STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 190

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Biennial Consolidated Carbon Plan and Integrated Resource Plans of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, Pursuant to N.C.G.S. § 62-110.9 and § 62-110.1(c)	)))))))	**REBUTTAL TESTIMONY OF GLEN SNIDER, MICHAEL QUINTO, AND THOMAS BEATTY ON BEHALF OF DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC**

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I. INTRODUCTION AND PURPOSE

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 525 South Tryon Street, Charlotte, North Carolina 28202. I am currently employed by Duke Energy as Managing Director of Carolinas Integrated Resource Planning and Analytics. I am providing rebuttal testimony on behalf of Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and together with DEC, "Duke Energy" or the "Companies") along with Michael Quinto and Thomas Beatty as the "IRP and Near-Term Actions Panel."

Q. ARE YOU THE SAME IRP AND NEAR-TERM ACTIONS PANEL THAT FILED DIRECT TESTIMONY IN THIS CASE?

A. Yes, with the exception of witness Ben Passty, who is not providing rebuttal testimony in this proceeding. Companies' witness Phil Stillman is providing load forecast-related Rebuttal Testimony on the Economic Development and Growth Panel responding to testimony about the Companies' integration of economic development activity into the load forecast.

Q. IS THE IRP AND NEAR-TERM ACTIONS PANEL INTRODUCING ANY EXHIBITS IN SUPPORT OF THE REBUTTAL TESTIMONY?

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

- **IRP and Near-Term Actions Panel Rebuttal Exhibit 1** provides key figures and tables presented in our testimony in a larger, more readable format.

- **IRP and Near-Term Actions Panel Rebuttal Exhibit 2** provides a report describing the Companies' recently-completed modeling and analysis of the Environmental Protection Agencies ("EPA") recent Final rule issued under Section 111 of the Clean Air Act ("CAA" and, collectively, "CAA Section 111 Final Rule" or "Final Rule") published in May 2024. The Companies refer to this document as the "CAA Section 111 Sensitivity Analysis."
- **IRP and Near-Term Actions Panel Rebuttal Exhibit 3** provides relevant discovery requests from the Public Staff, which the Panel references in testimony.

Q. MR. SNIDER, PLEASE EXPLAIN HOW THE PANEL HAS APPROACHED ITS REBUTTAL TESTIMONY.

A. Similar to the Modeling and Near-Term Actions Panel's rebuttal testimony in the 2022 Carbon Plan proceeding, this Panel's rebuttal testimony focuses on responding to testimony from intervenors that impacts the Near-Term Action Plan ("NTAP") and the Companies' requests for relief as set forth in the Companies' Second Amended Petition.[1] Given that the Public Staff is the only party that has submitted alternative modeling analysis and an alternative NTAP, the Companies address the Public Staff's modeling and NTAP in Sections III and IV and address the other material issues raised by other intervenors in Section V. The Companies provide additional perspective on the approach to

[1] The Companies filed their Second Amended Petition on April 30, 2024, to address a ministerial correction to one request for relief.

this CPIRP update and the need for an executable plan approving clear near-term actions in Section II of the rebuttal testimony.

Q. MR. SNIDER, ON BEHALF OF THE PANEL, PLEASE BRIEFLY SUMMARIZE THE PANEL'S REBUTTAL TESTIMONY.

A. The panel's testimony addresses the following:

<u>SECTION II: CPIRP Development</u>

1) Performing comprehensive modeling supporting near term actions is essential to the decisions before the Commission and needed to ensure critical factors are balanced to meet resource planning objectives and arrive at the most reasonable, least cost, and least risk plan to reliably serve North Carolina's future energy needs. Therefore, the Commission should consider the level of detailed analysis, modeling and overall technical objectivity applied by intervenors to support their positions, and not be compelled to address every issue raised in order to approve a reasonable NTAP.

2) While intervenors provided a significant amount of testimony on a broad range of issues, the Public Staff is the only party to present independent technical modeling to holistically assess the Companies' future resource needs and to offer an alternative resource plan in this proceeding.

3) There is substantial directional alignment between the Companies' and the Public Staff's modeling results and recommended near-term actions described in this testimony, which should provide the Commission with confidence that the Companies' modeled outcomes are reasonable for planning purposes and are appropriately informed by the balancing of core considerations around reliability, cost and pace of execution to guide the Commission's decisions in the proceeding.

<u>SECTION III: The Companies' and Public Staff's Modeling Assumptions are Largely Aligned, and Where Deviations Exist, the Companies' Assumptions are More Reasonable for Planning Purposes</u>

Core Modeling Assumptions Alignment and Deviations with Public Staff

4) The Companies and Public Staff are largely aligned on many key aspects of modeling assumptions, including but not limited to, load forecast (including economic development adjustments), coal retirement schedule, reserve margin requirement, effective load carrying capability ("ELCC") values, grid edge levels in the load forecast, selectable supply-side resource costs and operational parameters, and fuel supply and commodity price forecasts.

5) With respect to input differences, the Public Staff's modeling includes certain unreasonably aggressive resource availability assumptions relative to the levels the Companies' subject matter experts and industry information support as executable. In particular, their modeling assumed significantly accelerated timing for, and increased volumes of, offshore wind and to a lesser extent assumed increased availability of solar, storage and onshore wind resources. The Public Staff also made an incorrect assumption regarding the availability of DEC combined cycles ("CC") as early as 2029.

6) The Public Staff's incorporation of these flawed assumptions result in two fundamental problems: (1) because certain assumed resource availability assumptions are inexecutable, their modeling results call for a future build plan that is not fully achievable and, as a result, not reliable; and (2) the overly aggressive availability assumptions for offshore wind and other renewable resources eliminate or defer other more executable resources that would be selected but for the inclusion of inexecutable levels of offshore wind and other resources.

7) The Public Staff's base planning portfolio, designated PS1F 2034 ("PS – 2034 Base"), passed the reliability verification modeling step in test years 2033 and 2038 without the need of an additional reliability resource. However, this result is premised on the resources selected in the modeled portfolio actually being online and available on the timelines assumed and selected in the model. Because the Public Staff's recommended NTAP does not fully align with or support the levels of CC, CT or offshore wind resources identified as needed by 2034 in their modeling, the Public Staff's NTAP does not present a reliable and executable plan.

8) The Public Staff's modeling approach also increases reliability risk by delaying the application of the increased reserve margin to 2031 versus the Companies' approach of growing into the reserve margin incrementally between 2027 to 2031 to more reasonably achieve resource adequacy and maintain reliability.

EPA CAA Section 111 Final Rule Sensitivity Analysis Confirms New Gas is Critical to the NTAP

9) The Companies' and the Public Staff's modeling of the recent EPA CAA Section 111 Final Rule demonstrates that even when the most conservative approach of reducing capacity factors for new natural gas CC and CT resources is used, the model continues to select new natural gas CC and CT resources and confirms that these resources continue to be critical for reliability and part of the least cost plan to enable orderly coal unit retirements and to meet load growth.

10) The Companies' EPA CAA Section 111 Sensitivity Analysis confirms the need for the resources in the Companies' NTAP and identifies for the Commission the challenge, risks and tradeoffs of achieving the Interim Target between 2035 and 2038. This modeling also determines that the impacts of the Final Rule on the P3 Fall Base portfolio is an increase in CO2 emissions of over 4 million tons in the year 2035, a likely delay in the Interim Target date to 2036 or later, and an increase in the total system cost of more than $600 million.

Interim Target Alignment with Public Staff

11) The Companies and Public Staff agree that the Interim Target is not achievable prior to 2034, and the Companies agree with Public Staff witness Thomas that pursuing a more accelerated energy transition would require development and interconnection of unrealistic quantities of new resources, could threaten system reliability, and would significantly increase costs for customers. Given the EPA CAA 111 Final Rule and other uncertainty facing the Companies' longer-term planning and execution, the Companies and the Public Staff generally agree that the Interim Target is achievable at some point in the mid-2030s.

SECTION IV: The Companies' NTAP Remains the Most Reasonable, Least Cost and Least Risk Plan to Reliably Serve Customers' Future Energy Needs

The Companies' NTAP and Supporting Modeling Largely Aligns with the Public Staff's Modeling

12) The Companies recommend that, similar to the Commission's *Order Adopting Initial Carbon Plan and Providing Direction for Future Planning*, Docket No. E-100, Sub 179 (Dec. 30, 2022) ("Carbon Plan Order"), the Commission focus on defining a NTAP that selects resources and directs necessary actions based on "reasonable steps" required to pursue the goals of HB 951.

13) The Public Staff acknowledges the Companies' NTAP generally aligns with both their own and the Companies' modeling resulting in "a least cost path toward carbon neutrality"[2]

Specific Areas of NTAP Alignment and Deviation with Public Staff

14) The Companies' and the Public Staff's NTAPs are directionally aligned on volumes of most supply-side resources; however, the significant deviations between the Public Staff's NTAP and its modeling with regard to offshore

[2] Public Staff Thomas Direct Testimony at 8.

wind and new natural gas resources results in a risker and less reliable NTAP that is capacity-deficient and poses significant risk to customers.

15) Adopting Public Staff's "least regrets" plan, which actually constitutes a "wait and see" approach to executing on critical new natural gas CC and CT generation, will result in a "many regrets" scenario in which reliability, resource adequacy, and future economic development is jeopardized.

16) The Companies' NTAP supply-side volumes are derived from the Companies' comprehensive modeling analysis (and are generally aligned with Public Staff's modeling notwithstanding previously mentioned deviations in offshore wind and natural gas), which selects a balanced mix of resources that together can reliably respond to historic load growth and support coal retirements.

The Companies' NTAP Supports Aggressive but Achievable Actions on Renewables and Storage

17) The Companies' NTAP adds significant volumes of carbon-free resources in an aggressive but responsible manner that the Companies are reasonably confident can be achieved.

The Companies' NTAP Supports Critically Necessary Project Execution for New Natural Gas to Maintain or Improve Reliability at Least Cost

18) The Companies' NTAP includes model-selected five CCs by 2033 and five CTs by 2031, and the Companies must progress all necessary actions on all model-selected dispatchable resources to reliably meet new load growth and retire coal in this critical execution period of the CPIRP.

19) The Public's Staff decision to include only one CC and two CTs in their NTAP ignores the clear results of their modeling and relevant sensitivity analysis (including EPA CAA Section 111 sensitivity analysis) demonstrating that five to six CCs are needed by 2033 to 2034. It would be imprudent and contrary to HB 951's planning framework to delay commercial operations of essential dispatchable resources required to maintain reliability at a critical time when the Companies are planning to reliably execute coal retirements and meet unprecedented economic development-driven load growth in the State.

The Companies and Public Staff Support Selecting Bad Creek II at this Time

20) Both the Companies' and the Public Staff's NTAPs support selecting Bad Creek II as economically justified by the modeling and maintaining the project development path for Bad Creek II as a unique and valuable resource to the system.

NTAP Supports Optionality on Offshore Wind and New Nuclear

21) The Companies and the Public Staff's modeling supports the continued advancement of new nuclear small modular reactors ("SMRs") and offshore wind as necessary technologies available in the 2030s to further the energy transition as required to meet the interim target by the mid-2030s.

22) Based on the finalization of the Clean Air Act Section 111 Final Rule and the subsequent modeling of the impact of the Final Rule the Commission has flexibility to continue to assess the timing and trade-offs of offshore wind and new nuclear.

SECTION V: Response to Critiques from Non-Modeling Intervenors

23) No parties took fundamental issue with analytical process and modeling tools, including but not limited to, the Companies' use of the EnCompass and SERVM modeling software, capacity expansion modeling, and the Reliability Validation and Bad Creek II Verification steps.

24) The Companies provide responses to numerous critiques, comments, and recommendations from non-modeling intervenors in resource planning areas including but not limited to Reliability Requirements, Net Load Forecast, Grid Edge and Customer Programs, Supply-Side Resources, Interim Target Dates, Coal Retirement Schedule, and Financial Analysis of the Plan.

25) While the parties and the Companies agree that the Companies must aggressively pursue solar, energy storage, onshore wind resources, and grid edge solutions, the Commission should closely consider the reasonableness of the pace, volume and executability of the intervenor recommendations.

26) Several parties incorrectly assume that the addition of new gas resources will subject customers to the risk of stranded investments but fail to consider the critical value of these resources over the planning horizon and lack detailed analysis regarding how such a risk would actually materialize three decades from now.

27) Several parties recommend that the Commission direct the Companies to make more frequent CPIRP updates than is contemplated in HB 951 or the Commission's rules. This recommendation is impracticable and unnecessary given the regulatory schedule for adjudicating each CPIRP. The Companies will file an updated CPIRP just nine months after the Commission's deadline to issue an order in this proceeding.

II. APPROACH TO CPIRP UPDATE AND NEED FOR REASONABLE STEPS AND EXECUTABLE PLAN TO PROGRESS CPIRP

Q. HOW SHOULD THE COMMISSION ASSESS INTERVENOR RECOMMENDATIONS AND CRITICISMS OF THE COMPANIES' CPIRP MODELING AND RESULTS IN THIS PROCEEDING?

A. More than 35 Public Staff and intervenor witnesses have filed approximately 3,000 pages of testimony and supporting documents across a wide and complex array of topics and aspects of the Companies' modeling, resource plan assumptions, coal retirement analysis, and resulting Execution Plan and NTAP. Based upon the Companies' experience in the 2022 Carbon Plan proceeding as well as the varied perspectives presented through the 2023 CPIRP stakeholder process, it is unsurprising that certain intervenors dispute the reasonableness of the Companies' proposed Plan.

In contrast to the 2022 Carbon Plan proceeding, however, where four intervenors submitted alternative technical modeling and resource plans, it is notable that only the Public Staff presented independent technical modeling to offer an alternative resource plan in this proceeding. This is significant because, in the absence of comprehensive modeling that fully demonstrates how alternative planning assumptions and recommendations holistically impact future portfolios, maintain reliability and impact customers' rates, it is difficult to ascertain the real-world impact of certain intervenor recommendations. For example, some intervenors request the Commission accelerate coal unit retirements and require achievement of the Interim Target in 2030 or 2032, focusing exclusively on risks of new dispatchable natural gas generation, but provide no detailed plan for how to achieve such "no new gas" recommendations while maintaining reliability. In contrast, both the Companies' and the Public Staff's modeling confirms that an "all of the above" portfolio of resources, including renewables, battery energy storage, grid edge and other demand-side resources as well as new natural gas fueled CC and CT generation is needed as part of the most reasonable and least-cost plan to reliably execute coal retirements and meet unprecedented economic development-driven load growth in the State. Moreover, the Companies' and the Public Staff's modeling confirms that achievement of the Interim Target before 2034 is not feasible, and the Companies believe it is now beyond dispute that no reasonable modeling could generate an executable resource plan that reliably achieves the Interim Target earlier than the mid-2030s.

Q. HOW SHOULD THE COMMISSION ASSESS RECOMMENDATIONS BY NON-MODELING INTERVENORS IN THIS PROCEEDING?

A. While intervenors are undoubtedly entitled to present and advocate for different outcomes in this proceeding, this CPIRP is not a hypothetical planning exercise—it is the adjudication of a specific set of actionable "reasonable steps" to be taken over the next 24 months to execute the CPIRP and to progress the goals of HB 951 while maintaining or improving reliability. This distinction underscores the importance and material consequence of assessing the technical objectivity, depth, and applicability of intervenors' positions on the Companies' proposed Plan.

Without submitting comprehensive modeling, it is easy for certain intervenors to make narrow or siloed recommendations without having to genuinely wrestle with the follow-on implications regarding how such recommendations impact the entirety of the Plan or the important tradeoffs in terms of cost, risk, reliability or affordability that must be considered as outlined in HB 951. Similarly, parties that have not submitted comprehensive modeling can make very generalized recommendations without any quantitative analysis or detailed evidence to support how such recommendations would impact the totality of the CPIRP and whether such recommendations would, when assessed comprehensively, result in the most reasonable, least-cost solution for customers.

In contrast, the Companies have the unique responsibility to develop and execute the CPIRP under HB 951 in a manner that meets the challenges of the current changing energy landscape and plans for the Carolinas' energy transition towards carbon neutrality, while maintaining system reliability, promoting customer affordability, and ensuring executability of the Plan. While various interests and perspectives can be valuable to this process (indeed, HB 951 calls for stakeholder input into the development of the initial Plan), the probative value of such critiques and recommendations should be scrutinized to the extent they deviate from the Companies and the Public Staff's detailed modeling and analysis informing the next reasonable steps to execute the Plan.

Q. HOW SHOULD THE COMMISSION APPROACH UPDATING THE CARBON PLAN IN THIS PROCEEDING?

A. Similar to the 2022 Carbon Plan proceeding, the Companies reiterate that the Commission need not determine every contested issue or address every recommendation presented in this proceeding and should focus its efforts on approving near-term actions and the next "reasonable steps" that are necessary to progress the Companies' least cost Carolinas' system-wide energy transition.[3] The substantial alignment between the Companies' and the Public Staff's modeling approaches and recommended near-term actions addressed in Sections III and IV of this Rebuttal Testimony should provide the Commission with confidence that Duke Energy's modeled outcomes are reasonable for planning purposes and are appropriately informed by the core considerations around reliability, cost and pace of execution that should guide the Commission's ultimate decisions in the proceeding.

III. THE COMPANIES' AND PUBLIC STAFF'S MODELING ASSUMPTIONS ARE LARGELY ALIGNED AND, WHERE DEVIATIONS EXIST, THE COMPANIES' ASSUMPTIONS ARE MORE REASONABLE FOR PLANNING PURPOSES.

Q. DOES THE PUBLIC STAFF'S MODELING APPROACH GENERALLY ALIGN WITH THE COMPANIES' MODELING APPROACH AND ANALYTICAL PROCESS DESCRIBED IN APPENDIX C (QUANTITATIVE ANALYSIS) TO THE PLAN?

A. Yes. Public Staff witness Thomas describes the Public Staff's detailed review of the Companies' modeling approach and identifies only limited policy preferences and critiques to the Companies' modeling set up and analytical

[3] N.C.G.S. § 62-110.9.

process.[4] The Public Staff also used the same EnCompass modeling software used by Duke Energy to perform capacity expansion and production cost modeling and to develop its own portfolio analysis.[5] Similar to the Companies' portfolio development approach, the Public Staff established base portfolios for different Interim Target compliance years and then ran multiple sensitivities on each portfolio.[6] Summaries of the resources selected in each of those sensitivities are included as Exhibits 2-4 to Public Staff witness Metz's testimony.

As further explained below, there are many key areas of alignment between the Public Staff and the Companies regarding modeling inputs, assumptions and portfolio results. However, there were a few material divergences in modeling assumptions that resulted in limited but important differences in the Public Staff's resource selections. Before addressing the areas of alignment and differences in the Companies and the Public Staff's recommended near-term actions, the Companies first address the areas of alignment and key differences in modeling assumptions that support the Companies' proposed Plan as the most reasonable for planning purposes.

[4] Public Staff Thomas Direct Testimony at 13-20.

[5] Public Staff Thomas Direct Testimony at 7.

[6] Public Staff Thomas Direct Testimony at 80.

A. Public Staff's Modeling is Significantly Aligned with the Companies' Modeling on Many Key Aspects

Q. PLEASE DESCRIBE THE AREAS OF ALIGNMENT BETWEEN THE PUBLIC STAFF'S MODELING ASSUMPTIONS AND THE COMPANIES' MODELING ASSUMPTIONS.

A. The Public Staff conducted a detailed and thorough review of the Companies' modeling assumptions analytical processes.[7] Witness Thomas notes that the CPIRP is "based on energy system modeling performed in EnCompass," and that "[i]nputs come from the Companies' operational experience[.]"[8] The Public Staff and the Companies are aligned on core modeling assumptions, namely:

- The Updated 2023 Fall Load Forecast is reasonable for planning purposes;[9]
- The Companies' coal retirement schedule is reasonable for planning purposes and continues to provide an orderly transition out of coal;[10]
- The increased reserve margin[11] and Duke Energy's ELCC[12] values are reasonable; and
- Planning for achieving the Interim Target prior to 2034 is not reasonable.[13]

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[7] Public Staff Thomas Direct Testimony at 13-15.

[8] Public Staff Thomas Direct Testimony at 14.

[9] Public Staff Thomas Direct Testimony at 119.

[10] Public Staff Michna Direct Testimony at 11.

[11] Public Staff Thomas Direct Testimony at 34.

[12] Public Staff Thomas Direct Testimony at 39.

[13] Public Staff Thomas Direct Testimony at 8.

Furthermore, the Public Staff's modeling adopted Duke Energy's modeling assumptions regarding technology costs and gas supply,[14] and agreed that the resource availability assumptions used in the P1 Fall Base portfolio are infeasible.[15] Importantly, alignment on these key assumptions enables more of an "apples-to-apples" comparison between the Public Staff's and Companies' modeling, portfolio analysis and, ultimately, proposed resource selections. A summary of areas of alignment on core planning assumptions are presented in Figure 1 below.

[14] The Public Staff did not alter Duke Energy's interstate Firm Transmission gas cost assumptions; however, they replicated an error that the Companies had in the model that overstated costs for early gas units. This issue is discussed in more detail later in testimony.

[15] Public Staff Thomas Direct Testimony at 53.

<u>Figure 1: Modeling Inputs – Core Planning Assumptions Areas of Alignment</u>

Q. DOES THE PUBLIC STAFF'S TESTIMONY AND MODELING SUPPORT THE COMPANIES' UPDATED 2023 FALL LOAD FORECAST USED IN THE SUPPLEMENTAL PLANNING ANALYSIS

("SPA") AND RECOGNIZE THE NEED TO PLAN FOR RESOURCES TO MEET SIGNIFICANT FORECASTED LOAD GROWTH?

A. Yes. Public Staff witness Thomas describes a plan's load forecast as fundamental and influential to resource selection to meet customer needs.[16] The Public Staff relied upon the Companies' Updated 2023 Fall Load Forecast used in the SPA for base modeling purposes to develop its PS - 2034 Base portfolio and all sensitivities except for one sensitivity testing alternative load forecast assumptions.[17]

Q. DOES THE PUBLIC STAFF'S TESTIMONY AND MODELING SUPPORT THE COMPANIES' APPROACH TO PLANNING FOR ORDERLY COAL UNIT RETIREMENTS OVER THE NEXT DECADE, FURTHER ESTABLISHING THE NEED FOR REPLACEMENT RESOURCES?

A. Yes. The Public Staff does not identify any specific concerns or recommend any changes to the Companies' coal retirement schedule. Public Staff witness Michna highlights that the coal retirement analysis conducted is consistent with the methodology used in the Companies' 2022 Carbon Plan, which the Commission approved as reasonable for planning purposes at that time.[18] Witness Michna points out that the Companies' analysis considers operational and execution nuances that "reflect[s] the technical reality of retiring 8 GW of

[16] Public Staff Thomas Direct Testimony at 21.

[17] Public Staff Thomas Direct Testimony at 119.

[18] Carbon Plan Order at 64.

generation while maintaining a stable and reliable system."[19] Public Staff witness Metz further underscores the orderly transition out of coal stating "[t]he Companies must rely upon a glide path, a level of reasonableness, to properly manage the retirement of approximately 8.5 GW of coal generation while maintaining system reliability as other resources are added."[20]

Q. DOES THE PUBLIC STAFF SUPPORT THE 2023 RESOURCE ADEQUACY STUDY USED IN THE COMPANIES MODELING TO ESTABLISH THE PLANNING RESERVE MARGINS FOR THE CPIRP MODELING?

A. Yes. The Public Staff adopts the Companies' 22% planning reserve margin into its modeling. Public Staff witness Thomas noted that the overall trend of higher reserve margins has been observed throughout the Southeast[21] and it is not unreasonable to assume that a higher reserve margin is necessary given the changes to system dynamics that have occurred since the 2020 Resource Adequacy Study was completed.[22] The Public Staff targets the same 22% reserve margin by 2031 in developing its own modeling.

Q. DOES THE PUBLIC STAFF SUPPORT THE ELCC STUDY RESULTS USED IN THE COMPANIES MODELING TO ASCRIBE FIRM CAPACITY CONTRIBUTIONS OF VARIABLE AND ENERGY

[19] Public Staff Michna Direct Testimony at 11.

[20] Public Staff Metz Direct Testimony at 17.

[21] Public Staff Thomas Direct Testimony at 33.

[22] Public Staff Thomas Direct Testimony at 34.

LIMITED RESOURCES FOR MEETING THE PLANNING RESERVE MARGIN?

A. Yes. The Public Staff finds the Companies' determination of capacity values to be reasonable, noting that reliability-based estimates for determination of capacity values, as the Companies used in their ELCC studies, is a widely accepted industry standard.[23]

Q. DOES THE PUBLIC STAFF'S TESTIMONY AND MODELING CONFIRM THAT PLANNING FOR A 2030 OR 2032 INTERIM TARGET IS NO LONGER REASONABLE?

A. Yes. Public Staff witness Thomas states, "[t]he Public Staff's modeling shows that achieving compliance [with the 70% carbon emissions reduction target] earlier than 2034 would require development and interconnection of unrealistic quantities of new resources, could threaten system reliability, and would significantly increase costs borne by ratepayers."[24] After performing modeling of 2030 and 2032 interim target portfolios, witness Thomas says, "[t]he scale of resource additions and retirements necessary to comply by 2030 simply does not appear to be possible" and "the Public Staff believes that a delay beyond 2032 is necessary to ensure the adequacy and reliability of the grid."[25]

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[23] Public Staff Thomas Direct Testimony at 39-40

[24] Public Staff Thomas Direct Testimony at 8.

[25] Public Staff Thomas Direct Testimony at 56.

Q. DOES PUBLIC STAFF AGREE THAT THE COMPANIES' ENCOMPASS MODELING SET UP, INCLUDING USE OF A SEVEN YEAR OPTIMIZATION PERIOD, IS REASONABLE?

A. Yes. The Public Staff noted that the Companies were ordered in the Carbon Plan Order to test longer optimization periods and, to the extent practicable, use longer optimization periods, but ultimately utilized a seven-year optimization period for capacity expansion modeling due to model run time constraints.[26] Public Staff witness Thomas similarly recognizes the run-time constraints in the Public Staff's own modeling and states that, "Public Staff agrees with Duke's rationale for using a seven-year optimization period and has likewise used a seven-year optimization period in its own modeling."[27] Importantly, Public Staff noted, "while longer optimization periods did show slight variation in resource selection (e.g., slightly accelerated battery deployments), they generally did not impact the selection of offshore wind or CCs."[28]

Q. WHAT DID THE PUBLIC STAFF ASSUME REGARDING THE MODELING OF INCREMENTAL SUPPLY SIDE RESOURCES?

A. The Public Staff also generally agrees with the Companies' modeling of incremental supply side resources such as solar, storage, wind, Bad Creek II, CC, CT, and new nuclear. The Public Staff's modeling utilizes the updated SPA resource cost assumptions in their own modeling.[29] The Public Staff modeling

[26] Public Staff Thomas Direct Testimony at 17.

[27] Public Staff Thomas Direct Testimony at 19-20.

[28] Public Staff Thomas Direct Testimony at 19.

[29] Public Staff Thomas Direct Testimony at 48.

also utilizes the Companies' solar and battery costs and operational parameters. Public Staff witness Metz states that the advancement of solar energy generation is crucial for sustainable development in a carbon constrained world as well as in the selection of an economic resource.[30] Public Staff witness Metz also states that the integration of battery storage is becoming a cornerstone of modern utility systems, particularly with the shift towards intermittent renewable energy sources. The expansion of solar paired with storage ("SPS") procurement targets can strategically bolster energy reliability as SPS "firms" the otherwise intermittent nature of standalone solar PV and can respond rapidly to other grid events.[31] The Public Staff also finds the modeling nuclear resource availability and proposed action for meeting these timelines reasonable so long as the development of the SMR industry stays on pace and the cost estimates used in EnCompass modeling for the 2023 CPIRP for SMRs remain within a reasonable range, with the Companies' updated costs in the SPA "generally [aligning] with the public information provided in Dominion [Energy North Carolinas]'s recent 2023 Integrated Resource Plan."[32]. Public Staff witness Metz also agrees that the modeled CC and CT capital cost included in the SPA are reasonable for planning purposes reflecting "more recent pricing information given the trends with inflation and resources."[33] Finally, the Public

[30] Public Staff Metz Direct Testimony at 102.

[31] Public Staff Metz Direct Testimony at 108.

[32] Public Staff Metz Direct Testimony at 45-46.

[33] Public Staff Metz Direct Testimony at 25.

Staff is generally supportive of the modeling assumptions for both onshore[34] and offshore wind, including the assumed transmission system network upgrade costs, though the Public Staff did scale the costs to assume different project sizing, while not necessarily disputing the assumptions made by the Companies.[35]

Q. DOES THE PUBLIC STAFF AGREE WITH THE COMPANIES' ECONOMIC VERIFICATION MODELING AND ANALYSIS FOR BAD CREEK II?

A. Yes. The Public Staff opines that the Companies' "modeling approach and economic analysis supporting Bad Creek II [is] reasonable at this time,"[36] and further underscores the value that long duration storage provides, including the Bad Creek II project, as the system increasingly relies on carbon-free intermittent resources to meet demand.[37] I later address in Section IV of this testimony, the Public Staff's support for the Commission selecting Bad Creek II as part of the Companies' near-term actions for execution subject to ongoing review of the reasonableness of projected costs in future CPIRP updates.

Q. WHAT DID THE PUBLIC STAFF ASSUME REGARDING THE MODELING OF GRID EDGE AND DEMAND-SIDE RESOURCES?

A. In general, the Public Staff was supportive of the Companies' demand-side resource inclusions utilizing the Companies' energy efficiency ("EE") and

[34] Public Staff Lawrence Direct Testimony at 16.

[35] Public Staff Lawrence Direct Testimony at 35-36.

[36] Public Staff Metz Direct Testimony at 18.

[37] Public Staff Thomas Direct Testimony at 42.

demand-side management ("DSM") forecasts in their base modeling. Witness Williamson states that he recommended the impacts of PowerPair, a pilot program approved in early 2024 after the Companies developed its assumptions for the SPA, be included in rooftop solar and net metering, that the Commission should accept the Companies' EV load forecast, rate design forecast assumptions, the EE forecast, the DSM forecast and the request for relief related to Grid Edge.[38] The Public Staff did model availability of additional of demand-side resources, which the Companies do not agree with as discussed later in this testimony, but overall point to the recently approved DSM/EE Mechanism, which will allow for greater penetration of demand-side measures in the future, including achieving the Companies' 1% of eligible retail load EE forecast target and modeling assumption.[39]

Q. WHAT SHOULD THE COMMISSION CONCLUDE FROM THESE AREAS OF ALIGNMENT BETWEEN THE PUBLIC STAFF AND THE COMPANIES?

A. The Public Staff has largely deemed the Companies' planning and modeling approach and assumptions to be reasonable for planning purposes and used these assumptions in their modeling of the system. This alignment should provide the Commission with confidence that the Companies' overall modeling process and the vast majority of inputs and assumptions, verified by the Public Staff's detailed investigations, have led to reasonable modeling and planning of

[38] Public Staff Williamson Direct Testimony at 15-30.

[39] Public Staff Williamson Direct Testimony at 22, 27.

the system, with the isolated disagreements in limited but material assumptions highlighted in the remainder of this testimony as the basis for differences in modeling and recommended near term actions.

B. Certain Public Staff Modeling Assumptions are Flawed and Increase Risk in Execution, and Therefore are Not the Most Reasonable for Planning Purposes.

Q. PLEASE DESCRIBE THE MATERIAL MODELING ASSUMPTIONS UTILIZED BY THE PUBLIC STAFF THAT THE COMPANIES DO NOT SUPPORT.

A. While the Public Staff and the Companies are aligned on a significant number of modeling assumptions, as previously discussed, some modeling assumptions utilized by the Public Staff differ from the Companies' assumptions in a manner that the Companies do not support as technically justified or reasonable for planning purposes. Specifically, the Public Staff made the following assumptions that result in material differences in modeling results:

1. Accelerated and more aggressive resource availability assumptions:
    a. Greater volumes of solar, storage, and onshore wind resources are assumed to be available and interconnected at a faster pace;
    b. Offshore wind is assumed to be available earlier and in greater total volumes through the base planning period; and
    c. New CC resources are assumed to be available in DEC beginning in 2029.

2. Delayed application of reserve margin increase (Public Staff applies the increased reserve margin in 2031 instead of the year-over-year ramping in the Companies' modeling).
3. Assumed transmission transfer hurdle rate for power flows between the Companies.
4. Imposing generic siting assumptions and designating as "in-state" for carbon emission accounting purposes the Companies' recently announced planned South Carolina combined cycle generating facility as initially identified in the Companies' Supplemental Planning Analysis ("SPA") Execution Plan.[40]

Q. PLEASE DESCRIBE THE CONCEPT OF RESOURCE AVAILABILITY ASSUMPTIONS AND HOW THEY IMPACT MODELING.

A. "Resource availability" refers to constraints imposed in the capacity expansion model on the number of units of a particular resource that the model can select in a given year or cumulatively for DEP, DEC and collectively. All modeling must make resource availability assumptions because there is no resource that is available in infinite amounts on a given timeline. In addition, because of the parallel nature of execution and planning in the CPIRP, resource availability assumptions must take into account the real-world status of the Companies' execution activities. Unreasonable and unrealistic resource availability assumptions generally guarantee unreasonable and unrealistic modeling outcomes. Resource availability should reflect real world experience or

[40] Supplemental Planning Analysis at 57 (Table SPA 4-8).

executable assumptions in the same manner that the Companies' modeled cost or energy output of a resource should align with best-available projections at the time the resource plan is developed. The Companies resource availability assumptions used in CPIRP modeling which were supported by a variety of subject matter experts and operational experience across the planning process. The Companies describe major resource availability a2ssumptions used in Plan modeling in Appendix C and in Section 2 of the Supplemental Planning Analysis.[41]

Q. PLEASE DESCRIBE THE PUBLIC STAFF'S ADJUSTMENTS TO RESOURCE AVAILABILITY ASSUMPTIONS AND HOW SUCH ADJUSTMENTS IMPACTED THEIR MODELING.

A. The Public Staff takes a substantially more aggressive approach to resource availability in its modeling, assuming higher volumes of resources can be developed and interconnected compared to the Companies' aggressive but reasonable resource availability base planning assumptions.

Table 1 below recreates Public Staff witness Thomas Table 10, illustrating the differences in the selectable resource availability modeling assumptions. The Panel's Table 1 also identifies minor corrections to Thomas Table 10 where witness Thomas misstates the Companies' resource availability assumptions or left out additional resource availability assumptions in their modeling (corrections in bold and underlined).

[41] Supplemental Planning Analysis at 25-29 (Table SPA 2-11).

Table 1: Combined DEC/DEP Annual Resource Availability Assumptions Comparison

Technology	CPIRP SPA Assumption		Public Staff Base Assumption	
	Annual	Cumulative	Annual	Cumulative
Solar (including SPS)	2028-2030: 1,350 MW 2031: 1,575 MW 2032+: 1,800 MW	N/a	2028-2030: 1,875 MW[1] 2031: 2,100 MW 2032: 2,475 MW 2033: 2,550 MW 2034+: 1,800 MW	N/a
Stand-alone Battery	2027: 200 MW 2028-2029: 500 MW 2030+: 1,000 MW	N/a	2027: 300 MW 2028: 800 MW 2029: 900 MW 2030: 1,300 MW 2031-2033: 1,400 MW 2034+: 1,000 MW	N/a
BTM Solar paired with Storage[2]	N/a	N/a	2023, 2028-2029: 60 MW solar and 30 MW battery 2030+: 80 MW solar and 40 MW battery	N/a
CT	2029+: 2,125 MW	N/a	2029+: 2,125 MW	5,088 MW (12 CT Units; No H_2 CTs)
CC	2029: 1,360 MW 2030+: 2,720 MW	8,160 MW (6 CC Units)	2029: 1,360 MW[3] 2030+: 2,720 MW	8,160 MW (6 CC Units)
Onshore Wind	2031: 300 MW 2032+: 450 MW	2,250 MW	2031: 600 MW 2032-2033: 750 MW 2034+: 450 MW	2,250 MW
Pumped Storage	2034: 1,834 MW	1,834 MW	2034: 1,834 MW	1,834 MW
Offshore Wind	2033+: 800 MW	2,400 MW through 2038	2031+: 1,100 MW[4]	5,500 MW through 2038[4]
Advanced Nuclear	2035: 2 Units	11 Units through 2040	2035: 2 Units	11 Units through 2040

Note 1: Public Staff witness Thomas's Table 10 indicates that their modeling allowed standalone solar selectable up to 1,875 MW per year for 2028-2030, but limited SPS projects up to 1,350 MW per year in 2028 and 2029; however, the Companies' review of their modeling files indicates the model was not constraint to 1,350 MW of SPS in 2028 and 2029, but could select up to the 1,875 MW consistent with their standalone solar assumption.

Note 2: Public Staff modeling allowed selectable behind the meter ("BTM") solar and storage resources that the Companies did not allow.

