Fox Rothschild LLP
ATTORNEYS AT LAW

434 Fayetteville Street
Suite 2800
Raleigh, NC 27601
Tel (919) 755-8700 Fax (919) 755-8800
www.foxrothschild.com

BENJAMIN L. SNOWDEN
Direct No: 919.719.1257
Email: bsnowden@foxrothschild.com

September 2, 2022

Ms. A. Shonta Dunston
Chief Clerk
North Carolina Utilities Commission
430 N. Salisbury Street, Room 5063
Raleigh, NC 27603

Via Electronic Submittal

RE: Direct Testimony of Tyler Norris on Behalf of Clean Power Suppliers Association
In the Matter of
Duke Energy Carolinas, LLC and Duke Energy Progress, LLC
2022 Integrated Resource Plans and Carbon Plan
NCUC Docket E-100 Sub 179

Dear Ms. Dunston:

Enclosed for filing please find the Direct Testimony of Tyler Norris on behalf of Clean Power Suppliers Association.

Please do not hesitate to contact me if you have any questions. Thank you for your assistance in this matter.

Yours truly,

/s/ Benjamin L. Snowden

Benjamin L. Snowden
Counsel for
Clean Power Suppliers Association

pbb

cc: All parties and counsel of record
NC Public Staff

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 179

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of: Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plan and Carbon Plan	)))))	**DIRECT TESTIMONY OF TYLER NORRIS ON BEHALF OF CLEAN POWER SUPPLIERS ASSOCIATION**

Table of Contents

I. INTRODUCTION AND OVERVIEW 8

II. MODELING – METHODOLOGY, ASSUMPTIONS AND OTHER MODELING ISSUES 11

III. NEAR-TERM PROCUREMENT ACTIVITY—SOLAR, SOLAR-PLUS-STORAGE, STANDALONE STORAGE, ONSHORE WIND, NATURAL GAS GENERATION 29

V. COST ISSUES – DETERMINATION OF LEAST COST 46

VI. EXECUTION RISKS 49

VII. CONCLUSION AND RECOMMENDATIONS 57

Q. MR. NORRIS, PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION WITH CYPRESS CREEK RENEWABLES.

A. My name is Tyler H. Norris, and my business address is 5310 South Alston Avenue, Building 300, Durham, North Carolina 27713. I serve as Vice President of Development at Cypress Creek Renewables. I am also co-chair of the Clean Power Suppliers Association ("CPSA").

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

A. I graduated with distinction from Stanford University in Palo Alto, CA with a Bachelor of Arts in Public Policy, where I received the Harry S. Truman Scholarship, the federal government's highest recognition for public service leadership and academic achievement at the undergraduate level. I am a graduate of the North Carolina School of Science and Mathematics.

In 2012, I received a White House appointment to the Office of Secretary Steven Chu at the U.S. Department of Energy (DOE) in Washington, DC. As a Special Advisor for Commercialization, I spent nearly four years at DOE advising the Secretary and Assistant Secretaries on the development of programs to accelerate the commercialization of emerging energy technologies, and in crafting an enterprise-wide strategy for enhancing the commercial impact of DOE's multi-billion-dollar annual spending on energy research, development, and demonstration (RD&D). In this capacity, I was the lead author of DOE's first Technology Transfer Execution Plan, a report to Congress defining DOE's commercialization strategy for approximately $10 billion in RD&D programs.

Following DOE, I was a Director at S&P Global Platts, an international energy market intelligence firm. There I led the firm's U.S. market analysis for renewables and storage and co-authored its global energy technology outlook, providing forecasts and advisory services to electric utilities and integrated majors, among other clients. In this capacity, I regularly developed analysis on utility resource plans and state-level electricity sector policies.

In 2020, I was appointed to North Carolina's Carbon Policy Working Group, formed in response to Gov. Cooper's Executive Order 80, which advised the Duke University Nicholas Institute report, "Power Sector Carbon Reduction: An Evaluation of Policies for North Carolina." On behalf of Cypress Creek, I have commissioned and advised multiple electricity sector studies, including The Brattle Group's 2021 study, "A Pathway to Decarbonization: Generation Cost & Emissions Impact of Proposed NC Energy Legislation."

I have published on energy-related topics in *Harvard Law & Policy Review*, *Issues in Science & Technology*, and *Foreign Affairs*, among other publications, and I have co-authored numerous reports on electricity resource planning and energy technology policy. My work has been cited by the *New York Times*, *Wall Street Journal*, *Washington Post*, and other publications.

Q. WHAT ARE YOUR RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. My primary responsibility is to lead the US Southeast development division of Cypress Creek Renewables, a leading U.S. renewable developer and owner-operator. In this capacity, I oversee a project portfolio of approximately 2,500 MW and supervise a full-service development and power marketing team that manages large-scale solar, solar-plus-storage, and standalone storage projects from greenfield through Notice to Proceed (NTP). Given the heavily regulated nature of the Southeast electricity sector, a significant portion of my activities focus on resource planning, procurement program design, avoided cost tariffs, and interconnection standards.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION OR OTHER REGULATORY BODIES?

A. Yes. I testified in NCUC Docket No. E-100, Sub 158 regarding the topic of energy storage additions to existing utility-scale solar facilities, specifically regarding what avoided cost rate schedule and contract terms and conditions should apply when a Qualifying Facility ("QF") adds storage equipment. I also appeared before this Commission during its Technical Conference on the Competitive Procurement for Renewable Energy on May 23, 2019 for Commission Docket Nos. E-7, Sub 1156 & E-2, Sub 1159. I have also provided direct testimony before the South Carolina Public Service Commission in Docket 2019-2-E, Dominion Energy South Carolina's 2019 Annual Review of Base Rates for Fuel Costs, where my testimony addressed the topic of avoided cost methodology and variable integration costs.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to elaborate on topics raised in CPSA's July 15, 2022 Comments on the Carbon Plan ("CPSA Comments") and to respond to certain points raised in the direct testimony of Duke Witnesses Glen Snider, Bobby McMurry, Michael Quinto, and Matt Kalemba ("Modeling Panel"), filed in this docket on August 19. My testimony discusses Duke's modeled constraint on solar interconnection ("the Solar Interconnection Constraint") and its implications; the solar and solar-plus-storage procurement targets in

Duke's proposed near-term execution plan; the flaws in Duke's approach to assessing execution risk in the Carbon Plan; and issues related to transmission planning and Duke's proposed Red Zone Transmission Expansion Plan ("RZEP") projects.

In direct testimony filed today, CPSA witness Ryan Watts is providing direct testimony discussing the Solar Interconnection Constraint , and Duke's stated justifications for the constraint, from a technical standpoint. CPSA witness Michael Hagerty, of the Brattle Group, is providing testimony relating to modeling and other issues relating to Duke's proposed Carbon Plan portfolios and supplemental modeling, as well as CPSA's proposed alternative portfolios.

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. I note as an initial matter that, as directed by the North Carolina Utilities Commission ("the Commission"), my testimony is organized consistent with the outline provided in the Commission's July 29, 2022, Order Scheduling Expert Witness Hearing, Requiring Filing Of Testimony, and Establishing Discovery Guidelines. Because some issues raised in my testimony implicate more than one topic in the Commission's outline (for example, Duke's solar interconnection constraint is a modeling issue, but also implicates execution risk and Duke's near-term procurement plans), discussion of those issues may span multiple sections of testimony (although I have provided cross-references where appropriate).

The key points of my testimony are as follows:

1. <u>Modeling</u>

   a. Duke has made overly conservative assumptions about the volume of annual solar interconnections it can achieve (the Solar Interconnection Constraint) and has failed to justify these assumptions.

b. Duke's Solar Interconnection Constraint will make it difficult if not impossible to achieve 70% decarbonization by 2030, or even 2032; and, if compliance *is* possible, will increase cost to ratepayers.

c. CPSA has proposed a reasonable alternative assumption about the rate of annual solar interconnections that is not dramatically different from Duke's "High Solar" assumption.

d. Duke should be able to achieve significantly greater improvement over its historic solar interconnection rates because (i) it will be interconnecting a much smaller number of larger projects than in the past, (ii) the proactive upgrades that Duke is proposing to its transmission system – the Red Zone Expansion Plan or "RZEP" – (as well as other proactive upgrades that may be initiated during the planning period) will facilitate the interconnection of a very large volume of solar generation resources, (iii) the major overhaul of Duke's interconnection study process should also improve the pace of interconnection, and (iv) Duke has several years to focus on improving its performance in this high priority area.

e. Duke's overly conservative assumption about the rate of solar interconnections benefits Duke shareholders by skewing the Carbon Plan to favor more expensive utility-owned generation resources on which Duke can earn a higher rate of return.

f. There are significant benefits and minimal risks to including at least one additional resource portfolio in the Carbon Plan based on CPSA's more reasonable and appropriate solar cap.

2. <u>Near Term Procurement Activity</u>

a. Duke's proposed near-term (2022-24) solar procurements, which correlate with its assumed solar additions in 2026-28, are not sufficient to support Duke's own P1 portfolio (Duke's only portfolio that achieves 70% decarbonization by 2030), let alone a reasonable CPSA alternative portfolio that includes more least-cost solar additions.

b. Both Duke and Public Staff acknowledge that there is not an exact correlation between the year a solar resource is procured and the year in which it is place in service.

c. The primary disadvantage of greater near-term solar procurement cited by Duke is the possibility that later procurement could allow for the procurement of lower cost solar resources. However, this is an uncertain proposition and is more than offset by a host of benefits resulting from greater near-term solar procurement. These include the following:

i. Creating a significantly greater likelihood of achieving the H.B. 951 70% decarbonization mandate by 2030 or 2032.

ii. Accommodating uncertainty about Duke's rate of interconnection, facilitating the identification of contingent network upgrades, and avoiding significant additional increases in the cost of transmission system improvements.

iii. Providing an opportunity to test Duke's ability to improve solar interconnection rates rather than giving up on the possibility of greater progress at the outset.

iv. Avoiding reliance on higher cost alternative resources with greater execution risk.

v. Protecting against the likely attrition in the number solar projects that complete the development process.

d. CPSA supports near-term activities to advance the development of additional generation resources so that if its assumed rate of solar additions proves unachievable, alternative pathways to compliance remain viable.

e. CPSA conditionally supports Duke's proposed addition of the CPRE solar shortfall to the 2022 solar procurement, as further described below

3. Transportation Planning/RZEP

a. CPSA strongly supports proactive transmission planning and upgrades to the transmission system. It is widely recognized that a long-term, comprehensive proactive approach to the development of transmission resource is far more cost-effective than reactive generator-driven transmission improvement and provides a wide range of material benefits to the system and to customers.

b. Duke has amply demonstrated that the RZEP upgrades are needed to achieve compliance with H.B. 951 and that ratepayers would be well served by the completion of those upgrades as soon as possible.

4. Cost

a. Duke's Carbon Plan does not comply with the "least cost' mandate of H.B. 951 because portfolios with significantly more solar resources would achieve compliance at far less cost to ratepayers.

b. CPSA's proposal to increase near-term solar procurement targets will not materially increase costs to ratepayers, whether those procurements are fully subscribed or not.

c. Duke is not currently incentivized to support the least-cost plan for ratepayers because portfolios with a lower volume of solar resources allow Duke to own more, higher cost generation and thereby earn greater returns for its shareholders.

d. The Commission should consider in a separate proceeding adopting a performance incentive mechanism to encourage Duke to improve its annual rate of solar additions.

