envisions limited access to Appalachian gas with the same compliance year. Similarly, SP6 targets a 2034 interim 70% compliance year with the no Appalachian gas supply assumption, and like $SP5_A$, Supplemental Portfolio 6 with Alternate Fuel ("$SP6_A$") represents the fuel supply scenario with limited access to Appalachian gas and 2034 as the compliance year.

Table 1: Supplemental Portfolios' Key Development Assumptions

	Supplemental Portfolios			
	SP5	**$SP5_A$**	**SP6**	**$SP6_A$**
70% Compliance Year	2032	2032	2034	2034
Gas Supply Assumption	No App Gas	Limited App Gas	No App Gas	Limited App Gas

Duke Energy also performed the same Portfolio Verification steps and reliability modeling in EnCompass and in SERVM to evaluate each portfolio's loss of load expectation. Finally, the Companies developed present value of revenue requirements ("PVRR") and customer bill impacts analyses for the Supplemental Portfolios.

Q. DID THE COMPANIES UNDERTAKE ADDITIONAL SENSITIVITY ANALYSES AS PART OF THE SUPPLEMENTAL MODELING?

A. Yes. In response to recommendations from intervenors, the Companies conducted a limited set of sensitivities. The first is a "Low EE" sensitivity, which the Public Staff describes as "a better estimation of the impacts to future load."[32] The Public Staff points to legislative and regulatory changes as barriers to achieving the load reductions projected in the Carbon Plan due to the Companies' UEE forecast. While the Companies recognize the Carbon Plan's base UEE forecast is an aggressive target, the Companies continue to believe it is important to aggressively pursue the first prong of the Companies' strategy for meeting the objectives of HB 951, "shrinking the challenge." The Companies understand the risk of not reaching these projections, or other factors such as electrification otherwise raising the load forecast, could have material impacts on resources needed for capacity and to generate more zero carbon energy, and thus, see this sensitivity as an appropriate analysis of uncertainty around the net load forecast.

The second "High Solar Interconnection" sensitivity assumes for modeling purposes that the Companies are able to interconnect a larger amount of solar in the near-term and throughout the planning horizon. The High Solar Interconnection sensitivity was recommended by Clean Power Suppliers Association ("CPSA") and is also responsive to comments by multiple

[32] Public Staff Comments at 69.

intervenors, including the Attorney General's Office ("AGO") and Carolinas Clean Energy Business Association ("CCEBA"), that advocated for relaxing the solar selection constraints in the model to assess whether the model would economically select higher levels of solar in the near-term. For this sensitivity, the cap is raised to 1,500 MW per year for 2026 and 2027, above the High Solar Interconnection limit used in the development of Portfolio 1, and to 1,800 MW per year for 2028 and for every year thereafter, equal to the High Solar Interconnection limit used in the development of Portfolio 1 for 2028 and beyond. As addressed in Carbon Plan Appendix I (Solar) and further discussed herein, actually interconnecting this significantly higher level of solar generation to the Companies' systems, especially in the near-term, is unlikely to be achievable, but satisfies the hypothetical question of how much solar might be economically selected at the capital cost assumed in the Carbon Plan without these real-world constraints.

Q. PLEASE IDENTIFY THE SPECIFIC MODELING ASSUMPTIONS CHANGES THAT WERE INTEGRATED INTO THE SUPPLEMENTAL MODELING?

A. Table 2 below outlines the original assumptions used in the Carbon Plan portfolios compared to changes implemented in SP5 and SP6.

Table 2: Comparison of Assumptions: Portfolios 1 - 4 and Supplemental Portfolios 5 - 6

	Portfolios 1 - 4	Supplemental Portfolios 5 - 6
First SMR Availability	EOY* 2032	Mid-year 2032

	Portfolios 1 - 4	Supplemental Portfolios 5 - 6
Belews Creek Retirement	Retired EOY 2035	Retired EOY 2037
Solar Plus Storage (SPS) Battery Dispatch Optimization	Fixed battery dispatch profile	Model optimized battery dispatch
Available SPS Battery Configurations	▪ 4-hr, 25% battery to solar ratio ▪ 2-hr, 50% battery to solar ratio	▪ 4-hr, 25% battery to solar ratio ▪ 2-hr, 50% battery to solar ratio ▪ 4-hr, 50% battery to solar ratio
Cumulative Battery Limits	▪ 4-hr battery capped at 1500 MW in DEC and 2300 MW in DEP ▪ 6-hr battery capped at 1800 MW in DEC and 2000 MW in DEP	▪ 4-hr and 6-hr battery not capped, but continue to decline in capacity value at higher penetrations
Inclusion of Hydrogen Fuel	Yes	No
Limited Appalachian Fuel Supply Case	Existing CC fleet fueled in part by App Gas, FT for two new CCs, no CC on ULSD** backup	Existing CC fleet fueled in part by App Gas, FT for two new CCs, no CC on ULSD backup
No Appalachian Fuel Supply Case	Existing CC fleet fueled Transco Zone 4, no incremental FT for new CCs, new CC configured with ULSD backup	Existing CC fleet fueled Transco Zone 4, FT for two new CCs, no CC on ULSD backup
Back-up Fuel Supply	CTs operate on ULSD for entire month of January	CTs operate on ULSD for two weeks in January

	Portfolios 1 - 4	Supplemental Portfolios 5 - 6
Availability of F-Class and J-Class CCs and CTs	Smaller F-Class CC available in no Appalachian fuel supply case. Larger J-Class CC available in limited Appalachian supply case. Only J-Class CTs available.	Both J-Class and F-Class CCs and CTs available in both fuel supply scenarios.
DEC/DEP Energy Transfer Hurdle Rate	No energy hurdle rate imposed on DEC/DEP transfers	Energy hurdle rate imposed on DEC/DEP transfers included for resource selection
Notes: *EOY = End of Year **ULSD = Ultra Low Sulfur Diesel		

The development of SP5 and SP6 most closely align to the development of Portfolios 2 and 3, respectively. SP5 targets achieving the interim CO_2 emissions reductions goals in 2032, similar to Portfolio 2. SP6 conversely targets achieving the interim CO_2 emissions reduction goals in 2034. Because SP6 does not prescribe into the resource portfolio any offshore wind resources, it more closely parallels Portfolio 3 than Portfolio 4, which integrates offshore wind into the portfolio for resource diversity benefits and cost comparisons.

Q. PLEASE DESCRIBE SOME OF THE KEY INPUT ASSUMPTION CHANGES BETWEEN THE COMPANIES' CARBON PLAN PORTFOLIOS AND SUPPLEMENTAL PORTFOLIOS.

A. As discussed earlier, the Public Staff wanted to assess a no-Appalachian gas scenario as the base planning assumption. The Public Staff's natural gas transportation recommendation allows for Transco Zone 4 supply to all existing combined cycle units while allowing for the additional procurement of up to 400,000 dekatherms/day incrementally. The assumed incremental Transco firm transportation is enough firm supply for two large, or three small, CC units, representing a slightly less constrained fuel supply scenario than initially analyzed in the Carbon Plan's no Appalachian gas sensitivity.

Another key difference in the Supplemental Portfolio analysis is the removal of hydrogen as a fuel. In the Carbon Plan, the Companies assumed the development of a clean hydrogen market with hydrogen fuel blending starting in 2035. Based on the uncertainty in price and availability of this market, the Public Staff recommended the supplemental analysis exclude the zero-carbon emission fuel from these portfolios. In turn, however, the Public Staff and the Companies agreed to plan the system to 5% or less of CO_2 emissions compared to the 2005 baseline, by 2050, assuming the remaining emissions will be accounted for with carbon offsets, as provided for in HB 951. While no cost was included in the selection of resources in the modeling for these 2050 CO_2 emissions, the Companies did include a cost of $100/short ton of CO_2 emitted (2020 dollars, or ~$210/short ton nominally in 2050) in the final PVRR of the system.

One final key assumption adjustment to highlight is the accelerated implementation of the SMR in the modeling. As described in Carbon Plan

Appendix L (Nuclear), the Companies believe implementation of the first SMR unit is feasible for June 2032.[33] With SP5 targeting a 2032 compliance year, accurately modeling the deployment of a nuclear unit in mid-year 2032 could have a material impact on meeting the emissions reduction target. The model, however, was set up to retire and bring new resources on at the end of the year to meet the following year's winter peak capacity needs; thus, the first SMR in the Carbon Plan modeling was available at the end of 2032. Due to these potential material impacts of a half of a year of a nuclear SMR can have on CO_2 emissions, the Companies and the Public Staff agreed to allow the first SMR to be brought online in June 2032 for purposes of this supplemental modeling analysis. All other future additions of nuclear units continue to follow the end-of-year addition assumption used in the original Carbon Plan modeling.

[33] Carbon Plan Appendix L at 14.

Q. DO SP5 AND SP6 INCLUDE OR INTEGRATE OTHER MODELING OR ASSUMPTION CHANGES RECOMMENDED BY OTHER INTERVENORS?

A. Yes. The modeling and assumption changes included in the Supplemental Portfolios cover various modeling recommendations presented by other intervenors. For example, CPSA recommended the High Solar Interconnection sensitivity be included in the Supplemental Portfolio analysis. CCEBA and AGO also supported relaxing this constraint. Additionally, the AGO and other intervenors recommended incorporating modeling functionality allowing the capacity expansion and production cost models to determine the dispatch of batteries paired with solar, as well as an additional SPS configuration that includes a battery with higher energy capacity than was included in P1 through P4. Several intervenors expressed risk of relying on hydrogen for CO_2 emissions reductions and risk of long-lived natural gas assets. This supplemental modeling addresses those concerns by eliminating hydrogen as a fuel, including the assumption of blending into the natural gas pipeline (and its impact on CO_2 emissions and energy pricing of the resources using this fuel), the hydrogen-capable conversion costs associated with new and existing combustion technologies expected to be on the system in 2050, and the availability of 100% hydrogen capable peaking units, a proxy for long duration storage or carbon offsets generally, in the 2040s.

Q. DO SP5 AND SP6 INCLUDE SOME MODELING AND ASSUMPTION CHANGES THAT THE COMPANIES DISAGREE WITH?

A. Yes. First, the Companies continue to support using the Carbon Plan's limited Appalachian gas assumption as the appropriate base fuel supply assumption. The Public Staff's recommendation to rely upon the no Appalachian gas assumption as the base assumption reflects the continued uncertainty as to the completion of the Mountain Valley Pipeline ("MVP") and the Public Staff's view that Dominion South zone gas should be disallowed as a selectable fuel supply resource in the Companies' primary portfolios.[34] For the avoidance of doubt, the Companies continue to support the Carbon Plan's base limited Appalachian gas fuel supply assumptions, including the potential "pivot" if limited Appalachian gas does not become available,[35] as anticipated, to be reasonable for planning purposes and in the best interest of customers. However, the Companies agreed to adopt the Public Staff's view for the limited purpose of the Supplemental Portfolios and validating the Companies' proposed near-term actions.

The Companies also disagree with the Public Staff's recommendation to delay the retirement of Belews Creek's 2,220 MW past 2035. While the Public Staff expressed that delaying retirement presents a potentially lower cost option, the Companies continue to have concerns over future regulatory,

[34] Public Staff Comments at 73.
[35] Carbon Plan Executive Summary at 24; Carbon Plan Chapter 3 at 13; Carbon Plan Appendix E at 42.

operational and supply-chain risks of continued operations of coal resources beyond 2035. The Public Staff presents a concern that the latest available retirement date of Belews Creek in 2035 used in the Carbon Plan coincides with an arbitrary internal Duke Energy target to cease coal generation by 2035. While the Companies do recognize this target, the purpose of the target is to account for the risk[36] that cannot be fully quantified in an IRP model.

Additionally, the SPS revised modeling uses increased modeling functionality at this step in the analysis to identify the mix of standalone solar, standalone storage, and SPS. However, as explained by the Companies in the Carbon Plan, the use of the capacity expansion model alone is insufficient for selecting the optimal configuration of storage resources given simplifications to the load shape at this step in the analysis framework. Furthermore, the additional burden on the model to determine this optimization increases time required to solve and continues to limit the Companies' ability to perform modeling quickly and efficiently. The Companies will work in the coming months to continue to review how future resources added to the system impact the operation of storage on the system and look to find simplifying, though representative, assumptions to decrease model run times while accurately capturing the changes in dispatch due to other resource changes on the system.

The Companies also do not support the removal of hydrogen fuel from the development of these portfolios. The Companies understand the intent of

[36] Public Staff Comments at 117.

the removal of this fuel source was to further validate the selection of near-term CCs and CTs. However, the Companies continue to believe the development of future hydrogen fuel sources is likely while also recognizing in the Carbon Plan that there is uncertainty around its development.[37] The Companies believe this to be a bounding assumption. Hydrogen is highly likely to play a role in transforming the energy system over the next three decades. Therefore, the removal of hydrogen completely from this analysis is extraordinarily conservative. This assumption change excluding hydrogen fuel can be considered a boundary condition to assess whether CC and CT resources would still be selected regardless of the degree to which hydrogen is utilized in the future. This fuel source and its ability to be used for power generation should continue to be viewed as an important factor in long-term reliability of the system and as critical to executing a least cost plan in achieving the 2050 goal.

While the Companies do not fully endorse all of the assumption changes captured in the Supplemental Portfolio analysis, the Companies believe, in this case, this exercise yields additional useful information for the Commission to consider in developing the Carbon Plan.

[37] Carbon Plan Appendix E at 102.

Q. CAN YOU PROVIDE SOME EXAMPLES OF RECOMMENDATIONS FROM INTERVENORS THAT WERE CONSIDERED NOT APPROPRIATE FOR THIS SUPPLEMENTAL ANALYSIS?

A. Yes. As explained in more detail later in this testimony, the Companies do not believe the recommendations from AGO's consultant, Strategen Consulting, LLC ("Strategen") and North Carolina Sustainable Energy Association, Southern Alliance for Clean Energy, the Sierra Club, and the National Resource Defense Council's ("NCSEA et al.") consultant, Synapse Energy Economics, Inc. ("Synapse") to remove, or minimize the need for, economic and reliability verification steps is appropriate for supplemental analysis.[38] The Companies believe, and the Public Staff agreed, that the inclusion of these steps is necessary to determine least cost and reliable portfolios. The Companies respond to a number of other intervenor recommendations and critiques in Section V below.

Q. DOES THE SUPPLEMENTAL PORTFOLIO ANALYSIS INCLUDE ANY OTHER MODELING UPDATES OR ASSUMPTION CHANGES THAT WERE NOT SPECIFICALLY ADDRESSED ABOVE? IF SO, PLEASE EXPLAIN.

A. Yes. As outlined in greater detail in Modeling and Near-Term Execution Plan Panel Exhibit 1, the Companies identified a limited number of additional inputs and modeling updates that were appropriate to integrate into the Supplemental Portfolio analysis. Below is a list of the additional inputs and modeling updates

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[38] AGO Strategen Report at 35; NCSEA et al. Synapse Report at 33-34.

included in developing the Supplemental Portfolios:

- **Update to EnCompass version 6.1.3** - addressed several issues identified by intervenors in their ability to replicate the Companies' modeling results due to a modeling bug which affected the exporting of datasets, resulting in run failures.
- **Solution for declining capital cost modeling for emerging resources** – in the Carbon Plan the Companies used a cost input field within the EnCompass software to capture the near-term cost premium of resources that are expected to decline in price over the next decade, such as solar, battery and offshore wind. It was discovered that EnCompass was not recognizing these costs when selecting resources and therefore understating the cost of the resources in the selection process. The Companies outlined this issue and provided a solution to intervenors previously in this docket.[39] This resolution is also being deployed in the development of the Supplemental Portfolios to capture the near-term cost premium on these resources.
- **Transmission cost adder correction** – the transmission cost adders for all resources were discovered to be understated in the Carbon Plan portfolios. The understatement of costs resulted from an erroneous inflation factor incorporated into the fixed charge rate used to levelize the transmission costs to be applied to resource selection in the capacity

[39] See Public Staff Comments Exhibit 1.

expansion model. The error was unlikely to materially impact resource selection in the Carbon Plan Portfolios as the understatement was applied equivalently to all resources. The Companies have corrected the cost adder to more accurately reflect the transmission costs in the Supplemental Portfolio analysis.

- **New nuclear maintenance rates fix** – a modeling bug was discovered that reduced the accuracy of modeled maintenance activities for new nuclear units in the Carbon Plan (both SMRs and Advanced Reactors). Switching the new nuclear maintenance from discrete maintenance outage days to maintenance rates allowed the model to more closely reflect real-world dispersed maintenance outages. The input change further avoids the need for the Companies to add additional resources to ensure energy needs of the system are met near the end of the study horizon.
- **Solar paired with storage fixed O&M correction** - in adding an additional SPS configuration, the Companies discovered the fixed operations and maintenance ("FOM") costs for the combined solar sites were improperly reflected in the model. The resulting correction resulted in a lower FOM for all SPS resources.

- **Degradation of new solar output profile** – solar resources' output is expected to decline over time due to degradation of solar panels. Carbon Plan modeling was not capturing the degradation of new solar resources and was therefore overstating generation output over the life of the asset. The Supplemental Portfolio analysis accounts for this degradation over the life of new solar assets.

Overall, the modeling improvements and minor corrections to data incorporated into the Supplemental Portfolio analysis would not have resulted in material differences in the selection of resources in the Carbon Plan Portfolios, especially with respect to the near-term action plan, but may have had modest impacts to the overall costs of the plans.

Q. DO THE SUPPLEMENTAL MODELING RESULTS SUPPORT THE NEAR-TERM ACTIONS THAT THE COMPANIES PRESENTED IN THE CARBON PLAN FOR COMMISSION APPROVAL?

A. Yes. The Supplemental Portfolio analysis further validates the Companies' proposed near-term actions, confirming both the resources that the Companies are requesting the Commission select and approve for near-term procurement, as well as the long lead-time resources for which the Companies are requesting approval of development activities. For the Supplemental Portfolios, solar continues to be selected at an aggressive pace to comply with the interim emissions reduction compliance year. Onshore wind continues to be selected as soon as it is available in each of the Supplemental Portfolios. Natural gas CCs continue to be selected to help replace coal capacity and energy, despite the removal of hydrogen fuel in the long-term. New nuclear continues to be selected as soon as it is available for the model and deployed at significant scale across the planning horizon. Offshore wind is not selected for compliance with the interim emissions reduction target in any of the Supplemental Portfolios, but the resource is selected in all portfolios in the 2040s, underscoring the importance of this proven zero carbon technology for resource diversity in meeting the 2050 carbon neutrality targets.

Presented in Table 3 through Table 5 below are summaries of the final resource additions of each Supplemental Portfolio, both primary fuel scenario (SP5 and SP6) and the alternate fuel supply scenario ($SP5_{A}$ and $SP6_{A}$), for the year the interim target is achieved, 2035, and 2050. Of note, the solar and battery capacities noted below represent incremental additions on top of the existing solar on the system at the start of the Carbon Plan. These additions include both forecasted solar and batteries over these time frames and the Carbon Plan economically selected solar (both standalone and paired with storage) and battery (both standalone and paired with solar). Additional detail on the development process and resulting Supplemental Portfolios are included in Modeling and Near-Term Actions Panel Exhibit 1.

Table 3: Final Resource Additions by Portfolio [MW] for year interim target is achieved

	Coal Retirements	New Solar[1]	Onshore Wind	Battery[2]	CC	CT	Offshore Wind	SMR	PSH
SP5 (2032)	-3,500	8,600	1,200	4,500	2,400	1,200	0	300	0
SP6 (2034)	-6,300	9,200	1,400	3,000	2,400	400	0	300	1,700
SP5$_A$ (2032)	-3,500	8,600	1,200	4,100	2,400	1,100	0	300	0
SP6$_A$ (2034)	-6,300	9,400	1,200	2,500	2,400	1,200	0	300	1,700

Note 1: Includes solar capacity both standalone and paired with battery.
Note 2: Includes battery capacity both standalone and paired with storage.

Table 4: Final Resource Additions by Portfolio [MW] for 2035

	Coal Retirements	New Solar[1]	Onshore Wind	Battery[2]	CC	CT	Offshore Wind	SMR	PSH
SP5	-6,300	11,800	1,200	5,500	2,400	1,200	0	600	1,700
SP6	-6,300	10,000	1,400	3,400	2,400	400	0	600	1,700
SP5$_A$	-6,300	12,100	1,200	5,200	2,400	1,100	0	600	1,700
SP6$_A$	-6,300	10,300	1,200	3,000	2,400	1,200	0	600	1,700

Note 1: Includes solar capacity both standalone and paired with battery.
Note 2: Includes battery capacity both standalone and paired with solar.

Table 5: Final Resource Additions by Portfolio [MW] for 2050

	Coal Retirements	New Solar[1]	Onshore Wind	Battery[2]	CC	CT	Offshore Wind	New Nuclear[3]	PSH
SP5	-9,300	22,800	1,800	13,900	2,400	8,800	1,600	9,000	1,700
SP6	-9,300	21,700	1,800	12,700	2,400	8,200	2,400	9,000	1,700
SP5$_A$	-9,300	22,900	1,800	13,700	2,400	8,700	1,600	9,000	1,700
SP6$_A$	-9,300	22,600	1,800	14,100	2,400	8,800	1,600	9,000	1,700

Note 1: Includes solar capacity both standalone and paired with battery.
Note 2: Includes battery capacity both standalone and paired with solar.
Note 3: Includes SMR and advanced nuclear with integrated storage.

Q. DID ANY OF THE CHANGES INCORPORATED IN THE SUPPLEMENTAL PORTFOLIOS IMPACT THE MODEL SELECTION OF RESOURCES IN THE NEAR OR LONG-TERM?

A. Yes. The inclusion of the additional SPS option that included a 50% battery-to-solar ratio with 4-hour duration, along with the revised SPS modeling resulted in more storage paired with solar and less standalone storage being selected in SP5 and SP5$_A$. Most of the increase is due to a shift from standalone storage and standalone solar to SPS as the model recognizes some synergistic capital cost benefits of pairing larger storage with solar versus standalone storage. Overall, after accounting for these changes, the supplemental portfolios validate the total storage needs identified in the Companies' proposed near-term actions, and they indicate that the combination of standalone storage and storage paired with solar may need further study. However, at this point, the Companies continue to support the 1,000 MW of standalone storage and 600 MW of storage paired with solar as reasonable in the Companies' proposed near-term actions for several reasons. First, the new SPS option that the model selected includes a much larger battery (160 MWh vs 80 MWh) than the original SPS options, and this configuration was not studied as part of the ELCC study used for the Carbon Plan. It is likely that the capacity value of this resource is overstated in the Supplemental Portfolios. Second, the only SPS contract structures the Companies have used to date do not enable the flexibility and operation control modeled here. Substantial work is required to evaluate the extent to which it is possible to ensure that actual operations of solar paired with battery storage match the modeling assumptions for this resource. In that vein, Duke Energy will be working with stakeholders in advance of the 2023 procurement to assess potential commercial contract terms and conditions for leasing third-party owned SPS assets in a manner that replicates the operational characteristics, as well as qualitative benefits and risks, of Company owned SPS assets over the life of the contract. However, until that work has been completed and agreed upon by the Companies, developers, and this Commission, it is premature to materially adjust the Companies' targeted procurements. Third, the Carbon Plan and the Supplemental Portfolios assume similar transmission costs for standalone storage and solar paired with storage. Transmission costs are highly site specific. Standalone storage provides siting flexibility not captured in the Carbon Plan Portfolios or Supplemental Portfolios that can lead to reduced transmission costs. Similarly, standalone storage has the potential to provide multiple sources of value, or "stacked" benefits, to the bulk system that, depending on the design, storage paired with solar may not be able to provide. Such benefits include transmission and distribution capacity deferral, certain ancillary benefits, and blackstart capability among others.

Q. WHAT INSIGHTS DOES THE HIGH SOLAR INTERCONNECTION SENSITIVITY PROVIDE FROM A MODELING AND EXECUTION STANDPOINT?

A. Allowing for higher solar selection limits overall increases the deployment of solar energy by 700 MW by 2035 and by just 300 MW by 2050. The capacity expansion model selects up to the raised limit in five of the first six years solar is eligible for selection ahead of the targeted compliance year. The system adds up to the 1,500 MW limit in both 2026 and 2027, while selecting 1,800 MW in every year leading up to compliance, with the exception of 2028 which coincides with the selection of the two natural gas CC units in that year.

Overall, the additional solar limits had no impact on the net selection of onshore wind or new nuclear. The same amount of each resource was selected across the system by both 2035 and 2050. By 2050 there is very little impact to overall resource selection, with the 300 incremental MW of solar offsetting the need for a small number of batteries and CTs.

Q. WHAT INSIGHTS DOES THE LOW EE ACHIEVEMENT SENSITIVITY PROVIDE FROM A MODELING AND RESOURCE SELECTION STANDPOINT?

A. The low EE forecast results in a high load sensitivity requiring incrementally more resources to meet the energy and CO_2 emissions reductions targets. Notably, by 2035 the sensitivity selects 700 MW more of solar, 200 MW more of onshore wind, and 300 MW more of battery, picking both more standalone battery and battery paired with solar to offset the higher load. By 2050 under the Low EE sensitivity, 900 MW of additional solar and 200 MW of additional batteries are selected, which offset the need for small amount of CT capacity. Overall, the low EE sensitivity has little impact on peak winter load, which typically drives resource selection. The majority of the peak load impact in this sensitivity is realized in the summer, when the system has adequate reserves due to the significant amount of solar already on the system. These factors result in slightly more zero-carbon resources selected to offset incremental energy needs, while having little impact on firm, dispatchable resource requirements above what is already selected in Supplemental Portfolio 5 (no App Gas).

Q. DOES THIS SUPPLEMENTAL MODELING CONTINUE TO SUPPORT THE VALUE OF RESOURCE DIVERSITY IN THE INITIAL CARBON PLAN?

A. Yes. As mentioned above, in each of the Supplemental Portfolios the entire suite of resources is selected in solving for least cost paths to 70% CO_2 emissions reductions and net zero. SMR continues to be selected in significant quantities. CCs and CTs continue to be selected despite the removal of hydrogen fuel, providing the system with flexible and reliable back-stand to variable energy resources and enabling significant coal capacity retirements. Energy storage, standalone battery, battery paired with solar, and pumped storage, provides significant benefits for a higher variable energy resource portfolio with the significant quantities of solar and onshore wind. Finally, while offshore wind is not selected for meeting the interim emission reduction target, the resource is selected in each of the portfolios in the 2040s, providing large quantities of renewable energy with a complementary generation profile compared to the significant levels of solar projected to be on the system.

Q. DO THE COMPANIES BELIEVE THAT THE RESULTS OF THE SUPPLEMENTAL MODELING SUPPORT THEIR REQUEST FOR THE COMMISSION TO SELECT 3,100 MW OF SOLAR, 600 MW OF WIND, 1,000 MW OF STANDALONE BATTERY, AND 600 MW OF BATTERY PAIRED WITH SOLAR?

A. Yes. With the addition of the recommendation to procure the CPRE remainder MW (441 MW) in the 2022 SP as referenced in Witness Bowman's testimony, the Companies believe that modeling results continue to support their initial recommended amounts of solar, storage and storage paired with solar to be procured in the near-term.

Q. DO THE COMPANIES BELIEVE THAT THE RESULTS OF THE SUPPLEMENTAL MODELING SUPPORT THEIR REQUEST FOR THE COMMISSION TO SELECT 800 MW OF CTs AND 1,200 MW OF CC?

A. Yes. The Companies believe that modeling results continue to support their initial recommended amounts of CTs and CC. CCs and CTs continue to be economically included in each of the Supplemental Portfolios, despite the removal of hydrogen in the Supplemental Portfolio analysis, further affirming the near- and-long term benefits of these resources on the system. The two available CCs are selected for each of the portfolios in the capacity expansion step. Peaking CT capacity continues to show economic value to the system through the Portfolio Verification's economic Battery-CT evaluation.

Q. DO THE COMPANIES BELIEVE THAT SUPPLEMENTAL MODELING RESULTS SUPPORT THEIR REQUEST FOR APPROVAL OF NEAR-TERM DEVELOPMENT ACTIVITIES FOR BAD CREEK II, OFFSHORE WIND AND SMR?

A. Yes. The Companies believe that SP5/SP6 support the Companies' proposed near-term development activities for Bad Creek II, Offshore Wind and SMR. Such development activities will ensure that these resources remain potentially available on the timelines assumed in the Companies' modeling and furthermore, will allow the Companies to develop more refined cost estimates for Commission consideration in future proceedings.

IV. PROCURING CPRE PROGRAM REMAINDER IN 2022 SOLAR PROCUREMENT

Q. MR. KALEMBA, WHAT IS THE PROPOSED TARGET PROCUREMENT VOLUME FOR THE 2022 SP?

A. As explained in the Carbon Plan, the Companies are proposing a 750 MW target procurement volume for the 2022 Solar Procurement.

Q. DO THE COMPANIES RECOMMEND MODIFYING THE TARGET VOLUME IN THE 2022 SOLAR PROCUREMENT?

A. Not under HB 951. However, the Carbon Plan modeling assumed that all CPRE MW would be procured and online by 2025 in advance of evaluating the need for additional solar to achieve the Carbon Plan targets in 2026 and beyond. The CPRE Program also requires the Companies to hold an additional competitive procurement to seek any unawarded portion of the initial CPRE Program volume. Therefore, the Companies must hold an additional procurement soliciting the 441 MW CPRE Program Remainder MW. To accomplish this requirement and to close out CPRE as efficiently and expediently as possible, the Companies plan to seek the CPRE Program Remainder MW through the 2022 SP RFP in addition to the 750 MW being sought under HB 951. Subject to Commission approval, the Companies will contract with Proposals to procure the CPRE Program Remainder MW (441 MW) to the extent proposals meet the CPRE avoided cost cap requirements. Because the CPRE Program Remainder MW are being procured pursuant to the HB 589 CPRE Program and not under HB 951, the projects selected as CPRE Program Remainder MW would not count toward the HB 951 ownership requirements and also would not be included in the 2022 Solar Procurement volumetric adjustment mechanism. Further detail regarding the mechanics of how this procurement complies with HB 589 will be included in the Companies' September 1, 2022, CPRE Program Plan filing.

Q. HOW DOES ADDING 441 MW OF CPRE SOLAR TO THE SOLAR PROCUREMENT RELATE TO THE ANNUAL INTERCONNECTION LIMITS IN THE CARBON PLAN?

A. As explained in Carbon Plan Appendix I (Solar) and discussed in more detail below, the Companies believe that the maximum amount of solar that can be connected in 2026 is 750 MW. Several projects that bid into the 2022 SP have existing Interconnection Agreements ("IA"), and should those projects be selected, it is possible that they will connect prior to 2026; however, it is likely that most of the solar procured above 750 MW will not connect by year end 2026.

V. INITIAL RESPONSES TO SPECIFIC RECOMMENDATIONS AND CRITICISMS OF CARBON PLAN MODELING AND RESULTS

Q. MR. SNIDER, PLEASE PROVIDE AN OVERVIEW OF THIS SECTION OF YOUR JOINT TESTIMONY AND HOW DUKE ENERGY IS RESPONDING TO SPECIFIC RECOMMENDATIONS AND CRITICISMS OF THE CARBON PLAN MODELING AND RESULTS.

A. The Companies view the July 15 comments submitted by the Public Staff and intervenors as well as the alternative resource plans presented by certain intervenor advocacy groups as the next step in the stakeholder engagement and Carbon Plan development process that began with the enactment of HB 951. The Commission received more than 32 sets of comments, including eight technical reports and three alternative modeled plans, touching virtually every aspect of the regulated utility construct. As highlighted in the Carbon Plan, it is unsurprising based upon the Companies' experience in past IRP proceedings as well as the varied perspectives presented in the recent Carbon Plan stakeholder process that certain intervenors now dispute key planning assumptions and other aspects of the Companies' modeling process.[40] Fundamentally, however, HB 951 tasks the Commission with developing a Carbon Plan with the Companies and considering stakeholder input that meets HB 951's goals and accomplishes the four core Carbon Plan objectives of balancing CO_2 reductions, affordability, reliability, and executability.

As highlighted in the Carbon Plan and reiterated above, the Companies' focus is on ensuring the Commission has a complete understanding of the Companies' Carbon Plan modeling and finds that it is reasonable for planning purposes in this initial Carbon Plan proceeding and, based upon that modeling, can select resources required for near-term execution of the Carbon Plan. In this section, the Companies address certain alternative modeling recommendations and criticisms presented by other parties, including how certain recommendations have been incorporated in the supplemental modeling to further inform the Commission's assessment of the original Carbon Plan portfolios and the proposed near-term actions.

[40] Carbon Plan Executive Summary at 25.

(A) <u>Carbon Baseline and Accounting Methodology</u>

Q. MR. QUINTO, PLEASE BRIEFLY REINTRODUCE THE 2005 CO_2 EMISSIONS BASELINE CALCULATION METHODOLOGY AND HOW FUTURE EMISSIONS WERE ACCOUNTED FOR TO ENSURE EACH CARBON PLAN PORTFOLIO MEETS THE NECESSARY CO_2 REDUCTION TARGETS.

A. The 2005 baseline was calculated using the Environmental Protection Agency's ("EPA") Emissions and Generation Resource Integrated Database ("eGRID"). This reliable, auditable, and publicly available emissions reporting source provides the required data to establish the baseline.

Following the criteria specified in HB 951, the Companies aggregated CO_2 emissions from the electric generating facilities owned, operated by, or on behalf of the utilities located in North Carolina in 2005. The resources identified for inclusion in the baseline and their CO_2 emissions were included in the established baseline are shown in Table 6 below.

Table 6: Summary of 2005 CO_2 Emissions Baseline, North Carolina Electric Generation Facilities Owned, Operated by and Operated on Behalf of Duke Energy[41]

Electric Generation Facility	Utility	2005 CO_2 Emissions [Short Tons]
Allen	DEC	6,224,197
Asheville	DEP	2,622,902
Belews Creek	DEC	14,219,392
Blewett	DEP	603
Buck	DEC	1,767,345
Cape Fear	DEP	1,966,488

[41] Carbon Plan Appendix A at 5 (Table A-2).