Note 3: Public Staff modeling allowed selection of a DEC CC beginning in 2029, whereas the Companies did not allow a DEC CC until 2031, consistent with the expected achievable timeframe for putting a DEC CC in service.

Note 4: Public Staff modeling adjusted the size of the generic offshore wind resource to 1,100 MW, accelerated the first deployment of offshore wind from 2033 to 2031, and increased the cumulative capacity available from 2,400 MW to 5,500 MW by 2038.

Q. HOW DID THE PUBLIC STAFF DERIVE THEIR ALTERNATIVE RESOURCE AVAILABILITY ASSUMPTIONS USED AS THEIR BASE PLANNING ASSUMPTIONS?

A. Witness Thomas explains that for achieving the Interim Target before 2035, the Public Staff incorporated the Companies' resource availability assumptions used to model the P2 Fall Supplemental portfolio, with minor adjustments into its own modeling.[42]

Q. DO THE COMPANIES AGREE WITH PUBLIC STAFF'S ASSESSMENT OF P2 FALL SUPPLEMENTAL RESOURCE AVAILABILITY AS REASONABLE FOR PLANNING PURPOSES?

A. No. Use of the P2 Fall Supplemental Resource Availability is unreasonable for planning purposes.

Q. DID THE PUBLIC STAFF OFFER ANY COMPELLING TECHNICAL OR OTHER EVIDENCE TO CONFIRM THE EXECUTABILITY OF THE P2 FALL SUPPLEMENTAL RESOURCE AVAILABILITY ASSUMPTIONS?

A. No. The Public Staff has offered no detailed technical or other evidence to support their resource availability assumptions. Based on engagement with Public Staff, the Companies understanding is that Public Staff utilized the Companies' P2 resource availability assumptions as their starting point for

[42] Public Staff Thomas Direct Testimony at 60.

developing their own assumptions largely based on the fact that they were utilized in Supplemental Portfolios presented in the Companies' SPA. From the Companies' perspective, this approach was premised on a fundamental misunderstanding of the Companies' intent in presenting the P2 Fall Supplemental portfolio, as is discussed above.

Q. PLEASE ADDRESS THE COMPANIES' VIEW REGARDING ALTERNATIVE RESOURCE AVAILABILITY ASSUMPTIONS.

A. Fundamentally, the Companies do not believe that resource availability should change across portfolios based on factors such as increased load forecast or earlier achievement of the Interim Target, unless explicitly assessing a sensitivity to such variables. As background, in developing the initial Plan, the Companies deviated from this fundamental IRP planning principle in response to the Carbon Plan Order's directive to present a potential pathway to achieve the Interim Target by 2030.[43] In presenting this Commission-directed Interim Target by 2030 P1 Base modeling analysis, the Companies were required to substantially adjust resource availability beyond "real-world" achievable conditions to enable the model to solve. Accordingly, the Companies described the P1 Base portfolio as an "extra high" resource availability case requiring 40 to 50 major generation projects per year in 2027-2029, which represents an unprecedented and highly aggressive pace of new supply-side resource acquisition and deployment prior to the beginning of 2030.[44] Therefore, the

[43] Carbon Plan Order at 8.

[44] CPIRP Chapter 3 at 15, 31-32.

Companies concluded that pursuing the Interim Target by 2030 was "no longer attainable while maintaining or improving reliability, and pursuing it further is not in the best interest of customers,"[45] in part, because it exceeds the Companies' base resource availability assumptions. In contrast to the substantially more aggressive P1 Base resource availability assumptions, the Companies' P2 Base and P3 Base portfolios presented in the initial Plan used the same base resource availability assumptions, and while P2 Base selected more resources, the Companies regarded it as a reasonable portfolio for planning purposes.

In preparing the SPA, the Companies again reviewed resource availability and made limited updates as identified in Table SPA 2-11[46] to reflect best-available information and estimates of executable resource additions and retirements. These updated base resource availability assumptions were used to model the P3 Fall Base portfolio and related Pathway 3 sensitivity analyses. Applying these updated base resource availability assumptions to meet the significantly higher Updated 2023 Fall Load Forecast required nearly all available resources, with the Companies describing in the SPA that "the capacity expansion model selects nearly all available renewable and advanced nuclear resources available by 2035 to reach the Interim Target by that year in P3 Fall Base, leaving less than 2% of available solar capacity unselected."[47]

[45] CPIRP Chapter NC (2023-2024 CPIRP Update) at 11.

[46] Supplemental Planning Analysis at 28 (Table SPA 2-11: Combined DEC/DEP Annual Resource Availability Assumptions).

[47] Supplemental Planning Analysis at 38.

The Companies' SPA concluded that planning for the Updated 2023 Fall Load Forecast (let alone the higher Continued Economic Development Load Forecast) essentially required all available resources to be selected to achieve the Interim Target by 2035 and effectively rendered achievement of the Interim Target before 2035 unattainable. Nevertheless, as directed by the Commission's January 17, 2024 Order[48] providing direction regarding the Companies' supplemental modeling, the Companies again presented additional portfolio analysis for achieving the Interim Target by 2030 and, for completeness, also presented a P2 Fall Supplemental portfolio developed to achieve the Interim Target by 2033. The Companies provided P1 Fall Supplemental (with an Interim Target in 2030), and P2 Fall Supplemental (with an Interim Target in 2033) in a Technical Appendix to the SPA segregated from to the SPA's primary objective of presenting an updated, executable P3 Fall Base portfolio.

In summary, for certain portfolios, the Companies utilized inexecutable resource availability assumptions to present certain required modeling results to the Commission but, in doing so, was not affirming that that such availability assumptions (or the resulting model outcomes) were reasonable.

Q. PLEASE PROVIDE MORE DETAIL REGARDING THE PROCESS THAT LED TO THE P2 FALL SUPPLEMENTAL RESOURCE AVAILABILITY ASSUMPTIONS.

[48] Order Scheduling Public Hearings, Establishing Intervenors and Testimony Due Dates and Discovery Guidelines, Requiring Public Notice, and Providing Direction Regarding Duke's Supplemental Modeling, Docket No. E-100, Sub 190 (Jan. 17, 2024).

A. With the increased load forecast, to achieve the same Interim Target years, the Companies were required to increase resource availability of selectable resources to allow the models to solve against an accelerated achievement of the Interim Target. Because these portfolios were required by the Commission less than two weeks before the Companies committed to filing the SPA, the Companies took a simplified approach to allowing the model the necessary resources it needed to solve, generally making the Companies' base cumulative resource availability by 2035, enabling P3 Fall Base to achieve the Interim Target in 2035, to be available by 2030 and 2033 for P1 Fall Supplemental and P2 Fall Supplemental, respectively. For the avoidance of doubt, the Companies do not support these accelerated and significantly more aggressive resource availability assumptions as reasonable for planning purposes. Because the resource availabilities needed to model these portfolios exceed – and sometimes significantly exceed – the Companies' assumptions for when resources are first available along with annual and cumulative resource availability, the Companies designated these portfolios as "supplemental portfolios," as they did not believe the portfolios were reasonable for planning purposes but provided the Commission with additional information as directed.

Q. PLEASE CONFIRM THE COMPANIES' CONCLUSIONS REGARDING RESOURCE AVAILABILITY ASSUMPTIONS.

A. The Companies' base resource availability assumptions used in the development of P3 Fall Base remain the most reasonable for planning purposes, as explained in the testimonies of the Companies' Renewables and Battery

Storage Panel, Transmission and Interconnection Panel, and Long Lead Generation and Pumped Storage Hydro Panel. The Public Staff's significantly increased resource availability assumptions for solar, storage, onshore wind, and offshore wind create substantial execution risk and results in system reliability risk during the near-term period. In contrast, the Public Staff's P2 Fall Supplemental-informed resource availability assumptions used in their modeling are not attainable and do not maintain or improve reliability thereby making them unreasonable for planning purposes. I provide additional explanation as to why the Companies disagree with the Public Staff for each technology where they have adopted unreasonably aggressive modeling assumptions.

Q. THE PUBLIC STAFF INCREASED THE VOLUME OF SOLAR AND SOLAR PLUS STORAGE RESOURCES THAT COULD BE INTERCONNECTED AS SHOWN IN THE PANEL'S REBUTTAL TABLE 1. DO YOU BELIEVE THIS INCREASE IS REASONABLE?

A. No. The Companies do not believe that the Public Staff's assumptions represent a reasonable or executable volume of solar and solar plus storage resources that could be interconnected each year. The question of the appropriate volume of solar and SPS that should be assumed to be interconnected each year (and thus available for selection in the model) from a resource planning standpoint has been the subject of extensive debate and discussion before the Commission. This issue is addressed from an execution, procurement, interconnection and reliability standpoint by a number of panels, including later in this testimony, as well as in the Renewables and Battery Storage Panel and the Transmission and Interconnection Panel respective testimonies.

Q. THE PUBLIC STAFF'S ASSUMPTIONS REGARDING THE VOLUME OF ONSHORE WIND RESOURCES THAT ARE AVAILABLE FOR MODEL SELECTION ARE SIGNIFICANTLY HIGHER THAN THE COMPANIES' ASSUMPTIONS. WHY DO THE COMPANIES BELIEVE INCREASING THE VOLUMES OF ONSHORE WIND IN THIS MANNER IS NOT REASONABLE?

A. Onshore wind, while a proven technology in other parts of the country, remains a new-to-the-Carolinas resource, and thus, some uncertainty exists regarding the pace and volume of its development in the Carolinas. Based on the information known to the Companies today, Public Staff's assumptions do not represent a reasonable or executable volume of onshore wind resources that could be developed and commercially operational within the respective time frame. The Renewables and Battery Storage Panel's rebuttal testimony addresses the Companies' plans for onshore wind energy development and explains that based on the Companies' own development experience and information the Companies have received from industry experts, planning for the Public Staff's assumed increased volumes of onshore wind in the Carolinas is unrealistic at this time.

Q. THE PUBLIC STAFF'S MODELING ASSUMPTIONS FOR OFFSHORE WIND MOVE THE YEAR THAT OFFSHORE WIND COULD FIRST BE SELECTED FROM 2033 TO 2031 AND INCREASE THE

CUMULATIVE FROM 2,400 MW TO 5,500 MW, AS COMPARED TO THE COMPANIES' ASSUMPTIONS. DO YOU BELIEVE THESE CHANGES ARE REASONABLE?

A. No. The Companies do not believe that the Public Staff's assumptions represent a reasonable or executable volume of offshore wind resources. Company witness Roberts on the Transmission and Interconnection Panel discusses the challenges with interconnecting significant levels of offshore wind on an accelerated timeframe, as assumed by Public Staff in their modeling.

Q. PLEASE EXPLAIN FURTHER WHY THE PUBLIC STAFF'S ADJUSTMENT TO OFFSHORE WIND RESOURCE AVAILABILITY IS UNREASONABLE?

A. The Public Staff states that allowing offshore wind to first be available by 2031 is based on the Companies' P2 Fall Base resource availability.[49] As stated previously, the Companies accelerated resource availability, including the first deployment of offshore wind to 2031 in the P2 Fall Supplemental portfolio and 2028 in the P1 Fall Supplemental portfolio, simply as a modeling exercise to achieve interim compliance in 2030 and 2033 respectively.

Despite adopting this modeling assumption in its base modeling, Public Staff witness Thomas recognizes that achieving a 2031 interconnection for any amount of offshore wind may be an aggressive assumption, and then goes on to note that based on information Public Staff obtained after modeling assumptions had been finalized that 2032 is likely the earliest that even the

[49] Public Staff Thomas Direct Testimony at 59.

furthest along offshore wind energy resource could be available to the Companies.[50] Public Staff witness Lawrence goes further, suggesting that offshore wind is "unlikely to become available before 2034-2035."[51] In other words, the offshore wind timing assumed by Public Staff in its modeling is not supported and is even contradicted by its own testimony.

The Companies maintain that while some estimates from developers may indicate that these offshore wind facilities could achieve commercial operation on accelerated timeframes, the transmission required to reliably integrate these resources would be challenging even at the Companies' SPA resource availability assumption of 800 MW by 2033 and 1,600 MW by 2034, on top of the other challenges facing offshore wind development as discussed in the initial Plan and SPA.[52] Companies witness Roberts on the Transmission and Interconnection Panel confirms this view in his rebuttal testimony, suggesting that the planning and construction of new transmission upgrades required to interconnect offshore wind is expected to take approximately eight years. Likewise, Public Staff witness Metz opines on the potential challenges related to integrating offshore wind into the system from an interconnection and transmission system network upgrade perspective.[53]

Q. DO YOU HAVE OTHER CONCERNS WITH THE PUBLIC STAFF'S OFFSHORE WIND RESOURCE AVAILABILITY ASSUMPTION?

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[50] Public Staff Thomas Direct Testimony, at 92.

[51] Public Staff Lawrence Direct Testimony, at 5.

[52] Supplemental Planning Analysis at 27.

[53] Public Staff Metz Direct Testimony at 64-65

A. Yes. In addition to assuming an unreasonable first year of availability in 2031, the Public Staff also assumes 5,500 MW of offshore wind available for selection in their model by 2035. Selecting 4,400 MW or 5,500 MW of offshore wind by the mid-2030s would require the Companies to almost immediately pursue development of offshore wind at both Kitty Hawk and Carolina Long Bay ("CLB") across the four Wind Energy Areas ("WEAs").

Q. PLEASE EXPLAIN WHY DEVELOPING MULTIPLE OFFSHORE WIND PROJECTS AT THE SAME TIME PRESENTS UNNECESSARY RISK TO CUSTOMERS.

A. With a relatively new and developing domestic offshore wind energy supply chain, developing one project of this scale, let alone two, would present customers with significant cost and execution risk. As outlined in Appendix I (Renewables and Energy Storage) of the Plan, the offshore wind market on the east coast of the United States is still nascent with only a small number of projects in late-stage development or early construction. Additionally, an immature supply chain and inflationary pressures resulting in rising capital costs and interest rates, have led to projects recently being cancelled[54] or power purchase agreement terms being requested to be renegotiated.[55] The anticipated scale of capital investment for offshore wind resources must be balanced with a prudent pace that follows technology adoption in the United States, and that

[54] NYSERDA 2022 Offshore Wind Solicitation, https://www.nyserda.ny.gov/All-Programs/Offshore-Wind/Focus-Areas/Offshore-Wind-Solicitations/2022-Solicitation (last visited July 1, 2024) (explaining that in April 2024, material modifications to key turbine components causing "technical and commercial complexities" resulted in three offshore wind project bids in New York being cancelled.).

[55] Offshore Wind Market Report: 2023 Edition, U.S. Department of Energy.

includes staggering projects to better align with market maturity and to reduce risks related to timely and cost-effective delivery on behalf of customers. Company witness Roberts also highlights in his rebuttal testimony that targeting a second WEA/project exceeding 2,400 MW would require the siting and construction of new greenfield transmission to bring the wind energy ashore and deliver it to load. As such, the Companies limited offshore wind resource availability to generally the amount of capacity either the joint CLB areas or Kitty Hawk areas could provide. Despite allowing the modeling to select up to 5,500 MW by 2035, Public Staff witness Lawrence testifies that with current uncertainty regarding offshore wind development timelines and cost, that pursuing only 2,200 MW of offshore wind through the planned Acquisition Request for Information ("ARFI") is appropriate at this time.[56]

Q. DO YOU AGREE WITH PUBLIC STAFF'S RESOURCE AVAILABILITY ASSUMPTION THAT A NEW COMBINED CYCLE FACILITY CAN BE CONSTRUCTED IN BOTH DEC AND DEP IN 2029?

A. No. While the Companies recognize that imposing resource availability constraints on the model can impact resource selection and portfolio cost, it is critically important that modeling is informed by evolving Plan execution and does not assume inexecutable options that cannot be achieved in the real world. Similar to the Public Staff's aggressive and unrealistic assumptions on early availability of offshore wind, the Public Staff's flawed assumptions also allows

[56] Public Staff Lawrence Direct Testimony at 45-46.

the model to select CC generation in either DEC or DEP beginning in 2029. In contrast, the Companies modeling assumes a CC is first available for selection in DEP in 2029, an accelerated timeframe relative to DEC, to reflect ongoing development of CC1 and CC2 generation at Roxboro Station in DEP that is already underway today.

Q. PLEASE DESCRIBE THE COMPANIES' RESOURCE AVAILABILITY ASSUMPTION FOR NEW COMBINED CYCLE FACILITIES IN MORE DETAIL.

A. The Companies' SPA base planning assumptions allow the model to select up to six CC units in total over the planning horizon.[57] Additionally, the model allows no more than two CCs in DEP due to current assumptions on pipeline availability and allow no more than two CCs collectively in any given year to reflect practical execution risks and limits that it would be extremely challenging and risky to plan for more than two CC projects being placed into service in any single year. Furthermore, the model allowed DEP to start selecting CCs in 2029 while the earliest date for DEC was 2031. These in-service date differences reflect the early development work already underway for DEP's Person County CC1[58] which has completed transmission studies and has filed for both a CPCN and air permit to allow for commercial operation by 2029. Conversely, the model does not allow a new DEC CC to be in service

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[57] *See* Supplemental Planning Analysis at 26-27 (Table SPA 2-11).

[58] *See* SPA Table SPA 4-1 (identifying plans to construct "CC1" at Roxboro in DEP to achieve commercial operation by January 1, 2029).

until 2031 as no CC site in DEC is as far along in early development activities as the Person County site in DEP.

Q. PLEASE EXPLAIN WHY THE PUBLIC STAFF'S ASSUMPTION TO ALLOW ITS MODEL TO SELECT COMBINED CYCLE FACILITIES IN DEC STARTING IN 2029 IS NOT REASONABLE.

A. The Companies did not allow the model to select a combined cycle in DEC in 2029 because it is technically and commercially impossible and inexecutable for a new CC to be developed and operational in DEC by 2029, as further explained by the Dispatchable Generation Panel. The first year that a DEC-sited CC can be operational is 2031, based on current lead time requirements.[59] The Public Staff's decision to accelerate CC resource availability in DEC to 2029 creates an artificial and unreasonable assumption that affects follow-on modeling processing, and impacts various other model selection results as described in more detail below, but has significant impact to siting of DEC and DEP gas resources, compounded by other resource availability assumptions made by the Public Staff.

Q. DOES THE PUBLIC STAFF PROVIDE AN EXECUTABLE PLAN TO PLACE A CC INTO COMMERCIAL OPERATION IN DEC EARLIER THAN 2031?

A. No. As further addressed by the Dispatchable Generation Panel, this is not a reasonable assumption based on the Companies' ongoing Plan execution, and

[59] See CPIRP Appendix C at 35.

the Public Staff fails to provide any meaningful support for Plan execution to achieve commercial operation of a CC in DEC by 2029.

Q. YOU IDENTIFY IN SECTION II. A. ABOVE THAT THE PUBLIC STAFF SUPPORTS THE COMPANIES' 22% PLANNING RESERVE MARGIN. ARE THERE DIFFERENCES IN HOW THE PUBLIC STAFF'S MODELING APPLIED THE INCREASE IN RESERVE MARGIN FROM 17 PERCENT TO 22 PERCENT?

A. Yes. While the Public Staff's modeling achieves the increased 22 percent reserve margin in 2031, the same year as the Companies, the Public Staff' applies the total 5 percent increase to the reserve margin all in one year, 2031. In contrast, the Companies grow into the reserve margin incrementally by 2031 as described in Table SPA T-1 of the Companies SPA Technical Appendix.[60] Specifically, the Companies apply this increase over a five-year period from 2027 to 2031. Table 2 below summarizes the winter planning reserve margin constraints assumption between the Companies' SPA modeling and the Public Staff's modeling.

Table 2: Winter Planning Reserve Margin Constraints Assumption

Winter Planning Reserve Margin	CPIRP SPA Modeling	Public Staff Modeling
2024 – 2026	17%	17%
2027	18%	17%
2028	19%	17%
2029	20%	17%
2030	21%	17%
2031+	22%	22%

[60] Supplemental Planning Analysis Technical Appendix at 5.

Q. DO YOU BELIEVE PUBLIC STAFF'S DELAYED APPROACH TO INCREASING THE RESERVE MARGIN IS REASONABLE TO ACHIEVE RESOURCE ADEQUACY AND MAINTAIN OR IMPROVE RELIABILITY?

A. No. While there is no standard way to apply the Companies' increase in reserve margin, the fundamental objective of the reserve margin is to set a minimum threshold of target capacity to maintain reliability and to then plan and operate with reserves at or above that threshold. In developing the Plan, the Companies saw the challenge of maintaining reliability and immediately increasing the reserve margin from 17% to the Resource Adequacy Studies' recommended 22% reserve margin, in a timeframe where the Companies are executing an orderly transition out of coal while economic development load continues to drive significant energy and capacity needs for the system. Navigating this dynamic environment, while prioritizing reliability, requires the Companies to make progress on available resources in this time frame as an essential step to maintaining or improving the reliability of the grid. Public Staff witness Thomas acknowledges that "the period between approximately 2028 and 2032 is extremely constrained, with significant load growth and limited options for adding new resources."[61] The Public Staff's modeling assumption represents increased reliability risk relative to the Companies' modeling during this critical transitional timeframe as they impose a lower reserve margin requirement in these critical years. For example, in 2030, the Companies' reserve margin

[61] Public Staff Thomas Direct Testimony at 59.

modeling assumption plans for the system to add nearly 1.5 GW of additional firm capacity over the Public Staff's approach, which could be critical to maintaining reliable system operations as approximately 2.6 GW of new winter peak load is projected to be added to the system between 2027 and 2030.

Q. DO YOU AGREE WITH PUBLIC STAFF'S IMPOSITION OF A TRANSMISSION TRANSFER RATE TO SERVE AS A HURDLE RATE FOR TRANSFERRING ENERGY BETWEEN THE COMPANIES VIA THE JOINT DISPATCH AGREEMENT ("JDA")?

A. No. From a modeling standpoint, the Public Staff is conflating the concepts of cost allocation from a retail ratemaking standpoint with planning assumptions that are appropriate to be reflected in developing a model for IRP purposes. The Companies understand the Public Staff uses the Companies' FERC-approved Joint Open Access Transmission Tariff (OATT) to derive a hurdle rate cost for transferring energy between DEC and DEP in the capacity expansion modeling when optimizing the location of resources between DEC and DEP.[62] The intent of Public Staff's hurdle rate is to provide for an economic penalty to encourage siting incremental resources in the jurisdiction that receives energy flows and, in effect, to reduce power flows between the utilities. The Public Staff expresses concern that, in its CPIRP modeling, DEC may be unduly benefitting from resources that are selected in DEP, utilizing the transmission system to flow that energy to ultimately serve DEC load.

[62] Public Staff Metz Direct Testimony at 35-37.

The Companies understand the Public Staff's concerns regarding power flows between utilities and the potential for CPIRP investments to potentially drive rate differences between DEC and DEP (even though the Companies' analysis actually shows rate differences being reduced over time). However, this transfer cost proxy is not a real cost applicable to energy transfers through the JDA, as Public Staff witness Metz concedes.[63] Furthermore, including this non-existent cost adder is not appropriate in CPIRP modeling because imposing a "proxy" cost for non-firm energy transfers is not a real cost impacting operation of the system; accordingly, this cost should not be factored into the optimization of resources, but addressed with respect to cost allocation in rates proceedings should this issue not be resolved via a planned merger of the utilities or other cost allocation approaches. Imposing such assumption, which does not reflect an actual cost in the real world, artificially impacts the selected resources and arguably penalizes DEP by forcing alternative, less cost-effective resource selections to meet DEP's capacity needs. Furthermore, assuming that a merger is ultimately completed, Public Staff's hurdle rate simply results in less cost-effective resource selection overall, which would result in a more costly system in a post-merger scenario than would otherwise have been the case.

Q. DO YOU HAVE OTHER SPECIFIC CONCERNS WITH THE PUBLIC STAFF'S TESTIMONY ON THIS ISSUE?

[63] Public Staff Metz Direct Testimony at 43.

A. Public Staff witness Metz expresses his concerns regarding power flows by focusing solely on incremental gas resources; however, as witness Metz recognizes, Public Staff's modeling assumptions of high levels of offshore wind and solar in DEP are the primary drivers of DEP to DEC power flows rather than the natural gas resources being built in DEP to replace retiring DEP coal units.[64] Stated differently, the primary driver of increased energy flows is not new natural gas generation but instead is the offshore wind as well as solar and onshore wind resource, many of which Public Staff's modeling assumes at even higher (and unrealistic) amounts compared to the Companies' modeling, as discussed above.

Q. DO YOU AGREE WITH PUBLIC STAFF'S VIEW THAT THE COMPANIES' CARBON ACCOUNTING METHODOLOGY SHOULD NOT ASSUME A NEW COMBINED CYCLE FACILITY WILL BE BUILT IN SOUTH CAROLINA?

A. No. Public Staff witness Thomas does not dispute that excluding South Carolina-sited emissions sources from the North Carolina carbon emission constraint is reasonable,[65] but instead identified uncertainties regarding when a unit would be proposed and if it would be approved by the Public Service Commission of South Carolina ("PSCSC").[66] The Commission's Carbon Plan Order states that "it is appropriate for modeling purposes for Duke to assume

[64] Public Staff Metz Direct Testimony at 40.

[65] Public Staff Thomas Direct Testimony at 24.

[66] Public Staff Thomas Direct Testimony at 20.

that all new carbon dioxide-emitting resource will be located in North Carolina."[67] However, the Companies view this determination as applicable to *generic* resources where the Companies have not yet progressed execution. As explained in the Dispatchable Generation Panel's testimony, DEC is pursuing plans to site CC3[68] in South Carolina to achieve commercial operation in 2031 and has taken substantial execution activities, including recently submitting an interconnection request in the Definitive Interconnection System Impact Study ("DISIS") queue for a new CC that will be located in South Carolina. These execution-focused actions represent the significant steps necessary to support the assumption that CC3 will be located in South Carolina and align with the Companies' approach to allocating emissions for CC3 in its SPA modeling. The Public Staff has recognized in discovery that a site-by-site approach to the location of new carbon emitting generating facilities is appropriate and that definitively pursuing interconnection via DISIS is a significant development step (along with submitting local planning application and negotiating for fuel supply) to inform when new planned generation should no longer be viewed as generic IRP resources for modeling purposes. See IRP and Near-term Action Panel Rebuttal Exhibit 3. The Companies continue to support their modeled approach to CC3 as reasonable for planning purposes and reflective of execution planning that is underway today.

[67] Carbon Plan Order at 35 (Finding of Fact 2).

[68] See SPA Table SPA 4-1 (identifying plans to construct CC3 in South Carolina and to file application for SC Certificate of Environmental Compatibility and Public Convenience and Necessity ("CECPCN") and air permit in 2025).

C. Other Notable Modeling Concerns

Q. DID THE COMPANIES DISCOVER OTHER MODEL INPUT DISCREPANCIES OR ERRORS IN PUBLIC STAFF'S MODELING THAT CONTRIBUTE TO THE LIMITED DIFFERENCES BETWEEN THE COMPANIES' RESULTS AND THOSE OF THE PUBLIC STAFF?

A. Yes. As discussed below there are a finite number of additional issues with Public Staff's modeling that need to be considered when examining differences in the pace, scope and scale of resource additions selected in the Public Staff's modeling results relative to the Companies' results. The subsequent section highlights these issues and provides perspective on the nature and magnitude of the various issues.

Q. PLEASE DESCRIBE THE COMPANIES' MODELING INPUT ERROR REGARDING THE FIRM TRANSPORTATION COSTS ASSUMED IN THE SELECTION OF DEP COMBINED CYCLES THAT WAS DISCOVERED IN REVIEWING PUBLIC STAFF'S TESTIMONY?

A. In reviewing the Public Staff's testimony and analysis, the Companies realized that Public Staff's firm transportation ("FT") costs assumed in the selection of DEP CCs were based on an erroneous assumption derived from the Companies' SPA modeling provided to the Public Staff in this Docket. The Companies' EnCompass modeling data, which was provided by the Companies and used by Public Staff as a starting point, contained an input error in the interstate FT fuel rate for the new DEP CC units. The Companies incorrectly used the same generic interstate FT rate for the DEP CC from the initial Plan filing, which should have been updated to reflect updated market information as discussed in the SPA.[69] As discussed in more depth later in our testimony, correcting this erroneous input assumption in Public Staff's modeling results in their model siting the first CC in DEP which is consistent with the Companies results for the siting of the first CC in 2029.

Q. PLEASE EXPLAIN HOW THE PUBLIC STAFF INCORPORATED THE POWERPAIR PROGRAM INTO ITS MODELING AS A SELECTABLE RESOURCE.

A. As discussed above, the Companies' BTM solar and battery pilot program, PowerPair, was approved by the Commission in early 2024. As such, the Companies have no experience or results from this pilot and therefore it was not assumed as part of the demand side resources forecasted in the SPA modeling. By contrast, the Public Staff's modeling introduced paired BTM solar and battery (such as an expanded PowerPair program) as a newly selectable resource despite having no company data to base projected levels of customer participation and retention. The purpose of the PowerPair pilot is to further develop and understand the full suite of system benefits that may, or may not, be realized from the utility being able to control distributed energy resources or potentially benefits realized through price signals influencing customer usage of BTM resources within the pilot. While potentially a promising program it is clearly premature to count on significant capacity and energy contributions from this program at this point in time. Nonetheless,

[69] Supplemental Planning Analysis at 25.

Public Staff included this as a selectable resource in the Public Staff's modeling in units consisting of 1 MW of BTM solar paired with 0.5 MW/2.7 MWh of BTM batteries. The Public Staff priced the units at $360/kW for the BTM solar and $1,080/kW for the BTM storage, with no inflation over time and modeled the resource as a capital cost to the Companies rather than a program cost, assuming the customer elects to pay for the remainder of the cost of the installation. The Public Staff allowed 30 units of the resource to be selected beginning in 2023 and then more annually in 2028 and forward. The cumulative capacity available for the model to select was over 2,000 MW of behind the meter solar with over 900 MW of battery through 2050. The resource is noted in the Public Staff's modeling that each 1 MW BTM solar and 0.5 MW / 2.7 MWh resource represents 100 customers. This level of availability equates to approximately 185,000 C&I customers committing to participate in this type of program, or the equivalent of 28% of DEC's and DEP's non-residential customers as of 2023. The Grid Edge and Customer Solutions Panel discusses the PowerPair pilot program and challenges with the Public Staff's assumption for growth of this program.

Q. WHAT CONCERNS DO YOU HAVE WITH PUBLIC STAFF'S MODELING OF A MODEL SELECTABLE DEMAND-SIDE RESOURCE, SUCH AS BTM SOLAR AND STORAGE THROUGH A PROGRAM LIKE POWERPAIR?

A. Public Staff witness Thomas recommends the Commission "direct Duke to consider incorporating new DSM programs in future CPIRP cycles that can be economically selected by the EnCompass model".[70] It has been the Companies long-standing position regarding modeling EE and demand response that these valuable grid edge resources should be modeled as load modifiers or forecasted dispatchable resource and not 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 its role as does 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. While Public Staff witness Thomas points to creative solutions for enabling new resources to the system which can help in the transition of the system, the future availability of the collective resources has no actual system result nor firm analysis on program executability as described in Grid Edge and Customer Solutions Panel's testimony and it does not account for cannibalizing existing NEM/DSM forecasts, already assumed by the Companies. The Companies understand that the intention of the Public Staff's modeling approach is to assess the economic viability of the current PowerPair pilot (or potential future programs) and to assess the impact of the program to the resource portfolio, but the Companies disagree with the Public Staff's approach

[70] Public Staff Witness Thomas Direct Testimony at 124.

to determining the need for supply-side resources to maintain the reliability of the grid.

Q. HAS THE COMMISSION RECENTLY ADDRESSED HOW ENERGY EFFICIENCY SHOULD BE TREATED FOR IRP MODELING PURPOSES?

A. Yes. The Commission affirmed in its Order approving the new CPIRP rule, Commission Rule R8-60A, that "[f]or purposes of utility planning, the electric public utilities shall model energy efficiency as a load modifying resource, ensuring its priority in utility planning"[71] In the Carbon Plan Order, the Commission agreed with the Companies approach that "to reduce load through Grid Edge programs, including demand-side management, EE, customer self-generation, and voltage management, is a reasonable step towards achieving reductions in carbon dioxide emissions as required by N.C.G.S. § 62-110.9."[72] The Commission agreed with the Companies that "EE is a unique resource, in that customer adoption levels restrain it, and that allowing the model to select EE may overstate the amount of EE that Duke may cost effectively implement."[73] The same limitations apply to demand side management programs, as well.

[71] Rule R8-60A(f)(5).

[72] Carbon Plan Order at 106.

[73] Carbon Plan Order at 106.

Q. HOW DOES PUBLIC STAFF'S MODELED POWERPAIR PROGRAM RELATE TO THE GRID EDGE RESOURCES DUKE ENERGY HAD ALREADY INCLUDED IN MODELING?

A. It likely has the effect of double counting some amount of assumed Grid Edge resource customer participation.[74] The Companies' modeling already includes significant Grid Edge resources on the system today, totaling 1449 MW of Winter capacity. Over the Base Planning Period, growth in Grid Edge resources as either load reductions (load modifiers) or a forecast of controllable (dispatchable) resources is expected to expand significantly by over 2,600 MW contributing to winter peak planning capacity, as illustrated below in Figure 2, for a total of over 4,000 MW of winter peak grid edge capacity by 2038.

[74] Order Adopting Commission Rule R8-60A and Amending Commission Rules R8-60, R8-67, and R8-71, Docket No. E-100, Sub 191 (Nov. 20, 2023).

Figure 2: Growth in Grid Edge Resources (Winter MW) – Carolinas Combined System

Type	Program	2033	2038
Load Modifier	Utility Energy Efficiency (UEE)	924	1,095
	Net Energy Metering (NEM)	46	62
	Time of Use Rates (TOU)	383	538
Controllable Resource	Retail Demand Response (DR)*	618	761
	Integrated Volt-Var Control (IVVC)	116	137
	Wholesale Demand Response (DR)*	12	19
	Total:	**2,098**	**2,613**

** Includes Standby Generation, Interruptible Service, and other Demand-Side Management programs*

Q. HOW DO YOU RESPOND TO THE PUBLIC STAFF'S CRITICISM THAT THE COMPANIES DID NOT INCORPORATE THE ENERGY INFRASTRUCTURE REINVESTMENT PROGRAM ("EIR PROGRAM") INTO THEIR MODELING?

A. Public Staff witness Thomas states that the Companies should have considered assumptions around the EIR Program in its modeling and "aggressively investigate and apply for EIR Program funding for CPIRP projects."[75] Public Staff's EIR Program assumptions reduced the present value of revenue requirements ("PVRR") of Public Staff's PS – 2034 Base portfolio, although the assumptions were not a significant driver for renewable resource selection

[75] Public Staff Thomas Direct Testimony at 103-105.

differences as compared to the Companies' resource selections as both parties selected renewable levels at or near the availability maximums over the EIR Program eligible period. Furthermore, the Public Staff failed to account for all the potential costs and adverse effects of such a financing structure as addressed by the rebuttal testimony of Company witnesses Jordan Morgan and Paige Swofford.

D. The Companies' Sensitivity Analysis Evaluating the Impact of EPA CAA Section 111 Final Rule Confirms the Need for New Natural Gas CC Generation

Q. PLEASE DISCUSS MATERIAL CHANGES IN APPLICABLE LAW OR REGULATION THAT HAVE OCCURRED AFTER FILING THE COMPANIES' SUPPLEMENTAL PORTFOLIO ANALYSIS.

A. As a general rule, the Companies' modeling process must "snap the chalk line" on modeling inputs and assumptions to capture the best available information at a given snapshot in time with the understanding that updates can be made in future planning cycles. However, the Companies also continually evaluate whether changes in applicable laws or regulations could have such a material impact to modeling assumptions and resource selection that it is appropriate to perform supplemental analysis to ensure the proposed Plan remains robust and reasonable for planning purposes. During the 2022 Carbon Plan proceeding, Congress' enactment of the Inflation Reduction Act of 2022 only weeks before the evidentiary hearing necessitated such supplemental modeling as part of the Companies' rebuttal case. In this proceeding, the U.S. EPA's recently finalized rules under CAA Section 111 Final Rule again warrants supplemental analysis to ensure the reasonableness of Plan assumptions and results.

Q. PLEASE DISCUSS THE NEW CAA SECTION 111 FINAL RULE AND HOW IT IMPACTS THE COMPANIES' MODELING?

A. At a high level, the CAA Section 111 Final Rule establishes emission guidelines for existing coal plants and greenhouse gas ("GHG") emission limits for new natural gas generating facilities. Companies' witness Venu Ghanta on the Dispatchable Generation Panel explains the Final Rule in greater detail, including the specific impacts to coal and natural gas-fired generating facilities and potential options for compliance with the Final Rule.