5. Execution Risks

a. Duke's approach to execution risk is severely flawed and is biased against low-cost, proven solar that will only be partially owned by Duke and in favor of costlier, higher risk technologies that will be 100% owned by Duke.

b. The flaws with Duke's approach included the following:

i. Duke lumps resources with fundamentally different risk profiles into a single category, labeled "new-to-the-Carolinas resource types," in a way that inaccurately equates the execution risk of onshore wind, offshore wind, battery energy storage, and SMRs.

ii. Duke's risk assessment of solar interconnection rates is unreasonable, and there is ample reason to believe that Duke can achieve significantly higher solar interconnection rates.

iii. Duke does not reveal a methodology by which it translates its inputs (annual solar additions and cumulative "new-to-the-Carolinas" additions) into its overall ranking.

iv. Duke has structured its portfolios in a way that selectively increases the risk of certain portfolios and distorts the overall risk assessment.

v. Duke does not consider any ways to mitigate or otherwise address the execution risk it estimates for the portfolios is has constructed.

I. INTRODUCTION AND OVERVIEW

Q. WHAT IS CPSA'S OVERALL VIEW OF DUKE'S CARBON PLAN AND THE PROCESS BY WHICH IT WAS DEVELOPED?

A. As stated in CPSA's comments, Duke has provided a useful starting point for the Commission's Carbon Plan deliberations. Duke's proposed Carbon Plan and its supporting direct testimony obviously reflect an enormous amount of effort and analysis by a large team of Duke employees and consultants, for which they and the Company should be commended. There are many elements of the Carbon Plan that CPSA agrees with or does not take issue with. In addition, Duke conducted an extensive stakeholder process in advance of its Carbon Plan filing in which it actively encouraged participation by, and sought input from, a wide range of parties. Again, Duke should be commended for this effort.

A key aspect of the Carbon Plan that CPSA supports is Duke's recommendation that this Commission not select a single generation resource portfolio at this point in time, but approve a Carbon Plan that includes multiple potential resource portfolios, and defer the selection of a preferred portfolio until the first Carbon Plan Update in 2024. CPSA agrees that this approach allows the Commission's ultimate selection of a preferred portfolio to be informed by additional information and experience that can be accumulated in the next two years. CPSA further agrees that as part of this approach the Commission should approve a three-year execution plan that is consistent with Duke's ability to implement any of the alternative portfolios that are included in the 2022 Carbon Plan.

But for all its merit, this approach points to a major failing of Duke's Carbon Plan and the process by which it has been developed. Despite having sought and received an enormous volume of stakeholder input, including the results of complex, costly modeling performed by recognized experts on behalf of CPSA and other intervenors, Duke has not included in its proposed Carbon Plan a single portfolio developed or requested by any intervenor other than the Public Staff. This failing on Duke's part reflects the fact that it has been very open to seeking input but not very committed to seeking consensus. On the contrary, Duke has disparaged the exhaustive work of respected energy-industry experts by labeling it as "outcome oriented," implying that it is the product of either bad science or bad faith.

CPSA believes it is critical that this Commission correct this serious flaw in Duke's Carbon Plan and include a number of additional resource portfolios beyond those recommended by Duke. In particular, CPSA has proposed, and performed modeling for, 2030 and 2032 compliance portfolios that assume a higher rate of annual solar interconnections than is assumed by Duke (CPSA3 and CPSA5), and we believe that these should be included in the Carbon Plan and supported by the near-term Execution Plan.

Solar is both the least-cost form of new generation and most established, proven and readily available new generation resource in the Carolinas. The result of Duke's excessive and unsubstantiated conservatism about the rate of solar additions is a set of resource portfolios that cost more and present greater risk than ones that assume a faster, but reasonable, rate of solar additions. Duke's resignation and lack of ambition on this issue stands in stark contrast to the arguably excessive optimism its Carbon Plan brings to every other issue relating to resource development, including the timing of offshore wind development; the timing, cost, and siting and permitting uncertainty associated with advanced nuclear technology; the availability of adequate natural gas supplies to support gas plant additions and operation; the potential for onshore wind development in the Carolina; and the potential to reliably and affordably import wind generation from out of state.

Of all the near-term measures Duke could take to reduce execution risk, aggressive procurement of additional solar has the best risk/reward relationship. If Duke can procure and interconnect solar in excess of its modeled cap, it will substantially reduce the overall cost of compliance to ratepayers. If Duke proves unsuccessful, it will not result in additional costs or other negative consequences.

As discussed in my testimony, Duke's proposed near-term procurement targets are insufficient to achieve compliance with the 70% carbon reduction mandate of H.B. 951 by 2030, even under the most solar-reliant portfolio in the Carbon Plan (P1). Duke's modest near-term procurements also increase the exposure to all forms of execution risk and increase the likelihood that Duke will not be able to achieve compliance even by 2032. More ambitious near-term procurement of solar and solar-plus-storage, by contrast, mitigates execution risks across Duke's portfolios and may substantially reduce costs for ratepayers.

CPSA believes that the Carbon Plan ultimately approved by the Commission, and the associated near-term execution plan, should preserve the possibility of achieving compliance with the H.B. 951 interim decarbonization mandate by 2030 rather than giving up on that goal from the outset in favor of a bet on more expensive technology that has never been commercially deployed in the United States.

II. MODELING – METHODOLOGY, ASSUMPTIONS AND OTHER MODELING ISSUES

Q. DOES CPSA TAKE ISSUE WITH DUKE'S MODELING METHODOLOGY AND ASSUMPTIONS?

A. In the interest of narrowing the issues to be resolved by this Commission, CPSA has not objected to the great majority of Duke's modeling assumptions, even where it doesn't fully agree with them. However, CPSA strongly disagrees with the limits that Duke has imposed on the volume of annual solar additions that can be selected by Duke's model.

Fundamentally, CPSA believes that Duke's approach of setting a *limit* to how much solar it will model (based on a highly subjective prediction about how much solar it can interconnect), rather than a *goal* for how much solar it will try to interconnect in order to save ratepayers money while achieving timely compliance with H.B. 951, is imprudent and inconsistent with the requirements of H.B. 951.

As discussed below and in the testimony of other CPSA witnesses, Duke has failed to justify these limits and they would have a significant adverse effect with respect to both the timing and cost of compliance with H.B. 951, by reducing the amount of solar that would otherwise be economically selected by Duke's own modeling for the Carbon Plan, and requiring Duke to force in other, more expensive, forms of generation to fill those gaps.

a. Duke's Solar Interconnection Constraint

Q. WHAT ASSUMPTION DOES DUKE MAKE ABOUT ANNUAL SOLAR INTERCONNECTIONS?

A. Most of Duke's Carbon Plan portfolios assume annual solar interconnections of 750 MW in 2026, 1,050 MW in 2027, and 1,350 MW thereafter. Duke's P1 portfolio increases annual solar interconnections to 1,800 MW after 2027, but Duke doesn't accept this value for purposes of its near-term execution plan.[1]

[1] Duke states in Appendix I that "Most carbon plan portfolios select 750 MW of new solar to be added in 2026," which could be misinterpreted to imply that Duke allowed its model to economically select optimal solar additions in 2026 and later years. However, as detailed in the Brattle Report attached as Exhibit A to CPSA's Comments, Duke did not allow its model to select more solar in any given year than its proposed annual solar interconnection constraint, with the exception of the Supplemental Portfolio 5 High Solar Interconnection Sensitivity, in which its model selected up to the 1,500 MW limit in both 2026 and 2027.

Q. WHAT DOES CPSA THINK IS A MORE APPROPRIATE ASSUMPTION ABOUT ANNUAL SOLAR INTERCONNECTIONS?

A. Again in the interest of finding common ground and minimizing disputes, CPSA has proposed a rate of annual solar interconnection that is identical to Duke's P1 of "High Solar" assumption, except for the years 2026 and 2027, where CPSA believes it is reasonable to assume that 1,500 MW of solar can be interconnected rather than Duke's lower volumes. Thus, the difference between the CPSA assumption and Duke's High Solar assumption is only 1,200 MW over the planning period. The difference is much more substantial with respect to the even more conservative solar constraints in P2, P3, P4, and Duke's supplemental portfolios, which largely inform Duke's approach to the Carbon Plan.

Q. IS THERE UNCERTAINTY ABOUT HOW QUICKLY DUKE WILL BE ABLE TO INTERCONNECT ADDITIONAL SOLAR RESOURCES?

A. Yes. Even with perfect engineering judgement, the timeline required to interconnect any set of utility-scale generators always entails some degree of uncertainty due to the inherent uncertainties of real-world execution.

Some uncertainty should be expected here given that the annual volume of solar capacity in question beyond 2027 is higher than Duke has interconnected to date, although as Public Staff notes in its comments, Duke has previously interconnected a substantially larger amount of solar in terms of project volume than what is anticipated for purposes of Carbon Plan compliance. Of course, at the time those previous solar interconnection rates were achieved, it was similarly the case that such volumes were higher than Duke's then-current experience.

As any new technology matures and is more widely deployed due to consumer uptake or regulatory standards, vendors must supply those technologies at a higher rate than before. What makes this case of technology diffusion particularly unique and challenging as compared to most markets is that Duke is the only vendor authorized by state law to supply the interconnection of new utility-scale solar facilities onto the Companies' transmission system. Of course, Duke has a monopoly on interconnection service just as it has a monopoly on retail service, and the rate of solar interconnection depends very much on the utility's practices. So CPSA recommends oversight mechanisms and incentives to ensure accountability with respect to solar interconnection, as outlined below.

Q. HOW DID DUKE ARRIVE AT ITS SOLAR INTERCONNECTION CONSTRAINT?

A. According to Duke, the Solar Interconnection Constraint represents its "most reasonable forecast of the Companies' ability to interconnect solar."[2] As discussed in the direct testimony of CPSA Witness Ryan Watts, Duke does not specify a discernable methodology by which it determined what represents "the most reasonable forecast" – it appears to have weighed a number of conflicting factors and more or less arbitrarily picked a set of numbers.

In Carbon Plan Appendix I, Duke notes that "The Companies' assumed annual interconnection levels were informed by the following key factors and data points," followed by a bulleted list with high-level discussion related to project sizes, transmission upgrades, interconnection arrangements, and historical interconnection data. As Public

[2] Modeling Panel at 162.

Staff notes in its comments, "this upper limit on [solar] interconnections is an engineering judgement based on several factors, which the Companies outline in Proposed Carbon Plan Appendix I."[3] In response to discovery, Duke confirmed that "The Companies do not have specific underlying calculations for the annual selection constraints. These constraints are based on engineering judgement and transmission planning experience."[4] Duke's evidentiary basis for the proposed solar interconnection constraint has evolved little since it proposed a similar constraint in the 2020 IRP proceeding, despite having nearly two years to conduct additional diligence in response to challenges from the NC Attorney General's Office and other intervenors.[5]

In summary, in the face of uncertainty regarding solar interconnection, Duke's approach since the 2020 IRP has been to pick numbers for annual limitations that it perceives as attractive based on their judgment, but without rigorous analysis, methodological documentation, or consultation with independent experts.

Q. DOES THE COMMISSION HAVE TO RESOLVE THIS UNCERTAINTY?

A. No. As discussed below, Duke's future interconnection rates are inherently uncertain, but if the Commission authorizes more ambitious near-term solar procurements, the question will answer itself. Either Duke will achieve higher rates of interconnection than the modeled cap (in which case ratepayers get a cheaper portfolio with more solar), or it won't.

