PUBLIC (REDACTED) VERSION

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

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

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Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION.

A. My name is John Michael Hagerty. My business address is 1800 M St Northwest, Washington, DC 20036. My current position is Senior Associate for The Brattle Group ("Brattle").

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL QUALIFICATIONS.

A. I received a M.S. in Technology and Policy from the Massachusetts Institute of Technology and a B.S. in Chemical Engineering from the University of Notre Dame. I have over 10 years of experience in utility and electric power industry planning and regulatory reviews, including utility resource planning, transmission planning, valuation of renewable energy, storage, and transmission assets, wholesale market design to achieve resource adequacy requirements, and optimized approaches to economy-wide deep decarbonization. Amongst other publications, I was the lead author on a study of the Duke Energy system last year during the development of H.B. 951 legislation titled "A Pathway to Decarbonization: Generation Cost & Emissions Impact of Proposed NC Energy Legislation."[1]

Q. WHAT ARE YOUR RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. I provide economic and financial analysis for a broad set of clients in the electric utility industry that are mostly focused on the drivers for new infrastructure investment in a decarbonizing world, including renewable energy and gas-fired

[1] https://www.brattle.com/wp-content/uploads/2021/09/A-Pathway-to-Decarbonization-Generation-Cost-and-Emissions-Impact-of-Proposed-NC-Energy-Legislation_Revised-September-2021.pdf

generation resources as well as transmission assets. My clients include electric utilities, renewable energy and storage developers, transmission developers, system operators, environmental organizations, and state agencies.

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

A. I have not testified previously before the North Carolina Utilities Commission. I previously testified before the Public Service Commission of Wisconsin on behalf of Wisconsin Public Service Corporation ("WPSC") and Wisconsin Electric Power Company ("WEPCO"), regarding the cost effectiveness and system benefits of two facilities: (1) a natural gas-fired reciprocating internal combustion engine generating facility that WEPCO and WPCS proposed to construct and (2) a solar and battery energy storage system that WEPCO and WPCS proposed to acquire. I have also previously testified before the Alberta Utility Commission in Canada concerning the costs of new gas-fired resources in the Alberta Electric System Operator market. I submitted affidavits to the Federal Energy Regulatory Commission ("FERC") concerning the costs of new and existing generation resources on behalf of PJM Interconnection, LLC., end of life transmission planning processes on behalf of LS Power, and transmission needs for transportation electrification on behalf of Michigan Electric Transmission Company. I have also co-written filed regulatory reports to the California Public Utilities Commission on the benefits of a new high-voltage transmission facility and to the Public Service Commission of the District of Columbia on electricity demand growth from transportation and heating electrification.

Q. PLEASE DESCRIBE THE WORK BRATTLE PERFORMED IN SUPPORT OF CPSA'S INITIAL COMMENTS ON THE CARBON PLAN.

A. I reviewed the draft Carolinas Carbon Plan ("Carbon Plan") and evaluated options for Duke Energy Carolinas ("DEC") and Duke Energy Progress ("DEP") (collectively, "Duke") to achieve the 70% carbon reduction mandate of H.B. 951. To inform that evaluation, I conducted modeling simulations of generation and storage resources in Duke's service territory to identify alternative generation and storage resources portfolios, specifically evaluating the effects of the solar interconnection limit that Duke proposed in the Carbon Plan and the compliance year for achieving the 70% carbon reduction mandate.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is to (1) provide an assessment of the modeling simulations Duke performed in developing the Carbon Plan, (2) summarize the alternative modeling simulation I completed to inform the Carbon Plan, (3) respond to Duke's comments regarding our modeling simulations, (4) summarize alternative approaches to transmission planning, and (5) comment on the proposed Execution Plan.