Q. PLEASE BRIEFLY DESCRIBE THE PRIMARY COMPLIANCE PATHWAYS UNDER THE CAA SECTION 111 FINAL RULE.

A. The Final Rule includes restrictive measures on both existing coal units and new natural gas generation. As explained in more detail by the Dispatchable Generation Panel, the Final Rule would potentially impact the retirement dates or fuels used by existing coal units to meet emissions guidelines and require emissions standards for selectable CCs and CTs in the Companies' modeling. Table 3 below presents a high-level summary of the emissions guidelines for existing coal and emissions standards for new gas, including the EPA's specific best system of emissions reduction ("BSER") for the Final Rule is provided below.

Table 3: CAA Section 111 Final Rule Summary

Existing Coal	New Gas
Existing coal units are exempt if they retire by December 31, 2031	**Base Load** (>40% capacity factor) **Phase 1** 800 lbs. of CO_2 per MWh emission rate upon commercial operation (BSER: Highly efficient natural gas combined cycle generation) **Phase 2** 100 lbs. of CO_2 per MWh emission rate by January 1, 2032 (BSER: CCS with 90% capture rate)
Medium-Term Subcategory Presumptive 16% CO_2 emission rate reduction by January 1, 2030 (BSER: 40% co-fire with natural gas) must retire by 12/31/2038	**Intermediate Load** (20-40% capacity factor) 1,170 lbs. of CO_2 per MWh emission rate (BSER: Highly efficient natural gas simple cycle generation)
Long-Term Subcategory Presumptive 88.4% CO_2 emission rate reduction by January 1, 2032 (BSER: Carbon Capture and Sequestration/ Storage (CCS) with 90% capture rate) Continue operations indefinitely	**Low Load** (<20% capacity factor) Use of fuel with less than 160 lbs. of CO_2 per MMBtu (BSER: Lower emitting fuels, such as natural gas)
An existing coal unit may operate beyond 12/31/2039 by switching to the gas steam category through conversion to 100% natural gas firing by 1/1/2030. Base load units must comply with a 1,400 lbs. of CO_2 per MWh emission rate.	

For new gas resources, the Companies do not believe 90% CCS in operation by 2032 is feasible. Therefore, the Companies are conservatively assuming all new gas will be limited to Intermediate Load operations (20%-40% annual capacity factor) in order to achieve the emissions standard from technologies available in the Carolinas. The Companies will continue to monitor new developments related to the Final Rule and other regulations that impact our modeling, including results from the Companies' CCS study in the Carolinas. But to be clear, this reduced capacity factor is a clear and unambiguous compliance pathway under the Rule.

Q. ARE OTHER PATHWAYS TO COMPLIANCE FOR EMISSIONS STANDARDS FOR NEW GAS RESOURCES UNDER THE CAA SECTION 111 FINAL RULE AVAILABLE TO THE COMPANIES?

A. Yes. The CAA Section 111 Final Rule's emissions standard for Base Load new gas resources is an emissions rate of 100 lbs. of CO2 per MWh based on a BSER for this standard of CCS with a 90% capture rate. The Companies have begun to evaluate CCS in the Carolinas, but they do not believe it can be installed and operating by 2032 given the maturity of this technology and the time required for implementation of such a project. Utilizing hydrogen blending can also be used as a compliance pathway, so long as a resource can meet the emissions standard. The Companies, similarly, did not include high levels of hydrogen blending in this sensitivity analysis. The Final Rule does allow for new gas resources to switch between categories, so in the future, if incremental costs for complying with the Base Load emissions standards are economical compared to limiting operation of these units, the Companies may consider these technologies to reduce costs for customers in achieving carbon neutrality by 2050. The Companies will continue to monitor the development of these innovative technologies and will evaluate them in future iterations of the CPIRP.

Q. DID THE COMPANIES' MODELING TAKE INTO ACCOUNT THE CAA SECTION 111 PROPOSED RULE IN THE INITIAL PLAN?

A. Yes. The initial Plan addressed the EPA Section 111 proposed rule and presented the results of supplemental portfolio analysis of the proposed rule in Chapter 3

(Portfolios) and Appendix C (Quantitative Analysis) to the CPIRP.[76] Because the proposed rule was still under agency review at the time of the development of the initial Plan or the SPA, the Companies did not include the impacts of the proposed rule in it base planning assumptions but conducted sensitivity analysis to develop a supplemental portfolio to account for the proposed rule.

Q. DOES THE PUBLIC STAFF SUPPORT THE COMPANIES PROVIDING SUPPLEMENTAL MODELING TO ASSESS THE IMPACT OF THE NEW CAA SECTION 111 FINAL RULE ON THE COMPANIES' CPIRP AND PROPOSED EXECUTION PLAN?

A. Yes. Public Staff witness Metz states, "the final CAA Rule's impact on the energy sector remains uncertain, potentially affecting the long-term viability of CC generation as a bridge technology to carbon free resources."[77] Public Staff as well as other intervenors also identify that portfolio costs and coal retirements could be affected by the Final Rule.[78] This leads Public Staff witness Metz to express concern that "[t]he Companies have not presented a plan indicating how they will comply with the CAA Rule in their primary portfolio, or even for the two active natural gas CPCNs at Marshall and Roxboro."[79]

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[76] CPIRP Chapter 3 at 21-22; Appendix C at 99-101.

[77] Public Staff Metz Direct Testimony at 92.

[78] Public Staff Metz Direct Testimony at 94. Public Staff Nader Direct Testimony at 18-19. SACE et al. Roumpani Direct Testimony at 16-17 and 50-55. Appalachian Voices Hansen Direct Testimony at 4, 7-8 and 19-20.

[79] Public Staff Metz Direct Testimony at 155.

Consistent with the Companies' past IRP practice of assessing potentially significant impacts to the resource Plan and in response to these concerns raised by the Public Staff, the Companies have performed supplemental modeling to evaluate compliance with the CAA Section 111 Final Rule ("CAA Final Rule Sensitivity Analysis"). This analysis is presented as IRP and Near-Term Actions Panel Rebuttal Exhibit 1 and is further discussed below.

Q. PUBLIC STAFF WITNESS NADER RECOMMENDS THAT THE COMPANIES STUDY THE IMPACTS TO THE P3 FALL BASE ASSUMING ALL NEW CCs ARE LIMITED TO 40% ANNUAL CAPACITY FACTOR.[80] HAVE THE COMPANIES CONDUCTED THIS ANALYSIS?

A. Yes. The Companies' CAA Final Rule Sensitivity Analysis presents the impacts of the Final Rule to the P3 Fall Base portfolio assuming all new CCs are limited to 40% annual capacity factor because the Companies do not assume CCS will be installed and operating in the Carolinas by 2032, a timeframe which the Companies' view as unrealistic given the maturity of the technology and the time required for such a project. This analysis assesses the impacts of the Final Rule on resource selection, portfolio cost, and year in which achieving the Interim Target can be achieved. As discussed above, a capacity factor limitation on new gas resources will be the primary pathway to compliance with the Final Rule until more information is available regarding CCS in the Carolinas and

[80] Public Staff Nader Direct Testimony at 19.

other pathways to meeting the emissions standards for new Gas CCs. Since the Companies are not relying on the capabilities of CCs with CCS to assess the need and cost effectiveness of new gas CCs, the Companies did not perform any analysis regarding CCS with updated costs at this time.

Q. PLEASE BRIEFLY DESCRIBE THE IMPACT OF THE CAA SECTION 111 FINAL RULE ON THE P3 FALL BASE PORTFOLIO AS ASSESSED IN THE CAA FINAL RULE SENSITIVITY ANALYSIS.

A. The Companies' first step in the evaluation of the CAA Section 111 Final Rule was to apply the rules and restrictions directly to the previously presented Portfolio P3 Fall Base in order to quantify the impact of the Final Rule on the Plan. This analysis implemented the Companies' EPA 111 modeling assumptions for gas capacity factor restrictions, moved Cliffside 6 gas conversion up to 2030 (from 2036), and maintained P3 Fall Base coal retirements dates. Since Portfolio P3 Fall Base already reaches near maximum feasible interconnection limits for carbon-free resources, when the Final Rule capacity factor restrictions are applied to new gas CCs and CTs, the model is not able to shift this "lost" gas generation to renewable resources. Instead, in order to continue to serve the annual energy demand of the system, the model is forced to shift this generation to less efficient fossil resources – specifically, existing CCs, existing CTs, and existing coal units. As such, the impact of the Final Rule on the P3 Fall Base portfolio is an increase in CO2 emissions of over 4 million tons in the year 2035, a likely delay in achieving the Interim Target to 2036 or later, and an increase in the total system cost of more than $600 million.

Q. DOES THE COMPANIES' CAA FINAL RULE SENSITIVITY ANALYSIS CONFIRM THE NEED FOR THE FIVE COMBINED CYCLES INCLUDED IN THE COMPANIES' NTAP?

A. Yes. As further described in IRP and Near-Term Action Panel's Rebuttal Exhibit 2, the Companies' CAA Final Rule Sensitivity Analysis continues to support the Companies' proposed NTAP consisting of an all of the above approach to selecting new resources to meet the needs of the system. As observed in the supplemental portfolio analysis on the initially proposed rule presented in the initial Plan,[81] despite capacity factor restrictions, the portfolios continue to economically select new natural gas CC and CT resources to maintain reliability, meet load growth and enable economic development, and provide CO_2 emissions reduction for the system in the near and medium term, while providing long-term system flexibility and reliable dispatchable resources. The new gas resources are particularly important given the amount of variable energy and energy-limited resources that continue to be selected in these sensitivity analyses, confirming the criticality of this resource to serve important reliability functions on a long-term basis. Table 4 below summarizes the resources required under the Companies' NTAP evaluated pursuant to the CAA Final Rule Sensitivity Analysis.

[81] The initially proposed rule including restriction on existing natural gas fired CC units. This emissions guideline was removed in the Final Rule, but somewhat captures the more stringent effects of the capacity factor limitation assessed on new gas resources from approximately 50% to 40% capacity factor limitation for Base Load resources.

Table 4: NTAP Resources Compared to NTAP of CAA Final Rule Sensitivity Analysis

Resource Type	Resources Needed Through Year	NTAP Resources [MW]	NTAP Resources [MW] CAA Final Rule Sensitivities	NTAP Changes
Solar	2031	6,460	6,460	Confirmed Need
Battery Storage	2031	2,700	2,700	Confirmed Need
Onshore Wind	2033	1,200	1,200	Confirmed Need
CT	2032	2,125	2,125	Confirmed Need
CC	2033	6,800	6,800	Confirmed Need
Pumped Storage	2034	1,834	1,834	Confirmed Need
Advanced Nuclear	2035	600	600	Confirmed Need
Offshore Wind	2035	2,400	0 – 2,400	Potential Flexibility to Delay*

*Potential Flexibility based on whether Interim Compliance is targeted for 2036 or 2037, as explained below

Q. PLEASE SUMMARIZE THE ADDITIONAL KEY TAKEAWAYS FROM THE COMPANIES' CAA RULE FINAL SENSITIVITY ANALYSIS, ASIDE FROM VERIFYING THE APPROPRIATENESS OF THE COMPANIES' PROPOSED NTAP.

A. As discussed above and in more detail in the IRP and Near-term Action Panel Rebuttal Exhibit 2, the CAA Section 111 Final Rule results in increased customer cost and increased CO_2 emissions, which delays achieving the Interim Target beyond 2035 due to the inability to fully utilize highly efficient new natural gas combined cycle generation to meet load.

With the Companies' aggressive, but achievable resource availability assumptions, the system cannot meet the Interim Target by 2035, even when reoptimizing the resources selected. Because the Companies' modeling in Portfolio P3 Fall Base selects nearly all of the available carbon-free resources, in addition to five CCs, to meet the Interim Target in 2035, there are no incremental new low-carbon or zero carbon resources available for the model to select to supplement this low-carbon energy shortfall by 2035 when compliance with the Final Rule requires generation from new highly-efficient gas resources to be restricted to 40% capacity factors beginning in 2032. As a result, in order to serve load, the system is forced to operate more CO_2 emission intensive existing resources (including existing coal resources), resulting in the increases to cost and CO_2 emissions. Accordingly, under the conditions mandated by the Final Rule and requirement to run more CO_2 intensive resources, the system cannot meet the Interim Target by 2035.

As presented in the Sensitivity Analysis, the Companies also analyzed adjusting the Interim Target to 2036 in the P3 CAA Rule – 2036 Base portfolio, which reoptimizes the selection of resources under the constraints of the Final Rule and results in a PVRR increase of approximately $3.1 billion over Portfolio P3 Fall Base through 2050. To achieve the Interim Target in 2036, the portfolio requires all the resources selected in P3 Fall Base and the addition of a sixth CC unit and additional storage when the system is constrained due to the inefficient operation of the system complying with the Final Rule.

Given the highly aggressive nature of sustained resource additions requiring near-perfect execution across all resource types simultaneously, the Companies also assessed targeting Interim Compliance in successive years under a variety of resource availability scenarios. P3 CAA Rule -2037 Base portfolio reoptimizes resource selection with an Interim Target year in 2037. This portfolio reduces the amount of CC capacity selected to five CC instead of six required in P3 CAA Rule – 2036 Base, and a lower amount of offshore wind, which results in a $3.9 billion lower PVRR through 2050 when compared to P3 CAA Rule – 2036 Base. Figure 3 below summarizes the resource additions and PVRR for the 2036 and 2037 sensitivities, along with the Companies' P3 Fall Base portfolio.

<u>Figure 3: Resource Additions and PVRR of EPA CAA Final Rule Sensitivity Analysis</u>

	Solar	Onshore Wind	Nuclear	Offshore Wind	CCs	CT	Battery	Total	PVRR (In Compliance Year)	PVRR 2038	PVRR 2050
P3 Fall Base	12,600	2,100	600	2,400	6,795	2,124	5,100	**31,719**	$61	$78	$149
CAA Section 111 Sensitivity (2036)	14,625	2,250	900	2,400	8,154	1,699	7,140	**37,168**	$67	$80	$152
CAA Section 111 Sensitivity (2037)	16,425	2,250	1,500	1,600	6,795	1,699	6,740	**37,009**	$71	$77	$148

**Does not contain forecasted MWs

Note: This table shows MW adds in year of compliance; does not include Forecasted Resources or Bad Creek II which are common to all cases.

Q. PLEASE SUMMARIZE THE RESULTS OF THE COMPANIES' EPA CAA FINAL RULE SENSITIVITY ANALYSIS.

A. In summary, compliance with the Final Rule requires generation from new highly-efficient gas resources to be restricted. However, there are no incremental new low-carbon or zero carbon resources available for the model to select to supplement this low-carbon energy shortfall by 2035 (since nearly all available resources were selected before the application of the Final Rule). As a result, in order to serve load, the system is forced to operate more CO_2 emission intensive existing resources (including existing coal resources), resulting in the increases to cost and CO_2 emissions. Accordingly, under the conditions mandated by the Final Rule and requirement to run more CO_2 intensive resources, the system cannot meet the Interim Target by 2035. With an additional year of new resources available from solar, onshore wind, and nuclear, the system is able to achieve the Interim Target; however, an Interim Target year of 2036 is significantly more expensive than achieving the Interim Target in 2037. Furthermore, 2036 is unlikely to be achieved given that execution requires no delays in any technology or resource.

Q. HOW DOES THE CAA SECTION 111 FINAL RULE IMPACT THE COMPANIES' PLANNED COAL RETIREMENT SCHEDULE?

A. The detailed CAA Section 111 Final Rule guidelines for existing coal units are presumptive and subject to further evaluation by the state environmental regulator responsible for CAA implementation, the North Carolina Department of Environmental Quality ("NCDEQ"). The Companies support Public Staff witness Nader's assessment that the state's implementation of the emissions guidelines for coal units may allow Roxboro 2 and 3 to operate beyond 2032 in light of the compliance flexibilities provided in the CAA Section 111 Final Rule that may be included in state implementation plans.[82] As further discussed in Rebuttal Exhibit 2, the Companies similarly recognize the opportunity for compliance flexibilities in establishing the state plan and believe the current coal retirement schedule presented in the SPA continues to reflect the most cost-effective schedule that maintains an orderly transition out of coal and is reasonable for planning purposes given the compliance flexibilities available through state plans; however, the Companies also believe it would be prudent for NCDEQ to complete its analysis and develop the state plan that will be submitted to the EPA prior to the Companies determining appropriate compliance for existing coal units and, if needed, incorporating any changes to their coal retirement schedule.[83] Accordingly, the Companies continue to assess this issue, but, at this time, support the current coal retirement schedule presented in the SPA as reasonable for planning purposes.

Additionally, the Companies' CAA 111 Final Rule Sensitivity Analysis also assesses, despite potential reliability concerns, extending the life of existing coal units by converting them to 100% natural gas fired units by 2030. As shown in the Sensitivity Analysis, incremental conversions of the Companies' coal units to 100% natural gas are not economic, further reinforcing the Companies' planned coal retirement schedule.[84]

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[82] Public Staff Nader Direct Testimony at 19.

[83] IRP and Near-Term Actions Panel Rebuttal Exhibit 2.

[84] IRP and Near-Term Actions Panel Rebuttal Exhibit 2 at 9.

Q. GIVEN THE UNCERTAINTIES RAISED BY PUBLIC STAFF REGARDING THE CAA SECTION 111 FINAL RULE AND NEW GAS RESOURCES, DID THE COMPANIES EVALUATE ANY ADDITIONAL SENSITIVITIES ON NEW GAS RESOURCES?

A. Yes. Similar to the sensitivity analysis portfolio conducted in the SPA, the Companies assessed the selection of new gas resources in a high CC/CT cost (CapEx) scenario, using a 25% cost increase, while assuming the capacity factor limitations on these new gas resources. This sensitivity, P3 CAA Rule 2037 High CC/CT Cost, continues to select 5 CCs and 4 CTs (the maximum CTs available for selection in the CAA Final Rule Sensitivity Analysis) despite the increased resource cost assumptions for CCs and CTs and capacity factor limitations.

Q. DOES THE PUBLIC STAFF'S CAA SECTION 111 FINAL RULE ANALYSIS GENERALLY ALIGN WITH THE ANALYSIS COMPLETED BY THE COMPANIES WITH RESPECT TO THE PUBLIC STAFF'S CONCERNS ABOUT THE UNCERTAINTY REGARDING NEW NATURAL GAS COMBINED CYCLES?[85]

A. Yes. The Public Staff's analysis of the Final Rule is similarly challenged to meet the Final Rule's requirements under its initially-modeled portfolios, and the Companies' CAA Final Rule Sensitivity Analysis addresses some of the risk mitigants the Public Staff suggested. Importantly, just like the Companies, the Public Staff evaluated compliance with Final Rule by restricting the capacity

[85] Public Staff Metz Direct Testimony at 16.

factor of new gas to 40% and an Interim Target year of 2034. In Public Staff's modeling, either (1) the model was not able to meet the CO_2 emissions limits; or (2) Public Staff was required to assume an unreasonably aggressive deployment of SMR (2,400 MW by 2034) to meet a 2034 Interim Target date. Therefore, Public Staff's conclusions of the Final Rule focuses on a 2037 Interim Target year emphasizing "complying with the EPA rules in this way may end up increasing costs and requiring more natural gas resources, not less."[86] In total, both the Public Staff's and the Companies modeling continues to select five to six CCs (by 2033, including 2 in DEP), and continuing to support the need for new gas resources when considering the impacts of the Final Rule.

Q. PLEASE SUMMARIZE THE COMPANIES ASSESSMENT OF THE CAA SECTION 111 FINAL RULES ON THE COMPANIES PLANNING IN THIS PROCEEDING.

A. The CAA Final Rule Sensitivity Analysis continues to emphasize an all of the above approach to resource additions, including the need for new dispatchable natural gas CC and CT units, even under high capital cost assumptions. Duke Energy will continue to evaluate least cost, least risk compliance with CAA 111 regulations and will check and adjust compliance strategy in future Resource Plan Updates. However, nearly every portfolio analyzed confirms the need for new CC and CT resources consistent with Companies' NTAP presented in the SPA.

[86] Public Staff Thomas Direct Testimony at 119.

The reduction in efficient, low CO_2 emission energy from new gas resources, necessarily results in extending the time frame to meet the Interim Target to at least 2036, with the Companies presenting trade-offs for pursuing achieving the Interim Target in 2037 and 2038. The extended timeframe for achieving the emissions reduction targets provides the Commission with additional flexibility in reducing risk to customers by deferring decisions on incremental gas and offshore wind resource, discussed later in our testimony.

The coal retirements presented by the Companies in the SPA continues to plan for an orderly transition while mitigating long term risk to customers of operating coal, while full conversion of these units to run on natural gas are not economic alternatives relative to the retirement dates in the Plan

E. Reliability Verification of Public Staff Modeling

Q. DOES THE PUBLIC STAFF SUPPORT THE DETAILED RELIABILITY VERIFICATION ANALYSIS STEP USED IN THE COMPANIES' CPIRP ANALYTICAL PROCESS TO CONFIRM A MODEL-SELECTED PORTFOLIO MAINTAINS OR IMPROVES SYSTEM RELIABILITY OVER THE BASE PLANNING PERIOD?

A. Yes. Public Staff witness Metz states that SERVM, which the Companies use to perform the Reliability Verification step as part of the overall modeling framework, is a reasonable tool to address system reliability needs that may not be captured in traditional IRP modeling conducted in EnCompass.[87] Furthermore, witness Metz requested the Companies complete this SERVM

[87] Public Staff Metz Direct Testimony at 15.

reliability verification evaluation on the Public Staff's PS – 2034 Base portfolio.[88]

Q. DID THE COMPANIES CONDUCT THE RELIABILITY VERIFICATION ANALYSIS AS REQUESTED BY PUBLIC STAFF WITNESS METZ?

A. Yes.

Q. PLEASE PROVIDE THE RESULTS OF THE RELIABILITY VERIFICATION ANALYSIS FOR PUBLIC STAFF'S PS – 2034 BASE PORTFOLIO.

A. SERVM reliability verification analysis confirmed that the Public Staff's PS – 2034 Base portfolio met the industry reliability standard in test years 2033 and 2038 without the need of an additional reliability resource to the portfolio.

Q. DESPITE THIS VERIFICATION OF THE PUBLIC STAFF' PS—2034 BASE PORTFOLIO, DO THE COMPANIES HAVE CONCERNS ABOUT HOW THE RELIABILITY OF THEPUBLIC STAFF'S PROPOSED EXECUTABLE ACTIONS BASED ON THESE MODELING RESULTS?

A. The verification results are premised on the resources selected in the modeled portfolio actually being online and available on the timelines assumed and selected in the model. If, for example, a portion of the offshore wind selected in the Public Staff PS – 2034 Base portfolio was not actually online, the portfolios would fail the reliability verification step without incremental

[88] Public Staff Metz Direct Testimony at 15-16.

reliability resources. Similarly, as discussed later in the NTAP section, recommending fewer resources in their NTAP than what was required to maintain reliability such as CCs, CTs or offshore wind would likely present reliability concerns as well—a result that is contrary to the Companies' core planning objectives and the planning framework established by HB 951.

IV. DUKE ENERGY'S NTAP SUPPORTS THE MOST REASONABLE, LEAST COST AND LEAST RISK RESOURCE PLAN TO RELIABLY SERVE CUSTOMERS' FUTURE ENERGY NEEDS

A. The Companies' and the Public Staff's Modeling Results Support Focusing on Near-Term Reasonable Steps and Pursuing the Executable Actions Recommended by the Companies

Q. RECOGNIZING THE CHANGING ENERGY LANDSCAPE AND KEY NEW DEVELOPMENTS RELATING TO THE CAA SECTION 111 FINAL RULE, HOW SHOULD THE COMMISSION APPROACH UPDATING ITS 2022 CARBON PLAN?

A. The Companies are currently planning in a rapidly changing energy landscape as addressed in Chapter 1 (Planning for a Changing Energy Landscape) to the Plan and as demonstrated by the need to file the SPA in January 2024 and CAA Final Rule Sensitivity Analysis today. Since the Plan was filed less than a year ago, the Carolinas unprecedented economic development load growth has significantly impacted the Companies' load forecast while the impacts of the new CAA Section 111 Final Rule, if ultimately implemented, will constrain the operations of highly efficient and reliable new natural gas CC and CT capacity on the system requiring additional resources and resulting in a delay achieving the Interim Target beyond 2035—at a higher cost to customers.

Recognizing this challenging current planning environment, substantial uncertainty exists regarding the exact pace of energy transition towards achieving the Interim Target in the mid-2030s on the longer-term path towards carbon neutrality. Therefore, the Companies recommend the Commission adopt the initial Carbon Plan Order's approach of focusing on "near-term activities comprised of a number of reasonable steps needed to achieve the mandated carbon dioxide emissions reduction."[89] Said differently, the Commission should direct the Companies to pursue execution of the Companies' NTAP, which is designed to meet continued economic development load growth in the Carolinas and outlines the most reasonable actions required for achieving the Interim Target, both with and without the Final Rule. These "reasonable steps" must not be selected "piecemeal" from a variety of resource portfolios but require a comprehensive analysis to determine if ***together*** they support an executable resource plan that achieves the objectives of HB 951.

Q. PLEASE BRIEFLY SUMMARIZE THE PUBLIC STAFF'S MODELING APPROACH AND THE PORTFOLIOS DEVELOPED TO ASSESS PORTFOLIO SENSITIVITIES AND DEVELOP THEIR NTAP.

A. As discussed in Section III above, the Public Staff conducted a detailed and thorough review of the Companies' modeling assumptions and analytical processes. Public Staff witness Thomas describes the modeling conducted by the Public Staff which includes modeling assessing portfolio changes over various Interim Target years. They also conducted multiple sensitivities to

[89] Carbon Plan Order at 24.

assess the impacts of various resource availability, financial assumptions, and other planning constraints to understand how the risk and opportunities associated with the public staff's base planning assumptions drove resource selection and portfolio costs.[90] Public Staff witness Metz describes the development of the Public Staff's NTAP as informed by their modeling results considering additional risks not easily captured within a planning model.[91] Below is a list of some of the Public Staff's key portfolios and what each assessed:

- **PS – 2034 Base**: Public Staff's base planning assumptions with a 2034 Interim Target year;
- **PS – 2035 Base**: Public Staff's base planning assumptions with a 2035 Interim Target year;
- **PS – 2034 Limited Offshore Wind**: A 2034 Interim Target year portfolio which limits offshore wind to 2,200 MW through the Base Planning Period;
- **PS – 2034 Accelerated SMR**: – A 2034 Interim Target year portfolio which allows for SMR selection beginning in 2032;
- **PS – 2034 High Gas Price**: A 2034 Interim Target year portfolio which assumes a higher natural gas commodity price;
- **PS – 2034 Base Revised Load**: A 2034 Interim Target year portfolio with the Public Staff's alternative (lower) load forecast; and
- **PS – 2037 CAA Section 111**: Portfolio which imposes the Final Rule constraint of 40% capacity factor on new gas resources with a 2037 Interim Target year.

[90] Public Staff Thomas Direct Testimony at 80.

[91] Public Staff Metz Direct Testimony at 23-24.

Q. PLEASE SUMMARIZE HOW SUPPLY-SIDE RESOURCES COMPARE BETWEEN DUKE ENERGY'S AND THE PUBLIC STAFF'S PROPOSED NEAR-TERM ACTION PLANS.

A. Table 5 presents a summary comparison of the Companies' and the Public Staff's NTAP resources.

Table 5: Comparison of Companies' NTAP to Public Staff's NTAP

Technology	Companies' NTAP		Public Staff NTAP		Difference
	MW Target	Year	MW Target	Year	MW Target
Solar	6,460	2031	6,700	2031	+ 240
Battery Storage	2,700[1]	2031	2,700[2]	2031	0
Onshore Wind	1,200	2033	1,800	2033	+600
Combustion Turbines	2,125	2031	849[3]	2030	-1,276
Combined Cycle	6,800	2033	1,359[3]	2030	-5,441
Pumped Storage Hydro	1,834	2034	1,834	2034	0
Advanced Nuclear	600	2035	1,200	2036	+600
Offshore Wind	2,400	2035	2,200 – 2,400	2034-2035	*Generally aligned*

Note 1: Includes 1,475 MW of standalone battery and 1,225 MW of battery paired with solar
Note 2: As described later in this testimony, when put on a comparable basis with the Companies NTAP, the Public Staff identifies approximately 3,200 MW for battery storage which is composed of 1,475 MW of standalone battery and 1,710 MW of battery paired with solar[92]

[92] The Carbon Plan Order identified a total need for 1,600 MW of battery energy storage including 1000 MW of standalone battery storage, and 600 MW of storage paired with solar (Carbon Plan Order at 133). Metz Exhibit 1 calls for an additional 475 MW of standalone battery storage incremental to the 2022 Carbon Plan for a total of 1,475 MW of standalone battery energy storage. Metz Exhibit 1 also calls for an additional 1,110 MW of storage paired with solar incremental to the 2022 Carbon Plan, which results in 1,710 MW. These two numbers do not comport with 2,700 MW total of battery storage.

Note 3: Represents a "minimum" pending modeling of the CAA Section 111 Final Rule,[93] but no more than three CPCNs for CC to be filed before the 2025 CPIRP proceeding[94]

Q. PLEASE COMMENT ON THE PUBLIC STAFF'S PROPOSED NEAR-TERM ACTION PLAN FOR SOLAR, BATTERY ENERGY STORAGE, AND ONSHORE WIND?

A. Despite the apparent minimal difference between the Companies and the Public Staff's NTAPs the Companies do have some concerns with the Public Staff's recommended procurement and development actions for solar resources. Public Staff and the Companies are generally aligned with regard to the value of solar to the system and the need for battery storage to scale with solar resources through 2031. As discussed in Section III.B above the Companies believe that procuring an additional 240 MW of solar in the next two years with the expectation that all of the solar in the NTAP will be interconnected in 2029-2030, as recommended by Public Staff, exceeds reasonable resource availability limits and is likely not executable. As such, the recommended higher amounts of SPS projects, risks the interconnection of these recommended levels of both solar and storage to be reasonably relied upon to meet the need of the system by 2031. As discussed in Section II.B above, the Companies also do not support a 50% increase in onshore wind resource additions from 1,200 MW to 1,800 MW (+600 MW), as recommended by the Public Staff, as similarly not executable by 2033 and exceeding reasonable resource availability limits.

[93] Public Staff Metz Direct Testimony at 14-16.

[94] Public Staff Michna Direct Testimony at 48.

Based on the Companies' modeling and execution planning assumptions, these Public Staff-recommended assumed NTAP additions for solar and onshore wind are likely to result in a shortage of the low-carbon energy required to meet the Public Staff's Interim Target by the early 2030s. The Companies discuss these issues in more detail later in Section IV.A.1.

Q. DOES THE PUBLIC STAFF'S PROPOSED NEAR-TERM ACTION PLAN FOR NEW GAS ALIGN WITH ITS MODELING?

A. No. As recognized by Public Staff witnesses Thomas, Metz and Michna, the Public Staff is taking a substantially more conservative "least regrets" approach to planning for new natural gas CC and CT generation. While the Public Staff's PS - 2034 Base portfolio modeling selects 4,077 MW (3 CC units) by 2032, the Public Staff's NTAP only includes a single 1,359 MW unit in the NTAP. The Companies discuss these issues in more detail later in Section IV.A.2, including the selection of 5 CCs or more as shown through robust planning scenarios and sensitivities in both the Companies' and the Public Staff's modeling.

Q. DOES THE PUBLIC STAFF'S PROPOSED NEAR-TERM ACTION PLAN FOR OFFSHORE WIND ALIGN WITH ITS MODELING?

A. No. The Public Staff's PS - 2034 Base portfolio modeling selects 2,200 MW of offshore wind by 2032 and 4,400 MW by 2034. However, the Public Staff's NTAP supports only 2,200 to 2,400 MW of offshore wind by the 2034-2035 time period.[95] While the Public Staff's changes to its NTAP for offshore wind (as compared to its base plan modeling) result in an NTAP that aligns with the

[95] Public Staff Metz Direct Testimony at Metz Exhibit 1.

Companies' NTAP, such a dramatic change from modeling to NTAP without other adjustments, results in a fundamentally flawed and capacity-deficient NTAP with significant risk, as described in greater detail below.

Based on Public Staff's own modeling, assuming 2,200 MW of offshore in service between 2034 and 2035, as is evaluated in their "PS - 2034 Limit Offshore Wind" sensitivity, requires nearly 5,000 MW of battery storage online by 2031 and six total CC by 2033. This adjustment is further exacerbated by the recommended NTAP of fewer new gas resources than selected in their modeling as previously described. The Companies discuss these issues related to offshore wind in more detail later in Section IV.B.

Q. IN TOTAL, PLEASE SUMMARIZE THE CRITICAL CHANGES THE PUBLIC STAFF MADE FROM THEIR PS - 2034 BASE PORTFOLIO MODELING TO THEIR NTAP.

A. Table 6 below shows how the Public Staff's modeling compares to their recommended NTAP for CC and offshore wind resources. As explained later in this Section, the amount of offshore wind available and selected in the Public Staff's portfolio reduces the resources needed to meet the energy and capacity needs of the system during this critical transitional period. This risk is amplified considering the Public Staff is also recommending just one CC and 2,200-2,400 MW of offshore wind to be selected as needed for execution in their NTAP, significantly less capacity than selected in their modeling (though, as noted above, this amount is expressly contradicted by their own testimony, which supports up to three CCs in the near term).

Table 6: Resource Selections in PS-2034 Base Versus NTAP for CCs and Offshore Wind

	2029	2030	2031	2032	2033	2034	Total	NTAP
CC	1,360	0	1,360	1,360	0	2,720	**6,800**	**1,360**
Offshore Wind	0	0	1,100	1,100	1,100	1,100	**4,400**	**2,200-2,400**

Q. WHAT OBSERVATIONS OR CONCERNS DO YOU HAVE ABOUT THE METHODOLOGY PUBLIC STAFF USED TO DEVELOP ITS NTAP?

A. In totality, the Companies view the Public Staff's NTAP as capacity-deficient, and do not believe it supports an executable least-cost resource plan that maintains or improves reliability while reducing CO2 emissions. A shortage of generation and reliability risks are further exacerbated when viewing Public Staff's NTAP on new natural gas CCs and CTs. As described in greater detail below, the Public Staff's NTAP would lead the Companies and the State into a major shortage of generation, impede new economic growth in the State and significantly challenge the Companies' executable plan for coal retirements and plans for compliance with the CAA Section 111 Final Rule.

Q. DO YOU AGREE THAT PUBLIC STAFF'S NTAP PROPERLY IDENTIFIES A PLAN TO DEVELOP RESOURCES IN A "LEAST REGRETS" MANNER?[96]

A. No. The Companies recognize that the Carbon Plan Order framed its approval of near-term supply side activities as selecting resources and directing execution activities that were "no regrets" and designed to "avoid premature

[96] Public Staff Thomas Direct Testimony at 149-150.

commitments, and to provide flexibility for longer-term decisions."[97] The Public Staff does not specifically adopt this view or define the concept of "least regrets" but they seem to apply the concept to essentially pursue the least action at the least cost and with the least perceived risk for customers. However, they fail to account for other critical considerations needed to ensure that the Plan is holistically executable and balances all core planning objectives of HB 951—reliability, affordability, executability and transitioning towards a diverse and increasing clean resource mix. For example, the Companies' modeling and execution planning assumptions are grounded in the core planning objective of maintaining or improving reliability and a "replace before retire" approach to plan execution by ensuring sufficient dispatchable capacity is brought online before coal units are retired from service.[98] The Public Staff's NTAP does not address how these capacity deficiencies (which result from recommending the Commission select significantly less new gas generation and offshore wind (even assuming it was executable) than the Public Staff's model selects) can be overcome to allow for coal unit retirements while reliably meeting the growing customer loads on the system. In addition, the unachievable volumes of solar and onshore wind resources, as discussed above, exacerbates this concern. This unbalanced approach, if adopted in totality, would expose the Companies and the State to greater risk of a "many regrets" scenario wherein reliability,

[97] Carbon Plan Order at 25.

[98] See CPIRP Executive Summary at 6; Chapter NC at 8.

resource adequacy, and future economic development are jeopardized because needed and responsible actions were not taken in this critical execution period.

Public Staff witness Metz is correct that the "magnitude of the decisions being made in this case is different than in the previous CPIRP."[99] The pace, scope and scale of planned coal unit retirements and generation additions required to replace these aging but critical dispatchable resources and to meet the Carolinas' recent significant economic development load growth represents a challenge of much greater magnitude than in the Companies' initial Carbon Plan only two years ago. Therefore, as emphasized in the Plan, near-term actions—the "reasonable steps" contemplated by HB 951—need to be commensurate to meet this greater challenge.[100] This is especially critical as the Companies are now planning in the near-term for what witness Thomas recognizes as "a critical period between approximately 2027 and 2033 during which there are limited resources available to add to the system (only solar, battery storage, and natural gas) and load is expected to grow rapidly from economic development projects."[101] To meet this challenge, the Companies must proceed with all reasonable steps that includes all needed and executable resources that are selected and expediently progressed to commercial operation.

In contrast to comprehensively planning to meet this challenge, the Public Staff's "wait and see" posture underlying their NTAP may cause the

[99] Public Staff Metz Direct Testimony at 149-150.

[100] CPIRP Chapter NC at 4.