---

[3] Public Staff Comments at 146.

[4] Duke Response to NCSEA-SACE DR 3-30, Ex. 1 to Direct Testimony of Ryan Watts on Behalf of CPSA.

[5] *See* Duke Energy Carolinas, LLC's and Duke Energy Progress, LLC's Reply Comments, Docket No. E-100 Sub 165 (May 28, 201), at 166-169 (Duke describing timing and physical constraints limiting interconnection capacity on Duke's grid), at https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=7b91ba46-495e-4d55-b91c-a5293b9cb4f3.

So long as Duke is planning for this contingency by continuing to develop other resources, no harm will result.

Q. HOW DO DUKE'S FORECASTS OF SOLAR INTERCONNECTION RATES COMPARE TO DUKE'S INTERCONNECTION RATES IN THE PAST?

A. Duke reports that its rate of solar interconnection grew from less than 30 MW in 2012 to over 700 MW in 2015, a more than 20-fold increase over three years. Duke's rate of interconnection fell in 2016 to approximately 575 MW, resurged in 2017 to nearly 750 MW, and returned to around 550 MW in 2018. In other words, by proposing a constraint of 750 MW for 2026, Duke is claiming it is not possible to incrementally improve its solar interconnection rate over the course of a decade.

Duke's annual rate of solar additions fell to an average of approximately 300 MW from 2019-2021; however, this decline can be substantially attributed to North Carolina's 2017 Competitive Energy Solutions Act (H589), which made most new solar QFs unfinanceable.[6]

The Public Staff observes that Duke's solar interconnections prior to 2021 included a large quantity of smaller, distribution-scale solar projects, in contrast to today's significantly larger, transmission-scale facilities, which are generally 10 to 50 times the size of distribution-interconnected projects on Duke's system. For this reason, Public Staff concludes that "it is not appropriate to use historical interconnections as a gauge or limit on future interconnections… While larger projects can be more complex and trigger more upgrades, fewer total projects could possibly free up labor and material constraints."[7]

---

[6] CPSA Comments at 51.

[7] Public Staff comments at 146.

For illustrative purposes, if Duke's rate of annual *project* interconnection from 2015-2020 in North Carolina alone (72 projects annually) continued into the 2020s, but at an average project size equivalent to a standard transmission-scale solar facility (75 MW), Duke's annual rate of solar interconnection would be 5,400 MW. Fortunately, Duke need only achieve a fraction of this rate over the next decade.

In addition to the fact that Duke will be interconnecting a smaller number of larger projects, it's important to note that the major changes that have been made to the interconnection process through queue reform, and the construction of proactive transmission system upgrades such as the RZEP, should contribute to significant increases in the rate of solar interconnections.

Q. HOW DO DUKE'S FORECASTS OF SOLAR INTERCONNECTION RATES COMPARE TO WHAT OTHER STATES ARE ACHIEVING?

A. As Duke points out, the utility deserves credit for the solar interconnection rate it achieved in the 2010s, which at the time represented one of the highest rates in the country, most notably in terms of project volume, including an unprecedented quantity of utility-scale distribution-interconnected solar projects. With sufficient motivation and regulatory oversight, it is clear that Duke is capable of achieving industry-leading interconnection rates.

In light of its past leadership, Duke's projected under-performance compared to peer states and utilities is especially disappointing. By comparison, neighboring states are already achieving utility-scale solar interconnection rates that exceed Duke's proposed constraint for 2026, including Virginia at 900 MW and Georgia at 760 MW in 2021. The unreasonably pessimistic assumptions that inform Duke's proposed constraint is further compounded by the fact that Duke's combined Carolina's system encompasses large portions of two states instead of one.

Q. WHAT OTHER FLAWS HAVE YOU IDENTIFIED WITH DUKE'S APPROACH TO SOLAR INTERCONNECTION RATES?

A. There are several additional problems with Duke's approach. First, and as discussed at length in Mr. Watts' testimony, Duke fails to provide a robust analysis of its interconnection forecast, and the justifications Duke does provide are not technically persuasive. Rather than conducting a robust technical analysis, benchmarking to other states, or (better yet) engaging an independent third party to conduct a rigorous study of interconnection rates, Duke has come up with highly conservative and arbitrary numbers based on its "engineering judgment."

In short, Duke will not show its homework. Duke has repeatedly declined requests to pursue collaborative analysis in response to intervenor concerns in the 2020 IRP proceeding and to stakeholder outreach as part of the 2022 Carbon Plan stakeholder process. And even on a go-forward basis, Duke does not propose any concrete steps to further assess the constraint or identify opportunities for improvement. In essence, as discussed above, Duke's response to uncertainty on the achievable rate of solar interconnection is to err exceedingly on the side of conservatism while avoiding any substantive analysis that could lend itself to meaningful scrutiny.

Q. DUKE SUGGESTS ITS PROPOSED RATE OF SOLAR ADDITIONS IS SIMILAR TO OTHER JURISDICTIONS. HOW DO YOU RESPOND?

A. In his testimony, Duke Witness Kalema states, "In most instances, when viewed on an apples-to-apples basis, Duke Energy's interconnection assumptions are equal to, or more aggressive, than the peer utilities CCEBA cites in its comments."[8] First, it is notable that Mr. Kalemba focused on responding only to the examples of peer utilities cited by CCEBA, and did not respond to CPSA's discussion of solar installation rates that are *already occurring* in peer states, including utility-scale solar installations in 2021 of 900 MW in Virginia and 760 MW in Georgia. Mr. Kalemba's rebuttal to CCEBA's examples relies heavily on the significance of normalization in terms of number of customer accounts, which may in part explain why he declined to respond to CPSA's discussion of Nevada in particular, which interconnected 611 MW of utility-scale solar in 2021, despite having 26% of North Carolina's annual electricity sales.[9]

A detailed discussion of each utility resource plan and proposal in CCEBA's comments is beyond the scope of this testimony; however, it is important to note that the recent enactment of the Inflation Reduction Act (IRA) renders many of these irrelevant, as most utilities can be expected to update their resource plans and proposals in the months and years ahead to procure and interconnect even more renewable and storage capacity to take advantage of the IRA on behalf of their customers.

Q. DUKE SUGGESTS THAT SOLAR LOCATED OUTSIDE THE RED ZONE "MAY ACTUALLY LEAD TO HIGHER COSTS FOR CUSTOMERS IN REALITY EVEN THOUGH THE MODEL SUGGESTED THE UNCONSTRAINED SOLUTION WAS LOWER COST." HOW DO YOU RESPOND?

A. In his testimony, Mr. Kalemba states that "in order to connect the amount of solar intervenors such as CPSA or CCEBA suggest should be modeled, developers would need

[8] Modeling Panel at 169.
[9] CPSA Comments at 17.

to locate solar outside of transmission constrained areas that may be more costly than locations that could be connected once RZEP are completed. These costs are unknown and are not likely to be accurately captured in the model, so un-constraining solar interconnections may actually lead to higher costs for customers in reality even though the model suggested the unconstrained solution was lower cost."[10]

A simple solution to Mr. Kalemba's stated concern is to use conservative solar costs in the model. As noted elsewhere, this was the approach taken by Brattle, using NREL ATB's Conservative cost forecast, translating to a nominal solar LCOE forecast in excess of $60/MWh for 2030 COD projects. For comparison, average PPA award pricing in CPRE Tranche 2 was $37/MWh, or approximately $42/MWh in nominal terms in 2030 assuming an average annual inflation rate of two percent. All of these CPRE projects were located outside of transmission constrained areas.

It should be noted that Mr. Kalemba's concern here regarding potential discrepancies between modeled and real-world resource pricing is particularly relevant for SMRs, but to a much greater extent, given the lack of any available real-world SMR pricing in the U.S. and the long history of nuclear project cost overruns. However, with respect to SMRs, Duke used unsubstantiated, low, proprietary cost forecasts for its modeling instead of more credible cost forecasts from EIA, as discussed further by CPSA Witness Hagerty.

Q. IF DUKE LIMITS IT PROCUREMENT TARGETS TO THE SOLAR INTERCONNECTION CONSTRAINT AMOUNTS, HOW WILL WE KNOW IF DUKE COULD HAVE ACHIEVED MORE?

[10] Modeling Panel at 168.

A. We won't. This is one of the problems with the constraint. In fact (and as discussed below), because of the attrition that normally happens during any procurement, it is likely that Duke would ultimately never even try to interconnect the amount of solar capacity represented by the Solar Interconnection Constraint. The result is an approach that does the following, detailed further in Section VI below:

- Renders it extremely unlikely, if not impossible, to achieve compliance by 2030;
- Increases the risk of failing to achieve compliance by 2032;
- Elevates the risk of reliance on higher-risk, higher-cost resources;
- Exacerbates the risk of higher transmission upgrade costs; and
- Forgoes the opportunity to test the limits of Duke's achievable interconnection rates or identify opportunities for performance improvement.

Q. DUKE WITNESS KALEMBA TESTIFIES THAT "IF THE COMPANIES ARE UNDERESTIMATING THE AMOUNT OF SOLAR THAT CAN BE CONNECTED, THAT DOES NOT PRECLUDE THE COMPANIES FROM PROCURING SOLAR ABOVE THE INTERCONNECTION LEVELS SET FORTH IN THE MODEL."[11] COULD THIS HAPPEN?

A. Yes, but only if the Commission were to approve a near-term execution plan that authorized procurement targets in excess of the modeled constraints. Unfortunately, while Mr. Kalemba may approve of this approach, it's not consistent with Duke's proposed execution

[11] Modeling Panel at 164.

plan, which limits each annual procurement target to the assumed interconnection constraint for year for years after the procurement year (i.e. the 2022 target is limited to the constraint in 2026, 2023 is limited to the 2027 constraint, and 2024 is limited to the 2028 constraint).[12]

Q. DOES DUKE'S APPROACH IMPACT RATEPAYERS?

A. Very much so. The negative impacts of Duke's solar constraint on ratepayers is discussed in Section V below.

Q. DO DUKE'S CONSERVATIVE ASSUMPTIONS ABOUT THE ANNUAL RATE OF SOLAR ADDITIONS BENEFIT DUKE'S SHAREHOLDERS?

A. Yes. Because it artificially curbs the amount of solar that can be added to the system, Duke's approach is advantageous for its shareholders. There are several reasons for this. First, H.B. 951 requires that any new generation facilities selected to achieve the carbon reduction mandate shall be owned by Duke and recovered on a cost of service basis, with the sole exception of solar and solar-plus-storage, where Duke is required to own 55% of selected capacity additions. In other words, for every megawatt of solar or solar-plus-storage that is selected, Duke is foregoing opportunity to own and rate base additional capacity.

Second, since Duke's proposed solar interconnection constraint forces selection of resources with substantially higher capital costs, every megawatt of non-solar and non-solar-plus-storage resources selected provides greater earnings opportunity for Duke's

---

[12] It is the case that the volume adjustment mechanism approved for the 2022 Solar Procurement could result in an upward adjustment of procurement volumes up to 20%. However, in the context of the Carbon Plan this is a very modest adjustment. Moreover, it is likely not enough to account for (a) projects that will not come online in the target year due to project-specific time constraints; and attrition among projects selected in the procurement (discussed further below).

shareholders. This is illustrated in Table 1 below, which presents a rank-order of Duke's capital expenditure (CAPEX) opportunity per MW of each resource selected, accounting for the resource's forecasted CAPEX in 2032 and Duke's ownership share per MW. In this rank-order, nuclear SMRs provide a CAPEX opportunity for Duke that is 12 times larger than utility-scale solar, per MW selected, and nine times larger than solar-plus-storage. For offshore wind, the same value is six times larger than utility-scale solar and four times larger than solar-plus-storage. In his testimony, Mr. Hagerty details specifically how Duke's solar constraint forces selection of offshore wind and/or SMR capacity.

