**STATE OF NORTH CAROLINA**
**UTILITIES COMMISSION**
**RALEIGH**
**DOCKET NO. E-100, SUB 179**

**BEFORE THE NORTH CAROLINA UTILITIES COMMISSION**

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| In the Matter of<br>Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC 2022 Integrated Resource Plans and Carbon Plan | )<br>)<br>)<br>)<br>) | COMMENTS OF CLEAN POWER SUPPLIERS ASSOCIATION ON PROPOSED CAROLINAS CARBON PLAN |

# COMMENTS OF CLEAN POWER SUPPLIERS ASSOCIATION

Pursuant to the Commission's November 19, 2021 Order Requiring Filing Of Carbon Plan And Establishing Procedural Deadlines and its November 29, 2021 Order Granting Extension of Time, intervenor Clean Power Suppliers Association ("CPSA"), by and through counsel, hereby provides these Comments on the Carolinas Carbon Plan ("Carbon Plan") filed by Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and, together with DEC, "Duke" or the "Companies") in this docket on May 15, 2022.

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## I. Introduction and Executive Summary

This proceeding, which will determine North Carolina's energy future for decades to come, is arguably the single most important proceeding in the history of this Commission. Recognizing the enormous potential adverse impacts of global warming on North Carolina and the world, as well as the tremendous risk to ratepayers from continued reliance on coal-fired power plants, Governor Cooper has made the transition away from coal and the reduction of carbon emissions one of the top priorities of his administration. His Executive Order 80, issued in October of 2018, called for aggressive state-wide reductions in greenhouse gas emissions. That order led to a multi-year, multi-stakeholder process to develop a detailed roadmap for achieving the Governor's decarbonization goals, including a 70% reduction in electric power sector emissions below 2005 levels by 2030. The Governor then led historic, bipartisan negotiations with the legislative leadership to secure passage of H.B. 951—landmark legislation not only in North Carolina but in the Southeast—that gave the force of law to the Governor's 70% decarbonization goal.

Rather than attempting to prescribe a detailed pathway to decarbonization, the Governor and the General Assembly charged this Commission with the all-important task of devising a detailed plan for achieving the reduction in carbon emissions called for by the Governor and by the legislation. The Commission appropriately approached this historic task by requiring Duke Energy to submit a plan for achieving the mandates of the bill and seeking comments from interested parties to inform the Commission's decisions about the contours and contents of its carbon plan. But ultimately what the law requires is that this Commission, not Duke Energy or anyone else, determine the necessary elements of a carbon plan that achieves the reduction in emissions required by the law at least cost and while preserving system reliability.

Duke has performed an important service in providing a useful starting point for the Commission's deliberations, and as discussed below, there are many aspects of Duke Carbon Plan and approach to the task of decarbonization that CPSA agrees with and commends. However, Duke's Carbon Plan reflects numerous serious flaws that should not be embraced or repeated by this Commission. The most problematic of these it that, without sufficient evidence or explanation, Duke has taken an inappropriately bearish view about the rate at which it can add solar resources to its system. Because 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 conservatism 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 (which is acknowledged by representatives of the wind industry to be very limited); and the potential to reliably and affordably import wind generation from out of state. For the most part CPSA has not objected to Duke's ambitious assumptions with respect to these other technologies. Faced with this historic task, the Commission should be bold and ambitious, leave no stone unturned, preserve optionality, and, most importantly, require Duke and all parties to aggressively innovate and improve performance. The task before this Commission is no less important than the one President Kennedy faced in seeking to put a man on the moon, and it requires a comparable level of commitment to lofty ambitions, not acquiescence to the status quo.

Fortunately, the Commission's job is made easier by the fact that, as Duke proposes, it need not make ultimate decisions about all the details of the Carbon Plan now. CPSA agrees that the most prudent course for the Commission to take at this time is to approve a three-year Execution Plan that will support a range of potential resource portfolios and to defer the decision on the selection of a preferred portfolio in a follow-on proceeding two years from now. But to preserve the potential for that preferred portfolio to offer the least cost option for North Carolina ratepayers, it is essential that that Execution Plan require substantially more solar procurement in 2022 through 2024 than has been proposed by Duke. These comments explain in detail why that approach is reasonable and achievable, provides the least execution risk, and is in the best interest of ratepayers.

### A. Background on CPSA and the solar industry

CPSA is a non-profit corporation formed under the laws of North Carolina. CPSA's mission is to promote a sustainable future through the development of independent renewable energy resources in the Carolinas. CPSA's members are primarily developers of independent solar generating facilities in North Carolina and South Carolina. CPSA believes that independently developed renewable resources can deliver substantial benefits to the grid and to ratepayers while also satisfying customer demands for clean, carbon-free energy.

The solar industry in North Carolina and South Carolina has made significant contributions to the economies of both states. North Carolina has long been a national leader in solar, and as of June 2022, North Carolina ranks fourth in the country for total installed capacity and first in rural clean energy jobs.[1] The solar industry employs more than 8,000 North Carolinians, and the total

[1] Solar Energy Industries Association, Top 10 Solar States, https://www.seia.org/research-resources/top-10-solar-states-0; North Carolina Sustainable Energy Association, Clean Jobs North Carolina, February 14, 2022 (https://energync.org/publication/).

contribution of the renewable energy industry to North Carolina's gross state product between 2007 and 2020 was $22.5 billion.[2] South Carolina is currently ranked fourteenth in installed solar and employs over 3,000 workers in the solar industry.[3]

CPSA members have been deeply involved in renewable energy policies and programs in the Carolinas over the past decade including under PURPA, H.B. 589 and CPRE, and now under H.B. 951 and the Carbon Plan. CPSA believes that the Carbon Plan presents a critical opportunity for North Carolina to continue its role as a leader in renewable energy while meaningfully contributing to continued carbon emission reductions and providing substantial economic benefits to the state. CPSA worked closely with other parties in the stakeholder process leading up to the development of the Carbon Plan, as well as the stakeholder process relating to the 2022 RFP under H.B. 951. As part of the Carbon Plan stakeholder process, CPSA engaged the Brattle Group to better understand Duke's options for achieving the 70% carbon reduction mandate of H.B. 951 and to conduct modeling of alternative portfolios, the results of which are discussed below. Brattle's key findings are described in Exhibit A ("Brattle Report").

### B. Summary of Comments and Requested Modifications

As discussed further below, CPSA believes that the Carbon Plan is unreasonable and imprudent in a few respects, including the following:

a. Duke's annual solar interconnection caps are unsubstantiated, drive up costs for ratepayers, and make timely compliance with H.B. 951's 70% carbon reduction mandate much more difficult;

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[2] NCSEA, Clean Jobs North Carolina, February 14, 2022 (https://energync.org/publication/); RTI International, Economic Impact Analysis of Clean Energy Development in North Carolina – 2021 Update, ES-2 (June 2021).
[3] Solar Energy Industries Association, South Carolina Solar, https://www.seia.org/state-solar-policy/south-carolina-solar.

b. Duke's other modeling assumptions on several other issues, including capital costs, the availability of SMRs, transmission costs, and solar plus storage configurations, are unreasonable and unjustified;

c. H.B. 951 does not permit delays in compliance past 2032 in the manner proposed by Duke;

d. The Carbon Plan fails to present a full range of portfolios that would enable timely, least-cost compliance with H.B. 951 given a reasonable set of modeling assumptions; and

e. The near-term Execution Plan, and in particular the proposed target volume for the 2022 solar procurement, are unreasonable and do not support a reasonable range of portfolios.

CPSA therefore recommends that the Commission direct Duke to make the following changes to the Carbon Plan:

a. Add portfolio CPSA1 to the Carbon Plan;

b. Remove Portfolios P3 and P4 because they are legally deficient under H.B. 951.

c. Replace Portfolio P1 with portfolios CPSA2 and CPSA3, which achieve 70% compliance in 2030;

d. Replace Portfolio P2 with portfolios CPSA4 and CPSA5, which achieve 70% compliance in 2032;[4]

[4] To the extent that any of Duke's proposed portfolios are retained in the Carbon Plan, Duke should be required to re-model those portfolios with revised assumptions and methodology as discussed herein and in the Brattle Report.

e. Revise the near-term Execution Plan to include solar procurements in 1500 MW in 2022 and 2023, and 1800 MW in 2024; and

f. Direct that all solar procured after 2022 should be paired with storage until the storage requirements of the Carbon Plan portfolios are met, subject to appropriate PPA terms that adequately incentivize storage additions.

Finally, CPSA recommends that the Commission take the following additional actions:

a. Approve the construction of the Red Zone Upgrades as part of the Carbon Plan;

b. Direct Duke to engage stakeholders in the development of appropriate contract structures for the procurement of solar plus storage facilities;

c. Direct Duke to commission a third party, assisted by an independent technical advisory committee, 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; and to 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

d. Direct Duke to immediately commence the study of Grid Enhancing Technologies for possible use in transmission and interconnection studies and transmission planning; and

e. 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.

### C. Areas of Support for Carbon Plan

CPSA appreciates Duke's stakeholder engagement efforts and the amount of work that Duke has dedicated to preparing the Carbon Plan. Notwithstanding the ways in which the Carbon Plan is unreasonable and should be modified, there are many aspects of the Carbon Plan that CPSA actively supports.

First, CPSA supports Duke's general approach of presenting a set of portfolios designed to achieve H.B. 951's decarbonization mandates, without asking the Commission to select a preferred path, while seeking approval of a near-term Execution Plan that supports the portfolios presented. Although there are elements of the Execution Plan, such as expenditure of development costs on resources such as small modular reactors ("SMRs"), that may or may not play a role in the long-term resource plan that Duke ultimately implements, CPSA believes that these steps are reasonable in light of significant uncertainty about what carbon-free resources will ultimately be available (at reasonable cost) for H.B. 951 implementation.[5] Authorization of these activities in the Execution Plan is also consistent with H.B. 951's directive that the Commission "take all reasonable steps" to achieve compliance with the 2030 and 2050 decarbonization targets.[6] The future is highly uncertain. To the greatest extent possible, the Execution Plan should create and preserve optionality for a range of carbon reduction strategies.

Despite agreeing with Duke's general approach, CPSA (as discussed further below) believes that Duke's selection of portfolios is flawed and incomplete, and that there are additional portfolios that should be included for consideration in the Carbon Plan. CPSA further believes that Duke's portfolios P1 and P2 should be modified and that its portfolios P3 and P4 should be

[5] Notwithstanding its support for this general concept, CPSA would strongly support the imposition of reasonable constraints or guardrails on Duke's ability to obtain cost recovery for such development activities.
[6] CPSA takes no position on whether deferral or cost recovery as requested by Duke is appropriate.

eliminated because they fail to comply with H.B. 951. The Execution Plan, in turn, should be modified so that it supports these additional portfolios.

Except as discussed below, CPSA does not take issue with the vast majority the modeling inputs and assumptions utilized by Duke in its Carbon Plan modeling. This does not mean that CPSA necessarily agrees with those inputs and assumptions, and it may well be necessary to revisit them at a later date. However, given the wide array of contested issues that must be resolved by the Commission, and the preliminary nature of the 2022 Carbon Plan, the parties and the Commission should focus their attention only on those issues of greatest import, rather than litigating every aspect of the Carbon Plan.

An aspect of Duke's Carbon Plan modeling approach that CPSA actively supports is Duke's decision to model emissions from new generating facilities that may be located in South Carolina. Although H.B. 951 refers only to reduction of carbon dioxide "emitted in the State" of North Carolina, it would clearly frustrate the intent of the General Assembly if H.B. 951 simply drove Duke to relocate its carbon emissions to South Carolina.[7] In any event, as has been discussed in Integrated Resource Plan ("IRP") proceedings conducted by the South Carolina Public Service Commission ("SCPSC"), CPSA believes that a resource plan that reduces carbon emissions in Duke's South Carolina territories is consistent with resource planning principles required under South Carolina law.[8]

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[7] Given that the primary concern about carbon emissions is not a localized impact but their contribution to global warming, which has the potential to cause billions of dollars of damage to North Carolina, shifting carbon emissions across the state line would do nothing to provide the public health and welfare benefits for North Carolinians advanced by H.B. 951. Such carbon "leakage" is a well-known policy problem that can arise when greenhouse gas reduction measures in one jurisdiction simply shift carbon emissions to another location. (see, e.g., Carbon leakage - AR4 WGIII Chapter 11: Mitigation from a cross-sectoral perspective, available at https://archive.ipcc.ch/publications_and_data/ar4/wg3/en/ch11s11-7-2.html) For the same reasons, CPSA supports Duke's commitment, to the extent it relies on energy imported from outside its service territory, to import only carbon-free generation.

[8] *See generally* S.C. Code Ann. § 58-37-40.

CPSA also actively supports Duke's proposal to construct upgrades to address transmission constraints in the so-called "Red Zone," which comprises the most favorable areas of DEC and DEP's combined service territories for economically competitive solar development. This is discussed further in Section VIII.B below.

## II. Duke's modeling assumptions

Duke's Carbon Plan modeling relies on a number of assumptions and inputs that are unreasonable or unsupported. Some of these problematic assumptions have a major impact on the portfolios presented and the near-term Execution Plan and must be addressed by directing Duke to re-run its modeling and/or by including alternative portfolios that embody more reasonable assumptions. Other assumptions either do not have a significant impact on near-term portfolios and the Execution Plan, or there are insufficient facts to dictate a clear alternative. With respect to those assumptions, CPSA recommends that Duke be required to provide further substantiation or conduct a more rigorous analysis prior to filing an updated Carbon Plan in 2024.

### A. Duke's solar interconnection cap is unexplained and unsupported, increases costs, and makes compliance more uncertain.

In the Carbon Plan, Duke acknowledges that achieving the mandates of HB 951 will require accelerating the pace of interconnection for new generating resources.[9] Duke also claims that its proposed portfolios make aggressive assumptions about the pace of solar interconnection over the planning period.[10] In truth, however, Duke's Carbon Plan modeling severely limits the pace of solar interconnections over the next several years, even in the portfolio (P1) that leans most heavily on solar to achieve compliance by 2030. **This arbitrary and unsupported limit on solar additions is the single most salient issue affecting the timing and cost of compliance with the**

[9] Carbon Plan Appx. I p. 5.
[10] Id.

**H.B. 951 mandate.** But Duke has failed to provide a coherent explanation for this limitation, let alone empirical evidence to support it. This arbitrary limitation on solar interconnection rates, especially in the early years of the Carbon Plan, will make timely compliance with H.B. 951 much more difficult and will ultimately increase the cost of compliance to ratepayers.

While there are certainly limits to the amount of solar that Duke can interconnect each year, no one – not even Duke – knows what those limits are. Rather than draw highly conservative assumptions, Duke should approach that uncertainty the same way it approaches almost every other area of uncertainty in the Carbon Plan – by setting ambitious goals, doing the utmost to achieve them, and then making adjustments if those goals cannot be met.