[101] Public Staff Thomas Direct Testimony at 9, 35.

potential for resource deficiencies in this critical execution period that would be too late to "check and adjust." The Companies are instead focused on taking all reasonable steps, which means all required actions based on the resource needs formulated through detailed and comprehensive modeling analysis, and then checking and adjusting on those actions to ensure we are balancing all planning factors and not compromising on reliability, with the only consequences of calibrating certain actions or creating positive planning buffer towards the interim target in future CPIRP cycles.

Q. WITNESS THOMAS SUGGESTS THAT THE PUBLIC STAFF'S NTAP IS "LIKELY TO RESULT IN COMPLIANCE WITH THE [INTERIM TARGET] BY 2034."[102] BASED ON YOUR COMPREHENSIVE REVIEW OF THE PUBLIC STAFF'S MODELING, DO YOU AGREE THAT PUBLIC STAFF'S NTAP ALIGNS WITH A TRAJECTORY TO ACHIEVE THE INTERIM TARGET BY 2034?

A. No. The math simply does not add up. The Public Staff's modeling requires five new CCs by 2034 and 4,400 MW of offshore wind by 2034 to achieve the Interim Target by 2034. Because Public Staff's NTAP materially differs from its modeling results—supporting only one, and only up to three CCs (pending the Companies analysis of the Final Rule) and only recommends only 2,200 MW to 2,400 MW of offshore wind by 2034-2035—their NTAP does not support a trajectory that is "likely to result in compliance" with the Interim Target by 2034.

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[102] Public Staff Thomas Direct Testimony at 149-150.

Q. DOES THE PUBLIC STAFF'S NTAP SUPPORT A RESOURCE PLAN THAT IS RELIABLE IN LIGHT OF PROJECTED LOAD GROWTH AND PLANNED COAL RETIREMENTS?

A. No. While Public Staff's base modeled resources do represent a reliable resource plan, if executable, the simple matter is their NTAP identified resources are not consistent with the resources that were selected and required by their own modeling to maintain system reliability. As introduced in Table 6 (<u>Resource Selections in PS-2034 Base Versus NTAP for Offshore Wind and CCs)</u> above, the two major deviations in the Public Staff's NTAP relative to its own modeling come in the form of:

1) The Public Staff's PS – 2034 Base portfolio selects 4,400 MW of offshore wind by 2034, while their proposed NTAP only includes 2,200 MW to 2,400 MW of offshore wind by 2034-2035. Notably, the Public Staff models 2,200 MW of additional offshore wind relative to their NTAP supported level for offshore wind. Using round numbers with a 70% ELCC value and just over a 40% Capacity Factor the extra model selected offshore wind provides DEP with 1,540 MW of equivalent peak capacity and approximately 8,000 GWH of annual energy that are not included in the Public Staff's NTAP.

2) In a similar fashion, Public Staff's NTAP only shows one natural gas CC by 2030. However, Public Staff witness Michna seemingly contradicts the Public Staff's NTAP and supports Commission consideration of the "first tranche" of three CCs identified as needed between 2028 and 2031 as

reasonable pending the Companies' analysis of the CAA Section 111.[103] Given the previously-mentioned alignment in both the Companies' and the Public Staff's analysis showing the need for at least five CCs in both base modeling and CAA Section 111 sensitivities, it may be fair to assume that Public Staff would now support up to 3 CCs as part of an NTAP informed by the CAA Final Rule Sensitivity Analysis. However, even assuming Public Staff has an adjusted NTAP supporting three CCs, such an adjusted NTAP is still two to three CCs short of what Public Staff's own modeling results show as being required by 2034. Assuming Public Staff supports three CCs in their NTAP, just two additional model selected CCs operating at a 40% capacity factor represent 2,720 MW of peak capacity and approximately 9,500 GWH of system energy.

Q. WHAT OTHER BALANCING FACTORS ASIDE FROM RELIABILITY AND EXECUTABILITY DO THE COMPANIES CONSIDER WHEN EVALUATING THE DIFFERENCES BETWEEN THEIR NTAP AND THE PUBLIC STAFF'S NTAP.

A. One of the Companies' long term resource planning objectives, and consistent with HB 951, is least cost planning and affordability. The Companies evaluate cost as a major consideration with respect to the evaluation of Pathways in the Plan and the proposed NTAP resources and execution plan for the Commission to approve as the next reasonable steps to achieving the emissions reductions targets along a least cost path, while maintaining or improving the reliability of the grid.

[103] Public Staff Michna Direct Testimony at 47.

Q. WHAT OBSERVATIONS HAVE YOU MADE ABOUT THE COSTS OF PUBLIC STAFF'S BASE PORTFOLIO COMPARED TO THE COMPANIES' BASE PORTFOLIO?

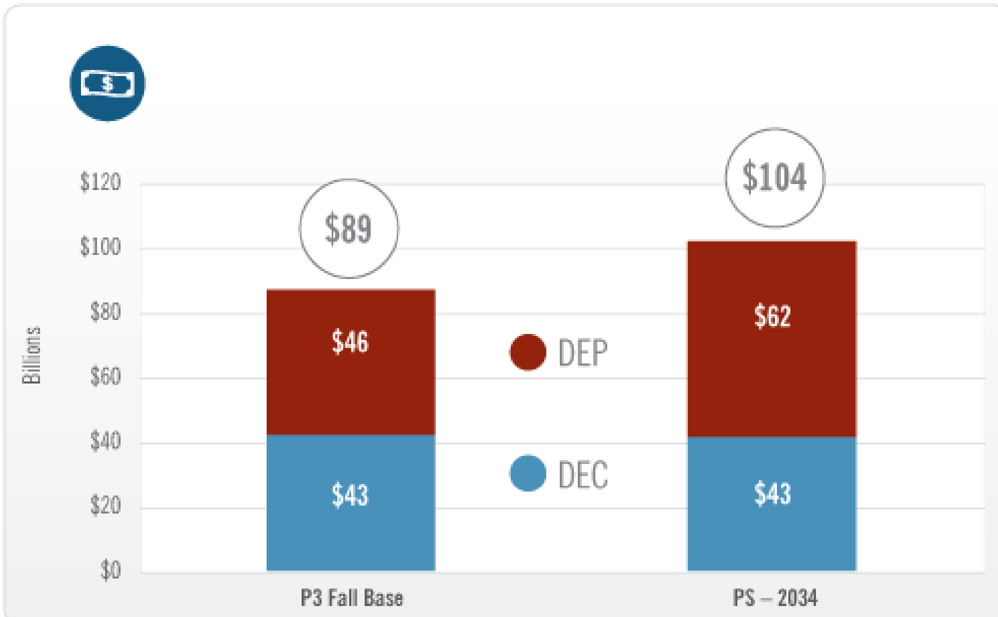
A. The Public Staff's PS – 2034 Base portfolio increases PVRR, increases capital deployed and shifts more capital to DEP compared with the Companies' P3 Fall Base portfolio. As seen in the Table 7, the PVRRs for the PS – 2034 Base portfolio and Companies' P3 Fall Base portfolio are relatively close from a PVRR perspective; however, Public Staff's base case requires much more capital investment and customer impact in the in near-term compared to the levelized cost captured in a PVRR.

Table 7: PVRR Comparison

PVRR ($B)	P3 Fall Base			PS – 2034 Base		
	2033	2038	2050	2033	2038	2050
DEC	$32	$48	$89	$31	$48	$88
DEP	$19	$30	$60	$21	$33	$63
CAR	**$51**	**$78**	**$149**	**$52**	**$81**	**$151**

Figure 4 below provides a closer look at the capital employed for each portfolio. The figure shows that the PS – 2034 Base portfolio not only deploys $15 Billion more capital by 2035 but also shifts capital spending from DEC to DEP. In the absence of the planned merger of DEC and DEP, the capital shift from DEC to DEP will serve to increase the current rate disparity between the two jurisdictions. This increase in capital spending in DEP, can also be observed in witness Williamson's testimony in Figure 8: DEP's Projected Bill Impacts by Portfolio.[104]

<u>Figure 4: Modeled Resource Capital Through 2035</u>



Note: Assumes 100% Solar, AFUDC, No Selectable BTM SPS, No Network Upgrades, No Forecasted Resources & No IRA

Q. HOW DO THE PUBLIC STAFF'S AND COMPANIES' INVESTMENTS COMPARE FOR EACH TECHNOLOGY TYPE BASED ON THEIR BASE MODELING?

A. As shown below in Figure 5, the PS – 2034 Base portfolio calls for more capital by 2035 in solar, offshore wind and batteries. Waiting an additional year for compliance reduces capital outlays by $15 Billion relative to the Public Staff's proposed PS – 2034 Base portfolio.

[104] Public Staff Williamson Direct Testimony at 36.

Figure 5: Modeled Resource Capital Requirement Through 2035 by Technology

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

1. The Renewable and Battery Storage Resources Proposed by Public Staff for Selection in the NTAP Create Cost, Reliability and Execution Risk

Q. DO YOU BELIEVE THE SOLAR RESOURCES RECOMMENDED IN THE PUBLIC STAFF'S NTAP ARE REASONABLE STEPS TO FURTHER THE PATHWAYS REQUIRED TO ACHIEVE THE PLANNING OBJECTIVES OF HB 951?

A. Not entirely. The Public Staff's NTAP represents an additional 240 MW of solar above the volume of solar recommended in the Companies' NTAP. In addition, the Companies' 6,460 MW of solar accounts for some level of anticipated future attrition of projects procured to achieve the solar interconnection levels required in the Companies modeling. In contrast, the 6,700 MW of solar included in the Public Staff's NTAP represents all of the incremental solar selected in their modeling as needed to achieve the Interim Target in 2034. As discussed previously in this panel's testimony, because of the Public Staff's NTAP is based on the unachievable modeling assumptions included in their modeling, the Public Staff's NTAP for solar likely exceeds achievable levels.

Additionally, as the Companies discussed in the 2022 Carbon Plan proceeding, over-procurement of resources with delayed interconnection increases the cost to customer in several ways. One of the primary risks for customers is losing out on technology maturation and development by over-procuring early on. As explained in Appendix I to the CPIRP,[105] battery technology is advancing rapidly and solar paired with battery storage is not as mature as standalone solar, especially in the Carolinas. To "frontload" the procurement of developing resources in this manner would cause the Companies and their customers to miss the technologies and resource advancements that are likely to be developed over the next few years. Increased target amounts in each procurement result in additional higher cost projects being selected to meet the targeted volumes as bids are generally selected from lowest to highest prices. If significant volumes of projects are delayed in being interconnected due to the time required to upgrade the transmission system, this creates a time lag where higher cost projects in the past are being connected

[105] CPIRP Appendix I at 10.

later, when they could have been procured later, potentially at a lower cost. Furthermore, unplanned lag times between contracting and projected commercial operations creates contractual complexities in equipment and EPC contracting considering these contracts have terms and conditions addressing expected in service dates. Delays in schedule can result in contractual penalties that create project execution and cost risk. As the Commission has recognized, while solar resources play an important role in meeting the carbon dioxide reduction mandates of N.C.G.S. § 62-110, "the need to develop solar generating capacity must be balanced against the cost to customers as well as the risks to the electric system."[106]

As stated above, the Companies support a limited amount of attrition-informed over-procurement to stay on track for meeting the needs of the system, but the compounding effects of increased procurements in excess of projected interconnection capabilities leads to greater risk for customers relative to a more reasoned but still aggressive pace of procurements that were included in the Companies' assumptions.

Because the Companies do not believe this incremental volume of solar can be developed and interconnected by 2031, the Companies view this increase as not reasonable. Table 8 compares the total forecasted solar procurements volumes targeted between the Companies' NTAP and the Public Staff's NTAP across the near-term 2023-2026 procurement cycles.

[106] Carbon Plan Order at 87.

Table 8: Comparison of Companies' and Public Staff's NTAP and Solar Procurement Recommendations

	NTAP	2023 Solar Procurement	2024 Solar Procurement	2025-2026 Solar Procurements (Low-end)	2025-2026 Solar Procurements (High-end)
Companies	6,460 MW*	1,435 MW (Procurement Complete)	1,585 MW (Procurement Underway)	2,700 MW	3,460 MW
Public Staff	6,700 MW			2,940 MW	3,700 MW

*Accounts for potential future attrition to meet modeled system needs

As Companies' witness Farver describes, the Volume Adjustment Mechanism in the Companies' RFP permits the Companies to select additional solar resources if it is cost effective to do so; however, the Companies are not confident in the likelihood of connecting this incremental volume of solar within the same time periods. Importantly, Public Staff expresses concerns over the RZEP 2.0 projects required to allow the Companies' NTAP, but yet Public Staff also recommended even higher solar volumes which is seemingly inconsistent given the criticality of RZEP 2.0 in order to achieve the higher end of the solar procurements in 2025-2026.

Q. DO THE COMPANIES AND THE PUBLIC STAFF AGREE ON THE AMOUNT OF STORAGE THE COMMISSION SHOULD SELECT?

A. Not completely. While the Companies' NTAP states the same amount of battery energy storage as the Public Staff's NTAP at 2,700 MW through 2031, the basis of these numbers is slightly different, resulting in the Public Staff effectively proposing 500 MW of incremental battery energy storage above what the Companies are proposing. As shown below in Table 9, in the Carbon Plan Order the Commission selected 1,000 MW of standalone storage and 600 MW of storage paired with solar for a total of 1,600 MW of storage to be added the system.[107] The Companies NTAP of 2,700 MW of battery energy storage represents a total amount of incremental storage need on the system by 2031, consisting of 1,475 MW of standalone storage and 1,225 MW of paired storage.[108] The Public Staff's NTAP, while also identifying a high level amount of storage at 2,700 MW, actually represents a total of approximately 3,200 MW of battery energy storage on the system by 2031. Public Staff witness Metz's Exhibit 1 identified 475 MW of additional standalone battery energy storage incremental to the 1,000 MW in the Commission's Carbon Plan Order. This aligns with the Companies' NTAP. Additionally, Metz's Exhibit 1 identifies 1,110 MW of storage paired with solar incremental to the 600 MW of paired storage identified in the Commission's Carbon Plan Order. In total, when compared on the same basis, the Public Staff's NTAP identifies a total of approximately 3,200 MW of storage on the system by 2031, compared to the Companies' 2,700 MW NTAP recommendation for battery energy storage.

Table 9: Comparison of Battery Energy Storage in the Public Staff's and the Companies NTAPs

	Standalone Battery Storage	Storage Paired with Solar	Total
Carbon Plan Order ***Total System***	**1,000 MW**	**600 MW**	**1,600 MW**
Companies NTAP ***Incremental to 2022 Carbon Plan***	475 MW	625 MW	1,100 MW
Companies NTAP Total	**1,475 MW**	**1,225 MW**	**2,700 MW**

[107] Carbon Plan Order, at 133.

[108] Supplemental Planning Analysis, at 52.

Total System			
Public Staff NTAP *Incremental to 2022 Carbon Plan*	475 MW	1,110 MW	1,585 MW
Public Staff NTAP Total *Total System*	**1,475 MW**	**1,710 MW**	**3,185 MW**

Q. DO THE COMPANIES HAVE CONCERNS WITH THE PUBLIC STAFF'S RATIO OF STANDALONE STORAGE TO PAIRED STORAGE?

A. Yes, while the Companies and the Public Staff agree on 1,475 MW of total standalone battery energy storage on the system by 2031, the Companies are concerned with the amount of battery energy storage the Public Staff has recommended being paired with solar. The Public Staff believes based on their modeling that higher ratios of solar paired with storage as compared to standalone solar is appropriate. However, the Companies believe the total 1,710 MW of paired battery included in the Public Staff's NTAP, specifically the 1,110 MW of battery energy storage they recommend be procured through the 2025 and 2026 solar procurements, is artificially high and impacted by the Public Staff's other unreasonable resource availability assumptions.[109]

Q. DOES MODEL SELECTION OF STANDALONE STORAGE OVER PAIRED STORAGE MEAN SUCH SELECTIONS REPRESENT THE OPTIMAL CONFIGURATION OR THE LEAST COST RESOURCE?

[109] Public Staff Metz Direct Testimony at 12, Metz Exhibit 1.

A. No. Based on the Companies' significant experience with modeling of energy storage in EnCompass, the model does not have the precision or granularity to perfectly select between the two generic modeling representations of standalone storage and storage paired with solar. Due to the number of projects that will inevitably be required to meet the total energy storage requirements of the system, these projects are likely to have a wide range of cost effectiveness and benefits to the system depending on the project-by-project economics. Therefore, the Companies should retain some latitude to optimize storage siting that best benefit the integration to the system for the customer. Such prescriptive values unnecessarily restrict the Companies from the flexibility needed to pursue these resources dependent upon cost-effective opportunities either as presented through upcoming RFPs for paired storage or through the opportunities Company witness Meeks on the Renewables and Battery Storage Panel describes in her testimony.

Q. DO YOUR CONCERNS RELATED TO THE PUBLIC STAFF'S RECOMMENDED SOLAR TARGET VOLUME ALSO PRESENT CONCERNS FOR THE AMOUNT OF STORAGE THE PUBLIC STAFF HAS RECOMMENDED?

A. Yes. Public Staff witness Metz appropriately recognizes the interrelated nature of solar growth and battery storage to shift energy throughout the day,[110] explaining that "[i]f the Companies do not develop and deploy energy storage at a commensurate pace of solar interconnections, negative impacts are likely

[110] Public Staff Metz Direct Testimony at 77.

to occur at the Companies nuclear generation fleet, absent substantial solar curtailments."[111] The Public Staff specifically calls for a higher portion of solar projects to be paired with storage. The Public Staff's recommendation to co-locate higher amounts of storage with solar carries the risk that it may not materialize on the time frame needed, which may impact reliability if that capacity is being relied on to meet reserve margins during this transitional period. In summary, the Companies continue to support their balanced execution plan for solar and SPS, committing to procure and develop 6,460 MW of new solar and 2,700 MW of batteries to be procured in the near-term and to be placed into service by 2031 as the most reasonable and executable plan at this snapshot in time.

Q. DO YOU BELIEVE THE ONSHORE WIND RESOURCES RECOMMENDED IN THE PUBLIC STAFF'S NTAP ARE REASONABLE STEPS TO FURTHER THE PATHWAYS REQUIRED TO ACHIEVE THE PLANNING OBJECTIVES OF HB 951?

A. Not entirely. As introduced above and similar to the Public Staff's more aggressive solar assumptions, the increased assumptions for onshore wind drive a reasonably large difference between the Companies' and the Public Staff's NTAPs. As described by witness LaRoche, the Companies view this 50% increase in onshore wind assumed to achieve commercial operation by 3033 (+600 MW difference) to be unreasonable from an execution standpoint. As a result, including this volume of onshore wind in the NTAP creates a reliability

[111] Public Staff Metz Direct Testimony at 103.

risk given the fact that the Companies count on approximately 30% of the incremental nameplate capacity to contribute to winter peak.

2. Selection of New Natural Gas-Fueled Resources is Supported by both the Companies and the Public Staff's Modeling, and the Companies must Progress all Necessary Actions on all Model-Selected Dispatchable Resources to Reliably Meet new Load Growth and Retire Coal in this Critical Execution Period of the CPIRP

Q. IT IS NOTABLE THAT PUBLIC STAFF ONLY INCLUDES ONE CC AND TWO CTs IN THEIR NTAP. PLEASE EXPLAIN YOUR UNDERSTANDING OF PUBLIC STAFF'S VIEW OF NATURAL GAS-FIRED RESOURCES TO BE SELECTED IN THE NTAP.

A. Public Staff witness Metz testifies that the "minimum amount" of CCs he recommends to be pursued is one unit (approximately 1,359 MW),[112] and the amount of CTs he recommends to be pursued is two units (approximately 850 MW);[113] however, he also comments that the Public Staff's proposed NTAP should not be interpreted as limiting the Companies to pursuing development activities for only one CC and two CTs.[114] Witness Metz explains that, at the time he developed his testimony, a maximum number of CCs and CTs could be determined until further review was completed on the CAA Rule.[115] As discussed earlier, the Companies have completed this analysis and it affirms the need for 5 CCs and 5 CTs that are included in the Companies' NTAP.

[112] Public Staff Metz Direct Testimony at 16.

[113] Public Staff Metz Direct Testimony at 15.

[114] Public Staff Metz Direct Testimony at 15 and 17.

[115] Public Staff Metz Direct Testimony at 17.

Witness Metz goes on to state that the Companies should submit CPCNs for new CCs and CTs as "need is determined."[116] Public Staff witness Metz describes the interrelated relationship between CCs and CTs, with CC selections often influencing the overall selection of CTs.[117] Despite the Public Staff's approach to including only one CC in its capacity deficient NTAP, Public Staff witness Michna testifies that the Public Staff recommends the Companies move forward with the first three CCs identified in the Companies' and Public Staff's modeling.[118] Witness Michna attests that the Public Staff "observed and validated the need for such generation in its modeling as part of the least-cost compliance pathway."[119]

Q. HOW DOES PUBLIC STAFF'S MODELING ALIGN WITH THE COMPANIES' VIEW THAT FIVE CCS MUST BE INCLUDED IN THE NTAP TO ACHIEVE COMMERCIAL OPERATION BY THE EARLY 2030s?

A. Without question, at least five CCs are required by 2034 in both the Companies' P3 Fall Base portfolio and the Public Staff's PS–2034 Base portfolio modeling results. Figure 6 below illustrates the CCs selected in these base portfolios. Figure 6 also illustrates the CCs that are required under relevant sensitivity analysis, such as the Public Staff's and the Companies' EPA sensitivity analysis and select sensitivity runs from the Public Staff' modeling. Both the Public

[116] Public Staff Metz Direct Testimony at 17.

[117] Public Staff Metz Direct Testimony at 15.

[118] Public Staff Michna Direct Testimony at 5

[119] Public Staff Michna Direct Testimony at 5.

Staff's and the Companies' analysis confirm a minimum of five CCs were selected in all cases shown below. Even under the CAA Final Rule Sensitivity Analysis, assuming high capital costs for CC/CTs and limiting CC capacity factors to comply with the Final Rule, five CCs were selected.

<u>Figure 6: Combined Cycle Units Economically Selected Per Base Portfolio and Sensitivity Analysis</u>

1,360 MW/CC unit	2029	2030	2031	2032	2033	2034	Total
Companies P3 Fall Base	1	1	1	1	1		6,800 MW
Public Staff 2034 Base	1		1	1		2	6,800 MW
Companies CAA Section 111 Sensitivity 2037 Base	1	1	1	2			6,800 MW
Public Staff CAA Section 111 Sensitivity 2037 Base	1		2	1	2		8,160 MW
Companies CAA Section 111 High Gas CapEx Sensitivity	1	1	1	1	1		6,800 MW
Public Staff High Gas Commodity Sensitivity	1	1	1	1		1	6,800 MW
Public Staff Revised Load Sensitivity	1		1	1		2	6,800 MW
Public Staff Limit Offshore Wind Sensitivity	1	1	1		1	2	8,160 MW

As described by Public Staff witness Metz, the cascading effect of the selection of CCs impacts the selection of CTs.[120] In addition to at least five CCs, the Companies' CAA Final Rule Sensitivity Analysis continues to support

[120] Public Staff Metz Direct Testimony at 16.

the need for the CTs proposed in the Companies' NTAP, especially to maintain and improve reliability in this critical transitional time in the late 2020s/early 2030s and in the light of the expected load growth and questions regarding materialization of other resources in the Plan. In general, the Public Staff identifies that there is potentially less overall risk related to peaking CTs resource compared to CCs with respect to the Final Rule based on the projected operations of these resources long term.[121]

Q. PUBLIC STAFF WITNESS MICHNA TESTIFIES THAT IT WOULD BE MORE PRUDENT TO WAIT SEVERAL YEARS BEFORE MOVING FORWARD WITH MORE THAN THREE CCS TO "IMPROVE OUR UNDERSTANDING OF MANY OF THE RISKS."[122] WHY DO THE COMPANIES NOT BELIEVE IT IS PRUDENT TO WAIT?

A. As Company witness Donochod on the Dispatchable Generation Panel testifies, waiting until 2026 to begin initial development activities and to pursue needed interconnection and permitting approvals on the fourth and fifth CC would delay development of these necessary resources in a way that could potentially jeopardize reliability. The Commission practice of "selecting" or affirming the need for resources in the CPIRP process allows the Companies to commit to development of resources to meet the needs of the system as identified in the Companies CPIRP filings. Ultimately, as the Commission underscored in their Carbon Plan Order, selections of resources in the CPIRP does not constitute

[121] Public Staff Metz Direct Testimony at 16.

[122] Public Staff Michna Direct Testimony at 6.

approval to construct a resources, but formally recognizes the need for the resource and provides the Companies with clarity to pursue the activities needed bring these resources online in the timelines as identified in their execution plan.[123] As such, the Commission's selection of five CCs in this CPIRP provides the Companies with the clarity required to engage in meaningful development to ensure these resources are available within the timeframe required and signals to economic development opportunities that the State and this Commission are committed to serving the load of existing and prospective customers. The Commission will continue to have the opportunity to assess the resources brought before it in CPCNs before proceeding with construction.

Q. WHAT WOULD BE THE IMPACT TO THE OVERALL RESOURCE PLAN IF THE IN-SERVICE DATE OF THE FOURTH AND FIFTH CCs WERE DELAYED BY TWO OR THREE YEARS, WHICH IS THE PRACTICAL RESULT OF PUBLIC STAFF'S RECOMMENDATION?

A. Delaying commercial operation of this amount of dispatchable capacity would have cascading adverse impacts across the Plan. In order to maintain system reliability, the Companies would have to continue to operate their coal fleet longer, delaying coal retirements, which the Commission put significant emphasis on avoiding if possible in their Carbon Plan Order.[124] Even continuing to operate the coal units, the Companies may still be faced with reliability concerns as several of the resources in this timeframe are required to

[123] Carbon Plan Order at 25.

[124] Carbon Plan Order at 63-64, 132.

meet load growth, regardless of retirements. Moreover, as mentioned previously, failing to pursue these resources may result in failure to retain existing, and attract new, economic development load to the Carolinas. The Public Staff also recognizes this is a critical period to the energy transition yet fails to recognize that delaying the development of these critical resources will also delay necessary coal retirements and would have negative affects to the State's "open for business" reputation as prospective economic development industries would take note of the lack of progress on new infrastructure needed to be a viable location for their business expansion needs.

Q. HOW DO THE COMPANIES BALANCE THE PUBLIC STAFF'S CONCERNS ABOUT SELECTION OF NEW CCs CARRYING SIGNIFICANT RISK, INCLUDING THAT THE EXPECTED LOAD GROWTH WILL NOT MATERIALIZE?[125]

A. As described above, the selection of natural gas-fired CCs 4 and 5 is in part responsive to the strong economic development load growth already incorporated into the Companies Updated 2023 Load Forecast in the SPA model. Pursuing these resources is prudent and necessary given the material commitments already made along with the pipeline of potential economic development on the heels of what is already included in the load forecast. For example, Tract Capital Management, LP ("Tract") witness Moe states that Tract intends to develop a 500 MW data center park in the Companies' North Carolina service territory and, provided the Companies can deliver the necessary

[125] Public Staff Thomas Direct Testimony at 10.

electricity, Tract expects to develop additional, larger data center parks and anticipate loads totaling 2,500 MW by the mid-2030s. Additionally, Tract witness Moe indicates that other companies intend to develop large-load data centers in the Companies' service territories.[126]

Importantly, the development of resources to meet the currently projected load growth has far more positive benefits compared to the converse of not planning for these resources, given the transition the DEC and DEP fleet are already planning. Figure 7 below shows the trade-offs between resource additions above or below the currently identified NTAP against the potential for forecast load growth to materialize faster or more slowly. Overall, the Companies seek to enable load growth to support the economic development efforts of the communities that we serve in a manner that ensures that the State has sufficient electric infrastructure to meet the needs of existing industries, businesses and residents, as well as those that are planning to locate here. Figure 7 below also highlights the importance of not falling behind in execution of the NTAP. As shown, the consequences of not keeping pace with needed resource additions present significant risks that are detrimental to customers while staying at or ahead of the pace of execution provides significant benefits.

[126] Tract Moe Direct Testimony at 3.

<u>Figure 7: Opportunities and Risks between Proposed Gas Resources and Load Growth Materialization</u>

Q. PLEASE SUMMARIZE THE TAKEAWAYS FROM FIGURE 7.

A. The potential negative consequences of failing to fully pursue the resources identified in the Companies' NTAP are substantial and cannot be mitigated if load growth continues as projected. Conversely, pursuing the NTAP identified levels of resources presents substantial positive opportunities, with multiple levers available to mitigate the impacts if load growth is less than projected.

Q. WHAT DIFFERENCES BETWEEN THE PUBLIC STAFF'S AND THE COMPANIES' MODELING CAUSE THE PUBLIC STAFF'S PS–2034 BASE PORTFOLIO TO DELAY THE SELECTION OF THE FOURTH

AND FIFTH CC TO 2034 AS OPPOSED TO SELECTION BY 2033 IN THE COMPANIES' P3 FALL BASE PORTFOLIO?

A. The Panel addresses in Section III.B above the unreasonable assumptions informing the Public Staff's modeling. For example, Public Staff's base portfolio assumes 2,200 MW of offshore wind is available in 2032, which the Companies believe to be unattainable. Coupled with an additional 600 MW of onshore wind and 2,000 MW of solar (in excess of the Companies' assumptions) that the Companies do not believe will materialize in 2032. Thus, the Public Staff's modeling relies on these resources that, in reality, are not likely to be in-service by this time period. As describe below, correcting even only a portion of these assumptions and rerunning the Public Staff's model results in substantial alignment between the Companies' identified need for new gas resources and the Public Staff's.

Q. PUBLIC STAFF WITNESS MICHNA ASSERTS THAT THE "LARGEST AND MOST IMMEDIATE CONCERN" WITH THE COMPANIES' FIVE CCS IS THE TOTAL COST OF THE UNITS.[127] DO YOU AGREE WITH HIS CHARACTERIZATION OF THIS COST RISK?

A. No. As identified above in Figure 5, the initial capital cost of the five CCs included in both the Companies P3 Fall Base and the Public Staff PS – 2034 Base portfolios does not represent a disproportionate amount of capital compared to the rest of the resources. As demonstrated by Figure 5 above, the initial capital costs for offshore wind in Public Staff's portfolios dwarfs that of

[127] Public Staff Witness Michna at 24.

the CCs, particularly given the overall capacity of offshore wind relative to that of the CCs. Overall, reasonable modeling must plan for maintaining reliability at least cost. The Companies' approach to modeling under Pathway 3 economically selects those resources that provide significant value in achieving the Interim Target, maintaining reliability, enabling economic development growth, and doing so in a least cost manner as prescribed by HB 951.

Q. DOES THE PUBLIC STAFF AGREE WITH THE SELECTION OF BAD CREEK II IN THE COMPANIES' NTAP AND THAT THE DEVELOPMENT COSTS PROPOSED FOR THE FACILITY ARE REASONABLE?

A. Yes. The Public Staff finds the modeling approach and economic analysis supporting Bad Creek II to be reasonable at this time[128] and supports the $165 million planned development costs for Bad Creek II to be reasonable and well supported. The Public Staff continues to recognize the value of long-duration energy storage as the system increasingly relies on carbon-free intermittent resources to meet demand. While the Public Staff supports the Companies' proposed near term actions and development costs, they do recommend updates to project cost projections in the next CPIRP and recommend that the Companies notify the Commission if project costs increase by more than 15% or if the estimated in-service-date goes beyond 2034, which recommendation is addressed by the Long-Lead Generation and Pumped Storage Hydro Panel.

[128] Public Staff Metz Direct Testimony at 18.

B. The Commission has Optionality and Flexibility with Regard to Committing to New Nuclear and Offshore Wind Resources

Q. DOES THE COMPANIES' NTAP REFLECT THE REASONABLE RESOURCE AVAILABILITY ASSUMPTIONS THE COMPANIES USED IN THEIR MODELING FOR NEW ADVANCED NUCLEAR?

A. Yes. The Companies' NTAP includes two SMRs in service by the beginning of 2035, consistent with achieving the Interim Target in that year. The updated detailed execution plan for advanced nuclear, in Section 4 of the SPA, supports these modeling selections and the first two SMR units at site 1 reflect these resources. Further details provided in the execution plan results in the continued selection of nuclear through the planning horizon as a least cost resource option, as highlighted by Public Staff witness Metz.[129]

Q. HOW WOULD THE PUBLIC STAFF'S NTAP RECOMMENDATION FOR 1,200 MW OF SMR BY 2036 IMPACT THE COMPANIES' EXECUTION PLAN?

A. As discussed in Appendix J (Nuclear) to the initial Plan, the Companies are supportive of the benefits to customers of a reasonably aggressive approach to deploying advanced nuclear as part of the least cost pathway to achieving carbon neutrality. However, executing this recommendation would require the acceleration of the development and construction of the Companies' second SMR site in order to put the first SMR unit at the second site in time to support an in-service date of beginning of year 2036, a year earlier than planned. The

[129] Public Staff Metz Direct Testimony, at 76.

Companies appreciate the considerations the Public Staff gives for this recommendation, finding it reasonable to provide additional guidance for new nuclear resources through 2036. However, as described in more detail in the Companies' Long Lead Generation and Pumped Storage Hydro Panel, the Companies continue to support the execution plan that they have proposed for new nuclear, balancing risk for customers and pursuing cost-effective deployment of the resources, while managing execution risk and allowing for construction learning and resources to transition from one unit to the next and one site to the next. As discussed above, the Companies evaluated the Public Staff's proposed NTAP schedule for new nuclear as an aggressive SMR scenario in its CAA Final Rule Sensitivity Analysis.

Q. DOES THE COMPANIES' NTAP REFLECT THE REASONABLE NEXT STEPS FOR PURSUING OFFSHORE WIND AS SELECTED IN THE COMPANIES' MODELING?

A. Yes. While offshore wind was not included in the initial Plan's NTAP, offshore wind was required to achieve the Interim Target by 2035 in the Companies' SPA to meet the increased Updated 2023 Fall Load Forecast, though it is notably the last carbon-free resource selected by the model based on its significant cost and limited operational contribution (approximately 40% annual capacity factor). Public Staff witnesses Metz and Thomas similarly acknowledge among sensitivities conducted by the Public Staff, "the amount and timing of offshore wind was also one of the most significant variations as resource assumptions changed"[130] and "runs with increased offshore wind result in generally higher PVRR impacts in 2033 and 2038."[131]

The Companies' NTAP and Execution Plan proposes the offshore wind ARFI as the next reasonable step to provide the Commission and the Companies with critical information to continue to evaluate offshore wind including: (1) acquisition structuring and related details, (2) payment structuring and risk sharing, (3) structures to ensure financing and construction capability, and (4) updated cost assumptions and proposed acquisition or development fees. The Companies continue to believe that the ARFI is a necessary step, which will provide the Commission and the Companies with important information for pursuing offshore wind in accordance with HB 951 ownership requirements, while informing future CPIRP modeling, particularly in light of the risk associated with the decisions to be made regarding this resource.

Q. HOW DO THE PUBLIC STAFF'S ASSUMPTIONS FOR OFFSHORE WIND RESOURCE AVAILABILITY INFLUENCE SELECTION OF RESOURCES OVER THE PLANNING HORIZON?

A. As described above, the availability of offshore wind impacts the timing and volume of other resource selections in its modeling. This impact is demonstrated to an extent in the sensitivity modeling performed by the Public Staff. The early deployment and increased quantities of offshore wind available have impacts on both the amount of energy and capacity it provides to the

[130] Public Staff Thomas Direct Testimony at 95

[131] Public Staff Metz Direct Testimony at 116.

system. Assuming this amount of offshore wind is available and is selected by the model defers the selection of executable resources needed in this time frame to achieve the Interim Target, creating a capacity deficiency between the Public Staff's modeled portfolio and proposed NTAP.

Q. BASED ON PUBLIC STAFF'S MODELING, WHAT CHANGES TO THE RESOURCE MIX IN THE PUBLIC STAFF'S NTAP WOULD BE NEEDED GIVEN THE REDUCTION OF OFFSHORE WIND INCLUDED IN THE PUBLIC STAFF'S NTAP?

A. Once again, there is a material inconsistency between the amount of offshore wind assumed in Public Staff's modeling and the amount included in Public Staff's NTAP. The Companies reiterate that it is methodologically unsound to have such an inconsistency when relying on modeling to create an executable NTAP. Imposing the lower level of offshore wind resources in the Public Staff's NTAP into the Public Staff's base modeling would significantly impact modeling results. The impact of this change is, in fact, demonstrated in the Public Staff's alternative portfolio that limits offshore wind (PS – 2034 Limited Offshore Wind). This portfolio selects 2,200 MW of offshore wind by 2034, which is similar to the Companies' P3 Fall Base portfolio, which selects 2,400 MW by 2035. In Public Staff's "PS – Limited Offshore Wind" portfolio, the model selects a sixth CC by 2034, almost doubles the volume of storage paired with solar (from 4,300 MW to 7,480 MW) and increases the volume of standalone storage from 1,400 MW to 4,100 MW. While the Companies do not believe these volumes of SPS or standalone storage are executable over these timeframes, the purpose of this example is to demonstrate the extreme volume of additional resources required to serve load, while attempting to maintain a 2034 Interim Target, if Public Staff's modeled selection of 4,400MW of offshore wind do not materialize.