Table 1 – Comparison of Duke CAPEX Opportunity

Resource	**Duke Ownership Share**[13]	**CAPEX** (2020$/kW, 2032 COD)[14]	**Duke CAPEX Per MW Selected** (Ranked)
Nuclear SMR	100%	$7,390	$7,389,785
Offshore Wind	100%	$3,506	$3,506,062
Battery Standalone (4hr)	100%	$1,174	$1,173,726
Onshore Wind	100%	$990	$990,000
Utility-Scale PV+Battery (4 hr)[15]	55%	$1,549	$851,814
Battery Standalone (2hr)	100%	$682	$681,622
Utility-Scale PV	55%	$1,106	$608,235

Third, Duke's shareholders have existing ownership interests in offshore wind via the company's recent $155 million bid in the Carolina Long Bay offshore wind auction, for which Duke was named provisional winner for the OCS-A 0546 lease area. With respect to emerging SMR technologies or ventures, it is unclear to CPSA to what if any extent Duke has existing ownership interests, although the company states in Appendix L

[13] Duke ownership share is defined in H.951.
[14] All CAPEX figures sourced from NREL ATB 2022 for 2032. All figures represent NREL's Conservative cost scenario, with the exception of SMRs, for which ATB only presents a Moderate scenario. Offshore wind is Class 5.
[15] NREL ATB assumes a DC-coupled system at 100 MWac with a 4-hr li-ion battery system sized at 50 MWac.

that it "partnered" to build the Natrium reactor and provides "ongoing consulting and advisory in-kind services" to TerraPower.

Q. WHAT ARE THE CONSEQUENCES OF DUKE'S SOLAR INTERCONNECTION CONSTRAINT ON THE TIMELINE FOR ACHIEVING THE 70% REDUCTION IN CARBON EMISSIONS REQUIRED BY H.B. 951?

A. Duke's approach makes it extremely unlikely that North Carolina will achieve compliance with its interim carbon emissions mandate by 2030, as explained in Section VI below, and increases the risk of failing to achieve compliance by 2032. As such, it is likely to result in higher annual emissions from North Carolina's electric power sector in 2030 and 2032, as well as higher aggregate emissions through 2050.[16]

Q. HOW SHOULD DUKE ADDRESS UNCERTAINTY ABOUT SOLAR INTERCONNECTION IN THE CARBON PLAN?

A. There is always uncertainty about the timeline required to interconnect any set of utility-scale generation facilities. This is true for any large-scale facility or tranche of facilities, including for well-established technologies like utility-scale solar. It is even more true for first-of-a-kind facilities in the Carolinas like nuclear SMRs and offshore wind. This uncertainty is compounded here by the fact that the interconnection rate is substantially contingent on the utility's behavior.

Under these circumstances, the most reasonable and prudent approach is to set a goal that is calibrated to one or more economically optimized portfolios for compliance with the carbon reduction mandate, and then make a good faith effort to achieve the goal.

[16] CPSA Comments at 39-42.

Given that available portfolios with more solar entail lower cost and execution risk,[17] it is imprudent to set an overly conservative limit on solar interconnection rates. At the same time, given the inherent uncertainty of any interconnection forecast, it is also appropriate to implement a near-term execution plan that advances the development of other resources in the event that more ambitious levels of solar interconnection cannot be achieved.

Q. DOES THE COMMISSION NEED TO RESOLVE THE QUESTION OF HOW MUCH SOLAR DUKE CAN INTERCONNECT ON AN ANNUAL BASIS?

A. No. CPSA acknowledges uncertainty about how much solar can be interconnected annually, and as discussed above, it is not possible or prudent at this stage to attempt a prediction regarding a specific solar interconnection limit for every year of the Carbon Plan. Fortunately, the Commission does not need to resolve this dispute. The question is how the Commission should address that uncertainty in the Carbon Plan and in the near-term execution plan in particular.

Duke maintains that the best approach is to make conservative assumptions about how much solar it can interconnect, the effect of which is to massively increase earning opportunity for Duke's shareholders at the expense of ratepayers by driving selection of higher cost resources. CPSA believes that it would be in the best interest of ratepayers to be more ambitious with regard to the solar interconnection assumption, rather than reserving that ambition for higher cost resources that will benefit Duke's shareholders at the expense of customers.

Q. WHAT ARE THE RISKS IF CPSA'S SOLAR INTERCONNECTION ASSUMPTION IS ADOPTED AND PROVES TO BE UNACHIEVABLE?

---

[17] See Sections V and VI below.

A. As an initial matter, CPSA is not requesting that its proposed solar interconnection rates be adopted in every Carbon Plan portfolio. Duke does need to plan for the possibility that it will not be able to achieve higher interconnection rates, just as it should be planning for other contingencies, such as delays in the availability of SMRs or offshore wind, or limitations on the availability of natural gas.

Rather, CPSA is requesting (i) that at least one portfolio utilizing its assumption be included in the Carbon Plan, and (ii) that the volume of solar procurement in the Near-Term Execution Plan be sufficient to support such a portfolio (as it would support the other portfolios in the plan). Since CPSA supports the early development of other resources during the Execution Plan period, the inclusion of a CPSA portfolio and increased near-term solar procurement presents no risk to the development of other resources should CPSA's assumed rate of solar additions prove unachievable.

If Duke procures a larger volume of solar and cannot interconnect those projects at a pace beyond their proposed interconnection constraint, those projects will be interconnected as soon as Duke is able to complete the interconnection facilities and any contingent network upgrades. Therefore, the only potential risk associated with the failure of CPSA's assumption and greater near-term solar procurement is the possibility of solar project costs declining such that solar resources procured earlier will cost more than those procured later.

As discussed in Section V, the projected decline in solar costs over the next several years is not significant enough for it to be prudent to delay procurement in the hope of capturing those savings. In any event, this possibility is counter-balanced by the risk of higher future solar and transmission costs and even more significantly by the fact that reduced solar procurement based on overly conservative interconnection assumptions requires the procurement of much more expensive alternative resources to achieve the H.B. 951 mandate

In addition, there are other benefits of larger initial procurement, including earlier identification of contingent network upgrades that increases the likelihood that necessary upgrades are completed in a timely fashion, thus reducing execution risk and mitigating the risk of increasing transmission upgrade costs.

Q. WHAT ACTIONS SHOULD THE COMMISSION TAKE TO ENSURE DUKE IS TAKING ALL REASONABLE STEPS TO IMPROVE THE RATE OF ANNUAL INTERCONNECTION FOR SOLAR AND SOLAR PLUS STORAGE RESOURCES?

A. As this Commission is aware, interconnection is a highly complex area of utility operations that is not easily amenable to comprehensive regulatory oversight. CPSA Witness Watts recommends some measures to improve interconnection rates, but no doubt there are many potential avenues for improvement. When recently faced with a similarly complex issue related to utility operations that had direct implications for customer costs, the Solar Integration Services Charge ("SISC"), this Commission ordered Duke to use of an independent technical review committee to review the SISC study and inform future Commission considerations.[18] Further, the Commission ordered Duke to include the recommended revisions from the technical review in its future SISC filing before this Commission.[19]

---

[18] NCUC Order in Docket No. E-100, Sub 158 at p. 95.
[19] NCUC Order in Docket No. E-100, Sub 158, Finding of Fact 42.

CPSA supports a similar requirement for assessing and improving upon Duke's current and planned interconnection practices. Especially given the expected time lag between the 2022 Procurement and the interconnection date for those facilities, there is ample time to have Duke undergo a similar technical review process as that required for the SISC, the results of which could be available prior to the 2024 Carbon Plan update. Depending on the results of that independent report, it may also be appropriate to require a qualified independent monitor to regularly report back to this Commission on interconnection activities and progress related to Carbon Plan implementation.

Given the disproportionate ratepayer costs and Carbon Plan compliance delays that will result from a failure to fully embrace all reasonable interconnection efficiencies, CPSA believes this approach is imminently achievable and necessary.

b. Carbon Plan Portfolios

Q. DOES CPSA BELIEVE THAT ADDITIONAL RESOURCE PORTFOLIOS SHOULD BE INCLUDED IN THE CARBON PLAN?

A. Yes. In our comments on Duke's Carbon Plan filed on July 15, 2022, we proposed five alternative portfolios for inclusion in the Carbon Plan based on modeling performed by Brattle. Those portfolios (as updated on August 16 to incorporate some technical corrections) are as follows:[20]

Scenario	2030 New Solar	2032 New Solar	2030 New BESS	Onshore Wind	Offshore Wind	Gas CC	Gas CT
CPSA1	9,500	12,700	3,300	600 MW in 2030	---	2,000 MW in 2030	---
CPSA2	5,200	7,900	1,800	600 MW in 2030	800 MW (2030)	2,400 MW in 2030	900 MW in 2030

[20] CPSA Corrected Comments at 38.

					800 MW (2032)		
CPSA3	7,500	11,100	2,700	600 MW in 2030	400 MW in 2030	2,400 MW in 2030	---
CPSA4	5,200	7,900	2,000	600 MW in 2030	1,100 MW in 2032	2,400 MW in 2030	1,100 MW in 2030
CPSA5	7,100	10,700	2,600	600 MW in 2030	---	2,400 MW in 2030	500 MW in 2030

CPSA1, which places no cap on solar additions, was included for illustrative and comparative purposes and is not a portfolio we believe needs to be included in the Carbon Plan at this point. Similarly, for comparative purposes, we included CPSA2 to illustrate what 2030 compliance would look like if Duke's most conservative Solar Interconnection Constraint were accepted, but it's not critical that that portfolio be included either. CPSA3 and CPSA5 are portfolios based on CPSA's recommended assumption about the annual rate of solar additions discussed above. CPSA strongly recommends that these portfolios be included in the Carbon Plan for further consideration in the 2024 proceeding and to inform Duke's near-term execution plan.

Finally, CPSA4 is a slight variation on Duke's P2 – its only 2032 compliance portfolio. CPSA4 utilizes Duke's low solar cap but corrects for the fact that in P2 Duke fails to add solar after 2029 at levels consistent with that cap. CPSA therefore believes that P2 should be replaced with CPSA4, but doesn't object to CPSA4 being included as an additional alternative portfolio.

III. NEAR-TERM PROCUREMENT ACTIVITY—SOLAR, SOLAR-PLUS-STORAGE, STANDALONE STORAGE, ONSHORE WIND, NATURAL GAS GENERATION

Q. WHAT ARE DUKE'S NEAR-TERM SOLAR AND SOLAR-PLUS-STORAGE PROCUREMENT TARGETS?

A. In its near-term execution plan, Duke proposes a total of 3,100 MW of solar and solar-plus-storage to be procured between 2022-2024, including 750 MW in 2022 with the remainder split between 2023 and 2024. 600 MW of this solar, or about 19%, is assumed to include paired storage.[21] In addition, Duke has recently proposed to increase its 2022 solar procurement by 440 MW to address a shortfall in solar procurement under CPRE.