In its Carbon Plan modeling, Duke limits the annual amount of solar allowed to interconnect annually (in MW) to the following amounts:[11]

| Portfolio | 2027 | 2028 | 2029 | 2030+ |
|---|---|---|---|---|
| **P1 (70% by 2030)** | 750 | 1050 | 1800 | 1800 |
| **P2-4 (70% by 2023/2034)** | 750 | 1050 | 1350 | 1350 |

No other resource in Duke's plan is subject to similar interconnection constraints.[12] For example, Duke assumes that up to <u>3000</u> MW of energy storage per year can be interconnected.[13] Moreover, in the case of both on-shore and off-shore wind, SMRs, and green hydrogen, Duke makes aggressive and arguably unrealistic assumptions about the timing and certainty of resource availability.

[11] Carbon Plan Appx. I p. 6 (Table I-2). The numbers in the table represent the amount of solar that can be interconnected by January 1 of the stated year.
[12] Some other resources, such as onshore wind and combined cycle gas turbines ("CC's"), are constrained in Duke's models. However, those constraints are based on the availability of the resource (or fuel, in the case of CC's), not on interconnection rates.
[13] Carbon Plan Ch. 2 p. 21.

1. Significance of the Solar Interconnection Cap

Of all the assumptions Duke makes in its modeling, this solar interconnection cap most strongly shapes the portfolios chosen by Duke's model. This is because solar is the cheapest, most certain, most widely available carbon-free energy resource available to Duke to meet the 2030 mandate.[14] And in the absence of an imposed interconnection constraint, Duke's model would almost certainly select solar to meet carbon-free energy needs through at least 2030, at a lower cost to ratepayers than offshore wind or SMRs.[15] Duke obliquely acknowledges that the interconnection cap drives the model, noting that the "total incremental quantities of solar achievable by 2030 were, in part, defined by the assumptions regarding the quantities of solar that can be interconnected each year."[16]

In modeling conducted by the Brattle Group ("Brattle") (discussed further in Section III below), Duke's solar interconnection cap reduces the amount of solar selected by the model for 2030 compliance by nearly half, from approximately 9500 MW in the unconstrained case to 5200 MW.[17] The solar limit forces the model to select more expensive wind resources (which may or may not be available) to meet the 70% carbon reduction mandate by 2030. As compared to the unconstrained case, this increases the total **annual** system cost of the portfolio by $900 million in 2030 and $800 million in 2032.

[14] Under even the most aggressive scenarios, small modular reactors will not be available in the Carolina until after 2030, and even then, will cost significantly more than solar. Onshore and offshore wind, even under the most aggressive projections, will be available in only limited amounts by 2030 and will also cost significantly more than solar.
[15] Gas-fired units would still be selected prior to 2030 to meet other resource needs that cannot be met by solar.
[16] Carbon Plan Appx. I p. 5.
[17] Brattle Report at 31. The 2030 compliance case with no solar interconnection constraint is represented by portfolio CPSA1; the constrained 2030 compliance case is portfolio CPSA2.

The same dynamic plays out in Duke's Carbon Plan portfolios. There, the solar interconnection cap means that 2030 compliance can only be achieved with the addition of 600 MW of onshore wind and 800 MW of offshore wind, both of which represent aggressive assumptions. Even if additional onshore and offshore wind resources are available by 2030, the solar interconnection cap increases the cost of 2030 compliance by approximately $900 million, primarily because of the higher cost of offshore wind relative to solar.[18] Because it forces the selection of other resources that may or may not be available by 2030 or 2032, the solar interconnection cap increases execution risk of all the portfolios in the plan.

2. <u>Duke has not justified the solar interconnection cap.</u>

Duke asserts that there are "'real-world' limitations on the ability of Duke Energy (or any utility or transmission operator) to interconnect projects,"[19] but does not attempt to justify, explain in detail, or provide any evidence for the specific interconnection limits assumed in the Carbon Plan. Duke cites the long lead time required to construct individual transmission upgrades but fails to explain how this translates into the aggregate annual limitations assumed in the Plan.[20]

During the stakeholder process, Duke cited the difficulty of coordinating line outages required for transmission upgrades as a key driver of annual solar interconnection limits, although it did not provide any analysis to support a linkage between outage coordination and its proposed annual limits.[21] However, Duke appears to have abandoned that justification as it does not appear in the Carbon Plan and is not mentioned in Duke's responses to data requests.

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[18] *Id.* Note that the cost impact is likely to be considerably higher, as this $400 million estimate is based on Brattle's conservative (*i.e.*, high) solar cost of $65/MWh, which assumes limited declines in the cost of solar modules.
[19] Carbon Plan Appx. I p. 4.
[20] Carbon Plan Appx. I p. 5.
[21] *See, e.g.*, Carolinas Carbon Plan Technical Subgroup #1 Stakeholder Meeting, slide 15 (February 18, 2022), available at https://desitecoreprod-cd.azureedge.net/_/media/pdfs/our-company/carolinas-carbon-plan/subgroup-1-slide-deck.pdf?la=en&rev=df0f840510894d58a1c8e5da6a0bbdaa.

In response to data requests, Duke acknowledges that "[t]he Companies do not have specific underlying calculations for the annual selection constraints," and that the constraints "are based on engineering judgement and transmission planning experience."[22] The factors Duke cites include:

- Transmission expansion needs and the time to construct new transmission infrastructure to accommodate increasing levels of renewables and other resources;
- Increasingly complex interconnections as solar facilities are located farther from existing infrastructure;
- Unknown future solar project size and impacts on interconnections;
- Finite interconnection resources allocated to non-solar resources;
- The Companies' historic annual interconnection rates, which Duke states is "not the primary determining factor in developing the solar interconnection capability in the Carbon Plan."[23]

Most of these factors speak to uncertainty about the rate of future interconnections, rather than clear limitations. In conceding the lack of any underlying calculations, Duke is acknowledging that it has simply picked an attractive number, without consulting any external data sources or conducting a rigorous analysis.[24]

As discussed, the solar interconnection cap is arguably the most important assumption in Duke's entire modeling exercise. It drives every portfolio and has huge impacts on customer cost and timely compliance with the 70% mandate. Duke appears to expect this Commission to rule on what is arguably the most consequential issue in this proceeding on the basis of Duke's internal

[22] See Exhibit B (Response to NCSEA-SACE DR 3-30).
[23] *Id.*; Exhibit B (response to CPSA DR 1-8).
[24] It should be noted that the principal consequence of Duke's arbitrary solar cap is to force into the P1 2030 portfolio (on an unrealistic, aggressive timeline) 800 MW of much more expensive offshore wind, which conveniently matches the amount of Duke's recent offshore lease award.

engineering judgement, for which they cannot or will not produce empirical justification – despite having years to do so since this issue was litigated in the 2020 IRP proceeding.[25]

In asserting that a solar interconnection rate of 1,800 MW per year presents extremely high execution risk, Duke states that "the 1,800 MW of solar projected be interconnected in 2028 in the 70% by 2030 case would surpass the total amount of solar interconnected since records began in the states of Louisiana, Mississippi, Alabama and Tennessee combined."[26] This is not a valid comparison because, unlike North Carolina, those states have not adopted policies to encourage solar development. In other words, the low rates of solar interconnection in those states have nothing to do with technical constraints on the pace of solar interconnections.[27]

Moreover, Duke's argument does nothing to justify its far lower assumed solar interconnection rates in 2026 and 2027 (750 MW and 1050 MW, respectively). These unreasonably low values assume that despite having implemented sweeping reforms to the interconnection process, having years in which to improve its interconnection efforts, and interconnecting a smaller number of larger projects than in past years, Duke can only marginally improve its historic performance in the area most important to successful implementation of H.B. 951.

A better comparison would be to other states that have, like North Carolina and South Carolina, significant experience with the interconnection and deployment of solar resources. As noted in Section II.4 below, numerous states have successfully interconnected and installed solar and wind at rates that are comparable to or exceed Duke's proposed solar interconnection cap. In

[25] *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.
[26] Carbon Plan Appx. I p. 7-8.
[27] It should also be noted that Duke's service territories span two states, not one.

comparison to these deployment figures, Duke's assumption that it will be able to interconnect no more than 750 MW of solar in 2026 is far too conservative.

3. Interconnection rates are likely to improve in the near term.

As stated, Duke assumes in each of its portfolios that no more than 750 MW of solar can be interconnected in any year from 2022 to 2026, and that interconnections will rise only incrementally (to 1050 MW) in 2027. This is approximately the same amount of solar that Duke reports having interconnected in 2015 and 2017.[28] In other words, Duke is assuming that it will go ten years without making any improvements in its ability to interconnect new generation to its system. However, there are several reasons to expect that solar interconnection rates will increase substantially over past rates, even without any deliberate action by Duke to improve its performance.

First, Duke will be called on to interconnect far fewer projects than it has in the past, meaning that far fewer actual studies will be required. As discussed in the Carbon Plan, 95% of the solar projects already interconnected to Duke's system are small distribution-interconnected projects (most of which are 5 MW or 2 MW standard-offer projects).[29] By contrast, utility-scale solar procured under the Carbon Plan will consist entirely of large transmission-interconnected projects, meaning that far fewer studies will need to be completed.[30] Duke acknowledges that this change is likely to improve interconnection rates, noting that "The total amount of annual MW for projects that can be completed will be highly dependent on the size of the projects that are procured."[31] Duke's ability to procure projects over 80 MW under the Utility Ownership Track

[28] Carbon Plan Appx. I p. 5; see also Duke Energy – Carolinas Carbon Plan Stakeholder Meeting 1 (Jan. 25, 2022, 2022), slide 60, available at https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=ffaa74fc-bcdf-4cb1-a298-8b6c473e86e4.
[29] Carbon Plan Ch. I p. 1-2.
[30] Id.
[31] Id. p. 4.



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will only amplify this phenomenon, further increasing interconnection rates. Duke acknowledges this, noting that "If the size of the projects procured trends higher than in the past (e.g., 200 to 300 MW projects or larger), then the Companies will be more likely to exceed the annual targeted amounts."[32]

The implementation of Queue Reform is also likely to accelerate the rate of interconnection. Duke persuaded other stakeholders and the Commission to support Queue Reform on the promise that "[t]ransitioning the generator interconnection process to a more structured and definitive 'first ready, first served' cluster study process is one of the necessary steps along Duke's path towards achieving broader renewable energy and other policy objectives for the benefit of customers,"[33] and now claims that Queue Reform "has substantially improved the efficiency of the interconnection study process."[34] Duke also cites a number of other measures it is now taking to improve process efficiency and reduce interconnection timelines.[35] These many claims of process improvement are completely inconsistent with Duke's assumption that no improvements in the rate of solar interconnection will occur until 2027.

Also relevant to this question are the "Red Zone" upgrades that Duke has proposed to the North Carolina Transmission Planning Collaborative ("TPC").[36] In filings with the TPC, Duke projects that those upgrades will be online by the end of 2026.[37] If those upgrades are ultimately approved by the TPC and this Commission, they will facilitate the interconnection of multiple

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[32] Id.
[33] NCUC Docket No. E-100, Sub 101, Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Queue Reform Proposal at p. 3 (May 15, 2020),
[34] Carbon Plan Appx. I p. 8.
[35] Id.
[36] CPSA supports those proposed upgrades, which are discussed further below.
[37] NCTPC 2021 Collaborative Transmission Plan Update (June 2022), available at http://www.nctpc.org/nctpc/document/TAG/2022-06-27/M_Mat/2021_Collaborative_Transmission_Plan_MidYear%20Update-DRAFT%20-6-21-2022.pdf

gigawatts of additional solar generation. This will significantly accelerate the interconnection of projects in the Red Zone and provide additional reason to expect that solar interconnection rates will increase significantly in the near term.

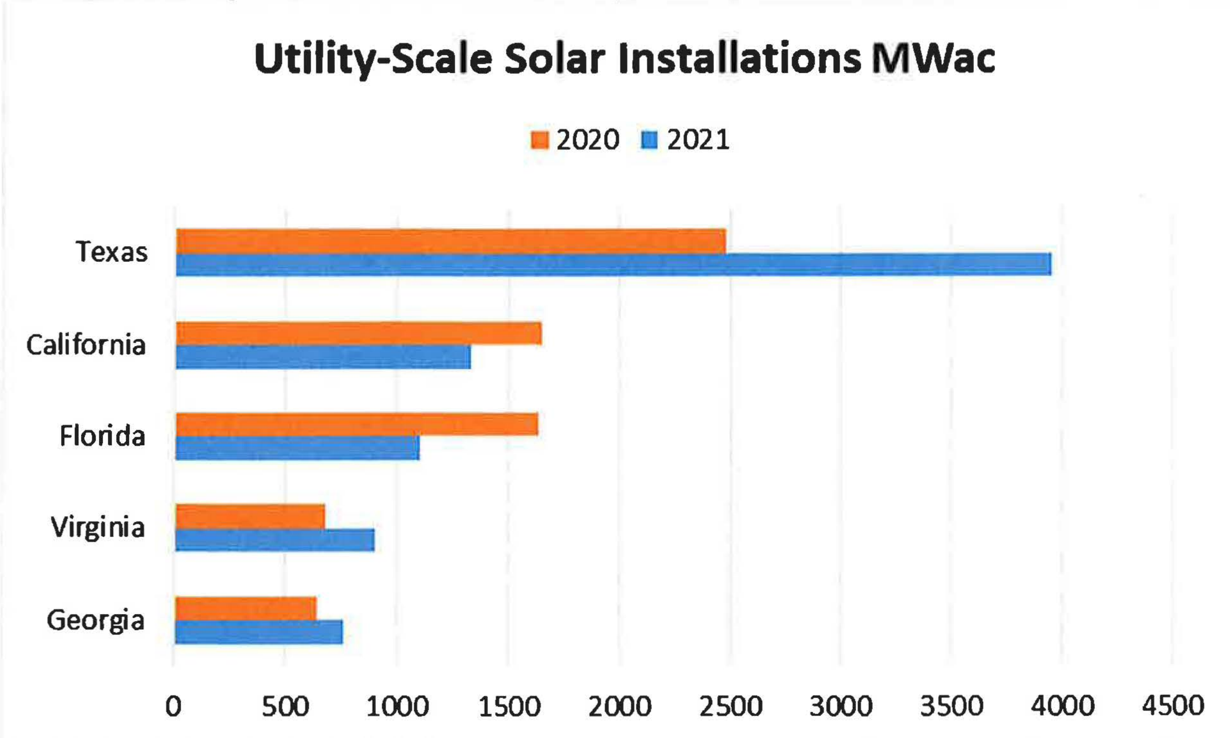
4. Other states are achieving higher interconnection rates.

Duke's proposed solar caps are significantly lower than what peer states are achieving. For example, according to the U.S. Energy Information Administration ("EIA"), multiple states are already interconnecting solar at volumes comparable to or greater than Duke's proposed solar cap. In 2021, utility-scale solar installations totaled approximately 3900 MW in Texas, 1330 MW in California, 1100 MW in Florida, 900 MW in Virginia, and 760 MW in Georgia. Nevada, a state with 34% of North Carolina's net summer generation capacity and 26% of North Carolina's annual electricity sales, interconnected 611 MW of utility-scale solar in 2021.[38]

In 2020, a year marked by extensive disruptions related to the COVID-19 pandemic, several states were similarly able to interconnect and install utility-scale solar volumes beyond Duke's proposed caps, including Texas at approximately 2480 MW, California at 1650 MW, and Florida at 1640 MW. In that same year, Virginia interconnected 675 MW, and Georgia installed 637 MW – more than 85% of the cap that Duke proposes for the entirety of the combined DEP-DEC system as late as 2026.[39]

[38] EIA Electric Power Monthly, Table 6.2B, available at https://www.eia.gov/electricity/monthly/.
[39] Id.