Q. PLEASE PROVIDE A BRIEF SUMMARY OF YOUR TESTIMONY.

A. My testimony comes to the following conclusions:

- Duke's modeling simulations include flawed assumptions, including its assumptions concerning solar interconnection limits, solar plus storage configurations, nuclear small modular reactor ("SMR") costs and development timeline, onshore wind capacity, and electric vehicle demand forecast;

- Duke's flawed assumptions increase the risk of Duke not achieving the Carbon Plan mandates, or doing so at higher cost to its ratepayers;
- Duke should increase the solar interconnection limits in its modeling simulations, while reflecting reasonable assumptions about the higher costs and risks of doing so that are based on technical analysis of their transmission system, instead of relying on their judgment of indicative trends;
- Duke's supplemental modeling relies heavily on the addition of a 285 MW nuclear SMR in mid-2032 to achieve the Carbon Plan mandates, even though the costs of this technology are unsupported, the selected technology has not yet received regulatory approval, and the nuclear industry has a recent track record of cost overruns and schedule delays;
- Despite the reliance on nuclear SMRs, the supplemental modeling runs (specifically SP5 and SP5 High Solar Interconnection) represent an incremental improvement over Duke's initial portfolios by (1) identifying more solar additions compared to P2, (2) incorporating new configurations of solar paired with storage, and (3) increasing the amount of battery storage paired with solar, all of which support CPSA's recommendation on higher near-term solar procurement;
- Our modeling demonstrates that the higher solar interconnection limit proposed by CPSA will increase projected solar additions and reduce the total costs of achieving the Carbon Plan requirements;
- Duke's criticisms of our modeling are unfounded. In particular, our modeling adequately accounts for system reliability, as evidenced by the fact that I

identify similar additions of gas CC (2,400 MW), gas CTs (up to 1,100 MW), and battery storage (2,300 – 4,200 MW) by 2032 to replace retiring coal plants and maintain system reliability;

- Duke should leverage existing experience across the power sector industry to establish a comprehensive and proactive transmission planning process for the Carolinas that will facilitate the achievement of the Carbon Plan mandate.

I. MODELING ISSUES

(a) Concerns with Duke's Modeling Assumptions

Q. DO YOU HAVE ANY CONCERNS WITH THE ASSUMPTIONS THAT DUKE INCLUDED IN ITS MODELING ANALYSIS FOR THE CARBON PLAN?

A. Yes. There are several issues with their modeling assumptions that are problematic. The most concerning modeling assumption is the interconnection limit set on new solar resources. In addition, I have concerns about Duke's modeling assumptions regarding the costs and configurations of solar paired with storage, the assumed costs and availability of new nuclear small modular reactor (SMR) plants, the assumed amount of onshore wind available for development in the Carolinas, and the projected demand from electric vehicles. Finally, I am concerned about Duke's approach to setting the annual CO_2 emissions in the years following achievement of 70% reduction relative to 2005 CO_2 emissions. In the sections below, I explain my specific concerns and the impacts of Duke's flawed assumptions.

Q. WHAT ARE THE IMPLICATIONS OF THESE CONCERNS REGARDING DUKE'S MODELING ON THE CARBON PLAN?

A. The cumulative implications of the concerns I have with Duke's Carbon Plan modeling is that they risk not achieving the requirements of the Carbon Plan by: (1) restricting the addition of solar in the near-term based on limited analysis and evidence, (2) relying on their aggressive assumptions with regard to the feasibility of new nuclear SMRs and onshore wind, and (3) under-forecasting total demand by 2032. The inability to develop sufficient onshore wind or nuclear SMRs by 2032 along with the potential for higher-than-forecast demand will risk coming up short on the CO_2 reduction goals. In addition, unsupported restrictions on new solar additions would likely increase future system costs. Duke can take step in the short-term to limit the risk of not achieving the CO_2 emissions reductions goals by increasing near-term procurements of solar generation above the currently proposed solar interconnection cap.

Q. CAN YOU PLEASE EXPLAIN YOUR CONCERN WITH DUKE'S SOLAR INTERCONNECTION LIMIT ASSUMPTIONS?

A. Duke sets an annual limit on how much solar capacity can interconnect to its system prior to the potential compliance dates. Duke applies a lower limit to the portfolios in which it sets the compliance date as 2032 or 2034. Duke applies a slightly higher limit to P1, the only portfolio that targets 2030 compliance. Duke's assumed interconnection limit allows 4,500 MW of new solar capacity to interconnect by 2030 in the low case and 5,400 MW in the high case.

Duke provides several considerations in the Carbon Plan and its testimony that inform their engineering judgment regarding the amount of solar capacity that can interconnect in a given year. The primary considerations are based on indicative trends in solar development and interconnection and not on detailed technical analysis that support the specific limits proposed. Their considerations include challenges associated with the interconnection process, including studying the interconnection requests to identify the necessary upgrades, and building upgrades in transmission constrained zones. However, as discussed in the direct testimony of CPSA witness Ryan Watts, Duke does not provide any technical analysis that would support the specific values they have assumed. Therefore, it is unclear how each of the considerations Duke raises on interconnection challenges relate to the specific capacity limits imposed on their modeling assumptions. The basis Duke provides also does not account for the potential between now and 2030 or 2032 to continue to improve their transmission planning process and allow for greater quantities of low-cost solar resources to interconnect to its system.