Q. HOW DID DUKE COME UP WITH THESE NUMBERS?

A. Duke's near-term solar procurement is determined by its proposed Solar Interconnection Constraint for 2026-2028, which limits total solar interconnections to 3,150 MW over those three years, including 750 MW in 2026, 1,050 MW in 2027, and 1,350 MW in 2028. As Duke states in its Execution Plan "the Companies propose to procure 750 MW of new solar resources through the 2022 SP Program, which reflects the volume of new solar-only resources that the Companies forecast can interconnect in 2026."[22] In other words, Duke's near-term procurement volumes are based on a precise correlation between the procurement amount and the volume of solar interconnections Duke assume it can achieve four years later.

Q. DOES DUKE'S APPROACH TO ESTABLISHING A 2022 SOLAR PROCUREMENT TARGET MAKE SENSE?

A. No, it does not. As discussed in Section II above and in the testimony of CPSA Witness Ryan Watts, Duke has failed to justify its annual interconnection limits.But even if Duke's Solar Interconnection Constraint were better justified, the near-term solar

[21] CP Executive Summary at 28.
[22] Carbon Plan Ch. 4 at 16.

procurement volume should be determined independently of forecasted solar interconnection constraints for 2026-2028, for reasons detailed below.

Specifically, the near-term solar procurement volume should be sufficient to ensure that all resource portfolios included in the Carbon Plan are capable of being achieved if ultimately selected by this Commission in the 2024 Carbon Plan proceeding. While Duke has claimed that this is the intent of the near-term execution plan, that plan as proposed does not in fact chart a course for achieving Duke's P1 portfolio – which is the only one that achieves 70% decarbonization by 2030 – let alone any of the CPSA proposed alternative portfolios or those of other intervenors. Duke's low levels of early solar procurement are also inconsistent with achieving 70% compliance in 2030, *even under Duke's 2030 compliance portfolio (P1).*

Q. PLEASE EXPLAIN WHY DUKE'S PROPOSED PROCUREMENT SCHEDULE FAILS TO SUPPORT ITS OWN PORTFOLIOS.

A. Under Duke's P1 portfolio (the only Duke portfolio that achieves 2030 compliance), even if 800 MW of offshore wind and 600 MW of onshore wind can be procured and placed in service by 2030 (a scenario carrying additional uncertainty and cost), a total of 5,400 MW of solar and solar-plus-storage must be online by the *beginning* of 2030 to achieve compliance. If Duke procures only 3,100 MW through 2024, Duke would have to procure at least 2,300 MW of additional solar in 2025 alone, and achieve an annual solar interconnection rate of 2,300 MW in 2029, in order to ensure that 5,400 MW of solar is online by early 2030.[23] In other words, under current timelines, Duke's proposed near-term

[23] Duke represents in its Carbon Plan that the 5,400 MW of solar in P1 is online by the beginning of 2030.

solar procurement is inconsistent with its own P1 scenario and its own high-end annal solar interconnection constraint of 1,800 MW.

To understand why this is the case, it is important to underscore that based on Duke's current standard interconnection timelines, it requires approximately four years between the collection of solar RFP bids (which are collected mid-year in each procurement year, in advance of the DISIS Phase 1 study each September) until those projects are placed in service. As such, it can be assumed for planning purposes that solar projects procured in the 2025 procurement cycle will require until late 2029 to come online (see Table 3). This is consistent with Duke's representations regarding the default timeframe for its initial proposed 3,100 MW procurement, which Duke indicates is "targeted in service in 2026-2028" (Duke Carbon Plan Table 4-1). For this reason, unless Duke's interconnection timelines improve, 2025 can be assumed to be the last year to procure projects with a reasonable likelihood of being interconnected by early 2030 for purposes of 2030 compliance.

Table 3

Procurement Year	Procurement MW (non-HB589)	Avg. In-Service Year (EOY)	Cumulative MWs In-Service
2022	750	2026	750
2023	1,050	2027	1,800
2024	1,300[24]	2028	3,100
2025	2,300	2029	5,400

Even if compliance is delayed to 2032, delayed solar procurement still increases execution risk. Duke's P5 High Solar scenario require 8,475 MW of solar by 2032, assuming that 300 MW of SMRs and 1,200 MW of onshore wind can be placed in service

[24] Note that Duke's proposed near-term solar procurement volume of 3,100 MW does not max out its proposed solar interconnection constraints for 2026-2028, leaving a gap of 50 MW.

by 2032. If only 3,100 MW of this total solar capacity is procured through 2024, Duke would have to procure 5,375 MW between 2025-2027 to ensure that 8,475 MW of solar is online by early 2032[25], requiring an average annual procurement and interconnection rate of 1,792 MW (see Table 4).

Table 4			
Procurement Year	**Procurement MW** (non-HB589)	**Avg. In-Service Year** (EOY)	**Cumulative MWs In-Service**
2022[26]	750	2026	750
2023	1,050	2027	1,800
2024	1,300	2028	3,100
2025	1,792	2029	4,892
2026	1,792	2030	6,684
2027	1,791	2031	8,475

Moreover, if as CPSA has demonstrated, the least-cost 2032 compliance plan requires the procurement of 10,700 MW by 2032, the annual procurement volumes after 2024 would need to be substantially higher than those in either of the foregoing tables (see Table 5).

Table 5			
Procurement Year	**Procurement MW** (non-H589)	**Avg. In-Service Year** (EOY)	**Cumulative MWs In-Service**
2022[27]	750	2026	750
2023	1,050	2027	1,800
2024	1,300	2028	3,100
2025	2,533	2029	5,633
2026	2,533	2030	8,166
2027	2,534	2031	10,700

[25] Duke confirms in its supplemental modeling report that "Consistent with data presented in Appendix E, resource changes are effective as of the start of the year listed. The one exception is for the new, 2032 mid-year, SMR which is selected in all portfolios." Modeling Panel Ex. 1 at 13.

[26] Shaded procurement years are within the near-term execution plan. It bears noting that Duke requests approval for low procurement targets during the near-term plan, while assuming (for now) that it will achieve higher interconnection rates in later years.

[27] Shaded procurement years are within the near-term execution plan.

Q. WHAT ARE CPSA'S RECOMMENDED PROCUREMENT TARGETS, AND HOW DID CPSA ESTABLISH THEM?

A. CPSA recommends a near-term solar procurement of 4,800 MW for 2022-2024, including 1,500 MW in 2022, 1,500 MW in 2023, and 1,800 MW in 2024. While these volumes happen to align with the solar interconnection assumptions recommended by CPSA, as I explain, that is not the only reason they are appropriate for inclusion in the near-term execution plan. CPSA established these targets to be consistent with portfolios CPSA2-5. But even if the Commission does not accept CPSA2-5 and retains Duke's P1-P5 portfolios, a near-term procurement of 4,800 MW would still be reasonable, for reasons discussed later in this section. CPSA further recommends that all solar procured after 2022 should be paired with storage.

Q. WHAT IS DUKE'S STATED RATIONALE FOR SETTING SMALL PROCUREMENT TARGETS FOR 2022-2024?

A. Duke's primary justification for its 2022-2024 procurement targets is the idea that these procurement volumes should be precisely matched with its claimed Solar Interconnection Constraint for 2026-2028. Duke does not explain why this is appropriate. It also acknowledges that annual procurement volumes cannot be calibrated precisely to future annual interconnection constraints, given uncertainty in interconnection timelines on both an average basis and a project-specific basis. As Witness Kalemba notes in his testimony, "The current timeline for projects to interconnect from the time that an IA is signed to the time they are commercially operational is 26 to 32 months *if the project does not require* *transmission system upgrades*...".[28] As discussed later, this uncertainty justifies larger rather than smaller initial procurement targets.

Q. WHAT ARE THE POTENTIAL DISADVANTAGES TO SETTING LARGER INITIAL PROCUREMENT TARGETS?

A. The only supposed disadvantage to setting larger initial procurement targets is the hypothetical opportunity cost of additional savings in the scenario that solar and solar-plus-storage costs decline more quickly than forecasted for projects procured after 2024. However, CPSA views the likelihood of lower versus higher future solar costs as relatively equivalent.

Q. PLEASE EXPLAIN.

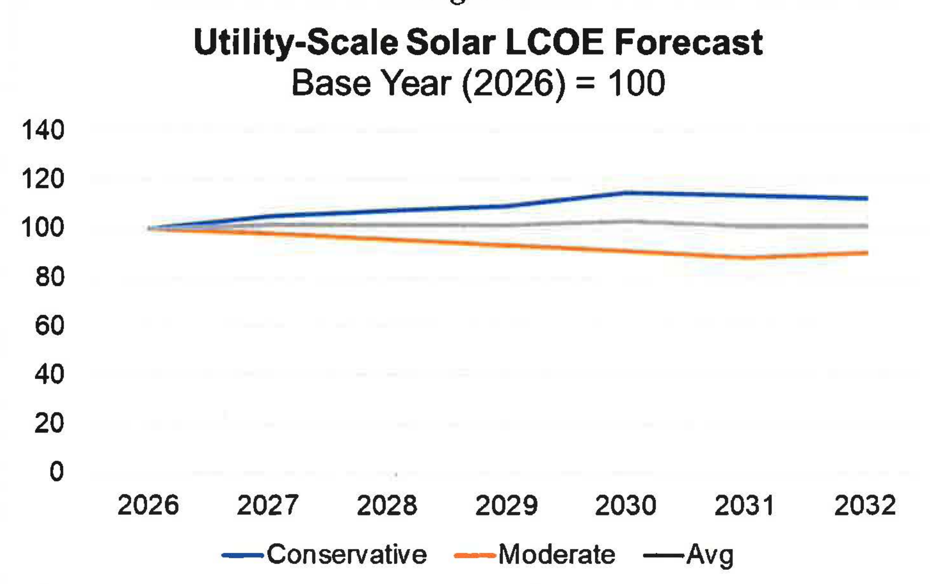
A. Figure 1 below indicates the change in nominal utility-scale solar LCOE under NREL ATB's Conservative versus Moderate scenario on a relative basis for projects with CODs between 2026 and 2032, with COD year 2026 as the base year for both scenarios set to 100.[29] This is a particularly useful comparison, because the question at hand is whether substantial cost savings could potentially be achieved by delaying procurement from the near-term execution plan (targeting COD years 2026-2028) to later years (targeting COD years 2029-2032). Also presented is an average of the conservative and moderate values. As the figure indicates, there is a relatively equivalent probability of higher and lower costs over time, with the average resulting in steady prices between 2026 and 2032.

---

[28] Modeling Panel at 159.

[29] To estimate nominal figures, NREL 2022 ATB's LCOE figures in 2020 dollars were adjusted assuming an average inflation rate of 2.0% between 2020-2032. NREL ATB Class 5 figures were used.

Figure 1



Of course, actual costs may depart significantly from these projections. The most likely sources of such a variance through the late 2020s are module costs and macroeconomic conditions, which are difficult to predict. In the case of modules, costs remain substantially contingent on U.S. federal trade policy, the trajectory of which is uncertain both in the near-term under the Biden administration (primarily due to the outstanding Auxin Solar petition), and in the medium-term depending on the trade policy priorities of the next administration beginning in 2025.

The anticipated growth in domestic module manufacturing driven by new federal incentives via the Inflation Reduction Act (IRA) is likely to mitigate this trade policy contingency; however, limited recent experience with domestic production makes it challenging to predict the cost and market penetration of domestic modules. On the other hand, an improvement in U.S.-Chinese relations and Chinese labor practices could lead to relaxed U.S. trade restrictions and a resurgence in the importation of lower-cost modules. Meanwhile, another key source of uncertainty in the module cost forecast is how much U.S. solar module demand will grow due to the IRA's solar tax incentives.