Figure 1 - 2021 and 2022 Utility-Scale Solar Installations – EIA




Wind energy interconnections, which require similar interconnection facilities and upgrades as utility-scale solar, should also be considered in this context. In 2021, wind installation volumes totaled approximately 4435 MW in Texas, 1700 MW in New Mexico, 1225 MW in Kansas, and 1100 MW in Oklahoma. Other states accomplished similar volumes in 2020, including 1500 MW in Iowa, and 1060 MW in Wyoming.[40]

Several of these states were able to accomplish these interconnection volumes despite having substantially smaller electrical power systems compared to North Carolina's. For example, in terms of annual electricity sales as a percent of North Carolina's, Wyoming is 11%, New Mexico is 19%, Kansas in 28%, Iowa is 36%, and Oklahoma is 47%. As another measure, in terms of total

[40] EIA Electric Power Monthly, Table 6.2B, available at https://www.eia.gov/electricity/monthly/.

net summer generation capacity as a share of North Carolina's, Wyoming is 27%, New Mexico is 26%, Kansas is 48%, Iowa is 61%, and Oklahoma is 27%.[41]

Meanwhile, many states and utilities are committed to resource plans and procurements that entail significantly higher annual renewable capacity installations than Duke is claiming is feasible for its system. These are discussed in Section VI below and are documented in the comments of the Carolinas Clean Energy Business Association ("CCEBA") filed today.

5. Duke's approach to uncertainty about solar interconnections

Duke handles uncertainty about solar interconnections very differently than it handles other kinds of uncertainty in the Carbon Plan. In almost every other instance, Duke makes the most aggressive assumptions it can, and relies on the ability to "check and adjust" the plan if those assumptions do not bear out.[42] For example, half of Duke's proposed portfolios assume that SMRs – a resource that has **never** been deployed at commercial scale in the United States – will be online by 2034, and all of the proposed portfolios assume that SMRs will be available in 2035.[43] Duke acknowledges that its assumptions about the availability of offshore wind are "extremely aggressive."[44] And Duke's modeling of green hydrogen relies on a U.S. Department of Energy ("DOE") cost assumption[45] that DOE itself has described as "a different kind of moonshot."[46]

[41] EIA State Electricity Profiles, available at https://www.eia.gov/electricity/state/.
[42] Duke takes a (self-described) "aggressive" approach to assumptions on issues including deployment of SMRs (Ch. 4 p. 19), availability of onshore wind (Ch. 4 p. 20), availability of offshore wind (Ch. 4 p. 6), implementing consolidated system operations (Ch. 4 p. 27-28), energy efficiency savings (Appx. G p. 5, Ch. 4 p. 29), demand response programs (Appx. E p. 23), development of gas-capable CT units (Ch. 4 p. 14), and the production cost of green hydrogen (Appx. O p. 7).
[43] Carbon Plan Executive Summary p. 14.
[44] Carbon Plan Ch. 4 p. 6.
[45] Carbon Plan Appx. O, p. 7 and n. 14.
[46] U.S. Department of Energy, Energy Earthshots Initiative, https://www.energy.gov/policy/energy-earthshots-initiative

But with respect to near-term solar interconnection rates, Duke instead takes the most conservative approach possible, by assuming in every portfolio that there will be no improvement over historic interconnection rates until 2027. Amazingly, in most of its portfolios (P2-P4) Duke assumes that it will **never** be able to interconnect more than 1350 MW of solar in a single year. As stated, this assumption fundamentally reshapes these plans, requiring Duke to hit much more aggressive interconnection targets in later years and dramatically increasing cost to ratepayers if those targets cannot be hit (because more costly resources are selected).

Rather than accept Duke's pessimistic prediction of its own ability to improve interconnection rates by 2026, the Commission should direct Duke to take the same approach to solar interconnection that Duke takes to other uncertainties – start with ambitious assumptions, which can then be adjusted if they prove unachievable. In practical terms, this would mean procuring more solar for the early years of the plan (2026 and 2027) and adjusting to the portfolio if those projects are not on track for interconnection in the target years. To that end, CPSA is proposing that the Carbon Plan include two additional portfolios reflecting higher solar interconnection rates (1500 MW) in 2026 and 2027, followed by Duke's own high solar cap assumption of 1800 MW per year in all future years.[47] As stated elsewhere, the Execution Plan should be modified to support these portfolios. In the event that the assumed levels of solar interconnections prove not to be achievable, the two other portfolios CPSA proposes for inclusion in the Carbon Plan provide alternative pathways for compliance by 2030 or 2032, albeit at higher cost because they require the model to select higher-cost resources to make up the gap in carbon-free generation.[48] These portfolios and changes to the Execution Plan proposed by CPSA are

[47] *See* Section III.C below.
[48] CPSA also recommends that for illustrative purposes the Carbon Plan include a fifth portfolio (CPSA1) that places no cap on solar additions and achieves compliance with the 70% mandate in 2030. This least-

discussed in Sections III.C and V, below. Taking CPSA's proposed approach would create more compliance options for Duke and would not interfere with execution of other portfolios if annual solar interconnection rates are lower than expected.

The total volume of solar that will ultimately be required for compliance with H.B. 951 will undoubtedly exceed the amount that could be procured over the next three years, even in the most aggressive scenarios. Because we know that solar will ultimately be needed, the only conceivable reason to wait to procure and interconnect solar (as called for under Duke's portfolios) is the assumption that the cost of solar will decrease significantly over the planning period. But as discussed in Section V below, this assumption is not reasonable and it is not prudent to delay significant procurements of solar on this basis.

Based on its unsupported assumptions about solar interconnection rate in the years beginning in 2026, Duke then compounds its error by proposing corresponding limits in solar procurements in the years beginning in 2022. The flaws in this approach are discussed in Section V below, but perhaps the most egregious is that it ensures that Duke will not even have the opportunity to improve upon its claimed interconnection limits.

6. <u>CPSA's proposed portfolios balance benefits and risks of higher interconnection rates.</u>

As discussed, Brattle's modeling demonstrates that the least cost plan for achieving the 70% carbon reduction mandate in 2030 (portfolio CPSA1) includes 9,500 MW of solar additions by that year. However, as discussed in Section IV.C below, this would require average annual solar additions of 1,900 MW. Although this rate of interconnections is likely achievable with additional process improvements and a focus on proactive transmission planning, CPSA

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cost option provides a usual reference point and underscores the point that maximizing the rate of solar additions is in the best interest of ratepayers. However, because this portfolio would require a rate of annual solar additions that presents significant execution risk, CPSA does not request that the near-term Execution Plan support this portfolio.

recognizes that it poses a significantly higher execution risk than portfolios that assume a more modest rate of interconnection. Accordingly, CPSA is not requesting that the Execution Plan be modified to support the CPSA1 portfolio. Instead, CPSA (as discussed below) is proposing a set of portfolios that incorporate moderate annual interconnection limits that in CPSA's view are achievable. These annual interconnection limits exceed the limits proposed by Duke in the P1 portfolio only in the first two years of the portfolio, 2026 and 2027. However, as discussed below, they significantly reduce costs and increase the prospects for timely compliance with the 70% mandate.

| Year | Duke P1 Cap (MW) | Duke P2-P4 Cap (MW) | CPSA Proposed Cap (MW)[49] |
|---|---|---|---|
| 2026 | 750 | 750 | 1500 |
| 2027 | 1150 | 1150 | 1500 |
| 2028 | 1800 | 1350 | 1800 |
| 2029 | 1800 | 1350 | 1800 |
| 2030 | 1800 | 1350 | 1800 |
| 2031 | 1800 | 1350 | 1800 |
| 2032 | 1800 | 1350 | 1800 |

These interconnection caps, and the portfolios they result in, balance the execution risk of moderate interconnection rates against the cost advantages of portfolios with more aggressive solar additions.

7. The Commission should require progress and accountability on interconnection rates.

CPSA appreciates Duke's efforts (as described in the Carbon Plan) to increase the efficiency of its interconnection process. However, given the critical significance of this issue to least-cost compliance with H.B. 951, CPSA does not believe that Duke should be left to address this issue entirely its own. Rather, the Commission should require Duke to commission a third

[49] End of year MW numbers are reported.

party, assisted by an independent technical advisory committee, 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. The results of this study should be used to inform future Carbon Plan revisions.

Duke should also be required to provide a report to the Commission, at least annually, on the steps it has taken and plans to take to expedite the interconnection process; and to provide clear quantitative metrics of its progress on improving interconnection rates.

### B. Energy storage

Duke's portfolios add between 1.7 and 2.2 GW of battery storage to meet the 70% decarbonization mandate. Duke also adds 1.7 GW of additional capacity to its Bad Creek pumped storage facility by 2033 in all portfolios. In its execution plan, Duke proposes to procure 1,000 MW of standalone storage and 600 MW of storage paired with solar. However, Duke provides no information on their modeling results when it comes to the levels of economic paired versus standalone storage built across scenarios. Rather, Duke simply puts forward a seemingly arbitrary 600 MW of paired storage in its Execution Plan, along with 1,000 MW of standalone storage.

This result is counterintuitive, because battery storage paired with solar enjoys significant economic advantages over standalone storage. First, paired resources would benefit from shared interconnection facilities and upgrades, which (given the high interconnection costs assumed by Duke in the Carbon Plan) should lead to material efficiencies.[50] Paired resources would also see cost efficiencies due to independent ownership, which would result in 45% of the capacity accruing Investment Tax Credit benefits upfront as opposed to being normalized over the asset lifetimes for

[50] For example, if it is assumed that paired facilities avoid the solar interconnection costs for the paired storage MWs (i.e., 50% storage pairing means 50% of solar interconnection costs are avoided), then this is effectively a minimum savings of $0.17 (2022$) for each MW of storage paired with solar.

utility-owned assets. For example, assuming a 20-year asset lifetime, the capital-related costs of an IPP-owned asset (return on and of capital) are over 15% below those of a utility-owned asset strictly due to accrual of tax benefits upfront. Even assuming that Duke owns 55% of solar plus storage facilities, this translates into nearly 7% lower capital costs for paired storage facilities versus standalone facilities.

There are additional advantages to paired storage facilities that one would expect to further accentuate their competitive advantage over standalone facilities, including lower development expenses (only one site, permitting process, IX process, etc.), mitigated solar energy curtailment (which could be as high as 5%-10%, not to mention clipping capture, in cases where resources are DC-coupled). Additional deployment of solar plus storage facilities would have collateral benefits, such as potentially relieving interconnection constraints.

It appears that Duke made several modeling errors that biased its model towards selection of less economic standalone storage resources. First, Duke failed to capture the full range of cost efficiencies that hybrid storage resources benefit from in comparison to standalone resources. While Duke did capture the interconnection cost efficiencies associated with sharing a single point of interconnection, they failed to capture the ITC benefits of hybrid resources, whereby these resources would benefit from 45% IPP ownership in which cases they would accrue all tax benefits upfront as opposed to accruing normalized benefits over the project lifetime, and also development cost efficiencies, whereby the cost of developing a single hybrid facility is approximately half of the cost of developing two standalone facilities.

Furthermore, Duke erroneously assumes that in the case of DC-tied hybrid solar and storage facilities, the storage system can only charge from the solar generating facility.[51] In fact, storage can charge from the grid if needed and only incurs minor costs to doing so in the form of incremental forfeiture of ITC benefits, and thus would economically do so during high-value events where it could not charge from the hybrid solar facility.[52]

Furthermore, Duke modelled an incomplete set of storage configurations – they only allowed for 2-hour, 50% storage capacity as a share of solar capacity and 4-hour, 25% storage capacity as a share of solar capacity scenarios. Duke should be required to model a more complete set of scenarios, allowing both combinations of duration and storage capacity for a total of four scenarios, which is what Brattle did in its modeling. In aggregate, these changes would have the effect of more accurately representing the advantages of hybrid storage facilities over standalone storage facilities, and as demonstrated by the Brattle modeling, this would lead to the more economic outcome of prioritizing hybrid over standalone storage facilities.

Duke's failure to accurately model hybrid storage facilities should be rectified as discussed in Section II below. Duke should be required to update all modeling for these critical assumptions, and insofar as its model continues to select standalone storage, which has no basis in the modeling given its higher costs, Duke should clearly document why the model is doing so.

<u>Contract structures for solar plus storage facilities</u>

Duke did not include solar plus storage resources in its 2022 procurement of solar resources, because of the short timeframe available to set up the 2022 procurement, and the

[51] Carbon Plan Appendix E, Page 33: "Standalone storage resources can charge from and dispatch to the grid, <u>whereas storage paired with solar is assumed in the Carbon Plan to be DC-tied, and thus, only able to charge from the solar facility</u> and dispatch to the grid when solar is not already using all of the interconnection limit." (emphasis added)

[52] This issue is further discussed in the comments of CCEBA, whose comments and recommendations on this issue CPSA fully supports.

complexity of establishing evaluation criteria for solar plus storage projects.[53] In recognition of that fact, and the urgency of moving forward to establish a procurement structure for 2022, CPSA supported that decision.

CPSA strongly recommends that future solar procurements call for significant amounts of solar plus storage (or "hybrid") facilities. However, existing contracting and procurement structures are not well-suited to procurement of hybrid resources, primarily because they do not capture the full resource value of hybrid facilities (and do not appropriately compensate hybrid projects for that value).

This issue is discussed in more detail in the comments of CCEBA, whose comments and recommendations on this issue CPSA fully supports.

### C. Duke's Cost assumptions

There are several issues with Duke's Carbon Plan cost assumptions. Duke's capital cost assumptions for new resources in the Carbon Plan are based on a variety of sources, many of them proprietary, and most of them based on 2021 inputs.[54] A table summarizing the comparisons between Brattle's and Duke's modeling assumptions is included as Exhibit C.

#### 1. Capital costs

Because of the significant changes in costs since 2021, and for purposes of consistency, Brattle Group used capital cost assumptions based on 2022 NREL ATB cost projects. For solar, onshore wind, and gas combined cycle units, Brattle used the Conservative (*i.e.*, high) cost projections.

[53] *Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Response to Commission Order Requesting Answers on 2022 SP Program Petition*, Docket Nos. E-2, Sub 1297 and E-7, Sub 1268 (Apr. 29, 2022) at 1-2.

[54] See Carbon Plan Ch. 2 p. 17 (solar cost assumptions), 18 (solar plus storage)

Notably, this resulted in higher solar cost assumptions than Duke, which used a modified capital cost slightly lower than the National Renewable Energy Laboratory ("NREL") 2021 ATB moderate scenario projection.[55] The observed long-term trend in declining solar costs has been interrupted in the last few years due to factors including trade disputes, supply chain disruptions, labor market disruptions, and inflation; and it is unclear whether and when that trend will resume. In addition, non-capital costs of solar development (e.g. labor, land costs) are trending upward. Consequently, it is prudent to use more conservative cost curves for solar. Brattle's use of more conservative cost assumptions for solar probably overstates the revenue requirements of CPSA's portfolios (which rely more heavily on solar for carbon-free generation) relative to Duke's portfolios, but also ensures that Brattle's results are robust across a range of possible future solar costs.