By limiting capacity additions of the lowest cost renewable energy resources available, Duke increases both costs to ratepayers and the risk that Duke will not meet the carbon reduction mandates of H.B. 951. As I will describe below, both the results of Duke's supplemental modeling and our modeling simulations in GridSIM demonstrate that the solar interconnection limit results in an increase in system costs.

Q. HOW COULD DUKE BETTER IDENTIFY THE LEAST-COST RESOURCE MIX TO MEETING THE CARBON PLAN GOALS WITHOUT THE SOLAR INTERCONNECTION LIMIT?

A. Identifying the least-cost resource mix to achieve the Carbon Plan must account for both generation and transmission costs. The least-cost generation and transmission resource plan can be identified either through including more detailed assumptions in a model, like EnCompass or GridSIM, that roughly co-optimizes generation and transmission expansion or by running multiple scenarios that consider different transmission expansion options.

For example, Duke included a transmission interconnection cost adder to its estimate of solar costs and other resources. However, they applied that interconnection cost adder to new solar only up to the imposed capacity limit, and then did not allow any additional solar capacity beyond that limit. This approach implies that there is no cost at which more solar and its associated transmission upgrades could be built beyond the assumed limit. Duke claims that the solar interconnection limit is justified because (1) the "[a]reas that are most viable for solar development from a land availability / land quality standpoint are primarily located in transmission constrained regions" and (2) cites the "transmission expansion needs and the time to construct new transmission infrastructure to accommodate increasing levels of renewables and other resources." Both of these limitations could be reflected in their modeling through higher interconnection cost assumptions at increasing levels of solar penetration, instead of completely cutting off the potential for additional solar development. For example, Duke could develop reasonable cost estimates based on the potential locations of new solar resources and the transmission system capability, or based on the network upgrades costs identified through the interconnection queue process. The estimated incremental interconnection costs for additional solar could then inform a step function in which transmission interconnection costs increase as greater amount of transmission upgrades are necessary to interconnect more solar.

For example, in its 2020 study the North Carolina Transmission Planning Collaborate ("NCTPC") studied the transmission upgrades and associated costs to interconnect offshore wind resources in its service territory. Duke then relied on the results of that study to determine the assumptions to include in its Carbon Plan simulation concerning the likely locations where offshore wind resources would interconnect into its system and the costs of the transmission upgrades.[2]

The California Public Utility Commission uses this approach in identifying the lowest cost resource mix to achieve similar carbon reduction goals in its Integrated Resource Planning process.[3] As shown in Table 1 below, the capacity expansion model assumes that additional transmission costs (shown in column 2 as "Incremental Deliverability Cost ($/kW-year)") will be necessary after a certain amount of resources are built in a renewable energy zone (shown in the three right-most columns).

[2] Draft Carbon Plan Appendix P at 16.
[3] https://files.cpuc.ca.gov/energy/modeling/Inputs%20%20Assumptions%202019-2020%20CPUC%20IRP%202020-02-27.pdf at 55.

Table 1: Incremental Transmission Costs in California Public Utility Commission Integrated Resource Planning Studies1

Transmission Zone or Subzone	Incremental Deliverability Cost ($/kW-yr)	FCDS Availability on Existing Transmission, Net of Post-2018 COD Baseline Capacity (MW)	Energy-Only Availability on Existing Transmission (MW, Default) ***	Energy-Only Availability (MW, Sensitivity) ****
Carrizo	$10	187	0	700
Central_Valley_North_Los_Banos	$36	791	0	500
GLW_VEA	$14	596	0	1470
Greater_Imperial	$221	919	1900	1900
Greater_Kramer	$48	597	0	0
Humboldt	$999**	0	100	100
Inyokern_North_Kramer	$161	97	0	0
Kern_Greater_Carrizo	$21	784	700	3680
Kramer_Inyokern_Ex*	$999**	0	0	0
Mountain_Pass_El_Dorado	$7	250	2150	3790
None	$0	0	0	0
North_Victor	$161	300	0	0
Northern_California_Ex*	$999**	866	0	0
Riverside_Palm_Springs	$88	2665	2550	3100
OffshoreWind_UnknownCost	$999**	0	0	0
Sacramento_River	$19	1995	2600	2600
SCADSNV	$102	2434	6600	10260
Solano	$21	599	700	700
Solano_subzone	$999**	0	0	0
Southern_California_Desert_Ex*	$999**	862	0	0
SPGE	$7	675	700	4080
Tehachapi	$13	3677	800	1800
Tehachapi_Ex*	$999**	0	0	0
Westlands_Ex*	$999**	1779	0	0