Other major assumptions carry greater degrees of confidence. Among the most significant of these is that crystalline silicon will remain the dominant technology for U.S. utility-scale solar PV projects through the 2020's, and it is highly unlikely that an unforeseen solar technology will emerge at commercial scale in this timeframe that results in a significant impact on NREL ATB's cost forecast. CPSA is not aware of any credible U.S. market forecast that suggests otherwise, and no evidence to the contrary has been presented in this proceeding. For this reason, with respect to consideration of the interim carbon reduction mandate, CPSA advises that the Commission dismiss Duke's speculation that "accelerating solar deployments based on today's technologies could crowd out future, unknown solar or other technologies that are more efficient or more cost-effective than today's solar."[30]

For these and other reasons, based on currently available information, CPSA views it as reasonable to assign roughly equivalent probabilities to NREL's ATB Conservative versus Moderate cost scenario, counterbalancing a potential "over-payment risk." As discussed in CPSA's comments,[31] CPSA's portfolios assume NREL ATB Conservative solar costs to ensure that capacity expansion modeling and selected solar volumes are not contingent on aggressive or even moderate cost forecasts.

Q. WHAT ARE THE ADVANTAGES TO SETTING LARGER INITIAL PROCUREMENT TARGETS?

A. The advantages to setting larger initial procurement targets include the following, each discussed further below:

---

[30] Modeling Panel at 168.
[31] CPSA Comments at 26-27.

1. Larger initial procurement decreases solar execution risk;
2. Larger initial procurement mitigates the risk of network upgrade delays and rising costs;
3. Larger initial procurement better enables assessment of interconnection limits;
4. Larger initial procurement reduces the need to rely on higher cost alternative resources with greater execution risk;
5. Larger initial procurement mitigates the risk of higher electricity load; and
6. Larger initial procurement accounts for project attrition.

Q. HOW DOES A LARGER INITIAL PROCUREMENT *DECREASE* SOLAR EXECUTION RISK?

A. Duke's proposal to limit solar procurement to 3,100 MW through 2024 would effectively foreclose any possibility of achieving 2030 compliance and would unnecessarily increase the risk of achieving compliance by 2032. As detailed below, Duke's proposed near-term solar procurement is inconsistent with its own P1 and P5 scenarios, requiring annual solar interconnection rates in later years that are higher than Duke's own proposed maximum limit. In contrast, larger initial procurement preserves the option of 2030 compliance and decreases the solar execution risk associated with achieving 2032 compliance.

Q. HOW DOES A LARGER INITIAL PROCUREMENT MITIGATE THE RISK OF NETWORK UPGRADE DELAYS AND RISING COSTS?

A. Duke's proposal to back-load procurement to later years, <u>after</u> the end of the current near-term execution plan, leaves precious little room for delay due to network upgrades or other factors. As discussed above, four years from solar project procurement to in-service is a reasonable base case assumption for resource planning purposes. Nevertheless, some degree of variance from this timeline is to be expected, particularly to the extent that projects procured in any given procurement cycle are contingent on significant network upgrades.

Whereas higher near-term procurement provides a buffer for any variance in the timeline required to interconnect each procurement tranche, "procurement procrastination" requires near-flawless execution in later years to achieve compliance. In other words, uncertainty in the rate of interconnection, especially to the extent that annual interconnection rates are limited due to extended timelines to complete network upgrades, is reason to procure more in the near-term execution plan, not less.

Larger initial procurement also mitigates the risk of network upgrade timelines by expediting the identification and completion of contingent network upgrades . As of now, beyond the RZEP upgrades, it is unclear what transmission system upgrades will be needed to integrate necessary solar volumes. The process of identifying these necessary upgrades will be meaningfully informed by the results of each DISIS study. As Public Staff notes in its comments (pg. 146), "[Public Staff] believes that the most efficient way for Duke to expand the necessary interconnection capabilities and to streamline transmission upgrades is to pursue them in large quantities."

Larger initial procurements will create incentives for market participants to originate and bid more projects, accelerating the assessment of the most valuable network upgrades. It will also increase the likelihood that certain contingent network upgrades can be completed as part of the DISIS process itself by spreading network upgrade costs across more projects.

Finally, by accelerating the identification and construction of network upgrades, larger initial procurements will mitigate the risk of rising average costs for transmission upgrades, which can be expected to increase over time due to rising costs of transmission equipment and labor, which will be in higher demand as more utilities pursue transmission upgrades in the years ahead.

Q. HOW DOES A LARGER INITIAL PROCUREMENT BETTER ENABLE THE ASSESSMENT OF INTERCONNECTION LIMITS?

A. Larger initial procurement provides the additional advantage of enabling Duke and the Commission to better assess real-world limitations to the annual interconnection of solar and solar-plus-storage resources. In other words, if the Commission does not direct Duke to procure more resources than its proposed interconnection constraints, there will be no opportunity to test the hypothetical constraints based on the Company's internal "engineering judgement" against real-world conditions.

In that case, Duke and the Commission would forego the opportunity to (a) determine if a higher volume of cost-effective solar projects can be procured; (b) identify the extent of network upgrades necessary to interconnect those projects; (c) gather data on the required timelines and costs to interconnect higher solar volumes; (d) assess bottlenecks to Duke's internal capabilities; (e) create and test incentives for Duke to innovate with respect to interconnection practices; and (f) determine if higher interconnection rates are reasonably achievable in subsequent years.

Q. HOW DOES A LARGER INITIAL PROCUREMENT REDUCE THE NEED TO RELY ON HIGHER COST ALTERNATIVE RESOURCES WITH GREATER EXECUTION RISK?

A. As explained above, Duke's low near-term solar procurement make it difficult if not impossible to achieve 70% decarbonization by 2030 or perhaps even 2032. And even if the target *can* in fact be achieved with Duke's low near-term solar procurements, that may require the procurement of significantly more expensive alternative generation resources, such as offshore wind or nuclear, or at least greater volumes of those resources than would otherwise be required.

In addition, based on currently available information regarding resources that are potentially available to the DEP and DEC system, non-solar zero-CO2 generation resources carry significantly greater execution risk than solar, at least through the early 2030s. The nature and extent of these execution risks will become clearer over time. As of now, the volume of non-solar carbon-free resources that will be able to be procured and interconnected by 2030 or 2032 is unknowable. Nor do we know how long it will take to obtain greater certainty about the availability of those resources.

Larger initial solar procurement provides a hedge against the risk that those alternative resources are ultimately not available at volumes or timelines required under proposed compliance scenarios where solar and solar-plus-storage resources are subject to low interconnection constraints.

Q. HOW DOES A LARGER INITIAL PROCUREMENT MITIGATE THE RISK OF HIGHER ELECTRICITY LOAD?

A. If electricity load is higher than Duke's forecast in the year of the interim carbon reduction mandate, under Duke's currently proposed portfolios, North Carolina will not achieve compliance with H951. This is because Duke will already be maxing out its available zero-carbon electricity generators, requiring Duke to dispatch its existing gas- and coal-fired generators to fill the gap unless Duke is able to secure supplementary imports (which could result in emissions leakage, depending on the source of imports). In other words, Duke's proposed portfolios are not resilient to upward variance in the load forecast for purposes of compliance.

Moreover, there is good reason to believe that Duke is underestimating its load forecast, particularly with respect to electric vehicle (EV) demand. As Mr. Hagerty testifies, "[Duke's] projections are well below even the more conservative forecasts for EV adoption in the United States through the early 2030s." Using a conservative forecast of EV adoption from Bloomberg New Energy Finance, Brattle's report concludes that Duke's Carbon Plan underestimates EV demand by at least 1,050 GWh in 2030 and 3,220 GWh in 2035.

Larger initial solar procurement mitigates this risk by increasing the likelihood that a sufficient volume of zero-carbon electricity can be available to Duke's system in the year of compliance, providing buffer and avoiding the need for excess dispatch of coal and gas generators. To be sure, a larger initial solar procurement does not commit Duke's system to having an "oversupply" of zero-carbon electricity for purposes of compliance, since the procurement volume after 2024 can be "right-sized" depending on the then-current load forecast. However, given the interconnection timeframes discussed in this section and Duke's concern around solar interconnection constraints, after 2024 it will be much more difficult to make a meaningful upward adjustment in zero-carbon electricity procurement for purposes of compliance by 2030 or even 2032.

Q. HOW DOES A LARGER INITIAL PROCUREMENT CONTROL FOR PROJECT ATTRITION?

A. Large initial procurements also control for the fact that target procurement volumes are unlikely to match the volume of projects that are ultimately constructed. Years of real-world experience across multiple types of Duke offtake programs – including CPRE, GSA, and PURPA QFs – suggest it is prudent to assume a certain level of project attrition when sizing a procurement.

Even if 100% of both solar procurement tracks under H.B. 951 (Utility and PPA tracks) are fulfilled at the time of contract award, unforeseen circumstances are inevitable and some projects are likely to withdraw, given the fundamentally uncertain nature of permitting, zoning, and macroeconomic conditions. This is true for both Duke-owned projects and for third-party PPA projects.[32]

Q. WOULD HIGHER NEAR-TERM SOLAR PROCUREMENT ADVERSELY AFFECT THE DEVELOPMENT OF OTHER ALTERNATIVE RESOURCES?

A, Not at all. As a general matter, and subject to reasonable guardrails, Duke should be authorized to proceed with the early-stage development of additional resources so that it is in a position to implement any Carbon Plan resource portfolio ultimately selected by the Commission.[33]

---

[32] Attrition has occurred in CPRE not only with PPAs, but also with Duke asset acquisitions. Source: https://www.greentechmedia.com/articles/read/duke-drops-largest-solar-project-in-north-carolina-procurement-its-own. The CPRE shortfall is instructive, although certain factors were likely unique to CPRE procurements. The primary cause for the overall CPRE shortfall is the Tranche 3 shortfall, where a material decline in avoided cost rates coincided with severe macroeconomic challenges arising after the bidding period, making it difficult for developers to deliver on necessarily low PPA bids. Furthermore, Tranche 3 was 100% allocated to DEC, where a combination of transmission congestion and constrained availability of highly competitive sites meant that a very limited number of sites were viable at a low avoided cost rate. Nevertheless, the CPRE shortfall is illustrative of how unforeseen macroeconomic conditions can contribute to project attrition.

[33] This is not to say that CPSA agrees that all of Duke's requests to authorize near-term development activities in the execution plan are reasonable. In particular, because no portfolio calls for the addition of natural gas fired generating facilities for the next several years, CPSA is not aware that it is necessary for Duke to seek CPCNs for any such units during the period of the near-term execution plan.

Q. PLEASE DESCRIBE DUKE'S PROPOSAL FOR INCORPORATING THE CPRE SHORTFALL INTO THE 2022 SP.

A. Duke proposes to add the current 441 MW shortfall in its CPRE procurement obligation to the 2022 solar procurement.[34] Only projects under the avoided cost cap would be eligible for contracts. Duke intends that this additional procurement, whatever the results, would "close out" its obligations under CPRE.[35] Duke provided additional information about its proposal in a September 1, 2022 filing in the Commission's CPRE dockets. Given that Duke make this filing only yesterday, CPSA has not had sufficient time to review and evaluate this filing.