Duke's capital cost assumptions for new nuclear units are also unreasonable. For its "high" nuclear cost scenario, Duke relies on EIA's 2022 "base case" cost forecast.[56] In comparison, Lazard's base case nuclear cost estimate is consistent with EIA's base case, while Lazard's "high" nuclear cost scenario is 70% higher than their base case.[57] Duke's use of the EIA base case forecast to represent Duke's "high" nuclear forecast is unreasonable and has the effect of inappropriately decreasing the modeled cost of nuclear.

Duke's use of depressed nuclear cost estimates is inappropriate because it fails to adequately consider the substantial cost and development risks inherent in the development and construction of new nuclear facilities. The use of unproven technologies such as SMRs can present availability and delay risks given the limited number of vendors and available models and

[55] Carbon Plan Ch. 2 p. 17.
[56] Carbon Plan Ch. 2, p. 21.
[57] *See*, https://www.lazard.com/media/451905/lazards-levelized-cost-of-energy-version-150-vf.pdf

associated technology.[58] Nuclear reactors may also face permitting delays related to required Nuclear Regulatory Commission ("NRC") approvals if new reactor models have not yet obtained such approvals, and fuel production, transport, and storage may present both delay and cost risks. Duke's timeline for obtaining a CPCN suggests that the NCUC would be asked to approve a CPCN based on assumptions of technology demonstration, fuel supply availability, cost, timing, federal permitting, and associated workforce and supply chain considerations that may not yet be verifiable. Duke's capital cost sensitivity analysis states that nuclear presents the second highest capital cost risk in all four Carbon Plan scenarios, up to $4 billion, and the factors described above help explain why the cost risk for these nuclear facilities is so high.[59]

Historical delays and cost overruns associated with the development and construction of nuclear facilities are well documented. Georgia Power's Vogtle nuclear plant is now projected to cost over $30 billion, more than double its initial estimate, and is more than seven years behind schedule.[60] In South Carolina, SCANA spent $9 billion for the partial construction of the V.C. Summer nuclear plant before cancelling construction, leaving ratepayers with the expense of a plant that will never generate a single kilowatt-hour.[61] Duke's cancellation of the Lee Nuclear Facility also resulted in stranded construction costs that the North Carolina and South Carolina utility commissions were required to allocate. Although development and construction lessons learned from these examples can be applied to future projects, compliance with the requirements of H.B. 951 should not rest on the successful development and construction of new nuclear facilities.

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58 Carbon Plan Appendix L, Table L-5.
59 Carbon Plan Appendix E, Figures E-18 through E-21.
60 *See* Associated Press, "Georgia nuclear plant's cost now forecast to top $30 billion" (May 8, 2022).
61 *See* The Wall Street Journal, "The $4.7 Billion Nuclear Bill That No One Wants to Pay" (August 25, 2018), https://www.wsj.com/articles/the-4-7-billion-nuclear-bill-that-no-one-wants-to-pay-1535194801 (last accessed September 11, 2018).

Because Brattle Group did not include new nuclear as a selectable resource in their 2030 and 2032 compliance portfolios, Duke's unreasonable cost assumptions as to SMRs do not impact CPSA's proposed portfolios, or the resource additions in the near-term Execution Plan. However, Duke's cost assumptions do impact the comparative evaluation of portfolio cost, and Duke should therefore be required to re-model its portfolios with more reasonable nuclear cost assumptions.

2. Transmission costs

Brattle also used different transmission cost assumptions than Duke. Based on the Offshore Wind Study conducted by the Southeast Wind Coalition[62], which draws on the NCTPC Offshore Wind study, Brattle assumed inflation-adjusted upgrade costs of $.441/W for offshore wind in 2030 – in Real 2022 dollars, this is substantially lower than Duke's assumption for the first 800 MW tranche and around half of the cost assumed by Duke for the second 800 MW tranche.[63] For all other resources, Brattle assumed transmission costs of $.10/W. Battery storage paired with solar was assumed to have no additional network upgrade costs beyond those assigned to the solar facility, which was also assumed by Duke.

## II. Brattle's Modeling of Carbon Plan Portfolios

CPSA has retained the Brattle Group, a well-respected international consulting group and thought leader on issues related to resource planning and economics, to help understand and critique Duke's Carbon Plan modeling and to conduct modeling of additional options for achieving the carbon reductions required by H.B. 951. A report detailing Brattle's modeling approach and results is included as Attachment A.

Brattle conducted preliminary modeling in March 2022, the results of which were shared with Duke and with other stakeholders at the March 22 stakeholder meeting facilitated by the Great

[62] https://e2.org/wp-content/uploads/2022/01/NC_Offshore_Wind_Cost-Benefit_Analysis_FINAL.pdf
[63] Carbon Plan Ch. 2 p. 23.

Plains Institute. After Duke made its EnCompass data sets available to stakeholders (and based on discovery conducted by CPSA and other parties), Brattle revised its modeling to better match Duke's inputs and assumptions.

The results of Brattle's modeling include five alternative resource portfolios, CPSA1-5, that represent alternative pathways to achieve compliance with the 70% carbon reduction mandate in 2030 and 2032, respectively. These portfolios are discussed in greater detail in Section III.C below.

Brattle conducted its resource plan modeling using GridSIM, a capacity expansion modeling tool that, like EnCompass, identifies the least-cost portfolio of resources to maintain system reliability, meet Carbon Plan GHG limits, and meet hourly demand. GridSIM was designed to simulate highly decarbonized systems and has been used by utilities and grid operators throughout North America. Brattle has relied on GridSIM in engagements for state governments, RTOs, electric utilities, generation and storage developers, investors, and other clients including the U.S. Department of Energy and the Electric Power Research Institute.[64]

Duke's EnCompass tool uses a different modeling approach that optimizes unit commitment decisions and simulates dispatch of resources chronologically throughout the year. Differences in modeling frameworks may result in a slightly different resource mix for compliance with the 2030 mandate, but the models themselves are likely to be less consequential than the input assumptions that go into them.

Because of the focus on compliance with the 70% carbon reduction mandate and the near-term Execution Plan, Brattle conducted modeling only through 2035, rather than 2050 (as Duke's

[64] More information about GridSIM and recent applications is available at https://www.brattle.com/practices/electricity-wholesale-markets-planning/electricity-market-modeling/gridsim/.

modeling does). This avoids having to rely on (or dispute) Duke's highly speculative assumptions regarding advanced nuclear reactors and green hydrogen. Brattle also focused its modeling on 2030 and 2032 compliance scenarios, and therefore did not include SMRs as a selectable resource because even Duke's aggressive assumptions about SMRs (further discussed in Section IV.C below) do not contemplate their availability before 2034.

This also means, however, that while Brattle's modeling generally concurs that Duke's proposed gas additions represent least-cost resources for 2030 compliance, GridSIM does not address the question of whether those resources will also be least-cost for achieving the 2050 net zero mandate.

Although Brattle used GridSim instead of EnCompass, Brattle attempted to replicate Duke's modeling assumptions and inputs, except in a limited number of instances where Brattle concluded that Duke's assumptions were inappropriate or unreasonable. Brattle departed from Duke's assumptions and inputs on a small number of issues, most of which are discussed in Section II and/or described in Exhibit C.

Brattle's modeling fully accounted for system reliability concerns. Brattle's capacity expansion modeling primarily meets resource adequacy requirements through the implementation of a 17% resource margin requirement, equivalent to the level that Duke uses from its 2020 Resource Adequacy Study. To meet this, Brattle attributes resources with the same resource adequacy value as does Duke, with the exception of solar, where they use a flat 2% ELCC, which is relatively conservative compared to what Duke uses in its modeling. Brattle's modeling also ensures system operability in terms of variable and duration-limited resources vis-à-vis demand, by modeling forty-nine representative days that capture a wide range of system conditions.

It is worth noting that Duke, in its modeling, also tested whether the resource mix "as-found" resulting from its EnCompass modeling met system reliability metrics through analysis in SERVM, a tailor-made tool for assessing system reliability. Duke compared the LOLE in scenarios P1-P4 to a Reliability Metric Threshold – effectively, an 'islanded' LOLE of 0.253, which it determine to be equivalent to an 'interconnected' LOLE of 0.1 days/year.[65] Duke documents how all scenarios modelled (P1-P4) see a LOLE that is substantially below their Reliability Metric Threshold in both 2030 and 2035, and that P1 has the lowest LOLE, at a level less than one fifth of said threshold in 2030 and 2035.[66]

Based on these factors—*i.e.,* that Brattle modelled the same reserve margin as Duke; that Brattle modelled granular system operations across diverse conditions; and that Brattle's modelled portfolios have a relatively large amount of solar compared to most of Duke's scenarios, and that Duke's scenarios saw a **positive** correlation between the level of solar and the level of reliability—it can be surmised that the scenarios modelled by Brattle would be similarly reliable. Nonetheless, upon adopting these scenarios, Duke should continue to run its own fundamental reliability modeling, subjecting them to the same LOLE analysis as done for the scenarios that it modelled as part of the Carbon Plan.

## III. Duke's Carbon Plan Portfolios

In the Carbon Plan, Duke presents four portfolios (P1 through P4). As discussed elsewhere, CPSA believes that: (i) Portfolio P1 should be replaced with two variations – one that is more conservative with respect to the pace of solar additions (CPSA2) and one that is somewhat more aggressive (CPSA3); (ii) Portfolio P2 should be replaced with CPSA4, which accepts Duke's low solar cap assumption but reflects Brattle's modeling results; (iii) an additional portfolio (CPSA5)

[65] Carbon Plan Appx. E, p. 62-64
[66] Carbon Plan Appx. E, Table E-58 & E-59

should be included that achieves compliance with the 70% reduction mandate by 2032 with less constrained solar additions than proposed by Duke; and (iv) Portfolios P3 and P4 are legally inconsistent with H.B. 951 and should be removed from the Carbon Plan.

There are two reasons for these proposed changes. First, the solar interconnection cap that drives Duke's portfolios is not sufficiently justified, increases costs to ratepayers, and needlessly delays compliance with the 70% mandate past 2030. Second, H.B. 951 does not permit Duke to delay compliance with the 70% carbon reduction mandate past 2032 solely because it includes in its resource plan a nuclear or wind unit that cannot be developed before 2032.

### A. The solar interconnection cap drives up costs and delays compliance.

As discussed in Section I.A above, Duke's assumption about its annual solar interconnection cap is by far the most important factor shaping its proposed portfolios, because solar is a mature, widely available, and least-cost carbon-free resource for Duke's system. Although solar does not obviate the need for all other resources, Duke's limit on incremental solar will either force the Carbon Plan model to invest in higher-cost resources or push back the date in which 70% reduction is achieved (or both).[67] As discussed below, CPSA has proposed four portfolios (two that achieve compliance in 2030 and two that do it in 2032) with moderately more aggressive interconnection limits. Based on Brattle's modeling, these portfolios are lower cost than Duke's P1 and P2 portfolios. Because P1 and P2 do not represent least-cost portfolios for

[67] Brattle Report at 7.

achieving compliance with H.B. 951 requirements, they should be replaced in the Carbon Plan by CPSA's portfolios (CPSA2 – CPSA5).

### B. H.B. 951 does not permit compliance to be delayed past 2032 in the manner proposed by Duke.

An important legal issue the Commission must resolve in considering the parties' proposed portfolios is whether, and under what circumstances, the Commission may permit Duke to delay achievement of the 70% carbon reduction mandate past 2030. H.B. 951 requires the Commission to "take all reasonable steps" to achieve a 70% reduction of carbon emission by 2030, but gives the Commission "discretion to determine optimal timing and generation and resource-mix to achieve the least cost path to compliance with the authorized carbon reduction goals[.]"[68] This includes:

> discretion in achieving the authorized carbon reduction goals by the dates specified in order to allow for implementation of solutions that would have a more significant and material impact on carbon reduction; provided, however, the Commission shall not exceed the dates specified to achieve the authorized carbon reduction goals by more than two years, except in the event the Commission authorizes construction of a nuclear facility or wind energy facility that would require additional time for completion due to technical, legal, logistical, or other factors beyond the control of the electric public utility, or in the event necessary to maintain the adequacy and reliability of the existing grid.[69]

This language is not a model of clarity, but what is clear is that delays past 2032 are not permitted, with two exceptions: (1) where it is necessary to maintain resource adequacy and reliability; and (2) where the Commission ***authorizes construction*** of a nuclear or wind facility that would require additional time for completion due to the specified factors.

The North Carolina General Statutes clearly spell out a process by which the Commission ***authorizes the construction*** of electric generating facilities, which is the through the issuance of a

[68] H.B. 951 Sec. 1(4).
[69] Id.

certificate of public convenience and necessity pursuant to G.S. § 62-110.1. As the Commission, the Court of Appeals, and Duke itself have long maintained, the mere inclusion of a resource in a utility's resource plan does not authorize the construction of that facility – only a CPCN does.[70] If the General Assembly meant to empower the Commission to approve a Carbon Plan that delays compliance with the 70% carbon reduction mandate beyond two years merely because the plan includes a wind or nuclear resource, it could and should have said that. The statute, as written, simply recognizes the unavoidable fact that nuclear power plants almost invariably take longer than expected to construct, and that wind projects may face unforeseeable delays. It does not give Duke a free pass on 2030 compliance just because it includes a wind or nuclear unit in its portfolio.[71]

In addition to the plain language of the legislation on this point, there is no reason and no need to interpret the law in this fashion. To the extent that wind or nuclear resources may be **needed** to ensure reliability after the retirement of additional fossil fuel-fired generating facilities, the law independently allows for delays beyond two years ("in the event necessary to maintain the adequacy and reliability of the grid"). However, Duke has not argued, or presented any evidence to support the proposition that, a delay to 2034 is needed for reliability purposes. And even if wind or nuclear resources reduced compliance costs, which is highly unlikely, the General

[70] *See e.g.*, Order Approving Integrated Resource Plans and REPS Compliance Plans, Docket No. E-100, Sub 141 (June 26, 2015), at 11; Duke Energy Carolinas, LLC and Duke Energy Progress, LLC Reply Comments, Docket No. E-100 Sub 157 (May 20, 2019) at 56 ("'the IRP proceeding is akin to a legislative hearing in which the Commission gathers facts and opinions that will assist the Commission and the utilities to make informed decisions on specific projects at a later time. . . . it is not an appropriate proceeding for the Commission to use in issuing 'directives which fundamentally alter a given utility's operations.' . . . decisions on the need, cost and timing of a specific generation resource would only be made after a CPCN application was filed and considered by the Commission in a public and transparent CPCN proceeding conducted pursuant to N.C. Gen. Stat. 62-110.1 and 62-82.").

[71] It also makes no sense that a delay in construction of, say, a 300 MW nuclear plant would authorize Duke to indefinitely delay all efforts to comply with the 70% reduction requirement. At most, Duke's compliance obligation should be mitigated in proportion to the capacity of the delayed unit.