* Resources that end in "Ex" refers to areas outside of the CAISO transmission cost and availability estimates

Source: https://files.cpuc.ca.gov/energy/modeling/Inputs%20%20Assumptions%202019-2020%20CPUC%20IRP%202020-02-27.pdf

Alternatively, Duke could develop several alternative future transmission buildout scenarios – one with minimal solar-focused transmission upgrades and one with significant solar-focused upgrades – and identify the least-cost resource mix in each case. The total costs of the scenarios would include both the costs of the transmission upgrades and the generation resources. PacifiCorp used this approach in their 2021 Integrated Resource Planning process, by studying the optimal resource mix with and without two major transmission upgrades, including the Gateway South project and the Hemingway-to-Boardman project.[4]

Additional examples of how other system planners have co-optimized transmission and generation investment include the ERCOT Long-Term System Assessment and the Midcontinent ISO Multi-Value Project planning.

In either case, once Duke has developed alternative approaches to achieving its Carbon Plan goals, they can then analyze the tradeoffs of the alternative portfolios, including additional detailed analysis of the transmission system impacts and any risks associated with the transmission buildout, such as outage coordination. Only if the optimal resource mix either cannot be achieved through transmission planning and interconnection processes or requires significant incremental costs or risks not considered in the capacity expansion modeling, should Duke deviate from the least-cost resource mix.

Q. CAN YOU PLEASE EXPLAIN YOUR CONCERN WITH DUKE'S ASSUMPTIONS ON SOLAR PAIRED STORAGE?

A. Duke's portfolios in its Draft Carbon Plan add between 1.7 and 2.2 GW of battery storage to meet the 70% decarbonization mandate without differentiating between standalone storage and storage paired with solar ("paired storage").[5] Then in its execution plan, Duke proposes to procure 1,000 MW of standalone storage and 600 MW of paired storage.[6] However, Duke provides no information based on their

[4] https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/Volume%20I%20-%209.15.2021%20Final.pdf at 263.
[5] Carbon Plan, Executive Summary at 14.
[6] Carbon Plan, Chapter 4 at 5.

modeling results to justify the levels of economic paired storage versus standalone storage built across scenarios.[7]

Duke's proposal to rely more on standalone storage than paired storage is counterintuitive because paired storage enjoys significant cost advantages over standalone storage. First, paired resources benefit from shared interconnection facilities and upgrades. Second, paired resources benefit from the cost efficiencies of independent ownership, which would result in 45% of the capacity accruing the benefits of the Investment Tax Credit ("ITC") upfront as opposed to being normalized over the asset lifetimes for 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 more than 15% below those of a utility-owned asset strictly due to accrual of ITC-related tax benefits upfront. Third, 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, which does not qualify for the Investment Tax Credit.[8]

There are additional advantages to paired storage over standalone facilities, including lower development expenses (only one site, permitting process, interconnection process, etc.) and mitigated solar energy curtailment (which could be as high as 5%-10%, not to mention clipping capture, in cases where resources

[7] Duke does provide information on standalone storage versus paired storage in its supplemental modeling runs.

[8] Note that standalone facilities will be able to qualify for the ITC going forward following the passage of the Inflation Reduction Act. We have not incorporated the changes due to the Inflation Reduction Act into our modeling simulations, as further discussed below.

are DC-coupled). Additional deployment of solar plus storage facilities would have collateral benefits, such as potentially relieving interconnection constraints.

I would not expect all battery storage to be built paired with solar however, as there are in some cases advantages to standalone battery storage. For example, in portions of the network that are import constrained and do not have high quality sites for solar development, standalone battery storage resources would be preferred over storage paired with solar. Despite that consideration, Duke's greater reliance on standalone battery storage (1,000 MW) than paired battery storage (600 MW) remains counterintuitive and requires additional justification.