Electric Generation Facility	Utility	2005 CO_2 Emissions [Short Tons]
Cliffside	DEC	3,929,892
Dan River	DEC	820,524
H.F. Lee / Wayne[1]	DEP	2,482,443
Lincoln	DEC	32,295
Marshall	DEC	13,331,274
Mayo	DEP	5,259,857
Morehead	DEP	332
Richmond / Smith	DEP	1,141,586
Riverbend	DEC	2,001,258
Rockingham	DEC	40,590
Roxboro	DEP	14,907,671
Sutton	DEP	3,524,532
Weatherspoon	DEP	1,012,322
Operated on Behalf of[2]	Other, Various	579,684
Total		**75,865,188**

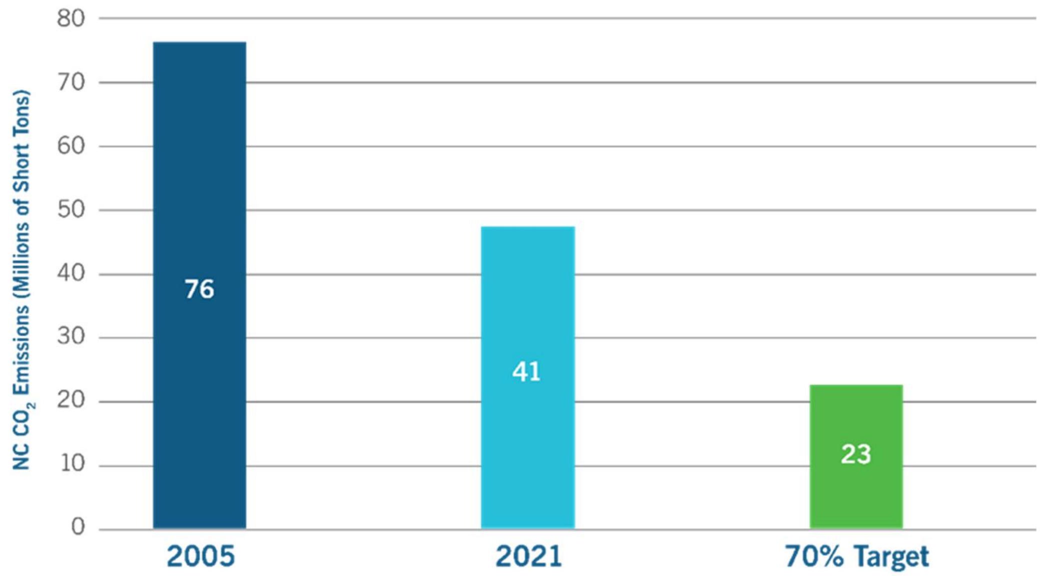
Note 1: eGRID data for DEP's H.F. Lee and Wayne plants was aggregated and calculated incorrectly, resulting in a double counting of CO_2 emissions. Adjustments were made to the reported data for these plants for the purpose of establishing the 2005 baseline for compliance with HB 951. The adjustment to the reported data lowered the 2005 baseline by approximately 100,000 short tons.

Note 2: The CO_2 emissions reported in the category "Operated on behalf of" include emissions from the Rowan facility owned by Southern Power Company, and several cogeneration and Small Power Producers who were under contract with Carolina Power and Light.

Future accounting of CO_2 emissions can be calculated consistent with this same methodology used to determine the baseline to track progress toward emissions reductions goals and verify the interim 70% and longer-term carbon neutrality targets have been achieved.

Once the baseline has been established, the interim 70% emissions reductions target can be calculated. Figure 8 below shows the 2005 baseline, the 2021 emissions of the system, and the 70% reduction target consistent with this reporting methodology.

Figure 8: North Carolina CO_2 Emissions Baseline, Progress and 70% Reduction Target[42]



For modeling and planning purposes, in ensuring the achievement of the CO_2 emissions reductions, the Companies have assumed that all incremental CO_2 emitting resources would be located in North Carolina and would contribute to the annual CO_2 emissions counted against achievement of the reductions target. Assuming all emissions from new resources count against the achievement of the carbon reduction targets requires the model to incrementally add any additional resources necessary to further reduce emissions to meet the reduction target.

[42] Carbon Plan Executive Summary at 8 (Figure 2).

Q. WHAT HAS BEEN THE RESPONSE OF OTHER PARTIES TO THE COMPANIES' METHODOLOGY FOR ACCOUNTING FOR CO_2 EMISSIONS WITH RESPECT TO BOTH THE 2005 BASELINE AND MEETING FUTURE TARGETS?

A. The Public Staff supports approval of the Companies' methodology for establishing the 2005 CO_2 baseline and tracking compliance with HB 951's CO_2 emissions reductions targets.[43] The Public Staff notes that the North Carolina Department of Environmental Quality's Division of Air Quality ("DAQ") also agrees with the Companies' carbon baseline and accounting of CO_2 emissions.[44]

The carbon accounting to establish baseline was done with publicly available, reliable, and auditable data from a credible source in the EPA, and includes necessary parameters for calculating the baseline and tracking future emissions.

Q. PLEASE REINTRODUCE THE NEED FOR THE COMMISSION TO CONFIRM ACCOUNTING REQUIREMENTS FOR EMISSIONS FROM OUT-OF-STATE RESOURCES SELECTED BY THE COMMISSION IN THE CARBON PLAN.

A. HB 951 specifies reductions in CO_2 emissions emitted in North Carolina from electric generating facilities owned, operated by, or on behalf of the electric public utilities. DEC and DEP each operate their dual-state systems in both

[43] Public Staff Comments at 162.
[44] Public Staff Comments at 39.

North Carolina and in South Carolina. As part of the stakeholder process, many stakeholders expressed concern for the Companies' siting new CO_2 emitting resources outside the State and, specifically, if those emissions do not contribute to the emissions for compliance with the CO_2 reduction target in the State, arguing this outcome would be counterproductive to regional CO_2 emissions reductions.

Q. CAN YOU PROVIDE A SPECIFIC EXAMPLE OF HOW OUT-OF-STATE EMISSIONS FROM A NEW COMMISSION-SELECTED CO_2 EMITTING RESOURCE COULD BE ACCOUNTED FOR?

A. Yes. The Companies request the Commission select the need for a 1,200 MW CC as part of the planned near-term supply-side development and procurement activities.[45] If the Companies then determine that the most cost-effective and prudent option at the time of execution would be to site the new CC resource in South Carolina, under this accounting methodology, the annual emissions of this future CC, from a generation facility located out-of-state, would be added to the total emissions of electric generating facilities, owned, operated by or on behalf of the electric public utilities, located in the State (North Carolina), and count against the achievement of the CO_2 emissions reductions goals. Without accounting for its emissions due to its hypothetical location, this additional resource would technically be available to serve energy of the entire dual-state systems, without its emissions counting in evaluating the Companies progress

[45] Companies' Verified Petition for Approval of Carbon Plan at 15-16.

towards meeting HB 951 emissions reduction goals.

The Companies reiterate their request for the Commission to determine whether it intends to deem CO_2 emission from new CO_2 emitting resources, selected by the Commission in achieving the emission reduction targets, that are ultimately sited outside of the state as 'in-State" for purposes of HB 951 compliance and emissions accounting.

Q. HOW DO THE COMPANIES RESPOND TO CIGFUR's RECOMMENDATION THAT THE COMMISSION SHOULD REQUIRE THE COMPANIES TO ACCOUNT FOR CARBON LEAKAGE ASSOCIATED WITH PRICE-INDUCED DEMAND EROSION?

A. CIGFUR has suggested that the Companies "should account for carbon leakage associated with the loss of incremental power demand from residential, commercial, and industrial customers leaving the state due to, at least in part, higher electric rates in [the Companies'] service territories."[46] The Companies are sensitive to the affordability of executing a least cost and reliable transition of the generation fleet to achieve the CO_2 emissions reduction targets. Economic sustainability and growth are important to the Companies and developing a Carbon Plan to achieve the least cost path is mandated in achieving HB 951's CO_2 emissions reductions targets. Impacts to customer affordability should be key in determining near-term and long-term actions the Companies

[46] CIGFUR Comments at 30.

should take. However, including such an adjustment to CO_2 emissions in achieving the emissions reduction targets is not envisioned by the law for any reason. HB 951 is unambiguous in its language on emissions to be counted towards the scope of ongoing assessment of CO_2 emissions and offers no relief or burden for load adjustments.

Conversely, should the growing supply of low-carbon and zero-carbon energy attract customers to the State, the Companies would not envision at this time any offsetting adjustment to the carbon accounting. Likewise, the Companies support further adoption of EVs, and, while it increases load on the system and decreases emissions from the transportation section, the Companies do not envision this to be an emissions adjustment in achieving the interim nor the 2050 emissions reduction targets.

Furthermore, CIGFUR's request for formal reporting on an ongoing basis associated with emission leakage from price-induced demand erosion[47] would not obviate the Commission's charge to take all necessary steps in achieving the authorized reduction targets. Tracking such "emission leakage," even if clearly defined, presumably would be extremely difficult and complex to quantify, and the results would not affect the Commission's mandate to take all reasonable steps to achieve the emissions reductions targets. Accordingly, the Companies do not agree with CIGFUR's tracking and reporting recommendation.

[47] CIGFUR Comments at 31.

Q. DID THE COMPANIES RECOGNIZE THE SOCIAL COST OF CARBON IN THEIR MODELING ANALYSIS?

A. Not directly in modeling the four Carbon Plan portfolios, as HB 951 called for the physical reduction in CO2 emissions in the State rather than imposing a social cost of carbon. However, the Companies did utilize the social cost of CO_2 metric in developing a Federal CO_2 tax production cost sensitivity analysis. As explained in Appendix E, the Companies are neither endorsing nor rejecting the social cost of CO_2 price forecast used in this analysis but are simply demonstrating the impact that an explicit federal cost of CO_2 could have on cost to customers. As recognized by the Public Staff, this analysis demonstrated that the "earlier incremental cost to enable CO_2 emission reductions is not fully offset by applying the Social Cost of CO_2 through 2050."[48]

[48] Public Staff Comments at 31-32 citing Carbon Plan Appendix E at 95-96.

(B) Criticisms of Analytical Methods and Tools

1. No Party Disputes the Appropriateness of Using EnCompass.

Q. MR. McMURRY, DO THE PUBLIC STAFF AND INTERVENORS GENERALLY AGREE WITH THE COMPANIES' USE OF ENCOMPASS AS THE PRIMARY MODELING TOOL TO PERFORM PRODUCTION COST AND CAPACITY EXPANSION MODELING?

A. Yes.

Q. PLEASE ADDRESS CRITIQUES OF THE COMPANIES' SEGMENTED CAPACITY EXPANSION MODEL RUN APPROACH.

A. The Public Staff raised the Companies' approach to model segmentation in addressing hydrogen fuel availability and conversion costs assumptions and the implication for near-term capacity cost of new gas CCs. Synapse also recognizes the need for segmentation but suggests that its 15-year approach strikes an appropriate balance between computing resource efficiency while allowing economic optimization to make decisions that take a long-term view of emissions and technology price trajectories into account.[49] While this issue was generally addressed through the supplemental modeling and the Public Staff "[g]enerally . . . does not take issue with the eight-year optimization period," the Companies briefly address this critique on model segmentation.[50]

The Carbon Plan was evaluated over the period 2022 through 2050 when net zero CO_2 emissions were achieved. In selecting resources within

[49] NCSEA et al. Synapse Report at 8-16.
[50] Public Staff Comments at 85.

Capacity Expansion, a full period optimization considers the costs of all resources and constraints through the entire study period. The Carolinas have a large number of resources and incorporating the additional constraint of achieving a declining CO_2 ton target made the problem size too large to solve within one full period in capacity expansion. Referring to Run Segments in the EnCompass help menu, it states that in these situations, the runs can be segmented to a size that will solve. An eight-year segment was used in the Carbon Plan with a one-year extension period so the optimization can look ahead instead of shutting down units and emptying storage reservoirs. The period of 8 years was used to ensure 2030 targets could be met in one segment using the available resources (on and offshore wind, solar, storage, gas). The second segment (between 2030 and 2038) introduced new nuclear and additional offshore wind as resources to meet the interim 70% targets and the use of hydrogen was included in the 3rd and 4th segments on the path to net zero by 2050.

Q. WHY DID THE COMPANIES OPT TO USE THE SEGMENTED MODEL RUN APPROACH?

A. The use of the eight-year segmentation accounted for all available resources in developing the expansion plans and allowed for more detailed commitment logic and better solution with a lower MIP (Mixed Integer Programming) Stop Basis as described below.

To ensure system reliability was considered in the development of the expansion plan within Encompass, Partial Commitment was used as the unit commitment option and a convergence tolerance (MIP Stop Basis) of 0.25% was used in conjunction with an 8-year segmented run.

The unit commitment option in EnCompass considers the unit operational parameters such as ancillaries, reserves, startup/shutdown cost, ramp rates and unit operational requirements. The Partial Commit option considers all these operational constraints but with partial units by bypassing the step in the optimization which searches the best way to commit whole units, thus reducing run time. In comparison the No Commitment option ignores most of these constraints and simplifies many others, which in turn runs the system with unrealistic flexibility. With increasing levels of system variable energy resources, the need to incorporate system reliability in the selection of resources will only increase.

The MIP Stop Basis is a measure of the accuracy of the expansion plan compared to the optimal plan. For example, a plan developed with a MIP Stop Basis of 2.0% represents a plan that is within 2% of the optimal objective function. The total system PVRR for P1- P4 is approximately $100 billion, so 2% would only result in a plan that was within $2 Billion of the optimal plan. When resources are close in cost and operability a lower MIP Stop Basis is needed to assure a cost-effective plan is selected. A MIP Stop Basis of 0.25% was used in the development of P1-P4.

In summary, the use of the eight-year segmentation accounted for all available resources in developing the expansion plans and allowed for more detailed commitment logic and better solution with a lower MIP Stop Basis.

The Companies will continue to evaluate the appropriate approach to modeling segmentation in developing future updates to the Carbon Plan.

2. Supplemental Modeling in SERVM and Portfolio Verification Step are Reasonable for Planning Purposes and Necessary to Ensure Least Cost and Reliability of the Grid.

Q. MR. SNIDER, HOW DO THE COMPANIES RESPOND TO NCSEA ET AL.'s CRITIQUE THAT MAKING MANUAL ADJUSTMENTS TO ENCOMPASS CAPACITY EXPANSION MODEL OUTPUTS VIOLATES MODELING BEST PRACTICES AND RENDERS A GIVEN PORTFOLIO UNREASONABLE FOR PLANNING PURPOSES?

A. As described in Chapter 2 and in Appendix E, and discussed by Witness Quinto previously in this testimony, the capacity expansion model is simply the first screen in developing a portfolio that is reasonable for planning purposes. Capacity expansion is a guide to the resource additions and retirements that should be considered, but further, more detailed analysis is required to confirm that the suggestions of the capacity expansion model would in fact maintain reliability and are in fact the most economic choices. If that additional analysis reveals improvements that can be made to the initial portfolios, then adjustments should be made. Similarly, if known real-world conditions render suggested resource additions or retirements unreasonable or inexecutable based on considerations outside the model, then adjustments should be made.

Q. PLEASE RESPOND TO SYNAPSE'S CONTENTION THAT THE BATTERY-CT OPTIMIZATION STEP IS NOT JUSTIFIED AND THAT THE COMPANIES ARE "UNABLE TO TEST WHETHER [CTS ADDED

IN THIS STEP] ENDANGER COMPLIANCE WITH CARBON REQUIREMENTS OR DETERMINE WHETHER THESE [CTS] ARE COST-EFFECTIVE WHEN PLANNING FOR A DE-CARBONIZED GRID."[51]

A. This contention is incorrect. As discussed in Appendix E and described previously in this testimony, the purpose of the battery-CT optimization step is to improve portfolio economics by ensuring that the amount of energy storage initially selected by the capacity expansion model is cost-effective.[52] This step is a required part of the analysis because of the necessary simplifications made in capacity expansion modeling. Because energy storage is used to move energy through time from periods with lower margin cost energy (typically minimum load conditions) to periods with higher margin cost energy (typically peak load conditions), the value of storage resources is heavily influenced by the spread between daily peak load and daily minimum load, with a larger spread enhancing the value of storage. The on-peak "typical day" load shape employed by the capacity expansion model includes both the monthly peak load and a monthly minimum hourly load. While including both the peak and the minimum is essential for assessing resource options under both conditions, it also substantially overstates the daily peak-minimum spread, which results in substantial over-estimation of the value of energy storage as perceived by the model. Following the battery-CT optimization step, a final production cost

[51] NCSEA et al. Synapse Report at 32.
[52] Carbon Plan Appendix E at 57.

model run on the adjusted portfolio confirms that CO_2 emissions targets are met.

Q. HOW DO THE COMPANIES RESPOND TO THE CRITIQUE THAT ENSURING RELIABILITY IS MERELY A MATTER OF SETTING THE RESERVE MARGIN TO THE CORRECT LEVEL IN THE ENCOMPASS CAPACITY EXPANSION MODEL AND THAT THE RELIABILITY VERIFICATION STEP IS NOT IN KEEPING WITH BEST PRACTICES?[53]

A. The major flaw with this critique is that it presupposes that the "correct" reserve margin for satisfying the 0.1 LOLE standard is fully known prior to capacity expansion modeling. Initial reserve margin and ELCC values[54] are dependent on many factors including 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, reliability 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 capacity expansion model, the "correct" reserve margin for the portfolio initially produced by the capacity expansion model cannot be definitively known in advance. It is therefore necessary to verify the

[53] NCSEA et al. Synapse Report at 32-33.
[54] The ELCC values used in development of the Companies' Carbon Plan portfolios were determined via modeling performed by Astrapé Consulting. The ELCC Study was Carbon Plan Attachment III.

reliability of initial capacity expansion results to confirm that resource changes made by the model do not compromise system reliability. Additional firm, dispatchable resources are added in this step if needed to maintain system reliability.

Q. WAS THE PUBLIC STAFF SUPPORTIVE OF THE RELIABILITY VALIDATION STEP?

A. Generally, yes. The Public Staff reviewed the Companies' reliability validation step and noted that it "… believes that sufficient capacity and energy resources are available in each portfolio to reliably satisfy customer demand."[55]

Q. WERE OTHER INTERVENORS SUPPORTIVE OF THE COMPANIES' RELIABILITY VALIDATION METHODOLOGY?

A. AGO's consultant, Strategen, stated that the out-of-model post-modeling reliability adjustment was not necessarily unwarranted but cautioned that such an adjustment should not become a "black box" that can be difficult to assess.[56] Strategen further stated "[i]t is essential that reliability be evaluated comprehensively, to ensure that any simplifications in models like EnCompass do not overlook any potential gaps."[57] The Companies appreciate this response and endeavored to provide transparency into this modeling step through the more detailed explanation of Portfolio Verification in Appendix E.

[55] Public Staff Comments at 101.
[56] AGO Strategen Report at 9-10.
[57] AGO Strategen Report at 9.

Q. SINCE FILING THE CARBON PLAN, HAVE THE COMPANIES BECOME AWARE OF ANY OTHER UTILITIES THAT CONDUCT A SIMILAR RELIABILITY VALIDATION STEP AS PART OF THEIR PLANNING PROCESS?

A. While the Companies have not surveyed the industry on this topic, they have recently become aware that the Public Service Company of New Mexico ("PNM") conducts a very similar reliability validation process. Similar to the Companies' methodology, PNM uses the EnCompass and SERVM models. PNM conducts LOLE analysis on resulting portfolios for a number of select years to evaluate the expected frequency of reliability events. PNM states:

> … we expect the general trends towards solar & storage and away from baseload firm resources to lead to (1) abundant supplies of energy during daylight hours, (2) highly constrained supplies during net peak hours, and (3) lower levels of energy available during nighttime/off-peak hours.[58]

Similar to the Companies' concerns regarding future market assistance, as a result of significant market uncertainty, the PNM analysis considered a "Base Case," a "Limited Imports" scenario and a "Very Limited Imports" scenario.[59]

Q. DOES DUKE ENERGY CONSIDER THIS RELIABILITY VALIDATION PROCESS TO BE "A MEANINGFUL DEPARTURE

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[58] PNM 2021 IRP for the Period 2020-2040, at 151-152, *available at* https://www.pnm.com/documents/ 28767612/31146374/PNM-2020-2040-IRP-REPORT-corrected-Nov-4-2021.pdf/7f2f46c4-f0a9-b936-715c-4b02e3586ce9?t=1648479305606.

[59] PNM 2020-2040 IRP at 151.

FROM THE TYPICAL USE OF RESOURCE ADEQUACY STUDIES" AS CLAIMED IN THE SYNAPSE REPORT?[60]

A. No. The Companies do not consider this a meaningful departure from the typical use of resource adequacy studies as suggested by Synapse. Simply relying on a reserve margin and probabilistically determined ELCC values is an appropriate initial step for ensuring reliability of a resource portfolio. However, as previously stated, it is not practical to conduct ELCC analyses for every possible combination of resources for a system adopting significant levels of variable energy renewables and storage. Thus, the Companies view the reliability validation as an enhanced modeling step and an extension to the typical use of resource adequacy studies. This step has become an essential and necessary element of the planning process to ensure a resource portfolio meets or improves reliability as required by prudent utility planning and HB 951.

[60] NCSEA et al. Synapse Report at 33.

(C) <u>The Carbon Plan's Approach to PVRR and Bill Impact Analysis is Reasonable and Appropriate for Portfolio Comparison Purposes</u>

Q. WITNESS QUINTO, PLEASE DESCRIBE THE PVRR METRIC AND EXPLAIN ITS PURPOSE IN THE COMPANIES' CARBON PLAN ANALYSIS.

A. As explained in Carbon Plan Appendix E, PVRR is a common resource planning metric used to evaluate cost differences across portfolios. PVRR incorporates all future costs that could vary across portfolios and sensitivities (i.e., costs related to resource decisions or operations that could differ across analytical cases). Importantly, PVRR is a comparison metric only and is not useful for nor intended to be useful for evaluating the total cost of serving customers. Given its limited purpose as a comparison metric, it is not necessary to include costs common to all portfolios in the PVRR calculation.

Q. PLEASE DESCRIBE THE BILL IMPACT METRIC AND EXPLAIN ITS PURPOSE IN THE COMPANIES' CARBON PLAN ANALYSIS.

A. As described above, while PVRR is an important metric for the long run costs of a portfolio, the Companies are also concerned with the immediate cost to customers. The average residential monthly bill impact metric presented in the Carbon Plan is an estimate of how much a residential customer using 1,000 kWh of energy per month can expect to see their bill change by the date specified as a result of system changes under a given Carbon Plan portfolio.[61] Importantly, the bill impact estimate, like PVRR, is a metric for comparing the

[61] Carbon Plan Appendix E at 82.

cost of alternate Carbon Plan portfolios and was not developed for the purpose of estimating the future total cost of serving customers in the Carolinas.

Q. HOW DO THE COMPANIES RESPOND TO THE CRITIQUE THAT PVRR AND BILL IMPACT ESTIMATES PREPARED IN THE CARBON PLAN ANALYSIS SHOULD HAVE BEEN MORE COMPREHENSIVE, INCLUDING MORE OR EVEN ALL COSTS OF SERVING CUSTOMERS THROUGH 2050?

A. These additional costs are well beyond the scope of what is required to compare Carbon Plan portfolios with respect to the affordability objective. Including additional costs common to all portfolios, like subsequent license renewals ("SLR") for existing nuclear units or red zone transmission upgrades, or costs unrelated to Carbon Plan projects would offer no additional information or insight for this comparison and therefore is unnecessary and potentially counter-productive to the extent that it could obscure the effects of investments that do differ across portfolios.

(D) Criticisms of Carbon Plan Inputs and Assumptions

1. DEC's and DEP's System Configuration and Modeled Approach to Consolidating System Operations is Reasonable for Planning Purposes.

Q. PLEASE REINTRODUCE HOW THE DEC AND DEP SYSTEMS WERE CONFIGURED IN THE CARBON PLAN MODELING AND EXPLAIN WHY THIS APPROACH IS REASONABLE.

A. As described in Carbon Plan Appendix R (Consolidated System Operations) and Appendix E, DEC and DEP are assumed to operate as two separate utilities and legal entities, operating across three areas that utilize the existing Joint Dispatch Agreement ("JDA") for co-optimizing the dispatch of the two utilities.[62] However, the Carbon Plan also incorporates Duke Energy's plans for, and assumes future regulatory approval of, implementation of Consolidation System Operations ("CSO") for DEC and DEP. Under this model, the North American Electric Reliability Corporation ("NERC") Balancing Authority, Transmission Service Provider, and Transmission Operator are consolidated for the two utilities. The functional consolidation allows for continued joint economic dispatch of the two utilities, but further allows the two utilities to jointly serve ancillary services. While this structure brings value to customers and further allows for the optimization of operational reserves, the two utilities do, however, retain responsibility for independently committing resources for

[62] Carbon Plan Appendix R at 1-2; Carbon Plan Appendix E at 7-9.

meeting forecasted demand and maintaining long-term capacity planning requirements in the Carbon Plan modeling.

The Carbon Plan explains that CSO represents a prudent and reasonable step for achieving lower cost and lower CO_2 emissions for customers, while maintaining or improving reliability of the consolidated system. Overall, CSO represents a no-regrets strategy for the Companies and their customers.

Many intervenors are in favor of continued consolidation of the utilities' roles and function with many, including the Public Staff, recommending an eventual merger. This proposition of merging the DEP and DEC utilities is addressed by witnesses Nelson Peeler and Laura Bateman in the Carolinas Utilities Operations Panel's testimony.

Q. HOW DO THE COMPANIES RESPOND TO CLEAN ENERGY BUYERS ASSOCIATION'S ("CEBA") CLAIM THAT THE "NEAR-TERM CONSOLIDATION PLAN DOES NOT APPEAR TO BE MODELED IN ANY OF DUKE'S FOUR MODELED PORTFOLIOS?"[63]

A. CEBA is mistaken. As explained in Appendix E, "the Carbon Plan analysis assumed the implementation of a [CSO] model where the NERC Balancing Authority ("BA"), Transmission Service Provider ("TSP") and Transmission Operator ("TOP") functions are consolidated for DEC and DEP."[64]

[63] CEBA Comments at 5.
[64] Carbon Plan Appendix E at 8.

2. <u>The Carbon Plan Appropriately Models Continued System-Wide Planning of the Companies' Dual-State Operations.</u>

Q. PLEASE DESCRIBE CIGFUR'S AND CUCA'S POSITIONS WITH RESPECT TO HOW CARBON PLAN COSTS SHOULD BE MODELED BETWEEN THE COMPANIES' NORTH CAROLINA AND SOUTH CAROLINA JURISDICTIONS.

A. CIGFUR states that the customer bill impacts of the Carbon Plan are underestimated and do not include the costs of each portfolio for North Carolina customers if the PSCSC denies recovery of certain Carbon Plan costs allocable to South Carolina ratepayers. CIGFUR recommends the Commission direct the Companies to perform this analysis and submit a supplemental filing.[65] Similarly, CUCA states that it is difficult to ascertain whether a new resource is the least cost option for North Carolina ratepayers without understanding whether South Carolina ratepayers will share the resource's cost.[66]

Q. HOW DO THE COMPANIES RESPOND TO CIGFUR'S AND CUCA'S ARGUMENT THAT THE COMPANIES SHOULD HAVE MODELED THE CARBON PLAN ASSUMING THE PSCSC DENIES RECOVERY OF CERTAIN CARBON PLAN COSTS FROM SOUTH CAROLINA CUSTOMERS?

A. The Carbon Plan assumes continuation of dual-state system operations, which has been in effect for over a century and delivers tremendous economies of

[65] CIGFUR Comments at 13-14.
[66] CUCA Comments at 3.

scale, resiliency, and savings to customers in both North Carolina and South Carolina. The Companies acknowledge that subsequent IRP reviews and other regulatory processes will be needed in South Carolina to ensure continued dual-state alignment; however, dual-state resource planning has been an iterative and ongoing process in the Carolinas over decades and the Companies continue to have the obligation to provide reliable, least cost electric service to customers in both states. Accordingly, the Carbon Plan appropriately assumes that system-wide cost allocation will continue between the jurisdictions and that the Companies will be afforded a fair opportunity to recover all reasonable costs incurred in the provision of utility service. HB 951 is consistent with the Company's goals for the Carolinas and the Carbon Plan is a reasonable path for prudent resource planning and energy transition for our systems serving North Carolina and South Carolina customers. The Companies are planning to work to achieve continued alignment through future South Carolina IRP proceedings.

Specifically, the Companies' next comprehensive South Carolina IRPs are targeted for filing in 2023 and will reflect the objectives and near-term activities consistent with those presented in the Carbon Plan. The Companies' next comprehensive IRP/Carbon Plan update in 2024 in North Carolina would account for PSCSC determinations as the Companies necessarily must be able to execute on a single system-wide resource planning pathway to continue to provide reliable, safe, and increasingly cleaner electric service to their customers in both North Carolina and South Carolina.

3. The Carbon Plan's 17% Winter Planning Reserve Margin is Reasonable for Planning Purposes and Minimally Necessary to Ensure Resource Adequacy of Future System Operations.

Q. WHAT PLANNING RESERVE MARGIN DID THE COMPANIES USE IN DEVELOPMENT OF THE CARBON PLAN PORTFOLIOS?

A. The Companies used a minimum 17% winter planning reserve margin in development of the Carbon Plan portfolios based on results of the 2020 Resource Adequacy Study conducted by Astrapé Consulting.[67] The 2020 Resource Adequacy Study used the same SERVM model used in the reliability validation process. The study determined the reserve margin needed to meet the widely accepted one day in 10-year loss of load expectation industry standard (0.1 LOLE).

Q. IS THIS THE SAME RESERVE MARGIN THAT WAS PREVIOUSLY ACCEPTED BY THE COMMISSION IN THE COMPANIES' 2020 IRPs?

A. Yes. The Companies rely on the same planning reserve margin that was previously accepted by the Commission in the 2020 IRPs, based on the same Resource Adequacy Study.[68]

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[67] 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.

[68] *See* Order Accepting Integrated Resource Plans, REPS and CPRE Program Plans with Conditions and Providing Further Direction For Future Planning at 5, Docket No. E-100, Sub 165 (Nov. 19, 2021) ("2020 IRP Order").

Q. DID THE PUBLIC STAFF EXPRESS ANY CONCERNS WITH USING THE 17% PLANNING RESERVE MARGIN?

A. The Public Staff generally accepted use of the 17% planning reserve margin and noted that "the reserve margin associated with each portfolio remains generally above the current target of 17% in 2030 and 2035, indicating sufficient capacity resources to meet demand even when the intermittent nature of solar, wind, and energy storage is taken into account."[69]

Q. DID ANY OF THE INTERVENORS EXPRESS CONCERNS WITH USE OF THE 17% PLANNING RESERVE MARGIN?

A. Yes. The joint comments of NC WARN and the Charlotte Mecklenburg NAACP claim that the Companies' Carbon Plan proposes "excessive reserve margins."[70] Additionally, the Tech Customers' consultant Gabel believes the planning reserve margin is conservative based on their incorrect assumption that the 17% planning reserve margin does not include the load and resource diversity benefits associated with neighbor assistance.[71]

Q. HOW DO YOU RESPOND TO THE COMMENTS FROM NC WARN AND CHARLOTTE MECKLENBURG NAACP?

A. NC WARN and Charlotte Mecklenburg NAACP make essentially the same arguments that NC WARN raised in the 2020 IRP proceedings and the Commission should again reject these arguments. In the 2020 IRPs, the

[69] Public Staff Comments at 101.
[70] Joint Comments of NC WARN and the Charlotte Mecklenburg NAACP at 26.
[71] Tech Customers Gabel Report at 57.

Companies presented actual operating reserve data during extreme winter weather events for the period 2014-2019 to demonstrate that planning to a 17% reserve margin is not excessive. The analysis showed occasions where actual operating reserves approached zero during some extreme events even though the IRP reserve margin was well above the 17% target.[72] The Powers Report included with NC WARN's comments misused and misrepresented the data in the Companies' 2020 IRPs to claim that a 17% planning reserve margin is excessive. The Commission ultimately found that DEP's and DEC's 2020 biennial IRPs are adequate and reasonable for planning purposes with respect to matters concerning resource adequacy and reserve margins.[73] NC WARN's claim that a 17% planning reserve margin is excessive has already been rejected by the Commission and it should be rejected again in this proceeding.

Q. TURNING TO THE TECH CUSTOMERS COMMENTS, THE GABEL REPORT CONTENDS THAT A 17% PLANNING RESERVE MARGIN WOULD BE REQUIRED ASSUMING THE COMPANIES HAVE *NO* ASSISTANCE FROM NEIGHBORING UTILITIES. IS THIS CORRECT?

A. No. As explained in the Resource Adequacy Study, the 17% planning reserve margin is based on the DEC and DEP combined scenario that allows market assistance as well as preferential support between DEC and DEP to approximate

[72] The IRP reserve margin reflects the projected reserve margin based on normal weather peak from the previous year's IRP.
[73] 2020 IRP Order at 5.

the reliability benefits of operating the DEC and DEP generation systems as a single balancing authority.[74] With no market assistance, DEC would require a 22.5% reserve margin to meet the 0.1 LOLE standard and DEP would require a 25.5% reserve margin to meet 0.1 LOLE.

Q. HOW DOES THE COMPANIES' 17% WINTER PLANNING RESERVE MARGIN COMPARE TO OTHER UTILITIES?

A. In the modeling completed to support the Carbon Plan, the Companies applied a 17% winter reserve margin requirement. The Companies reviewed the most recent resource planning documents for Southeastern utilities to see how the current 17% planning reserve margin value compared to others in the region. Table 7 presents current planning reserve margin benchmarking data that was gathered from the other utilities.

[74] Carbon Plan Attachment I DEC 2020 Resource Adequacy Study at 5-11; Attachment II DEP 2020 Resource Adequacy Study at 5-11.

Table 7: Utility Planning Reserve Margin Target Comparison[75]

Utility	Planning Reserve Margin
Duke Energy Progress, LLC **Duke Energy Carolinas, LLC**	Winter – 17%
Georgia Power Company	Summer – 16.25% Winter – 26%
Virginia Electric & Power Company (“VEPCO”)	PJM Planning Year – 15.9%
Tennessee Valley Authority (“TVA”)	Summer – 17% Winter – 25%
Florida Power & Light (“FP&L”)	Summer – 20% Winter – 20%
Dominion Energy South Carolina, Inc.	Summer – 14% Winter 21%
Louisville Gas & Electric (“LG&E”)	Summer – 17%-24% Winter – 26%-32%

Table 7 above illustrates the Companies' winter reserve margin target to be lower than its regional peers. Additionally, PJM's winter weekly reserve target for the 2021/2022 winter period is recommended to be 24% for December 2021, 27% for January 2022, and 21% for February 2022.[76] Georgia Power Company,

[75] Carbon Plan Chapter 2 at 6; Georgia Power 2022 Integrated Resource Plan at 1-2, Docket No. 44160 (Jan. 31, 2022) (“Georgia Power 2022 IRP”); Virginia Electric & Power Company 2021 Update to the 2020 Integrated Resource Plan at 11, Docket No. PUR-2021-00201 (Sept. 1, 2021) (“2021 Dominion Energy Virginia IRP Update”); Tennessee Valley Authority 2019 Integrated Resource Plan, Vol. 1 at G-7, 2019 Integrated Resource Plan Volume I - Final Resource Plan (azureedge.net); Florida Power & Light 2022 Ten Year Site Plan at 298, Docket No. 20220000-OT (April 2022) (“FP&L 2022 Ten Year Site Plan”); Dominion Energy South Carolina, Inc. Integrated Resource Plan 2021 Update at 32, Docket No. 2021-9-E (Aug. 17, 2021) (“DESC 2021 IRP Update”); Louisville Gas & Electric 2021 IRP Resource Screening Analysis at 27, Docket No. 2021-00393 (Oct. 19, 2021).

[76] 2021 PJM Reserve Requirement Study at 11, *available at*

TVA, FP&L, Dominion Energy South Carolina and LG&E all have higher winter reserve margins than DEC and DEP.

Q. MR. SNIDER, HOW DO YOU RESPOND TO PARTIES THAT SUGGEST DUKE ENERGY SHOULD REDUCE ITS RESERVE MARGIN BY GREATER RELIANCE ON OFF-SYSTEM RESOURCES AND IMPORTS?