Assembly did not authorize the Commission to delay compliance beyond two years simply because it would be less expensive to do so.

A more plausible reading of the language and legislative intent is that the General Assembly sought to address situations where unanticipated events beyond Duke's control result in delays on bringing wind or nuclear resources on-line once their construction has been authorized through the issuance of a CPCN. In other words, the fact that new nuclear technologies still in the R&D phase may not be available until the mid-2030s is not grounds for delaying compliance with the 70% reduction mandate beyond 2032. Those resources may prove to be an important part of the resource mix needed to achieve the 2050 net-zero requirement, but the Commission cannot permit Duke to delay compliance past 2032 simply because Duke plans to eventually build offshore wind or SMRs.

However, in its P3 and P4 portfolios, Duke proposes to do just that. Both portfolios delay compliance until *at least* 2034, based on the presence of offshore wind and/or planned SMRs in the portfolio. Duke claims that H.B. 951 "allows for adjustments to the timeline for achieving the 70% interim target should additional time be needed to accommodate development of wind or new nuclear resources as part of the Companies' least-cost energy transition pathway."[72] But (as discussed above) the statute does not permit extensions past 2032 based on the planned "development" time for wind or SMRs in a potential portfolio; it only permits such an extension when additional time is required for the "completion" of a wind or nuclear facility whose construction has previously been authorized by the Commission. It will be many years before Duke will be in a position even to ask the Commission to "authorize construction" of a wind or nuclear facility and the Commission's action on such a request is far from certain.

[72] Carbon Plan Ch. 2 p. 2.

It should also be noted that although H.B. 951 requires the Commission to "comply with current law and practice with respect to the least cost planning for generation, . . . in achieving the authorized carbon reduction goals," it does not follow that the Commission may authorize Duke to delay compliance with the 70% reduction mandate past 2030 simply because it would cost less to do so. Indeed, all things being equal, delaying compliance costs will *always* result in a lower cost on a present-value basis (because deferred costs always have a lower PVRR). If delayed costs were a sufficient reason to delay compliance past 2030, the General Assembly's 2030 mandate would, in effect, be a 2032 mandate.

### C. CPSA's alternative portfolios

As previously discussed, Brattle has conducted capacity expansion modeling to formulate five alternative resource portfolios, CPSA1 through 5, that represent alternative pathways to achieve compliance with the 70% carbon reduction mandate in 2030 and 2032, respectively. Those portfolios model the impacts of different solar interconnection limits on the compliance, as follows:

| Portfolio | Overview |
|---|---|
| CPSA1 | Achieves 70% compliance by 2030 with no cap on the annual rate of solar additions |
| CPSA2 | Achieves 70% compliance by 2030 with Duke's conservative assumption about the annual rate of solar additions[73] |
| CPSA3 | Achieves 70% compliance by 2030 with CPSA's more reasonable assumption about the annual rate solar additions |
| CPSA4 | Achieves 70% compliance by 2032 with Duke's conservative assumption about the annual rate of solar additions |
| CPSA5 | Achieves 70% compliance by 2032 with CPSA's more reasonable assumption about the annual rate solar additions. |

[73] "Conservative assumptions" here refers to the annual rate of solar additions permitted in Duke's portfolios P2-P4.

These portfolios are described at length in the Brattle Report. At a high level, the resource additions called for by each portfolio are as follows:

| Scenario | 2030 New Solar | 2032 New Solar | 2030 New BESS | Onshore Wind | Offshore Wind | Gas CC | Gas CT |
|---|---|---|---|---|---|---|---|
| CPSA1 | 9,500 | 13,900 | 3,400 | 600 MW in 2030 | --- | 2,000 MW in 2030 | --- |
| CPSA2 | 5,200 | 7,900 | 1,800 | 600 MW in 2030 | 800 MW (2030) 800 MW (2032) | 2,400 MW in 2030 | 900 MW in 2030 |
| CPSA3 | 7,500 | 11,100 | 2,800 | 600 MW in 2030 | 400 MW in 2030 | 2,400 MW in 2030 | --- |
| CPSA4 | 5,200 | 8,000 | 2,000 | 600 MW in 2030 | 800 MW in 2032 | 2,400 MW in 2030 | 1,200 MW in 2030 |
| CPSA5 | 6,700 | 10,800 | 2,400 | 600 MW in 2030 | --- | 2,400 MW in 2030 | 700 MW in 2030 |

As indicated below, the more solar-reliant portfolios perform better from an annual system cost standpoint. Conversely, portfolios with solar interconnection limits tend to drive portfolio costs up.

| Scenario | 2030 New Solar | 2032 New Solar | 2030 System Costs | 2032 System Costs |
|---|---|---|---|---|
| CPSA1 | 9,500 | 13,900 | $7.0B | $7.9B |
| CPSA2 | 5,200 | 7,900 | $7.9B | $8.7B |
| CPSA3 | 7,500 | 11,100 | $7.0B | $8.0B |
| CPSA4 | 5,200 | 8,000 | $6.8B | $7.9B |
| CPSA5 | 6,700 | 10,800 | $6.8B | $7.8B |

Portfolios CPSA2 and CPSA3 are intended to replace Duke's Portfolio P1, which assumes Duke's high cap on solar additions, with one version that is more conservative on solar additions (Duke's low solar cap) and one that is slightly more aggressive (CPSA's proposed assumption on the rate of annual solar additions[74]). CPSA4 is effectively Duke's Portfolio P2, as remodeled by

[74] CPSA's assumption about the rate of annual solar additions differs from Duke's high solar cap only in the first two years. In all subsequent years, CPSA has accepted Duke's value of 1800 MW of solar additions per year.

Brattle. For reasons discussed above, Duke's Portfolios P3 and P4 should be eliminated as non-compliant with H.B. 951.

## IV. Duke's Comparison of its Carbon Plan Portfolios

In addition to omitting portfolios that could achieve compliance with the 70% carbon reduction mandate at a lower cost to customers than the portfolios presented, the Carbon Plan's comparison of the portfolios it does present is distorted and misleading – in part because of how the portfolios are structured, and in part because of how the information is characterized and presented. The net effect of these distortions is to bias the presentation of portfolios against P1 (the only portfolio that actually meets the 2030 compliance deadline) and to a lesser extent P2 (which achieves compliance by 2032), and in favor of portfolios intended to achieve compliance by 2034, with significant additions of SMRs and offshore wind resource (which will all be 100% owned by Duke). If the Commission agrees to replace Duke's proposed portfolios with those proposed by CPSA, these issues become less relevant. If, on the other hand, some or all of Duke's portfolios are retained, this information should be taken into consideration by the Commission when assessing the relative merits of each portfolio and of the Execution Plan.

Duke states that the Carbon Plan assessed each of the portfolios presented against "four core Carbon Plan objectives - CO2 reduction, affordability, reliability and executability." With respect to each of these criteria, Duke's comparison is distorted and misleading.

### A. CO2 reduction

Duke's comparison of the CO2 emission reductions of its portfolios is very brief, noting only that "the pace of the CO2 emissions reductions in each portfolio varies," quantifying the system-wide emission reductions achieved by each portfolio in 2030 and 2035, and stating that all portfolios reach carbon neutrality by 2050.[75]

Notably missing from this comparison is either a tally of the total carbon emissions allowable under each portfolio, or a comparison of the cost per ton of CO2 emission reductions achieved by each portfolio.

One fact the Carbon Plan fails to explain is that Duke structured portfolio P1 not only to achieve 70% carbon reduction earlier than the other portfolios, but also to require greater carbon reductions in every year from 2026 through 2050. This is laid out in Table 1.

[75] Carbon Plan Ch. 3 p. 16, 22.

**Table 1 - CO2 Emissions Cap (% reduction from 2005 levels)**[76]

| | P1 (2030) | P2 (2032) | P3, P4 (2034) |
|---|---|---|---|
| **2026** | 50% | 49% | 48% |
| **2027** | 54% | 53% | 52% |
| **2028** | 59% | 56% | 55% |
| **2029** | 64% | 60% | 58% |
| **2030** | **69%** | 64% | 62% |
| **2031** | 70% | 68% | 65% |
| **2032** | 72% | **69%** | 68% |
| **2033** | 73% | 70% | 71% |
| **2034** | 75% | 72% | **69%** |
| **2035** | 76% | 73% | 70% |
| **2036** | 78% | 75% | 72% |
| **2037** | 80% | 76% | 73% |
| **2038** | 81% | 78% | 75% |
| **2039** | 83% | 80% | 76% |
| **2040** | 84% | 81% | 78% |
| **2041** | 86% | 83% | 80% |
| **2042** | 87% | 84% | 81% |
| **2043** | 89% | 86% | 83% |
| **2044** | 91% | 87% | 84% |
| **2045** | 92% | 89% | 86% |
| **2046** | 94% | 91% | 87% |
| **2047** | 95% | 92% | 89% |
| **2048** | 97% | 94% | 91% |
| **2049** | 98% | 95% | 92% |
| **2050** | **100%** | **100%** | **100%** |

Two important consequences follow from Duke's decision to structure its portfolios in this way. First, P1 achieves significantly greater reductions in carbon emissions across the planning period than Duke's other portfolios. From 2026 (when the portfolios begin to diverge) through 2050, portfolio P2 results in 7% more projected carbon emissions than P1 does, while P3 and P4 permit 12% and 11% more, respectively, than P1.[77]

[76] Based on information presented in Duke Response to CPSA DR 1-2 (Exhibit B).
[77] Brattle Report at 12-13.

The second consequence is that P1 is structured (perhaps deliberately) to cost more than other portfolios, because it achieves greater emission reductions than those portfolios even when it doesn't have to. The more stringent cap on CO2 emissions in later years accounts for about **half** of the difference in PVRR between Duke's P1 and P2 portfolios.[78]

If Duke had wanted a fair cost comparison between compliance paths, it could have constructed a portfolio that achieved 70% reduction in 2030, and required the same level of carbon reductions as the other portfolios in the years after they reached 70%. This would have isolated the incremental cost of 2030 compliance in Duke's plans (versus 2032 compliance), which Brattle estimates to be about $1.3 billion.[79] Instead, Duke constructed a 2030 portfolio that outperforms (in terms of carbon reduction) the other portfolios in every single year of the planning period. To the extent that carbon reduction leads to additional cost, this unnecessarily increases the cost of the 2030 portfolio, contributing to the (inaccurate) impression that compliance by 2030 is necessarily more costly to ratepayers than delaying compliance.

### B. Affordability

Duke's comparison of the relative affordability of each portfolio is also skewed. One reason for this is that portfolio P2 delays the costs of complying with the 70% decarbonization mandate by two years as compared to P1; P3 and P4 delay it by four years. All things being equal, delaying a cost reduces is impact on PVRR. But as discussed above, H.B. 951 does not permit the Commission to delay compliance past 2030 simply because it would defer costs.

Another reason the cost comparison is skewed is that P1 is (unnecessarily) designed to result in greater CO2 reductions than other portfolios in every year of the planning period, rather than simply to achieve timely compliance with the 70% mandate in 2030. This compounds the

[78] Id.
[79] Id.

impact of delayed costs on the relative PVRR of each portfolio – because portfolio P1 accelerates compliance with greater carbon reductions across the life of the portfolio.

P1 is more expensive than other portfolios in PVRR terms not because it includes higher-cost resources, but because it puts those resources on the system earlier than the other portfolios. Waiting to comply with carbon reduction requirements will always cost less, no matter what the resource plan is. (Of course, waiting to comply will also result in higher emissions of $CO_2$, and other pollutants that come with health and cost implications, and a larger contribution to climate change from North Carolina electric generation.) Based on Brattle's analysis, this "overcompliance" overstates the difference in revenue requirements by P1 and P2 by about $1 billion.[80]

Brattle's modeling of CPSA's proposed portfolios, attempts to address this phenomenon more accurately. It achieves convergence between 2030 and 2032 compliance portfolios by 2035 so that the cost of the former relative to the latter is not artificially inflated.

**C. Executability**

CPSA agrees that executability is an important factor to be considered by the Commission in the evaluation of Carbon Plan portfolios. Moreover, the near-term Execution Plan ultimately approved by the Commission should take all reasonable steps to mitigate execution risk for all portfolios, given the many uncertainties surrounding the plan. Unfortunately, the comparison of execution risk among Duke's portfolios is incomplete and distorted. More troublingly, Duke has structured its portfolios and its proposed Execution Plan to increase, not decrease, the risk that certain portfolios (in particular, the 2030 compliance plan) cannot be achieved.

[80] Brattle Report at 10-11.

As described by Duke, portfolio execution risk can arise from a number of factors, including but not limited to supply chain delays, skilled labor shortages, external contractor availability limitations, extended state and federal permitting process, legal challenges, etc."[81] But to the extent Duke tries to compare execution risk across portfolios, it boils risk down to two factors: (1) annual solar additions reached to achieve 70% carbon reduction, and (2) cumulative additions of new-to-the-Carolinas resource types.[82] Duke goes on to characterize P1 as the riskiest Portfolio in the Carbon Plan because it will require annual additions of solar of "2.4X" the historical maximum interconnection rate of 750 MW; and because the "cumulative additions of new-to-the-Carolinas resource types" in P1 will amount to 3140 MW in 2030 and 6480 in 2035.[83] P4, the least risky portfolio (according to Duke), will only require solar additions of 1.8X the historical maximum; and only 1150 MW of "new-to-the-Carolinas resource types" by 2030 and 4210 MW 2035.

The risk metrics Duke uses do not hold up to scrutiny. As discussed in detail above, there is ample reason to believe that Duke can achieve the solar interconnection rates proposed by CPSA. And Duke's "cumulative additions of new-to-the-Carolinas resource types" is misleading for several reasons. First, it lumps onshore wind, offshore wind, battery energy storage, and SMRs into a single category of "new-to-the-Carolinas" resources. These resources have very different execution risk profiles. Battery energy storage is a mature, well-developed technology, with nearly 4.2 GW of new battery storage deployed in the United States in 2021 alone.[84] Nor is battery storage "new to the Carolinas" – Duke been piloting battery storage projects in the Carolinas for a

[81] Carbon Plan Ch. 3 p. 25.
[82] Carbon Plan Ch. 3 p. 19.
[83] Carbon Plan Executive Summary p. 16; Ch. 3 p. 20.
[84] Energy Storage News, "4.2GW of battery storage deployed in US last year" (Mar. 4, 2022), available at https://www.energy-storage.news/4-2gw-of-battery-storage-deployed-in-us-last-year/.

decade and has 300 MW of battery storage projects "in flight" at this time.[85] Other utilities in the Carolinas have also developed battery energy storage projects.[86]

By contrast, there is only one onshore wind project extant in the Carolinas – the Amazon Wind Farm U.S. East, a 208 MW facility located in Dominion's service territory. There are no offshore wind facilities in the Carolinas at present. While onshore and offshore wind are well-established resources globally, the development timeline for such facilities in the Carolinas is highly uncertain. SMRs, for all practical purposes, do not even exist yet in the United States now, and it is uncertain when SMRs might be available for deployment (and at what cost). In assessing the execution risks facing Duke's proposed development plan for a SMR to contribute to the 70% reduction requirement, consider the following:

- Only one of the four reactor designs Duke identifies as viable for contributing to the 70% requirement (identified in Table L-5) has been approved by the Nuclear Regulatory Commission (NRC) to date.
- The earliest date by which any of these first-of-a-kind reactors is currently forecasted to come online is 2028, with significant risk of additional delay.
- Duke anticipates receiving its Combined License (COL) in 2029, one year or less after the earliest potential online date for four of the identified reactors, leaving little time for learning adjustments in the COL review and approval and making Duke's COL timeline and subsequent milestones contingent on a near flawless reactor demonstration.
- If demonstration of Duke's chosen reactor design fails, Duke's vendor selection process will have to be restarted, unless Duke pursues this workstream for multiple designs in parallel at higher cost.
- Duke's proposed timeline for obtaining a CPCN is either ahead of or near coincident with the earliest potential online date of the proposed reactors, suggesting that Duke will seek a

[85] Carbon Plan Appx. K p. 2, 6.
[86] The 6.9 MW Grissom solar / energy storage project, which is interconnected with the Halifax EMC system, went online in June 2021. https://www.carolinacountry.com/your-energy/energytech/energy-sense-2/halifax-emc-solar-storage-project-marks-nc-milestone. Other North Carolina electric cooperatives have 14 solar plus storage projects, with an aggregate storage capacity of 53 MW, in development as well. https://www.ncelectriccooperatives.com/who-we-are/spotlight/electric-cooperatives-adding-14-solar-storage-sites-across-rural-n-c/.