Duke's modeling assumptions did not capture all of these considerations, resulting in a bias towards selection of less economic standalone storage resources. First, Duke failed to capture the full range of cost efficiencies that paired 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 IPP-owned paired battery storage resources and did not account for the reduced development costs of paired storage.

Second, Duke assumes that in the case of DC-tied hybrid solar and storage facilities, the storage system can only charge from the solar generating facility. 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.

Finally, Duke modelled an incomplete set of paired storage configurations. They only allowed for two configurations: 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 model a more complete set of scenarios, including (1) 2-hour, 25% storage capacity as a share of solar capacity and (2) 4-hour, 50% storage capacity as a share of solar capacity.

In aggregate, these changes would more accurately represent the advantages of paired storage facilities over standalone storage facilities, and would lead to the more economic outcome of prioritizing hybrid over standalone storage facilities.

Q. DID DUKE ADDRESS THE CONCERNS YOU HAVE RAISED ABOUT SOLAR PAIRED STORAGE IN ITS TESTIMONY?

A. Partially. Duke indicated that they "generally agree with intervenors that modeling additional SPS options is preferable."[9] Duke then included additional solar plus storage options in the SP5 and SP6 portfolios, specifically allowing the EnCompass model to select paired solar with a 4-hour battery storage at 50% of the solar capacity. Duke also allowed the battery storage, whether in standalone or paired configurations, to be economically dispatched. However, Duke did not adjust its assumptions regarding capital costs or the benefits of the ITC.

Q. CAN YOU PLEASE EXPLAIN YOUR CONCERN WITH DUKE'S NUCLEAR SMR COST ASSUMPTIONS?

A. Duke's capital cost assumptions for new nuclear SMR units are unreasonable and unjustified. Duke assumes total installed capital costs (overnight costs plus

[9] Modeling Panel at 153.

AFUDC) in 2032 of [redacted] (nominal dollars) for the GE BWRX-300 Small Modular Reactor.[10] Duke provided little basis for the assumed costs in the Draft Carbon Plan. When requested for more information, Duke provided no additional sources of the costs or the underlying assumptions.[11]

As a point of comparison, the EIA AEO estimates the capital costs of nuclear SMRs of [redacted] in 2021 dollars for first-of-its-kind plants and [redacted] in 2021 dollars for nth-of-kind. The difference between the two cost estimates is the EIA's "technological optimism factor." The EIA states that they "apply the technological optimism factor to the first four units of a new, unproven design; it reflects the demonstrated tendency to underestimate actual costs for a first-of-a-kind unit."[12] The EIA's first-of-its-kind cost is more relevant as few, if any, SMRs are expected to be completed by 2032, the earliest possible online date projected by Duke. For example, an August 2022 report by NARUC listed only two entities currently pursuing the GE-Hitachi BWRX-300 SMR design: Tennessee Valley Authority ("TVA") and Ontario Power Generators ("OPG").[13] The TVA unit is not expected to come online until at least 2032.[14]

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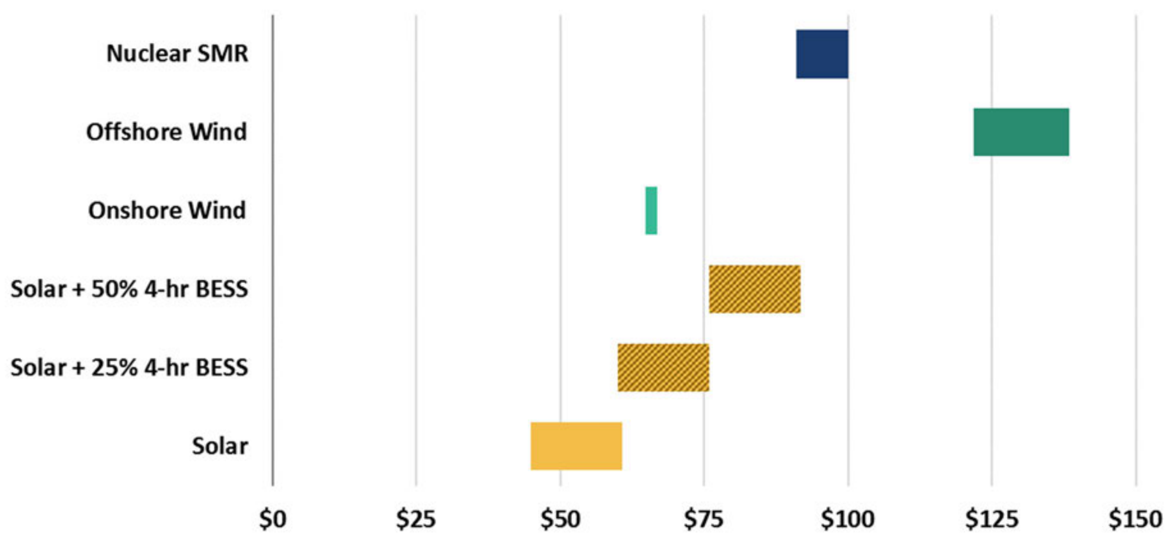
[10] Ex. 1, Duke Response to PSDR3-17 (confidential)
[11] Ex. 2, Duke Response to CPSA DR1-4.
[12] EIA, Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2022, at https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf (March 2022).
[13] Energy Ventures Analysis, Nuclear Energy as a Keystone Clean Energy Resource, prepared for NARUC, August 22 at 24, available at https://pubs.naruc.org/pub/916FC2AB-1866-DAAC-99FB-1A9F58CA5ECB.
[14] *Id.* 30.