Q. DOES CPSA SUPPORT THIS PROPOSAL?

A. There are elements of Duke's proposal that CPSA supports in concept. However, given the limited information Duke provided, it is impossible even to guess whether the proposal would actually result in any signed contracts. CPSA therefore believes it is premature to approve Duke's proposal.

CPSA acknowledges that it would be very burdensome to run a separate CPRE procurement in order to complete Duke's statutory obligation under H.B. 589, and it is appropriate to consider ways for Duke to fulfil its remaining CPRE obligation short of conducting a separate procurement under an entirely different set of rules. However, CPSA opposes approving Duke's plan without some indications that it is likely to be successful, and result in the procurement of projects equal to or greater than Duke's CPRE shortfall, which currently stands at 441 MW. Because proposals in the 2022 SP were not capped at

---

[34] Modeling Panel p. 76-78.
[35] Id. p. 77:10.

avoided cost, it is uncertain how many (if any) of the proposals in the 2022 SP would be below avoided cost, even before consideration of network upgrades.[36] Indeed, because Duke hasn't published the avoided cost rate schedule that would apply to the proposed procurement, 2022 SP bidders don't even know whether their *own* proposals are below avoided cost. Duke has also not provided any information on how it would propose to handle the cost of Network Upgrades with respect to avoided cost evaluation.

It appears more appropriate for the Commission to resolve Duke's CPRE proposal in the CPRE dockets rather than in this proceeding. However, if the Commission does elect to take action on Duke's proposal, CPSA recommends that any approval be contingent upon: (1) "upsizing" the target procurement to account for expected attrition; and (2) providing some assurances that there are sufficient bids that may fall under avoided cost, after consideration of any network upgrade costs.

Most importantly, any procurement amount intended to satisfy Duke's CPRE obligation must be *added* to any procurement target authorized under H.B. 951. Both Duke's and intervenors Carbon Plan portfolios include the full CPRE procurement amounts in the baseline for their modeling. The CPRE shortfall represents *additional* solar capacity that must be added to Duke's system just to restore that baseline.

IV. TRANSMISSION PLANNING, PROACTIVE TRANSMISSION, AND RZEP

a. Duke's RZEP Proposal

Q. WHAT IS CPSA'S VIEW ON DUKE'S RZEP PROPOSAL?

---

[36] CPSA acknowledges that the RFP currently contemplates an opportunity for bidders to provide refreshed pricing in April 2023, and expects that this will likely result in lower prices due to the passage of the Inflation Reduction Act. However, initial RFP pricing should provide an indication of how far (in the aggregate) bids would have to be adjusted downward in order to comply with the avoided cost cap.

A For the reasons discussed in CPSA's Comments, CPSA strongly favors Duke's request that the Commission recognize the need for the RZEP Projects.[37] The additional analysis provided in Duke's direct testimony further demonstrates that these projects represent a "no-regrets" set of upgrades that will be required to cost-effectively achieve H.B. 951's carbon reduction mandates. Duke's supplemental study is consistent with CPSA members' experience in developing solar projects in the Carolinas.

In addition, CPSA believes that it would be extremely helpful for the Commission to provide additional guidance regarding its expectations for justifying a set of transmission upgrades for inclusion in the Carbon Plan or future revisions. Although the RZEP will facilitate the addition of a significant amount of additional generation, it is likely that additional upgrades will eventually be needed to fully achieve the goals of H.B. 951. Although CPSA and other parties recommend changes to Duke's current transmission planning process to better integrate with the resource planning process, it will take some time for such processed to be developed. In the meantime, guidance from the Commission on how additional upgrades should be identified and justified would significantly advance the goals of H.B. 951.

V. COST ISSUES – DETERMINATION OF LEAST COST

Q. HAS DUKE PROPOSED A CARBON PLAN THAT COMPLIES WITH THE "LEAST COST" MANDATE OF H.B. 951?

A. No. As demonstrated in detail by CPSA Witness Hagerty and the modeling performed by The Brattle Group, Duke's proposed portfolios increase the cost to ratepayers relative to CPSA proposed portfolios that include a higher volume of solar additions. Indeed, the

[37] CPSA Comments at 58-65.

single biggest step that Duke can do to save ratepayers money is to install more solar on its system. This is because solar is by far the cheapest source of carbon-free energy available at scale in North Carolina in the next decade. Solar is also a mature technology that can be constructed quickly and has been widely deployed in the Carolinas.

Q. WHAT ARE THE CONSEQUENCES OF DUKE'S APPROACH FOR RATEPAYERS?

A. Duke's approach increases the cost to ratepayers. As detailed in CPSA's comments[38] and the testimony of CPSA Witness Hagerty, Duke's proposed solar interconnection constraint forces selection of higher cost and higher risk resources for achieving compliance with the interim carbon reduction mandate, whether that mandate is achieved in 2030 or 2032.

Duke's proposed constraint also increases the risk of higher transmission upgrade costs. Whereas larger initial procurements will allow for the identification and construction of network upgrades more quickly, deferred procurement will delay the commencement of those upgrades, whose average costs can be expected to increase over time due to rising costs of transmission equipment and labor. As discussed in CPSA's comments, Duke's CP portfolios do not provide an accurate picture of the cost benefits of greater solar additions.[39]

Q. IS DUKE CURRENTLY INCENTIVIZED TO INCREASE THE EFFICIENCY OF ITS INTERCONNECTION PROCESS FOR SOLAR AND SOLAR PLUS STORAGE RESOURCES AND THEREBY SAVE MONEY FOR RATEPAYERS?

A. No. H.B. 951 requires that solar and solar plus storage resources be subject to a 55/45% ownership split between Duke and third party generators. All other generation resources

[38] CPSA Comments at 12, 20, 33.
[39] CPSA Comments at 39-42.

selected within the carbon plan are to be 100% owned by Duke[40]. As a consequence of these statutory requirements, Duke's earning potential is inversely correlated with the amount of solar and solar plus storage resources that are included in the approved Carbon Plan. Additionally, because other resources like SMRs and OSW come with an additional cost premium as compared to solar, Duke is further incentivized to prefer these more expensive resource options that provide higher earnings potential on a MWh-to-MWh basis.

Ultimately, by constraining the amount of solar in the Carbon Plan sue to an assumed Solar Interconnection Constraint, Duke can default to other more expensive resource options that it will 100% own and rate base. At present, Duke has no financial incentive to increase the efficiency of its interconnection process for solar and solar plus storage facilities, and it will be up to this Commission to ensure that Duke is taking all necessary steps to improve interconnection efficiencies to the benefit of customers.

Q. COULD A PERFORMANCE INCENTIVE MECHANISM ("PIM") BE DESIGNED TO EFFECTIVELY INCENTIVIZE DUKE TO MORE EFFICIENTLY INTERCONNECT SOLAR AND SOLAR PLUS STORAGE RESOURCES?

A. Possibly. However, to the extent that a PIM does not fully account for the lost earnings that Duke would otherwise expect to recover from investing in resources that it 100% owns and rate bases, then there will remain a financial disincentive for Duke to materially improve the interconnection rate of solar and solar plus storage resources. Nonetheless, CPSA is

[40] 62-110.9(2): "Any new generation facilities or other resources selected by the Commission in order to achieve the authorized reduction goals for electric public utilities shall be owned and recovered on a cost of service basis by the applicable electric public utility [...]" CPSA does not take a position on the question, raised by other intervenors, of whether the ownership requirements of H.B. 951 apply to generating resources not located within Duke's service territories or within the state of North Carolina.

supportive of potential PIMs that are likely to improve marginal interconnection efficiencies, but any PIM-based approach to interconnection improvements should not be viewed by this Commission as a panacea for reaching Duke's interconnection potential.

VI. EXECUTION RISKS

Q. WHY IS EXECUTION RISK ASSESSMENT A CRITICAL CONSIDERATION IN THIS PROCEEDING?

A. Compliance with H.B. 951 is only possible to the extent that selected resources can actually be sited, permitted, procured, financed, constructed, and interconnected by the mandated compliance dates. Alongside cost and reliability, execution risk is an essential metric by which to evaluate any given technology and portfolio, and the near-term execution plan should seek to mitigate execution risk as much as reasonably possible.

Q. WHAT IS DUKE'S GENERAL APPROACH TO EVALUATING COMPARATIVE EXECUTION RISK IN THE CARBON PLAN?

A. Duke's executability ranking for each portfolio is summed up in the form of a pie chart for each proposed portfolio, labeled "Overall Level of Risk to Achieving 70% CO2 Reduction by Target Year".[41] Alongside this chart, Duke presents two figures for each portfolio, including annual solar additions and "cumulative additions of new-to-the-Carolinas-resource types." Duke notes that "The more a portfolio relies on technologies new to the Carolinas and the more substantial the pace and scale of deployment and dependence on constrained supply chains, the higher the risk," but does not provide additional detail on how each chart was constructed. In summary, Duke's overall portfolio risk assessment

[41] Carbon Plan Executive Summary at 16 (Table 1).

appears to be based on two factors: (1) annual solar additions; and (2) cumulative additions of "new-to-the-Carolinas" resource types.

Q. WHAT DOES DUKE'S EXECUTION RISK ASSESSMENT CONCLUDE?

A. Duke's rank-order of its Portfolios from highest to lowest execution risk appears as follows, based on the presented pie charts. Duke did not indicate a quantitative value for its estimated risk levels, requiring a visual approximation as provided below in Table 6.

Table 6

Portfolio	Compliance Year	Risk Level for Compliance Year	Max Annual Solar Additions MW	Aggregate "New-to-Carolinas" Resource MW (2030 | 2035)
P1	2030	85 out of 100	1,800	3,140 | 6,480
P2	2032	75 out of 100	1,350	2,170 | 5,380
P3	2034	50 out of 100	1,350	1,270 | 3,820
P4	2034	40 out of 100	1,350	1,150 | 4,210

Duke characterizes P1 as carrying the greatest risk for achieving compliance by its target year (2030) because of its higher maximum rate of solar interconnections, and because its cumulative addition of "'new-to-the-Carolinas' resource types" amounts to 3,140 MW in 2030, including 600 MW of onshore wind, 2,067 MW of energy storage, and 800 MW of offshore wind (Duke's reported aggregate MW volume here does not match its separately reported values for each resource in 2030, for unclear reasons).

It is unclear if Duke used a quantitative methodology for converting these capacity figures into its overall risk level assessment, or whether that conversion was performed qualitatively based on Duke's internal judgement. Duke also makes difficult an apples-to-apples comparison by not presenting the aggregate "new-to-Carolinas" resource volume in the year of *compliance*, and by not providing a breakdown of the "new-to-Carolinas" volumes by resource type.

Q. WHAT WOULD A FAIR COMPARISON OF THE EXECUTION RISK OF DUKE'S PROPOSED PORTFOLIOS SHOW?

A. When an apples-to-apples rank-order of the portfolios is conducted based on the aggregate "new-to-Carolinas" resources that are required in the year of *compliance* (the values for which are reported separately in Figure 6 of the Carbon Plan Executive Summary), P2 carries the most risk, followed by P4 and P3. P1 carries the least risk, due to substantially lower volume of offshore and onshore wind, along with no SMRs (see Table 7 below).