CPCN based on assumptions of technology demonstration, fuel supply availability, cost, timing, associated workforce and supply chain considerations that likely will not yet be verifiable.

- SMRs require a more highly enriched form of uranium than traditional light water reactors, called High-Assay Low-Enriched Uranium (HALEU), for which Russia is currently the world's only viable commercial supplier.[87]

- Nuclear power projects have a long and well-documented history of delays and cost overruns, not only in the United States (including in North Carolina) but around the world.[88] Proponents of SMRs hope that standardization and widespread deployment of SMRs will reduce costs and delays. However, in the absence of any track record for SMRs, those benefits are purely speculative. Moreover, Duke's resource plans would deploy SMRs at the earliest possible availability. Those units would be among the first constructed in the United States, and would not enjoy the benefits (if any) that might result from widespread commercial deployment of SMRs.

It is disingenuous and misleading for Duke to claim, as they do, that these resource types carry no more execution risk than battery storage. Going back to the sources of execution risk cited by Duke in the Carbon Plan, it is fair to say that onshore and offshore wind and nuclear facilities are likely to face far greater risk related to "state and federal permitting processes" and "legal challenges" than battery storage facilities, which (unlike those other technologies) have a small geographic footprint and low environmental impacts (perceived or actual), and are unlikely to generate legal challenges in siting.

It is worth noting that battery storage makes up 2067 MW of the 3140 MW of "new to the Carolinas resource types" in P1. Offshore wind – which, as discussed in Section II.1, is non-economically forced into the model by Duke's solar interconnection cap – makes up 800 MW of

[87] Third Way. "Developing Domestic HALEU Supply Spells Freedom from Russian Dependency." April 6, 2022. https://www.thirdway.org/memo/developing-domestic-haleu-supply-spells-freedom-from-russian-dependency

[88] Philip Eash-Gates, Magdalena M. Klemun, Goksin Kavlak, James McNerney, Jacopo Buongiorno, Jessika E. Trancik,"Sources of Cost Overrun in Nuclear Power Plant Construction Call for a New Approach to Engineering Design," *Joule*, Vol. 4, Iss. 11 (2020), p. 2348-2373, available at https://www.sciencedirect.com/science/article/pii/S254243512030458X.

the remainder. And 600 MW of onshore wind is forced into not only P1 but every other portfolio.[89] And although it is not reflected in Duke's comparison chart, the P2, P3, and P4 portfolios actually rely on truly "new to the Carolinas resource types" (*i.e.*, offshore(?) wind and SMRs) to achieve compliance with the 70% reduction requirement.

1. CPSA's portfolios mitigate execution risk

Not only is Duke's analysis of execution risk across portfolios misleading; Duke also provides no meaningful way to mitigate or address the execution risk involved with any its portfolios. For example, every one of Duke's proposed portfolios counts on the deployment of 600 MW of SMRs and 1.2 GW of onshore wind by 2035; there is no consideration of a "fallback" plan if those highly speculative resources are not available on that timeframe. It is true that the Carbon Plan will be reviewed and may be adjusted every two years. However, prudence dictates that the Carbon Plan give some consideration to how Duke can achieve compliance if its highly aggressive assumptions do not bear out – and whether the near-term Execution Plan should include measures to create more options in the future.

CPSA's proposed portfolio CPSA5 show that relying on solar and battery storage – two well-established and commercially proven technologies – can achieve 70% compliance by 2032 without any reliance on these more uncertain resource types. For that reason, CPSA believes that it carries less execution risk than Duke's proposed portfolios or CPSA's other portfolios. However, to the extent there is any risk associated with that portfolio, CPSA mitigates that risk by proposing that the Carbon Plan include alternative portfolios that add solar at a slower rate and

[89] The capacity numbers for battery storage, onshore wind, and offshore wind in P1 actually add up to 3467 MW – 327 more than the "new to the Carolinas resource types" figure reported in the Carbon Plan. Exec. Summary p. 16. Other portfolios have similar discrepancies (in the range of 300+ MW), though they are not identical.

thus do require new wind resources to achieve compliance. In addition, CPSA fully supports the approval of an Execution Plan that keeps all these options open.



### D. Reliability

Finally, Duke compares the relative reliability of its portfolios based on two metrics: expected impacts on net load ramping, and forecasted annual CC starts. Duke goes on to state that "The greater net load ramp and CC starts associated with the more rapid adoption of new renewable energy resources required for Portfolio 1 will create additional flexibility challenges and operational risk."[90]

With respect to ramp rates, Duke notes that "two key challenges that must be met in future portfolios: accommodating very low (or even negative) net loads at midday and managing the associated increasingly rapid decreases and increases in net load as the sun rises and sets."[91] While CPSA does not dispute that these issues must be addressed, Duke fails to acknowledge that these issues have been effectively addressed in other jurisdictions with higher levels of renewables on the system. For instance, California and MISO use ramping products today, and both have been procured at very limited costs, to deal with both expected and unexpected ramping needs.

It should also be noted that energy storage is highly effective at dealing with ramping issues, in both directions. Energy storage can ramp up and down faster than traditional resources, and thus, can effectively deal not only with expected ramping needs, but also with forecast errors and balance the system in real time. Furthermore, energy storage can be a demand 'sink', thereby mitigating the rate of ramping needed in the system and alleviating low net load periods by adding load. For this reason, additional deployment of energy storage can also reduce the need for CC starts cited by Duke. Duke acknowledges this in the Carbon Plan, noting that "Energy storage

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[90] Carbon Plan Ch. 3 p. 22-24.
[91] Carbon Plan Ch. 3 p. 23.

resources have many operational characteristics that make them ideal for providing fast response reserves. These types of units can commit and ramp quickly and tend to have wide operating ranges."[92]

These operating benefits of energy storage were not captured in the Carbon Plan, such that the forecasted economic volumes likely underestimate the economic volume of energy storage in the system. To the extent Duke believes that an increased number of CC starts may result in higher maintenance costs to avoid reliability issues, it should incorporate those projected costs in its modeling – as well as energy storage's ability to reduce those costs.

One issue Duke neglects to mention in its reliability comparison is the differences in resource adequacy differences across portfolios. However, as discussed in Section II above, Duke's most solar-heavy portfolio, P1, is consistently the most reliable scenario across time. According to Duke's analysis, the average LOLE across P2-P4 would be over two and a half times the level of P1 in 2030, and over three times the level of P1 in 2035.[93] This difference was not captured in Duke's assessment of reliability of the various portfolios, nor in terms of costs to end-users.

## V. <u>Execution Plan and 2022 Procurement Volume</u>

As stated, CPSA concurs with Duke's general approach of presenting a set of portfolios in the Carbon Plan, along with a near-term Execution Plan that is consistent with and supports all the proposed portfolios. CPSA also supports, or does not oppose, most aspects of the Execution Plan.

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[92] Carbon Plan Appx. Q p. 13.
[93] Carbon Plan Appx. E, Table E-58 & E-59

However, the Execution Plan must be modified to support the additional portfolios (CPSA2, 3, 4, and 5) that should be added to the Carbon Plan as replacements for portfolios P1 and P2.[94]

In the Carbon Plan Duke states that to achieve the 70% carbon reduction target, decisive near-term procurement and development activities will be required.[95] CPSA agrees but contends that Duke is being much too conservative and unambitious in its assumptions about the achievable rate of solar additions. To support portfolios CPSA2-5, the Execution Plan should provide for 1500 MW of solar procurement in 2022 and 2023 and 1800 MW of solar procurement in 2024, for a total of 4800 MW, as opposed to the 3100 MW contained in Duke's Execution Plan.[96] Furthermore, all solar procured after 2022 should be paired with storage, subject to appropriate PPA terms that adequately incentivize storage additions.[97]

Exhibit D includes a geographic analysis, conducted by CPSA members, of potential solar project combinations and locations that might achieve approximately 1800 MW in aggregate annual solar capacity additions across DEP and DEC. The analysis shows a material solar opportunity, with concentrated opportunities across many geographically diverse regions, showing that transmission upgrades and expansion can likely cost-effectively unlock material additional capacity on Duke's system.

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[94] As discussed, portfolios CPSA2 and CPSA3 (which achieve compliance with the 70% mandate in 2030) are intended to replace Duke's portfolio P1; CPSA3 and CPSA4 (2032 compliance) replace P2. Porfolios P3 and P4 are inconsistent with H.B. 951 and should be removed from the plan. As noted above, CPSA is proposing portfolio CPSA1 for illustrative or reference purposes at this time and is not suggesting that the Execution Plan support that portfolio.

[95] Carbon Plan Ch. 4, pp. 5-6.

[96] It should be noted that Duke's proposed 3100 MW of procurement does not even support its own P1 portfolio.

[97] See Section II.B above.

This analysis illustrates scenarios in which it would be feasible to achieve 1800 MW of annual solar additions by selecting projects from specific geographic areas to reduce the number of significant upgrade projects that would be required to interconnect a large volume of solar.

These 2022 and 2023 procurement levels are reasonable and achievable when compared to past Duke procurements, as well as procurements underway in other jurisdictions. Procurements under the CPRE program, which were limited to specific allocation between DEC and DEP and were limited to projects 80 MW or smaller, resulted in 551 MW in Tranche 1[98] and 664 MW in Tranche 2.[99] Unlike CPRE procurements, H.B. 951 procurements can include projects larger than 80 MW, which means that Duke will be required to interconnect fewer actual projects to meet specified capacity targets. It should also be noted that the avoided cost cap required by H.B. 589 also limited the scope of participation in CPRE. Although market competition, in combination with the bid refresh and volume adjustment mechanisms incorporated in the 2022 RFP, will serve to keep costs in check, the lack of an arbitrary cost cap will facilitate greater participation and more successful procurements. Proactive transmission planning will also help to promote the success of larger procurements in the future.

Utilities in other states are also procuring renewables at rates comparable to those proposed by CPSA. In April 2022, Dominion Energy Virginia issued an RFP for the acquisition of 1200 MW of new solar and onshore wind development assets, plus up to 125 MW of energy storage, with annual capacity additions of wind and solar of approximately 700 MW.[100] Dominion will

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[98] NCUC Docket No. E-2, Sub 1159, Updated CPRE Tranche 1 Final Independent Administrator Report, Executive Summary p. 1 (July 23, 2019).
[99] NCUC Docket No. E-2, Sub 1159, Updated CPRE Tranche 2 Final Independent Administrator Report, Executive Summary p. 1 (February 12, 2021).
[100] https://cdn-dominionenergy-prd-001.azureedge.net/-/media/pdfs/global/renewable-projects/rfp/2022-solar-rfp/ce-4-rfp-release-042922.pdf?la=en&rev=de2762ae52694bb89d562276fd07587e&hash=7DDE4F2B2CB25674541FB0A392DA356D

issue a separate RFP for additional PPAs in September 2022. Entergy issued RFPs in 2022 for 3 GW of new renewables, including 1500 MW in Louisiana, 1000 MW in Arkansas, and 500 MW in Mississippi.[101] Additionally, Georgia Power issued a 2021 RFP seeking 1 GW of renewables,[102] Indiana Michigan Power issued a 2022 RFP seeking 1.3 GW of renewables,[103] Duke Energy Indiana issued a 2022 RFP seeking 1.1 GW of renewables,[104] and Arizona Public Service issued a 2022 RFP seeking up to 800 MW of renewables.[105] NextEra plans 86 GW of solar additions to Florida Power and Light by 2045, an average of at least 4 GW per year.[106]

CPSA also notes that Duke's proposed 2022 procurement volume (750 MW) is unreasonably small because it is keyed to the amount of solar Duke's Carbon Plan portfolios add in 2026.[107] Although CPSA's portfolios include larger solar additions because they help achieve timely compliance at least cost, even under Duke's resource plans this makes no sense. As Duke acknowledges, some projects that are selected in the 2022 procurement are likely to go online in 2026, while others will likely not be interconnected until 2027 or even 2028. If Duke only procures 750 MW of projects with online dates ranging from 2026 to 2028, then its estimated 2026 interconnection capacity of 750 MW will not be fully utilized. Moreover, it will be difficult if not impossible to make up the resulting shortfall in 2026 solar additions with a *later* procurement.

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[101] https://pv-magazine-usa.com/2022/07/06/entergy-seeks-to-grow-renewables-up-to-2500-over-next-decade/
[102] https://www.prnewswire.com/news-releases/georgia-power-continues-renewable-energy-expansion-by-seeking-1-000-mw-of-new-generation-301418902.html
[103] https://www.prnewswire.com/news-releases/im-seeks-detailed-proposals-for-1-300-mw-of-solar-wind-energy-301503013.html
[104] https://www.renewablesnow.com/news/duke-energy-targets-expansion-plans-11-gw-renewables-rfp-773761/
[105] https://www.solarpowerworldonline.com/2022/05/arizona-public-service-is-seeking-proposals-for-solar-storage-projects/
[106] https://www.nexteraenergy.com/content/dam/nee/us/en/pdf/NextEraEnergyZeroCarbonBlueprint.pdf.
[107] Carbon Plan Appx. I p. 9.

It should also be noted that the solar additions called for in Duke's Carbon Plan portfolios all assume that it will have met its obligation to procure the full volume of CPRE solar required by H.B. 589. It is now clear that Duke will not meet that goal, and that there will be a shortfall of at least a few hundred MW of solar.[108] Both Duke and the Public Staff have suggested that this shortfall can be made up in the 2022 procurement under H.B. 951.[109] This provides a further reason for adjusting the volume of the 2022 procurement upward.