A. First it should be noted again that HB 951 clearly mandates that the Carbon Plan must maintain or improve reliability. As discussed above, DEC and DEP already rely to a significant degree on non-firm imports for satisfying reserve margin needs. DEC relies on interties and non-firm purchases to reduce its reserve margin by 6.5% representing approximately one third of DEC's total required reserve margin to meet the 0.1 LOLE standard. Similarly, DEP relies on interties and non-firm purchases to reduce its reserve margin by 6.25%, which represents approximately one quarter of DEP's total reserve margin required to meet the 0.1 LOLE standard. It is also important to note that in addition to reliance on non-firm purchases and interties, DEP currently imports over 1,600 MW of its IRP-defined firm capacity resources resulting in a significant reliance on off-system resources and transmission capability to serve firm customer load. Duke Energy agrees with Astrapé's assessment that the 2020 Resource Adequacy Study reflects a moderate to aggressive approach (i.e.

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https://www.pjm.com/-/media/committees-groups/subcommittees/raas/2021/20211004/20211004-pjm-reserve-requirement-study.ashx.

taking significant credit for neighboring regions) to modeling neighboring assistance compared to other surrounding entities such as PJM and MISO.[77]

Utilities around the country are continuing to retire and replace dispatchable, firm fuel supply, fossil-fuel resources with variable energy and energy limited resources such as solar, wind, and battery storage. For example, Dominion Energy Virginia's 2020 IRP adds substantial solar and other renewables to its system that could cause additional winter reliability stress relative to what is modeled in Astrapé's 2020 Resource Adequacy Study for the Companies.[78] Dominion also noted that they will likely need to import a significant amount of energy during the winter but would need to export or store significant amounts of energy during the spring and fall.[79] Additionally, PJM now considers the DOM Zone to be a winter peaking zone where winter peaks are projected to exceed summer peaks for the forecast period.[80]

The Companies' 17% planning reserve margin is among the lowest of southeast utilities and Duke Energy believes there is significant risk in over reliance on non-firm market purchases. Future market assistance for reliability planning purposes is highly speculative due to the uncertainty in the pace of neighboring utilities' transition to variable energy and energy limited resources to achieve CO2 reduction targets. As neighboring systems continue to install

[77] 2020 Resource Adequacy Study at 7.
[78] Virginia Electric and Power Company's 2020 Integrated Resource Plan at 2-8, Case No. PUR-2020-00035 (May 1, 2020) ("Dominion Energy Virginia 2020 IRP").
[79] Dominion Energy Virginia 2020 IRP at 6.
[80] Dominion Energy Virginia 2020 IRP at 40.

solar and storage resources, neighbors' LOLE risk may shift to the winter months as it has for DEC and DEP, which could potentially lower the amount of neighbor assistance available in the future since there may be fewer capacity reserves available during winter peak periods. Changes in neighboring system resource portfolios and load profiles will be important considerations in future resource adequacy studies. The Companies are concerned that to the extent historic diversification between the Companies and neighboring utilities declines, the historic reliability benefits DEC and DEP have experienced from being an interconnected system will also decline. As the Companies reduce dependence on dispatchable fossil fuels and increase dependence on intermittent resources, prudent utility planning and HB 951 requires that this transition be planned and executed in a manner that does not impact reliability to customers.

4. <u>Accurately Modeling the Economic Load Carrying Capability of All Supply-Side Resource Options is Essential to Ensuring Reliability is Maintained or Improved in the Carbon Plan.</u>

Q. PLEASE RESPOND TO BRAD ROUSE'S ASSERTION THAT THE COMPANIES ARE "BLOCKING RENEWABLES" BY USING LOWER ELCC VALUES FOR SOLAR PLUS STORAGE AND WIND.[81]

A. The Companies disagree with Mr. Rouse's suggestion. Duke Energy incorporated the results of comprehensive resource adequacy and ELCC studies in developing the Carbon Plan portfolios to ensure the portfolios maintain or

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[81] Brad Rouse Comments at 9.

improve reliability as required by HB 951.[82] Use of a reserve margin target and ELCC values is utility standard practice in optimization planning models to help ensure that the initial selected portfolio(s) from EnCompass will satisfy reliability targets. However, as previously discussed, the Companies believe that additional modeling through the reliability validation step is needed to ensure the final portfolio provides adequate reliability. Determination of ELCC values is essential to ensure that the capacity value of the different resource technologies and contribution to the reserve margin requirement is known and quantifiable.

DEC and DEP are winter planning utilities and have the highest loss of load risk in the early morning winter hours when solar output is low or not available. A resource such as battery storage that contributes a significant level of output during high risk hours will have a higher capacity value than a resource such as solar that delivers output during low risk hours. The EnCompass capacity expansion model selects the least cost resource mix that ensures minimum reserve margin and carbon reduction targets are met. Thus, even though standalone solar may have a low ELCC value, it still may be selected for its low cost energy and zero-carbon properties. The Companies reserve margin and ELCC modeling construct, and additional reliability

[82] 2020 DEC and DEP Resource Adequacy Studies are included as Attachments I and II to the Carbon Plan and the 2022 ELCC Study is included as Appendix III to the Carbon Plan.

validation step, used in developing the Carbon Plan portfolios is reasonable, sound, and treats resources on a fair and equitable basis.

Q. DO YOU AGREE WITH THE AGO / STRATEGEN'S CLAIM THAT THE COMPANIES ASSUMED AN UNREALISTIC ELCC VALUE OF 100% FOR CCs AND CTs AND DID NOT ACCOUNT FOR THE TYPICAL OUTAGE RATES FOR THESE RESOURCES?[83]

A. No. Strategen cites tables on pages 31-32 of Carbon Plan Appendix E as the source for the 100% ELCC assumption for CTs and CCs; however, Strategen's reference to the Duke Appendix E tables in this context is misleading and mis-understands how the renewables and storage ELCC values were determined.

Q. PLEASE EXPLAIN.

A. The ELCC of a resource can be thought of as the amount of additional load that the system can supply when a new generator is added while maintaining the same level of reliability. The ELCC of a resource can also be thought of as the equivalent capacity of a new thermal generator that results in the same level of reliability that another generator, such as a variable energy generator, can provide. This second definition reflects the framework in which Astrapé developed the ELCC values for solar, wind and storage.[84]

In development of the ELCC values, it is important to note that Astrapé modeled resources with their unit specific outage rate values to ensure resources

[83] AGO Strategen Report at 28.
[84] The ELCC study methodology is described beginning page 5 of the ELCC Study.

are placed on a level playing field in the capacity expansion process. For example, battery storage was given an outage rate of 2.4% compared to a new thermal resource that was given a 4% outage rate. The 4% outage rate represents the high end of new thermal resources such as new CTs or CCs. Thus, the ELCC values for storage and renewables were created in terms of the equivalent amount of a new thermal resource with a 4% outage rate that can be displaced when added to the system. This results in higher ELCC values for renewables and storage than if developed in terms of pure additional load that could be supplied and ensures all resources are assessed on a comparable basis in the system optimization process. Further, since Encompass targets an installed capacity reserve margin of 17%, it is appropriate to give the thermal resources 100% ELCC value and include ELCC values for storage and renewables based on how they compared against the thermal resource with a 4% outage rate.

Q. HOW DO YOU RESPOND TO AGO/STRATEGEN's RECOMMENDATION THAT THE COMMISSION SHOULD CONSIDER DERATING THE ELCC OF CC AND CT UNITS TO REFLECT THE LACK OF FIRM FUEL SUPPLY?[85]

A. The Companies do not agree. AGO/Strategen's recommendation fails to recognize that the Companies have either firm transmission service (fuel supply) of natural gas to their generation facilities or multiple days' worth of ultra-low sulfur diesel as a secondary fuel on site to provide firm fuel sources for this capacity. Future natural gas resources are planned accordingly. Also as noted above, the ELCC value for all resources is compared to a new thermal resource that is not assumed to be 100% available. For example, if a CT has a 96% availability during high demand periods, then a resource that also had 96% availability during the same period would have an ELCC of 100%.

5. <u>The Carbon Plan's Net Load Forecast is Reasonable for Planning Purposes and Already Assumes Aggressive Deployment of Grid Edge Resources.</u>

Q. PLEASE BRIEFLY REINTRODUCE THE PROCESS UTILIZED TO DEVELOP THE LOAD FORECAST FOR THE CARBON PLAN?

A. As discussed in further detail in Carbon Plan Appendix F (Electric Load Forecast), the forecasts, which cover the years 2023-2037, are geared toward assessing the energy needs of the following customer classes: residential, commercial, and industrial, street lighting. The result allows analysis of the

[85] AGO Comments at 14; Strategen Report at 25-27.

impact of varying inputs on sales and customer growth, including substitution of different economic or weather inputs.

The Companies developed the Load Forecast in four steps. First, the Companies obtained a service area economic forecast using economic projections from Moody's Analytics, a nationally recognized economic forecasting firm, which includes economic forecasts for the Carolinas. Moody's forecasts consist of economic and demographic projections, which are used in the energy and demand models. Second, the Companies prepared an energy forecast by estimating statistical models based on these economic conditions. Preparing the energy forecast involves a mix of Statistical Adjusted End-Use Model techniques (which use EIA data for projected appliance saturation and efficiency trends) and traditional economic models, which calculate how variation in energy volumes can be explained by variations in weather and economic data. Third, the Companies perform ex post modifications that account for the growth in electric vehicle, solar and energy efficiency programs that must be considered, with adjustments to these programs applied to results that follow statistical estimation. Finally, using the energy forecast, the Companies developed summer and winter peak demand forecasts using an adjustment for the mix of end-uses at the time of peak.

Q. PLEASE DISCUSS ANY ADJUSTMENTS MADE TO THE GROSS LOAD FORECAST TO ARRIVE AT THE NET LOAD FORECAST UTILIZED IN THE MODELING OF THE CARBON PLAN.

A. Once the Companies develop their gross load forecast, several load modifiers are then applied to the load. These modifiers are necessary adjustments to the gross load in order to account for load projections that either increase or decrease the load the Companies must serve. Examples of modifiers that may increase the load forecast are EV load, additional wholesale load served by the Companies or to account for expected line losses and Company use. Examples of modifiers that may decrease the load forecast are Utility Energy Efficiency ("UEE"), behind-the-meter renewables or net energy metering ("NEM") and Peak Time Rates ("PTR") and Integrated Volt-Var Control ("IVVC"). DEC and DEP tables for both forecasted energy and capacity are provided in Tables 2-1 to 2-4 of Chapter 2 of the Carbon Plan.

Q. WHAT ARE THE PUBLIC STAFF'S CONCLUSIONS REGARDING THE COMPANIES' NET LOAD FORECASTS UTILIZED IN THE CARBON PLAN?

A. After reviewing the Carbon Plan, the Public Staff concludes that the Companies' 2022 peak demand and energy forecasts are reasonable for planning purposes.[86] With respect to the Companies' adjustments to the peak demand forecasts of NEM and EVs, the Public Staff states:

[86] Public Staff Comments at 49.

> [T]he forecast assumptions regarding NEM growth and, at this time, has no issue with the assumptions used to develop the NEM forecast, including the Companies' estimated incremental NEM capacity growth of approximately 575 MW (system) for DEC and 307 MW (system) for DEP by calendar year 2035.[87]

The Public Staff also finds the Companies' EV load forecast to be reasonable for the purposes of developing the Carbon Plan,[88] but urges the Companies to continue to study consumer EV charging behaviors, market trends, and to develop rates and programs to encourage managed charging behaviors.[89] Nevertheless, the Public Staff does question the achievability of the 1% EE target utilized in the development of the Carbon Plan, stating that "an increase in EE savings to 1% of both total and available sales would be substantial, particularly after 2030."[90]

Q. PLEASE DISCUSS YOUR OVERALL IMPRESSION OF OTHER INTERVENORS' CRITIQUES OF THE COMPANIES' NET LOAD FORECAST UTILIZED IN THE CARBON PLAN?

A. In general, most intervenors do not appear to take issue with the process utilized to develop the gross peak demand forecast, and instead challenge individual adjustments made to the gross peak demand forecast to arrive at the net peak demand modeled in the Carbon Plan. A high-level overview of the intervenors' load forecast adjustment arguments is shown in Figure 9, below.

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[87] *Id*. at 62.
[88] *Id*. at 63.
[89] *Id.* at 65.
[90] *Id.* at 52.

Figure 9: Summary of Intervenors' Load Forecast Adjustments

Intervenor	UEE	NEM	EV	Net Peak Load
AGO	↑			
Appalachian Voices	↑		↑	
City of Asheville/Buncombe County				~
CCEBA	~			
City of Charlotte	↑			
CIGFUR		↑		
NCSEA et al.	↑	↑		↓
CPSA	↑		↑	
EWG				↓
NCSEA/Synapse	↑	↑		↓
NCWARN				↓
Public Staff	↓	✓	✓	
Brad Rouse				↑
Tech Customers	↑			↓

Notes:

1) Public Staff believes Companies' process to develop load forecast is reasonable. No other intervenors had comments about the process.
2) No intervenor had significant comments about Critical Peak Pricing (CPP) or Peak Time Rates (PTR).
3) Key:
   - ✓ Intervenor agrees with Companies' assumption
   - ↑ Intervenor believes variable should be higher
   - ~ Intervenor's suggested change will have an unknown effect on variable
   - ↓ Intervenor believes variable should be lower

As shown in Figure 9 above, many intervenors, contrary to the Public Staff, assert that the Companies' EE assumption is too low. CPSA and EWG believe the Companies underestimated electrification in the load forecast alongside NCSEA et al. and Tech Customers.[91] Intervenor Brad Rouse cited that some analysts are projecting 50% more electricity demand than the utilized in the Carbon Plan.[92] The City of Asheville/Buncombe County state that load forecasts should be adjusted proactively to account for the impact of DSM programs and technological advances that reduce load as well as the impact of EVs and electrification that may increase it, resulting in and unknown impact to net peak demand.[93]

Ultimately, the Companies stand behind the development of their load forecast and the projections of the adjustments made to the load forecasts. The assumptions made by the Companies are based upon solid projections unlike those made by intervenors who are outcome-based in their comments and alternative plans as discussed below. To the contrary, the following sections show that Companies' forecasts are based on the best information available at the time the forecasts were developed and are appropriate for planning purposes.

[91] Exhibit A to CPSA Comments E-100 Sub 179 at 11; EWG Comments at 3; NCSEA et al. Comments at 28.
[92] Brad Rouse Comments at 3, 13.
[93] City of Asheville/Buncombe County Comments at 3.

(E) Grid Edge/Demand-Side Resources in Carbon Plan

1. The Carbon Plan Appropriately Values Utility Energy Efficiency in Order to "Shrink the Challenge."

Q. PLEASE PROVIDE A SUMMARY OF HOW THE COMPANIES INCORPORATED ENERGY EFFICIENCY ("EE") AND DEMAND-SIDE MANAGEMENT ("DSM") INTO THE CARBON PLAN MODELING PROCESS.

A. In developing the Companies' EE/DSM Forecast for the Carbon Plan the Companies sought to incorporate an aggressive, yet attainable, modeling assumption about the amount of load reduction included in the Carbon Plan. The Companies' modeling assumed a floor, or minimum amount of annual utility program energy efficiency savings, of 1% of eligible sales.

The Companies prioritized EE/DSM savings by then modeling the 1% of eligible retail load reduction associated with energy efficiency programs prior to evaluating any supply-side resources necessary to achieve the 70% CO_2 emissions reduction by 2030. This is part of the Companies' planning effort to "shrink the challenge" by focusing on reducing the amount of load the Companies must serve. The impact of this reduction is seen in Table 1 of the Grid Edge Panel testimony, which shows that the Companies' assumption of a minimum of 1% reduction in eligible sales from energy efficiency will deliver approximately a 5% cumulative reduction in total retail load by 2030 over a seven-year period.

Q. DOES THE PUBLIC STAFF RAISE CONCERNS WITH THE COMPANIES' MODELING BASED ON 1% OF EE SAVINGS, AS PRESENTED IN THE CARBON PLAN?

Yes. The Public Staff stated concern with the achievability of the 1% EE target utilized in the development of the Carbon Plan, noting that "an increase in EE savings to 1% of both total and available sales would be substantial, particularly after 2030."[94] The Public Staff also notes that the 1% EE target deviates from the traditional approach of projecting EE utilized in previous IRPs, which has historically been based upon Market Potential Studies. To meet these goals, the Public Staff believes that policy and legislative changes would be necessary.[95]

Q. HOW DO THE COMPANIES RESPOND TO THE PUBLIC STAFF'S STATEMENT THAT THE 1% EE TARGET IS AGGRESSIVE?

A. The Companies agree that their assumption of a minimum of 1% of eligible sales reduction through the Companies' UEE programs is aggressive. However, the Companies believe it was important to include an increase in energy efficiency achievement in the Carbon Plan compared to their base case (i.e., the amount of EE approved in the IRP) as that is a reasonable increase in light of energy transition, and we also identified enablers that could potentially support the increased energy efficiency achievements. As discussed in more detail in the Grid Edge Panel's testimony, the fact that the Companies identified potential

[94] Public Staff Comments at 52.
[95] *Id.* at 51-52.

enablers to achieve the increased EE should help to ease the Public Staff's concerns.

Q. IN CONTRAST TO THE PUBLIC STAFF, DO OTHER PARTIES ADVOCATE THAT THE CARBON PLAN SHOULD BE MODELED USING A HIGHER EE SAVINGS TARGET?

A. Most intervenors disagree with the Public Staff, instead arguing that the Companies' EE assumption is unreasonable because it is too low. NCSEA et al. and their consultant Synapse's modeling utilized EE assumptions of approximately 1.5% of *total* load.[96] Tech Customers and their consultant, Gabel Associates, claim that an 7.7% reduction in the load forecast is achievable with EE alone.[97] The AGO similarly states that the Companies' EE assumptions are "arbitrary" and should be modeled as a selectable resource[98] while the City of Asheville/Buncombe County and City of Charlotte argue that EE targets based on the 1% of retail sales utilized by the Companies is below other states.[99]

Q. TECH CUSTOMERS' GABEL/STRATEGEN REPORT ARGUES FOR SIGNIFICANTLY HIGHER CUMULATIVE ENERGY AND PEAK DEMAND LOAD REDUCTIONS THROUGH EE/DSM MEASURES IN ITS MODEL RELATIVE TO THE COMPANIES' ASSUMPTIONS.

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96 NCSEA et al. Synapse Report at 24-25, 44.
97 Tech Customers Gabel Report at 12.
98 AGO Comments at 22, 32.
99 Asheville Comments at 5-6; Charlotte Comments at 3, 12.

HOW DO THE COMPANIES RESPOND TO THIS MODELING DISCREPANCY?

A. Contrary to the concerns of the Public Staff that EE/DSM savings assumed in the Carbon Plan may be overly aggressive; the Gabel Report assumes in its model EE/DSM savings of almost twice the already aggressive energy and capacity savings the Companies estimate by 2032.[100] To support its model inputs and argue that higher EE savings are achievable, the Gabel Report refers to the 2020 American Council on for an Energy Efficient Economy ("ACEEE") Report "How Energy Efficiency Can Help Rebuild North Carolina's Economy: Analysis of Energy Cost and Greenhouse Gas impacts" ("ACEEE Report") and 2020 Scorecard. As detailed in the Grid Edge Panel's testimony, the ACEEE Report contains a number of relevant factors to consider that seem to have been ignored by the parties referencing its recommendations and the 2020 Scorecard fails to account for the fact that electric usage and electric rates vary widely in different states and these variables play a significant role in both the adoption and impact of EE programs. If in the future, actual EE/DSM savings exceed the Companies' forecasts, such changes will be reflected in future Carbon Plan iterations.

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[100] Tech Customers Gabel Report at 41.

Q. HOW DO THE COMPANIES RESPOND TO THE AGO's ARGUMENT THAT EE AND DEMAND RESPONSE SHOULD BE MODELED AS SELECTABLE RESOURCES?[101]

A. The Companies do not agree that EE and demand response should be modeled as selectable resources. Modeling a resource that is almost entirely dependent on customer preferences and participation as a selectable resource is problematic and does not place the appropriate priority on it as the Companies' methodology. At this time, the Companies believe the current methodology of basing assumed UEE impacts on the Companies' load forecasts based on reasonable projections of customers that are eligible to participate is a reasonable and appropriate approach to forecasting the amount of UEE that can be achieved through the Companies' EE programs.

2. <u>The Carbon Plan's Distributed Energy Resource NEM Forecast is Reasonably Tailored to Customer Class and Appropriate for Use in This Proceeding.</u>

Q. PLEASE BRIEFLY DESCRIBE THE PROCESS THE COMPANIES UTILIZED TO DEVELOP THE COMPANIES' ROOFTOP SOLAR FORECAST.

A. As described in Carbon Plan Appendix F, the rooftop solar forecast is derived from a series of capacity forecasts and hourly production profiles tailored to residential, commercial, and industrial customer classes. Each capacity forecast is the product of a customer adoption forecast and an average capacity value.

[101] AGO Comments at 22-23.

The adoption forecasts are developed using economic models of payback, which is a function of installed cost, regulatory incentives, regulatory statutes and bill savings. A relationship between payback and customer adoption is developed through regression modeling, with the resulting regression equations used to predict future customer adoptions based on projected payback curves. Historical and projected technology costs are sourced from energy consulting firm Guidehouse, while projected incentives and bill savings are based on current regulatory policies as well as input from internal subject matter experts. Average system size (capacity) values are based on trends in historical adoption.

The hourly production profiles have 12x24 resolution, which equates to one 24-hour profile for each month. Profiles are derived from actual production data, where available, and solar PV modeling. The PV modeling is performed in the PVsyst model using 20+ years of historical irradiance data sourced from Solar Anywhere and Solcast. Models are created for 13 irradiance locations across DEC's service area and nine irradiance locations across DEP's service area with 21 tilt/azimuth configurations. The results for each jurisdiction are combined on a weighted average basis to produce the final profiles.

Q. HOW DO THE COMPANIES RESPOND TO THE CONTENTION THAT THE COMPANIES' FORECAST FOR BEHIND-THE-METER DISTRIBUTED ENERGY RESOURCES IS TOO CONSERVATIVE?

A. NEM policy in the Carolinas is evolving. The "Solar Choice" net metering tariff and "Smart $aver Solar" program discussed in Appendix G, as well as in the

Grid Edge Panel are awaiting NCUC action.[102] As such, the Companies modeled future NEM adoptions based on regulatory policies in place at the time the Carbon Plan was developed.

While the Public Staff "has no issues with the assumptions used to develop the NEM forecast,"[103] NCSEA et al. suggest "Duke Energy's projections for future net metering (NEM) adoption are too conservative. The projections for both North Carolina and South Carolina included in Appendix G show an additional 2,027 NEM customers for DEC per year and an additional 850 NEM customers for DEP per year from 2022 to 2030. These numbers are below recent trends."[104] NCSEA et al. then assert that there "were more than 3,000 new NEM customers for DEC and DEP each in North Carolina [in] 2021."[105] Though this account of recent adoptions is correct, the projected adoptions are not correct. Table 8 below shows the installed totals as of the end of 2021 while Table 9 shows the 2030 snapshot based on net new adoptions since the beginning of 2022.

[102] *See* Application of Duke Energy Progress, LLC and Duke Energy Carolina, LLC for Approval of Smart $aver Solar Energy Efficiency Program Docket Nos. E-2, Sub 1287 & E-7, Sub 1261 (Dec. 16, 2021).
[103] Public Staff Comments at 62.
[104] NCSEA et al. Comments at 28.
[105] *Id.*

Table 8: Number of Customers Enrolled in Net Metering Rates and Forecasts BTM Generation[106]

System	2022 Enrollment (as of Jan. 1, 2022)		2022 BTM Generation Forecast	
	Residential	Non-Residential	Residential	Non-Residential
DEC	22,252	745	223,447 MWh	86,816 MWh
DEP	14,017	477	138,325 MWh	44,755 MWh

Table 9: Number of Forecasted Customers and Incremental MWh Enrolled in Net Metering Rates and Forecasted BTM Generation by 2030[107]

	DEC		DEP	
	Residential	Non-Residential	Residential	Non-Residential
Customers	38,464	1,050	20,839	846
MWh	354,255	92,192	189,168	62,092

To calculate the proper projected average adoption rate for residential customers, one would simply need to divide the net new values in Table 9 by the number of years in the period, thus: DEC = 38,464 / 8 = 4,808 NEM Customers per year and DEP = 20,839 / 8 = 2,605 NEM Customers per year. These numbers show that Duke Energy's projections of NEM adoption are in line with recent trends. It is true that both future state and federal policy changes may change these trends, but until there is more certainty, Duke Energy agrees with the Public Staff that the point-in-time NEM forecast used in the Carbon Plan is appropriate for planning purposes. As NEM policy and adoptions evolve, changes to the Companies' forecasts will be reflected in future Carbon Plan iterations.

[106] Carbon Plan Appendix G at 18 (Table G-7).
[107] Carbon Plan Appendix G at 18 (Table G-8).

3. <u>The Carbon Plan's Electric Vehicle Forecast is Reasonable for Purposes of This Proceeding.</u>

Q. PLEASE BRIEFLY DESCRIBE THE PROCESS TO DEVELOP THE COMPANIES' ELECTRIC VEHICLE FORECAST.

A. The electric vehicle forecast is developed using the Vehicle Analytics and Simulation Tool ("VAST"). The electric vehicle forecast was developed in Fall 2021 using variable inputs from the middle of the year of 2021. The VAST tool uses these multiple variables as inputs to develop jurisdictional vehicle projections by duty (light, medium, and heavy). The electric vehicle forecast is then used as an input, along with other variables (such as historical registration data, vehicle miles traveled, fuel cost projections, vehicle efficiency, etc.), to develop the forecasted energy and loading demands that are provided to load forecasting.

Q. WHAT ARE POTENTIAL VARIABLES THAT COULD IMPACT THE COMPANIES' ELECTRIC VEHICLE FORECAST?

A. There are a variety of variables that will heavily influence electric vehicle adoption. Some critical variables that may lead to higher adoption levels than those included in the forecast include increased consumer acceptance, automaker commitments, and strong public government support (policy and funding). Alternatively, there are some critical headwinds that could lead to reduced adoption levels including the current global chip shortage, supply chain issues, cost of EVs for the public, and manufacturing limitations.

The electric vehicle forecast in the Carbon Plan considered all of these variables at the time the forecast was developed, and the Public Staff found the Companies' electric vehicle load forecast to be reasonable for the purposes of developing the Carbon Plan.[108] The Companies continue to evaluate the electric vehicle marketplace and will continue to update the electric vehicle forecast going forward. If in the future, actual EV adoption exceeds the Companies' forecasts, such changes will be reflected in future Carbon Plan iterations.

Q. WHAT IS THE COMPANIES' RESPONSE TO OTHER INTERVENORS' CRITIQUES OF THE COMPANIES' ELECTRIC VEHICLE FORECAST UTILIZED IN THE CARBON PLAN?

A. CPSA alleges that the Carbon Plan modeling significantly underestimates electric vehicle demand based on BNEF's Economic Transition Scenario (30% sales in 2030) and that higher EV demand must be matched by additional solar or other clean energy resources to achieve the Carbon Plan CO_2 goals.[109]

The Companies recognize there are numerous public electric vehicle forecasts and while BNEF forecasts 30% EV sales in 2030, other forecasts from the same time period, such as IEA's "Global EV Outlook 2021" show 15% electric vehicle sales by 2030[110] which is comparable to Duke's forecast of 12.5%. Additionally, the impact of more than doubling Duke Energy's forecast by 2030 to match BNEF's forecast is approximately 430 MW of additional solar

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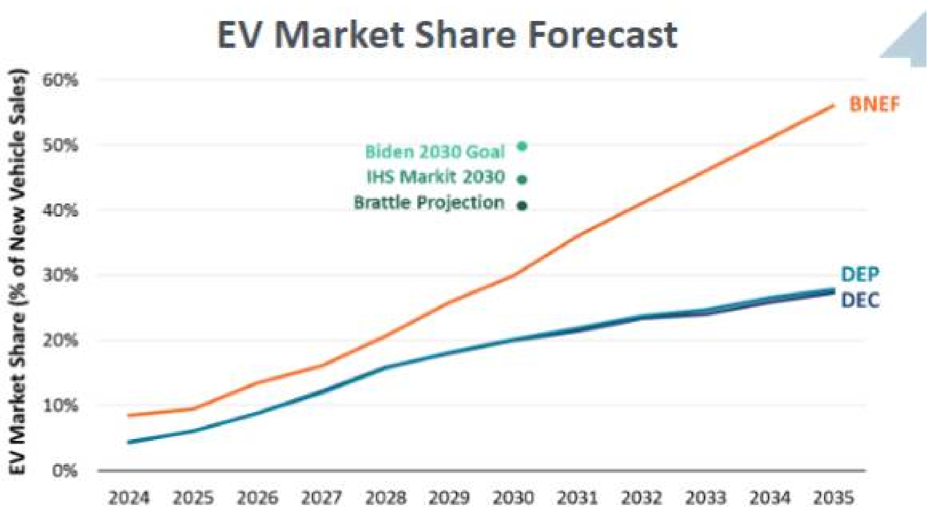
[108] Public Staff Comments at 63.
[109] CPSA Brattle Report at page 11.
[110] IEA Global EV Outlook 2021 at 80, *available at* https://iea.blob.core.windows.net/assets/ed5f4484-f556-4110-8c5c-4ede8bcba637/GlobalEVOutlook2021.pdf.

which is less than 5% of total solar online by 2030 in the four Carbon Plan portfolios. Importantly, BNEF forecasts EV adoptions at the national level. As shown in Figure 10 below, taken from CCEBA's Exhibit A, Duke's electric vehicle forecast is approximately one-half of BNEF's forecast at the start of the forecast period. This difference is largely driven by higher electric vehicle adoptions in California and other western states compared to electric vehicle adoptions in the Carolinas. Finally, as Figure 10 shows, the forecasts do not start to diverge until 2028 so, when accounting for regional differences in the forecasts, the impact to the near-term action plan is negligible.

Figure 10: CCEBA Exhibit A Figure Comparing Electric Vehicle Market Share in Duke Energy's Forecast to BNEF's National Forecast



4. The Companies Appropriately Modeled Demand Response as a Dispatchable Resource at a Reasonable Strike Price for Planning Purposes.

Q. HOW DOES THE COMPANIES' MODEL ACCOUNT FOR DEMAND RESPONSE PROGRAMS?

A. Demand Response ("DR") is modeled as a dispatchable resource in the Companies' Carbon Plan modeling. The Companies include a monthly strike price proxy based on an ultra-low-sulfur diesel ("ULSD" or sometimes referred to informally as "oil-fired") unit with a 10 MMTBU/MWh heat rate for demand response in Encompass. When the system marginal prices in the simulation model exceed this strike price, demand response capacity is dispatched to meet demand. This methodology simulates real-world deployment of demand response programs during peak conditions.

Q. THE PUBLIC STAFF STATES THAT THE STRIKE PRICE USED IN THE COMPANIES' MODEL FOR EXISTING DEMAND RESPONSE PROGRAMS IS LIKELY TOO HIGH AND DISTORTS ECONOMIC SIGNALS TO SHAVE SYSTEM LOAD FROM DR-ENROLLED CUSTOMERS.[111] HOW DO THE COMPANIES RESPOND?

A. The DR strike price used in the Carbon Plan modeling is appropriate for planning purposes. DR is primarily used as an emergency capacity resource in system operations today. The prices at which the DR is activated in the Carbon

[111] Public Staff Comments at 131.

Plan modeling reflect these historical usage trends when both residential and non-residential DR programs are activated to reduce load during system peaks.

Additionally, use of weather normal load forecasts in the Companies' Carbon Plan results in low utilization for peaking resources. Because the Companies plan for a 17% winter and 15% summer planning reserve margins, in any given year the amount of capacity planned to be available for the system is in excess of 17% of the peak load that is forecasted for that year. Therefore, the most expensive units result in infrequent utilization such as oil-fired CTs and DR. In real-world situations with non-weather normal load, this planning reserve margin may be utilized more. When loads are higher than expected due to higher-than-normal weather impacts, and generator outages are occurring at a higher co-incident rate than normal, these peaking resources have more opportunity to get utilized.

The Companies are evaluating new programs and new strategies for existing programs that could result in the use of a lower strike price in DR modeling, especially using the residential programs in ways that will be less noticeable by customers. To the extent that it is shown in future pilot testing of more frequent activation of demand response, particularly with residential customers, does not negatively impact participation, the Companies will evaluate integrating a lower strike price for some of these programs modeled. The Companies agree with the Public Staff's comments that this topic deserves more attention in future Carbon Plan modeling, especially as it relates to the first prong of the Companies' approach to achieve carbon reduction targets, leverage grid- edge participation.

(F) Existing System Resources Assumptions

1. The Companies' Plans for Enhanced Flexibility of Existing Gas Units and Subsequent License Renewal for the Nuclear Fleet is Reasonable.

Q. PLEASE SUMMARIZE INTERVENORS' COMMENTS REGARDING THE COMPANIES' PROPOSED ACTIONS WITH RESPECT TO EXPANDING FLEXIBILITY OF THE EXISTING GAS FLEET.

A. The Public Staff supports expanding flexibility of the existing gas fleet, which will allow the Companies to maintain system reliability and quality of service while integrating intermittent resources, such as wind and solar, that may not match customer demand.[112] Examples of expanding flexibility for the existing gas fleet include increasing up and down ramp rates, improving minimum load capabilities and reducing minimum up and minimum down time. The Portfolio Evaluation section in Chapter 3 of the Carbon Plan illustrates the need for increased flexibility as the resource portfolio transitions to larger penetrations of variable energy renewable resources.

Q. PLEASE SUMMARIZE INTERVENORS' COMMENTS REGARDING THE COMPANIES' PROPOSAL TO CONTINUE TO PURSUE SUBSEQUENT LICENSE RENEWAL FOR EXISTING NUCLEAR UNITS.

[112] Public Staff Comments at 159-160.

A. The Public Staff supports continued pursual of SLR to maintain the zero-carbon existing nuclear fleet based on the response to Duke Energy's relief request on pages 159-160 of their comments. The Public staff recommends continuing to pursue prudent and reasonable decisions that support execution of the Carbon Plan. CIGFUR stated that an analysis of additional costs including SLR should be performed, but since metrics are used for portfolio comparison and SLR is included in all portfolios the Companies do not find this recommendation appropriate for reasons more fully explained above. Other intervenors were either generally supportive of SLR or made no comments on SLR.

2. <u>The Companies' Plans for Coal Retirements Are Reasonable and Alternative Recommendations to Accelerate Coal Retirements Are Not Supported and Should be Rejected.</u>

Q. HOW DO THE COMPANIES RESPOND TO THE CRITIQUE THAT COAL RETIREMENT DATES SELECTED BY ENCOMPASS SHOULD NOT HAVE BEEN SUBJECT TO FURTHER ANALYSIS AND ADJUSTMENT?

A. The Companies recognized this would likely be a concern for some parties and therefore proactively addressed the adjustments made to the initially identified coal retirement dates in detail in Appendix E of the Carbon Plan.[113] To further reiterate, while the Companies' capacity expansion and production cost models are sophisticated tools, capacity expansion modeling, in general, is not an exact indication of the optimal selection of resources nor, in this case the optimal

[113] Carbon Plan Appendix E at 44-49.

timing to retire a unit. The capacity expansion model's ability to determine optimal timing of retirements is inadequate. The simplifications used in the model, along with the inability to adjust on-going costs for different retirement dates, makes the evaluation useful as a general guide only.

Additionally, there are several factors which could influence optimal timing of retirements including timing with new resources, transmission constraints, and the ability to leverage sites for future development. These factors do not lend themselves to perfect integration into the model. As such, it is appropriate for the utilities to consider these factors in determining the optimal timing of such decisions, such as coal retirements.