To make an apples-to-apples comparison to the Duke costs, I escalated the EIA's first-of-its-kind capital costs from 2021 dollars to nominal dollars as of its commercial online date in 2032, which results in installed costs in 2032 of $9,614/kW (nominal dollars).[15] The EIA projected costs for nuclear SMRs are thus 33% higher than Duke's projected costs.

In either case, the nuclear SMR costs are significantly higher than solar, including solar paired with 4-hour battery storage (both in 25% and 50% of solar capacity configurations). Figure 1 below shows the projected range of levelized costs of several clean energy technologies in 2030. The range of renewable energy costs are based on the Moderate (lower costs) and Conservative (higher costs) projections in the 2022 Annual Technology Baseline. The range of nuclear SMR costs are based on the Duke cost assumptions (lower costs) and the EIA cost assumption (higher costs), assuming a 95% capacity factor.

Figure 1: Comparison of 2030 Levelized Costs by Technology (nominal $/MWh)



[15] EIA, Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2022, March 2022.

Source and Notes: Brattle analysis. The range of levelized costs for renewable energy resources are based on NREL 2022 Annual Technology Baseline costs, using the Moderate (low cost) and Conservative (high cost) cases. The range of nuclear SMR costs are based on Duke's cost estimates (low cost) and EIA cost estimates (high cost).

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 associated technology. Nuclear reactors may also face permitting delays related to required Nuclear Regulatory Commission ("NRC") approvals because new reactor models like the BWRX-300 have not yet obtained such approvals. In addition, fuel production, transport, and storage may present both delay and cost risks.

Duke's timeline for obtaining a CPCN for a new advanced nuclear plant[16] 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.

Recent 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

[16] Carbon Plan Ch. 4 at 18-19; Appx. L at 12.

estimate, and is more than seven years behind schedule.[17] In South Carolina, SCANA and Santee Cooper spent $9 billion for the partial construction of the V.C. Summer nuclear plant before cancelling construction.[18] 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.[19]

Q. CAN YOU PLEASE EXPLAIN YOUR CONCERN WITH DUKE'S ELECTRIC VEHICLE DEMAND ASSUMPTIONS?

A. Duke assumes 310,000 light-duty and nearly 12,000 medium- and heavy-duty vehicles will be electric-powered by 2030.[20] While Duke increased its estimated adoption of electric vehicles ("EV") from the 2020 IRP, these projections are well below even the more conservative forecasts for EV adoption in the United States through the early 2030s.

As I explain below, I conservatively estimate their assumptions could under-forecast EV demand by 1,050 GWh in 2030, 2,160 GWh in 2032, and 3,220 GWh in 2035. Higher electricity demand from EVs will need to be matched by increased procurement of clean energy resources, including solar, to achieve the Carbon Plan CO_2 goals. For example, an additional 2,160 GWh of demand in 2032 would require an additional 880 MW of solar. If higher demand occurs in the compliance year than forecasted by Duke and there are insufficient resources installed in its system to provide zero carbon generation, Duke will need to operate

[17] https://www.gpb.org/news/2022/05/09/georgia-nuclear-plants-cost-now-forecast-top-30-billion
[18] https://www.postandcourier.com/business/3-years-later-how-the-fallout-from-scs-9-billion-nuclear-fiasco-continues/article_5d2a2684-d264-11ea-946f-935bbd3ffa98.html
[19] https://www.greentechmedia.com/articles/read/duke-cancels-lee-nuclear-project-rate-increase
[20] Carbon Plan Appendix F at 12.

its natural gas- and coal-fired power plants more than expected, increasing emissions and coming up short on its required goal.