Q. PLEASE ELABORATE ON WHY PUBLIC STAFF'S MODEL SELECTION OF 4,400 MW OF OFFSHORE WIND CARRIES SIGNIFICANT RISK RELATIVE TO OTHER RESOURCES SUCH AS NEW NUCLEAR.

A. To achieve the greatest efficiencies of scale, offshore wind facilities are generally large projects, with significant costs associated with a single project. Conversely, new nuclear, especially SMRs, are resources that can be added incrementally over time, reducing the execution risk across projects with separate individual resources. These separate and distinct projects allow for the Companies to leverage learning from one unit to the next and from one site to the next.

The Companies' modeling assumes availability of 2,400 MW of offshore wind by 2035; however, the model often selects incremental offshore wind in the 2040s. The Companies' offshore wind resource availability assumptions stagger the availability of offshore wind projects, which provides benefits to customers by spreading out the cost impact to customers of the offshore wind resource additions. In contrast, the Public Staff's PS – 2034 Base portfolio selects 4,400 MW of offshore wind—to achieve the Interim Target by 2034, but then never selects incremental offshore wind thereafter.

As previously discussed, the Companies and the Public Staff both recognize that offshore wind is the last resource the model selects to meet the Interim Target (Public Staff's modeling in 2034 and the Companies' modeling in 2035). To demonstrate the impact of limiting customer uncertainty related to offshore wind cost exposure, the Public Staff conducted various sensitivities that limited offshore wind, delayed the year of achieving the Interim Target, and took aggressive approaches to deploying new nuclear. When the Public Staff modeled a 2035 Interim Target year, their PS - 2035 Base portfolio required 2,200 MW less of offshore wind with a PVRR of reduction of $1 billion through 2050, compared to their PS – 2034 Base portfolio with a 2034 Interim Target year. Notably, the savings in portfolio cost and reduction in offshore wind resources was, partially if not significantly, a result of allowing the 600 MW of new nuclear that becomes available the next year in 2035 to achieve the Interim Target. Notably, the Public Staff's CAA Section 111 sensitivity, which target achieving the Interim Target in 2037 (PS – 2037 CAA Section 111) also select only 1,100 MW of offshore wind by 2037.

In total, both the Companies and the Public Staff recognize the risks associated with offshore wind and are seeking to understand the impact of alternative resource portfolios to mitigate risk to customers while advancing the energy transition.

Q. DO THE COMPANIES AGREE WITH THE PUBLIC STAFF'S DISCUSSION ON THE TRADEOFFS BETWEEN DEPLOYMENT OF ADVANCED NUCLEAR DEPLOYMENT AND OFFSHORE WIND?

A. Yes. To continue to assess the risk trade-offs between nuclear and offshore wind, as pointed out by Public Staff witness Metz,[132] the Companies CAA Final Rule Sensitivity Analysis assessed an aggressive approach to SMR deployment, similar to the Public Staff's analysis discussed by witness Metz.[133] The Companies modeled a 2037 Interim Target year, allowing for 1,200 MW of SMR available by 2036 (consistent with the Public Staff's recommended NTAP), and an additional two SMRs per year thereafter, but not allowing the portfolio to select offshore wind. In this sensitivity (P3 CAA Rule 2037 Aggressive SMR No OSW), the model continues to achieve the Interim Target without offshore wind in the portfolio.

The Companies also evaluated a scenario assuming that only the base planning assumptions for the level of SMR deployment was executable and assuming that offshore wind was not available to the resource portfolio. This portfolio (P3 2037 CAA Rule – 2038 No OSW) is able to achieve the Interim Target by 2038 without offshore wind by relying on the Companies' base planning assumption for nuclear SMR deployment. This portfolio results in PVRR reduction of approximately $1.0 billion over the P3 CAA Rule 2037 Base portfolio, allowing for another year before achieving the Interim Target.

These portfolios are particularly informative as they provide the Commission with additional optionality and flexibility given that under the CAA Section 111 Final Rule, achieving the Interim Target by 2035 is not

[132] Public Staff Metz Direct Testimony, at 113.

[133] Public Staff Metz Direct Testimony at 83-84.

achievable and 2036 is exceedingly challenged and carries risk requiring all model selectable solar, onshore wind, offshore wind, pumped storage hydro, nuclear and CCs, and significant levels of battery energy storage. These sensitivities show that with an extended timeframe for achieving the Interim Target due to CAA Section 111 Final Rule, the Commission may be able to defer a decision on offshore wind. This is consistent with the testimony of witness Metz, who asserts that offshore wind is the resource that is most often economically deferred when the model has the option to defer resource or to pursue a more aggressive approach to nuclear. Deferral also allows for more time to receive information from lease holders through an ARFI, and gain alignment on significant investments between both North Carolina and South Carolina, as identified by CIGFUR witness Collins, who advocates for both the Commission and the PSCSC to provide clarity on cost recovery of selected resources in the CPIRP.[134] In sum, such an extended timeline will allow the Commission more time to gather information to inform their decision on this significant resource, while still allowing sufficient time to support having offshore wind in service by 2037.

C. Updating the Public Staff's Modeling with Limited, More Reasonable Planning Assumptions Results in Significant Alignment Between the Public Staff's Modeling and the Companies NTAP and Execution Plan

Q. DID THE COMPANIES PERFORM FURTHER LIMITED MODELING UTILIZING PUBLIC STAFF'S MODELING TO ASSESS THE

[134] CIGFUR Collins Direct Testimony at 65-66.

IMPACTS OF TARGETED CHANGES WITHIN PUBLIC STAFF'S MODELING.

A. Yes. For informational and illustrative purposes, it was helpful for the Companies to work within Public Staff's modeling to assess the impact of various targeted changes on the modeling results.

As described above in Section III.B, the Companies disagree with various material modeling assumptions that the Public Staff integrated into their modeling including their resource availability assumptions, application of the planning reserve margin, transmission transfer rates, and the carbon accounting with respect to the Companies' planned South Carolina CC. Furthermore, as described in Section III.C, due to the Companies' error included in its own modeling in the SPA, the Public Staff's modeling also included an overstatement of interstate FT rate for the DEP CC available beginning in 2029. While each of these is important, the Companies assessed limited changes to the Public Staff's modeling assumptions to see how such changes impact the resources selected.

Q. PUBLIC STAFF ASSERTS THAT ENCOMPASS ECONOMICALLY SELECTS THE FIRST TWO CCS IN DEC (INSTEAD OF DEP) [135] AND THAT "ALLOWING THE MODEL TO HAVE THE FREEDOM TO ECONOMICALLY LOCATE RESOURCES RESULTS IN MORE GENERATION ASSETS BEING BUILT IN DEC TO SERVE DEC LOAD

[135] Public Staff Metz Direct Testimony at 87.

IS REASONABLE."[136] PLEASE RESPOND TO PUBLIC STAFF'S STANCE ON THIS ISSUE.

A. Public Staff witness Metz states in his key takeaways about their modeling runs that "[s]ome model results are for illustrative purposes and are not likely achievable given real world implementation constraints."[137] He also states that "[w]hile some constraints may be reasonable and reflect practical real-world factors that must be taken into consideration, other constraints may not be reasonable" and goes on to explain that the Companies not allowing the selection of DEC CC before 2031 is a reasonable constraint.

As a threshold matter, it is technically and commercially inexecutable to build a new CC in DEC to be in service prior to 2031. The Companies prudently limited the model to selecting CCs in DEC beginning in 2031, while ongoing real world execution factors previously described enable the deployment of the first DEP CC beginning in 2029. As has been emphasized throughout this Panel's testimony, it is critical to build an NTAP and overall resource plan that is executable and that such executable assumptions be based on the parallel execution activities being pursued by the Companies. It is important to note that the Companies did not force the selection of CCs in DEP in 2029 and 2030. If truly the least cost option, the model could have forgone selecting DEP CCs in 2029 and 2030 in the Companies modeling and selected

[136] Public Staff Metz Direct Testimony at 77.

[137] Public Staff Metz Direct Testimony at 76.

all six available CCs in DEC starting in 2031 and beyond—but the model did not do so.

Q. PLEASE DESCRIBE THE IMPACT TO THE PUBLIC STAFF'S MODELING THAT OCCURS WHEN CORRECTING THE FT COST ASSUMPTIONS FOR CCS LOCATED IN DEP.

A. As discussed in Section III.C., the Companies' SPA modeling contained an error in which the Companies overstated the FT cost for DEP CCs. When correcting for this error alone and making no other changes in the Public Staff's modeling, under the PS–2034 Base scenario, the portfolio selects the first CC in DEP in 2029 and shifts the first CT resources from DEP to DEC. This correction aligns with the Companies' modeling that identified the need for the Person County CC1 in 2029 in DEP and the Marshall CTs in DEC in 2029, as presented in the updated SPA Execution Plan.

Q. WHAT ARE THE IMPACTS TO THE PUBLIC STAFF'S RESOURCE SELECTION WHEN CHANGING A LIMITED NUMBER OF OTHER MATERIAL ASSUMPTIONS USED BY THE PUBLIC STAFF, THAT THE COMPANIES DISAGREE WITH, IN CONJUNCTION WITH THE CORRECTION OF THE COMPANIES FT MODELING ERROR?

A. Rather than modeling 4,400 MW of offshore wind being available by 2034, if Public Staff used an offshore wind availability modeling assumption of 2,200 MW by 2034-2035, consistent with their own NTAP recommendation and more closely aligned to the Companies' modeling, achieving the Interim Target in 2034, as suggested by Public Staff, would not be possible. Therefore, planning for 2035 is reasonable and appropriate for planning purposes while also allowing nuclear to be part of the resources used to achieve the Interim Target to the benefit of customers.[138]

To demonstrate the combined impact of:

1. a more reasonable timing and amount of offshore wind,
2. the correction to FT rates as previously discussed,
3. and the removal of Public Staff's transmission hurdle rate, which, as discussed previously, is not a real cost applicable to energy transfers through the JDA,

the Companies conducted modeling adjusting just these assumptions to the Public Staff's model while retaining the rest of the Public Staff's other planning assumptions. As summarized in Table 10 below, these limited changes to the Public Staff's model resulted in the selection of CCs and CTs that even more closely aligns with the resources in the Companies' NTAP, including five total CCs, with the selection of two CCs in DEP. In other words, while there is already substantial alignment between most aspects of the Companies' and the Public Staff's modeling, relatively minor but reasonable adjustments result in even greater alignment in outcomes.

[138] Public Staff Thomas Direct testimony at 121.

Table 10: NTAP Comparisons with Adjusted Public Staff Modeling NTAP

Technology	Duke Energy NTAP		Public Staff NTAP		Adjusted PS Modeling	
	MW Target	Year	MW Target	Year	MW Target	Year
Solar	6,460	2031	6,700	2031	6,700	2031
Battery Storage	2,700	2031	2,700	2031	2,300[1]	2031
Onshore Wind	1,200	2033	1,800	2033	1,350	2033
Combustion Turbines	2,125	2031	849	2030	1,700	2031
Combined Cycle	6,800	2033	1,359	2030	5,440	2033
Pumped Storage Hydro	1,834	2034	1,834	2034	1,834	2034
Advanced Nuclear	600	2035	1,200	2036	600	2035
Offshore Wind	2,400	2035	2,200	2034-2035	2,200	2035

Note 1: Accounts for Total Battery Energy Storage on the system by 2031, in contrast to the Public Staff's listed NTAP volumes as explained above.

The Companies reiterate that, as explained above, the adjusted analysis made limited changes and did <u>not</u> adjust the additional resource availability assumptions made by Public Staff for solar and onshore wind. As a result, these higher levels of solar and wind assumed by Public Staff continue to influence the selection of other resources, including the deferral, but not elimination, of a fifth CC and 2,200 MW of offshore wind, and the reduction in the amount of battery energy storage needed by 2031 and onshore wind needed by 2033. However, the very limited and more reasonable modeling assumptions integrated into the Public Staff's modeling further aligns the Public Staff modeling to the Companies stated NTAP.

Q. HOW SHOULD THE COMMISSION WEIGH THIS ANALYSIS ALONG WITH THE REST OF THE MODELING PRESENTED IN THE DOCKET?

A. The Companies and the Public Staff have presented robust analysis in this docket including the extensive modeling in the initial Plan, the SPA, and now in testimony including the Companies CAA Final Rule Sensitivity Analysis. This modeling robustly assesses the risks and opportunities presented in the energy transitions. In sum, this analysis presented in the Panel's Table 10 above demonstrates that with modest changes to more reasonable planning assumptions, informed by additional modeling of the CAA Section 111 Final Rule, that the Companies' NTAP should be considered the next reasonable steps the Commission should approve on the least cost path to achieving the objectives of HB 951.

V. NO INTERVENOR OFFERS AN ALTERNATIVE RESOURCE PORTFOLIO OR SPECIFIC CHANGES TO THE COMPANIES' NTAP THAT CREATES A MORE REASONABLE PLAN

A. The Commission Should Consider the Technical Objectivity of Recommendations Not Supported by Modeling and Need Not Decide Every Issue Raised to Approve a Reasonable NTAP.

Q. WHAT CONCLUSIONS CAN BE REACHED ABOUT INTERVENOR RECOMMENDATIONS?

A. Intervenor testimony and recommendations vary tremendously and are often conflicting among the intervenors. Given that none of the intervenors other than Public Staff provides an alternative NTAP or provides specific changes to the Companies' NTAP that are supported by holistic technical modeling, the

Companies respond to these recommendations more generally given that technical modeling would be required to actually adopt changes to the NTAP.

Furthermore, many of these critiques, analyses, and recommendations advance planning outcomes that exclude some resource options and are over-reliant on others, concentrating risks and depriving customers of a balanced, diversified approach to decarbonization. These critiques and alternative recommendations especially fall short of the core CPIRP 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, to the extent that these results-oriented critiques and alternative proposals would create substantial execution risk and/or undermine system reliability, they should be dismissed.

A common theme from intervenors is risk and value tradeoffs of resources. Importantly, all resource types have beneficial characteristics as well as limitations and risks. Table 11 below demonstrates a holistic view of some of the benefits and risks for the various technologies contained within the Plan.

Table 11: Benefits and Risks/Limitations of Resources Evaluated in the CPIRP

Holistic Overview of Plan Resources		
Technology	**Beneficial Characteristics**	**Limitations and Risks**
Dispatchable Distributed Energy Resources	Distributed nature provides geographic diversity, reduces system peak demand, BTM DERs require little to no transmission interconnection investments, customer focused resource	Scale of resource depends on customer adoption and retention rates, not universally applicable to all customer groups, generally provides limited energy contributions to the system, can involve complex system controls
Natural Gas CTs and CCs	Capable of 24X7 energy production, efficient resource to backstand intermittent renewable resources and replace retiring coal units, very mature technology, robust underlying infrastructure as the largest source of electricity production in the US	Operational cost variability based on gas prices, tightening supply chains for equipment and EPC contracts, requires new gas transportation infrastructure, susceptible to mitigation costs associate with potential future carbon regulations
Li-Ion Battery Storage	Provides operational flexibility, aligns hourly intermittent resources with hourly customer demand, distributed nature can reduce interconnection costs, eligible for significant IRA tax credits	Net energy consumer rather than energy producer, immature at utility scale, less long-term operational and performance data, uncertain lifecycle costs inclusive of decommissioning costs and risks, exposure to global supply chain issues
Solar	Carbon free fuel free resource, mature technology, reduces system gas and coal fuel costs, eligible for significant IRA tax credits	Intermittency in hourly, daily and weekly output, land intensive, requires significant supporting transmission infrastructure, exposure to global supply chain issues, long term operational and decommissioning risks
On-Shore Wind	Carbon free fuel free resource, mature technology, reduces system gas and coal needs, diversifies increasing solar centric energy profile on the system, favors multi-purpose land use, eligible for significant IRA tax credits	Intermittency in hourly, daily, weekly output, very large lease areas required, new resource within the Companies' service area creates uncertainty and challenges with siting and development
Off-Shore Wind	Carbon free fuel free resource, mature technology, reduces system gas and coal needs, higher capacity factor than solar and on-shore wind, strong coincidence with system winter peak needs, eligible for significant IRA tax credits	New resource to the Carolinas with unique challenges such as significant transmission requirements and hurricane risks. Complex long-lead time resource with the highest single project cost of all resources in the Plan that would require concurrence of both NC and SC state utility commissions.
New Nuclear	Only Carbon Free resource capable of consistent baseload operations, SMRs design provides construction efficiencies and smaller investment requirements relative to large scale projects, eligible for significant IRA tax credits	Long-lead time project requiring significant state and federal regulatory approvals. Immature technology supply chain. Limited number of projects currently in development.
Bad Creek II	Mature storage technology application developed at existing site, adds large scale storage capabilities in a single project to effectively integrate significant levels of new renewable and nuclear resources, 80 year useful life, longer duration than current applications of chemical BESSs, eligible for significant IRA tax credits	Long-lead time project requiring significant state and federal regulatory approvals. Extensive scope and scale of the project involves an extended construction timeline with attendant project and inflation risk.

As discussed subsequently in more detail, many intervenors in this proceeding tend to focus on particular limitations or risks of one technology while excluding or ignoring others. Assessing various resource technologies through a holistic lens, such as provided in Table 11, reduces the risk of biased perspectives and helps ensure a balanced and informed evaluation of potential outcomes. Thus, in evaluating these recommendations the Commission should consider the technical objectivity of recommendations not supported by modeling and, as discussed in Section II above, need not decide each and every issue raised in order to approve a reasonable NTAP.

B. <u>No Party Takes Issue with the Companies' General CPIRP Analytical and Modeling Processes.</u>

Q. PLEASE BRIEFLY REINTRODUCE THE COMPANIES' ANALYTICAL AND MODELING PROCESSES USED TO DEVELOP THE CPIRP.

A. As described in Appendix C (Quantitative Analysis) to the CPIRP, the Companies employed a robust modeling, analysis, and reliability verification process that built on the modeling performed in the 2022 Carbon Plan proceeding using EnCompass and SERVM as the core modeling tools. A high-level description of this process is reflected in Figure 8 below.

Figure 8: Carolinas Resource Plan Analytical Process Flow Chart

Q. DO INTERVENORS CHALLENGE THE COMPANIES' GENERAL ANALYTICAL PROCESS AND MODELING TOOLS?

A. No. Recognizing that the Companies used the same modeling tools and generally followed the same analytical process that the Commission accepted as reasonable in the 2022 Carbon Plan proceeding, no other parties meaningfully engaged with the Companies' modeling set up and analytical process, including, but not limited to, the Companies' use of the EnCompass and SERVM modeling software, capacity expansion modeling, the performance of the Reliability Validation and Bad Creek II Verification steps, etc.

Q. SACE ET AL. WITNESS ROUMPANI RAISES A DISCRETE ISSUE REGARDING THE RELIABILITY VERIFICATION PROCESS AND ADVOCATES THAT THE COMPANIES SHOULD CONSIDER ALL RESOURCE TYPES TO FILL ANY IDENTIFIED RELIABILITY

GAP.[139] WHY DO THE COMPANIES CONSIDER ONLY NATURAL GAS RESOURCES TO ADDRESS A RELIABILITY GAP?

A. SACE, et al. witness Roumpani's testimony recommends that the Companies modify the reliability verification process to consider all available resource types, including energy storage and renewable resources, when determining how to address any reliability gaps. Witness Roumpani's recommendation fundamentally misunderstands the purpose of introducing firm capacity resources to meet the reliability target. As described in Appendix C, the Companies' Reliability Verification step used a CT as a proxy for a generic firm capacity reliability resource in the event the Companies' SERVM modeling identified that a portfolio failed to meet the reliability target. In addition, the Companies conducted reliability verification modeling for study years 2033 and 2038; accordingly, any CTs that were added to a portfolio during this step are outside of the NTAP window. In other words, the reliability verification step does not "select" optimal resources to fill an identified reliability gap, as witness Roumpani's recommendation appears to assume. Instead, the Companies' use of the CT as proxy is designed to simplify an otherwise complex modeling analysis.[140]

To be clear the Companies' recommended portfolio P3 Fall Base met the reliability threshold without the need to add additional CTs.[141] In any event,

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[139] SACE et al. Witness Roumpani at 69-70.

[140] CPIRP Appendix C at 72-76.

[141] SPA Technical Appendix at 4.

the Companies are not requesting that the Commission take action on any of the CT capacity that may have been added in the reliability verification modeling. The optimal resource selection across time will continue to be evaluated in subsequent CPIRP filings. Thus, the use of CT capacity as the firm reliability resource in the reliability verification step is a simplifying assumption and is inconsequential to this proceeding.

C. <u>Duke Energy's Assumptions Regarding Resource Adequacy are Reasonable for Planning Purposes.</u>

Q. DO THE COMPANIES BELIEVE THAT THE RESULTS OF THE RESOURCE ADEQUACY AND ELCC STUDIES CONDUCTED BY ASTRAPÉ ARE REASONABLE?

A. Yes. The Companies believe the results of the Resource Adequacy Study and ELCC Studies conducted by Astrapé and used in the Companies' CPIRP modeling are reasonable. Further, the Public Staff found the recommended 22% reserve margin[142] and ELCC values[143] to be reasonable for planning purposes.

Q. DO YOU AGREE WITH CIGFUR WITNESS COLLINS' CLAIM[144] THAT "JOINT CAPACITY RESOURCE PLANNING" BY DEC AND DEP COULD REDUCE THE COMPANIES' RESERVE MARGIN?

[142] Public Staff Thomas Direct Testimony at 33-34.

[143] Public Staff Thomas Direct Testimony at 39-40.

[144] CIGFUR Witness Collins Direct Testimony at 31.

A. No. The Resource Adequacy Study[145] addresses how the 22% reserve margin was determined based on the Base Case Combined Scenario.[146] Under currently-effective regulatory conditions approved by the Commission,[147] DEC and DEP must operate as separate utilities and each separately plan for and satisfy their capacity needs (including the necessary reserve margin). While a merged utility would allow for efficiencies and cost savings in collectively satisfying the reserve margin as one utility, prior to a merger, the Companies are not permitted to jointly plan for capacity needs.

D. While Intervenors have wide-ranging views on the Companies' Load Forecast, the 2023 Updated Fall Load Forecast used to develop the Supplemental Planning Analysis Remains the Most Reasonable for Planning Purposes.

Q. PLEASE BRIEFLY SUMMARIZE THE HIGH-LEVEL CONCERNS INTERVENORS EXPRESS ABOUT THE COMPANIES' LOAD FORECAST.

A. Most of the intervenors' concerns regarding the Companies' load forecast are addressed by the Economic Development and Growth Panel. For the purpose of supporting the reasonableness of the CPIRP modeling, however, this Panel notes the wide range of positions taken by intervenors commenting on the issue. For example, while AGO witness Burgess agrees that some significant amount

[145] The 2023 Resource Adequacy Study was included as Attachment I to the Companies' CPIRP.

[146] *See* 2023 Resource Adequacy Study, page 6, FN 8 stating the study assumptions include "joint unit commitment, dispatch and ancillary services, and consolidates the balancing authorities and removes associated transmission constraints between existing individual BAs."

[147] Order Approving Merger Subject to Regulatory Conditions and Code of Conduct, Docket Nos. E-2, Sub 998 and E-7, Sub 986, (June 29, 2012) Appendix A Regulatory Conditions, Merger Condition 3.5, at 10.

of load growth is occurring and will occur, he also expresses concern that not all of the new, large site load that the Companies are projecting will materialize or may materialize at a later date than projected.[148] In contrast, Tract Capital Management, LP witness Moe expressed concern that the Companies' Updated 2023 Fall Load Forecast is too low and that the Updated 2023 Fall High Load Forecast is likely nearer to a true base case forecast.[149]

Importantly, the Public Staff adopts the Companies' Updated 2023 Fall Load Forecast, including the economic development adjustments, as reasonable for planning purposes, relying upon it for base modeling purposes to develop the Public Staff's PS – 2034 Base portfolio.[150]

Q. IS THE UPDATED 2023 FALL LOAD FORECAST REASONABLE FOR PLANNING PURPOSES IN THIS CPIRP?

A. Yes. The Updated 2023 Fall Load Forecast is reasonable for planning purposes in this CPIRP and strikes a balance between intervenor positions. Further, not planning to this expected significant load increase introduces risk to system reliability and may deter future economic development in the Carolinas as discussed earlier.

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[148] AGO Burgess Direct Testimony at 69.

[149] Tract Capital Moe Direct Testimony at 3-4.

[150] Public Staff Thomas Direct Testimony at 119 (The Economic Development and Growth Panel addresses the Public Staff's adjusted load forecast sensitivity in more detail.).

E. Duke Energy's Modeling Methodology For Incorporating Grid Edge and Similar Customer Programs Is Reasonable.

Q. SACE ET AL. WITNESS DUNCAN RECOMMENDS THAT THE COMPANIES SHOULD BE REQUIRED TO MODIFY THE CPIRP TO INCLUDE A BEHIND-THE-METER ("BTM") STORAGE FORECAST.[151] WHY DID THE COMPANIES NOT INCLUDE BTM STORAGE IN ITS LOAD FORECAST?

A. BTM storage generally refers to small, customer-sited storage resources that are primarily coupled with on-site solar generation. As discussed in Section II.C in response to the Public Staff, modeling BTM storage as a load modifier or forecasted dispatchable resource is a standard and accepted modeling practice. BTM storage is in the early stages of adoption across the industry, and while there are pilots and anticipated growth as noted by witness Duncan, there is not sufficient scale or operational experience or scaled program outcomes with BTM storage to derive industry-vetted planning profiles that have operational verification at scale. The Companies' PowerPair program was approved by the Commission in early 2024 and is in the initial stages of launching. Therefore, as the Companies (and broader industry) continue to gain operational experience and scale, the Companies will check and adjust in parallel with industry peers on integration of BTM into load forecast and planning models.

[151] SACE et al. Duncan Direct Testimony at 4.

Q. WHY IS IT UNREASONABLE TO MODEL GRID EDGE AND CUSTOMER PROGRAMS AS SELECTABLE RESOURCES AS RECOMMENDED BY SACE ET AL. WITNESS DUNCAN?

A. SACE et al. witness Duncan recommends that the Commission should require Duke to work with stakeholders to develop two modeling changes intended to incorporate virtual power plants ("VPP") in the next CPIRP. Specifically, witness Duncan recommends that the Companies should "(1) use the learnings from the PowerPair Pilot to develop and model a dispatchable BTM solar paired with storage program and model that as a selectable resource; and (2) use the cost and operational profiles of existing and planned EE/DSM, DER, and other customer programs to create a series of VPP resources of different sizes and compositions and allow the CPIRP model to select VPP resources."[152]

The issue with witness Duncan's recommendations from a long-term planning and IRP modeling perspective is that witness Duncan ignores the fact that energy and capacity impacts of customer grid edge programs are entirely dependent on customer adoption and retention rates for the various grid edge programs offered by the Companies. Even with significant experience operating these programs, it is difficult to estimate a long-range forecast of the impact of these programs looking out over the planning horizon, which is the method currently employed in the planning framework. The Companies' approach to this complex process already takes into account near-term program experience and a long-term market potential study in an attempt to discern technical,

[152] SACE et al. Duncan Direct Testimony at 5.

economic, and achievable market potential for programs while accounting for changing technology, government end-use standards, customer preferences, and a host of other factors such as customer adoption rates and "free rider" rates. These forecasted impacts then must be integrated into the broader load forecast in a manner that does not double count efficiency gains that are already accounted for in the Companies' load forecast. The notion that this process could be further refined to include multiple "selectable" levels of customer programs with varying participation and adoption rates correlated to varying economic incentives is not realistic. Furthermore, adoption of such an approach would significantly add to model complexity, model run times, regulatory complexity and uncertainty in model results.

As previously explained in response to the Public Staff's recommendation to model the Companies' recently approved PowerPair pilot, the Companies model grid edge and customer programs that depend on customer preferences and participation as load modifiers or as forecasted levels of dispatchable resources, and not as selectable resources. Further, the Reliability and Operational Resiliency Panel's testimony confirms that reliance on any programs that depend on customer behaviors are situational and their operational impacts can be difficult to predict or accurately rely upon at this time, requiring more study and operational experience by the Companies and industry. The CPIRP biennial update process will allow the Companies to evaluate and check and adjust based on new information and outcomes of the Companies' and the broader industries' grid edge and customer programs—

from both planning and operations perspectives—including actual adoption rates for both programmatic and "naturally occurring" BTM storage as identified by witness Duncan, as well as to incorporate evolving forecasting and planning standards, as well as to socialize any relevant updates to forecasting or modeling approaches with stakeholders.

In Section II.C above, the Companies discuss the Commission's views on the issue of EE and other customer programs as selectable resources in the 2022 Carbon Plan proceeding. For all of these reasons, modeling customer programs as selectable resources continues to be inappropriate as it would create an unnecessary reliability risk for the Companies and negatively impact their ability to maintain or improve grid reliability as required by HB 951.

F. Duke Energy's Cost and Operational Assumptions Regarding Supply-Side Resources are Informed by Industry-Specific Data and Actual Operational Experience and are Reasonable for Planning Purposes.

Q. SEVERAL INTERVENORS ALLEGE THAT THE COMPANIES' SUPPLY-SIDE RESOURCE ASSUMPTIONS INDICATE A BIAS IN FAVOR OF CERTAIN RESOURCES AND AGAINST RENEWABLES. HOW DO YOU RESPOND?

A. I disagree with that contention. More specifically, several intervenors allege that Duke Energy overstates the costs and availability constraints for renewable resources while understating costs and availability constraints for natural gas and nuclear resources. Those intervenors claim that Duke Energy's assumptions show a biased risk tolerance in favor of central station generation resources over renewables. Instead, as explained in this Section, Duke Energy's supply-side resource cost and availability assumptions reflect real-world conditions and result in a balanced portfolio. Adopting more aggressive assumptions for renewables introduces unnecessary execution risk that could impede the Companies' ability to maintain or improve the reliability of the grid during the energy transition as they are obligated to do under HB 951.

1. *The Companies' Cost and Resource Availability Assumptions of Renewable Resources are Based on Informed Industry Knowledge and Experience*

Q. AGO WITNESS BURGESS CLAIMS THAT THE CPIRP ASSIGNS DISPARATELY HIGH COSTS TO SOLAR, STORAGE, AND WIND. DO YOU AGREE?

A. No. AGO witness Burgess opines generically that the assumed costs of all renewable resources and battery storage "may be overstated" because they differ from other data sources like National Renewable Energy Lab ("NREL") Advanced Technology Baseline ("ATB").[153] Witness Burgess provides no specific criticisms or rationale other than this blanket comparison to NREL ATB cost estimates.

As described below and in greater detail in Appendix E (Screening of Generation Alternatives) of the Plan, the Companies' resource cost assumptions are built on detailed technical analysis. Specifically, the Companies' resource cost assumptions for solar and solar paired with storage are based on estimates from Guidehouse tools specific to the Carolinas with input from the Companies' recent 2022 solar procurement. Onshore wind technology costs are also based

[153] AGO Burgess Direct Testimony at 42-43.

on the Guidehouse tools, and offshore wind technology costs were obtained through a Commission-required analysis of the Wind Energy Areas off the North Carolina coast. These resource cost assumptions are narrowly tailored to reflect the specific type of resource the Companies expect to see (or historically have seen) in the Carolinas. While they may differ from more generic data like NREL ATB, such deviation does not mean that they are unreasonable. As noted previously in testimony, Public Staff witness Thomas is generally supportive of the Companies' capital cost assumptions in the SPA and Public Staff adopted those costs for their own modeling.[154]

Q. SACE ET AL. WITNESS GOGGIN RECOMMENDS THAT THE COMPANIES' "ARBITRARY LIMITS" ON SOLAR AND BATTERY INTERCONNECTION SHOULD BE "GREATLY INCREASED IF NOT ELIMINATED" AND PROVIDES SEVERAL RECOMMENDATIONS TO EXPEDITE INTERCONNECTION OF NEW SOLAR RESOURCES.[155] HOW ARE THE COMPANIES ADDRESSING THE ISSUE OF SOLAR INTERCONNECTION?

A. As discussed by the Transmission and Interconnection Panel, the pace of interconnection must be carefully informed by real-world operating conditions to ensure the reliability and resiliency of the grid. Unrealistic resource assumptions will inevitably lead to model outcomes that do not match real world factors. The Companies are tasked with developing a forecast that

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[154] Public Staff Thomas Direct Testimony at 48-49.

[155] SACE et al. Goggin Direct Testimony at 33-34.

reflects real-world limitations to ensure that the resulting CPIRP is actually executable. This includes the Companies' assumptions of the realistically achievable rates of solar resource interconnections. It is also important to highlight that the Companies' reasonably-aggressive solar interconnection and resource availability assumptions are already informed by the Companies' significant ongoing efforts to identify strategic transmission solutions, such as the RZEP 2.0 upgrades, to enable more efficient interconnections as well as the Carbon Plan Order's directive that new solar resources, including Solar Plus Storage, "must be interconnected and integrated in a manner that poses no risk to the reliability of the system and affords customers and the electric system as cost-effective a resource as possible."[156]

It is important to reiterate that, just like other assumptions included in the CPIRP, 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.). The interconnection constraints will evolve as more information becomes known and the Companies will check and adjust these forecasts in future iterations of the CPIRP.

Q. SACE ET AL. WITNESS GOGGIN STATES THAT THE SOLAR INTERCONNECTION LIMITS "ARTIFICIALLY CONSTRAIN THE DEPLOYMENT OF COST EFFECTIVE RENEWABLE AND STORAGE

[156] Carbon Plan Order at 87.

RESOURCES, INCREASING COSTS FOR RATEPAYERS."[157] PLEASE RESPOND.

A. Solar interconnection constraints represent an actual, real-world constraint that must be included in resource planning modeling, just like a number of other constraints the Companies (and Public Staff) used when conducting their modeling. Much like solar interconnections, the Companies included constraints in the model to reflect natural gas availability, onshore wind timing, advanced nuclear deployments, and many others. Including any constraint in a capacity expansion or system production cost model will increase costs when compared to an unconstrained solution. Relieving any one of these constraints would lead to a lower cost modeled solution; however, the Companies must reflect real-world limitations so that the resulting CPIRP 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 real-world. For instance, accelerating solar deployments based on current technologies could discount the value of solar resources available in the future, based on the potential for solar cost to decline or performance gains or other technologies that are more efficient or more cost-effective than solar available today. Also, in order to connect additional solar, as suggested by intervenors such as SACE et al., developers would need to locate solar further from existing

[157] SACE et al. Goggin Direct Testimony at 33

transmission and currently planned transmission infrastructure which may be more costly than locations that could be connected once the RZEP projects 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 2023 Solar Procurement, as well as future procurements. As has been discussed in great detail through the Companies' rebuttal testimony in this proceeding and through the 2022 Carbon Plan proceeding, committing to overly aggressive and unrealistic solar interconnections before more data is available supporting this approach would not be reasonable or prudent for customers.

Q. AGO WITNESS BURGESS OBJECTS TO THE 20% COST RISK PREMIUM APPLIED TO SOLAR AND WIND ADDITIONS IN THE COMPANIES' P1 MODELING.[158] PLEASE EXPLAIN THE COMPANIES' RATIONALE FOR INCLUDING THIS COST PREMIUM IN THE PVRR COST EVALUATION OF THE P1 PORTFOLIO.

A. The Companies' use of the 20% cost adder for assessing the cost of the P1 portfolio was reasonable for all technologies. Even if transmission and other market constraints were not limiting factors on resource availability, achieving such a high level of resources in such a short period of time would come at a

[158] AGO Burgess Direct Testimony at 42-43.

cost premium. As noted previously, the cost adder was only included in the PVRR cost evaluation after resource selection was complete and, notably, Public Staff accepts the 20% adder as a reasonable proxy for this cost risk of essentially pursuing an infeasible number of interconnections by 2030. The Public Staff accurately highlights that increasing the volume of selectable renewable resources requires selection of higher costs projects to obtain those volumes.[159] In fact, as noted by Public Staff witness Thomas, the cost adder had no impact to resource selection and the P1 Fall Supplemental would not be least cost even if the adder was removed.[160]

2. *The Companies' Cost Assumptions for Natural Gas Resources are Reasonable and the Companies' Modeling and Portfolio Analysis Presents a Technically Objective Assessment of the Risks of all Resources, Including Natural Gas*

Q. CCEBA WITNESS HAGERTY SUGGESTS THAT DUKE ENERGY'S GAS-FIRED GENERATION RESOURCE COSTS ARE INCONSISTENT WITH PJM'S LATEST COST OF NEW ENTRY STUDY.[161] HOW DO YOU RESPOND?

A. As previously discussed in Section II.A, the Public Staff supports the costs the Companies used for selectable new gas resources as reasonable for planning purposes. Nonetheless, comparing the Companies' new resource cost assumptions to PJM's 2022 Cost of New Entry ("CONE") is an apples-to-oranges undertaking. PJM's quadrennial gross CONE updates referenced by

[159] Public Staff Thomas Direct Testimony at 45.