Overall, as discussed in Carbon Plan, Appendix E, the adjustments made to coal retirements dates are not material to the achievement of CO_2 emissions reductions nor to the selection of near-term resources.

Q. HOW DO YOU RESPOND TO CRITIQUES FROM STRATEGEN THAT THE ADJUSTMENTS THE COMPANIES MADE ARE IN FACT MATERIAL TO THE PROPOSED NEAR-TERM ACTIONS AND THE "CROWDING OUT" OF MORE ECONOMIC RESOURCES EARLIER?

A. The Companies recognize that retirement analysis is complex and that it is necessary to consider a wide range of real-world factors related to feasibility and economics when determining optimal retirement dates. Capacity expansion models attempt to co-optimize retirements and replacements, but the scope of this analysis necessitates the use of simplified, imprecise cost assumptions and simulations. While the results of this co-optimization are a useful general guide in the determination of unit retirement dates, it is also important to consider the broader range of near-term and long-term risks and benefits that cannot be comprehensively incorporated in capacity expansion modeling.

The retirement dates the Companies have selected are optimal in the broader context of the Carbon Plan portfolios and, importantly, these dates reflect realistic timelines for accommodating the development and construction of required transmission and generation replacement resources that need to be in place prior to coal unit retirements. The assertion that the Companies adjustments to the endogenously identified retirement dates for Marshall 1 and 2 and Mayo crowd out more economic resources reflects a misunderstanding of the analysis and ignores the need for supporting infrastructure to enable such retirements. For example, optimally timing the coal retirements to recognize the necessary transmission timelines is an appropriate consideration. In doing so, this further allows for the selection from a wider array of resources in meeting the near-term and long-term needs of the system. The timelines additionally allow for the Companies to take advantage of continued cost declines for declining cost resources, such as batteries, if they are selected as a part of the collective optimal replacement resources.

The Companies discuss in Appendix E, the necessary adjustment to the Marshall 1 and 2 retirement dates endogenously identified by the capacity expansion model. To reliably retire Marshall 1 and 2 requires the completion of a transmission project to retire the units without replacement resources on site. While Strategen points to the earlier deployment of batteries as a potential replacement resource at the site, which could alleviate the need for the transmissions project to accelerate the retirement of the unit, this is not a feasible solution. The replacement resources alluded to in the explanation for the adjustment provided in Appendix E, must be dispatchable resources capable of longer run times to satisfy grid reliability requirements. In short, energy limited batteries that need to be charged do not allow for the avoidance of the transmission project to enable these coal retirements.

With respect to the adjustment to the endogenously identified retirement of Mayo, Strategen cites to a data response where the Companies gave additional justification on the adjustment. Strategen points out, according to this data response, that the Companies retirement of Mayo could be as retired as early as 2027 and that battery technology could be a replacement option for Mayo. While both of those are options, in combination, the accelerated timeline for Mayo and the replacement at site with batteries is increasingly unlikely. Completing any transmission project by 2027 to enable the Mayo retirement continues to be an aggressive timeline and the Companies believe 2029 to be more achievable. Until official interconnection studies are performed, considering the addition of charging load at Mayo Plant, and associated transmission upgrades are implemented, replacing with batteries at the site presents considerable system operations and reliability concerns given transmission contingency impacts on voltage support for Duke Energy's Harris Plant, especially with respect to long run time requirements. These considerations make an accelerated retirement ahead of 2029 significantly challenging.

Q. HOW DO THE COMPANIES RESPOND TO THE PUBLIC STAFF'S COMMENT THAT KEEPING BELEWS CREEK ON-LINE UNTIL 2037 COULD POTENTIALLY DEFER THE SELECTION OF ADVANCED REACTORS IN EVERY DEC PORTFOLIO IN 2037?[114]

A. The Public Staff's concern that accelerated retirement of Belews Creek from 2037 to 2035 accelerates the need for SMRs and ARs is unfounded, and this is supported by the Supplemental Portfolio analysis. The delayed retirement of Belews Creek in the Supplemental Portfolios results in the same amount of new nuclear units selected through the end of 2037. From 2032 through 2037, in all portfolios in the Carbon Plan and all portfolios in the Supplemental Portfolio analysis, four SMRs and one AR are selected. Moving the retirement date from EOY 2035 to EOY 2037 did not result in any less nuclear selected in that time frame. Regardless of the need to replace Belews Creek in 2035 versus 2037, the system still finds these nuclear units economic for selection in this timeframe. The Supplemental Portfolios do begin selecting some of these nuclear units into DEP, compared to all of the new nuclear units being in DEC in the Carbon Plan portfolios in this timeframe. This somewhat suggests that the 2035 date was more optimal for Belews Creek in that its retirement corresponded with the

[114] Public Staff Comments at 118.

already necessary build out of new nuclear for the system for emissions reduction purposes.

Q. HOW DO THE COMPANIES RESPOND TO CUCA'S RECOMMENDATION THAT THE COMMISSION SHOULD ENSURE ALL SUBCRITICAL COAL PLANTS THAT ARE RETIRED ARE SUBJECT TO SECURITIZATION?[115] DID THE COMPANIES INCLUDE SECURITIZATION IN COAL RETIREMENT ANALYSIS FOR SUB-CRITICAL COAL PLANTS?

A. Yes. The Companies did include securitization in the retirement analysis for all sub-critical coal plants. The securitization opportunity value was added to the FOM cost stream provided to Encompass for its consideration in the coal unit economic retirement analysis. To the extent FOM is an avoidable cost with retirement, adding the securitization opportunity value to FOM enables Encompass to consider it. To the extent the securitization opportunity is a declining stream, Encompass has to incrementally choose year after year to continue to operate the unit and incur the securitization opportunity value as a cost (or rather in the inverse, choose to retire and take the securitization opportunity value as a benefit). As the value gets lower with time, it has less and less effect over time on that decision being made by the model.[116]

[115] CUCA Comments at 4.

[116] Modeling and Near-Term Actions Panel Exhibit 3 (Duke Energy Response to NCSEA et al. Data Request 4-22(b)).

Q. HOW DO THE COMPANIES RESPOND TO CIGFUR'S SUGGESTION THAT THEY SHOULD HAVE CONSIDERED CONVERTING EXISTING COAL UNITS TO RUN ON GAS RATHER THAN RETIRING THEM?[117]

A. Prior to the Carbon Plan, the Companies evaluated the high-level business case of expansions of gas cofiring beyond the current 50% at Belews Creek Units 1&2 and Marshall Units 3&4. While the expansions were potentially feasible (detailed engineering studies would be needed to confirm), the evaluation did not show favorable economics and is not under further consideration at this time.

Q. HOW DO THE COMPANIES RESPOND TO CIGFUR'S SUGGESTION THAT THEY SHOULD HAVE CONSIDERED CARBON CAPTURE AND SEQUESTRATION AS A MEANS OF REDUCING CARBON EMISSIONS FROM EXISTING COAL UNITS?[118]

A. Carbon capture from existing coal units could be considered, but it would likely be cost prohibitive given the relatively short remaining lives of the coal units. Beyond the challenge of capturing the CO_2, the larger problem is carbon sequestration in the North Carolina. Geologic storage is unlikely to be economically or technically feasible within North Carolina due to a lack of storage capacity.[119] Therefore, CO_2 pipelines would need to be constructed from

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[117] CIGFUR Comments at 20.
[118] CIGFUR Comments at 20.
[119] https://nicholasinstitute.duke.edu/sites/default/files/publications/carbon-capture-pipeline-and-storage-a-viable-option-for-north-carolina-paper.pdf.

the Carolinas to other states with suitable geology. As for other carbon utilization methods such as enhanced oil recovery, North Carolina is presently not an option for oil drilling. Other carbon utilization methods could be a possibility but are premature to plan around.

Q. HOW DO THE COMPANIES RESPOND TO SYNAPSE'S CONTENTION THAT ADJUSTMENTS MADE TO THE RETIREMENT DATES OF BELEWS CREEK, CLIFFSIDE 5, AND MARSHALL 1 & 2 "WOULD COST RATEPAYERS AN ADDITIONAL $1.4 BILLION"?[120]

A. Synapse's statement is seriously flawed and should be disregarded by the Commission. As explained in more detail below, the cost Synapse has calculated does not account for net capacity changes on the system and is based on a generalized industry study that does not specifically apply to the Companies' coal units in question.

First, Synapse fails to recognize that the accelerated retirement of the coal resources would also require the accelerated deployment of additional firm capacity to preserve system reliability. Even if Synapse had used the appropriate coal operational costs, this accelerated replacement cost should have been netted out of their cost figure. Said differently, the costs Synapse are reflecting with this statement can be thought of as the costs required to reliably maintain system firm capacity resources. Therefore, costs to maintain the coal units are offsetting costs associated with otherwise needed new firm replacement

[120] NCSEA et al. Synapse Report at 29.

resources to similarly meet energy and capacity needs of the system. As such, those avoided costs for new replacement resources should be factored as a savings against the cost to keep the coal units reliably on the system.

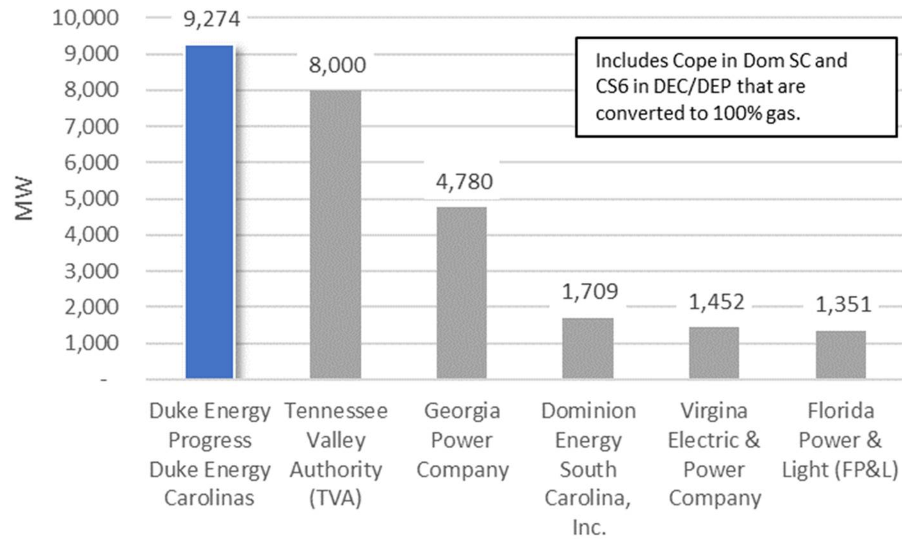
Next, the projected coal fixed costs used by Synapse are far higher than the Companies' estimates to maintain the reliability of the coal units while they are on the system. Synapse uses an EIA report prepared by Sargent and Lundy Consulting which looks to estimate aging-related capital and O&M costs across the industry. The Companies, when evaluating on-going capital expenses and fixed O&M costs at coal units, use unit specific projections of costs based on specific unit characteristics and are developed with consideration given to projected maintenance cycles, run times, fuel usage, and projected retirement dates for each coal units. The Companies' far more detailed unit specific estimates for on-going capital expenses and fixed O&M costs is approximately \$0.4 Billion for the same period as compared to the Synapse's estimate of \$1.4 Billion. This more detailed dynamic model for forecasting ongoing costs was discussed in the Companies presentations on Coal Retirement Analysis in the 2020 IRP Second Technical Workshop. The Sargent and Lundy report on the other hand uses industry data from a wide range of coal units across the country, attempting to provide general guidance on costs based on age and if the unit has certain environmental equipment. This methodology does not factor in how costs are impacted based on projected operations of these coal units on the system nor on how much longer the unit is expected to remain on the system. Conversely, the Companies account for these important factors in their cost projections which have significant impacts on the projected costs to maintain reliable resources. As such, the Companies use of unit specific cost projections based on detailed performance data and unit specific characteristics is far superior to the approximation used by Synapse in this analysis.

For these reasons, the Companies believe the ascribed costs presented by Synapse with respect to the Companies' coal retirement dates used in the Carbon Plan to be to be severely overstated. If each of the factors stated above were corrected, the Companies believe this resulting cost to be minimal. Finally, as stated in the Carbon Plan and in this testimony, the Companies optimal coal retirement used for the development of the Carbon Plan portfolios recognized a number of real-world constraints which make the coal retirements used appropriate for planning purposes.

Q. HOW DOES DUKE ENERGY'S COAL RETIREMENT TIMING COMPARE TO OTHER PEER UTILITIES BENCHMARKED?

A. Figure 11 below compares Duke Energy's proposed coal capacity reduction plan with its Southeastern peer utilities. The graph reflects the most recent coal retirement plans of the surveyed utilities by 2035. Duke Energy is reducing more coal capacity than any utility surveyed. The Companies' plans are almost double Georgia Power and about five to six times higher than Dominion Energy South Carolina, FP&L and Virginia Electric and Power Company.

Figure 11: Planned Coal Capacity Reductions by 2035[121]



(G) Criticisms of Supply-Side Resource Selection and Capital Costs

1. The Companies' Technology Costs Assumptions are Reasonable and Recommended Changes by Intervenors are not Accurate or Objective.

Q. PLEASE SUMMARIZE INTERVENOR RESPONSES TO THE COMPANIES' TECHNOLOGY COST ASSUMPTIONS USED TO DEVELOP THE CARBON PLAN PORTFOLIOS.

A. Many intervenors submitted comments relating to Duke Energy's estimated capital costs for various technologies. Certain intervenors advocated for using public costs instead of the costs developed by the Companies based on input from Burns & McDonnell, Guidehouse, and other third party and internal sources. The primary capital costs used for alternative modeling were from

[121] Carbon Plan Appendix E at 73; TVA announced they will retire their 8000 MW of coal by 2035; Georgia Power 2022 at A-137; DESC 2021 IRP Update at 130; 2021 Dominion Energy Virginia IRP Update at 16; FP&L 2022 Ten Year Site Plan at 21.

NREL's Electricity Annual Technology Baseline ("ATB") and EIA's Annual Energy Outlook ("AEO").

Q. PLEASE BRIEFLY EXPLAIN THE MAIN DIFFERENCES BETWEEN THE COMPANIES' CAPITAL COST FORECASTS AND THOSE FROM EIA AND NREL.

A. The differences between the NREL ATB, EIA AEO, and Duke Energy capital costs can be broken into categories of differences in estimates of current (2021 or 2022) costs, and differences in the rates at which costs will increase or decrease over time (technology cost curve differences). NREL 2022 costs were released after the Carbon Plan was submitted, so Duke Energy costs were benchmarked against the 2021 NREL ATB. Duke Energy relies primarily on the EIA AEO technology cost curves through 2050 to create its analysis, so there is a high level of alignment between the technology cost curves of EIA and Duke Energy. Additionally, Duke Energy relies on the Guidehouse 10-year forecast for solar, storage, and offshore wind, and the Guidehouse curve generally looks similar to the 2021 NREL Moderate curve. So, the primary differences between the Duke Energy costs and the NREL/EIA costs used by other parties are caused by the 2021 versus 2022 starting point. Generally, all capital costs have risen since the modeling input data was finalized due to the significant inflation seen across most industries. Additionally, there are costs included within the Companies' estimates that may not be included in the public sources – primarily interconnection costs, network upgrade costs, and owner's costs. When comparing costs on an "apples to apples" basis, including adjustments for real vs. nominal costs, the additional costs discussed above, regional differences, and capacity differences Duke Energy generally views the technology capital costs used for Carbon Plan modeling as being similar to the public sources.

Q. PLEASE RESPOND TO TECH CUSTOMERS' CRITIQUE THAT "DUKE'S MODELING USED ESTIMATED COSTS FOR A CT AND CC GENERATION FACILITIES THAT WERE SIGNIFICANTLY BELOW PUBLICLY AVAILABLE BENCHMARKS."[122]

A. The publicly available reports are typically the EIA AEO and NREL ATB publications that are updated annually with estimated capital costs. The criticism based on EIA AEO should be reviewed for both Simple Cycle Combustion Turbine ("CT") costs and Combined Cycle Combustion Turbine ("CC") costs. The CT costs generated by EIA AEO are based on a single unit F-Class CT and do not account for economies of scale savings from building multiple CT units on a single site. Large utilities would not build a site with a single unit CT due to the savings that can be observed building multiple CTs on a single site. Consistent with past IRPs, Duke Energy's CT costs are based on a typical 4-unit CT site. For benchmarking, Duke Energy analyzed its single unit CT cost against the 2022 EIA AEO costs and found that its single-unit costs are actually higher than EIA when making an "apples to apples" comparison.

For the CC costs, Duke Energy includes duct firing capability in the estimates which allows for a higher number of MW to be generated from a

[122] Tech Customers Comments at 10.

similar class of CC. Additionally, CC output varies based on time of year, so a comparison needs to be done based on similar temperature assumptions –winter ratings are often used for $/kW calculations, which is the time of year when the most MW are produced. However, public sources typically use International Standards Organization ("ISO") ratings, which leads to a higher $/kW cost. Both of these differences between EIA and the Companies' $/kW calculation methodology leads to a larger perceived cost differential than actually exists.

The NREL ATB costs for both CT and CC options were based on "state-of-the-art" F-Class technology even though F-Class is no longer state-of-the-art due to the emergence of the advanced J and HA-class turbines. The NREL ATB costs have the same issues as the EIA AEO costs relying on a single-unit F-Class CT and not including duct firing when creating CC costs. The additional issue presented in the NREL CC costs is basing the costs on the F-Class rather than an advanced class (J or HA), since the F-Class has highest capital costs on a $/kW basis along with a worse heat rate. Based on internal Duke Energy estimates F-Class CC on a $/kW basis are between 25-30% higher than an advanced class CC.

The Companies routinely benchmark their costs against NREL ATB and EIA AEO as well as other sources to ensure the costs input to the modeling are informed by several sources. It is notable that the EIA AEO CC costs appear to be the highest among all public sources and are much higher than the costs seen in benchmark analysis performed against a 2022 EPRI technology cost and performance report.[123] Based on the two cost methodology differences above and the other sources reviewed for cost data Duke Energy believes the costs for CC at the time of modeling input finalization are valid. It is also notable that the Public Staff and other intervenors did not challenge Duke Energy's CC and CT capital cost assumptions and economies of scale assumptions.

Q. DID ANY INTERVENORS RECOMMEND DIFFERENT CAPITAL COST ASSUMPTIONS FOR SOLAR AND STORAGE RESOURCES?

A. Several intervenors recommended using alternative capital costs for solar and solar plus storage resources. Intervenors primarily recommended using NREL ATB, although there were a variety of suggestions for which NREL ATB case to use for each technology. The solar capital cost recommendations varied between Moderate and Conservative cases, while the storage varied between the Advanced and Moderate cases.

When it comes to NREL ATB Advanced costs, NCSEA et al. (using Synapse's analysis) said they used those costs due to "judgment and relative maturity of the technology,"[124] but the NREL Advanced, Moderate, and Conservative curves already consider the relative maturity of each technology in developing the curves. For example, the utility solar PV cost reductions from 2020 through 2030 for the advanced case in real terms is 53.7%, but the utility battery storage in the same time period is 60.6%. The moderate reductions

[123] 2022 Energy System Technology Cost and Performance Summary: Market Trends & Technology Insights, EPRI Report # 3002024231 (May 5, 2022).
[124] *See* Modeling and Near-Term Actions Panel Exhibit 4 (NCSEA et al. Response to Duke Energy Data Request 2-9).

during that same time period for solar and storage are 43.6% vs 48.2%, respectively. Since the relative maturity is already factored into the NREL cost reduction curve Synapse is essentially double counting cost reductions due to technology maturity in an effort to make solar costs more favorable for model selection.

Q. PLEASE COMMENT ON WHY THE NREL ATB ADVANCED TECHNOLOGY COST CURVES DIFFER FROM THE COMPANIES' PLANNING ASSUMPTIONS?

A. The NREL ATB Advanced technology cost curves for emerging technology costs have been consistently too aggressive in forecasting cost declines compared to actuals and creates a forecast that significantly undercounts total cost due to assuming extremely high cost declines early in the curve. The best example to demonstrate this is to assess the cost of battery storage since there are actual costs from industry projects (unlike Offshore Wind where costs are still mostly unknown in the US). NREL assumes a common price point for all cases in the year before the release (*e.g.,* the 2022 ATB uses 2021 costs as the starting point and then applies their cost reduction curve to 2022 and beyond). The Advanced case has been consistently too low projecting the starting point in the following year. Table 10 below shows how NREL's Advanced case for standalone 4-hour storage compares to the next year's starting point. These results show that NREL Advanced case assumptions have consistently been too aggressive over the past few years. The Advanced case is more appropriate for a low-cost sensitivity and should not be used for base modeling.

Table 10: NREL ATB Advanced Forecast to Next Year's Actual Capital Cost

ATB Year (2020$s)[1]	2019	2020	2021
Projected Next Year Starting Capital Cost ($/kW)	$1452	$1263	$1281
Actual Next Year Starting Capital Cost ($/kW)	$1622	$1397	$1475
% Assumption Too Aggressive	13.8%	10.6%	15.2%

Note 1: All costs have been converted to 2020$s.

The NREL Moderate storage costs have been reviewed against the storage costs used in Duke Energy's modeling efforts and although NREL Moderate has a slightly lower starting point, by the mid-2020s the NREL Moderate costs are actually higher than the modeled storage costs. Therefore, NREL Moderate and Duke Energy's technology cost assumptions for battery storage planning appear to be fairly well aligned.

Turning the to the cost of solar resources, the NREL solar costs from the 2022 NREL ATB appear to be substantially lower than the NREL solar costs from 2021, which is surprising given the inflationary environment of the past year. The NREL Moderate case appears to show solar costs starting 13% lower in 2022 with the cost decline decreasing to 6% by 2030. Additionally, NREL utilizes a lower Inverter Loading Ratio of 1.28 compared to the Companies' 1.40. The Companies also modeled only bifacial panels based on stakeholder feedback while NREL Moderate specifies only some use of bifacial panels in its assumptions. The Companies also benchmark costs against actual project costs from their internal solar development team to ensure generic costs are aligned with real world costs.

In summary, the Companies continue to view the solar and storage capital costs used to develop the Carbon Plan as reasonable assumptions at the time and will continue to evolve technology capital costs in future Carbon Plan updates.

(H) Solar and Storage Configurations and Modeling Approach

1. The Companies have evolved their approach to modeling solar paired with storage in response to the Public Staff and Intervenor Comments.

Q. WHAT TYPE OF SOLAR PAIRED WITH STORAGE ("SPS") RESOURCES WERE ALLOWED TO BE ECONOMICALLY SELECTED IN THE CARBON PLAN?

A. In the filed Carbon Plan, two SPS resources were allowed to be economically selected:

- 75 MW blocks of 1.6 ILR SAT Bifacial solar DC-tied with 20 MW / 80 MWh storage (25% 4-hour storage)
- 75 MW blocks of 1.6 ILR SAT Bifacial solar DC-tied with 40 MW / 80 MWh storage (50% 2-hour storage)

In addition, Duke Energy included a third SPS resource in the modeling of SP5 and SP6:

- 75 MW blocks of 1.6 ILR SAT Bifacial solar DC-tied with 40 MW / 160 MWh storage (50% 4-hour storage)

Q. DID INTERVENORS TAKE ISSUE WITH THE SPS RESOURCE MODELING ASSUMPTIONS INCLUDED IN THE CARBON PLAN?

A. Yes. Several intervenors, including the Public Staff, took issue with the

Companies' decision to model the SPS assets with fixed profiles in the Encompass model and several intervenors argued additional SPS resources should also have been included as model selected options in the Carbon Plan.[125]

Q. HOW DO THE COMPANIES RESPOND TO THE SUGGESTION THAT THE SPS ASSETS SHOULD HAVE BEEN ALLOWED TO BE ECONOMICALLY DISPATCHED IN THE CARBON PLAN?

A. The Companies see merit in the issue raised by intervenors. In the Carbon Plan, the Companies developed a fixed dispatch profile for a solar paired with storage asset that was based on the nine premium-peak, on-peak, and off-peak energy hours defined in the Sub 167 avoided cost proceedings. This profile allowed storage that was paired with solar to be charged during off-peak hours and discharged during on-peak and premium peak hours across the year.

SPS was modeled in this manner primarily for efficiency. The Companies found that the run times for a single case more than quadrupled when Encompass was allowed to endogenously dispatch the storage asset. Including a fixed dispatch profile that aligned with expected on-peak and off-peak hours was a reasonable assumption that enabled the Companies to complete the significant modeling required for filing the Carbon Plan.

As discussed previously, for the purposes of SP5 and SP6, the Companies enabled this capability in Encompass and found the model run-time increased from 2-3 hours to 12-48+ hours. The Companies are evaluating

[125] Public Staff Comments at 120; AGO Comments at 20-21; CPSA Comments at 24-25; CCEBA Comments at 37.

options to reduce run time, but a potential solution may require fixed dispatch profile modeling that better aligns with marginal hourly costs in the Carbon Plan portfolios.

Q. HOW DO THE COMPANIES RESPOND TO THE CRITIQUES FROM THE AGO, CCEBA, AND CPSA THAT ADDITIONAL SPS OPTIONS SHOULD HAVE BEEN INCLUDED?

A. The Companies generally agree with intervenors that modeling additional SPS options is preferable, and the Companies did include an additional SPS option in the SP5 and SP6 that included a larger battery than the two original configurations included in the Carbon Plan. Further study is needed to assess how the ELCC of the larger storage resources that are DC-coupled with solar should be treated. It is likely that if the SPS asset with a larger storage component can only charge from solar there will be times that the storage component will not be fully charged at the time of peak demand and therefore its contribution to meeting peak demand will be diminished. This was not fully analyzed in the latest ELCC study.

Q. IN COMMENTS RECEIVED FROM CCEBA, THERE SEEMED TO BE CONFUSION ABOUT HOW THE STORAGE PAIRED WITH SOLAR ASSET WAS CHARGED IN THE CARBON PLAN. PLEASE RESPOND.

A. CCEBA's comments confuse whether the SPS asset was a co-located resource or a hybrid resource. As CCEBA points out, co-located solar and storage share a point of interconnection but operate independently while a solar paired with storage hybrid system shares a point of interconnection and operates as a single system as they are physically coupled and share a control system.[126] The two SPS assets included in the Carbon Plan, and the additional SPS asset included in the Supplemental Portfolios, are considered SPS hybrid systems. The SPS operates as a single system and the capital costs in the Carbon Plan reflect the synergies of a hybrid system.

Additionally, CCEBA also surmised that the hybrid SPS system was allowed to grid charge through a bidirectional inverter in the model based on the Companies' response to AGO Data Response 3-4, where Duke Energy stated "the ELCCs of standalone solar and standalone storage were assumed to be additive". [127] To be clear, the SPS system was not allowed to be charged from the grid. The only source of charging for the SPS system was the full DC solar energy output of the solar resource that the storage asset was coupled with. The Companies acknowledge that hybrid SPS assets are being designed with bidirectional inverters to enable charging the storage asset with both DC solar energy and grid energy. However, as of August 2022, the EnCompass model is not equipped with this capability. The functionality to charge storage with both DC energy and grid energy is expected to be available in an update to the Encompass model to be released later this year.

2. <u>The Companies' Assumed Solar Interconnection Constraint is Reasonable and Necessary for Planning Purposes to Ensure</u>

[126] CCEBA Comments at 36.
[127] CCEBA Comments at 36.

<u>Carbon Plan Executability and Should not be Adjusted Upwards.</u>

Q. MR. KALEMBA, HOW MUCH SOLAR AND SOLAR PAIRED WITH STORAGE DID THE COMPANIES ASSUME COULD BE INTERCONNECTED ANNUALLY IN THE CARBON PLAN?

A. As shown in Table 11 below, the Companies made the following assumptions regarding future solar interconnection capability:

Table 11: Maximum Solar (MW) Allowed to Connect Annually (by Jan. 1 of year shown)[128]

Beginning of Year	2027	2028	2029	2030+
70% by 2034 with Wind or Nuclear	750	1,050	1,350	1,350
70% by 2030	750	1,050	1,800	1,800

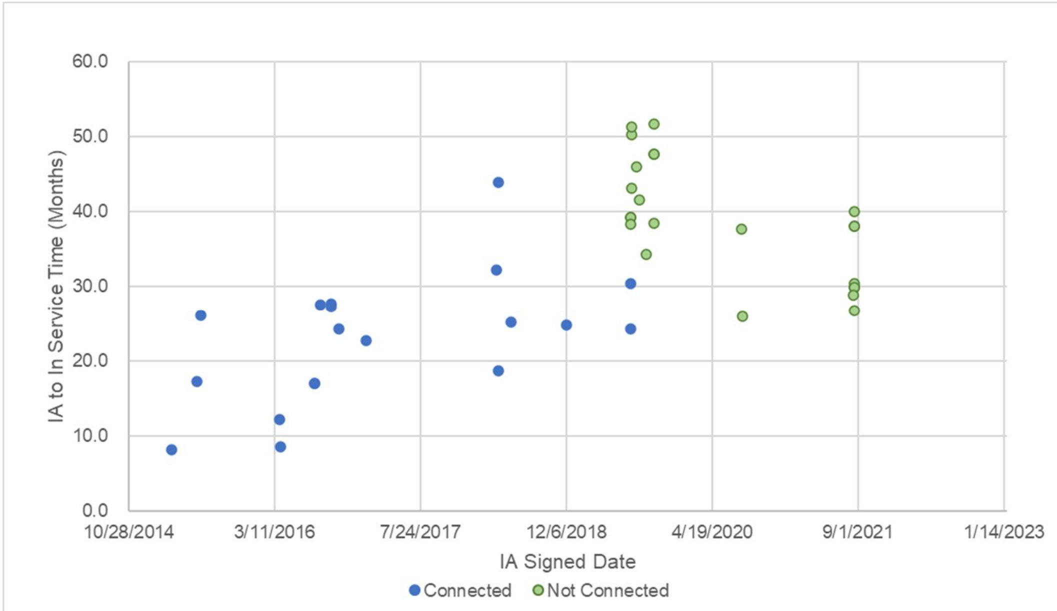
Q. HOW DID THE COMPANIES DEVELOP THESE ASSUMPTIONS?

A. The forecast of annual solar interconnection constraints is based on engineering judgement taking into account a variety of factors. These factors are described below, as well as in Appendices I (Solar) and P (Transmission Planning and Grid Transformation) of the Carbon Plan and in the Companies' response to CPSA DR 1-8:[129]

- ***Increasingly complex interconnections as solar facilities are located farther from existing infrastructure.*** Increasingly complex interconnections are one of the factors leading to longer durations from the time the project signs an IA to the time the project is commercially available or is considered "in-service." Figure 12 below shows that the minimum time to interconnect has increased from as little as 9 months in 2016 to 26 months in 2021.

[128] Carbon Plan Appendix I at 6 (Table I-2).
[129] Modeling and Near-Term Actions Panel Exhibit 5 (Duke Energy Response to CPSA DR 1-8).

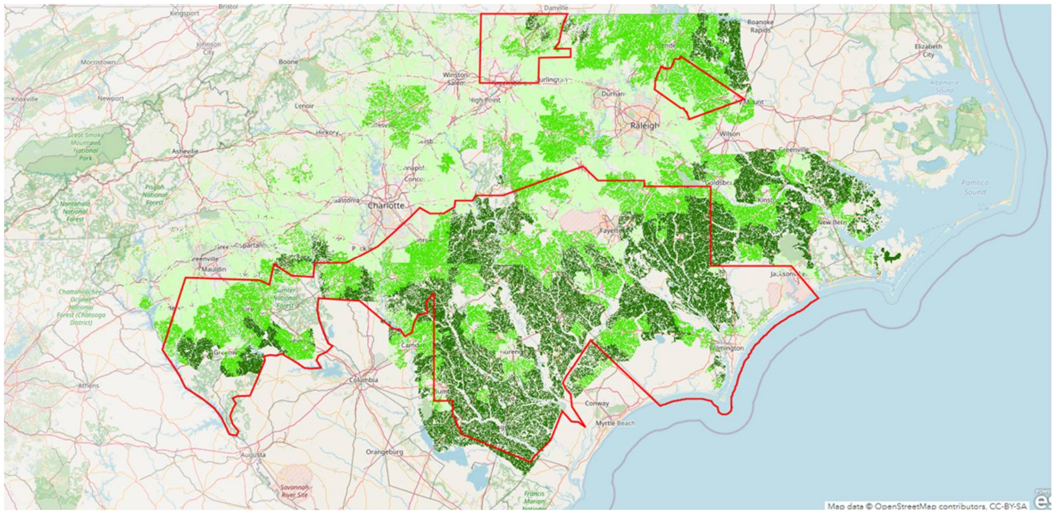
Figure 12: Transmission Project Duration (IA Signed to In Service Date)



- ***Areas that are most viable for solar development from a land availability / land quality standpoint are primarily located in transmission constrained regions.*** The transmission constrained areas, or "Red Zones", are primarily located in regions where solar development grew rapidly in the Carolinas historically. The growth in those regions was driven by relatively low land costs, as well as preferred terrain (i.e. flat, unforested) for solar development. Figure 13 below shows the "viability" of land for solar development in the Carolinas overlayed with the transmission Red Zone boundaries.[130]

[130] Darker green areas represent land areas that have lower population density, larger land parcel sizes and are less developed and less forested. "Non-viable" areas are non-green shaded areas and include developed land, land with steep slopes, protected areas and flood zones. Layers are sourced from NREL while viability rankings are developed by Duke.

Figure 13: Solar viability map overlayed with transmission "Red Zone" boundaries

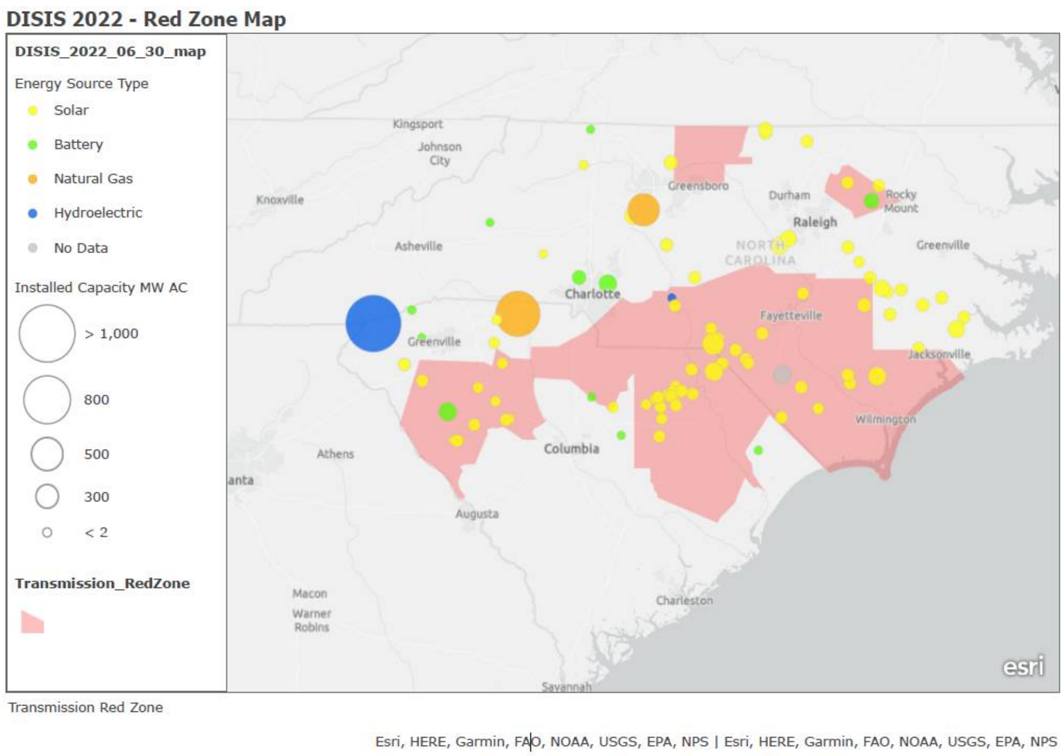


- ***Transmission expansion needs and the time to construct new transmission infrastructure to accommodate increasing levels of renewables and other resources***. The Carbon Plan portfolios show the need to add between 11 GW and 15.3 GW of new generating resources over the next 8 years which is a 30% to 80% increase over the amount of new generation added over the last decade (2012-2022).[131] Additionally, as of August 9, 2022 the 2022 DISIS shows that of the approximately 6,000 MW of solar requesting interconnection in DEC and DEP, almost 3,800 MW are located in Red Zone regions where significant transmission infrastructure upgrades will be required to enable those projects to interconnect without transmission constraints.