In discussing its proposed volume for the 2022 procurement, Duke claims that because of "the significant headwinds that solar generation currently faces that put upward pressure on solar energy costs," it is likely that customers will pay higher prices in the 2022 RFP than in a future RFP.[110] Other parties expressed the view in the stakeholder process that solar procurements should be delayed because it is likely that solar prices are likely to decline significantly. However, there is a great deal of uncertainty about the cost of solar modules over the next several years, and it now appears that the current federal investment tax credit for solar may well not be extended or expanded after 2026.[111] Moreover, there is a significant likelihood that the U.S. Department of Commerce, in response to a petition from Auxin Solar, will impose substantial duties on solar cells and modules imported from Southeast Asia (the current source of most U.S. solar farm components) that could significantly increase solar installed costs after the expiration of the current Presidential moratorium on new duties in June of 2024.[112]

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[108] See Rebuttal Testimony of Angela M. Tabor, Docket No. E-7, Sub 1262 (May 26, 2022) at 6-10.
[109] See Testimony of Jeff Thomas on Behalf of the Public Staff North Carolina Utilities Commission, Docket No. E-7, Sub 1262 (May 17, 2022) at 12-15.
[110] Carbon Plan Appx. I p. 19.
[111] Tony Room and Jeff Stein, "Manchin says he won't support new climate spending, tax hikes on wealthy", *The Washington Post* (July 15, 2022), at https://www.washingtonpost.com/us-policy/2022/07/14/manchin-climate-tax-bbb/.
[112] *See* Crystalline Silicon Photovoltaic Cells, Whether Or Not Assembled Into Modules From The People's Republic Of China: Auxin Solar's Request For An Anti-Circumvention Ruling Pursuant To

At the same time, there is every reason to believe that transmission costs, labor costs, and other costs associated with solar development (such as land costs) will continue to rise. Given the significant consequences of delay, it is not reasonable and prudent to delay procurement of solar on this basis. Any "over-payment risk"[113] associated with earlier procurement of solar is counterbalanced both by the risks that solar costs will in fact rise, and (more importantly) by the real possibility that delaying procurement will force Duke to rely on higher-cost resources to achieve compliance.

## VI. Duke's Transmission Plan and the Red Zone Upgrades

CPSA supports the proposal by Duke, as set forth in Appendix P of the Carbon Plan, to construct additional upgrades to its transmission grid ("the Red Zone Upgrades") to alleviate congestion in the so-called "Red Zone" and facilitate the interconnection of renewable generation needed to comply with H.B. 951.

CPSA believes that it is critical to establish a comprehensive and proactive transmission planning process for the Carolinas. Doing so will facilitate the achievement of the ambitious decarbonization mandate of H.B. 951 and will ultimately reduce costs to ratepayers. But until such a process is established, the Red Zone Upgrades represent a critical first step towards proactive planning. The need for and cost-effectiveness of the Red Zone Upgrades are supported both by Duke's analysis and by the experience of industry participants including PGR and CPSA's other

Section 781(b) Of The Tariff Act Of 1930, As Amended (Feb. 8, 2022), at https://www.seia.org/sites/default/files/2022-02/Circumvention%20Petition%20Filed%202.8.22.pdf. Projects coming online in 2026 and 2027 may be able to procure modules not subject to these duties.

[113] Carbon Plan Appx. I. at 9.

members. CPSA and PGR believe that the Transmission Planning Collaborative should move swiftly to approve the Red Zone Upgrades.[114]

### A. The need for proactive transmission planning in the Carolinas

It is well understood that the deployment of significant amounts of new renewable resources in the United States, will require significant upgrades to the transmission grid.[115] Those investments in the grid, however, will create additional benefits and cost savings beyond just facilitating the interconnection of more generation.[116]

There is also overwhelming consensus that planning and constructing those upgrades proactively is far more efficient and cost-effective than doing so piecemeal, in response to generator interconnection requests.

For example, a review of PJM generation interconnection studies for 15.5 GW of individual offshore wind plants identified \$6.4 billion in onshore transmission upgrades (a cost of \$400/kW).[117] In contrast, a recent PJM Offshore Wind Transmission Study that proactively evaluated all existing state public policy needs identified only \$3.2 billion in onshore upgrades

[114] While CPSA believes that the case for the Red Zone upgrades is overwhelming, and makes that case below, under federal law in order for Duke to proceed with those upgrades they must first be approved by the Transmission Planning Collaborative -- an approval that Duke is actively seeking and that is under consideration by the TPC. CPSA is not suggesting that the Commission include the Red Zone Upgrades in the Carbon Plan without TPC approval. On the other hand, CPSA contends that such approval would provide conclusive probative evidence that the Red Zone Upgrades are in fact needed and should be included in the Carbon Plan.

[115] See, e.g., Princeton University, *Net-Zero America: Potential Pathways, Infrastructure, and Impacts*, available at https://netzeroamerica.princeton.edu/img/Princeton%20NZA%20FINAL%20REPORT%20SUMMARY%20(29Oct2021).pdf (estimating \$1.2-3.5 trillion in transmission investment required to achieve net zero emissions in the United States by 2050);

[116] See, e.g., National Renewable Energy Laboratory, *The North American Renewable Integration Study: A U.S. Perspective – Executive Summary* (June 2021), available at https://www.nrel.gov/docs/fy21osti/79224-ES.pdf (discussing economic benefits of interregional transmission expansion) (full report available at https://www.nrel.gov/docs/fy21osti/79224.pdf).

[117] *The Business Network For Offshore Wind: Offshore Wind Transmission* (white paper) (Oct. 2020), available at https://gridprogress.files.wordpress.com/2020/11/business-network-osw-transmission-white-paper-final.pdf.

required for over 75 GW of renewable resources (up to 17 GW of offshore wind, 14.5 GW of onshore wind, 45.6 GW of solar, and 7.2 GW of storage) (a cost of $40/kW).[118] And in March 2022, the Midcontinent Independent System Operator (MISO) released a detailed business case for $10.4 billion in transmission improvement projects to enable increasing amounts of renewable energy that were identified by its Long Range Transmission Planning process. MISO's analysis demonstrated that the projects would bring benefits equal to more than 2½ times their cost, primarily by avoiding additional local power projects and reducing transmission congestion and fuel costs.[119]

The advantages and benefits to ratepayers of long-term, comprehensive transmission planning are a key driver of FERC's recent Notice of Proposed Rulemaking relating to transmission planning ("the 2022 NOPR").[120] And a key conclusion of the North Carolina Clean Energy Plan, prepared in 2019 by the North Carolina Department of Environmental Quality, is that "comprehensive utility planning processes" should be used "to determine the sequence, needed functionality, and costs and benefits of grid modernization investments."[121] The Clean Energy

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[118] PJM Interconnection, *Offshore Wind Transmission Study: Phase 1 Results* (Oct. 19, 2021), available at https://www.pjm.com/-/media/library/reports-notices/special-reports/2021/20211019-offshore-wind-transmission-study-phase-1-results.ashx.

[119] Mid-Continent Independent System Operator, *LRTP Tranche 1 Portfolio: Detailed Business Case* (presentation) (March 29, 2022), available at https://cdn.misoenergy.org/20220329%20LRTP%20Workshop%20Item%2002%20Detailed%20Business%20Case623671.pdf.

[120] *Notice of Proposed Rulemaking: Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 87 Fed. Reg. 25,604 (May 4, 2022) ("2022 NOPR") at P 25 ("We are concerned that the absence of sufficiently long-term, comprehensive transmission planning processes appears to be resulting in piecemeal transmission expansion to address relatively near-term transmission needs. We are concerned that continuing with the status quo approach may cause public utility transmission providers to undertake relatively inefficient investments in transmission infrastructure, . . . That dynamic may result in transmission customers paying more than necessary to meet their transmission needs, customers forgoing benefits that outweigh their costs, or some combination thereof[.]")

[121] NC DEQ, *North Carolina Clean Energy Plan: Transitioning to a 21st Century Electricity System* (Oct. 2019), available at https://files.nc.gov/ncdeq/climate-change/clean-energy-plan/NC_Clean_Energy_Plan_OCT_2019_.pdf.

Plan recommends that the Commission "determine how grid modernization can be linked to and informed by comprehensive system planning processes," and "develop submission requirements, including expectations for grid needs assessments and clear cost-effectiveness parameters."

This Commission has also noted the need for comprehensive transmission planning for generation, noting that "more deliberate and comprehensive planning" rather than the generator interconnection process, "is the appropriate method. . . to identify and plan for upgrades to the system that are in the public interest."[122] The North Carolina Utilities Commission Public Staff has taken a similar view, expressing in testimony its belief that comprehensive system planning "will produce more efficient, cost-effective results than the piece-meal planning and construction approach currently being used."[123]

Proactive transmission carries clear and significant benefits to utility customers and other users of the grid. The ambitious decarbonization mandates of H.B. 951 make it even more critical that a process for proactive transmission planning be established in North Carolina. Achieving 70% carbon reduction and ultimately carbon neutrality will require the integration of a great deal of new generation on Duke's system. However, no proactive planning process exists at this time and no definitive steps have been taken to establish such a process.

Establishing a proactive transmission planning process, especially one that is coordinated with utility resource planning, is a complex endeavor that cannot be completed quickly. Given the significant resources that are being dedicated to simply to establishing the initial Carbon Plan, it is unlikely that any progress will be made on establishing a proactive process before the end of 2022. However, given the urgency of adding new resources to meet the 2030 mandate, and the

[122] Order Denying Certificate of Public Convenience and Necessity, Docket No. EMP-105, Sub 0 (June 11, 2020) ("Friesian Order") at 7.
[123] *Id.* at 30.

long lead time for construction of transmission upgrades, it would be imprudent to wait until a proactive process is established before beginning construction of transmission upgrades for new generation in North Carolina.

Although the Red Zone Upgrades are not the product of an integrated, proactive transmission planning process (of the type that should ultimately be established in North Carolina), the analysis supporting those upgrades is sound, and the experience of sophisticated solar development companies supports the need for those upgrades to meet the decarbonization mandates of H.B. 951. Accordingly, the proposed Red Zone Upgrades represent an important first step towards proactive transmission planning in North and South Carolina.

### B. The Red Zone Upgrades are needed to integrate significant new solar resources in Duke's service territories.

#### 1. History of the Red Zone Upgrades

A very significant proportion of the early solar project development Duke's service territories occurred in DEP's service territory in southeastern North Carolina and northeastern South Carolina, and in the portion of DEC's service territory in South Carolina. These primarily rural areas, collectively referred to as the "Red Zone" because of transmission constraints, are particularly desirable for solar development for several reasons. These include low land costs, favorable topography and irradiance, the availability of large parcels of land, and the willingness of landowners to lease their property out for solar development (perhaps owing to a lack of economically competitive uses for that land). The income from solar project leases has allowed many landowners to continue farming on portions of their land not made available for solar project development.

Duke had identified the Red Zone as transmission constrained by 2017 and barred any further development of utility-scale solar projects in the Red Zone (even on distribution circuits) due to potential impacts on transmission circuits. By early 2018, Duke had concluded that no additional projects could interconnect in these areas, even on the distribution system, without triggering major upgrades.

In a letter filed with the Commission in December 2019 in the CPCN docket for the Friesian Solar project,[124] Duke stated that one subset of the Red Zone Upgrades (the so-called "Friesian upgrades") was representative of the types of upgrades that would be required to achieve future CO2 reduction targets. Duke noted that the Friesian upgrades would "provide sufficient transmission capacity to allow the interconnection of additional solar generating facilities in the southeast portion of the DEP service territory," and that those upgrades would accommodate the interconnection of approximately 1000 MW of additional generation. Duke also noted that if the Friesian upgrades were not constructed at that time, "the need for the Friesian Network Upgrades will not go away" and the cost of the upgrades would simply be allocated to later-queued projects.

The Friesian project was not approved, in part because the associated upgrades had not been approved by the North Carolina Transmission Planning Collaborative ("TPC"), and so the Friesian upgrades were not constructed. However, the necessity for those upgrades, as well as most of the other Red Zone Upgrades, was identified in the Transitional Cluster Study ("TCS"), the first cluster study conducted by Duke after the approval of its Queue reform proposal.[125] In

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[124] NCUC Docket No. EMP-105, Sub 0.

[125] See *Duke Energy Progress, LLC Transitional Cluster Study Phase 1 Report* (Feb. 28, 2022), available at https://www.oasis.oati.com/woa/docs/CPL/CPLdocs/2022-02-28_DEP_TC_Phase_1_Study_Report.pdf; and *Duke Energy Carolinas, LLC Transitional Cluster Study Phase 1 Report* (Feb. 28, 2022), available at https://www.oasis.oati.com/woa/docs/DUK/DUKdocs/2022-02-28_DEC_TC_Phase_1_Study_Report.pdf. Other RZEP upgrades had been identified in prior serial interconnection studies.

another CPCN proceeding last year (this one related to the Juno Solar project), Duke engineers testified that the upgrades identified in the TCS process would be needed to achieve the requirements of H.B. 951.[126] Although the TCS spread the cost of those upgrades across a number of projects, the per-project cost of those upgrades was prohibitive and the projects to whom those costs had been allocated (including Juno Solar) withdrew.

In short, the need for the Red Zone Upgrades have been identified in several successive generator interconnection studies, including grouping studies carried out post queue reform. And if any project in a future DISIS cluster seeks to interconnect in the Red Zone, the same upgrades (or a subset thereof) will again be triggered.

The repeated identification of the Red Zone Upgrades in successive interconnection studies conducted since 2017 provides a reasonable basis for identifying the need for these projects considering the significant deployment of additional solar resources that will be needed for H.B. 951 compliance.

In the current Notice of Proposed Rulemaking on transmission planning, FERC observes that when an upgrade is identified in multiple successive interconnection requests and it has not been constructed, that is a good indication that the area of the grid where the upgrade is triggered is favorable for development. However, the allocation of upgrade costs in the interconnection process either to single customers or small clusters of customers may mean that it is never economic for customers to fund those upgrades – even if the upgrades have significant transmission benefits that extend beyond the interconnection customer.[127] Consequently, FERC

[126] NCUC Docket No. EMP-116, Sub 0.
[127] 2022 NOPR at P 161-165.

is proposing to require that such upgrades be considered for inclusion in Local Transmission Plans developed through processes like the TPC.[128]

The Red Zone Upgrades provide a textbook example of the dynamic FERC is concerned with: they have been identified in several successive interconnection studies over a short period of time, but no customer or cluster of customers has found it economic to fund them. The need for those upgrades will not go away. And their construction will create significant benefits to the system, in that they will facilitate the interconnection of significant additional generation, which is unquestionably needed. But under the piecemeal approach to system planning through the generator interconnection process, they will probably never be built.

2. The Red Zone Upgrades are needed for H.B. 951 compliance.

Duke's Carbon Plan, as proposed, projects that the company will add between 8 and 12 gigawatts (GW) of additional solar and solar plus storage to its system by 2035. Given that the Red Zone areas contain the largest concentration of land assemblages for competitive solar sites in DEP and DEC territory, there is no doubt that if the Red Zone Upgrades are constructed, they will be utilized for additional generation.