[160] Public Staff Thomas Direct Testimony at 44-45.

[161] CCEBA Hagerty Direct Testimony at 9.

witness Hagerty represent the first-year total net revenue (net of variable operating costs) a new generation resource would need to recover its capital investment and fixed costs used as reference technology cost inputs to the PJM capacity market function. In contrast, the Companies' modeling relies upon generic unit costs for new natural gas facilities, which is derived from an adjusted overnight capital cost excluding interest during construction. While both the CONE resource[162] and the generic unit cost have an overnight capital cost component, the costs are not fully comparable, and the referenced CONE data is based on 2022 data while the Companies' generic unit cost is based on more current 2023 data. More specifically, the CONE and generic cost unit use differing assumptions for inflation, supply chain constraints, labor costs, location specific costs, the timing of the study and many other variables that can result in differing study results.

Furthermore, all resources within the energy sector as a whole have been subject to significant volatility in underlying resource costs driven by inflation uncertainty and domestic and global supply chain cost volatility that can be further exacerbated by evolving global trade policies and tariffs. For these reasons, the Companies ran a capital price stress sensitivity on the cost of new gas resources to ascertain the impact of a 25% increase in the cost of new gas resources relative to base planning assumptions. The results of that sensitivity demonstrate that natural gas CTs and CCs were still selected at levels consistent

[162] Notably, the PJM report referenced by witness Hagerty did recommend the use of CCs as the reference resource contending CCs were the most economically viable and had the lowest CONE of other candidate resources. See Newell, Samuel, et al., Brattle PJM CONE 2026/2027 Report, April 21 2022.

with those contained in the Companies' NTAP even against the backdrop of higher inflationary prices for the resources.

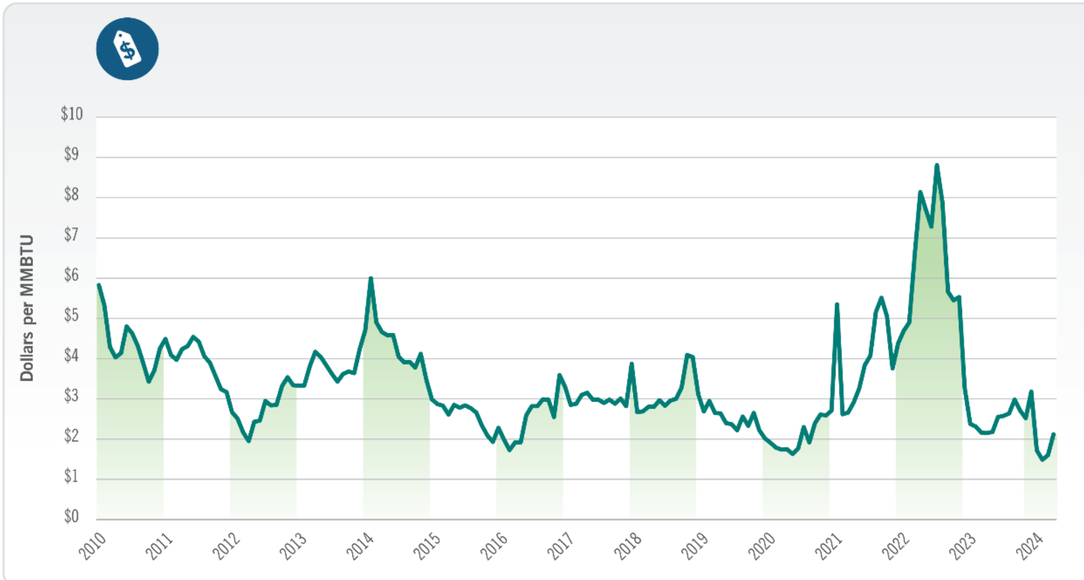
Q. CEBA WITNESSES ALDERFER AND URLAUB SUGGEST THAT DUKE ENERGY'S MODELING IS BIASED BECAUSE IT TOLERATES GREATER RISKS FOR NATURAL GAS RESOURCES—INCLUDING FUEL SUPPLY AND PRICE RISK—THAN IT DOES FOR RENEWABLE RESOURCES.[163] HOW DO THE COMPANIES RESPOND TO THESE ALLEGATIONS?

A. CEBA witnesses fail to take a holistic view of risks and fail to acknowledge the critical need for new natural gas resources as part of a comprehensive NTAP in this proceeding. As it relates to gas price volatility risk, CEBA witnesses raise a specific point in time when gas prices were elevated in 2022,[164] but acknowledge that gas prices can move both up and down. Figure 9 below illustrates that since 2010 Henry Hub spot prices have averaged less than $4 per MMBTU over more than a decade, even including the 2022 price spike.

[163] CEBA Alderfer and Urlaub Direct Testimony at 49-51.

[164] CEBA Alderfer and Urlaub Direct Testimony at 49.

Figure 9: Henry Hub Natural Gas Prices[165]



In fact, the Companies have highlighted the risk of lagging fundamental forecasts over-estimating forward gas prices in multiple avoided cost proceedings before this Commission dating back nearly a decade.[166] Importantly, gas price volatility does not imply gas resources should not be part of an all-of-the-above energy transition. Again, the Companies urge that a holistic approach to assessing risk requires the understanding that many resources are subject to price volatility over time and have their own inherent operational risks and limitations.

The Natural Gas Firm Transportation and Supply Panel also addresses the CEBA witnesses' critique as well as their comments on fuel supply risk,

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[165] U.S. Energy Information Administration (EIA) Natural Gas Data, *available at* https://www.eia.gov/dnav/ng/hist/rngwhhdM.htm.

[166] Order Establishing Standard Rates and Contract Terms For Qualifying Facilities at 77, Docket No. E-100, Sub 148 (Oct. 11, 2017) ("The Commission agrees with Duke that lagging fundamental forecast pricing has proven to be inaccurate over the past few years and has led to overpayment to QFs.").

addressing in detail the Companies' plans to secure additional interstate firm transportation of natural gas pipeline capacity into the Carolinas to reliably and economically support the gas generation facilities proposed in the Companies' NTAP.

Q. CAN YOU PROVIDE BRIEF EXAMPLES OF RISKS THAT ARE INHERENT ACROSS OTHER RESOURCES THAT HELP TO DEMONSTRATE THE UNBIASED NATURE OF RESOURCE SELECTION IN THE COMPANIES' PLAN?

A. As described previously, and as shown in Table 11 above, the Companies' all-of-the-above strategy recognizes that all resource types contribute benefits and introduce risks to the system. The Companies' long-term planning must consider balancing cost, reliability, and market execution realities as the Companies alone are responsible for reliably meeting new load obligations while transitioning the system to an increasingly clean resource mix. For example, achieving the prescribed levels of solar energy outlined in the Plan involves significant amounts of land acquisition and grid interconnection needs relative to a similar amount of energy produced from other resources. Wind resources have cost, siting, and unique community-specific risks, to consider during development. Battery storage systems are dependent on complex global supply chains and have limited long-term operating, performance, and safety records. New incremental nuclear and pumped hydro storage must meet several federal regulatory requirements in order to advance, increasing delivery timeline risk.

From a planning perspective, some level of risk exists for all resources while integrating the unique capacity and energy benefits brought by each resource. Taking into account the Companies' commercial expertise and operational experience with fuel transport and supply, the Companies did not accept a wholly different or unreasonable risk profile in defining modeling assumptions for both fuel supply and natural gas asset availability parameters than it did for any other resources modeled in the plan.

Q. SACE ET AL. WITNESS ROUMPANI ALONG WITH OTHER INTERVENING PARTIES ALLEGE THAT THE COMPANIES FAIL TO ACCOUNT FOR STRANDED ASSET RISK OF NEW NATURAL GAS GENERATION. TO BEGIN, HOW DO THE COMPANIES CONSIDER WHETHER A "STRANDED ASSET RISK" EXISTS?[167]

A. In the context of long-term resource planning, the Companies consider stranded asset investment risk to mean: "The risk that a resource will stop providing used and useful benefits to customers prior to reaching the end of its projected depreciable life." Said differently, stranded asset risk is the risk that a particular resource would have a remaining net book value that would be "stranded" assuming no value from that resource was accruing to customers from the point at which the resource stopped providing service to customers.

Q. BASED ON THIS DEFINITION, HOW DO YOU RESPOND TO INTERVENOR CONCERNS OVER THE POTENTIAL FOR NEW

[167] SACE et al. Roumpani Direct Testimony at 6,13-16 and 46-50; CEBA Alderfer and Urlaub Direct Testimony at 10-11 and 15- 17; CIGFUR Collins Direct Testimony at 33.

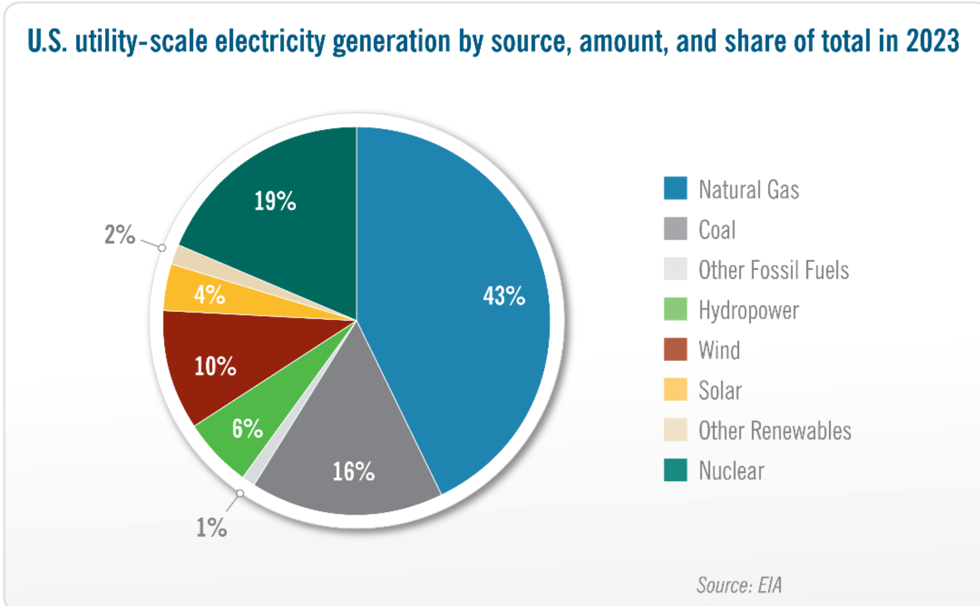
NATURAL GAS UNITS THAT ARE IDENTIFIED AS NECESSARY IN THE COMPANIES' NTAP TO BECOME STRANDED ASSETS?

A. Based on the definition above, the Companies believe the risk that these facilities could become stranded risk assets is extremely remote. The Companies see new natural gas units providing essential functional and operational value to the system over the entirety of their 35-year projected life. Examining risk holistically and objectively in context of an "all-of-the-above" resource plan, as the Commission must do under HB 951, all new generation carries risk. In the Companies' view intervenors greatly exaggerate this risk relative to reality. Considering the numerous combination of factors that would actually have to exist in the future for new natural gas resources to stop providing operational value to the system over their projected 35-year depreciable life, the actual risk of new natural gas becoming stranded is highly unlikely.

From a macro perspective, existing natural gas resources are by far the largest source of electricity production in the United States providing 43% of all U.S. electricity in 2023 according to the U.S. Energy Information Administration (EIA).[168] This is more than twice the level of any other any other resource in the country as shown in Figure 10 below.

[168] U.S. Energy Information Administration, U.S. utility-scale electricity generation by source, amount, and share of total in 2023, https://www.eia.gov/tools/faqs/faq.php?id=427&t=3 (last visited July 1, 2024).

<u>Figure 10: U.S. Utility-Scale Electricity Generation by Source (2023)</u>



Moreover, demand for new natural gas resources is increasing significantly on a national scale as the country faces increasing demand for power from the electrification of the transportation sector, onshoring of manufacturing and significant growth in data storage and data computational needs. In addition to domestic demand growth, additional resources are required to replace coal generation as these resources continue to be phased out nationally due to obsolescence and increasing regulatory pressures. Furthermore, new gas resources represent more efficient and lower carbon emitting resources relative to both existing coal generation and existing natural gas resources.

The macro-view of the industry and increasing demand for natural gas described above illustrates that the industry recognizes the need – in the near-term, intermediate-term and long-term – of the unique operational characteristics of natural gas resources to provide essential reliability services and provide continual capacity and energy during multi-day reliability events to maintain service to customers in a manner that only CTs and CCs can provide. This industry imperative for, and the crucial role of, natural gas assets providing operational support for the system is further addressed by the Reliability and Operational Resilience Panel.

As such, it stands to reason that before future zero carbon technologies and commensurate levels of energy storage could even approach penetration levels that would be required to theoretically displace or "strand" new natural gas resources, these future carbon free resources and associated energy storage resources would first have to be added to the grid at a pace, scope and scale that could meet national load growth, replace retiring coal generation and replace the entirety of the existing gas generation in the nation.

Q. DO YOU AGREE WITH SACE ET AL. WITNESS ROUMPANI THAT NEW CC CAPACITY FACTORS WILL DECLINE OVER TIME AS ADDITIONAL CARBON FREE GENERATION COMES ONLINE?

A. Yes. The Companies' Plan fully recognizes and accounts for the changing mission of new CC resources over time. Initially, when placed in service toward the end of this decade and into the early 2030s new CCs will run at higher annual capacity factors and then decline over time as additional renewable resources are brought onto the system. Importantly, these new CCs are highly efficient, lower carbon emitting resources, relative to both existing coal and existing natural gas resources on the system. As a result, in an economic dispatch, these new CCs will initially provide critical low carbon, low-cost annual energy to the system as well as providing critical peak capacity capabilities, particularly for extended time periods (multi-day, weeks), that are required to meet the core planning objectives of HB 951, importantly maintaining reliability, in the most reasonable manner. As the system begins to saturate with renewable resources over the 2030s and 2040s, the role of the new CCs will transition to more of a reliability focused resource providing critical customer value to meet high load periods and backstand the system during periods of low renewable output, particularly in a sustained manner over extended time periods at the scale needed for the size of the combined Carolinas system that limited peak-clipping solutions cannot provide.

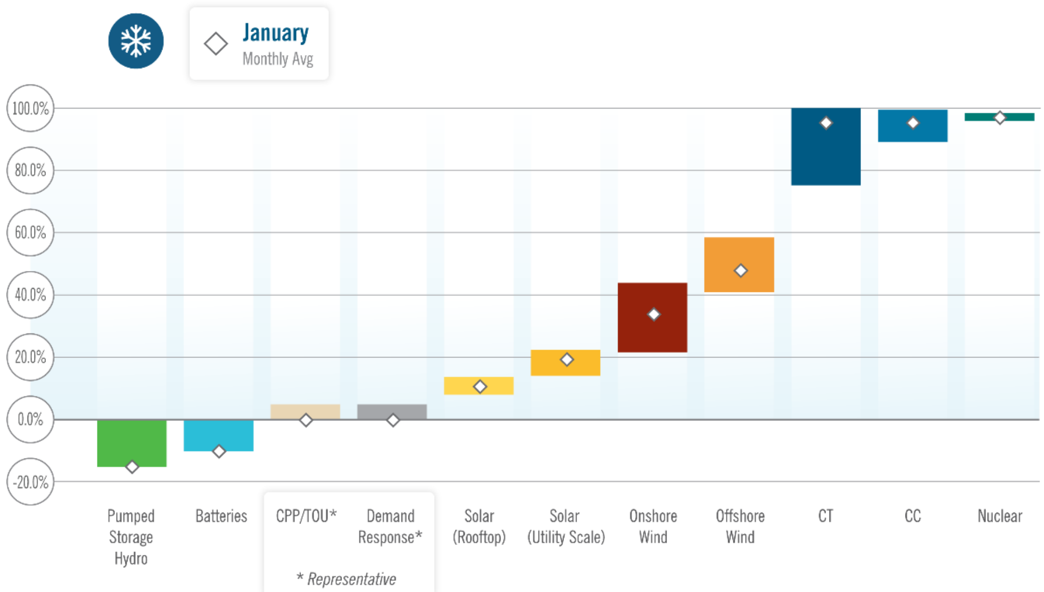
Q. DOES THE CHANGING ROLE OF THE NEW COMBINED CYCLES OVER THE PLANNING HORIZON IMPLY LESS IMPORTANCE TO MAINTAINING A RELIABLE SYSTEM OR A HIGH LIKELIHOOD OF STRANDED ASSET RISK FOR THESE RESOURCES AS SOME INTERVENORS CLAIM?

A. Absolutely not. The economic selection of these resources in the Companies' modeling fully accounts for the changing nature of projected operations of these resources. Furthermore, from a reliability perspective, the new CCs continue to provide unique operational and reliability characteristics that cannot be reasonably replicated by other resources in the Plan, as further discussed by the Reliability and Operational Resilience Panel.

Q. CAN YOU PLEASE ELABORATE ON THE UNIQUE OPERATIONAL AND RELIABILITY CHARACTERISTICS OF NEW GAS GENERATION RELATIVE TO OTHER RESOURCES?

A. As explained throughout this docket, a resource plan must have a sufficient resource mix that maintains or improves system reliability under the requirements of HB 951. To accomplish that objective, new gas combined cycle and simple cycle resources are a necessary part of an "all of the above" resource plan. To illustrate the unique characteristics of new gas resources, consider an example of a future cold weather week across the Carolinas that resulted in high winter peak loads that persisted over the course of the week. During such a high-demand winter week sufficient resources must be available to reliably meet the load 24 hours a day for all 7 days of the week or all 168 hours in that high demand week. For example, if a baseload nuclear unit tripped offline for the week, other resources must be available to fill the 24X7 energy that was being provided by the nuclear unit. Figure 11 below depicts the amount of weekly energy that each resource type could be counted on to replace the loss of the nuclear unit in the example.

Figure 11: Weekly Energy Availability (Winter)



As can be seen in Figure 11, storage resources (pumped storage and batteries) actually require extra energy relative to what they produce during discharge to make up for round trip efficiency losses associated with energy storage. TOU rates and dispatchable demand response programs contribute by shifting energy consumption from one period to another but provide little to no cumulative energy savings over the course of a week. Renewable resources have a range of potential energy production over the course of a winter week dependent on the level of cloud cover and wind speeds experienced during the week. Solar is also limited by the shorter days in the winter relative to higher output potential in the summer when days are much longer.

Notably, as coal units are retired from the system, only new gas resources and new nuclear resources have the capability to reasonably provide around the clock energy that would be needed to replace the lost nuclear unit in any reasonable manner. For illustration, to attempt to provide the replacement of 24x7 baseload energy with solar and storage would require roughly six times the amount of nameplate solar and two-to-three times the amount of nameplate batteries to try and replace the lost nuclear unit in the example. Once again this illustrates the need for natural gas as part of a balanced "all of the above" resource plan that is compliant with HB 951 given its unique ability to meet high load needs on the system and to backstand periods of low renewable output.

Q. INTERVENORS IMPLY THAT ACHIEVING NET CARBON NEUTRALITY BY 2050 AS DIRECTED IN HB 951 WILL EXPOSE CUSTOMERS TO STRANDED ASSET RISK FOR NEW GAS STARTING IN 2050, HOW DO YOU RESPOND TO THOSE CRITICISMS?

A. While I am not an attorney, it is my understanding that there is nothing in HB 951 that mandates CC units cease operation in 2050. Rather the law requires that the Commission approves a plan that takes all reasonable steps to achieve net carbon neutrality by 2050. As previously discussed, the significant drop in projected capacity factors for these resources meaningfully reduces the amount of residual carbon emissions remaining on the system as 2050 approaches. From an IRP vantage point of evaluating the need for dispatchable new generation today—26 years away from 2050—there are currently four possible outcomes to meet net carbon neutrality by 2050 as prescribed in HB 951.

- **Option 1:** Convert the gas units to burn carbon free hydrogen when called upon for system capacity needs;
- **Option 2:** Utilize emerging carbon capture and sequestration ("CCS") technology to capture and sequester the small residual amounts of carbon being produced from these units in 2050;
- **Option 3:** Utilize future carbon offset markets to offset up to 5% of baseline carbon emissions as allowed for under the law; and
- **Option 4:** Operate the units only during critical capacity periods as needed to maintain system reliability also as allowed for under the law.

Should other options emerge or should current law be changed, there is ample time between now and 2050 to adjust plans and continue to plan for carbon neutrality to be achieved over time.

Q. FROM A HOLISTIC PERSPECTIVE IS NATURAL GAS THE ONLY RESOURCE IN THE PLAN THAT MAY BE SUBJECT TO THE SMALL RISK OF NOT PROVIDING VALUE OVER THE ENTIRETY OF ITS ORIGINALLY PROJECTED USEFUL LIFE?

A. No. As previously described, each resource being added to the system has its own set of unique benefits and risks. As it relates to the possibility that a resource may need to be retired, or completely replaced, prior to its originally projected book life, this "stranding" risk exists for all resources in the portfolio. For example, battery storage resources could potentially be retired or replaced early if operational costs of this original technology become more expensive than anticipated or if replacement with a future storage technologies becomes economic relative to today's technology. Operating offshore wind off the coast of North Carolina, which has higher hurricane risk than other parts of the world where offshore wind is deployed, could potentially result in a shortened useful life. Solar degradation and operating costs may be greater than expected which could shorten its useful life relative to the original book life of the resource. To be clear, this does not imply these risks will materialize over the 30-year projected lives of these resources. Rather, these examples simply highlight the fact that if taken out of context or in isolation, a case could be made for stranded asset risk for any resource in the portfolio. As is the case with any risk category, diversification that results from a Plan that includes a broad range of technologies limits exposure to any single risk factor for a given technology.

3. *The Companies' Hydrogen Conversion Assumptions are Reasonable for Planning Purposes*

Q. WITNESSES MICHNA,[169] COLLINS,[170] AND MCALEB[171] CLAIM THAT THE COMPANIES' MODELING FAILS TO CONSIDER ALL COSTS ASSOCIATED WITH HYDROGEN CONVERSION, INCLUDING COSTS FOR TRANSPORTATION, STORAGE, AND SELF PRODUCTION OF HYDROGEN. HOW DO YOU RESPOND?

A. The Companies disagree with these assertions. As discussed by the Dispatchable Generation Panel, the projected future production cost of

[169] Public Staff Michna Direct Testimony at 40-41.

[170] CIGFUR Collins Direct Testimony at 33-34.

[171] EDF McAleb Direct Testimony at 28-29.

hydrogen included in the Plan is based on third party forecasts, to which the Companies have added costs to account for pipeline infrastructure which, while not yet well defined, could include upgrades and storage. The Companies have captured reasonable costs of conversion estimates and the commodity and fixed cost adders necessary to produce, transport, store, and utilize hydrogen in the future. Based on previous recommendations from the Public Staff and stakeholders in the CPIRP process, the Companies have included a future cost for the conversion of newly selected CC and CT resources to operate exclusively on hydrogen in 2050 that is seen by the model when selecting these resources in the 2020s and 2030s. The Companies' Plan reasonably assumes, based on guidance and publications from leading industry experts, that a hydrogen market develops in the 2040s from which the Companies will purchase hydrogen fuel. Specifically, the Plan's hydrogen fuel assumption relies on hydrogen price forecasts from Bloomberg New Energy Finance, the Hydrogen Council, and International Renewable Energy Agency (IRENA). These forecasts factor in the cost of production of hydrogen including the energy and capital requirements to produce the clean hydrogen assumed in their forecasts. While the Companies do not model direct production of hydrogen in their CPRIP modeling, such as the load and incremental resources required to self-generate hydrogen from the Companies system, the costs to produce the hydrogen are appropriately captured in the hydrogen forecasts used in the Companies' assumed market price. Furthermore, the Companies have assumed full conversion of gas resources to hydrogen, a fixed cost adder that covers the transportation and/or storage of hydrogen to allow for these fully converted hydrogen resources to operate reliably on hydrogen.

G. Intervenors' Recommendations to Accelerate the Achievement of the Interim Target Should be Rejected for Failure to Provide any Technical Analysis or Modeling to Support Such Result.

Q. PLEASE DESCRIBE THE VARIOUS RECOMMENDATIONS MADE BY INTERVENORS REGARDING THE DATE OR TIMEFRAME FOR ACHIEVEMENT OF THE INTERIM TARGET.

A. Intervenors take a range of positions on the appropriate timeframe for compliance with the Interim Target. As stated previously in testimony, the Public Staff acknowledges that achievement of the Interim Target prior to 2034 is not executable or reasonable for planning purposes. CIGFUR witness Collins recommends compliance with the Interim Target beyond 2030, noting the increased cost and risk associated with meeting the Interim Target by that time.[172] In contrast, the AGO recommends achievement of the Interim Target no later than 2032[173] and CEBA witness Davis recommends that the Commission approve a 2030 Interim Target[174] though neither presents a comprehensive plan supported by modeling to achieve such goal.

The Companies' detailed and comprehensive modeling, reinforced by the Public Staff's similar conclusions, confirms that compliance with the

[172] CIGFUR Collins Direct Testimony at 9.

[173] AGO Burgess Direct Testimony at 6 and 95.

[174] CEBA Davis Direct Testimony at 5 and 11.

Interim Target is only reasonably executable and achievable after 2034 while maintaining or improving the reliability of the grid.[175]

In their initial Plan, the Companies modeled Energy Transition Pathway P1 to reach Interim Target by 2030. As explained throughout the Plan, Pathway P1 is the highest cost portfolio through 2038 and requires an unattainable level of resource additions and transmission improvements to be complete and in service by 2030. The rate of resource development required through Pathway P1 exceeds what is possible to interconnect in that timeframe without jeopardizing system reliability, including approximately 9,600 MW of solar (including approximately 3,000 MW currently in advanced development), 1,600 MW of offshore wind, two advanced-class, hydrogen capable combined-cycle generators, and over 5,000 MW of battery energy storage.[176] The SPA further confirms that Pathway P1 is infeasible, as incorporating the Updated Fall 2023 Load Forecast results in an even more unattainable level of resource additions.[177] Pathway 2, which achieves Interim Target by 2033, likewise requires aggressive deployments of new resources—including 800 MW of offshore wind by 2032 and another 800 MW by 2033, along with solar and onshore wind additions at or very near the limits of total availability, increasing execution risks and costs.[178] Again, the increased load modeled in the January 2024 SPA filing illustrates that Pathway 2 remains unreasonable for planning

[175] Public Staff Thomas Direct Testimony at 56.

[176] CPIRP Chapter 3 at 9 and 25.

[177] SPA Technical Appendix at 8-9.

[178] CPIPR Chapter 3 at 11 and 25.

purposes by further increasing the already aggressive deployment amounts of renewables.[179]

In sum, the Companies' modeling confirms that achievement of the Interim Target before 2034 is not attainable. As the Public Staff notes, "a delay beyond 2032 is necessary to ensure the adequacy and reliability of the grid. The scale of resource additions and retirements necessary to comply by 2030 simply does not appear to be possible."[180]

H. Intervenors' Recommended Changes to the Coal Retirement Schedule Have no Supporting Technical Modeling or Portfolio Analysis and are not Reasonable for Planning Purposes.

Q. PLEASE SUMMARIZE INTERVENORS VIEWS OF THE COMPANIES' COAL RETIREMENT ANALYSIS AND SCHEDULE AND HOW THE COMPANIES RESPOND TO THE VARYING OPINIONS OF INTERVENORS.

A. Intervenors present a range of opinions regarding the Companies' proposed coal retirement schedule. AGO witness Burgess claims that "Duke overlooked practical, reasonable strategies for accelerating coal retirements and renewable additions that could assist with meeting the Interim Target while maintaining reliability."[181] In contrast, SACE et al. witness Roumpani critiqued the Companies for "restricting the timeline in which coal units can retire" in its P1 portfolio, suggesting that delayed coal retirements would enable the Companies

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[179] SPA Technical Appendix at 8 and 10.

[180] Public Staff Thomas Direct Testimony at 56.

[181] AGO Burgess Direct Testimony at 5.

to maintain reliability while simultaneously achieving the Interim Target in 2030.[182] Further, witness Roumpani suggests that the Companies lack of additional trade-off analysis of retiring some units earlier or condensing retirements into a narrow timeline leads to a "false dichotomy" between a delayed schedule and an aggressive, more expensive one, with nothing in between.[183]

Importantly, none of these opinions are supported with modeling, or even cursory analysis of why such additional modeling would be holistically beneficial or provide superior results to the Companies' modeled Plan and SPA. There is simply no adequate evidence in the record to support these assertions.

Counter to these positions advocating a more accelerated coal unit retirement schedule, CIGFUR witness Muller states, "[r]etiring all coal plants before the end of their economic lives, and during a period of increased load growth, is a threat to reliability; not a 'reasonable step' to retire all coal plants."[184]

In response to these varying critiques, the Companies stand by the coal retirement schedule presented in the SPA, as reasonable for planning purposes and informed by detailed analysis that considers the risks and uncertainties of future coal transport, supply and operations outlined in Appendix F (Coal Retirements Analysis). The Public Staff accepts that analysis and incorporates

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182 SACE et al. Roumpani Direct Testimony at 21-22.

183 SACE et al. Roumpani Direct Testimony at 19-21.

184 CIGFUR Muller Direct Testimony at 12.

the Companies' coal unit retirement schedule as reasonable for planning purposes, as noted earlier in this testimony. Additionally, as noted above and further addressed in the Panel's Exhibit 1, the CAA Section 111 Final Rule does not at this time change Companies' planned coal retirement schedule, as further explained in the Dispatchable Generation Panel's testimony relative to future state compliance plans.[185] The Companies will continue to check and adjust the schedule based on the successful in-service of the replacement resources through NTAP and the Execution Plan to "replace before retire" coal in order to maintain or improve reliability.

Q. AGO WITNESS BURGESS TAKES ISSUES WITH THE COMPANIES' BELEWS CREEK NATURAL GAS CONVERSION ANALYSIS.[186] PLEASE RESPOND TO HIS CRITICISM OF THE ANALYSIS.

A. AGO witness Burgess first takes issue with the Companies' assumption that Belews Creek would retire in 2041, rather than an earlier date such as 2035. However, The Companies intentionally selected 2040 to address the Commission's order in which Burgess cites in his testimony that the analysis should capture operating Belews Creek for longer as a bridge resource until *fully* capable hydrogen resources could be brought online.[187] The Companies' planning assumptions as stated in Appendix C to the Plan allow hydrogen CTs to be selected beginning in 2040,[188] appropriately assessing the conversion of

[185] Dispatchable Generation Direct Testimony at 16-19.

[186] AGO Burgess Direct Testimony at 36-40.

[187] Carbon Plan Order at 65.

[188] Carolinas Resource Plan, Appendix C at 33.

Belews Creek as a bridge to when alternative fuel options or other non-carbon emitting resources may be available. Additionally, Public Staff witness Michna advocates for appropriately considering the time over which costs would need to be recovered when making investment decisions such as natural gas conversion of Belews Creek. Assuming a shorter recovery period would be an increased impact to customers allowing for less time for customers to benefit from the investment.[189]

Next, AGO witness Burgess claims that assuming a 15-year term for gas FT was too long and a shorter term would have been more appropriate and cost less. Moreover, he suggests that assuming FT on gas assets is inconsistent with the Companies' past practice for gas resources. It is important to note that, while today the Companies do not have FT for all of its gas resources on the system, the gas fleet does have a firm fuel supply. For those CCs and CTs which are not covered by interstate FT, they have ultra-low sulfur diesel oil back-up fuel to be able to reliably operate the units in circumstances that natural gas supply is not available. Similar, dual fuel optionality ("DFO") coal units which are co-fired with natural gas have coal back up to operate the units entirely on coal if natural gas is unavailable or otherwise more expensive to operate based on the relative commodity prices. Appropriately, when the Companies performed this natural gas conversion analysis, they assumed the removal of coal generating capabilities and therefore rely on natural gas as the single fuel supply, which required FT to support full load burn capabilities to maintain the

[189] Public Staff Michna Direct Testimony at 14.

capacity value. Furthermore, on the FT cost assumed, the Companies assumed the price of a 15-year term, however, Burgess suggests that shorter term would have been more appropriate and cheaper. While 20-year terms are traditionally more commonplace to support incremental pipeline facilities, the Companies are not aware of any short-term contracting for new FERC regulated facilities, such as a five-year term. Witness Burgess also fails to recognize that a shorter term would almost certainly result in much higher overall rate for FT, recognizing that the pipeline operators still need to recover their capital cost of incremental pipeline facilities to create the FT capacity, whether over five years or 15 years.

Finally, the analysis, as witness Burgess points out, defers the selection of 425 MW of CT resources, but does not defer any CCs, which underscores the limited ability for gas conversions of existing coal units to provide the same value of low carbon energy, system flexibility and efficient operations that is provided by new advanced class CCs. Overall, when considering the needs of the system, to maintain reliability and provide for a system that best optimizes new and existing resources to integrate variable energy resources, and Belews Creeks ability to defer resources selected in the 2030s to the 2040s, it is apparent that the operational parameters, of even a natural gas converted Belews Creek station, is not economic for customers. This is further supported by the analysis the Companies conducted in its CAA Final Rule Sensitivity Analysis, which performed conversion analysis for all of the Companies existing coal units and found that the impacts to the system did not outweigh the costs and allocation of a finite amount of gas supply into the Carolinas to a lesser efficient unit.

I. The Companies' Financial Assumptions are Reasonable.

Q. THE AGO,[190] SACE ET AL.,[191] AND THE CITY OF CHARLOTTE SUGGEST THAT THE COMPANIES SHOULD LEVERAGE EIR PROGRAM FINANCING FOR THE COMPANIES' INVESTMENTS. ARE THE COMPANIES MODELING THE USE OF EIR PROGRAM FINANCING WHEN DEVELOPING FINANCING COST ASSUMPTIONS FOR VARIOUS RESOURCES?

A. The Companies' EIR Loans and Financing Panel addresses this issue in their testimony, explaining that while the EIR Program loans offer slightly lower interest rates, those interest rate savings are largely or wholly offset by increased compliance costs that are required in order to obtain the EIR Program loans. As such, the Companies did not model EIR Program loans in this CPIRP.

Q. WHAT DID INTERVENORS RECOMMEND REGARDING THE COMPANIES' IRA MODELING ASSUMPTIONS?

A. TotalEnergies expresses concern that the IRA credits will phase out in 2032 and offshore wind will miss out on the credits.[192] The IRA states that credits will phase out the later of "the year after 2032" or when the electric power sector GHG emission achieves a 75% reduction of 2022 levels. Based on the

[190] AGO Burgess Direct Testimony at 19.

[191] SACE Roumpani Direct Testimony at 24.

[192] TotalEnergies Tanner Direct Testimony at 13.

Companies' review of industry studies as well as recent IRPs of utilities such as Santee Cooper and DTE, the Companies have determined that the 75% reduction from 2022 levels will not be reached until the mid-2040s at the earliest and with safe harbor and the phase out, the credits would be available to the end of the Companies' study period.

J. The Commission Should Decline to Impose Requirements to Prepare More Frequent CPIRP Updates

Q. SEVERAL INTERVENORS RECOMMEND ADDITIONAL MODELING AND REPORTING REQUIREMENTS IN ADDITION TO THE CPIRP. HOW DO YOU RESPOND?

A. Tract witness Moe recommends that the Commission order the Companies to file a "mid-cycle update" to the CPIRP that incorporate large economic development projects through March 31, 2025 and that it should further order the Companies to file annual updates to the CPIRP. [193] CIGFUR witness Collins recommends the Commission require updates from the Companies every six months on the status of the IRP.[194] These additional requirements are not consistent with N.C.G.S. § 62-110.9 and Commission rule R8-60A, which require the Companies file a biennial CPIRP on September 1 with testimony and exhibits of expert witnesses and shall include the NTAP. The Companies object to such recommendations as unduly burdensome and impracticable given the regulatory schedule for adjudicating each biennial CPIRP. The Companies

[193] Tract Capital Management Moe Direct Testimony at 5 and 21.

[194] CIGFUR Collins Direct Testimony at 9 and 43.

will be filing a new CPIRP nine months after the Commission is required to issue its order in this proceeding. Accordingly, there is no need for the additional CPIRP filings suggested by intervenors, as updates will be incorporated through the biennial check and adjust process.

Q. IS PUBLIC STAFF WITNESS MICHNA'S RECOMMENDATION REGARDING UPDATED COAL UNIT RETIREMENT OUTLOOKS REASONABLE?

A. Public Staff witness Michna suggests that the Companies "should provide an updated coal unit retirement outlook in each iteration of the CPIRP.[195] The Companies fully expect to do so in developing the 2025-2026 CPIRP update, and will continue to check and adjust whether future coal unit retirement analyses are needed based on the Companies' evolving approach to the CAA Section 111 Final Rule and other considerations that may evolve over time.

VI. CONCLUSION

Q. DOES THIS CONCLUDE THE PANEL'S REBUTTAL TESTIMONY?

A. Yes.

[195] Public Staff Michna Direct Testimony at 5.