[131] Generation added last 10 years = 97 MW CTs (Sutton), 3,860 MW CCs (Dan River, WS Lee, Asheville, Lee, Sutton CCs), 24 MW CHP (Clemson), 9 MW Storage (Asheville-Rock Hill), and 4,350 MW Solar (Utility Owned + PPA).

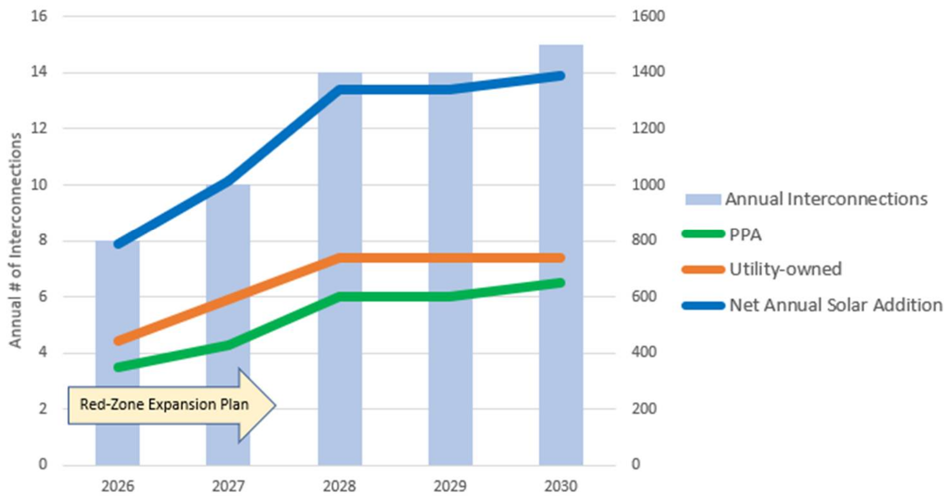
Figure 14 below shows the locations of 2022 DISIS projects in relation to transmission Red Zones.

Figure 14: Map Showing 2022 DISIS Projects with Red Zone Overlay



- ***Transmission expansion projects are expected to enable increased solar interconnections over time.*** The current timeline for projects to interconnect from the time that an IA is signed to the time they are commercially operational is 26 to 32 months *if the project does not require transmission system upgrades* such as those needed to interconnect projects in the Red Zones. When transmission system upgrades are needed, the timeline could be an additional 3 to 5 years before the project is operational. Duke Energy assumed those transmission system upgrade projects would materialize, thereby enabling increased annual solar interconnections as shown in Figure 15 below.

Figure 15: Forecasted Impacts of Red Zone Expansion Projects



The transmission requirements to interconnect solar resources in these regions, as well as efforts to reduce the time from signed IA to commercial operation, are further discussed by Witness Roberts on the Transmission Panel.

- ***Finite interconnection resources with some allocated to non-solar resources.*** As noted above, the Carbon Plan calls for 11 GW to 15.3 GW of new generation to be added by 2030. Of this amount, only 50% - 60% is solar and solar paired with storage. Importantly, to interconnect these resources and perform other transmission system maintenance and upgrades, Duke Energy primarily plans for transmission outages to take place during "shoulder" seasons when system demand is reduced, and then, only a finite number of transmission lines can be out of service at a time. Additionally, if the current tight labor market does not improve, competition for labor resources to perform transmission project and interconnection work will only increase as Duke and other neighboring utilities seek to rapidly interconnect new generation.

- ***The Companies' historic number of annual interconnections***. Since 2015, the Companies have interconnected on average 520 MW/year of new solar facilities, which has consistently been among the highest rate of interconnection in the United States. While not the primary determining factor in developing the solar interconnection capability in the Carbon Plan, it is important to note that the Carbon Plan allows for over 3 times this annual amount in Portfolio 1 and over 2.5 times this annual amount in all other portfolios.
- ***It is likely that larger solar projects will request interconnection going forward, compared with historic size of projects***. HB 951 allows 55% of future solar resources to be utility owned and are not limited to 80 MW capacity. Generally larger projects should enable more aggregate MW to be connected on an annual basis, but they are also more likely to trigger transmission system upgrades which could lead to longer lead times for individual projects.

Q. DO INTERVENORS GENERALLY ACCEPT THAT THERE SHOULD BE CONSTRAINTS INCLUDED THAT REFLECT THE ABILITY TO INTERCONNECT SOLAR?

A. Yes, intervenors generally accept that solar should not be modeled assuming an unlimited interconnection capability. While the Public Staff does not provide a recommended constraint, the Public Staff's comments recognize that "[r]elying on very high, unprecedented levels of annual solar interconnections—and any necessary interconnection facilities and transmission upgrades—could jeopardize interim compliance. P1 adds an average of over 1,400 MW of solar each year from 2026 through 2030. Duke would have to accelerate interconnection processes and transmission upgrades significantly to accommodate this schedule, which would cause cost increases that are not reflected in the PVRR estimates or bill impacts."[132]

Intervenors suggest varying limitations on solar that were more aggressive than the Companies' forecast.[133] Indeed, the question to be addressed is not whether a limitation or constraint is appropriate, but what specific limitation is the most reasonable forecast of the Companies' ability to interconnect solar in the future.

[132] Public Staff Comments at 13.
[133] NCSEA et al. Synapse Report at A-12; AGO Strategen Report at 7; CPSA Comments at 22.

Q. CCEBA AND CPSA ARGUE IN VARIOUS WAYS THAT DUKE ENERGY'S INTERCONNECTION CONSTRAINTS ARE ARBITRARY. DO YOU AGREE WITH THIS CHARACTERIZATION?

A. No. The Companies evaluated all of the factors discussed above to develop a forecast of what the Companies believe to be realistically achievable rates of solar resource interconnections. It is important to reiterate that, just like other assumptions included in the Carbon Plan, the annual interconnection limit is a ***forecast*** based on the best information available at the time the analysis is conducted. This is no different than other forecasts developed for purposes of resource planning (***i.e.***, future resource technology costs, NEM deployment, EV adoption, etc.). As more information becomes available, the Companies will adjust these forecasts in future iterations of the Carbon Plan.

Q. CPSA ARGUES THAT SOLAR INTERCONNECTION ASSUMPTIONS ARE CONSERVATIVE IN CONTRAST TO MORE AGGRESSIVE ASSUMPTIONS MADE IN OTHER PARTS OF THE CARBON PLAN. IS THIS THE CASE?

A No. First, the Public Staff recognizes that "higher level of solar interconnections over the near-term is a significant execution risk."[134] In addition to the risks and unknowns regarding solar interconnections stated previously, the Carbon Plan is projected to nearly double the demand for solar generation in the Carolinas at a time of heightened supply chain risk. At the same time, demand for solar is

[134] Public Staff Comments at 89.

only increasing as other states and utilities set aggressive carbon reduction goals.

Q: WHAT IS THE RISK IF YOU OVERESTIMATE OR UNDERESTIMATE THE ACHIEVABLE LEVEL OF SOLAR INTERCONNECTIONS?

A. As the Public Staff notes, "[r]elying on very high, unprecedented levels of annual solar interconnections…could jeopardize interim compliance."[135] If the Companies are overestimating how much solar can be connected, then meeting the goal by 2030, 2032, or even 2034 will be challenging. Alternatively, if the Companies are underestimating the amount of solar that can be connected, that does not preclude the Companies from procuring solar above the interconnection levels set forth in the model.

Q. BOTH THE PUBLIC STAFF AND CPSA SUGGEST THAT HISTORICAL INTERCONNECTION RATES ARE NOT AN APPROPRIATE INDICATOR FOR FUTURE INTERCONNECTIONS BECAUSE THE INTERCONNECTION PROCESS IS BEING IMPROVED (LARGER PROJECTS IN FUTURE, QUEUE REFORM, RZEP). PLEASE RESPOND.

A The Companies disagree that historical interconnection rates cannot reasonably *inform* future interconnection expectations. While historic interconnection rates should not be used exclusively to dictate future interconnections, they certainly

[135] Public Staff Comments at 13.

are appropriate to take into account when developing a forecast. Queue reform and the ability to construct larger projects will enable Duke Energy to connect more solar capacity to meet the requirements of HB 951 even in the short-term. However, as the Transmission Panel explains, the benefits that larger projects provide are not maximized until long lead-time transmission system upgrade projects are completed.[136] These transmission upgrade projects, whether completed incrementally through annual cluster studies or in a more efficient and proactive manner through RZEP, will still take 3 to 5 years to construct. Queue reform and the possibility of larger solar projects will help increase solar interconnections above historical rates in the 2026 and 2027 timeframe, and the addition of RZEP will maximize their benefits to allow Duke to achieve 1,350 MW per year of solar interconnections beginning in 2028.

Q. BEYOND PHYSICAL CONSTRAINTS OF CONNECTING THESE LEVELS OF SOLAR, WHAT OTHER FACTORS CAN IMPACT THE ANNUAL LEVEL OF SOLAR ADDITIONS?

A. Supply chain and community acceptance can also impact deployment of solar resources. Both Duke Energy and 3rd party developers are still experiencing constraints related to supply chain and availability of equipment. Through July 2022, Duke Energy has been able to meet the in-service date requirements of all projects, however 3rd parties are experiencing delays in sourcing equipment that are causing projects to miss their original in-service dates. As an example,

136 Transmission Panel Direct Testimony at 33.

in January 2022, the Company expected to interconnect about 550 MW of solar in the Carolinas. As of July 1, 2022, approximately 120 MW of solar has already requested a delay to interconnect in 2023 and an additional approximately 80 MW are at high risk of missing interconnection in 2022. Even the IRA, with all of its benefits to spur clean energy growth, comes with the risk that a rapid increase in demand for renewable energy products will further strain supply chains and/or increase costs of these resources, at least until production meets the demand.

In addition to supply chain concerns, community acceptance and land availability can impact the rate at which solar connects in the Carolinas. 1,350 MW/year of solar will require approximately 10,800 acres/year of land to be developed, and 1,800 MW/year will require approximately 14,400 acres/year. In ten years, 1,800 MW/year of solar would cover approximately 225 sq. miles of land which is about half the area of Mecklenburg County. In a recent article, Steve Kalland, executive director of the North Carolina Clean Energy Technology Center, stated, "[Local opposition to development] is increasingly one of the top barriers that we're going to face. If we can't get projects sited and deployed, then we're going to have real problems on our hands."[137] In that same article, the American Clean Power Association's director of solar policy, David Murray stated, "Community concerns have made it harder for some developers to scale solar projects at the rate that science dictates that we need

[137] Special Report: U.S. solar expansion stalled by rural land-use protests, Reuters *accessible at* https://www.reuters.com/world/us/us-solar-expansion-stalled-by-rural-land-use-protests-2022-04-07/.

to."[138] These factors are difficult to quantify and may not materialize here in the Carolinas to the same extent as elsewhere in the U.S., but as Armond Cohen, executive director of Clean Air Task Force stated, "There's this assumption that there's so much solar and wind available at such low cost, it's obviously going to get built... maybe it will, but something pretty serious is going to have to change."[139]

Q. CPSA STATES THAT THE SOLAR INTERCONNECTION CONSTRAINTS USED IN THE CARBON PLAN "DRIVE UP COSTS FOR RATEPAYERS."[140] PLEASE RESPOND.

A Including any constraint in a capacity expansion or system production cost model will increase costs when compared to an unconstrained solution. Much like solar interconnections, the Companies included constraints in the model to reflect natural gas availability, onshore wind timing, advanced nuclear deployments, etc. Relieving any one of these constraints would lead to a lower cost modeled solution; however, Duke Energy must reflect real-world limitations so that the resulting Carbon Plan is actually executable. Stated differently, cost savings based on unrealistic and un-executable assumptions are illusory.

It is also important to note that including a constraint within a model does not necessarily mean costs will actually be driven up for customers in the

[138] *Id.*
[139] *Id.*
[140] CPSA Comments at 4.

real-world. For instance, accelerating solar deployments based on today's technologies could crowd out future, unknown solar or other technologies that are more efficient or more cost-effective than today's solar. Also, in order to connect the amount of solar intervenors such as CPSA or CCEBA suggest should be modeled, developers would need to locate solar outside of transmission constrained areas that may be more costly than locations that could be connected once RZEP are completed. These costs are unknown and are not likely to be accurately captured in the model, so un-constraining solar interconnections may actually lead to higher costs for customers in reality even though the model suggested the unconstrained solution was lower cost.

Finally, the solar interconnection constraints will evolve as more information becomes known through the current 2022 Solar Procurement, as well as future procurements. Committing to overly aggressive solar interconnections before more data is available would not be a prudent choice.

Q. CCEBA SUGGESTS THAT DUKE'S INTERCONNECTION ASSUMPTIONS ARE MUCH LOWER THAN PEER UTILITIES. HOW DOES DUKE RESPOND?

A In most instances, when viewed on an apples-to-apples basis, Duke Energy's interconnection assumptions are equal to, or more aggressive, than the peer utilities CCEBA cites in its comments. Furthermore, with the addition of the 441 CPRE Program Remainder MW to the 2022 Solar Procurement, the combined targeted quantity of solar in Duke Energy's active 2022 solar RFP is greater than nearly every RFP noted in CCEBA's comparison. Finally, several utility resource plans referenced by certain intervenors, including NextEra's "Real Zero Resource Plan", Entergy's "2022 Resource Plan", and the "NY Climate Leadership and Community Protection Act," are aspirational, visionary documents that are not equivalent to Duke Energy's Carbon Plan modeling which is required to meet the core objectives referenced above including executability. Table 12 below includes CCEBA's representation of peer resource plans and active RFPs, as well as Duke Energy's rebuttal to CCEBA's representation.

Table 12: Duke Energy Review of CCEBA Peer Solar/Renewables RFPs[141]

Peer Document Reference	CCEBA Summary	Duke General Rebuttal
NextEra Zero Carbon Blueprint[142]	Plans 86 GW of solar additions to FPL by 2045, an average of 4 GW/yr. Realistically, given ramp-up period, this will likely require 4.5-5.0 GW/yr average additions starting 2025-2026. (see page 14 of blueprint)	- This "blueprint" is a high-level visionary document intended for investor audiences and developed at the parent company level. The blueprint is aspirational and is not tied to any binding statutes or other specific policy requirements. **This is not equivalent to a "resource plan"** and should not be identified as such as CCEBA has done. - Includes assumptions on page 20 of document including "FPL can cost-effectively secure land, permits, equipment and contractors for solar and storage builds in Florida"
Entergy "The Future Is On" Analyst Day 2022 Slide Deck[143]	Entergy announced in June 2022 that it is now forecasting up to 17 GW of renewable additions by 2031 (see pg 31 of recent investor presentation). Assuming this capacity doesn't start coming online substantially until 2026, this will require adding up to ~3.4 GW/yr on average.	- Similar to the NextEra document, this is a high-level visionary document intended for investor audiences and developed at the parent company level. **This is not equivalent to a "resource plan"** and should not be identified as such as CCEBA has done. - Page 31 of document states that additions are "Subject to integrated resource planning processes, economic evaluations, and regulatory approvals" - Entergy serves retail customers in Louisiana, Arkansas, Texas, and Mississippi, predominantly if not entirely within the MISO region, making it **not directly comparable to DEC/DEP.**

[141] CCEBA Comments at 17–19. Note the "Peer Document Reference" column has been changed from CCEBA's original table to reflect the actual title of the document referenced.

[142] NextEra Energy, Zero Carbon Blueprint, *available at* NextEraEnergyZeroCarbonBlueprint.pdf.

[143] Entergy, The Future is On (June 16, 2022), *available at* 2a90a616-8405-4f74-b76b-97b579dd0f18 (gcs-web.com).

Peer Document Reference	CCEBA Summary	Duke General Rebuttal
TVA 2022 RFP[144]	TVA procuring 5 GW of CO2-free resources, planned for commercial operation by 2029. Assuming 4.5 GW of this is placed in service from 2026-2029, this entails 1.13 GW/yr of resource additions.	- **Duke's assumptions for interconnections are more aggressive than TVAs plans**. - The RFP is for **all zero-carbon resources** including "solar, wind (offshore and onshore), hydro, geothermal, biogas, nuclear, green gas, battery energy paired with above resources, standalone storage, and hybrid combinations of aforementioned resources."[145]
Dominion Energy VA Resource Plan[146]	VA Clean Economy Act (VCEA) calls on DOM to procure 21.3 GW of renewables by 2035; assuming those resources are online by 2039, and assuming the first resources come online in 2025, this translates to ~1.5 GW/yr avg. installation rate.	- **Duke's assumptions of potential interconnections are in line with the VCEA from 2026 through 2039 (Duke average allowed interconnections = 1.3 GW/yr – 1.7 GW/yr)**
CPUC 2022 Resource Plan[147]	Plans for 25.5 GW of renewables and 15 GW of storage/DR to be added by 2032. Assuming this capacity [doesn't] start coming online substantially until 2026, it will require adding ~4.3 GW/yr of renewables on average.	- This plan covers resources across the California Independent System Operator's (CAISO) system in California and includes resources needed to serve all retail customers within the distribution service territories of PG&E, SCE, and SDG&E (the three large investor-owned utilities in California). This reflects about 12 million customer accounts, more than three times the number of customers served by DEC/DEP. **The 4.3 GW/year**

[144] Tennessee Valley Authority, TVA Issues One of the Nation's Largest Requests for Carbon-Free Energy (July 12, 2022), *available at* TVA Issues One of the Nation's Largest Requests for Carbon-Free Energy.
[145] *Id.*
[146] Virginia Electric and Power Company 2021 Update to the 2020 Integrated Resource Plan, Case No. PUR-2021-00201 (Sept. 1, 2021).
[147] California Public Utilities Commission Approves Long Term Plans to Meet Electricity Reliability and Climate Goals (Feb. 10, 2022), *available at* CPUC Approves Long Term Plans To Meet Electricity Reliability and Climate Goals**.**

Peer Document Reference	CCEBA Summary	Duke General Rebuttal
		renewables addition found in the CPUC plan would equate to about 1.3 GW for DEC/DEP if normalized by customer accounts. - California was an early adopter of ambitious renewable energy goals and, as a result, has completed substantial expansion of its transmission system to regions with high potential for wind and solar. Notably, the linked webpage discussing this plan notes that the California Public Utilities Commission's (CPUC) preliminary analysis of the preferred system plan portfolio of the load serving entities (LSEs) **indicates there is sufficient space for all of these new resources on the existing transmission system, with only limited transmission upgrades needed by 2032.**
NY Climate Leadership and Community Protection Act[148]	To reach CLCPA's 70% renewable electricity by 2030 target, the state will need to procure up to 2 GW/yr of renewables (4,500 GWh/yr)	- **This is neither a resource plan nor RFP** and thus is misrepresented by CCEBA. - The 2 GW/year renewables addition need identified in this document would **equate to about 0.8 GW/year for DEC/DEP if normalized by customer accounts.** - The S&P Global article cited recognizes the **challenges with siting and transmission needs to meet the state's renewable energy targets.**

[148] New York State Approves First Expedited Power Transmission Project, Supports Renewables, HIS Markit (Nov. 22, 2020), *available at* New York State approves first expedited power transmission project, supports renewables | IHS Markit**.**

Peer Document Reference	CCEBA Summary	Duke General Rebuttal
Public Service Oklahoma Q4 2021 RFP[149]	Seeking 4.15 GW of renewable capacity (2.8 GW wind, 1.35 GW solar)	- Oklahoma is part of the Southwest Power Pool ISO/RTO region, making it **not directly comparable to DEC/DEP.** - The RFP allows resources to be **located in a wide geographic region that includes Oklahoma, Arkansas, Kansas, Louisiana, and Texas.** - Resources must be operational by mid-December 2025 so this is arguably a multi-year ramp up between 2022 and 2025 and thus **comparable with the proposed additions found in Duke's Carolinas Carbon Plan.**
Duke Energy Indiana (1.1 GW of renewables),[150] Indiana Michigan Power (1.3 GW of renewables),[151] Georgia Power (1 GW of renewables),[152] and Arizona Public Service (800 MW of renewables)[153] RFPs in 2021 and 2022 are **all seeking similar or lower levels of renewables** as the Companies through the Carolinas 2022 Solar Procurement.		

Q. WHEN WILL MORE INFORMATION BE KNOWN SO THAT DUKE ENERGY CAN UPDATE THEIR PROJECTIONS OF SOLAR INTERCONNECTION CAPABILITIES?

A. The Companies will update their projections of solar interconnection

[149] Public Service Company of Oklahoma Issues Requests for Proposals for Purchase of Wind and Solar and Generation Resources, Cision (Nov. 17, 2021), *available at* https://www.prnewswire.com/news-releases/pso-issues-requests-for-proposals-for-purchase-of-wind-and-solar-generation-resources-301426753.html.

[150] Duke Energy Targets Expansion, Plans 1.1-GW renewables RfP, Renewables Now (Feb. 18, 2022), *available at* https://www.renewablesnow.com/news/duke-energy-targets-expansion-plans-11-gw-renewables-rfp-773761.

[151] I&M Seeks Detailed Proposals for 1,300 MW of Solar, Wind Energy, PR Newswire (Mar. 15, 2022), *available at* https://www.prnewswire.com/news-releases/im-seeks-detailed-proposals-for-1-300-mw-of-solar-wind-energy-301503013.html.

[152] Georgia Power Continues Renewable Energy Expansion by Seeking 1,000+ MW of New Generation, PR Newswire (Nov. 8, 2021), *available at* https://www.prnewswire.com/news-releases/georgia-power-continues-renewable-energy-expansion-by-seeking-1-000-mw-of-new-generation-301418902.html.

[153] Arizona Public Service Co. is Seeking Proposals for Solar + Storage Projects, Solar Power World, *available at* https://www.solarpowerworldonline.com/2022/05/arizona-public-service-is-seeking-proposals-for-solar-storage-projects.

capabilities in the 2024 Carbon Plan update. The Companies' ability to interconnect new solar resources will be informed by both the 2022 DISIS as well as ongoing transmission planning through the North Carolina Transmission Planning Collaborative ("NCTPC"). As explained above, the Companies plan to seek approximately 1,200 MW of new solar resources through the 2022 Solar Procurement between the HB 951 target procurement volume (750 MW) and the CPRE Program Remainder MW. Additional interconnections may also occur outside of the 2022 Solar Procurement. The Companies expect to execute IAs in the 2022 DISIS by early 2024. At that point, estimates for commercial in-service dates, as well as the necessary transmission system upgrades to connect this solar, will be known. Witness Roberts on the Transmission Panel addresses the Companies' plans for pursuing NCTPC approval of the RZEP Projects, which will also inform the Companies' future ability to interconnect solar resources between now and 2030.

(I) Assumptions Regarding Availability of Imported Onshore Wind Resource in the Carbon Plan are Reasonable.

Q. PLEASE RESPOND TO NCSEA ET AL.'S SUGGESTION THAT THE COMPANIES SHOULD INCREASE THE AMOUNT OF MODEL-SELECTABLE ONSHORE WIND THAT COULD BE IMPORTED FROM OUTSIDE OF THE CAROLINAS.

A. The Carbon Plan included up to 300 MW/year of wind available to be imported into DEC. Imported wind was selected as part of the resource mix to achieve the 70% CO_2 reduction target in only one of the alternative portfolios ($P3_A$).

Limited availability of onshore wind imports did not impact the ability to achieve 70% CO_2 reduction in the Carbon Plan.

(J) **<u>Natural Gas Price Forecasting and Assumptions are Reasonable for Planning Purposes and Further Assessed in Supplemental Modeling.</u>**

Q. HOW DO THE COMPANIES RESPOND TO ASHEVILLE BUNCOMBE COUNTY'S RECOMMENDATION THAT INCLUSION OF NATURAL GAS IS NOT PRUDENT ECONOMIC DECISION?

A. Firm, dispatchable natural gas resources will be critical to maintaining system reliability on the path to achieving carbon reductions, filling part of the resource adequacy needs created by the retirement of coal facilities. As NERC President and CEO James Robb explained to the United States Senate Committee on Energy and Natural Resources in March 2021:

> Natural gas is essential to a reliable transition. . . . [O]n a daily basis in areas with significant solar generation, the mismatch between the solar generation peak and the electric load peak necessitates a very flexible generation resource to fill the gap. Natural gas generation is best positioned to play that role. The criticality of natural gas as the "fuel that keeps the lights on" will remain unless or until very large-scale battery deployments are feasible or an alternative flexible fuel such as hydrogen can be developed.[154]

As highlighted in greater details by witnesses Sammy Roberts and Sam Holeman ("Reliability Panel"), additional gas generation capacity is a necessary

[154] James R. Robb, North Am. Elec. Reliability Corp., Testimony Before United States Senate Committee on Energy and Natural Resources, Full Committee Hearing on the Reliability, Resiliency, And Affordability of Electric Service, at 9-10 (Mar. 11, 2021), *available at* https://www.energy.senate.gov/services/files/EB1D7E02-4DFF-A6A9-002341DA34CF.

complement to renewables and storage to provide energy adequacy during winter months when solar outputs are not well correlated to the peak load shape and overall energy demands can remain high for extended periods of time. Gas generation resources are also needed to work in tandem with storage to provide the increasing level of dispatchable operational reserves necessary to match the growing variability and uncertainty that accompany a grid more reliant on weather-dependent renewables.

Q. HOW DO THE COMPANIES RESPOND TO INTERVENOR COMMENTS THAT THE NATURAL GAS PRICE FORECAST USED IN DEVELOPING THE CARBON PLAN PORTFOLIOS IS OUTDATED OR OVERLY OPTIMISTIC?

A. Commodity markets, specifically natural gas, change constantly. Thus, resource planning assumptions should be viewed as dynamic while respecting that it is necessary to "snap a chalk line" on price inputs. The current natural gas market conditions largely have nearer-term price implications, which is well before any new natural gas generation would come into service in the late-2020's.

The Carbon Plan's Henry Hub natural gas NYMEX market prices were captured as of March 8th, 2022. Comparing the forward market prices as of August 5th, 2022, the mid- to long-term annual prices have not seen as high of an increase as prices for gas delivery in 2022. According to the Companies' proposed Execution Plan, the first-year new gas generation is proposed to be in-service is 2027. The annual market price increase is $0.71 for 2027, which is slightly less than a 20% increase from the Carbon Plan input for 2027. This level of increase is similar to the inflationary and market pressures of other commodities during this period, while longer-term prices beyond 2027 have increased at even lower levels. Additionally, other non-fuel commodities, such as lithium, have increased substantially more than natural gas since 2021.

Notably, fundamental pricing is not as impacted by current events as near-term market pricing. Using the EIA AEO Reference Case as an example, comparing years 2030-2050, the forecasted price increased from $5.46 in the 2021 edition to $5.64 in the 2022 edition, or an approximate 3% increase from the Carbon Plan's input pricing. These fundamental gas price forecasts are generally only updated once or twice per year. As discussed in Appendix E, the Companies utilize a blend of four respected third-party forecast providers: EIA, Wood Mackenzie, Energy Ventures Analysis and IHS Markit.[155] These entities, which includes the United States government, do not have any incentive to produce an overly optimistic price forecast.

The Companies will continue to revise natural gas inputs in future Carbon Plan updates; nevertheless, the Companies believe the natural gas inputs in the current Carbon Plan are still reasonable for decision making regarding incremental natural gas generation as part of the proposed near-term actions.

[155] Carbon Plan Appendix E at 39-40.

Q. INTERVENORS HAVE RAISED CONCERNS REGARDING THE FUTURE AVAILABILITY OF NATURAL GAS FROM THE APPALACHIA REGION. PLEASE DESCRIBE WHY APPALACHIAN GAS WAS USED AS THE BASE FUEL SUPPLY ASSUMPTION.

A. Limited incremental Appalachian gas was utilized as the base fuel supply assumption since it follows least cost planning principles. Additionally, planning for future limited access to Appalachian gas is in the best interest of the Companies' customers and other North Carolina stakeholders. Without additional interstate pipeline firm transportation capacity to deliver gas from Appalachia, the Companies have increased fuel assurance risk, increased customer fuel cost exposure and increased risk of delayed coal retirements.

From an availability perspective, MVP has worked diligently to begin providing access to Appalachian gas, completing approximately ninety-four percent (94%) of all planned construction. However, continued legal challenges to required permits to finish the remaining construction have extended the time needed to complete the project. The pipeline currently forecasts an in-service in the second half of 2023.

To address its existing generation fleet's need for natural gas firm transportation and supply, the Companies have entered into a definitive agreement with a third-party that relies on the services to be provided by MVP, assuming timely pipeline completion. This agreement is evidence of the Companies' ability to access Appalachian gas, assuming an MVP completion. Once in-service, the agreement provides access to firm, lower-cost, Appalachian supply that would help mitigate high levels of Transco Zone 5 cost exposure for the Companies' customers.

While the Carbon Plan's base incremental natural gas supply assumption is from the Appalachia Region, the Companies understand that this assumption is not fully certain given its dependency on factors outside of the Companies' control. This is why an Alternate Fuel Supply Sensitivity was developed to consider the possibility that no Appalachian gas supply is available.

(K) Hydrogen Fuel Production and Transportation Cost Assumptions Were Reasonably Considered in the Carbon Plan and Should Continue to be Evaluated in Future Carbon Plan Updates.

Q. DID THE COMPANIES INCLUDE FUEL PRODUCTION AND TRANSPORTATION COSTS IN THEIR HYDROGEN ASSUMPTIONS?

A. Yes. The Companies did include the capital expense of electrolyzers in its hydrogen production assumption. These expenses were derived using data compiled by the Department of Energy.[156] Furthermore, there was an embedded transportation cost assumption included in the hydrogen commodity cost development.

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[156] H2@Scale for Decarbonizing Heavy Industries, U.S. Department of Energy Office of Energy Efficiency & Renewable Energy (Sept. 14, 2021), *available at* https://www.energy.gov/sites/default/files/2022-02/Miller%20-%20HFTO%20-%20H2%20at%20Scale%20for%20Decarbonizing%20Heavy%20Industries.pdf.

Q. ARE THERE CONCERNS ABOUT THE HYDROGEN COUNCIL'S LONG-TERM HYDROGEN COST OF $140/MWH AS REFERENCED IN NCSEA ET AL.'s SYNAPSE REPORT?[157]

A. Yes. Synapse assumes an unreasonably high forecast for the cost of hydrogen fuel. The Hydrogen Council's "Path to hydrogen Competitiveness: A Cost Perspective"[158] does reference a $140/MWh cost assumption given a hydrogen import price of $3 per kg. This is one of several assumptions within the document and the $140/MWh assumption considers the full cost of importing hydrogen.

The Hydrogen Council also states in the same document that "[v]olumes of low-carbon hydrogen should increase to about 12 million tons of hydrogen per year, with costs of about USD 1 to 2 per kg by 2030."[159] This statement is relevant because it considers both the implications of scale and regional production. Additionally, the Hydrogen Council generally has higher forecasted hydrogen costs than other third-party sources such as Bloomberg or IRENA.

Q. IF HYDROGEN IS SPECULATIVE AS NCSEA ET AL. STATED IN THEIR COMMENTS, THEN WHY ARE THE COMPANIES INCLUDING IT IN THEIR TECHNOLOGY SELECTION?

A. Hydrogen is a known and proven industrial gas that is currently used in multiple

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[157] NCSEA et al. Synapse Report at 42.

[158] See Hydrogen Council, Path to hydrogen competitiveness A cost perspective (published January 20, 2020), accessible at https://hydrogencouncil.com/wp-content/uploads/2020/01/Path-to-Hydrogen-Competitiveness_Full-Study-1.pdf ("2020 Hydrogen Council Report").

[159] 2020 Hydrogen Council Report at 22.

domestic manufacturing and production industries such as steel, cement, ammonia, and other chemicals. Today, there are approximately 1,600 miles of dedicated hydrogen pipelines and both above-ground and underground storage in-service in the United States today. Additionally, electric production from hydrogen is developing rapidly. For example, Mitsubishi Heavy Industry is targeting to have 100% hydrogen capable gas turbines by 2025.[160] Indeed, a number of the Companies' peer utilities, such as Florida Power & Light and Georgia Power are also evaluating and in some cases are in active development of hydrogen blending projects as early as 2025.[161]

Q. IN NCSEA ET AL.'S SYNAPSE REPORT CONFIDENTIAL FIGURE A-3, ARE THERE CONCERNS ABOUT SYNAPSE'S INTERPRETATION OF THEIR CITED SOURCES USED TO DEVELOP THEIR HYDROGEN PRICE FORECAST?

A. Yes. First, regarding development of raw hydrogen fuel costs, Synapse interpreted a graphical representation from their selected data source[162] in which, they inappropriately interpolated linearly between their estimated data midpoints. For example, in 2050 Synapse stated a raw fuel cost midpoint from their data source of $1.0 per/kg. However, through their inappropriate use of

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160 Hydrogen Gas Turbine | Solutions | Power | Energy Transition MITSUBISHI HEAVY INDUSTRIES GROUP (mhi.com).

161 Georgia Power 2022 IRP at I-172; NextEra Sets Goal to Decarbonize, Proposes Big Transition for Florida Power & Light, June 15, 2022.

162 NCSEA et al., Synapse Report A-3, Fn. 2, citing Mitsubishi Power (2020, October). Advancing Green Hydrogen for the Danskammer Project, *accessible at* https://www.greenhydrogenny.com/wp-content/uploads/2020/09/Mitsubishi-Hitachi-Power-Systems-Advancing-Green-Hydrogen-for-the-Danskammer-Project.pdf.

interpolation, they utilized a 2050 raw fuel cost of $2.0 per/kg in their hydrogen price forecast. Furthermore, their visual interpretation of $1.0 per/kg is clearly not the midpoint number based on their source's graphic. As a result, the hydrogen fuel price forecast derived for Figure A-3 is biased due to Synapse's incorrect use of interpolation instead of the source's actual data points.

Secondly, regarding Synapse's development of fuel transportation costs, they utilized quantitative numbers from their data source.[163] This includes costs for hydrogen preparation, distribution, and fueling station. While Duke Energy accepts their inclusion of preparation and distribution costs, the inclusion of fueling station costs is inappropriate and excessive. Power generation connects directly to distribution and does not utilize fueling stations. Thus, it is not prudent to include hydrogen fueling station costs in this price forecast.