Questions have been raised by some stakeholders as to whether there may be other more cost-effective areas of Duke's service territory in which to site solar projects. Providing a reasonably definitive answer to this question would require developing an integrated, comprehensive process for generation and transmission planning across Duke's entire transmission system. As discussed, such a process does not currently exist and probably will not exist for some time.[129]

[128] 2022 NOPR at P 107, 150, 162

[129] Moreover, it is unclear whether any such process can identify the best location for transmission investments with precision because there are many factors that affect whether land will ultimately be available for generation project development.

However, the commercial experience of PGR and other CPSA members indicates that, while it may be possible to build some additional solar on Duke's system at low cost and without incurring large upgrade costs, it is simply not possible to build an additional 8 to 12 additional GW of solar at a reasonable price without constructing the Red Zone Upgrades.

There are several factors that make the territories outside the Red Zone less viable for development of large solar facilities. But first, it must be noted that the Red Zone represents a very substantial portion of Duke's combined service territories. And transmission-scale projects need to be located within a reasonable distance from Duke's transmission lines. The footprint of Duke's transmission system is significantly smaller than that of the distribution system, and there are large portions of Duke's service territory (especially in rural areas) where there are simply no transmission lines nearby. So transmission-accessible, non-Red Zone territory represents well under half of Duke's combined territories.

As noted, the Red Zone contains the highest concentration of land assemblages with favorable topography, prices, contiguity, and size, as compared to other regions in DEP and DEC. On this last issue, the target size for solar development has increased from an average of 2-10 MWAC to the more recent target of 50-80 MWAC. This means that the geographical size of solar projects has increased by an order of magnitude, making the availability of large contiguous tracts even more of a limiting factor for development. It also requires getting consent from more landowners, which developers have found is significantly more difficult outside of the Red Zone.

The difficulty of developing competitive solar projects outside the Red Zone is discussed in further detail in letters from CPSA members Pine Gate Renewables and Southern Current, in recent comments to the TPC's Transmission Advisory Group ("TAG"). Pine Gate and Southern Current are among the most sophisticated and experienced solar developers operating in Duke's service territories, and collectively they have developed multiple gigawatts of utility-scale solar projects in the Carolinas and throughout the United States. Their experience is consistent with that of other companies attempting to develop projects in and out of the Red Zone.

3. Can the Red Zone Upgrades be "market tested"?

Another way to investigate solar development potential in various areas of Duke's service territory is to put the question to the market via a competitive solicitation and see whether there is a sufficient volume of projects in areas outside the Red Zone, inclusive of upgrades, with pricing beats pricing inside the Red Zone with upgrades.[130]

However, there are several limitations with this approach. First, a solicitation must be structured to encourage robust market participation in all areas of Duke's service territory. In particular, there must be a significant number of projects located in areas where there are likely to be significant upgrades. If only a small number of projects in constrained areas participate (which may be the case if the developers of those projects believe they will not be competitive due to significant Upgrade costs), then the full cost of those upgrades will be allocated to a small number of projects, even if those upgrades will create enough headroom for gigawatts of projects to interconnect.

Even if there is robust participation, the results of the procurement will not provide an accurate market test unless the procurement is large enough to spread the cost of those Upgrades across a large number of projects. Even then, the cost of those upgrades (on a LCOT basis) will be overstated, because (unless the procurement is very large) the upgrades will facilitate significantly more generation that will be selected in a single procurement. It would defeat the whole purpose of proactive planning to rely on a single procurement, no matter the size, to identify

[130] This approach weighs in favor of a much larger 2022 procurement than Duke has proposed.

and allocate the cost of long-term upgrades that will also create headroom for additional generation on the system. Although cluster studies are an improvement over the serial interconnection process, this is just a variation on constructing upgrades through the generator interconnection process, which (as discussed) is less efficient and more costly than long-term, proactive planning.

In the absence of a comprehensive, integrated transmission and generation planning process, with clear cost-effectiveness metrics, the Commission will not have definitive information about the cost-effectiveness of the Red Zone Upgrades, or any other set of upgrades.[131] Indeed, even if such a process existed today, it would not provide a completely certain answer.

However, there is already more than enough information to conclude that the Red Zone Upgrades will be utilized, and that they represent a set of "no regrets" upgrades for achieving the mandates of H.B. 951. Given the long lead time for transmission projects and the large volume of renewables that will need to be deployed to achieve H.B. 951's 2030 mandate, it is imperative that these upgrades move forward sooner rather than later. Moreover, given the inefficiency of transmission upgrades scoped by the current generator interconnection process, and the consistent increases in transmission costs in recent years (a trend that is likely to continue), it's almost certain that waiting means it will cost more to build the same upgrades.

Waiting to construct these upgrades means that Duke will be constructing more upgrades in a piecemeal, reactive fashion. That takes longer, is less efficient and costs more. Moreover, the cost of constructing transmission projects has been increasing at a rate of 15-20% per year – a trend that is expected to continue or become worse in a time of record inflation and unprecedented supply chain challenges. Whether those upgrade costs are passed directly through to ratepayers or

[131] It should be noted that the $748 million in reliability projects already in the Local Transmission Plan also have not been subject to any cost-effectiveness analysis.

included in bid pricing, that means higher cost to ratepayers. Waiting also means that it will be that much harder to meet the requirements of H.B. 951 in a timely fashion.

### C. The Commission Should Consider the Benefits as Well as the Costs of Transmission Upgrades.

Duke's analysis in Appendix P of the Carbon Plan, and the additional information provided by CPSA herein, provide a compelling case that construction of the Red Zone Upgrades is necessary to achieving the requirements of H.B. 951. That case is even stronger when the additional benefits of those upgrades – not discussed in detail by Duke – are considered.

There are well-established practices from other jurisdictions for quantifying the ancillary benefits of transmission investments, which are described in reports prepared by Brattle.[132]

In studying benefits, it is critical to use realistic projections of the anticipated generation mix, policy mandates, load levels, and load profiles over lifespan of the transmission investment.[133] Benefits should not be limited to production cost savings – as Brattle points out, there is extensive experience elsewhere around quantifying multiple additional values that transmission investment can generate. These benefits include production cost savings, congestion relief, reduced curtailment, and lower transmission outage costs, reliability improvements for load customers, and avoided costs for the replacement of aging facilities.[134]

Given the long lifetime of transmission assets, it is important to calculate benefits over the lifetime of the assets. This is important given the cost-benefit profile of these assets, whereby costs under the utility ownership model tend to decrease over time as the assets depreciate in the asset

[132] Brattle Report at 38-51; Exhibit E, Brattle Group / GridStrategies, Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs (Oct. 2021) ("Brattle/GridStrategies Transmission Planning Report"), available at https://www.brattle.com/wp-content/uploads/2021/10/2021-10-12-Brattle-GridStrategies-Transmission-Planning-Report_v2.pdf.
[133] Brattle Report at 44.
[134] Brattle Report at 47.

base, while benefits often increase over time. Hence, taking a levelized measure of costs and benefits over a forty-odd year period (the regulatory lifetime of the transmission asset) is important to a robust analysis of costs and benefits.



### D. Duke should be required to study grid enhancing technologies.

As discussed above, the Red Zone Upgrades represent a "no regrets" set of upgrades that will, with a high degree of certainty, be needed to enable compliance with H.B. 951. However, over the long term, additional upgrades are likely to be needed, at higher cost. Duke acknowledges that one set of upgrades will not be sufficient to enable compliance, noting that while the Red Zone upgrades will be "very successful with enabling interconnections of the first phase of Carbon Plan resources," they "will not be sufficient to interconnect later phases of incremental resources associated with Carbon Plan implementation."[135]

CPSA does not dispute that additional upgrades are likely to be required, and should be proactively planned in an integrated transmission planning process. However, Duke should also be investigating the potential for so-called Grid Enhancing Technologies (GETs) to increase the cost-effectiveness of any additional upgrades required for 951 compliance.

GETs, which include such measures as dynamic line ratings, topology optimization, and advanced power flow control, have the potential to reduce costs, enhance benefits, and expedite interconnection timelines for new generation and load.

Although Duke does not discuss them in the Carbon Plan, GETs are increasingly deployed in other jurisdictions, to the benefit of customers. For example, a report published by the DoE in February 2022[136] looks at a case study of a specific area of New York State, and finds that Dynamic

[135] Carbon Plan Appx. P p. 14.
[136] U.S. Department of Energy, Grid-Enhancing Technologies: A Case Study on Ratepayer Impact (Feb. 2022), available at https://www.energy.gov/sites/default/files/2022-

Line Ratings and Power Flow Controllers can be deployed to great effect, and, depending on the solution, would have payback periods of around one to no more than six years.

Another report recently published by Brattle[137] considered a case study of an SPP region (focused on Kansas and Oklahoma) and found that employing GETs (dynamic line ratings, topology optimization, and advanced power flow control) can unlock over twice the renewables integration capability with the same infrastructure. The annual benefits of GETs in this study would be approximately two times the upfront costs, and over seventeen times the ongoing O&M costs – around a half-year payback period.[138]

Recognizing the significant system benefits of GETs, FERC has proposed reforms to more holistically incorporate GETs into regional planning in the current transmission planning NOPR.[139] To enhance the cost-effectiveness of solutions identified through regional planning processes, FERC proposes that dynamic line ratings (DLR) and advanced power flow control (APFC) devices be more fully considered by transmission providers in regional planning processes.[140]

FERC proposes that, for each identified regional transmission need, utility transmission providers consider whether selecting facilities with DLRs or APFCs would be more efficient than

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04/Grid%20Enhancing%20Technologies%20-%20A%20Case%20Study%20on%20Ratepayer%20Impact%20-%20February%202022%20CLEAN%20as%20of%20032322.pdf.

137 Brattle Group, Unlocking the Queue with Grid-Enhancing Technologies (Feb. 1, 2021), available at https://watt-transmission.org/wp-content/uploads/2021/02/Brattle__Unlocking-the-Queue-with-Grid-Enhancing-Technologies__Final-Report_Public-Version.pdf90.pdf.

138 Id. p. 11.

139 Notice of Proposed Rulemaking, Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection , 87 Fed. Reg. 26,504 (May 4, 2022) ("NOPR"), at P 256-277, available at https://www.govinfo.gov/content/pkg/FR-2022-05-04/pdf/2022-08973.pdf

140 See NOPR at P 272 ("We believe that selecting transmission facilities that incorporate dynamic line ratings or advanced power flow control devices in the regional transmission plan for purposes of cost allocation may offer a more efficient or cost-effective alternative to other regional transmission facilities in certain instances.")

without DLRs or APFCs – both in terms of whether incorporating DLRs/APFCs into existing facilities would avoid the need for new facilities, and whether it would be more efficient to incorporate these into new facilities when built.[141]

To be clear: despite the eventual promise of GETs to reduce upgrade costs, it would not be prudent to delay construction of needed transmission upgrades while Duke implements grid enhancing technologies. It is clear that system expansion will be needed and beneficial to realizing the Carbon Plan goals at the lowest cost to ratepayers while retaining reliability. Moreover, by all appearances Duke has not even begun to consider implementation of GETs and will likely have to complete extensive studies to ensure that GETs do not compromise reliability.

However, GETs may ultimately reduce aggregate costs to ratepayers, by expanding the capabilities of upgrades that are constructed and by avoiding the need for some other upgrades. Importantly, GETs may also and can accelerate the timeline over which resources can be interconnected. Given that Duke has referenced transmission upgrades as one of the primary bottlenecks creating a solar interconnection cap, GETs should be seriously considered as a near-term opportunity to bolster headroom in the system in the interim period while Duke constructs necessary network upgrades.

Accordingly, Duke should be directed to investigate the role for GETs in the system, including the potential additional headroom that these technologies can create, and the attendant costs and benefits of different GETs integration opportunities.

## VII. Conclusions and Request for Modification of Carbon Plan

Although Duke's proposed Carbon Plan represents a sophisticated and thorough analysis in most respects, there are several aspects in which Duke falls short of its obligation to achieve

[141] Id. at P. 274.

compliance with the 70% carbon reduction mandate of H.B. 951 on time and at least cost to ratepayers. For the reasons discussed above, CPSA makes the following recommendations to the Commission.

1. Direct Duke to make the following changes to the Carbon Plan:
   a. Add portfolio CPSA1;
   b. Remove Portfolios P3 and P4;
   c. Replace Portfolio P1 with portfolios CPSA2 and CPSA3;
   d. Replace Portfolio P2 with portfolios CPSA4 and CPSA5;
   e. Revise the near-term Execution Plan to include solar procurements in of 1500 MW in 2022 and 2023, and 1800 MW in 2024; and
   f. Direct that all solar procured after 2022 be paired with storage until the storage requirements of the Carbon Plan portfolios are met.
2. Approve the construction of the Red Zone Upgrades;
3. 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. Commission a third party, assisted by an independent technical advisory committee, 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
   d. Immediately commence the study of Grid Enhancing Technologies for possible use in transmission and interconnection studies and transmission planning; and
4. 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.

## VIII. List of disputed issues

In compliance with the Commission's April 1, 2022 Order Establishing Additional Procedures and Requiring Issues Report; and its June 25 Procedural Order, CPSA's list of potentially contested issues is presented below. Please note that this list is preliminary and is subject to change based on other intervenors' comments and discussions with Duke and other parties. CPSA believes that it would be possible for the Commission to resolve most of these issues without the need for an evidentiary hearing by approving a Carbon Plan that replaces Duke's portfolios with those proposed by CPSA.

In the interest of facilitating this outcome and limiting the need for an expensive and time-consuming hearing, CPSA has intentionally included portfolios in its proposal that are consistent with Duke's overly conservative assumptions regarding the annual rate of solar additions. CPSA is also not proposing that the Execution Plan support a portfolio with no constraints on solar additions, and is proposing a lower rate of solar additions in 2026 and 2027 than in future years.

If, however, the Commission is not prepared to approve CPSA's requested modification to the Execution Plan to increase the rate of near-term solar procurement without an evidentiary hearing, then a hearing should be held on that issue. In addition, CPSA believes that TPC approval of the Red Zone Upgrades would provide strong probative evidence that those upgrades are in fact needed such that an evidentiary hearing on that issue would not be required.

| **Issue** | **Comment Section** |
|---|---|
| CPSA alternative portfolios | III.C |
| Solar Interconnection cap | I.A |
| Solar + storage configurations modeled | II.B |
| SMR risks / assumptions | IV.C, II.C |
| Modeling Cost assumptions | II.C |
| Legality of extending compliance with 70% mandate beyond 2032 | III.B |
| Comparison of portfolios (execution risk, affordability, CO2 reductions, reliability) | IV |
| CPSA Proposed Portfolios | III.C |
| Execution plan | V |
| 2022 procurement volume | V |

| | |
|---|---|
| Red Zone Upgrades | VI.B |
| Need for proactive transmission planning | VI.A |
| Grid enhancing technologies | VI.D |
| Need to factor benefits as well as costs of transmission improvements | VI.C |

Respectfully submitted this the 15th day of July 2022.


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**CERTIFICATE OF SERVICE**

I hereby certify that all persons on the Commission's docket service list have been served true and accurate copies of the foregoing Petition to Intervene by hand delivery, first class mail deposited in the U. S. mail, postage pre-paid, or by e-mail transmission with the party's consent.

This the 15th day of July 2022.

/s/ Benjamin L. Snowden

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