Figure 1: Modeling Inputs – Core Planning Assumptions Areas of Alignment

Model Parameter	Assumption	Alignment
Modeling Software and Analytical Framework	Companies' EnCompass Modeling Setup	✓
Reliability Verification	Detailed SERVM analysis to ensure reliability	✓
Load Forecast	Updated 2023 Fall Load Forecast	✓
Forecasted Grid Edge Resources	SPA Assumptions	✓
Coal Retirements and Existing Supply-side Resources	SPA Assumptions	✓
Selectable Supply-side Resource Cost & Operational Parameters	SPA Assumptions	✓
Fuel Supply and Commodity Price Forecasts	SPA Assumptions	✓
ELCCs	2022 and 2023 ELCC Studies	✓
Reserve Margin Target	2023 Resource Adequacy Study's Recommendation (22%)	✓
Interim Target	Before 2034 is Unachievable	✓

Figure 2: Growth in Grid Edge Resources (Winter MW) – Carolinas Combined System

Growth in Grid Edge Resources (Winter MW)

Carolinas Combined System

Type	Program	2033	2038
Load Modifier	Utility Energy Efficiency (UEE)	924	1,095
	Net Energy Metering (NEM)	46	62
	Time of Use Rates (TOU)	383	538
Controllable Resource	Retail Demand Response (DR)*	618	761
	Integrated Volt-Var Control (IVVC)	116	137
	Wholesale Demand Response (DR)*	12	19
	Total:	**2,098**	**2,613**

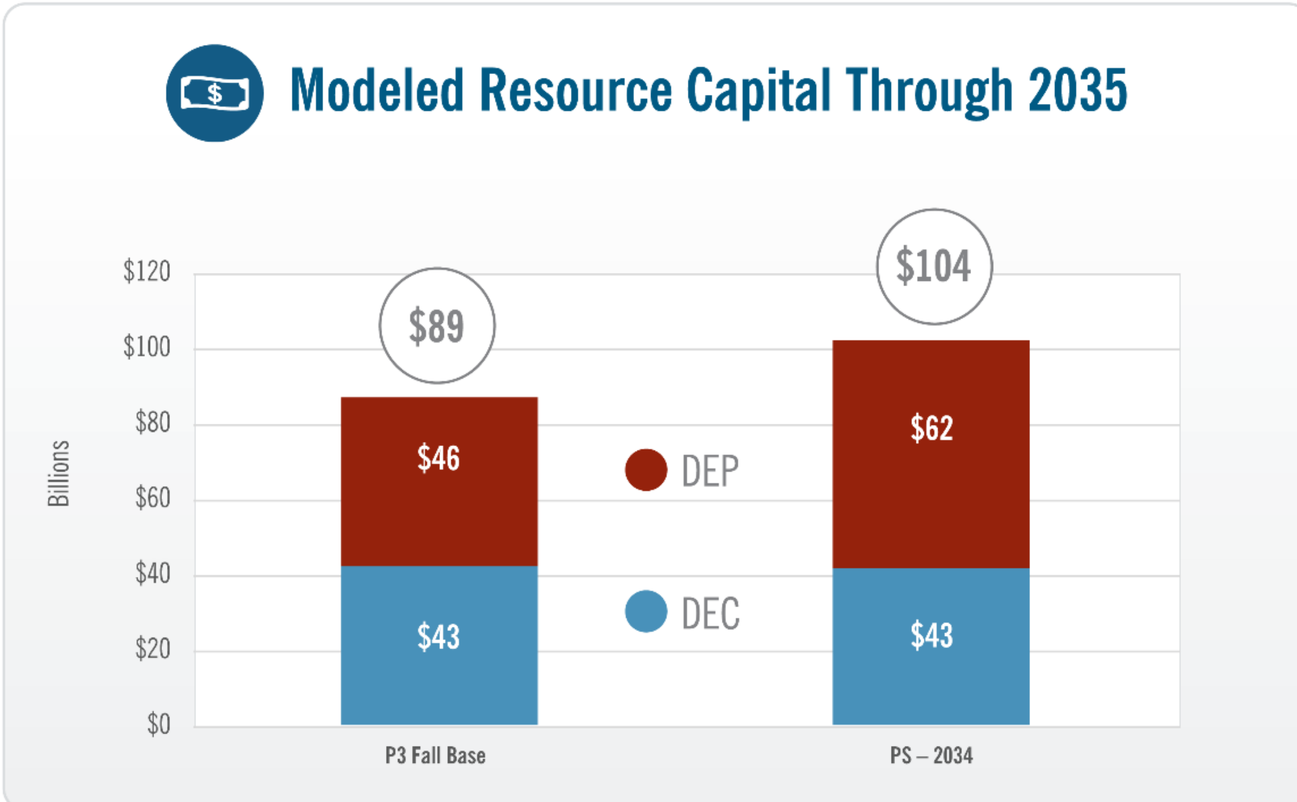
** Includes Standby Generation, Interruptible Service, and other Demand-Side Management programs*

Figure 3: Resource Additions and PVRR of EPA CAA Section 111 Sensitivity Analysis

	Solar	Onshore Wind	Nuclear	Offshore Wind	CCs	CT	Battery	Total	PVRR (In Compliance Year)	PVRR 2038	PVRR 2050
P3 Fall Base	12,600	2,100	600	2,400	6,795	2,124	5,100	**31,719**	$61	$78	$149
CAA Section 111 Sensitivity (2036)	14,625	2,250	900	2,400	8,154	1,699	7,140	**37,168**	$67	$80	$152
CAA Section 111 Sensitivity (2037)	16,425	2,250	1,500	1,600	6,795	1,699	6,740	**37,009**	$71	$77	$148

**Does not contain forecasted MWs

Figure 4: Modeled Resource Capital Through 2035



Note 1: Assumes 100% Solar, AFUDC, No Selectable BTM SPS, No Network Upgrades, No Forecasted Resources & No IRA

Figure 5: Modeled Resource Capital Through 2035 by Technology

[redacted]

Figure 6: Combined Cycle Units Economically Selected by Portfolio

1,360 MW/CC unit	2029	2030	2031	2032	2033	2034	Total
Companies P3 Fall Base	1	1	1	1	1		6,800 MW
Public Staff 2034 Base	1		1	1		2	6,800 MW
Companies CAA Section 111 Sensitivity 2037 Base	1	1	1	2			6,800 MW
Public Staff CAA Section 111 Sensitivity 2037 Base	1		2	1	2		8,160 MW
Companies CAA Section 111 High Gas CapEx Sensitivity	1	1	1	1	1		6,800 MW
Public Staff High Gas Commodity Sensitivity	1	1	1	1		1	6,800 MW
Public Staff Revised Load Sensitivity	1		1	1		2	6,800 MW
Public Staff Limit Offshore Wind Sensitivity	1	1	1		1	2	8,160 MW

Figure 7: Opportunity and Risks between Proposed Gas Resources and Load Growth Materialization

Figure 8: Carolinas Resource Plan Analytical Process Flow Chart

Figure 9: Henry Hub Natural Gas Prices

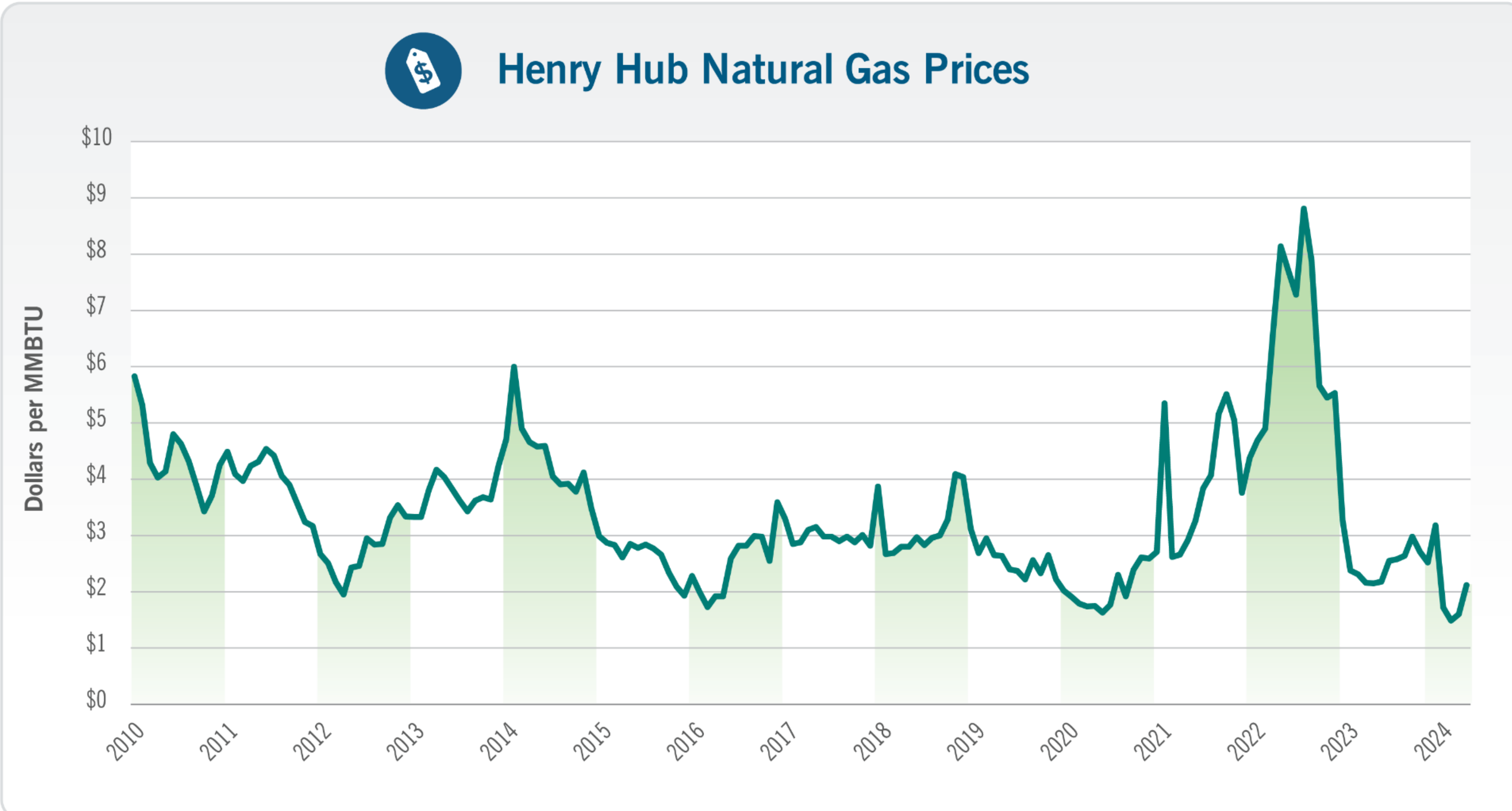


Figure 10: U.S. Utility-Scale Electricity Generation by Source (2023)

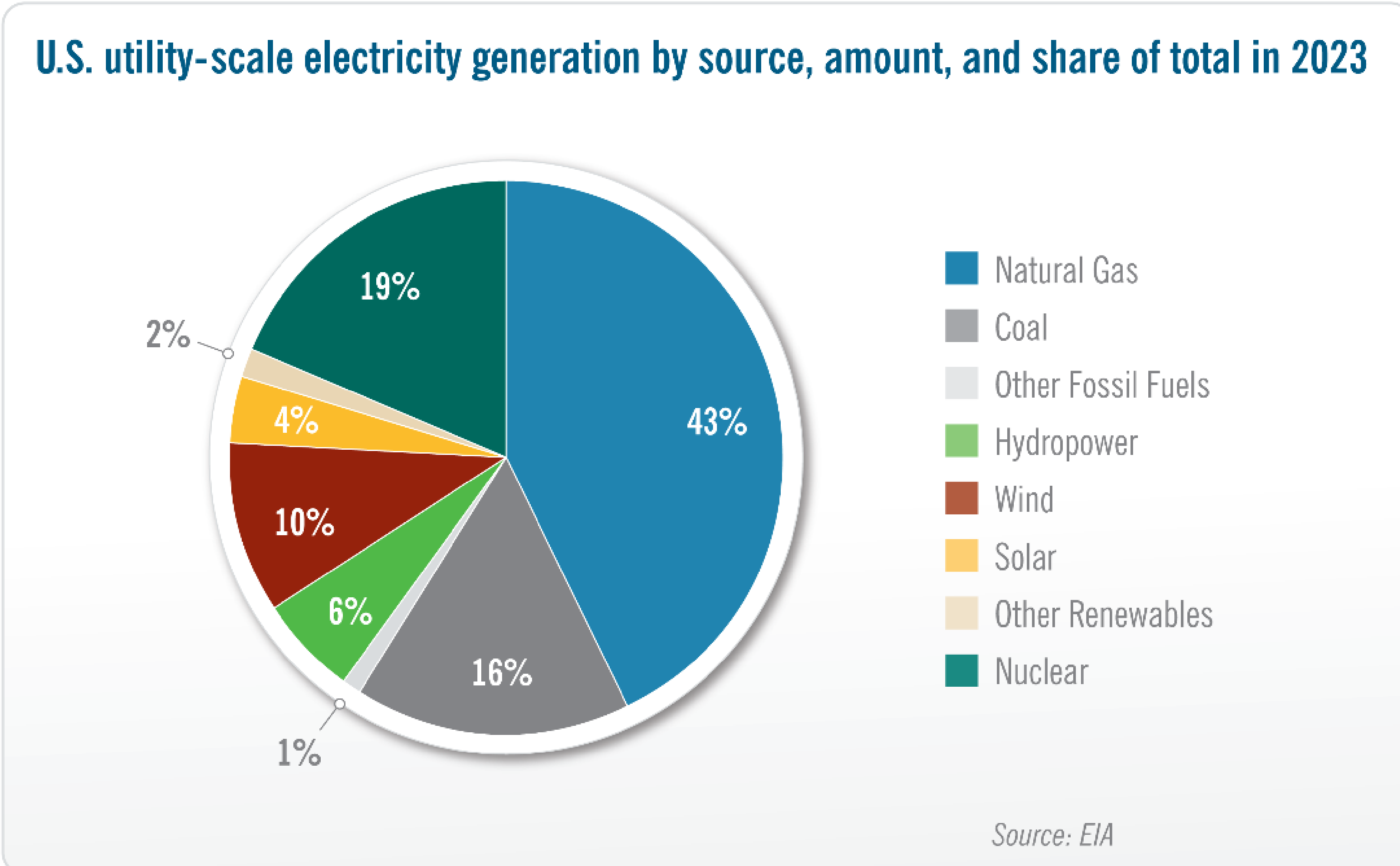


Figure 11: Weekly Energy Availability (Winter)

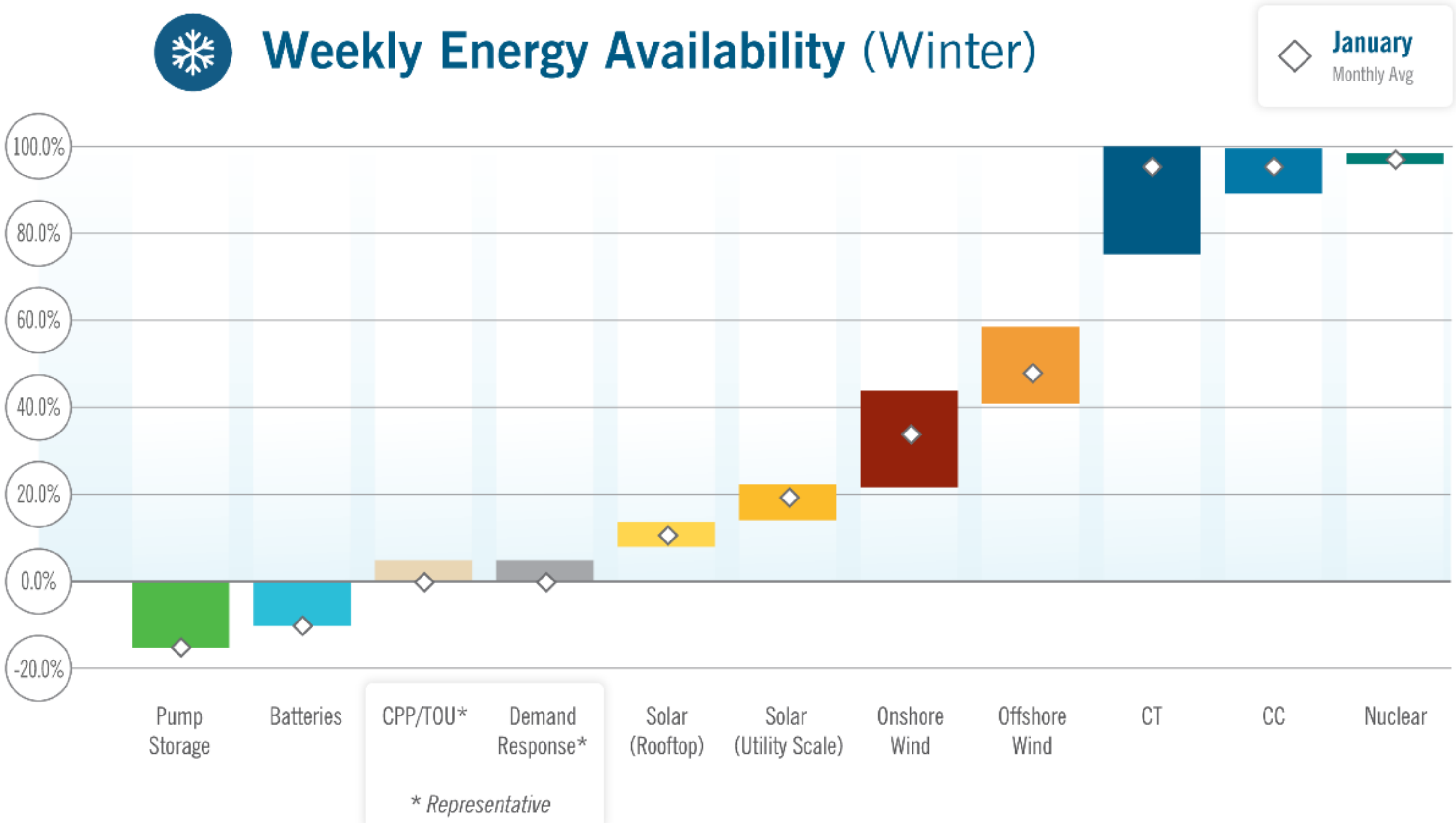


Table 1: Combined DEC/DEP Annual Resource Availability Assumptions Comparison

Technology	CPIRP SPA Assumption		Public Staff Base Assumption	
	Annual	Cumulative	Annual	Cumulative
Solar (including SPS)	2028-2030: 1,350 MW 2031: 1,575 MW 2032+: 1,800 MW	N/a	2028-2030: 1,875 MW[1] 2031: 2,100 MW 2032: 2,475 MW 2033: 2,550 MW 2034+: 1,800 MW	N/a
Stand-alone Battery	2027: 200 MW 2028-2029: 500 MW 2030+: 1,000 MW	N/a	2027: 300 MW 2028: 800 MW 2029: 900 MW 2030: 1,300 MW 2031-2033: 1,400 MW 2034+: 1,000 MW	N/a
BTM Solar paired with Storage[2]	N/a	N/a	2023, 2028-2029: 60 MW solar and 30 MW battery 2030+: 80 MW solar and 40 MW battery	N/a
CT	2029+: 2,125 MW	N/a	2029+: 2,125 MW	5,088 MW (12 CT Units; No H_2 CTs)
CC	2029: 1,360 MW 2030+: 2,720 MW	8,160 MW (6 CC Units)	2029: 1,360 MW[3] 2030+: 2,720 MW	8,160 MW (6 CC Units)
Onshore Wind	2031: 300 MW 2032+: 450 MW	2,250 MW	2031: 600 MW 2032-2033: 750 MW 2034+: 450 MW	2,250 MW
Pumped Storage	2034: 1,834 MW	1,834 MW	2034: 1,834 MW	1,834 MW
Offshore Wind	2033+: 800 MW	2,400 MW through 2038	2031+: 1,100 MW[4]	5,500 MW through 2038[4]
Advanced Nuclear	2035: 2 Units	11 Units through 2040	2035: 2 Units	11 Units through 2040

Note 1: Public Staff witness Thomas's Table 10 indicates that their modeling allowed standalonesolar selectable up to 1,875 MW per year for 2028-2030, but limited SPS projects up to 1,350 MW per year in 2028 and 2029; however, the Companies' review of their modeling files indicates the model was not constraint to 1,350 MW of SPS in 2028 and 2029, but could select up to the 1,875 MW consistent with their standalone solar assumption.

Note 2: Public Staff modeling allowed selectable behind the meter ("BTM") solar and storage resources that the Companies did not allow.

Note 3: Public Staff modeling allowed selection of a DEC CC beginning in 2029, whereas the Companies did not allow a DEC until 2031, consistent with the expected achievable timeframe for putting a DEC CC in service.

Note 4: Public Staff modeling adjusted the size of the generic offshore wind resource to 1,100 MW, accelerated the first deployment of offshore wind from 2033 to 2031, and increased the cumulative capacity available from 2,400 MW to 5,500 MW by 2038.

Table 2: Winter Planning Reserve Margin Constraints Assumption

Winter Planning Reserve Margin	CPIRP SPA Modeling	Public Staff Modeling
2024 – 2026	17%	17%
2027	18%	17%
2028	19%	17%
2029	20%	17%
2030	21%	17%
2031+	22%	22%

Table 3: CAA Section 111 Final Rule Summary

Existing Coal	New Gas
Existing coal units are exempt if they retire by December 31, 2031	**Base Load** (>40% capacity factor) **Phase 1** 800 lbs. of CO_2 per MWh emission rate upon commercial operation (BSER: Highly efficient natural gas combined cycle generation) **Phase 2** 100 lbs. of CO_2 per MWh emission rate by January 1, 2032 (BSER: CCS with 90% capture rate)
Medium-Term Subcategory Presumptive 16% CO_2 emission rate reduction by January 1, 2030 (BSER: 40% co-fire with natural gas) must retire by 12/31/2038	**Intermediate Load** (20-40% capacity factor) 1,170 lbs. of CO_2 per MWh emission rate (BSER: Highly efficient natural gas simple cycle generation)
Long-Term Subcategory Presumptive 88.4% CO_2 emission rate reduction by January 1, 2032 (BSER: Carbon Capture and Sequestration/ Storage (CCS) with 90% capture rate) Continue operations indefinitely	**Low Load** (<20% capacity factor) Use of fuel with less than 160 lbs. of CO_2 per MMBtu (BSER: Lower emitting fuels, such as natural gas)
An existing coal unit may operate beyond 12/31/2039 by switching to the gas steam category through conversion to 100% natural gas firing by 1/1/2030. Base load units must comply with a 1,400 lbs. of CO_2 per MWh emission rate.	

Table 4: NTAP Resources Compared to NTAP of CAA Final Rule Sensitivity Analysis

Resource Type	Resources Needed Through Year	NTAP Resources [MW]	NTAP Resources [MW] CAA Final Rule Sensitivities	NTAP Changes
Solar	2031	6,460	6,460	Confirmed Need
Battery Storage	2031	2,700	2,700	Confirmed Need
Onshore Wind	2033	1,200	1,200	Confirmed Need
CT	2032	2,125	2,125	Confirmed Need
CC	2033	6,800	6,800	Confirmed Need
Pumped Storage	2034	1,834	1,834	Confirmed Need
Advanced Nuclear	2035	600	600	Confirmed Need
Offshore Wind	2035	2,400	0 – 2,400	Potential Flexibility to Delay*

*Potential Flexibility based on whether Interim Compliance is targeted for 2036 or 2037, as explained below

Table 5: Comparison of Companies' NTAP to Public Staff's NTAP

Technology	Companies' NTAP		Public Staff NTAP		Difference
	MW Target	Year	MW Target	Year	MW Target
Solar	6,460	2031	6,700	2031	+ 240
Battery Storage	2,700[1]	2031	2,700[2]	2031	0
Onshore Wind	1,200	2033	1,800	2033	+600
Combustion Turbines	2,125	2031	849[3]	2030	-1,276
Combined Cycle	6,800	2033	1,359[3]	2030	-5,441
Pumped Storage Hydro	1,834	2034	1,834	2034	0
Advanced Nuclear	600	2035	1,200	2036	+600
Offshore Wind	2,400	2035	2,200 – 2,400	2034-2035	*Generally aligned*

Note 1: Includes 1,475 MW of standalone battery and 1,225 MW of battery paired with solar
Note 2: As described later in this testimony, when put on a comparable basis with the Companies NTAP, the Public Staff identifies approximately 3,200 MW for battery storage which is composed of 1,475 MW of standalone battery and 1,710 MW of battery paired with solar

Table 6: Resource Selections in PS-2034 Base Versus NTAP for Offshore Wind and CCs

	2029	2030	2031	2032	2033	2034	Total	NTAP
CC	1,360	0	1,360	1,360	0	2,720	**6,800**	**1,360**
Offshore Wind	0	0	1,100	1,100	1,100	1,100	**4,400**	**2,200-2,400**

Table 7: Present Value of Revenue Requirements Comparison

PVRR ($B)	P3 Fall Base			PS – 2034 Base		
	2033	2038	2050	2033	2038	2050
DEC	$32	$48	$89	$31	$48	$88
DEP	$19	$30	$60	$21	$33	$63
CAR	**$51**	**$78**	**$149**	**$52**	**$81**	**$151**

Table 8: Comparison of Companies' and Public Staff's NTAPs Solar Procurement Recommendations

	NTAP	2023 -Solar Procurement	2024 -Solar Procurement	2025-2026 Solar Procurements (Low-end)	2025-2026 Solar Procurements (High-end)
Companies	6,460 MW*	1,435 MW (Procurement underway)	1,585 MW (Procurement underway)	2,700 MW	3,460 MW
Public Staff	6,700 MW			2,940 MW	3,700 MW

*Accounts for potential future attrition to meet modeled system needs

Table 9: Comparison of Battery Energy Storage in the Public Staff's and the Companies NTAPs

	Standalone Battery Storage	Storage Paired with Solar	Total
2022 Carbon Plan Order *Total System*	**1,000 MW**	**600 MW**	**1,600 MW**
Companies NTAP *Incremental to 2022 Carbon Plan*	475 MW	625 MW	1,100 MW
Companies NTAP Total *Total System*	**1,475 MW**	**1,225 MW**	**2,700 MW**
Public Staff NTAP *Incremental to 2022 Carbon Plan*	475 MW	1,110 MW	1,585
Public Staff NTAP Total *Total System*	**1,475 MW**	**1,710 MW**	**~3,185 MW**

Table 10: NTAP Comparisons with Adjusted Public Staff Modeling NTAP

Technology	Duke Energy NTAP		Public Staff NTAP		Adjusted PS Modeling	
	MW Target	Year	MW Target	Year	MW Target	Year
Solar	6,460	2031	6,700	2031	6,700	2031
Battery Storage	2,700	2031	2,700	2031	2,300[1]	2031
Onshore Wind	1,200	2033	1,800	2033	1,800	2033
Combustion Turbines	2,125	2031	849	2030	1,700	2031
Combined Cycle	6,800	2033	1,359	2030	5,440	2033
Pumped Storage Hydro	1,834	2034	1,834	2034	1,834	2034
Advanced Nuclear	600	2035	1,200	2036	600	2035
Offshore Wind	2,400	2035	2,200	2034-2035	2,200	2036

Note: Accounts for Total Battery Energy Storage on the system by 2031, in contrast to the Public Staff's listed NTAP volumes as explained above.

Table 11: Benefits and Risks/Limitations of Resources Evaluated in the CPIRP

Holistic Overview of Plan Resources		
Technology	**Beneficial Characteristics**	**Limitations and Risks**
Dispatchable Distributed Energy Resources	Distributed nature provides geographic diversity, reduces system peak demand, BTM DERs require little to no transmission interconnection investments, customer focused resource	Scale of resource depends on customer adoption and retention rates, not universally applicable to all customer groups, generally provides limited energy contributions to the system, can involve complex system controls
Natural Gas CTs and CCs	Capable of 24X7 energy production, efficient resource to backstand intermittent renewable resources and replace retiring coal units, very mature technology, robust underlying infrastructure as the largest source of electricity production in the US	Operational cost variability based on gas prices, tightening supply chains for equipment and EPC contracts, requires new gas transportation infrastructure, susceptible to mitigation costs associate with potential future carbon regulations
Li-Ion Battery Storage	Provides operational flexibility, aligns hourly intermittent resources with hourly customer demand, distributed nature can reduce interconnection costs, eligible for significant IRA tax credits	Net energy consumer rather than energy producer, immature at utility scale, less long-term operational and performance data, uncertain lifecycle costs inclusive of decommissioning costs and risks, exposure to global supply chain issues
Solar	Carbon free fuel free resource, mature technology, reduces system gas and coal fuel costs, eligible for significant IRA tax credits	Intermittency in hourly, daily and weekly output, land intensive, requires significant supporting transmission infrastructure, exposure to global supply chain issues, long term operational and decommissioning risks
On-Shore Wind	Carbon free fuel free resource, mature technology, reduces system gas and coal needs, diversifies increasing solar centric energy profile on the system, favors multi-purpose land use, eligible for significant IRA tax credits	Intermittency in hourly, daily, weekly output, very large lease areas required, new resource within the Companies' service area creates uncertainty and challenges with siting and development
Off-Shore Wind	Carbon free fuel free resource, mature technology, reduces system gas and coal needs, higher capacity factor than solar and on-shore wind, strong coincidence with system winter peak needs, eligible for significant IRA tax credits	New resource to the Carolinas with unique challenges such as significant transmission requirements and hurricane risks. Complex long-lead time resource with the highest single project cost of all resources in the Plan that would require concurrence of both NC and SC state utility commissions.
New Nuclear	Only Carbon Free resource capable of consistent baseload operations, SMRs design provides construction efficiencies and smaller investment requirements relative to large scale projects, eligible for significant IRA tax credits	Long-lead time project requiring significant state and federal regulatory approvals. Immature technology supply chain. Limited number of projects currently in development.
Bad Creek II	Mature storage technology application developed at existing site, adds large scale storage capabilities in a single project to effectively integrate significant levels of new renewable and nuclear resources, 80 year useful life, longer duration than current applications of chemical BESSs, eligible for significant IRA tax credits	Long-lead time project requiring significant state and federal regulatory approvals. Extensive scope and scale of the project involves an extended construction timeline with attendant project and inflation risk.

Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's
CPIRP CAA Final Rule Sensitivity Analysis
Docket No. E-100, Sub 190

I. Executive Summary

On May 9, 2024, the U.S. Environmental Protection Agency (EPA) finalized rules under Section 111 of the Clean Air Act ("CAA", and, collectively, "CAA Section 111 Final Rule" or "Final Rule"). These rules address fossil fuel-fired electric generating unit greenhouse gas emissions ("GHG"). For the purposes of this appendix, the CAA Section 111 Final Rule establishes emission guidelines for existing coal plants and GHG emission limits for new natural gas generating facilities.

Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and, together with DEC, the "Companies") conducted sensitivity analysis ("CAA Final Rule Sensitivity Analysis" or "Sensitivity Analysis") modeling that is consistent the Supplemental Planning Analysis ("SPA") filed on January 31, 2024, with the additional application of the CAA Section 111 Final Rule. The Companies' approach to meeting new emission standards for new natural gas resources is to limit the annual capacity factor, to an emission rate achievable by resources in the Carolinas on a time frame specified by the Final Rule. The results of this analysis further support the Companies' Execution Plan and Near-term Action Plan ("NTAP") updated in the SPA from the initial 2023-2024 Carbon Plan and Integrated Resource Plans (the "initial Plan") (the SPA together with the initial Plan, is the "Resource Plan" or the "Plan"). The CAA Final Rule Sensitivity Analysis continues to emphasize an all-of-the-above approach to resource additions, including the addition of new natural gas resources. The Sensitivity Analysis indicates that the coal retirements presented by the Companies in the SPA continue to plan for an orderly transition while mitigating long-term risk to customers of operating coal, while full gas conversion of these units are not economic relative to the planned retirement dates.

This reduction in efficient, low-CO_2-emission energy from new natural gas resources, necessarily results in extending the time frame to meet the 70% carbon dioxide emissions reductions target ("Interim Target") under HB 951 to at least 2036, with the Companies presenting trade-offs for pursuing 2037 and 2038. The extended time frame for achieving the emission reduction targets provides the Commission with additional flexibility in reducing risk to customers by deferring decisions on incremental natural gas and offshore wind resources.

II. Purpose

While it is standard practice in long-term resource planning to "snap the chalk line" and move forward with the best information available at the time of the development of a plan and "check and adjust" planning assumptions in subsequent planning cycles, understanding whether potential impacts of the Final Rule could be material to the Companies' plans for executing the energy transition is important. Therefore, the Companies conducted preliminary assessments of the impact of the Final Rule to verify if the Companies' recommended NTAP in the SPA continues to support the Companies' proposed resources for selection by the North Carolina Utilities Commission (the "Commission"). The CAA Final Rule Sensitivity Analysis seeks to provide initial clarity with regards to the next reasonable steps the Commission should take in this CPIRP proceeding, acknowledging that refinement of the plan will be captured in future planning cycles as more information becomes available with respect to the Final Rule surviving legal challenges, compliance technology availability and costs, and state regulatory processes for the implementation of state plans required by the Final Rule.

CAA Final Rule Sensitivity Analysis modeling supporting certain near-term actions the Companies presented in their SPA and aligning with the modeling presented by the Public Staff of the North Carolina Utilities Commission ("Public Staff") would provide reasonable evidence to proceed with the near-term actions as previously proposed.

III. <u>CAA Section 111 Final Rule Overview</u>

The CAA Section 111 Final Rule covers two types of fossil fuel-fired power plants:

1. New, modified, and reconstructed sources – Covered under CAA Section 111(b)

2. Existing sources – Covered under CAA Section 111(d)

The Final Rule regulating new, modified and reconstructed sources would apply to the selectable new CCs and CTs in the Companies' CPIRP modeling. The Final Rule regulating existing resources would apply to existing coal units.

A. Standards for New Stationary Combustion Turbines

Under the Final Rule, new CC and CT operations are regulated based on subcategories according to utilization (and size[1]), and each subcategory is subject to its own set of standards. The three subcategories and applicable standards based on the utilization of the unit are as follows:

1. Base Load – Units that operate with an annual capacity factor greater than 40% must achieve a Phase 1 emission rate of 800 lbs. of CO_2 per MWh upon startup, the best system of emission reduction ("BSER") being highly efficient combined-cycle generation. To continue to operate at a capacity factor greater than 40% starting January 1, 2032, units must operate at a Phase 2 emissions rate of 100 lbs. of CO_2 per MWh, with the BSER for this emission rate being carbon capture and sequestration ("CCS") at a 90% capture rate.

2. Intermediate Load – Units that operate with an annual capacity factor less than or equal to 40% and greater than 20% must achieve an annual emission rate of 1,170 lbs. of CO_2/MWh upon startup, the BSER being highly efficient simple-cycle combustion turbine generation. There is no phase 2 requirement for Intermediate Load units.

3. Low Load – Units that operate with an annual capacity factor less than or equal to 20% must operate on fuels with a CO_2 content of 160 lbs. of CO_2/MMBtu upon startup, the BSER being lower-emitting fuels. Natural gas and fuel oil meet this requirement. There is no phase 2 requirement for Low Load units.

[1] The Companies are only discussing standards applicable to the size of generic resources in the Companies' Plan.

Units are able to switch between subcategories, meaning units capable of meeting the Phase 1 Base Load standard can operate above 40% through 2031 and then if they are not able to meet the Phase 2 Base Load standard, they can recategorize as Intermediate Load units and limit their capacity factor starting in 2032 and continue to operate against a less stringent standard. Compliance is calculated on both a 12-operating month and 3-year rolling average basis.

B. Guidelines for Existing Steam Generating Units

Under the Final Rule, the Companies' existing coal-fired generating units are subject to emission guidelines through the implementation of state plans. The emission guidelines are applicable to existing coal-fired steam generating units and existing natural gas-fired and oil-fired steam generating units. The guidelines related to coal-fired units are regulated by subcategories with respect to the unit retirement date:

1. Near-term retirement – Units that demonstrate they plan to permanently cease operations by January 1, 2032 are not subject to incremental standards.

2. Medium-term retirement – Units operating on or after January 1, 2032 must achieve a presumptive 16% emission rate reduction starting January 1, 2030, with the BSER being natural gas co-firing the coal unit at 40%. Units in this subcategory must demonstrate that they plan to permanently cease operation before January 1, 2039.

3. Long-term retirement – Units operating on or after January 1, 2039 must operate with CCS at a 90% capture rate on January 1, 2032, with CCS being the BSER. Units in this subcategory do not have a required retirement date.

In addition, the Final Rule imposes guidelines related to natural gas and oil-fired steam generating units. These units must perform routine methods of operation and maintenance with no emission rate increase starting January 1, 2030. Existing coal units can be recategorized as gas steam units if converted to operate on 100% natural gas by January 1, 2030.

The implementation of the guidelines for existing steam generating units are subject to the development of a state plan, which must be approved by the EPA. The Final Rule allows for certain compliance flexibility tools for states to meet the standards more efficiently as part of a state plan.