Lastly, regarding the kg to MMBtu conversion, Synapse incorrectly used the Low Heating Value ("LHV") for the energy content of hydrogen instead of the High Heating Value ("HHV"). This underrepresents the energy content per kg of hydrogen for power generation. Per the values in Synapse's source, the 141.9 MJ HHV should be utilized instead of Synapse's modeled 120.1 MJ LHV.

Utilizing Synapse's non-interpolated midpoint of $1.0 per/kg in 2050 and 2030 transportation costs escalated to 2050 of $0.927 per/kg, which

[163] NCSEA et al., Synapse Report A-3, Fn. 3, citing Hydrogen Council and McKinsey & Company (2020, January). Path to Hydrogen Competitiveness: A cost perspective. Retrieved at: https://hydrogencouncil.com/wp-content/uploads/2020/01/Path-to-HydrogenCompetitiveness_Full-Study-1.pdf.

excludes fueling station costs, this results in a hydrogen fuel cost of approximately $1.927 per/kg or $16.94 per MMBtu. Further adjusting to the proper energy content of hydrogen, it results in a corrected hydrogen fuel cost of approximately $14.33 per MMBtu in 2050. These three corrections lead to a 61% lower value than Synapse's filed cost of $36.76 per/MMBtu in 2050.

Given these issues, Synapse's hydrogen price forecast is flawed in its creation and interpretation.

VI. REVIEW OF INTERVENOR-SPONSORED ALTERNATE MODELING AND PORTFOLIOS

Q. SEVERAL INTERVENORS PRESENT ALTERNATE CARBON PLAN MODELING PROPOSALS. MR. SNIDER, WHAT ARE THE COMPANIES' GENERAL OBSERVATIONS ABOUT THESE OTHER PLANS?

A. Gabel/Strategen on behalf of Tech Customers and Brattle on behalf of CPSA submitted alternative modeling on July 15. Synapse on behalf of NCSEA et al. submitted an alternative plan on July 20. In the limited time since these intervenor-sponsored plans were submitted, the Companies have assessed these alternate proposals for technical objectivity and the degree to which intervenors' modeling and analysis achieve the HB 951 targets, while also meeting the core planning objectives which informed the Companies' development of the Carbon Plan.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY TECHNICAL OBJECTIVITY?

A. Technical objectivity refers to unbiased assumptions, thorough and robust analysis, and the validity of the conclusions reached given those analytical methods and assumptions. To inform the Carbon Plan development process, modeling must be developed based on a technically objective approach and be designed to (or have the ability to) meet the Carbon Plan objectives and fairly consider the full range of risks, costs and capabilities of all resource options without narrow emphasis on favoring or dis-favoring a subset of objectives or resources.

Q. HAVE INTERVENORS MAINTAINED TECHNICAL OBJECTIVITY IN DEVELOPING THEIR ALTERNATE PORTFOLIOS?

A. Unfortunately, no. Based upon the Companies' review, Intervenor proposals were developed using methods and assumptions that unduly favor certain resource types and appear to have been structured with desired portfolio composition in mind.

Q. WHAT ARE THE RAMIFICATIONS OF INTERVENORS' FAILURE TO MAINTAIN TECHNICAL OBJECTIVITY AND TO APPROACH THIS COMPLEX MODELING EXERCISE FROM A HOLISTIC AND UNBIASED PERSPECTIVE?

A. The Companies have identified several significant concerns with the technical objectivity of the inputs and assumptions used and the outcome-driven analysis conducted by intervening parties. Taken together, intervenors' non-technically objective inputs and modeling approach result in portfolios that exclude some resource options and are over-reliant on others, concentrating risks and depriving customers of a balanced, diversified approach to decarbonization. These portfolios especially fall short of the core Carbon Plan objectives to ensure the Plan is executable and adequately reliable, both of which are critically important to successfully balancing affordability in developing the least cost plan to meet the HB 951 CO_2 emissions reduction targets. Furthermore, because these alternative proposals entail substantial execution risk and would undermine system reliability, they are also not likely to achieve the CO_2 emissions reductions they target on the schedule presented. These flaws are necessarily also present in intervenors' proposed near-term actions, which are based on these incomplete and non-technically objective analyses.

Q. PLEASE SUMMARIZE THE COMPANIES' MAJOR CONCERNS REGARDING INTERVENORS' CHANGES TO CARBON PLAN INPUTS AND ASSUMPTIONS.

A. Recalling the Companies' three-pronged approach to developing the Carbon Plan presented in Figure 2 above, Intervenors have introduced modified inputs and assumptions at each step that create material risks that the core Carbon Plan objectives will not be achieved. At the highest level, intervenors' assumptions tend to unreasonably favor grid edge, renewable, and energy storage resources, and introduce bias against firm, dispatchable resource types. These include outcome-oriented assumptions for achievable resource deployment rates, outcome-oriented forecasts for fuel costs and resource capital costs, and outcome-oriented assumptions about resource availability and useful life. Intervenors also take a simplified and incomplete approach to ensuring reliability that, if adopted, would further introduce risk under their portfolios.

Q. PLEASE DESCRIBE THE ASSUMPTIONS THAT UNREASONABLY FAVOR GRID EDGE RESOURCES.

A. Both the Synapse Report and Gabel/Strategen Report assumed materially greater levels of future EE savings and behind-the-meter ("BTM") solar generation than the Companies did in their base case analysis. As discussed in more detail by witness Duff in the Grid Edge Panel, both intervenors ignore several key details in the 2020 ACEEE Report they relied upon to develop their aggressive EE forecasts. Notably, this includes ignoring the fact that the same ACEEE Report specifically commends North Carolina as the highest-performing state in deploying EE programs in the Southeast region.[164] It is important to note that the success of utility sponsored programs in recent years reduces future savings potential through utility efficiency programs as existing measures and programs become saturated. Much of the exceptional achievements in recent years were driven by lighting programs, many of which are no longer available as utility sponsored programs due to increased baseline efficiency standards. The ACEEE Report identifies the primary barrier to achieving higher levels of EE savings in the future to be legislative or procedural and, thus, introduce risks that are outside the control of the Companies. The conclusions of the ACEEE Report clearly show that Investor-Owned Utility EE savings grow minimally in the absence of significant changes

[164] 2020 ACEEE Report at iv.

in legislation and policy and reach only 3.7% of total load by 2030. The ACEEE Report provides a lengthy list of legislative and policy changes assumed in its aggressive "Energy Efficiency Policy" scenario and even in the most optimistic and unlikely scenario that *ALL* of these policy changes are quickly adopted, projected Investor-Owned Utility EE program savings reach a reduction of 5.0% of total load by 2030. By comparison, Synapse aggressively assumes annual savings which increase each year by 1.5% of total load cumulatively reaching 8.3% of total load by 2030 and 12.2% by 2035 while Gabel/Strategen assumes a reduction of 7.7% of total load by 2030.

The Synapse Report and Gabel/Strategen Report also forecast materially greater BTM solar generation adoption and are unreasonably optimistic in this assumption. Synapse arbitrarily uses the Companies' "high" net metering forecast—an aggressive assumption developed for sensitivity analysis purposes in the development of the Companies' Carbon Plan—as the base case for their analysis. Gabel/Strategen forecast that behind-the-meter solar generation in the Companies' service territories will increase at a sustained rate of 33.5% per year following the development, approval, and successful implementation of a "best-in-class BTM solar/storage program."[165]

Q. WHAT ARE THE CONSEQUENCES OF SYNAPSE AND GABEL/STRATEGEN UNDULY FAVORING EE AND BTM AND ASSUMING UNREASONABLY HIGH ADOPTION IN THE

[165] Gabel Report at 44.

CAROLINAS?

A. These EE and BTM solar forecasts, which were developed based on desired outcomes for these resources rather than objective factual considerations and technical analysis, yield significant reductions in net load, both peak demand and total energy, that must be served by supply-side resources over the planning period. Figure 16 below shows the combined system load forecasts net of contributions from UEE and BTM solar through 2050 comparing the Duke Energy load forecast with the Gabel/Strategen preferred portfolio and the Synapse optimized portfolio.

Figure 16: Combined System Load Forecast Net of Contributions from UEE and BTM PV

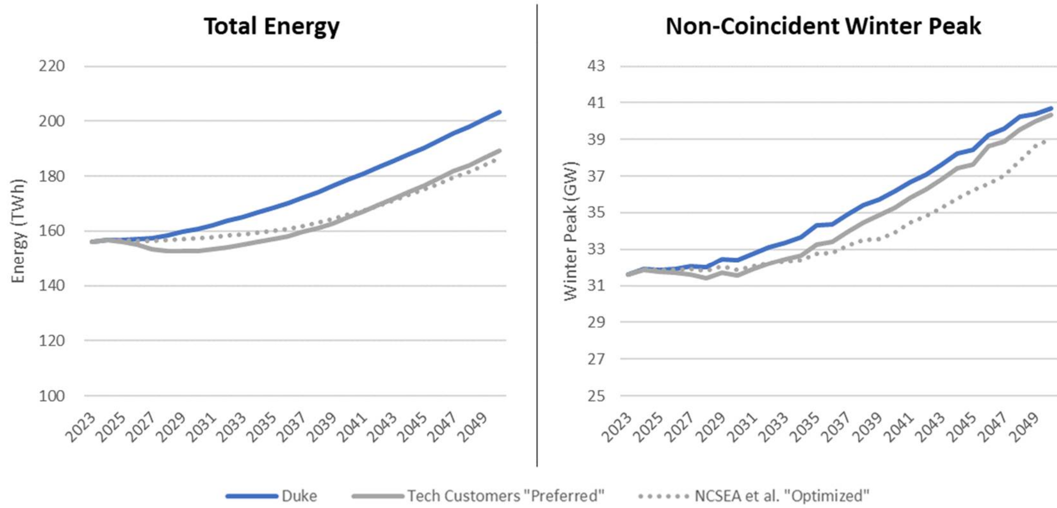


Figure 16 above shows how Gabel/Strategen's and Synapse's UEE and BTM solar result in a significant (and unjustified) reduction in the Companies' system load required to be served on both an energy and peak demand basis.

Overly optimistic net-load forecasts could lead to under-investment in supply-side resources, putting system reliability at risk and potentially stalling progress in the energy transition, a potential consequence acknowledged by Synapse.[166] Importantly for this proceeding, these artificially low net-load forecasts could result in the omission or under-representation of needed firm, dispatchable resources from near-term development activities.

[166] Modeling and Near-Term Actions Panel Exhibit 6 (NCSEA et al. Response to Duke Energy Data Request 2-18).

Q. DO THE ALTERNATIVE PLANS ALSO UNREASONABLY FAVOR SOLAR RESOURCES IN A WAY THAT INCREASES EXECUTABILITY AND RELIABILITY RISKS?

A. Yes. The intervenors who modeled alternative Carbon Plan portfolios tended to favor solar resources by assuming new capacity can be connected to the system more rapidly than is likely to be possible, by assuming improbably low capital costs, or both.

Q. PLEASE EXPLAIN HOW THE ALTERNATIVE PLANS UNREASONABLY FAVOR SOLAR RESOURCES BY ASSUMING AN OVERLY AGGRESSIVE PACE OF SOLAR ADDITIONS?

A. Synapse was the most aggressive in the near-term, adding 825 MW of new solar in 2025, *over and above* forecasted additions in 2025 related to existing programs (646 MW). This accelerated deployment in the earliest part of the planning period is particularly aggressive in light of the fact that, as discussed previously in this testimony, solar procurements to satisfy HB 589 requirements are behind schedule. The Companies assume solar additions beyond those driven by existing programs will not begin until 2026. Synapse cites only "the reasonable expectation of further improvements to solar deployment in the Carolinas"[167] to support its assumptions. After 2026, the Synapse Report continues to assume unreasonably aggressive solar interconnections of 1,800

[167] Modeling and Near-Term Actions Panel Exhibit 7 (NCSEA et al. Response to Duke Energy Data Request 2-15).

MW per year through 2028 and 2,300 MW per year from 2029 onward.[168]

CPSA and Brattle also assume that an improbably rapid solar deployment will be achievable, suggesting that 4,800 MW of new Carbon Plan solar should be procured by the end of 2024 and can be connected by the end of 2028, starting with 1,500 MW in 2026. This aggressive timeline fully doubles the Companies' expectations for 2026 solar additions, carries substantial execution risk and is unsupported by any analysis demonstrating a need for this pace or confirming system reliability during this period. The CPSA consultant, The Brattle Group, did not model any years from 2026 to 2029 when developing their alternative portfolios so there is no modeling justification for this aggressively accelerated pace of adoption.

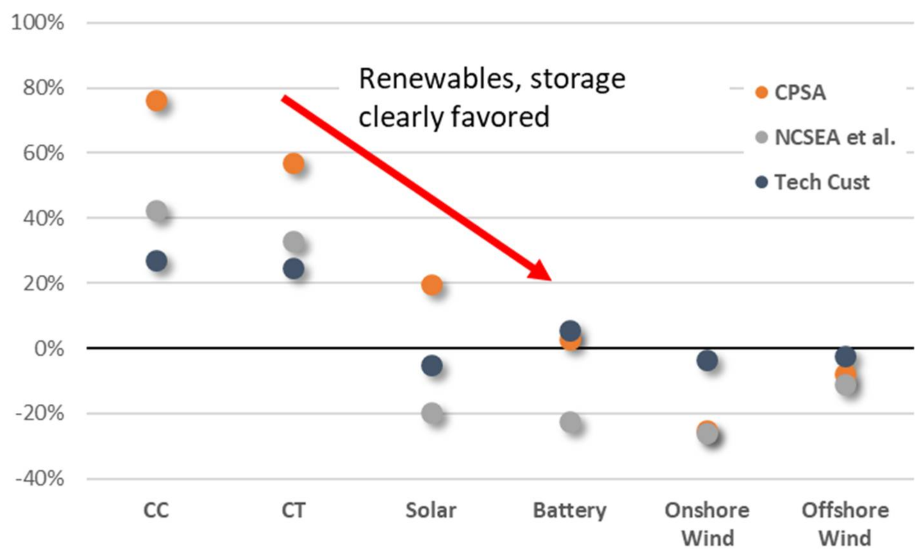
As stated previously in this testimony, the Companies agree with the Public Staff that "[r]elying on very high, unprecedented levels of annual solar interconnections—and any necessary interconnection facilities and transmission upgrades—could jeopardize interim compliance."[169] This risk is present to some degree in all Carbon Plan portfolios, but the near-term actions proposed by CPSA and NCSEA et al. substantially and unnecessarily increase exposure to this risk based on unsupported, outcome-oriented assumptions for the achievable pace of new solar resource additions.

[168] NCSEA et al. Synapse Report at A-12.
[169] Public Staff Comments at 13.

Q. PLEASE DESCRIBE HOW THE RESOURCE CAPITAL COST ASSUMPTIONS FOR NATURAL GAS TURBINES AND SOLAR, BATTERIES, AND WIND DEMONSTRATE THAT INTERVENORS TOOK AN OUTCOME-ORIENTED APPROACH.

Figure 17 below shows a comparison of intervenors' overnight capital cost forecasts to the Companies' assumptions for the year 2030.

Figure 17: Intervenor Overnight Cost Forecasts for 2030 as % Deviation from the Companies' Estimates



All three intervenors who performed modeling analysis and developed alternative portfolios overstated the capital costs of new CC and CT resources in their analyses. The flaws in their assumptions and their misunderstandings of the necessary adjustments made by the Companies to ensure cost forecasts reflect actual unit configurations and operating conditions are discussed previously in Section V of this testimony. The two most important misunderstandings of natural gas capital costs are based on the usage of a single unit CT rather than a multi-unit CT and the lack of duct firing incorporation into the CC capital cost calculation. CT costs for a single unit rather than 4-unit site are 40% higher based on Duke Energy estimates. Duct firing reduces the $/kW estimate 10-15% depending on the assumed amount of duct firing expected. By inflating the cost of firm, dispatchable gas generation, Synapse and Gabel/Strategen specifically biased the EnCompass capacity expansion model against selection of these resources in the development of their portfolios.

In contrast, the Synapse and Gabel/Strategen forecasts for solar capital costs unreasonably favor solar resources with low estimates that fail to account for all costs and that are not specific to the system configurations modeled. These flaws are described previously in this testimony. Synapse then compounded the impact of using unreasonably lower solar costs by also using the NREL Advanced cost forecast for storage resources, by far the lowest cost forecast for storage used by any party developing a Carbon Plan portfoliothen enabled the model to select imprudent levels of renewables since these could be supported by the artificially low-cost storage. Synapse's flawed analysis supports NCSEA et al.'s proposal that 4 GW of solar and 4 GW of storage should be procured by the end of 2024 and deployed by the end of 2028 is the demonstrable result of relying upon these outcome-oriented cost assumptions.

It is notable that CPSA, in analysis performed by The Brattle Group, used the highest cost forecasts for solar resources of any party proposing Carbon Plan portfolios. However, this is more than offset by the fact that Brattle also used the highest cost forecasts of any party for new CC and CT resources, preserving the incorrect cost advantage for new solar. As indicated previously, The Brattle Group conducted only screening-level resource selection analysis and the extent to which CPSA's proposed near-term actions, which include the highest proposed solar procurement of any party, are influenced by capital cost forecasts is not clear.

Q. PLEASE DESCRIBE OUTCOME-ORIENTED ASSUMPTIONS RELATED TO AVAILABILITY AND USEFUL LIFE OF CC AND CT RESOURCES.

A. Both Gabel/Strategen and Synapse artificially burden new CTs and CCs in capacity expansion modeling. Gabel/Strategen take the straightforward approach of simply eliminating new CCs as an option for model selection in the "Preferred" portfolio,[170] undermining the validity of their conclusion that "[t]he corrected EnCompass capacity expansion model shows that new gas-fired generation is not needed in the timeframe that the Companies propose and may not be necessary at all."[171] Notwithstanding this assertion, the Gabel/Strategen "Preferred" portfolio does recognize the need for new CC and CT capacity and assumes that the Companies can purchase nearly 900 MW of *additional* CC and CT capacity from existing, third-party-owned units) that do not sell this power to DEC and DEP today. Notably, Gabel presents no justification for assuming that an *additional* 900 MW of firm CC and CT capacity will be available for

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[170] Modeling and Near-Term Actions Panel Exhibit 8 (Tech Customers' Response to Duke Energy Data Request 1-7(a)).
[171] Tech Customers Gabel/Strategen Report at 59.

purchase by the Companies on the timeline required to ensure reliability is maintained as the Companies retire substantial coal units and transition the fleet to meet the HB 951 targets.[172] Assuming that the Companies can rely upon substantial dispatchable capacity from third-party owned generators that are needed for reliability but not available today is not prudent planning and is also inconsistent with HB 951's requirement that new generating facilities selected by the Commission to meet the Carbon Plan targets shall be owned and recovered on a cost of service basis.

Synapse allowed the capacity expansion model to select new CCs and CTs, but unreasonably reduced the useful life of these assets to 25 years and forced cost recovery to be completed over 20 years. The former substantially decreases the lifetime value of these resources and the latter substantially increases the PVRR impact. These changes, combined with artificially high cost assumptions for CCs and CTs and artificially low cost assumptions for renewables and storage effectively eliminate CCs and CTs from the portfolio in the near-term without the need for explicit exclusion. (Synapse's "Optimized" portfolio does require 2.6 GW of hydrogen-fired CTs to be added in the 2040s to achieve carbon neutrality.)

Q. DO THE COMPANIES ALSO HAVE CONCERNS WITH THE COAL RETIREMENT DATES USED BY INTERVENORS?

A. Yes. Most significantly, Gabel/Strategen, in their analysis developed for the

[172] Tech Customers Gabel/Strategen Report at 30.

Tech Customers, elected to assume that all of the Companies' existing coal units would be retired by 2030. However, as stated in the Gabel Report and reiterated in discovery, Gabel/Strategen performed no unit-level analysis to provide any economic justification for or to confirm the feasibility of this timetable.[173] Instead, Gabel/Strategen suggest their approach to retiring all coal units by 2030 is a "modeling exercise to illustrate hypothetical results that may be possible" while "acknowledging that actual retirement decisions must be taken with consideration of factors outside those available in the model."[174]

Synapse also accelerated certain coal unit retirement dates, advancing the retirements of Belews Creek 1 & 2, Cliffside 5, and Marshall 1 & 2. Synapse reports that these dates were selected by the EnCompass capacity expansion model and that Synapse declined to adjust them. However, as explained in Appendix E and previously in this testimony (and seemingly also recognized by Gabel/Strategen), there are several factors not considered in capacity expansion modeling that influence the prudent retirement date for any unit. In addition, Synapse elected to estimate fixed operating and maintenance cost forecasts for the Companies' coal units using a 2018 study of coal stations nationwide, rather than on the Companies' own proprietary, unit-specific cost forecasts that were provided to Synapse for their analysis.[175]

Q. DO THE COMPANIES ALSO HAVE CONCERNS THAT

[173] Modeling and Near-Term Actions Panel Exhibit 9 (Tech Customers Response to Duke Energy Data Request 1-8).
[174] Tech Customers Gabel/Strategen Report at 28.
[175] NCSEA et al. Synapse Report at 10.

INTERVENORS' MODELING FAILS TO SUFFICIENTLY ADDRESS RELIABILITY AND EXECUTABILITY?

A. Yes. All three alternative Carbon Plan proposals are the result of incomplete analyses. No intervening party performed the steps necessary to evaluate whether the alternative proposals can be affordably executed in the timeframes suggested while preserving system reliability. Specifically, intervenors omitted the Portfolio Verification steps, described in Appendix E and summarized previously in this testimony, which are necessary to ensure resource adequacy and reliability. In addition to these omissions and as indicated previously in this testimony, The Brattle Group appears to have conducted little more than capacity expansion analysis and to have evaluated only four years of the planning period to develop the resource portfolios supporting the near-term actions proposed by CPSA.[176]

[176] Modeling and Near-Term Actions Panel Exhibit 10 (CPSA Response to Duke Energy Data Request 1-8).

Q. WHAT RISKS COULD OMITTING THE BATTERY-CT OPTIMIZATION STEP INTRODUCE TO THE RESULTING PORTFOLIO?

A. Omitting this step could result in the inclusion in the portfolio of greater amounts of energy storage than is cost-effective. As described previously in this testimony, the necessary simplification of the hourly load shape in the capacity expansion model exaggerates the magnitude and duration of the maximum peak-valley spread. This similarly exaggerates the value of energy storage resources, which is heavily influenced by that spread. As a consequence of this inherent bias in the simplified load shape, the capacity expansion model will tend to select more than the cost-effective amount of energy storage resources, which is why verification in the more detailed production cost model is required. None of the intervenors proposing alternative portfolios completed a comparable validation step, making it highly likely that energy storage resources are over-represented in those alternatives and that none of them is consistent with the least cost requirements of the Carbon Plan.

Q. HOW WOULD OMITTING THE RELIABILITY AND RESOURCE ADEQUACY STEPS AFFECT PORTFOLIO RESULTS?

A. Failure to perform these reliability verification steps substantially increases the risk that, if the resulting portfolio were implemented, the Companies would be unable to maintain system reliability as mandated by HB 951. As stated previously in this testimony, the continuing transition to greater reliance on variable energy and energy-limited resources makes the inclusion of enhanced reliability verification methods a vital part of a robust Carbon Plan analysis. The capacity expansion model's reliance on a static reserve margin and a limited set of resource ELCC values makes it an inadequate tool for ensuring system reliability across a wide range of forced outage and weather scenarios, particularly for portfolios that contemplate a transition away from firm, dispatchable resources and towards substantially higher levels of variable energy and energy-limited resources. Similarly, the deterministic, hourly production cost model that relies on weather-normal load and renewable energy generation forecasts is a necessary step, but it is not sufficient for ensuring system reliability for Carbon Plan portfolios across a range of potential real-world conditions.

Q. DO THE PARTIES PERFORMING ALTERNATIVE MODELING EFFECTIVELY SUGGEST THAT PLANNING TO A 17% WINTER RESERVE MARGIN MEANS THAT THEIR PLANS ARE RELIABLE?

A. Yes. CPSA comments that "Brattle's modeling fully accounted for system reliability concerns" explaining that "Brattle's capacity expansion modeling primarily meets resource adequacy requirements through the implementation of a 17% resource margin requirement, equivalent to the level that Duke Energy uses from its 2020 Resource Adequacy Study."[177] Synapse touts that its portfolio meets Duke Energy's 17% winter reserve margin "in every month between 2022-2050."[178] Indeed, Gabel/Strategen even suggest (wrongly) that a

[177] CPSA Comments at 31.
[178] NCSEA et al. Synapse Report at 4.

17% planning reserve margin is "conservative, given the benefits that the Companies can receive from neighbor assistance" but ultimately elect to "appl[y] the same reliability constraints that Duke used in the Carbon Plan modeling" in the form of a 17% planning reserve margin.[179] As noted above, the Companies' 2020 Resource Adequacy Study already factors neighbor assistance into the 17% planning reserve margin which is materially below the winter planning reserve margins for peer utilities in the southeast.

Q. DID DUKE CONDUCT THE MORE DETAILED RELIABILITY VALIDATION STEP USED IN DEVELOPING THE CARBON PLAN FOR ANY OF THE INTERVENORS' ALTERNATIVE PLANS?

A. Yes. The Companies conducted the reliability validation step for the Synapse "Optimized" portfolio and the Gabel/Strategen "Preferred" portfolio. Essentially, the Companies performed the same analytical process outlined in Carbon Plan Appendix E under the heading "Portfolio LOLE and Resource Adequacy Validation." The proposed CPSA portfolios are based on only screening-level analysis and were not presented in sufficient detail to be included in the reliability validation.

[179] Tech Customers Gabel/Strategen Report at 57.

Q. WHAT DOES THE RELIABILITY VALIDATION ANALYSIS EVALUATE?

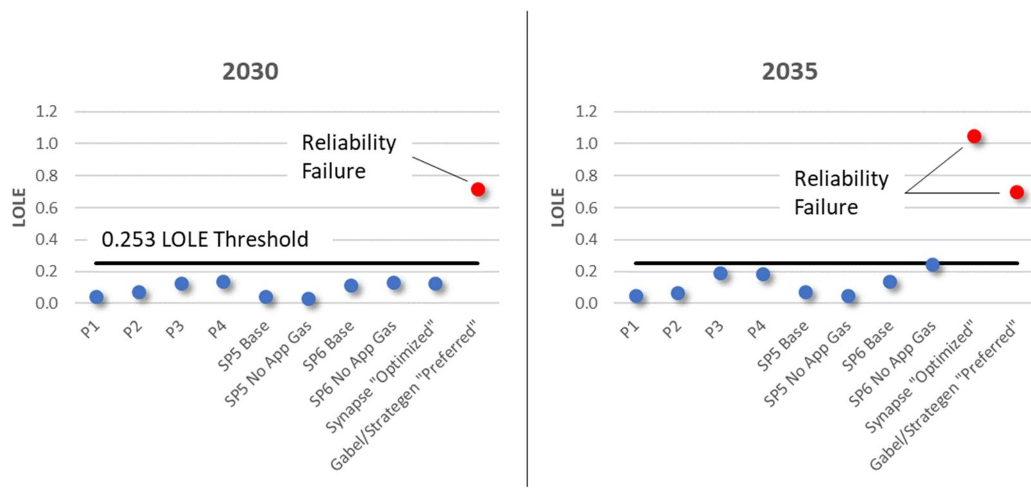
A. As discussed previously in Section II and explained in detail in Appendix E, the reliability validation analysis tests the portfolios against forty-one weather years, each simulated fifty times to properly capture the impact of unanticipated forced outages. In this way it is possible to confirm whether the portfolios would enable the Companies to reliably serve load under real world conditions. As described in Appendix E,[180] LOLE, the industry metric which measures the expected number of days in a year during which the utilities will experience a load shed event, is the primary metric used for this analysis. As previously described, the Companies utilized modeling data from the 2020 Resource Adequacy Study to develop an island case LOLE target that would correspond to achieving a 0.1 LOLE on an interconnected system basis. The corresponding island case LOLE was determined to be 0.253 event-days per year. Thus, the intervenor alternative portfolios were run as island scenarios with the LOLE compared to 0.253 event-days per year, corresponding to 0.1 LOLE on an interconnected basis.

[180] Carbon Plan Appendix E at 62.

Q. WHAT WAS THE RESULT OF PERFORMING THE SAME RELIABILITY ANALYSIS USED IN DEVELOPING THE CARBON PLAN TO ASSESS THE SYNAPSE AND GABEL/STRATEGEN ALTERNATE PORTFOLIOS?

A. Figure 18 below shows the results of the LOLE analysis in 2030 and 2035 for P1-P4, SP5 and SP6 with and without limited Appalachian gas, and the Synapse "Optimized" and Gabel/Strategen "Preferred" portfolios on an "as found" basis, that is, before any firm, dispatchable resources were added to ensure reliability.

Figure 18: LOLE Results for As-Found Portfolios



As Figure 18 shows, the Synapse and Gabel/Strategen alternate portfolios do not pass the resource adequacy validation analysis in 2035. The Gabel/Strategen "Preferred" portfolio also does not pass the resource adequacy validation analysis in 2030. Because the intervenors neglected to perform this reliability validation step, they failed to identify these shortcomings and their final portfolios consist of scheduled retirements and resource additions that do not meet the reliability requirement under HB 951. In addition, as discussed previously, the load forecasts intervenors used to develop these portfolios included unrealistically optimistic forecasts for energy efficiency and behind-the-meter solar. Therefore, the reliability shortcomings identified here are understated in light of the fact that actual load is likely to be higher than the intervenors assumed.

Q. HOW MUCH ADDITIONAL FIRM CAPACITY WOULD THE SYNAPSE "OPTIMIZED" PORTFOLIO REQUIRE IN 2035 TO MEET THE LOLE THRESHOLD?

A. The Synapse "Optimized" portfolio would require 2,250 MW of additional firm capacity. This is the equivalent of being short the capacity value of *six* additional J Frame CTs. With the addition of this capacity, the LOLE would drop from 1.046 event-days per year to 0.233 event-days per year.

Q. HOW MUCH ADDITIONAL FIRM CAPACITY WOULD THE GABEL/STRATEGEN "PREFERRED" PORTFOLIO REQUIRE IN 2030 AND 2035 TO MEET THE LOLE THRESHOLD?

A. In 2030 the portfolio would require 1,875 MW of additional firm capacity. This is the equivalent of being short the capacity value of *five* additional J Frame CTs. In 2035 the portfolio would require 1,500 MW of additional firm capacity, which is the equivalent of *four* additional J Frame CTs. With these additions, the LOLE would drop from 0.717 event-days per year to 0.212 event-days per year in 2030 and from 0.698 event-days per year to 0.251 event-days per year in 2035.

Q. WHAT ARE THE IMPLICATIONS OF THE FLAWED ASSUMPTIONS AND METHODS DISCUSSED IN THIS SECTION FOR THE PROPOSED NEAR-TERM ACTIONS BASED ON ALTERNATIVE PORTFOLIO ANALYSIS?

A. NCSEA et al., Tech Customers and CPSA each argue that substantial modifications to the Companies' near-term actions proposal are needed based upon their alternate modeling. As we have demonstrated, the modeling inputs and methods these parties use to support their recommendations are not technically objective and tend to over-value renewables and storage and under-value firm, dispatchable thermal resources. These studies were also based on unrealistic assumptions about the pace of adoption of new EE measures and BTM solar generation, as well as the pace at which new solar resources can be interconnected to the system. Finally, no focused assessment of economics or reliability was performed that could have helped identify the economic and reliability shortcomings that these flawed assumptions introduced to the portfolio proposals. These flaws are reflected in the unreasonably high levels of near-term solar procurement proposed by NCSEA et al. and CPSA; the unreasonably high levels of near-term energy storage procurement (some of which is paired with solar) proposed by NCSEA et al., CPSA, and the Tech Customers; and the omission of new thermal resources from the Tech Customers and NCSEA et al. proposals. In addition to jeopardizing system reliability and unnecessarily increasing costs to customers, intervenors' emphasis on some resource types and exclusion of others would limit rather than preserve optionality, putting carbon reduction targets at risk.

VII. RECOMMENDATIONS FOR FUTURE CARBON PLAN MODELING AND CONCLUSION

Q. DO THE COMPANIES HAVE A RECOMMENDATION REGARDING FUTURE UPDATES TO THE CARBON PLAN AND FUTURE IRP PROCEEDINGS?

A. Yes. As discussed in the Carbon Plan Executive Summary, the Companies believe it is appropriate to reestablish an "even-year" cadence for filing comprehensive IRPs and Carbon Plan updates starting in 2024.[181] This approach will also allow time in 2023 for review of the Commission's IRP Rule R8-60 and related rules to ensure that the resource planning regulatory framework aligns with the new IRP/Carbon Plan requirements of HB 951.[182]

[181] Carbon Plan Chapter 4 (Executive Summary), at 40.
[182] Carbon Plan Chapter 4 (Executive Summary), at 40.

Q. **DO THE COMPANIES AGREE TO MEET WITH THE PUBLIC STAFF AND OTHER STAKEHOLDERS TO DISCUSS THE MODELING PROCESS IN ADVANCE OF FILING THE 2024 CARBON PLAN UPDATE?**

A. Yes, the Companies plan to conduct robust stakeholder engagement including stakeholders from both North and South Carolina associated with the development of the 2024 Carbon Plan update to our energy transition plans and will further evaluate the Public Staff's and other Intervenors' modeling recommendations at that time.

Q. **MR. SNIDER, MR. McMURRY, MR. QUINTO, AND MR. KALEMBA, DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?**

A. Yes.

Modeling and Near-Term Actions Panel Exhibit 1:
Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's
Carolinas Carbon Plan – Supplemental Portfolio Analysis
Docket No. E-100, Sub 179
August 19, 2022

I. Background

On July 15, 2022, the Public Staff - North Carolina Utilities Commission ("Public Staff") submitted comments on the Companies' proposed Carbon Plan. While supportive of many aspects of the Carbon Plan, as filed, the Public Staff recommended Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and, together with DEC, the "Companies" or "Duke Energy") perform supplemental modeling incorporating certain recommended alternative inputs and adjustments, as presented in Appendix B to their Comments ("Supplemental Portfolio analysis"), and to submit the supplemental modeling by August 19, 2022, ahead of the evidentiary hearing on the Carbon Plan before the North Carolina Utilities Commission (the "Commission"). The Public Staff stated that the purpose of the supplemental modeling was to validate the Companies' proposed short-term execution plan submitted with the Carbon Plan. To the extent the supplemental modeling supported these near-term actions, the Public Staff would recommend approval of those actions within the near-term action plan.[1]

The Companies subsequently met with the Public Staff over a number of meetings to work through details of the recommended Supplemental Portfolio analysis. Through these collaborative discussions, the Companies and the Public Staff evolved and/or limited certain Public Staff recommendations for adjusting the modeling and modeling inputs utilized in the Carbon Plan, which after being reviewed in greater detail, seemed to not influence the results of the Plan. Concurrently, the Companies continued to review the numerous comments from other intervenors with respect to modeling recommendations. The Companies carefully weighed the potential impact to modeling along with the time and resources needed to integrate any additional modeling recommendations on the accelerated schedule of this proceeding. The Companies were able to integrate several modeling recommendations which were consistent across intervenors' comments, perform additional limited sensitivities and address additional recommendations proposed by intervenors in this analysis. This alignment was documented in the Companies' July 28, 2022 update letter to the Commission.[2]

The supplemental analysis contained herein provides background on key topics, modeling assumption changes, and portfolio results of the Supplemental Portfolio analysis.