Table 7

Portfolio	Compliance Year	Onshore Wind	Battery Storage	Offshore Wind	SMR	Aggregate	Risk Rank
P1	2030	600	2,067	800	0	3,467	#4
P2	2032	1,200	1,700	1,600	0	4,500	#1
P3	2034	1,200	2,200	0	300	3,700	#3
P4	2034	1,200	1,800	800	300	4,100	#2

Q. IS DUKE'S GENERAL APPROACH REASONABLE?

A. No. Duke's approach to assessing overall execution risk is deeply flawed and misleading. These flaws are discussed at length in the comments of CPSA and other intervenors, and they include but are not limited to the following:

- Duke lumps resources with fundamentally different risk profiles into a single category, labeled "new-to-the-Carolinas resource types," in a way that inaccurately equates the execution risk of onshore wind, offshore wind, battery energy storage, and SMRs.
- Duke's risk assessment of solar interconnection rates is unreasonable, and there is ample reason to believe that Duke can achieve significantly higher solar interconnection rates.

- Duke does not reveal a methodology by which it translates its two figures (annual solar additions and cumulative "new-to-the-Carolinas" additions) into its overall ranking.
- Duke has structured its portfolios in a way that selectively increases the risk of certain portfolios and distorts the overall risk assessment.
- Duke does not consider any ways to mitigate or otherwise address the execution risk it estimates for the portfolios is has constructed.

Q. HOW COULD DUKE'S EXECUTION RISK COMPARISON BE MODIFIED TO MORE APPROPRIATELY ACCOUNT FOR THE VERY DIFFERENT RISK PROFILES OF BATTERY STORAGE, WIND, AND SMRS?

A. This could be accomplished by assigning a different numerical weighting corresponding the relative execution risk of each resource. If a more appropriate risk weighting is assigned to each "new-to-the-Carolinas" resource, the change in rank-order is significant. For example, by assigning a risk adjustment factor of just 2.5 for SMRs (i.e. if each installed SMR megawatt counts as 2.5 megawatts instead of one) and 0.8 for battery storage, the rank-order based on aggregate "new-to-the-Carolinas" resources changes significantly, with P4 carrying the highest, followed by P2, P3, and then P1.

With even more granular risk weights assigned to each resource, the comparison is starker. For example, Table 8 shows a comparative assessment with more reasonable risk weights assigned to each resource (specific risk weightings are for illustrative purposes only). In this scenario, P4 and P2 carry around 1.65 times the risk of P1 in terms of aggregate "new-to-the-Carolinas" resources.

Table 8 - Risk-Adjusted MW of "New-to-Carolinas" Resources							
Portfolio	Compliance Year	Onshore Wind	Battery Storage	Offshore Wind	SMR	Aggregate	Risk Rank
Risk Weight		1.5	0.5	2.0	5.0		
P1	2030	900	1,034	1,600	0	3,534	#4
P2	2032	1,800	850	3,200	0	5,850	#1
P3	2034	1,800	1,100	0	1,500	4,400	#3
P4	2034	1,800	900	1,600	1,500	5,800	#2

In this scenario, to achieve an equivalent overall risk assessment across these portfolios that accounts for the execution risk of achieving an annual solar interconnection rate of 1,800 instead of 1,350, one would have to assign a risk adjustment factor of more than 5.0 to each MW of incremental solar above 1,350 in order to reach an equivalent overall risk ranking between P1, P2, and P4 – the same risk adjustment factor used here for SMRs.

The point of this exercise is not to provide a definitive risk calculation for each portfolio, but to illustrate how misleading Duke's approach is with respect to the relative risks of each portfolio.

Q. WHAT DOES DUKE'S APPROACH TO COMPARATIVE RISK ASSESSMENT TELL US ABOUT ITS RESOURCE PREFERENCES?

A. Duke's approach discriminates against solar and solar-plus-storage resources in favor of generation resources that provide greater earnings opportunity for Duke's shareholders. In general, in its treatment of uncertainty, Duke is highly conservative (risk averse) with respect to its evaluation of execution risk for solar and solar-plus-storage, and much more aggressive with other resources. Nowhere is this more apparent than in the approach Duke takes to assessing the execution risk of solar and solar-plus-storage as compared to SMRs, although there is similar comparative bias for natural gas (regarding pipeline execution risk), hydrogen, and to some extent, offshore wind.

In essence, Duke's execution risk assessment suggests that installing a SMR by 2032 – a technology that has never been demonstrated in the United States for which the earliest first-of-a-kind demonstration isn't forecasted until the late 2020s – carries lower execution risk than Duke achieving an incremental rate of solar interconnection that is 450 MW above its default annual solar interconnection constraint (1800 MW vs. 1350 MW), or an increment of around 4-6 standard transmission-scale solar projects. Similarly, Duke appears to view the addition of nearly 10 gigawatts of new nuclear to its system through 2050 as presenting less risk than achieving any incremental improvement in its annual solar interconnection rate between 2028 and 2050.

With respect to this comparison, CPSA believes the available evidence speaks for itself, as detailed in the direct testimony of CPSA Witness Watts and in the comments of numerous intervenors, including CPSA's. Moreover, whereas the commercial availability of SMRs by the early 2030s depends on factors that are far beyond Duke's control, Duke's rate of annual solar interconnection is well within its control. As Public Staff notes, "Even if the most recent manufacturer [COD] estimates are correct, a significant amount of development must first occur, much of which is outside of Duke's control (such as fuel supply chain, NRC approvals, and construction activity), in order to have Duke's SMRs online by 2032 or 2033… Given that the NRC has not given approval to any SMR or advanced reactor design at this time, the timelines are highly speculative." (94) Nevertheless, in its supplemental modeling, Duke accelerated the date of earliest SMR entry from late 2032 to mid-2032.

In terms of execution risk mitigation, Duke's treatment of SMRs as compared to solar interconnection rates is similarly revealing. Whereas Duke goes to lengths in its testimony (Nolan) to discuss various risk mitigation efforts it is pursuing for SMRs and advanced reactors, it suggests few if any similar steps it is pursuing to diligence the potential for higher solar interconnection rates.

Q. WHAT NEAR-TERM STEPS DOES CPSA RECOMMEND TO MITIGATE THE EXECUTION RISK OF SMRS AND OTHER LONG-LEAD TIME RESOURCES?

A. As discussed in this testimony, Duke's proposed portfolios and short-term execution plan serve to *increase* execution risk, primarily by delaying solar procurement and failing to present a 2032 compliance portfolio with larger solar additions that doesn't rely on SMR availability in that year.

Larger initial solar procurement will mitigate the likelihood that alternative resources with higher execution risk and cost will be required to achieve compliance. The procurement and interconnection of any new generation resource carries some degree of execution risk. However, based on currently available information regarding resources that are potentially available to the DEP and DEC system, non-solar zero-CO2 generation resources carry significantly greater execution risk than solar, at least through the early 2030s.

The specific nature and extent of these execution risks will become clearer as more real-world data is made available to the Commission with each subsequent Carbon Plan proceeding. As of now, the volume of non-solar zero-CO2 resources that will be able to be procured and interconnected by 2030 or 2032 is currently unknowable. Similarly, the timeline to ascertain certainty regarding the availability of those resources is currently unknowable.

For these reasons, larger initial solar procurement provides a hedge against the risk that those alternative resources are ultimately not available at volumes or timelines required under proposed compliance scenarios where solar and solar-plus-storage resources are subject to low interconnection constraints.

Specifically, CPSA's portfolio CPSA5 demonstrates that 2032 compliance is achievable without reliance on any long-lead time resources, thus carrying less execution risk than Duke's proposed portfolios. Recognizing that any portfolio carries uncertainty, however, CPSA also proposes an additional portfolio, CPSA3, that adds solar at a slower rate and thus does require new long-lead time resources, albeit not SMRs.[42] Also, CPSA fully supports a near-term execution plan that pursues all technological pathways and preserves optionality.

Q. HOW DOES THE PUBLIC STAFF APPROACH TO COMPARATIVE EXECUTION RISK ASSESSMENT ACROSS DUKE'S PORTFOLIOS?

A. The Public Staff offers useful commentary on the execution risks facing each resource type. With respect to their comparative assessment of execution risk across Duke's four proposed portfolios, it is important to note that Public Staff takes a meaningfully different approach from Duke.

Instead of considering the resource additions required for each portfolio to achieve compliance with the interim carbon reduction mandate (i.e., the mix of resource additions in each portfolio by the compliance date), Public Staff considers each portfolio's mix of

---

[42] CPSA Comments at 37-39.

resources additions through the first year of SMR selection, which is late 2032 or 2033 for P1-P4, as illustrated in Table 1 of their comments.[43]

This approach in part leads the Public Staff to conclude that, between those four portfolios, P1 carries the highest execution risk because it requires high levels of annual solar and battery storage additions, *and also* adds significant quantities of both offshore wind and SMRs.[44] Public Staff similarly notes that "P2 may be unrealistic given the schedule for offshore wind development, even if it allows one additional year to bring the first SMR online."[45]

However, P1 and P2 do not rely on SMR additions to achieve compliance with the 70% carbon reduction mandate, even if the specific inputs and assumptions used in Duke's modeling resulted in selection of SMRs for those portfolios in 2032 or 2033.

VII. <u>CONCLUSION AND RECOMMENDATIONS</u>

Q. MR. NORRIS, PLEASE SUMMARIZE CPSA'S RECOMMENDATIONS IN THIS DOCKET.

A. CPSA recommends that the Commission accept the Carbon Plan, with the following changes:

1. Direct Duke to make the following changes to the Carbon Plan:
   a. Add portfolios CPSA3 and CPSA5;
   b. Replace portfolio P2 with CPSA4;
   c. Remove portfolios P3 and P4, for the reasons stated in CPSA's comments;[46]

[43] Public Staff Comments at 13.
[44] *Id.* at 18.
[45] *Id.*
[46] CPSA Comments at 34-37. Per the Commission's directives, this issue will be addressed in written comments to be filed on September 9 and not in testimony.

d. Revise the near-term Execution Plan to include solar procurements in of 1500 MW (plus any authorized CPRE procurement) in 2022 and 2023, and 1800 MW in 2024; and

e. Direct that all solar procured after 2022 be paired with storage until the storage requirements of the Carbon Plan portfolios are met.

2. For purposes of future Carbon Plan updates and revisions, direct Duke to adopt the modifications to its modeling criteria recommended by CPSA Witness Michael Hagerty;

3. Confirm that construction of the RZEP is reasonable and necessary to achieve the requirements of HB 951;

4. Direct Duke to take the following additional actions:

a. Engage stakeholders in the development of appropriate contract structures for the procurement of solar plus storage facilities;

b. Establish an independent technical advisory committee, with stakeholder participation, to study the achievability of higher interconnection rates in Duke's territory, and advise the Company and the Commission on measures that can be taken to expedite interconnections;

c. Provide periodic reports to the Commission on the steps it has taken and plans to take to expedite the interconnection process, and on its interconnection performance; and

5. Immediately commence the study of Grid Enhancing Technologies for possible use in transmission and interconnection studies and transmission planning; and

6. Initiate proceedings, including but not limited to the convening of a technical conference, with the goal of establishing a proactive, long-term transmission planning process consistent with applicable FERC requirements.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CERTIFICATE OF SERVICE

I hereby certify that the foregoing Direct Testimony of Tyler Norris on behalf of Clean Power Suppliers Association has been served upon parties and counsel of record in NC Utilities Commission Docket E-100, Sub 179 and NC Public Staff by electronic mail, or depositing the same in the United States mail, postage prepaid.

This the 2nd day of September, 2022.

/s/ Benjamin L. Snowden

Benjamin L. Snowden