IV. <u>Scope</u>

The CAA Final Rule Sensitivity analysis assesses the impact to economic inclusion of resources to meet the objectives of the Companies' energy system including compliance with the Final Rule. This analysis will also assess the impacts on achieving the Interim Target under HB 951 and the opportunity to defer decisions on resources given their associated risks and opportunities to make a more informed decision in future planning cycles. Finally, this analysis assesses the impacts of converting existing coal units to operate 100% on natural gas, impacting both the required retirement timeline and the natural gas fuel supply availability for incremental new resources on the system. Below is a summary of the portfolios assessed in this analysis.

Table CAA Rule SA-1: Portfolio Matrix for CAA Final Rule Sensitivity Analysis

Portfolio	CO_2 Constraint	CAA RULE Constraints	Load	Resource Availability	Coal Retirements / Incremental Conversions	Supply-Side Resource Costs
Pathway 3						
P3 Fall Base	70% reduction by 2035 Carbon-neutral by 2050	New Gas 40% CF: 2032+; CS6 Conversion: 2030	Updated 2023 Fall Load Forecast	Fall Base	P3 Fall Base	Fall Base
Pathway 3 Portfolio Sensitivity Analysis – CAA Rule						
P3 CAA Rule – 2035 Base[1]	70% reduction by 2035 Carbon-neutral by 2050	New Gas 40% CF: 2032+; CS6 Conversion: 2030	Updated 2023 Fall Load Forecast	Limit to 4 CT (No Incremental Fuel Security)[2]	P3 Fall Base	Fall Base
P3 CAA Rule – 2036 Base	70% reduction by 2036 Carbon-neutral by 2050					
P3 CAA Rule – 2037 Base	70% reduction by 2037 Carbon-neutral by 2050					
Supplemental Portfolio Analysis – CAA Rule Sensitivities						
P3 CAA Rule – 2036 Roxboro 2&3 Accelerated Retirement	70% reduction by 2036 Carbon-neutral by 2050	New Gas 40% CF: 2032+; CS6 Conversion: 2030	Updated 2023 Fall Load Forecast	Limit to 4 CT (No Incremental Fuel Security)[2]	Roxboro 2&3 Retired: 2032; Marshall 3&4 Retired: 2034	Fall Base
P3 CAA Rule – 2037 High CC/CT Cost	70% reduction by 2037 Carbon-neutral by 2050				P3 Fall Base	1.25x CC/CT Capital Cost
P3 CAA Rule – 2037 Aggressive SMR / No OSW				Aggressive SMR; No OSW before 2040		Fall Base
P3 CAA Rule – 2038 No OSW	70% reduction by 2038 Carbon-neutral by 2050			No OSW before 2040		
Supplemental Portfolio Analysis – CAA Rule Gas Conversions						
P3 CAA Rule – 2036 Belews Creek Conversion	70% reduction by 2036 Carbon-neutral by 2050	New Gas 40% CF: 2032+; CS6 Conversion: 2030	Updated 2023 Fall Load Forecast	Limit to 4 CCs and 3 CTs (no Incremental Fuel Security)[2]	Belews Creek Converted: 2030; Retired: 2046	Fall Base
P3 CAA Rule – 2036 Cliffside 5 Conversion				Limit to 2 CTs (no Incremental Fuel Security)[2]	Cliffside 5 Converted: 2030; Retired: 2046	
P3 CAA Rule – 2036 Marshall 1&2 Conversion				Limit to 2 CTs (no Incremental Fuel Security)[2]	Marshall 1&2 Converted: 2030; Retired: 2046	
P3 CAA Rule – 2036 Marshall 3&4 Conversion				Limit to 5 CCs and 3 CTs (no Incremental Fuel Security)[2]	Marshall 3&4 Converted: 2030; Retired: 2046	
P3 CAA Rule – 2036 Mayo Conversation				Limit to 5 CCs and 4 CTs (no Incremental Fuel Security)[2]	Mayo Converted: 2030; Retired: 2046	
P3 CAA Rule – 2036 Roxboro 1&4 Conversation				Limit to 5 CCs and 4 CTs (no Incremental Fuel Security)[2]	Roxboro 1&4 Converted: 2030; Retired: 2044[3]	
P3 CAA Rule – 2036 Roxboro 2&3 Conversation				Limit to 5 CCs and 3 CTs (no Incremental Fuel Security)[2]	Roxboro 2&3 Converted: 2030; Retired: 2046	

Note 1: As discussed below, P3 CAA Rule – 2035 cannot meet the Interim Target by 2035 when complying with the Final Rule

Note 2: Total number of CTs selectable is not limited, but CTs above specified volumes require incremental fuel security costs based on the gas conversion assumptions of each sensitivity.

Note 3: The P3 CAA Rule – 2036 Roxboro 1&4 Conversation sensitivity presented modeling issues solving with a retirement in 2046, consistent with the other natural gas conversion sensitivities, so a 2044 date was used.

The CAA Final Rule Sensitivity Analysis also includes analysis of CO_2 emission of portfolios relative to the Interim Target, present value of revenue requirements ("PVRR"), and discussion of risk considerations to evaluate the trade-offs of cost and risk to inform the Companies' NTAP recommendations.

V. CAA Final Rule Sensitivity Analysis Input and Modeling Updates

A. Application of Capacity Factor Limitation for New Natural Gas Resources

New CC and CT natural gas-fired resources are eligible for selection beginning in 2029. The advanced class CCs and CTs assumption for generic new gas resources are highly efficient machines as described in Appendix K (Natural Gas, Low-Carbon Fuels and Hydrogen) to the Plan.

Upon startup, new CCs are expected be able to meet the Phase 1 emission rate standard of 800 lbs. of CO_2 per MWh for Base Load units running at greater than 40% annual capacity factor. By 2032, DEC/DEP do not expect to be able to deploy CCS at 90% capture rate, or otherwise meet the 100 lbs. of CO_2 per MWh Phase 2 emission rate standard to continue to operate at an annual capacity factor above 40%. Therefore, starting January 1, 2032, the CAA Final Rule Sensitivity Analysis assumes all new CCs change from the Base Load subcategory to the Intermediate Load category and must operate at or below 40% capacity factor to comply with the Final Rule. Operating below 40% annual capacity factor, the Intermediate Load subcategory requires units to operate meeting the emission rate standard of 1,170 lbs. of CO_2 per MWh, a standard the highly efficient CCs should be able to achieve, even at less efficient operating parameters.

Similarly, the new CTs are expected to be able to meet the emission rate standard of 1,170 lbs. of CO_2 per MWh upon startup, and therefore are assumed to have a maximum operating capacity factor of 40% over the long-term.

B. Conversion of Cliffside to Gas Steam Unit

Cliffside 6 currently has dual fuel optionality (DFO) meaning the unit can run on coal or natural gas. Cliffside 6 is the only unit the Companies operate that has DFO up to 100% on natural gas today, whereas other coal units on the system are DFO-capable up to 50% on natural gas at full load. In the CPIRP modeling, the Companies assume conversion of Cliffside 6 by the start of 2036, mitigating long-term risk of continued operation of coal resources. Given the Final Rule, as the Companies were already planning to cease coal operations on the unit in 2036, the Companies have accelerated this assumption to 2030 for the CAA Final Rule Sensitivity Analysis modeling, which re-categorizes Cliffside 6 as a natural gas-fired steam generating unit, rather than a coal-fired steam generating unit under the Final Rule. Under this categorization, Cliffside 6 is required to meet routine methods of operations and maintenance while operating through its remaining planned life with no restricted retirement date.

C. Coal Retirements and Implementation of State Plan Assumption

The Companies' current coal retirement schedule presented in the SPA largely minimizes the impact of the Final Rule on the retirement of DEC's and DEP's coal units. Today, including Cliffside 6 as mentioned previously, the Companies have eight (8) DFO coal units, all in DEC. With the capability of co-firing on natural gas, these units could meet the emission rate reduction based on co-firing each independently on their own and therefore could operate beyond 2032. The remaining seven (7) coal units on the system are coal only. Per the Final Rule, these units must be retired by January 1, 2032. The Companies P3 Fall Base coal retirement schedule already assumes the retirement of five (5) of these coal units by 2032, with just two units, Roxboro Units 2 and 3, currently reflecting retirement dates beyond the 2032 deadline.

Table CAA Rule SA-2: Coal Unit Statistics and Retirement Assumptions

Unit	Utility	Location	Unit Capacity [Winter MW]	In-Service Year	Natural Gas Co-Firing Capability	P3 Fall Base Retirement Date
Allen 1	DEC	NC	167	1957	0%	2025
Allen 5	DEC	NC	259	1961	0%	2025
Belews Creek 1	DEC	NC	1110	1974	50%	2036
Belews Creek 2	DEC	NC	1110	1974	50%	2036
Cliffside 5	DEC	NC	546	1972	40%	2031
Cliffside 6	DEC	NC	849	2012	100%	2049
Marshall 1	DEC	NC	380	1965	40%	2029
Marshall 2	DEC	NC	380	1966	40%	2029
Marshall 3	DEC	NC	658	1969	50%	2032
Marshall 4	DEC	NC	660	1970	50%	2032
Mayo 1	DEP	NC	746	1983	0%	2031
Roxboro 1	DEP	NC	380	1966	0%	2029
Roxboro 2	DEP	NC	673	1968	0%	2034
Roxboro 3	DEP	NC	711	1973	0%	2034
Roxboro 4	DEP	NC	698	1980	0%	2029

The Companies continue to believe that an orderly transition out of coal appropriately balances long-term risk of operating coal as described in Appendix F (Coal Retirement Analysis) to the CPIRP. The Final Rule does not ease these risks and has the potential to increase volatility in the coal markets.

The Final Rule requires that the existing source standards be implemented through a state plan. Importantly, the Final Rule allows for state plans to leverage compliance flexibilities for managing and achieving emission reductions relative the retirements and capabilities of coal units across the state: Remaining Useful Life and Other Factors (“RULOF”) and emission averaging and trading. Of note, all existing coal units in DEC and DEP are located in North Carolina and would be subject to a single state plan.

RULOF allows states in their implementation of the emission guidelines to take into consideration among other factors, the remaining useful life of the existing source to which such standard applies. This means that in a state plan, an affected facility may be subject to a less stringent standard of performance or have a longer compliance schedule, taking into consideration that facility’s remaining useful life and other factors. To illustrate this with an example, in the case of Roxboro 2 and 3, because these units are already planned for retirement by 2034, and considering the magnitude and progress of the retirement of other coal unit retirements in the state, North Carolina may elect to use RULOF to allow the units to reasonably retire two years after the guidelines.

Additionally, an emission averaging and trading program that provides compliance flexibility for existing units could provide real and significant benefits for the pace of orderly transitioning the fleet. The EPA is allowing states to incorporate averaging and emission trading into their state plans, provided these states ensure that use of these compliance flexibilities will result in an aggregate level of emission reduction that is equivalent to each source individually achieving its standard of performance. The Companies are confident this is achievable given there are already natural gas co-fired units operating in the state capable of offsetting the coal-only generation from the Roxboro units 2 and 3.

Duke Energy supports these types of compliance flexibilities because they have historically reduced the cost of compliance while delivering the required environmental benefits. The Companies will need to continue to work with the state to determine the appropriate compliance flexibilities to maintain reliability and minimize cost impact to customers given the transition timeline.

While the Companies note that the EPA has explicitly called out these compliance flexibilities, which would reasonably apply to the Companies' coal units in North Carolina and would provide significant benefits in the transition of the state's 9 GW of coal capacity, there is a possibility that these may not be included in the state plan or accepted by the EPA. In the event that RULOF or emission averaging and trading programs cannot be done through the state plan, to provide these compliance flexibilities expressly identified in the regulation, the Companies have modeled a scenario where Roxboro units 2 and 3 are retired by 2032 as they are not capable of meeting the emission rate reduction by 2030 on their own. In this scenario, the Companies have in turn delayed the retirement of Marshall units 3 and 4 to continue to provide the systems with the orderly transition required to mitigate cost and reliability risks of transitioning on a compressed and accelerated timeline.

D. Pace of Energy Transition under Final Rule

The Final Rule does not impact the Companies' reasonable but aggressive resource availabilities presented in the SPA. P3 Fall Base portfolio required nearly all available carbon-free resources be cumulatively available by 2035 to achieve the Interim Target in that year. While the projected new advanced-class CCs the Companies assume in the CPIRP will emit CO_2, they are the most efficient resource utilizing fossil fuels, and compared to other fossil fuel-fired resources, such as existing coal and gas CCs and CTs, provide significant emission reductions per megawatt-hour of electricity generated. While the Companies have begun evaluating the potential for CCS in the Carolinas, because the Companies do not believe they can meet a 2032 deadline for this technology, the output of these resources is limited to a 40% capacity factor or less beginning in 2032. This results in an increase in CO_2 emissions, as energy must be generated from less efficient fossil resources. Without significant increases in availability of incremental resources to fill this low CO_2 energy gap, the system is not able to achieve the same emission reductions on the same timeline.

With respect to achieving the Interim Target, if additional resources cannot be added to the system to achieve the emission reductions in a rapidly growing load environment, the Interim Target would necessarily be required to be delayed to allow for more carbon-free resources, such as incremental nuclear facilities and wind facilities, along with additional solar to be available with successive years of deploying carbon-free resources.

Accordingly, the Companies have also modeled extended timelines for achieving the Interim Target to evaluate potential trade-offs against the costs and risks associated with achieving the emission reductions on accelerated timelines and pursuing multiple long-lead time mega projects in parallel.

E. Incremental Conversions of Coal Units to Gas Steam Units Modeling

For this analysis, the Companies did not model incremental co-firing or extending resources' lives based on current co-firing capabilities, except as explained above in section C. (Coal Retirements and Implementation of State Plan Assumption). While the Final Rule does allow the Companies to operate natural gas co-fired resources beyond 2036, the Companies continue to believe the risks of operating coal, across the entire coal supply chain, persist and have the potential to increase. Therefore, it is prudent for the Companies to continue to execute an orderly transition out of coal, planning to cease coal operations by the end of 2035.

However, the Companies are evaluating in the CAA Final Rule Sensitivity Analysis the scenario to prioritize finite gas supply to the Carolinas for fully converting additional coal and DFO units to 100% natural gas-fired steam units. This evaluation includes the cost to convert the exiting coal and DFO units to 100% natural gas-fired units, assuming costs for changing out and modifying plant equipment, such as changing out burners and installing natural gas piping.

This analysis also includes the cost to transport natural gas from the interstate system to the plants on a firm basis, as this conversion would remove coal as a backup fuel requiring firm interstate fuel supply of natural gas to ensure operability of the capacity. Additionally, the Companies have also factored in the impact of designating the finite supply of gas availability to the Companies in the Carolinas to these resources, therefore limiting the availability of new gas resources.

Investing in these units and the infrastructure would allow operation of these units to continue beyond 2039, as they would then be designated as natural gas-fired steam units, rather than coal-fired steam units. However, continuing to extend the reliable operations of these units may require other incremental and significant infrastructure costs, that would need to be further evaluated, and would further challenge the cost effectiveness of these options. Therefore, for incremental conversions of gas units, the Companies have assumed the operation of these units through the mid-2040s, providing a bridged gap between the early- to mid-2030s when these units were planned to retire, to the mid-2040s when incremental resources and technology may be available.

F. High CC/CT Resource Cost Assumption

Given the scenario of utilizing gas resources on a limited basis under Final Rule as explained above and the scenario of potential increases in costs across all technologies, but specifically with respect to new CC and CT gas resources in light of the Final Rule's emissions standards for new natural gas resources, the Companies evaluated the selection of resources given the Final Rule and increased projected costs. This sensitivity utilized the same assumption presented in the SPA, a 25% increase in CC and CT initial capital costs.

G. No Offshore Wind Resource Availability

The Companies evaluated a scenario where the Interim Target is challenged by delayed execution of offshore wind resources. The Companies evaluated the impacts related to limiting offshore wind resource availability to the 2040s, allowing increased focus on the other resources, including other long-lead time resources such as pumped storage expansion and advanced nuclear deployment. This assumption is tied to later compliance dates or aggressive deployment of new nuclear.

H. Aggressive SMR Availability

The Companies' resource availability presented in the SPA already represents an aggressive pursuit of deploying new nuclear resources to the system. However, in the CAA Final Rule Sensitivity analysis, the Companies have assumed a modestly accelerated deployment schedule, which would be the result of significantly aggressive actions to achieve, to assess the impacts of this advanced development on the resource portfolio, especially with respect to achieving the Interim Target date and in the event that offshore wind is not connected to the system in the timelines outlined in the SPA.

This aggressive SMR availability assumption assumes the first unit is available at the beginning of 2034, for a whole year of operation, an acceleration from the SPA modeling, which assumed the first and second SMR units available by the start of 2035. Additionally, this assumption accelerates the deployment of the first unit at a second site by one year, while maintaining a constraint of construction on only two nuclear sites at the same time and continuing to allow for a stagger between the first and second site. This assumption increases the total number of nuclear SMRs available by one incremental unit in both 2037 and 2050 and allows the Companies to evaluate the impact of these resources on accelerated time frames, especially with respect to achieving the Interim Target.

VI. <u>Capacity Expansion Portfolio Development Analysis</u>

As discussed in Appendix C (Quantitative Analysis) to the CPIRP, the capacity expansion model seeks to develop a portfolio of resources that will minimize overall system costs inclusive of capital costs for new resources as well as ongoing operation, maintenance and fuel costs of the system. In the CAA Final Rule Sensitivity Analysis, the Companies developed and assessed portfolios based on the assumptions used in the SPA modeling, with the additional constraints for the Final Rule as described in Section V (CAA Final Rule Sensitivity Analysis Input and Modeling Updates).

The following sections discuss the development of each portfolio under each Pathway and summarizes the preliminary resource additions and retirements from the capacity expansion modeling.

A. P3 Fall Base in CAA Rule Scenario

The Companies' first step in the evaluation of the CAA Section 111 Final Rule was to apply the rules and restrictions directly to P3 Fall Base previously presented in the SPA in order to quantify the impact of the Final Rule on the Companies' updated Pathway 3 Core Portfolio. In this evaluation, a capacity expansion scenario was not performed. Instead, the P3 Fall Base portfolio from the SPA was evaluated in a production cost model run to determine how the CAA Section

111 Final Rule would affect the overall system cost, CO_2 emissions, and dispatch patterns. Specifically, this scenario (and all subsequent scenarios below) implemented the Companies' base modeling assumptions for gas capacity factor restrictions, Cliffside 6 gas conversion, and coal retirements dates (as detailed above in sections V.5, V.6, and V.7 respectively).

The results of this production cost run illustrated a failure to achieve the Interim Target by 2035 under the Final Rule. As introduced in section V.D above, the P3 Fall Base portfolio already reaches near maximum feasible interconnection limits for carbon-free resources, and in a production cost model these resources are contributing their maximum amount of carbon-free energy to the system. As such, when the Final Rule capacity factor restrictions are applied to new gas CCs and CTs, the model is not able to shift this "lost" gas generation to renewable resources. Instead, in order to continue to serve the load demand, the model is forced to shift this generation to less efficient fossil resources—specifically, existing CCs, existing CTs, and existing coal units. As such, the impact of the Final Rule on the P3 Fall Base portfolio is an increase in CO_2 emissions of over 4 million tons in the year 2035, a delay in the interim compliance date to 2036 or later, and an increase in the total system cost of more than $600M.

B. P3 CAA Rule – 2035 Base

In light of the results of the previous evaluation, the next step the Companies took was to evaluate whether a re-optimized portfolio could still meet the 2035 Interim Target date. In this case, the CAA Section 111 Final Rule base modeling assumptions were applied to a capacity expansion scenario. However, the EnCompass model was unable to optimize the portfolio in any manner that would meet a 2035 Interim Target. The model was not able to deploy the total amount of resources needed to solve to the targeted carbon trajectory. This reinforces the findings discussed in sections V.D and VI.A above that the Final Rule restrictions on new gas do not promote further reductions in carbon emissions in the Carolinas because the Companies' P3 Fall Base portfolio already incorporates the maximum feasible levels of renewable additions. Instead, the Final Rule restrictions simply shift generation from new gas to existing gas and/or existing coal resources, a dispatch behavior that only delays the Companies' timeline for achieving Interim Target.

C. P3 CAA Rule – 2036 Base

To meet the Interim Target, the Companies evaluated a re-optimized portfolio with the CAA Section 111 Final Rule base modeling assumptions with the Interim Target year delayed to 2036. The model was able to solve for a 2036 Interim Target year given the additional year of resource availability, as compared to the P3 CAA Rule – 2035 Base portfolio. However, the critical takeaway for this scenario is that the model selects nearly all resources available. Where the previous SPA P3 Portfolio maxed out renewable additions and complemented them with a selection of gas and storage assets, P3 CAA Rule – 2036 Base portfolio builds the maximum amount of nearly every technology type.

As shown in Table CAA Rule SA-3 below, this sensitivity requires the selection of all available solar, onshore wind, offshore wind, SMRs, CCs, and CTs through 2036, with a very large amount of storage to complement this portfolio and time-shift carbon-free energy to a considerable extent. This introduces significant increases in new resource costs to the system, as compared to the P3 Fall Base portfolio (see Table SA-6 below). Furthermore, this portfolio leaves no flexibility in resource additions over time across all resource types, with no ability to adapt to any project delays. Overall, while this scenario was identified as a feasible optimized pathway by the model, the Companies consider the execution requirements presented by this portfolio to be of considerable risk.

D. P3 CAA Rule – 2037 Base

Based on the considerable execution challenges presented with an Interim Target in 2036, the Companies modeled a portfolio with a one-year extension for achieving an Interim Target to 2037. This optimized portfolio, P3 CAA Rule – 2037 Base, reduces the system transition execution risk and introduces a much more feasible portfolio that is not dependent on an extraordinarily challenging execution of maximum level resource additions across nearly all technologies. As detailed in Table CAA Rule SA-3 below, this portfolio only builds five CCs, compared to the six required in P3 CAA Rule – 2036 Base, reduces the total capacity of offshore wind, and reduces the plan's dependence on storage. In addition, the PVRR is decreased by $3.9 billion through 2050 compared to P3 CAA Rule – 2036 Base portfolio.

E. P3 CAA Rule – 2036 Roxboro 2&3 Accelerated Retirement

As outlined in section V.C, the Final Rule requires that any coal unit that cannot meet an emission rate reduction based on co-firing must be retired by January 1, 2032. The only units that do not comply with this reduction requirement and timeline today are Roxboro units 2 and 3. As discussed in section V.C, there are a number of regulatory mechanisms available to the state to meet the Final Rule guidelines. This modeling sensitivity assesses the impact if Roxboro units 2 and 3 are required to retire in 2032. In conjunction with this retirement acceleration at Roxboro units 2 and 3, this sensitivity also delays the retirement of Marshall units 3 and 4 from 2032 to 2034. This extension is allowable under the Final Rule due to Marshall's current co-firing capability and would allow the Companies to continue to promote an orderly transition through staggered retirements of coal capacity from the system.

As seen in Table SA-6 below, this portfolio was found to be a more expensive plan. There are no major changes to the resources selected in this portfolio relative to P3 CAA Rule – 2036 Base portfolio, but a few minor shifts in DEC occur due to the Marshall retirement delay.

F. P3 CAA Rule – 2037 High CC/CT Cost

To evaluate the sensitivity of the resource portfolio and exposure of the optimized plans with respect to future gas resource initial capital costs, the Companies conducted a sensitivity where new gas project costs were modeled with an increased cost by 25%. The results of this analysis illustrate that gas is still robustly selected as an integral part of the portfolio and remains an essential resource in the overall energy transition and emission reductions trajectory. Of note, the only changes to the gas buildout are a delay of one DEC CC from 2032 to 2033 and a delay of one DEC CT from 2029 to 2030. As expected, with minimal changes to the portfolio, the only significant result of this sensitivity is an increase in overall portfolio cost, as shown in Table SA-6 below.

G. P3 CAA Rule – 2037 Aggressive SMR / No OSW

As outlined in sections V.G, the Companies recognize the correlation between offshore wind additions and SMR additions, as they each contribute to the total carbon-free energy needed to meet the Interim Target. To evaluate the trade-off scenario of increasing the execution pace of nuclear projects and experiencing offshore wind execution delays, the Companies modeled this sensitivity, P3 CAA Rule – 2037 Aggressive SMR / No OSW, which assumes aggressive nuclear SMR deployment and restricts the availability of offshore wind resource until the 2040s.

As compared to P3 CAA Rule – 2037 Base, this sensitivity selects the accelerated availability of SMRs, while selecting a 6th CC and increases the amount of solar paired with storage at an overall increase PVRR of $1.6 billion through 2050.

H. P3 CAA Rule – 2038 No OSW

Assuming a scenario without aggressive deployment of new nuclear SMR, the Companies assess a portfolio with no offshore wind available and the base SMR availability assumptions. This portfolio was able to meet the Interim Target in 2038. As compared to the 2037 case with aggressive SMR plans, this scenario avoids the need for a 6th CC, reduces the reliance on storage, and reduces the overall portfolio PVRR (Table SA-6 below) relative to P3 CAA Rule – 2037 Base.

I. CAA Rule Sensitivity Analysis Portfolio Summaries

Table CAA Rule SA-3 presented below summarizes the resource changes in each of the portfolios described above.

Table CAA Rule SA-3: Resource Additions and Retirements (MW) through 2038

	Coal	Solar	Battery	CC	CT	Onshore Wind	Pumped Storage	Nuclear	Offshore Wind
P3 Fall Base	-8,445	17,475	6,320	6,800	2,125	2,250	1,834	2,100	2,400
P3 CAA Rule - 2036 Base	-8,445	17,550	7,140	8,160	1,700	2,250	1,834	2,100	2,400
P3 CAA Rule - 2037 Base	-8,445	17,850	6,960	6,800	1,700	2,250	1,834	2,100	1,600
P3 CAA Rule - 2036 Roxboro 2&3 Accelerated Retirement	-8,445	17,625	7,160	8,160	1,700	2,250	1,834	2,100	2,400
P3 CAA Rule - 2037 High CC/CT Cost	-8,445	17,700	7,220	6,800	1,700	2,250	1,834	2,100	1,600
P3 CAA Rule - 2037 Aggressive SMR / No OSW	-8,445	18,225	8,020	8,160	1,700	2,250	1,834	2,400	0
P3 CAA Rule - 2038 No OSW	-8,445	18,225	7,660	6,800	1,700	2,250	1,834	2,100	0

J. P3 CAA Rule – Natural Gas Conversions

In addition to the re-optimization of resources selected in portfolios discussed above, the Companies also assessed the impact of converting the existing coal and DFO units to 100% natural gas by 2030 and operating these units into the 2040s, as a potential alternative to new gas resources. The Companies assessed the impacts of individually converting each of the coal groupings from the SPA's supplemental coal retirement analysis. In general, incrementally converting any of these coal units to 100% natural gas was uneconomic when considering the cost to covert the resource, the firm fuel transportation costs, and impacts to available selection of incremental natural gas resources, by using the finite gas supply into the Carolinas on less efficient and less flexible assets. Because the system continues to add other low-carbon and carbon free resource to the system over time, the units converted to natural gas operate sparingly with their capacity factors dropping significantly and remaining low in the late 2030s and early 2040s until the units are retired.

VII. Performance Analysis

A. CO_2 Emissions Reductions

Tables SA-4 and SA-5 show the CO_2 emissions in the CAA Final Rule Sensitivity Analysis. Table SA-4 shows the Combined Carolinas CO_2 emissions, and Table SA-5 shows only the North Carolina CO_2 emissions with the year each portfolio achieves the Interim Target. As described above, P3 Fall Base emissions are lower than all of the CAA Final Rule Sensitivity Analysis portfolios based on the ability of the system to utilize the new gas resources more efficiently for the benefit of the system. As expected, when the CAA Section 111 Final Rule is enforced on the resource portfolios, with less gas generation providing lower CO_2 energy and limited availability to increase deployment of renewables, existing, less efficient resources must run more, thus resulting in an increase in the CO_2 emissions and moving compliance out in time.

Table CAA Rule SA-4: CO_2 Emissions of EP 111 Cases – Combined Carolinas

(bold red font indicates compliance year)

Combined Carolinas (MM tons)		**2030**		**2035**	**2036**	**2037**	**2038**
P3 Fall Base (SPA)		48.8		**28.1**	25.7	23.6	21.8
P3 Fall Base (CAA Rule)		48.5		31.4	27.4	**25.0**	22.7
P3 CAA Rule - 2036 Base		48.3		30.3	**26.2**	24.0	22.0
P3 CAA Rule - 2037 Base		48.3		33.8	29.1	**25.8**	23.5
P3 CAA Rule - 2037 Aggressive SMR/No OSW		48.2		34.3	29.1	**26.1**	23.6
P3 CAA Rule - 2038 No OSW		48.1		36.0	31.6	28.6	**25.4**

Table CAA Rule SA-5: CO_2 Emissions of EP 111 Cases – NC Only

(bold red font indicates compliance year)

NC Only (MM tons)		**2030**		**2035**	**2036**	**2037**	**2038**
P3 Fall Base (SPA)		45.9		**22.8**	20.5	18.7	17.1
P3 Fall Base (CAA Rule)		45.6		27.2	22.9	**20.7**	18.7

P3 CAA Rule - 2036 Base		45.3		26.2	**22.0**	20.0	18.2
P3 CAA Rule - 2037 Base		45.3		29.5	24.5	**21.5**	19.4
P3 CAA Rule - 2037 Aggressive SMR/No OSW		45.2		30.0	24.7	**21.9**	19.6
P3 CAA Rule - 2038 No OSW		45.2		31.5	26.8	24.1	**21.2**

B. Present Value of Revenue Requirement

Below in Table SA-6 are summaries and comparisons of the present value of revenue requirements (PVRR) for the CAA Final Rule Sensitivity Analysis sensitivities that were modeled through 2038 and 2050. The PVRR is shown for DEC, DEP, and the combined Carolinas system.

Table CAA Rule SA-6: PVRRs of EPA 111 Cases

Portfolio	2038			2050		
	DEC	DEP	CAR	DEC	DEP	CAR
Pathway 3						
P3 Fall Base (SPA)	48.0	29.9	77.9	89.0	60.0	149.0
P3 Fall Base (CAA Rule)	48.6	29.8	78.4	89.8	59.8	149.6
Pathway 3 Portfolio Sensitivity Analysis – CAA Rule						
P3 CAA Rule – 2036 Base	49.7	29.9	79.6	90.6	61.5	152.1
P3 CAA Rule – 2037 Base	48.8	28.2	77.1	90.3	57.9	148.2
Supplemental Portfolio Analysis – CAA Rule Sensitivities						
P3 CAA Rule – 2036 Roxboro 2&3 Accelerated Retirement	49.0	30.9	80.0	90.6	62.1	152.7
P3 CAA Rule – 2037 High CC/CT Cost	48.9	28.2	77.2	91.1	58.9	150.0
P3 CAA Rule – 2037 Aggressive SMR / No OSW	49.5	28.2	77.7	90.7	59.2	149.8
P3 CAA Rule – 2038 No OSW	48.6	28.0	76.5	89.9	57.3	147.2
Supplemental Portfolio Analysis – CAA Rule Gas Conversions						
P3 CAA Rule – 2036 Belews Creek Conversion	52.4	30.8	83.2	93.5	65.9	159.4
P3 CAA Rule – 2036 Cliffside 5 Conversion	50.2	30.4	80.7	92.4	61.3	153.7
P3 CAA Rule – 2036 Marshall 1&2 Conversion	49.3	30.7	80.0	91.0	61.7	152.7
P3 CAA Rule – 2036 Marshall 3&4 Conversion	50.9	30.0	80.9	93.2	61.1	154.3
P3 CAA Rule – 2036 Mayo Conversion	49.3	31.2	80.6	91.8	62.1	153.9
P3 CAA Rule – 2036 Roxboro 1&4 Conversion	50.3	30.8	81.81	93.1	61.5	154.6
P3 CAA Rule – 2036 Roxboro 2&3 Conversion	49.8	32.5	82.3	91.6	64.1	155.7

The PVRRs calculated above are consistent with how the system costs were developed for the CPIRP. The P3 Fall Base portfolio under CAA Section 111 Final Rule planning assumptions has a PVRR of $149.6 billion through 2050 while not meeting the Interim Target until 2037. P3 CAA Rule – 2036 Base portfolio achieves the Interim Target by 2036 but is a higher cost portfolio through both 2038 and 2050 while presenting more cost and execution risk than the P3 CAA Rule

– 2037 Base portfolio. Also, with two additional years to achieve the Interim Target, P3 CAA Rule – 2037 Base portfolio is less expensive than the P3 Fall Base, despite the increased operational costs that result from the Final Rule constraints.

The portfolios assessing 100% natural gas conversion of existing coal units and the P3 CAA Rule – 2036 Roxboro 2&3 Accelerated Retirement portfolio reflect varying retirement assumptions of the Companies' existing coal units. None of the portfolios result in PVRRs that are less than the P3 CAA Rule – 2036 Base portfolio, indicating that the conversion and alternative retirement portfolios cases are not economic. As expected, the P3 CAA Rule – 2037 High CC /CT Cost portfolio results in a portfolio with a higher PVRR as compared to P3 CAA Rule – 2037 Base, however the model continues to economically select the gas resources. While the P3 CAA Rule – 2037 Aggressive SMR / No OSW portfolio does result in a higher PVRR, the portfolio presents flexibility in resource selection for achieving the Interim Target. Finally, P3 CAA Rule – 2038 No OSW has a lower PVRR than both the P3 CAA Rule – 2038 Base and P3 CAA Rule – 2037 Base portfolios, given the additional year for lower cost resources to contribute to achieving the Interim Target, and does so without offshore wind.

VIII. NTAP Comparison Summary and Conclusion

As discussed above, the sensitivity analysis performed by the Companies show that the Final Rule imposed on DEC's and DEP's resource portfolios results in increased portfolio cost, increased CO_2 emissions, and results in a delay in achieving the Interim Target by at least one year. Because the model required nearly all available resources to achieve the Interim Target in 2035 under the increased load and SPA base planning assumption, restricting low-CO_2 emitting, efficient gas generation without the ability to add incremental low-carbon or carbon-free resources leads to increased system CO_2 emissions. Natural gas resources continue to be selected, and in some cases greater volumes are required to achieve the Interim Target as early as possible. The Companies' coal retirement schedule presented in the SPA continues to reflect the most cost-effective schedule that maintains an orderly transition out of coal and is reasonable for planning purposes given the compliance flexibilities available through state plans. Table CAA Rule SA-7 below compares the Companies' NTAP as proposed in the SPA with the modeling results in this analysis and illustrates the resources selected would continue to support the SPA's NTAP while providing some flexibility and optionality on incremental gas and offshore wind resources.

Table CAA Rule SA-7: NTAP Resources Compared to NTAP of CAA Section 111 Sensitivity Analysis

Resource Type	Resources Needed Through Year	NTAP Resources [MW]	NTAP Resources [MW] CAA Final Rule Sensitivities	NTAP Changes
Solar	2031	6,460	6,460	Confirmed Need
Battery Storage	2031	2,700	2,700	Confirmed Need
Onshore Wind	2033	1,200	1,200	Confirmed Need

CT	2032	2,125	2,125	**Confirmed Need**
CC	2033	6,800	6,800	**Confirmed Need**
Pumped Storage	2034	1,834	1,834	**Confirmed Need**
Advanced Nuclear	2035	600	600	**Confirmed Need**
Offshore Wind	2035	2,400	0 - 2,400	**Potential Flexibility to Delay***

*Potential flexibility based on whether interim compliance is targeted for 2036 or 2037

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 190

In the Matter of Biennial Consolidated Carbon Plan and Integrated Resource Plans of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, Pursuant to N.C.G.S. § 62-110.9 and § 62-110.1(c)	)))))))	PUBLIC STAFF RESPONSE TO DUKE'S SECOND DATA REQUEST TO THE PUBLIC STAFF- NORTH CAROLINA UTILITIES COMMISSION

2-21. Referring to the statement, on page 31 of Witness Michna's testimony, that "The Public Staff also takes issue with Duke's decision to model a CC in South Carolina, given that no CPCN application has yet been filed for the unit and it is premature to assume that the CC will be sited in South Carolina" please identify any other indicia of siting or execution planning beyond filing a CPCN application that the Public Staff believes would inform a modeling assumption to site a generating facility in North Carolina or South Carolina.

Response:

As stated in the December 30, 2022 Order Adopting Initial Carbon Plan and Providing for Future Planning in the 2022 Carbon Plan proceeding: "it is appropriate for modeling purposes for Duke to assume that all new carbon-dioxide emitting resources will be located in North Carolina." Respective to this statement, the Public Staff assumes that all future fossil generation assets will be sited in North Carolina. The Public Staff would consider a site-by-site approach to considering modeling assumptions outside North Carolina and would evaluate planning aspects such as an approved CPCN, a CPCN application, an interconnection queue application, or planning applications or negotiations for fuel supply for the site to be some such factors that may inform modeling inclusion.

Response by: Blaise C. Michna