II. Scope

The supplemental modeling consisted of the development of two additional portfolios, each with two fuel supply assumption scenarios. As recommended by Public Staff, the "primary" natural gas supply assumption for the supplemental analysis is Public Staff's "no Appalachian gas"

[1] Public Staff Comments at 20.
[2] *See* Development of Supplemental Modeling Portfolios.

assumption, whereas the "limited Appalachian gas" assumption is considered the "alternate" fuel supply scenario. Therefore, for this Supplemental Portfolio analysis, supplemental portfolio 5 ("SP5") represents a no Appalachian gas supply scenario and targets a 2032 interim 70% compliance year, while supplemental portfolio 5 with Alternate Fuel ("$SP5_A$") represents a fuel supply scenario which envisions limited access to Appalachian gas, consistent with the Companies' base fuel supply cases used to develop the Carbon Plan portfolios. Similarly, Supplemental Portfolio 6 ("SP6") targets a 2034 interim 70% compliance year, and like $SP5_A$, Supplemental Portfolio 6 with Alternate Fuel ("$SP6_A$") represents the fuel supply scenario with limited access to Appalachian gas and a 2034 as the compliance year.

The Supplemental Portfolios underwent the same economic evaluations as the filed Carbon Plan portfolios, including the evaluation of capacity expansion selection of peaking resources and reliability modeling within the EnCompass model and in Strategic Energy Valuation and Risk Model ("SEVRM") to evaluate a portfolio's loss of load expectation (LOLE) against the benchmark threshold. Finally, all portfolios underwent CO_2 reduction analysis, present value of revenue requirements (PVRR), and customer bill impact analysis.

Additionally, responsive to intervenor recommendations, the Companies conducted a limited set of sensitivities. The first is a "Low EE" sensitivity, which the Public Staff describes as "a better estimation of the impacts to future load" due to the net effects of potential lower achievement in utility-sponsored energy efficiency ("UEE" or "EE") overall. The second is a "High Solar Interconnection" sensitivity. This sensitivity was proposed by Clean Power Suppliers Association ("CPSA") and was generally supported by multiple intervenors, including the NC Attorney General's Office ("AGO"), with respect to assessing the impact of relieving binding solar selection constraints in the Carbon Plan modeling.

III. Recommendations Integrated into Supplemental Portfolio Analysis

A. Base Supplemental Portfolio Analysis Assumptions

The development of the Supplemental Portfolio consisted of economic selection of resources, including offshore wind and nuclear SMR, for achieving the interim emissions reduction target in 2032 and 2034. The table below summarizes the base cases changes integrated in the Supplemental Portfolio analysis compared to the Carbon Plan portfolio assumptions.

Table SPA-1: Base Case Modeling and Assumption Changes in Supplemental Portfolio Analysis

Supplemental Portfolio Parameter	Carbon Plan Portfolios 1 – 4 Assumption	Supplemental Portfolios 5 – 6 Assumption
First SMR Availability	End of Year ("EOY") 2032	Mid-year 2032
Belews Creek Retirement	Retired EOY 2035	Retired EOY 2037

Supplemental Portfolio Parameter	Carbon Plan Portfolios 1 – 4 Assumption	Supplemental Portfolios 5 – 6 Assumption
SPS Battery Dispatch Optimization	Fixed battery dispatch profile	Model optimized battery dispatch
Available SPS Battery Configurations	• 4-hr, 25% battery to solar ratio • 2-hr, 50% battery to solar ratio	• 4-hr, 25% battery to solar ratio • 2-hr, 50% battery to solar ratio • 4-hr, 50% battery to solar ratio
Cumulative Battery Limits	4-hr battery capped at 1,500 MW in DEC and 1,800 MW in DEP; 6- hr battery at 32,00 MW in DEC and 2,000 MW in DEP	4-hr and 6-hr battery not capped, but continue to decline in capacity value at higher penetrations
Inclusion of Hydrogen Fuel	Yes	No
2050 Emission Reduction Target	100% (Absolute Zero)	95% (Net-Zero)
Limited Appalachian Fuel Supply Case	Existing CC fleet fueled in part by App Gas, FT for two new CCs, no CC on ultra-Low Sulfur Diesel ("ULSD") backup	Existing CC fleet fueled in part by App Gas, FT for two new CCs, no CC on ULSD backup
No Appalachian Fuel Supply Case	Existing CC fleet fueled Transco Zone 4, no incremental FT for new CCs, new CC configured with ULSD backup	Existing CC fleet fueled Transco Zone 4, FT for two new CCs with Transco Zone 4, new CC do not require ULSD backup
Back-up Fuel Supply	CTs operate on ULSD for entire month of January	CTs operate on ULSD for two weeks in January
Availability of F-Class and J-Class CCs and CTs	Smaller F-Class CC available in no Appalachian fuel supply case. Larger J-Class CC available in limited Appalachian supply case. Only J-Class CTs available.	Both J-Class and F-Class CCs and CTs available in both fuel supply scenarios.
DEC/DEP Energy Transfer Hurdle Rate	No energy hurdle rate imposed on DEC/DEP transfers	Energy hurdle rate imposed on DEC/DEP transfers included for resource selection

Additional details on each of the parameter change are described in more detail in the following sub-sections.

1. <u>2032 Mid-year SMR</u>

In the Supplemental Portfolio Analysis, the Companies integrated feedback from intervenors on allowing the accelerated integration of the SMR in the modeling. As described in Appendix L of the Carbon Plan, the Companies believe implementation of the first nuclear SMR unit is feasible for June 2032. Because the capacity expansion model is set up to retire and bring on new resources on at the end of the year to ensure the following winter peak capacity needs are met, the originally SMR was first available at the end of 2032. However, due to the material impact a half of a year of a nuclear SMR can have on supplying carbon-free energy, the Companies decided to allow the first SMR to be brought online in June of 2032 in this one instance. All other future additional selection of nuclear units continues to follow the end of year addition assumption.

2. Belews Creek Retirement

The Companies, in the Carbon Plan modeling, originally identified the optimal retirement of the 2,220 MW Belews Creek Coal Station to be retired at the end of the year 2035. The Companies recognize as the industry continues to move forward, coal fuel security and regulatory risk grows. For this reason, the Companies limited the latest retirement of Belews Creek to end of the year 2035, two years ahead of its depreciable life. The Public Staff also recognizes this fact of increased fuel security risk in the industry but concern that the latest available retirement date of Belews Creek in 2035 used in the Carbon Plan coincides with an arbitrary internal Duke Energy target to cease coal generation by 2035.

While the Public Staff recommended in their comments to eliminate coal operation at Belews Creek in 2035, consistent with the Companies' goal, but to allow the station to continue to operate on natural gas through its depreciable life. The units are currently able to generate up to 50% of their rated capacity on natural gas. The Public Staff's recommendation to allow the units to cease coal operations and operate exclusively on natural gas, however, did not originally consider the need for a firm fuel supply for this capacity. Ceasing coal operations at the site means the unit would rely solely on natural gas for firm capacity of the units. While the units are capable of operating up to 50% of rate capacity on natural gas, the Companies do not have enough interstate transportation to supply these units with firm fuel, leaving their capacity subject to potentially constrained supply at Transco Zone 5 delivered. Other natural gas units of the Companies' that do not have firm fuel supply are equipped with backup fuel supply to ensure the capacity of resource if natural gas supply were to be constrained at Transco Zone 5 delivered. For the Companies' existing CCs and CTs, this backup fuel is ultra-low sulfur diesel (ULSD). For the dual fuel optionality (DFO) coal units, such as Marshall and Belews Creek, this backup fuel is coal. The first supply of coal sitting in the coal yards at these sites provides assurance that their capacity can be counted from a fuel supply perspective, in case the units had to operate without access to natural gas supply.

In summary, removing the coal operations at Belews Creek would not result in 50% of firm capacity contribution, but constitute an energy only resource, with ability to generate year around, but whose capacity could not be counted as firm and would therefore need to be replaced regardless. For this reason, the Companies compromised for the purposes of the Supplemental Portfolio analysis, to allow for this analysis that Belews Creek could continue to run through 2037, consistent with its depreciable lives, operating on both coal and natural gas to ensure firm capacity of the resources, while extending the timeline for additional resources to be brought onto the system. The Companies continue to caveat this risk, that fuel security remains an issue and an orderly exit from coal may require 2035 or earlier retirement of Belews Creek.

3. SPS Battery Dispatch Optimization and Available SPS Battery Configurations

In response to multiple intervenors, to include more detailed and granular operation of solar paired with storage (SPS), the Companies deployed revised storage modeling in the Supplemental Portfolio analysis. The Companies modeling of SPS in the Carbon plan consisted of two SPS configurations. The solar asset included in each SPS configuration had an inverter loading ratio (ILR) of 1.6, while standalone solar had an ILR of 1.4. Also generally referred to as "over paneling" or "DC / AC ratio," ILR represents the ratio of installed DC capacity to the inverter's AC power rating. Therefore a 1.6 ILR on a 75 MW AC inverter limited solar site would have 120 MW DC of Solar capacity at the site. This over paneling of solar sites helps maximize energy output in the shoulder hours when higher cost energy is on the margin, and in the case of solar plus storage, the excess energy that would be "clipped" by the inverter can be captured in batteries and then discharged when the system needs it the most.

The Carbon Plan's modeling of solar plus storage used a fixed generation profile developed by the Companies to optimize the generation profile of the SPS site based on the nine premium-peak, on-peak, and off-peak energy hours defined in the 2020 Sub 167 avoided cost proceedings. The Companies model optimized the dispatch of the hybrid resource based on the DC solar profile, the size of the storage asset and the avoided cost peak periods to maximize value of the SPS system. This has been a reasonable assumption in the past. However, as pointed out by intervenors, with the rapid transformation of the system projected in the Carbon Plan may result in a disconnect between the dispatch of the solar plus storage site and the needs of the system.

For this reason, the Companies have implemented model functionality for the Supplemental Portfolio analysis to allow the Encompass model to optimize the charging and discharging of the resource to best meet system needs. The SPS resource continues to be charged by the paired solar asset exclusively, based on limitations of the model and the storage resource eligibility to qualify for the ITC.

Additionally, the Companies have included in the Supplemental Portfolios, at the recommendation of intervenors, an additional SPS configuration that included a larger battery than those assumed in the Carbon Plan. In addition to the 20 MW / 80 MWh battery (25% battery to solar ratio with 4-hr battery duration) and 40 MW / 80 MWh battery (50% battery to solar ratio with 2-hr battery duration), the Companies have included a 40 MW / 160 MWh battery option paired with solar. To help simplify the modeling, the Companies and the Public Staff agreed to use a single solar transmission cost adder for all solar units. The change from using different solar transmission cost adders based on in service year to using an average used for solar in all years in the Carbon Plan, acknowledges that this cost differential likely had little impact on the selection of solar over time.

While there are nearly infinite combinations and permutations of solar paired with storage, the three SPS configurations included in the Supplemental Portfolios capture a reasonable number of configurations for planning purposes. More precise optimization of combinations is best evaluated in the procurement execution phase of the process.

Finally, in the Carbon Plan modeling, the selection of SPS and standalone batteries did not impact the others effective load carrying capabilities ("ELCC" or "Capacity Value"). In reality, the more short-duration storage added to the system, the less each incremental block is able to contribute to meeting system peak as an energy limited resource. With the revised modeling of SPS, the Companies were now able to capture the cumulative impact of short duration storage on the system, both paired with solar and standalone, with respect to its capacity value to the system.

Optimization of storage is computationally intensive in capacity expansion and production cost models. The Companies recognize this as a more accurate depiction of the usage of SPS, but the Companies will continue to evaluate ways to decrease model run time, while also capturing general value of SPS to the system.

4. Cumulative Limits of 4-Storage and 6-hr Storage

The Companies, in an effort to recognize the rapidly declining value of short duration storage, limited the amount of 4-hr and 6-hr storage on the system in the development of the Carbon Plan portfolios. As identified by the Public Staff and other intervenors, short duration storage, despite is declining capacity value at higher penetrations may still be able to provide value to the system with its ability to shift energy from lower cost energy from one period to higher cost energy periods, perhaps being able to overcome the decreased capacity value ascribed. The Companies recognize this possibility, and accordingly have allowed 4-hr and 6-hr battery to be selected across their entire ELCC curves, including down to essentially no capacity value, resulting in energy only resources.

5. Removal of Hydrogen as Fuel

Due to concerns from intervenors on the uncertainty of cost and overall development of a clean hydrogen market and hydrogen production overall, the Supplemental Portfolio analysis removes hydrogen as a fuel. Removing this fuel includes removing the fuel being blended into natural gas supply beginning in 2035 as assumed in the Carbon Plan portfolio. This assumption change removed the cost and CO2 impacts of hydrogen being used to fuel all natural gas units on the system. Additionally, the Companies have also removed the conversion costs associated with converting existing and new natural gas resources built before 2040, to operate exclusively on hydrogen by 2050. These units are now assumed to operate throughout the planning horizon on natural gas exclusively.

Hydrogen as a standalone fuel, stating in 2040 has also been removed for this analysis. These peaking CT resources, in the Carbon Plan modeling, were assumed to be built and operate exclusively on hydrogen fuel. This assumption generally represented a placeholder for future technology such as long duration storage or other zero emitting, load following resources (ZELFRs) options. Peaking CT resources could still be selected by the capacity expansion model in the Supplemental Portfolios in the 2040s but would operate exclusively on natural gas.

As a result of removing hydrogen fuel from the portfolios, and as agreed upon by Public Staff, the Companies modeled net zero (95% reduction) CO2 emissions by 2050, rather than the absolute zero goal used in the Carbon Plan modeling. The Companies utilized the same system mass cap approach used in the Carbon Plan modeling, but once reductions reached 5% or less, the Companies held this level flat through 2050. While not factored into the optimization of the portfolio of resources or simulation of the system, a $210/short ton of CO_2 emitted cost was applied to CO_2 emissions in 2050 in the present value of revenue requirements. As part of the Portfolio Verification steps, the Companies verified that the portfolio in fact achieved 5% or less emissions of CO_2 compared to their 2005 baseline, as established in Appendix A of the Carbon Plan.

The Companies believe this to be a bounding assumption. It is highly unlikely that hydrogen will play no role in transformation of the energy system over the next three decades and therefore this extraordinarily conservative assumption is to simply determine if CC and CT resources would still be selected regardless of the degree of development of hydrogen play in the future. This fuel source and its ability to be used for power generation should continue to be viewed as an important factor in long-term reliability of the system and as critical to executing a least-cost plan in achieving the 2050 goal.

6. Natural Gas Supply

As stated above in Section II. Scope, the Companies have run each of the two portfolio development scenarios (compliance with interim reduction target in 2032 and 2034 using the assumptions outlined in the Supplemental Portfolio analysis) in both the Companies primary fuel supply scenario from the Carbon Plan and in the Public Staff's primary fuel supply assumption. The Public Staff's primary fuel supply assumption envisions the Companies securing firm transportation ("FT") service of fuel supply for the remaining existing CC on the Companies' fleet, which do not already have firm natural gas fuel supply, through a Transco expansion project assuming Zone 4 pricing of natural gas. Additionally, the Staff's fuel supply assumption also allows for incremental capacity of FT for approximately 2,400 MW of new CC capacity. The Companies primary fuel supply assumption remains consistent to the Carbon Plan modeling, with the equivalent amount of incremental Appalachian gas supply as assumed in the Public Staff's recommend natural gas fuel supply scenario from Transco Zone 4.

The Companies assumed in the alternate fuel supply scenario in the Carbon Plan that incremental natural gas supply would be limited, and the Companies would not be able procure incremental FT for new CC units. The Companies also assumed that because of the lack of additional incremental supply and overall supply diversity, that CC capacity should be limited to 800 MW and would have to assume operations on ULSD in January due to continued constrained supply at Transco Zone 5 delivered. This is consistent with the treatment of peaking resources in the Carbon Plan modeling, assuring firm capacity through ULSD backup fuel. As a result of slightly relieving this constraint in their recommended gas assumption, the Public Staffs gas supply assumes operation of all CC units exclusively on natural gas throughout the planning horizon.

One final change with respect to fuel supply is the limiting the operation of CT to USLD backup from the entire month of January to only a two-week period in January. During these two weeks, to recognized and acknowledge potential price volatility and supply constraints at Transco Zone 5 delivered, these units operate exclusive on ULSD. However, during the remainder of the month, and throughout the rest of the year, these units operate exclusively on natural gas.

7. Natural Gas Resources

The Supplemental Portfolio analysis retains 35-year book life of assets, while removing associated hydrogen conversion costs from existing and future resources expected to be on the system by

2050. Because hydrogen conversion is not a consideration in these portfolios, the Companies have adjusted the price and operation from the J-Class peaking CT from one assuming a selective catalytic reducer ("SCR"), to one assuming no SCR. The incremental cost and constraints on operations for these units are more necessary if the CT is expected to need the SCR environmental equipment to lower NOx rates, especially in the case that the CT unit is expected to burn hydrogen in the future. This assumption update represents a cost saving for customers on equipment that is not necessary to the reliable operation of the unit into the future.

Additionally, responsive to multiple intervenors, the Companies have allowed the selection of both F-Class and J-Class CCs and CTs. F-class combustion units generally are smaller and less efficient though more widely deployed today as compared to J-Class units. J-Class combustion units are generally large and more efficient representing advanced turbine technology. The Companies collaboration with Siemens Energy on Lincoln represents a first-of-its-kind deployment of this industry-leading advanced turbine technology. The Supplemental Portfolio analysis allows for the selection among all of these resources, whereas, the Companies only allowed J-Class units in the Company's primary fuel supply scenario, and J-Class CTs and F-Class CCs (for sizing purposes representing a smaller exposure to fuel supply constraints) in the Companies alternative fuel supply scenario.

8. Energy Hurdle Rate

The Public Staff identified in their comments a growing concern over rate disparity between DEP and DEC. According to their comments, this rate disparity is exacerbated in the Carbon Plan modeling failing to adequately represent the true nature and cost of electric utility service. In the Carbon Plan, abundant amounts of renewable resources are integrated into the DEP service territory, with access to offshore wind and higher capacity factor solar and generally lacks existing storage capacity. Due to this modeling result, accompanied with DEC utilizing the Joint Dispatch Agreement ("JDA") to buy over 10% of their annual energy from DEP, DEP is incurring the cost for these resources and based on the analysis of the Public Staff, not being fairly compensated by the JDA for the investment they are making to jointly serve the energy needs of the combined system.[3]

To influence the capacity expansion model to select resources into the service territories in which they are being utilized, the Public Staff has recommended applying an energy hurdle rate to JDA transfers. This hurdle rate would be an additional marginal dispatch cost differential between DEP and DEC that would need to be overcome before transferring energy across the JDA. As a proxy, the Public Staff has recommended using the Open Access Transmission Tariff ("OATT") non-firm transmission service rate. This recommended hurdle rate would not be a real cost incurred by or paid to either of the utilities, but merely a threshold at which the cost disparity would need to reach before the JDA would be used.

The Companies recognize these are not real costs that could or should be applied to either utility as the non-firm transmission service used to execute the JDA has a no "pancaking" provision which would preclude this additional cost for transmission. However, the hurdle cost in modeling

[3] Public Staff Comments at 96-98.

may influence new resources to rather be selected by DEC rather than selected by DEP and utilize the JDA for serving DEC's load.

B. Supplemental Portfolio Analysis Sensitivity Assumptions

The Supplemental Portfolio analysis includes two sensitivities which are performed from Supplemental Portfolio 5 (no App gas). The parameters for the assumption changes are further described below.

1. Low UEE Load Sensitivity

The Companies used a 1% of available load UEE forecast as a base assumption in the Carbon Plan. This means that UEE grows at a minimum of 1% of annual retail load, net of larger commercial and industrial customers who have opted out of participation in utility sponsored efficiency programs. This methodology yields a higher UEE forecast, particularly in later years, than the standard IRP UEE base case and results in a lower net load forecast. The Companies' base UEE forecasts, such as the UEE forecast used in the Companies' 2020 IRPs, are a blend of near-term program projections transitioning in later years to the achievable potential quantified in a Market Potential Study specific to the Companies service territories. The 1% of available retail load represents an aspirational goal of the Companies through ongoing engagement with the EE Collaborative.

The Public Staff recommended the Carbon Plan's Low UEE forecast be used as a base assumption for the Supplemental Portfolio analysis. After discussion, the Public Staff agreed to use of the Companies' base load forecast, with the use of the 1% of available retail load UEE assumption, as the base load forecast for the Supplemental Portfolio analysis and to conduct a sensitivity for Low EE off the SP5 (no App gas). The Companies have completed this sensitivity and resource selection impacts of this sensitivity are summarized in the results section of this analysis.

2. High Solar Interconnection Sensitivity

The selection of solar in the Carbon Plan portfolios often hit their annual selection limit. Physical constraints exist limiting the Companies' ability to interconnect solar at higher rates than the limits imposed on the Carbon Plan model, as discussed in Carbon Plan Appendix I (Solar). However, to analyze the impacts on achieving the emissions reduction targets if the Companies were able to interconnect more solar capacity each year, the Companies performed a High Solar Interconnection Sensitivity. The High Solar Interconnection sensitivity was performed for informational modeling purposes and the Companies' July 28 update letter explained that the Companies continue to believe that the very aggressive solar volumes proposed by CPSA are not executable in terms of achieving annual solar generator interconnections.

Below is a comparison table of the Companies' base solar selection limits used in P2 through P4 and $P2_A$ through $P4_A$, and the high solar selection limits, increasing risk of creating an un-executable plan, but necessary for achieving the interim emission reduction targets by 2030, used in Portfolio 1 and Portfolio 1_A in the Carbon Plan. Additionally, the solar selection limits used in the Supplemental Portfolio 5-High Solar Interconnection Sensitivity.

Table SPA-2: Solar Interconnection Limits by Portfolios

	Portfolios 2-4, Supplemental Portfolios 5-6	Portfolio 1	Supplemental Portfolio 5-High Solar Sensitivity
2023	0	0	0
2024	0	0	0
2025	0	0	0
2026	0	0	0
2027	750	750	1,500
2028	1,050	1,050	1,500
2029	1,350	1,800	1,800
2030	1,350	1,800	1,800
2031	1,350	1,800	1,800
2032+	1,350	1,800	1,800

The dates used in the table above reflect a beginning of year basis, meaning resources are selected at the end of the previous year, for the full calendar year listed. The increased solar selection limits allow for up to 3 GW of additional solar by 2032 over the base Supplemental Portfolio 5.

The Companies have completed this sensitivity and resource selection impacts of this sensitivity are summarized in the results section of this Supplemental Portfolio analysis.

IV. Additional Post Carbon Plan Filling Modeling Updates

Additionally, the Companies have identified a limited number of input assumptions or modeling updates that were appropriate to incorporate into the Supplemental Portfolio analysis.

A. Update to EnCompass Version 6.1.3

For the modeling of the Carbon Plan, the Companies used the EnCompass capacity expansion and production cost simulation software package from Anchor Power Solutions. This is the first filing in which the Companies have used the EnCompass model to model resource selection and detailed system simulations for resource planning purposes. While the new model offers several enhancements over previous tools that are no longer supported by the vendor, the Companies are still learning the intricacies of the model, especially with respect to sharing modeling inputs and results with intervening parties.

Several issues identified by intervenors in their modeling of the Companies' system have been addressed in version 6.1.3, including a bug in version 6.0.4 that resulted in issues with exporting datasets, resulting in unexpected run failures by the intervenors attempting to recreate the Companies' modeling results.

B. Declining Capital Cost Modeling for Emerging Resources

As described in the "EnCompass Input Data: Declining Cost Adder Issue and Resolution" briefing to the Commission, the Companies discovered an issue with how the EnCompass model handles certain costs that were being used to reflect the declining cost of emerging technologies. The cost inputs the Companies were utilizing to account for this cost decline was not being recognized or factored into the economic selection decisions of the capacity expansion model. Resources such as offshore wind, solar, and battery technologies are expected to experience price declines over the next decade in the Companies' capital cost forecast for these resources. To account for different near-term and long-term inflation rates (or a short-term deflation rate and long-term inflation rate), the Companies input long-term cost trajectories and then account for near-term deflation using cost adders. The issue identified resulted in the underestimation of the costs of these resources in the selection of resources in the capacity expansion model.

As a resolution, the Companies worked with Anchor Power Solutions and was able to identify an alternative input parameter to use to correctly capture these costs and factor the near-term cost decline into the selection of the resources. The Companies performed preliminary diagnostic runs to show that the selection of resources would not be materially impacted with this change. This change resulted in minor shifts between solar and standalone battery and solar paired with battery, but overall, the materiality of the Final Carbon Plan portfolios was not affected.

Knowing that intervenors would be using this data to conduct their own modeling and, in an attempt, to avoid for intervenors the same modeling issue the Companies encountered, the Companies included this fix in the modeling files made available to intervenors. Upon filing their alternative modeling input parameters, the Companies uploaded to the data site modeling files that included the fix needed to account for this resolution. Additionally, for the Supplemental Portfolio analysis, the Companies have implemented this resolution to capture these near-term cost declines on selectable resources.

C. Transmission Cost Adder

After filing the Carbon Plan, it was discovered that the fixed charge rate used to develop transmission cost adders factored into the cost of new resources, was understated. The Companies have corrected the fixed charge rate for transmission assets, which more accurately reflects the cost of an asset over its projected life. The original misrepresentation of the annual real levelized costs impacted all new resources equivalently, so while the costs were lower, they are lower for all generation resources.

D. New Nuclear Maintenance Rates

With continued use of the EnCompass model and engagement with Anchor Power Solutions, after filing the Carbon Plan, the Companies identified a modeling bug dealing with new nuclear units' maintenance rates. The Companies input maintenance rates for nuclear with discrete number of days on maintenance. This modeling bug resulted in a reduced ability for new nuclear to reliably serve load needs by taking all of the new nuclear offline at the same time. This was particularly impactful at the end of the planning horizon with the retirement of the majority of the Companies' existing natural gas fleet. The revised input change, changing from a discrete number of maintenance days to a maintenance rate, allowed nuclear units to capture dispersed maintenance outages more closely reflecting real-world maintenance activities. This update overall reduced the need for the Companies to add additional resources late in the period to meet the energy needs of the system.

E. Solar paired with Storage Fixed O&M

In reviewing the solar paired with storage (SPS) inputs to integrate an additional configuration for the Supplemental Portfolio analysis, as detailed in Section III. A. 3., the Companies discovered that fixed operations and maintenance (FOM) rates for SPS sites had been improperly reflected in the model. This correction resulted in a lower FOM rate for all SPS resources.

F. Degradation of New Solar Output

Solar resources are expected to lose output over time due to degradation of solar panels. This degradation results in the loss of about 0.5% energy output annually. To capture this degradation, the Companies have corrected the output profile for solar paired with storage to account for this degradation.

Reviewing the additions of solar in the Carbon Plan, by 2050, the average life of a unit on the Companies' system is approximately 15 years old. To correct for the degradation factor, the Companies have simulated what this degradation would look like over this average 15-year time frame for a solar unit. The Companies then averaged the annual output over that 15-year time frame to come up with a solar generation profile that approximates this degradation.

This was applied to both new standalone solar and new solar paired with storage for the Supplemental Portfolio analysis. This correction allows both new and existing solar to more accurately factor degradation into the energy they provide to the system.

V. Portfolio Development

A. Preliminary Capacity Expansion and Portfolio Verification

The Companies developed the 2032 and 2034 Compliance year portfolios, SP5 and SP6, with the same approach to the Carbon Plan portfolios. The Companies ran a preliminary capacity run for each portfolio, where the initial selection of resources was selected by the EnCompass model. The Companies then conducted the Portfolio Verification process including the Battery-CT Optimization, Overall Portfolio Reliability and 2050 CO2 Reduction Verification, and the Portfolio LOLE and Resource Adequacy Validation modeling; crucial steps to ensuring low cost and reliable portfolios. Overall, the portfolios required only minor resource adjustments. Due to, in part, the revised input change to new nuclear units' maintenance rates, no Portfolio Reliability and CO2 Reduction Requirement Resources were required to meet the energy and CO2 reduction needs of the system for 2050. Additionally, the portfolios each passed the 2030 and 2035 LOLE validation steps, requiring no additional peaking CT resources in these timeframes to maintain the reliability standard of the system. Finally, due to the revised SPS modeling technique, the Companies Battery-CT economic evaluation including verifying the SPS selection compared to standalone solar and CTs. Below are the results of the economic replacements in this step for Supplemental Portfolios 5 and 6.

Table SPA-3: Battery-CT Optimization Results through 2050 [Nameplate MW]

	Supplemental Portfolio 5 (No App gas)	Supplemental Portfolio 6 (no App gas)	Supplemental Portfolio 5 (with Limited App gas)	Supplemental Portfolio 6 (with Limited App gas)
Standalone 4-hr Battery Capacity Removed	0	0	0	0
SPS (4-hr, 50% battery to solar ratio) Capacity Removed	1,350	675	1,350	1,350
SPS (4-hr, 25% battery to solar ratio) Capacity Removed	0	0	0	0
Standalone Solar Capacity Added	1,350	675	1,350	1,350
CT Capacity Added	704	352	704	704

Of note, Supplemental Portfolio 6 (No App Gas), resulted in the selection of very few standalone batteries and SPS-50% battery-to-solar ratio, 4-hr batteries in DEP in the near term. The Companies therefore replaced the remaining SPS-25% battery-to-solar ratio, 4-hr batteries with CTs and conducted the economic evaluation. These batteries were found to not be economic to replace. When this portfolio was further evaluated for portfolio reliability, the LOLE benchmark in 2035 was only barely met, achieving a 0.248 event-days per year LOLE against the 0.253 event-days per year LOLE threshold. The other portfolios, which all included more economic battery CT replacements, resulted in lower LOLEs. This points to evidence, that some of these peaking resources may be necessary from a reliability perspective to ensure resource adequacy and reliability are maintained or improved, in accordance with HB 951.

B. Final Supplement Portfolios 5 and 6

The annual resource additions and coal retirements for DEC and DEP for each final Supplemental Portfolio are presented below in Table SPA-4 through Table SPA-11. Consistent with data presented in Appendix E, resource changes are effective as of the start of the year listed. The one exception is for the new, 2032 mid-year, SMR which is selected in all portfolios. This resource is selected mid-year 2032 and available for system capacity and generation for the second half of the year. Resource changes are included through 2038 consistent with the retirement of the last coal unit at the end of the year 2037. DEC Cliffside 6's capacity is reflected in the coal retirements column, as its coal capacity is retired in 2036, though the unit continues to operate on natural gas exclusively thereafter. Capacities in these tables below reflect nameplate capacity of resources including the forecasted solar and storage resources.