Based on our analysis of vehicle sales in Duke's service territory, Duke's EV forecast implies that EVs will make up about 20% of new vehicle sales by 2030. Their 2030 EV sales outlook is well below recent forecasts and policy goals. For example, the Bloomberg New Energy Finance ("BNEF") forecast estimates that 30% of new vehicle sales will be electric by 2030. The BNEF forecast is conservative relative to similar projections by IHS Markit (45% by 2030) and my colleagues and I at The Brattle Group (40% by 2030), and the policy goals set by the Biden Administration (50% by 2030).

Q. DID DUKE RESPOND TO THE CONCERNS YOU HAVE RAISED ABOUT EV ADOPTION IN ITS TESTIMONY?

A. Yes, they explained that their forecast is reasonable due to differences in adoption between their service territory and the rest of the country and the timing of when EV adoption starts increasing in the BNEF forecast compared to their forecast, such that the impact on the near-term action plan is "negligible."[21] They also note that their EV forecast aligns with the International Energy Association ("IEA") Global EV Outlook 2021.

First, Duke compares their EV forecast for North Carolina to a global EV forecast developed by the IEA. In addition, the IEA forecast that they cited was the 2021 forecast, which is now outdated. The IEA's 2022 forecast projects 33% higher EV adoption by 2030 compared to its 2021 forecast. Even if Duke's assumptions

[21] Modeling Panel at 130.

align with a single forecast, in my experience the EV adoption forecast they used is well outside the range of publicly-available forecasts.

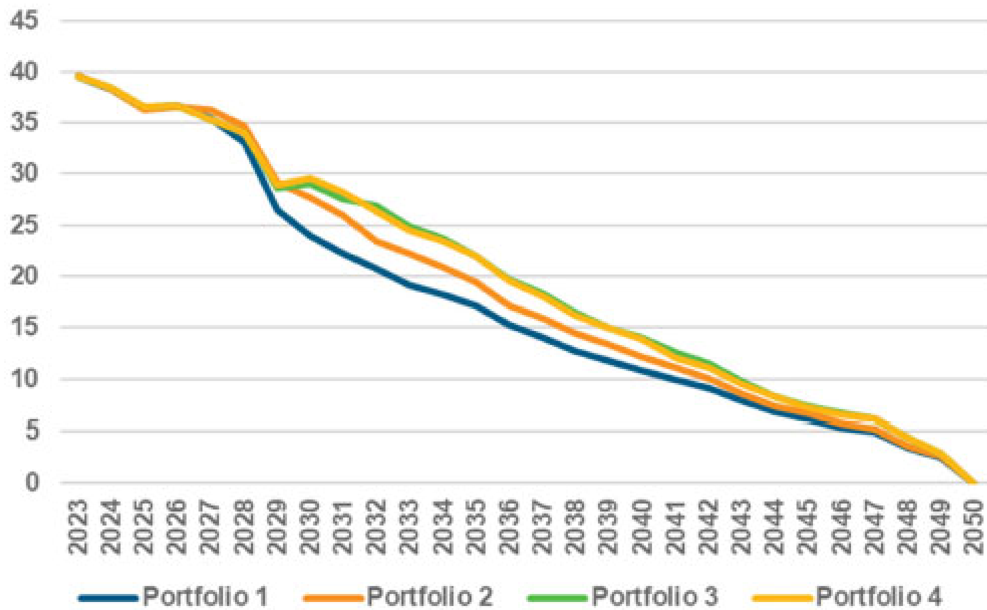
By underforecasting electricity demand and having a limited set of clean energy resources that could be developed in time to meet the Carbon Plan goals, the near-term limit on the procurements of solar resources will provide Duke less options for achieving its CO_2 emissions requirements in the case where EV adoption does increase through 2030 or 2032 faster than currently planned by Duke.