Table SPA-4: Supplemental Portfolio 5 (no App gas) - Final DEC Annual Resource Additions and Coal Retirements [MW]

	Coal Capacity Retirements	Standalone Solar	SPS	Onshore Wind	Standalone Battery	Battery Paired with Solar	CC	CT	Offshore Wind	SMR	PSH
2024	-426	412	75	0	29	20	0	0	0	0	0
2025	0	290	40	0	53	11	0	0	0	0	0
2026	-546	586	60	0	31	16	0	0	0	0	0
2027	0	34	300	0	0	160	0	0	0	0	0
2028	0	34	450	0	0	240	0	0	0	0	0
2029	-760	34	0	0	0	0	1,216	0	0	0	0
2030	0	34	525	0	0	140	1,216	0	0	0	0
2031	0	559	0	0	0	0	0	352	0	0	0
2032	0	150	375	0	0	200	0	0	0	285	0
2033	-1,318	0	525	0	0	140	0	0	0	0	1,680
2034	0	0	0	0	0	0	0	0	0	0	0
2035	0	0	525	0	0	140	0	0	0	0	0
2036	-849	0	525	0	0	280	0	0	0	0	0
2037	0	0	525	0	0	280	0	0	0	285	0
2038	-2,220	0	450	300	0	240	0	0	0	500	0

Table SPA-5: Supplemental Portfolio 5 (No App Gas) - Final DEP Annual Resource Additions and Coal Retirements [MW]

	Coal Capacity Retirements	Standalone Solar	SPS	Onshore Wind	Standalone Battery	Battery Paired with Solar	CC	CT	Offshore Wind	SMR	PSH
2024	0	10	0	0	30	0	0	0	0	0	0
2025	0	120	0	0	155	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0
2027	0	110	375	0	28	200	0	0	0	0	0
2028	0	635	0	0	800	0	0	352	0	0	0
2029	-1,766	35	825	300	0	220	0	462	0	0	0
2030	0	35	825	300	0	220	0	0	0	0	0
2031	0	35	825	300	150	440	0	0	0	0	0
2032	0	0	825	300	950	420	0	0	0	0	0
2033	0	0	825	0	0	220	0	0	0	0	0
2034	-1,409	0	450	0	0	240	0	0	0	285	0
2035	0	0	825	0	0	220	0	0	0	0	0
2036	0	0	825	0	0	420	0	0	0	285	0
2037	0	0	825	0	0	220	0	0	0	0	0
2038	0	0	825	0	0	440	0	0	0	0	0

Table SPA-6: Supplemental Portfolio 6 (no App gas) - Final DEC Annual Resource Additions and Coal Retirements [MW]

	Coal Capacity Retirements	Standalone Solar	SPS	Onshore Wind	Standalone Battery	Battery Paired with Solar	CC	CT	Offshore Wind	SMR	PSH
2024	-426	412	75	0	29	20	0	0	0	0	0
2025	0	290	40	0	53	11	0	0	0	0	0
2026	-546	586	60	0	31	16	0	0	0	0	0
2027	0	259	75	0	0	20	0	0	0	0	0
2028	0	34	450	0	0	120	0	0	0	0	0
2029	-760	34	0	0	0	0	0	0	0	0	0
2030	0	34	0	150	0	0	1,216	0	0	0	0
2031	0	559	0	0	0	0	0	352	0	0	0
2032	0	150	375	0	0	200	0	0	0	285	0
2033	-1,318	0	150	0	0	80	0	0	0	0	1,680
2034	0	0	0	0	0	0	0	0	0	0	0
2035	0	0	525	0	0	280	0	0	0	0	0
2036	-849	0	525	0	0	280	0	0	0	285	0
2037	0	0	525	0	0	280	0	0	0	285	0
2038	-2,220	0	525	300	200	280	0	0	0	500	0

Table SPA-7: Supplemental Portfolio 6 (no App Gas) - Final DEP Annual Resource Additions and Coal Retirements [MW]

	Coal Capacity Retirements	Standalone Solar	SPS	Onshore Wind	Standalone Battery	Battery Paired with Solar	CC	CT	Offshore Wind	SMR	PSH
2024	0	10	0	0	30	0	0	0	0	0	0
2025	0	120	0	0	155	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0
2027	0	35	450	0	28	120	0	0	0	0	0
2028	0	110	525	0	0	140	0	0	0	0	0
2029	-1,766	35	450	300	0	120	1,216	0	0	0	0
2030	0	35	825	150	0	220	0	0	0	0	0
2031	0	35	825	300	0	220	0	0	0	0	0
2032	0	0	825	300	0	320	0	0	0	0	0
2033	0	0	675	150	0	200	0	0	0	0	0
2034	-1,409	0	675	0	550	360	0	0	0	0	0
2035	0	0	225	0	0	60	0	0	0	285	0
2036	0	0	825	0	0	440	0	0	0	0	0
2037	0	0	825	0	50	440	0	0	0	0	0
2038	0	0	525	0	0	280	0	352	0	0	0

Table SPA-8: Supplemental Portfolio 5 (with Limited App gas) - Final DEC Annual Resource Additions and Coal Retirements [MW]

	Coal Capacity Retirements	Standalone Solar	SPS	Onshore Wind	Standalone Battery	Battery Paired with Solar	CC	CT	Offshore Wind	SMR	PSH
2024	-426	412	75	0	29	20	0	0	0	0	0
2025	0	290	40	0	53	11	0	0	0	0	0
2026	-546	586	60	0	31	16	0	0	0	0	0
2027	0	34	300	0	0	160	0	0	0	0	0
2028	0	34	450	0	0	240	0	352	0	0	0
2029	-760	34	0	0	0	0	1,216	0	0	0	0
2030	0	34	525	0	0	140	0	0	0	0	0
2031	0	559	0	0	0	0	0	352	0	0	0
2032	0	150	375	0	0	200	0	0	0	285	0
2033	-1,318	0	525	0	0	280	0	0	0	0	1,680
2034	0	0	525	0	0	140	0	0	0	0	0
2035	0	0	525	0	0	160	0	0	0	285	0
2036	-849	0	525	0	0	280	0	0	0	285	0
2037	0	0	375	0	0	200	0	0	0	285	0
2038	-2,220	0	300	300	0	160	0	0	0	0	0

Table SPA-9: Supplemental Portfolio 5 (with Limited App gas) - Final DEP Annual Resource Additions and Coal Retirements [MW]

	Coal Capacity Retirements	Standalone Solar	SPS	Onshore Wind	Standalone Battery	Battery Paired with Solar	CC	CT	Offshore Wind	SMR	PSH
2024	0	10	0	0	30	0	0	0	0	0	0
2025	0	120	0	0	155	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0
2027	0	110	375	0	28	200	0	0	0	0	0
2028	0	635	0	0	500	0	0	352	0	0	0
2029	-1,766	35	825	300	0	220	1,216	0	0	0	0
2030	0	35	825	300	0	220	0	0	0	0	0
2031	0	35	825	300	350	440	0	0	0	0	0
2032	0	0	825	300	600	440	0	0	0	0	0
2033	0	0	825	0	0	220	0	0	0	0	0
2034	-1,409	0	300	0	0	80	0	0	0	0	0
2035	0	0	825	0	0	220	0	0	0	0	0
2036	0	0	825	0	0	440	0	0	0	0	0
2037	0	0	825	0	0	440	0	0	0	0	0
2038	0	0	825	0	0	440	0	0	0	500	0

Table SPA-10: Supplemental Portfolio 6 (with Limited App gas) - Final DEC Annual Resource Additions and Coal Retirements [MW]

	Coal Capacity Retirements	Standalone Solar	SPS	Onshore Wind	Standalone Battery	Battery Paired with Solar	CC	CT	Offshore Wind	SMR	PSH
2024	-426	412	75	0	29	20	0	0	0	0	0
2025	0	290	40	0	53	11	0	0	0	0	0
2026	-546	586	60	0	31	16	0	0	0	0	0
2027	0	334	0	0	0	0	0	0	0	0	0
2028	0	484	0	0	0	0	0	0	0	0	0
2029	-760	34	0	0	0	0	1,216	0	0	0	0
2030	0	34	375	0	0	100	0	0	0	0	0
2031	0	559	0	0	0	0	0	352	0	0	0
2032	0	150	375	0	0	200	0	0	0	285	0
2033	-1,318	0	525	0	0	280	0	0	0	0	1,680
2034	0	0	0	0	0	0	0	0	0	0	0
2035	0	0	0	0	0	0	0	0	0	285	0
2036	-849	0	525	0	0	280	0	0	0	285	0
2037	0	0	525	0	0	280	0	0	0	285	0
2038	-2,220	0	525	300	250	280	0	0	0	500	0

Table SPA-11: Supplemental Portfolio 6 (with Limited App gas) - Final DEP Annual Resource Additions and Coal Retirements [MW]

	Coal Capacity Retirements	Standalone Solar	SPS	Onshore Wind	Standalone Battery	Battery Paired with Solar	CC	CT	Offshore Wind	SMR	PSH
2024	0	10	0	0	30	0	0	0	0	0	0
2025	0	120	0	0	155	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0
2027	0	35	450	0	28	120	0	0	0	0	0
2028	0	35	600	0	0	160	0	0	0	0	0
2029	-1,766	35	0	300	0	0	1,216	462	0	0	0
2030	0	35	825	300	0	220	0	0	0	0	0
2031	0	710	150	300	0	60	0	352	0	0	0
2032	0	0	825	300	0	440	0	0	0	0	0
2033	0	0	600	0	0	160	0	0	0	0	0
2034	-1,409	0	675	0	100	260	0	0	0	0	0
2035	0	0	825	0	150	400	0	0	0	0	0
2036	0	0	825	0	0	440	0	0	0	0	0
2037	0	0	825	0	0	440	0	0	0	0	0
2038	0	0	750	0	0	400	0	352	0	0	0

Presented below in Table SPA-12 through Table SPA-14 is a summary of the final resource additions of each portfolio for the year the interim target is achieved, 2035, and 2050. For summary purposes, the solar capacity associated with solar and solar plus storage is grouped together. Similarly, all battery capacity (standalone battery and battery paired with solar) and, for the 2050 summary data, all new nuclear (SMR and Advanced Nuclear with Integrated Storage) additions are grouped together. Of note, the solar and battery capacities noted below represent incremental additions on top of the existing solar on the system at the start of the Carbon Plan. These additions include both forecasted solar and batteries over these time frames and the Carbon Plan economically selected solar (both standalone and pair with storage) and battery (both standalone and paired with solar). Additionally, capacity changes have been rounded for summary purposes and may not sum to data in the previous data presented in this section.

Table SPA-12: Final Resource Additions by Portfolio [MW] for year interim target is achieved

	Coal Retirements	New Solar[1]	Onshore Wind	Battery[2]	CC	CT	Offshore Wind	SMR	PSH
SP5 (2032)	-3,500	8,600	1,200	4,500	2,400	1,200	0	300	0
SP6 (2034)	-6,300	9,200	1,400	3,000	2,400	400	0	300	1,700
SP5$_A$ (2032)	-3,500	8,600	1,200	4,100	2,400	1,100	0	300	0
SP6$_A$ (2034)	-6,300	9,400	1,200	2,500	2,400	1,200	0	300	1,700

Note 1: Includes solar capacity both standalone and paired with battery.
Note 2: Includes battery capacity both standalone and paired with solar.

Table SPA-13: Final Resource Additions by Portfolio [MW] for 2035

	Coal Retirements	New Solar[1]	Onshore Wind	Battery[2]	CC	CT	Offshore Wind	SMR	PSH
SP5	-6,300	11,800	1,200	5,500	2,400	1,200	0	600	1,700
SP6	-6,300	10,000	1,400	3,400	2,400	400	0	600	1,700
SP5$_A$	-6,300	12,100	1,200	5,200	2,400	1,100	0	600	1,700
SP6$_A$	-6,300	10,300	1,200	3,000	2,400	1,200	0	600	1,700

Note 1: Includes solar capacity both standalone and paired with battery.
Note 2: Includes battery capacity both standalone and paired with solar.

Table SPA-14: Final Resource Additions by Portfolio [MW] for 2050

	Coal Retirements	New Solar[1]	Onshore Wind	Battery[2]	CC	CT	Offshore Wind	New Nuclear[3]	PSH
SP5	-9,300	22,800	1,800	13,900	2,400	8,800	1,600	9,000	1,700
SP6	-9,300	21,700	1,800	12,700	2,400	8,200	2,400	9,000	1,700
$SP5_A$	-9,300	22,900	1,800	13,700	2,400	8,700	1,600	9,000	1,700
$SP6_A$	-9,300	22,600	1,800	14,100	2,400	8,800	1,600	9,000	1,700

Note 1: Includes solar capacity both standalone and paired with battery.
Note 2: Includes battery capacity both standalone and paired with solar.
Note 3: Includes SMR and advanced nuclear with integrated storage.

VI. Portfolio Analysis

A. General Findings

Overall, the selection of resources in the Supplemental Portfolios supports the near-term execution plan presented by the Companies in the Carbon Plan. Each portfolio continues to add significant levels of solar by the compliance year, ranging from 8.6 GW in the 2032 emissions reduction achievement year scenarios up to 9.4 GW in the 2034 emissions reduction achievement year scenarios. The significant solar additions are further supported by the selection of substantial quantities of storage, both standalone and paired with solar. Additionally, the inclusion of onshore wind continues to be supported by the Supplemental Portfolio analysis, selecting at least 1.2 GW in all portfolios for achievement of the emissions reduction targets. To further support these variable energy and energy limited resources, and help replace retiring existing coal and gas, both CCs and CTs are economically included in each of the portfolios. The capacity expansion model, in both fuel supply scenarios and compliance year targets scenarios, identified the two eligible CCs to be economic and compatible with the net zero 2050 target. The CTs were identified both in the capacity expansion step and in the economic evaluation of batteries and CTs step for inclusion in the portfolios.

While no offshore wind is selected for compliance with the interim emissions reduction target, the resource is selected in all portfolios in the Supplemental Portfolio analysis, re-emphasizing the benefits of resource diversity in achieving the 2050 goal. Furthermore, the first SMR is selected in all portfolios as soon as it is available, in mid-year 2032 for the Supplemental Portfolio analysis. By the end of 2036, the first four SMR units continue to be selected, on pace with the availability of the resources through that time frame. Pumped storage continues to provide significant capacity and energy arbitrage benefits to the system when implemented.

The resource selections in the Supplemental Portfolio analysis were certainly impacted by the assumption and modeling changes integrated into the analysis. However, these differences mainly manifest as shifts between standalone solar and battery and solar paired with battery. Without the assumption of hydrogen but allowing the system to plan to a 95% reduction in 2050, assuming the rest is met with offsets, allowed for the economic selection of CCs and CTs, which over time are used increasing less, primarily for system flexibility and back-standing renewables. Finally, improvements to the modeling, such as upgrading to EnCompass Version 6.1.3 and resolving new nuclear maintenance rate issues, allowed for less adjustments in these Supplemental Portfolios.

B. CO2 Emissions Reductions

Below, Table SPA-15 shows the CO2 reduction percentage with respect to meeting the HB 951 CO2 emissions reductions targets and for the combined DEC and DEP systems relative to the 2005 baseline.

Table SPA-15: Annual HB 951 CO2 Emissions Reduction in 2030, the Portfolios Interim Target Year, 2035 and 2050 [Percent reduction relative to 2005]

	2030	Portfolio Targeted Compliance Year	2035	2050
SP5	65%	71%	77%	95%
SP6	63%	71%	74%	95%
$SP5_A$	65%	70%	77%	95%
$SP6_A$	63%	72%	74%	95%

Each of the Portfolios achieves the interim emissions reductions goals by the targeted compliance year. Additionally, each portfolio achieves 95% emissions reductions by 2050, consistent with net-zero goal using up to 5% carbon offsets. As expected, the 2032 compliance portfolios have slightly more aggressive emission reductions by 2030 and 2035, and throughout the planning horizon resulting in overall lower cumulative CO2 emissions through 2050. Because the overall resources do not vary much across each of these portfolios, the timing of resources, based on the targeted interim emissions reduction year, accounts for the majority of the differences in emissions over the planning horizon.

C. Present Value of Revenue Requirement

Shown below in Tables SPA-16 and SPA-17 are the cumulative present value of revenue requirements of each of the Supplemental Portfolios. Annual revenue requirements are discounted to present value at DEC's and DEP's Company specific discount rate. A combined DEC and DEP PVRR is also shown.

Table SPA-16: Present Value of Revenue Requirements through 2050 [2022, $B] – Supplemental Portfolio Analysis (no App gas)

	DEC	DEP	DEC + DEP
SP5	$57.3	$44.4	$101.7
SP6	$56.1	$42.2	$98.4

Table SPA-17: Present Value of Revenue Requirements through 2050 [2022, $B] - Supplemental Portfolio Analysis (with limited App gas)

	DEC	DEP	DEC + DEP
SP5	$55.6	$42.2	$97.8
SP6	$54.8	$39.9	$94.7

The PVRRs calculated above are consistent with how the system costs were developed for the Carbon Plan. Table SPA-16 shows the PVRRs for Supplemental Portfolios 5 and 6, which are developed in and dispatched in the Public Staff's recommended no Appalachian Gas assumption. Table SPA-17 shows the PVRRs for Supplemental Portfolios 5_A and 6_A, which are developed in and dispatched in the Companies' primary fuel supply scenario which assumes limited access to Appalachian Gas. Each of these portfolios include the assumed cost of carbon offsets as described in Section III. A. 5. for CO2 emissions in 2050 to comply with HB951 carbon neutrality goal.

Due to the variety of assumption and modeling changes in the Supplemental Portfolio analysis, these costs should not be used as direct comparisons to compare the Carbon Plan Portfolios presented in the Carbon Plan. However, it is appropriate to continue to compare SP5 to SP6 and $SP5_A$ to $SP6_A$. These cost differentials represent the cost trade off, in addition to increased executability, for allowing additional time and resources to contribute to the interim emissions reduction target achievement.

D. Customer Bill Impacts

1. Supplemental Portfolio Analysis – "No App Gas" Fuel Supply Scenario

Below, Table SPA-18 through Table SPA-21 show the projected changes to a typical residential customer's bill for the "no App gas" Supplemental Portfolios through 2030 and 2035. Additionally, the projected average annual percentage change from 2023 through 2030 and through 2035 is also shown representing how much a customer's bill would increase on average annual basis over that time frame. The costs reflected in these bill impacts are consistent with the parameters to evaluate the CO2 reductions of the system and development of the PVRRs.

Table SPA-18: DEC Cumulative Residential Bill Impacts [$/Month] through 2030 and 2035 – Supplemental Portfolio (no App Gas)

	2030	2035
SP5	$17	$33
SP6	$12	$31

Table SPA-19: DEC Annual Average Residential Bill Impacts [%] through 2030 and 2035 – Supplemental Portfolio (no App Gas)

	2030	2035
SP5	2.1%	2.2%
SP6	1.5%	2.1%

Table SPA-20: DEP Cumulative Residential Bill Impacts [$/Month] through 2030 and 2035 – Supplemental Portfolio (no App Gas)

	2030	2035
SP5	$20	$42
SP6	$18	$33

Table SPA-21: DEP Annual Average Residential Bill Impacts [%] through 2030 and 2035 – Supplemental Portfolio (no App Gas)

	2030	2035
SP5	2.4%	2.9%
SP6	2.1%	2.4%

2. <u>Supplemental Portfolio Analysis – "with Limited App Gas" Fuel Supply Scenario</u>

Below, Table SPA-22 through Table SPA-25 show the projected changes to a typical residential customer's bill for the "with limited Agg gas" Supplemental Portfolios through 2030 and 2035. Additionally, the projected average annual percentage change from 2023 through 2030 and through 2035 is also shown representing how much a customer's bill would increase on average annual basis over that time frame. The costs reflected in these bill impacts are consistent with the parameters to evaluate the CO2 reductions of the system and development of the PVRRs.

Table SPA-22: DEC Cumulative Residential Bill Impacts [$/Month] through 2030 and 2035 – Supplemental Portfolio (with Limited App Gas)

	2030	2035
$SP5_A$	$6	$30
$SP6_A$	$4	$26

Table SPA-23: DEC Annual Average Residential Bill Impacts [%] through 2030 and 2035 – Supplemental Portfolio (with Limited App Gas)

	2030	2035
$SP5_A$	0.8%	2.0%
$SP6_A$	0.6%	1.8%

Table SPA-24: DEP Cumulative Residential Bill Impacts [$/Month] through 2030 and 2035 – Supplemental Portfolio (with Limited App Gas)

	2030	2035
$SP5_A$	$24	$37
$SP6_A$	$19	$32

Table SPA-25: DEP Annual Average Residential Bill Impacts [%] through 2030 and 2035 – Supplemental Portfolio (with Limited App Gas)

	2030	2035
$SP5_A$	2.7%	2.6%
$SP6_A$	2.2%	2.2%

VII. Sensitivity Analyses

A. Low EE

The capacity expansion model's net resource changes in 2035 and 2050 from the Supplemental Portfolio 5 (no App gas) are presented below in Table SPA-26 for the Low EE sensitivity.

Table SPA-26: Low EE Load Sensitivity - Resource Changes from Supplemental Portfolio 5 (without App Gas) [MW]

	Coal	Solar	Onshore Wind	Battery	CC	CT	Offshore Wind	New Nuclear	PS
2035	0	+700	+200	+300	0	0	0	0	0
2050	0	+900	0	+200	0	-100	0	0	0

The low EE forecast results in a high load sensitivity requiring incrementally more resources to meet the energy and CO2 emissions reductions targets. Notably, by 2035 the sensitivity selects 700 MW more of solar, 200 MW more of onshore wind, and 300 MW more of battery, picking both more standalone battery and battery paired with solar to offset the higher load. By 2050 the Low EE sensitivity selects 900 MW of additional solar, 200 MW of additional battery, while slightly offsetting the need for small amount of CT capacity. Overall, the low EE sensitivity has little impact on peak winter load, which typically drives resource selection. The majority of the peak load impact in this sensitivity is realized in the summer when the system already has adequate reserves due to the significant amount of solar already on the system. These factors result in slightly more solar resources selected to offset incremental energy needs, while having little impact on peak load resource requirements above what is already selected in Supplemental Portfolio 5 (no App Gas).

B. High Solar Limit

The capacity expansion model's net resource changes in 2035 and 2050 from the Supplemental Portfolio 5 (no App gas) are presented below in Table SPA-27 for the High Solar Interconnection sensitivity.

Table SPA-27: High Solar Interconnection Sensitivity - Resource Changes from Supplemental Portfolio 5 (without App Gas) [MW]

	Coal	Solar	Onshore Wind	Battery	CC	CT	Offshore Wind	New Nuclear	PS
2035	0	+700	0	-700	0	-500	0	0	0
2050	0	+300	0	-100	0	-100	0	0	0

Allowing for higher solar selection limits overall increases the deployment of solar energy by 700 MW by 2035 and by just 300 MW by 2050. The capacity expansion model selects up to the raised limit in five of the first six year solar is eligible for selection ahead of the targeted compliance year. The system selects up to the 1,500 MW limit in both 2026 and 2027, while selecting 1,800 MW in every year leading up to compliance, with the exception of 2028 which coincides with the selection of the two natural gas combined cycles in that year.

The additional solar in the near-term allows the system to avoid building incremental batteries and CTs in DEP to maintain near-term reserve margin requirements. Instead, the portfolio selects more solar in both jurisdiction and selects a CC in DEP, rather than selecting two CC units in DEC in Supplemental Portfolio 5 (no App gas), to fill the remaining capacity needs created by the retirement of three of the Company's coal units in that time frame.

Overall, the additional solar limits had no impact on the net selection of onshore wind or new nuclear. The same amount of each resource was selected across the system by both 2035 and 2050. By 2050 there is little impact to overall resource selection with the 300 incremental MW of solar offsetting the need for a small number of batteries and CTs.

Figure 3: Carbon Plan Analytical Process Flow Chart

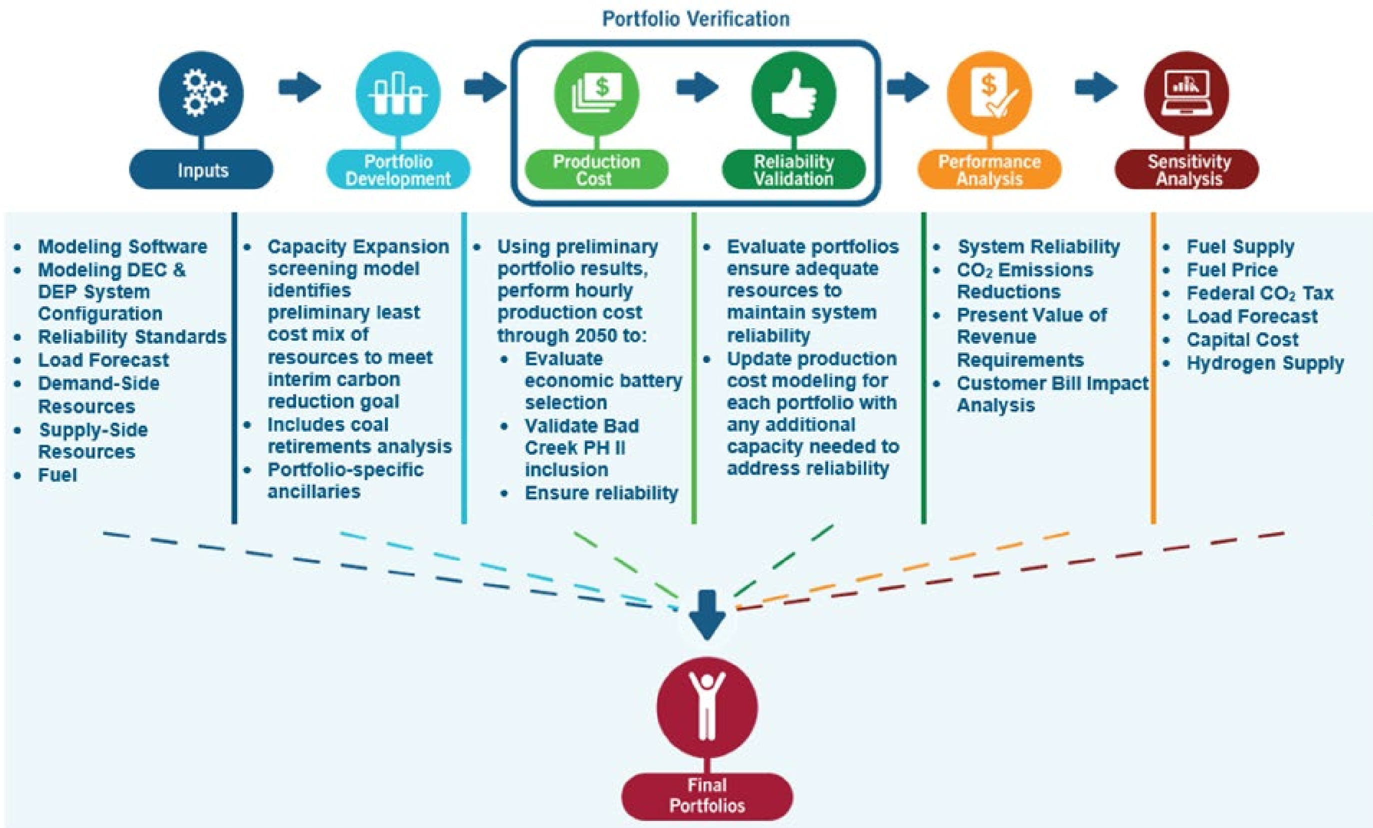


Figure 4: Portfolio Snapshot to Achieve 70% Interim Target (2030-2034)

<table>
<tr><th colspan="3">PORTFOLIOS</th><th>Grid Edge</th><th>Coal Retirements</th><th>New Solar</th><th>Battery</th><th>Onshore Wind</th><th>Offshore Wind</th><th>New Nuclear</th><th>New Pumped Storage</th><th>New CC</th><th>New CT</th></tr>
<tr><td>2030</td><td>P1</td><td>70% by 2030</td><td rowspan="4">EE 1% of eligible retail sales
IVVC growing to 96% (DEC) and 97% (DEP) circuits
Winter DR & CPP</td><td rowspan="2">(-4.9 GW)</td><td>5.4 GW</td><td>2.1 GW</td><td>0.6 GW</td><td>0.8 GW</td><td></td><td></td><td rowspan="4">2.4 GW</td><td rowspan="3">1.1 GW</td></tr>
<tr><td>2032</td><td>P2</td><td>70% 2032 OSW</td><td>5.6 GW</td><td>1.7 GW</td><td rowspan="3">1.2 GW</td><td>1.6 GW</td><td></td><td></td></tr>
<tr><td>2034</td><td>P3</td><td>70% 2034 SMR</td><td rowspan="2">(-6.2 GW)</td><td>7.7 GW</td><td>2.2 GW</td><td></td><td rowspan="2">0.3 GW</td><td rowspan="2">1.7 GW</td></tr>
<tr><td>2034</td><td>P4</td><td>70% 2034 OSW + SMR</td><td>6.8 GW</td><td>1.8 GW</td><td>0.8 GW</td><td>0.8 GW</td></tr>
</table>

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

Figure 5: Portfolio Snapshot in 2035

<table>
<tr><th colspan="3">PORTFOLIOS</th><th>Grid Edge</th><th>Coal Retirements</th><th>New Solar</th><th>Battery</th><th>Onshore Wind</th><th>Offshore Wind</th><th>New Nuclear</th><th>New Pumped Storage</th><th>New CC</th><th>New CT</th></tr>
<tr><td rowspan="4">Resources by 2035</td><td>P1</td><td>70% by 2030</td><td rowspan="4">EE 1% of eligible retail sales
IVVC growing to 96% (DEC) and 97% (DEP) circuits
Winter DR & CPP</td><td rowspan="4">(-6.2 GW)</td><td>11.9 GW</td><td>4.2 GW</td><td rowspan="4">1.2 GW</td><td>0.8 GW</td><td rowspan="4">0.6 GW</td><td rowspan="4">1.7 GW</td><td rowspan="4">2.4 GW</td><td rowspan="3">1.1 GW</td></tr>
<tr><td>P2</td><td>70% 2032 OSW</td><td rowspan="2">8.6 GW</td><td>2.3 GW</td><td>1.6 GW</td></tr>
<tr><td>P3</td><td>70% 2034 SMR</td><td>2.4 GW</td><td></td></tr>
<tr><td>P4</td><td>70% 2034 OSW + SMR</td><td>7.6 GW</td><td>2.0 GW</td><td>0.8 GW</td><td>0.8 GW</td></tr>
</table>

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

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DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

Request:

Regarding the Companies' answer to question (b) in NCSEA-SACE DR 2-24, please:

a. Provide all files that were used to determine the "retirement securitization value" for each coal plant retiring according to the Carbon Plan. These files include, but should not be limited to, spreadsheets, databases, programming code, depreciation studies, etc. In the spreadsheets that the Companies will provide, please leave the formulas intact and all data references included.
b. Clarify how the difference between the two recovery streams mentioned in the Companies' response. standard post-retirement amortization versus securitized recovery, flows through the production cost model, and how or where it is considered in the calculation of PVRR.

Response:

a. Duke Energy objects to this request to the extent it seeks "all files" and all "spreadsheets, databases, programming codes" as overbroad, unduly burdensome, not reasonably calculated to lead to the discovery of admissible evidence, and not proportional to the scope and needs of this case. In particular, Duke Energy objects to this request to the extent it seeks access to a confidential and proprietary internally developed financial analytics model which contains data for all Duke Energy regulated jurisdictions, and which cannot be separated to be limited to provide outputs for DEC and DEP. Notwithstanding the foregoing objection, please see the representative information provided in response NCSEA-SACE DR3-39(g).

b. The securitization opportunity value is added to the FOM cost stream provided to Encompass for its consideration in the coal unit economic retirement analysis. To the extent FOM is an avoidable cost with retirement, adding the securitization opportunity value to FOM enables Encompass to consider it. To the extent the securitization opportunity is a declining stream, Encompass has to incrementally choose year after year to continue to operate the unit and incur the securitization opportunity value as a cost (or rather in the inverse, choose to retire and take the securitization opportunity value as a benefit). As the value gets lower with time, it has less and less effect over time on that decision being made by the model.

Responder: Keith B. Pike, Rates & Regulatory Strategy Director

NCSEA et al. Response to Duke Energy Data Request 2-9

2-9. Referring to the revised inputs listed under "Existing Resources" in Table 3 on page 10 of the Synapse Report, please provide support for why the "Advanced" NREL ATB costs were used for Offshore wind and storage while "Moderate" was used for the other renewable resources.

Response:

Synapse's use of "Advanced" versus "Moderate" technology cases is based on a judgment of the relative maturity of those technologies in the United States today and anticipated achievement of economies of scale and learning curves.

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

REQUEST:

With respect to solar interconnection projections, Appendix I (page 8) states that "The projections are based on a range of factors, some of which are unknown at this time or outside of the Companies' control." Please describe in detail the factors that specifically support the proposed solar capacity limits in each year.

RESPONSE:

Appendices I and P provide substantial details regarding the factors that impact the proposed annual solar capacity amounts included in the Carbon Plan modeling. These factors include, but are not limited to:

- Transmission expansion needs and the time to construct new transmission infrastructure to accommodate increasing levels of renewables and other resources as described in Appendix P.
- Increasingly complex interconnections as solar facilities are located farther from existing infrastructure
- Unknown future solar project size and impacts on interconnections. Generally larger projects should enable more aggregate MWs to be connected on an annual basis, but it is not known at this time what the size of projects will be in the future and whether larger projects will lead to additional transmission expansion projects beyond those contemplated in Appendix P.
- Finite interconnection resources allocated to non-solar resources. Details of potential other non-solar resources can be found throughout the Carbon Plan including Chapter 3 and Appendix E.
- The Companies' historic annual interconnections, which have consistently been among the highest in the United States, is approximately 520 MW/year since 2015. While not the primary determining factor in developing the solar interconnection capability in the Carbon Plan, it is important to note that Carbon Plan allows for over 3x this annual amount in Portfolio A1 and over 2.5 X this annual amount in all other portfolios.

- The timeline for interconnection is often delayed by the actions of interconnection customers, who may elect to delay interconnection due to business considerations or other factors.
- Land availability and community acceptance. While not described in great detail in the Carbon Plan, 1,350 MW/year of solar will require approximately 10,800 acres/year of land to be developed, and 1,800 MW/year will require approximately 14,400 acres/year. Community acceptance of this level of development is an unknown factor that may impact the amount of solar that can be added annually.
- Energy storage development will be important to ensure energy supply meets demand and delays in storage development can limit the effectiveness of solar deployments needed to meet the goals of the Carbon Plan.

Responder: Matthew Kalemba, Director DET Planning & Forecasting

NCSEA et al. Response to Duke Energy Data Request 2-18

2-18. Did Synapse analyze or otherwise take into account the risk of potentially under-achieving the EE targets used in the Synapse portfolios that results in accelerated coal retirements?

a. If yes, please explain in detail how this analysis was considered and incorporated into Synapse modeling and Report.
b. If yes, please provide any documents supporting this analysis.
c. Does Synapse agree that under-achieving aggressive EE targets could lead to a less reliable system if unit retirements are planned and executed ahead of achieving the load reductions?

<u>Response</u>:

Yes.

a. Yes. Synapse ran a capacity expansion and production cost modeling sensitivity using lower energy efficiency targets to understand the impact of lower energy efficiency on results. See pages 26-27 of the *Carbon-Free by 2050* report.
b. Inputs and outputs for the *Optimized Low EE – CapEx* and *Optimized Low EE – PC* scenarios were provided in Synapse's share of EnCompass datasets and outputs.
c. Synapse agrees that failure to develop any planned supply- or demand-side resource could have reliability implications if other elements of the resource plan are not adjusted.

NCSEA et al. Response to Duke Energy Data Request 2-15

2-15. On page 14 of the Synapse Report, in Table 4, the Annual Solar development Limits are raised to 1,200 MW in 2025, to 1,800 MW in 2026-2028, and 2,300 MW in 2023 and onward as revised inputs for the alternate portfolios developed by Synapse. Please provide justification for the increased limits, with respect to the Limits Duke used in its 2030 interim 70% compliance portfolios. Additionally, please clarify that Synapse did not adjust the forecasted solar into the portfolios and that the 1,200 MW able to be selected for 2025 is on top of the nearly 600 MW that are already forecasted to come into service in 2025.

Response:

Synapse based its solar development limit forecast on the reasonable expectation of further improvements to solar deployment in the Carolinas.

Synapse adjusted total solar resource availability in 2025 to 1,200 MW in order for maximum total deployment in that year to be consistent with Duke Energy's indicated short-term maximum solar deployment of 1,800 MW.

Tech Customers' Response to Duke Energy Data Request 1-7(a)

1-7. Regarding the statement on page 10 of your Comments that "Duke hardcoded several asset selections into its modeling," please:

a. identify and provide a detailed explanation of any constraints or limits that Gabel and/or Strategen used in performing alternative modeling in EnCompass.
b. Explain whether in your modeling experience, imposing constraints or limits on resources in the model is never appropriate or sometimes appropriate based on the circumstances and judgment of the modeler.

<u>Response</u>:

a. The Preferred Portfolio maintains most of the annual and cumulative resource limits imposed by Duke. However, the following adjustments were made.
   i. Wind resources are available one year earlier than in Duke's model, and in 600 MW annual increments.
   ii. There was no change in limits on storage. Although no limit is specified in Appendix E, standalone batteries are subject to an annual limit in the Duke modeling analysis.
   iii. Annual solar limits are relaxed for years 2026-2029.
   iv. No Combined Cycle units were allowed to be selected. This was to reflect the risk of stranded assets, fuel supply, and fuel cost.

b. A modeling analysis requires critical thinking from the modeler(s). As such, resource limits are often used to reflect the operational and execution issues that would not otherwise be captured in a capacity expansion model. However, based on our experience, we find that Duke's setup of the model in this case overly restricted resources in years with significant energy and capacity need, leaving the model minimal flexibility in selecting resources based on their economics.

Tech Customers' Response to Duke Energy Data Request 1-8

1-8. Regarding the statement on page 5 of the Gabel Report "Our capacity expansion analysis assumes the Companies' coal assets all retire by 2030 per the Carbon Plan Schedule for retirements before 2030, and a latest retirement date of 2030 for the rest", please explain how you determined that accelerating all coal unit retirement dates to 2030 is reasonable and produce any analysis developed to support this statement.

Response:

As referenced in the Gabel report (pg. 54): "Due to time restrictions and the limited information provided by Duke, the analysis did not attempt to study coal retirement decisions on a per unit basis." Coal fixed operating and maintenance costs, incremental capital expenses (including environmental capital expenses), and securitization benefits were not provided with adequate detail for such an analysis. Still, the preferred portfolio shows that earlier retirement of coal units can be achieved while reducing cost, emissions, and risks for ratepayers..

CPSA Response to Duke Energy Data Request 1-8

1-8. Please provide detailed documentation for the GridSIM model (user manual or equivalent), including detailed explanations of capacity expansion and production cost methodology as well as the manner in which the model ensures system reliability.

Response: GridSIM is a proprietary software model developed by Brattle. As such, there is no user manual or similar documentation. GridSIM optimizes capacity expansion and system dispatch to meet hourly demand, winter capacity requirement, and CO2 limits, while respecting other constraints included in the model, by minimizing the net present value of system costs over the timeframe modeled. The timeframe modeled in this case was 2020 to 2035, with 2020, 2025, 2030, 2032, and 2035 modeled. The system costs of achieving the specified constraints in each modeled year are assigned a weighting based on the number of years between modeled years. The system costs in each year are based on the levelized costs of adding new resources to meet the necessary constraints (e.g., CO2 limits, winter capacity requirement, and hourly demand) and the operating costs of existing and new resources, including fuel costs, variable operations and maintenance (O&M) costs. The operating costs of existing and new resources are based on simulated chronological hourly dispatch of 49 representative days, including 4 representative days within each of the 12 months and the peak demand day. The 4 days within each month are selected by accounting for differences in demand and renewable generation within each month using a clustering algorithm. The operating costs of meeting hourly demand in each representative day are assigned a weighting based on the number of days within the month of which they is representative.

Please see Response 1-7 for an explanation of how the model ensures that the system meets the winter capacity requirement to maintain system reliability.