Q. CAN YOU PLEASE EXPLAIN YOUR CONCERN WITH DUKE'S CO_2 EMISSIONS LIMIT ASSUMPTIONS?

A. Yes. In its modeling, Duke set annual CO_2 emissions limits for each portfolio depending on the year in which the portfolio achieves the 70% reduction in CO_2 emission (i.e., 2030, 2032 or 2034).[22] Their approach results in lower near-term CO_2 emissions limit for P1 than the other three portfolios to meet earlier compliance dates. This approach to setting the CO_2 emissions limit up to the compliance year is reasonable. However, in the years following the compliance date, Duke continues to set lower annual CO_2 emissions limit in the P1 case compared to the other portfolios, as shown in the figure below from the Draft Carbon Plan.

[22] Carbon Plan, Chapter 3 at 26.

Figure 1: Duke Carbon Plan Annual CO2 Emissions Limits by Portfolio



Source: Duke Carbon Plan Appendix E at 79.

The lower annual CO_2 emissions limits in P1 beyond 2030 results in significantly lower cumulative CO_2 emissions in the P1 scenario compared to the other portfolios. The cumulative CO_2 emissions for 2022 to 2050 are 533 million short tons for P1, which are 7% lower than P2 (569 million short tons), 12% lower than P3 (601 million short tons), and 11% lower than P4 (599 million short tons). However, Duke does not account for the CO_2 reduction benefits of P1 in its assessments of the portfolios.

In fact, Duke does just the opposite by highlighting that P1 has the highest ratepayer costs, without also acknowledging that it achieves the most CO_2 emissions reductions. The difference in the total present value of revenue requirements ("PVRR") between P1 and P2 is $2.3 billion, just a 2% difference. In my analysis of the annual revenue requirements for P1 and P2, I calculated that at least $1.0 billion of the difference in the PVRR between P1 and P2 occurs in the years following 2032, the P2 compliance year. This demonstrates that nearly half of the cost difference between P1 and P2 is due to the differences in long-term emissions limits.

Instead of setting separate emissions goals in the later years, Duke instead should have adopted a more apples-to-apples comparison between its portfolios by aligning the long-term CO_2 emissions limits beyond the compliance dates. Without doing so, the costs of P1 are artificially increased compared to the other portfolios.

Q. CAN YOU PLEASE EXPLAIN YOUR CONCERN WITH DUKE'S ONSHORE WIND ASSUMPTIONS?

A. Duke assumes that up to 1,200 MW of onshore wind will be available by 2032 and its modeling selects 600 MW by 2030 for P1 and 1,200 MW by 2032 and 2034 for the remaining portfolios, including the supplemental portfolios (P5 and P6). However, there currently are no active requests in the DEC or DEP generation interconnection for onshore wind facilities. In addition, there is currently 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.[23] While onshore wind is a well-established renewable resource globally and in other states in the U.S., the development pipeline for new onshore wind farms and the timeline for such facilities in the Carolinas is highly uncertain.

(b) Duke's Supplemental Modeling

[23] EIA Form 860, available at https://www.eia.gov/electricity/data/eia860/.

Q. DO YOU HAVE ANY CONCERNS RELATED TO THE UPDATED ASSUMPTIONS DUKE INCLUDED IN THE SUPPLEMENTAL MODELING?

A. Yes. The most significant change in assumptions that Duke made in developing its Supplemental modeling is shifting the online date for the Nuclear SMR six months earlier from the end of 2032 to the middle of 2032. As Duke notes in Appendix L of its Draft Carbon Plan, Duke finds that date is feasible for building a new nuclear plant, but also states that "2032 is the earliest possible date that advanced nuclear could be placed in service in the Carolinas."[24] They note several factors that could impact that timing of the development of the Nuclear SMR, including that the timing is "dependent on the action of the NRC"[25] and that "the project timeline for an actual project could have different permitting, licensing, construction and commissioning time frames due to design specifics of the technology chosen and potential regulatory change."[26]

I raise this as an issue since it could have significant impacts on whether Duke is able to achieve the Carbon Plan goals in 2032. Specifically, Duke assumes that the new Nuclear SMR will generate 1,400 GWh in 2032. If the Nuclear SMR does not start operating at the earliest possible date when it could be brought online, a natural gas-fired or coal-fired generation resource is likely to fill the gap, resulting in an additional 0.6 million short tons to 1.4 million short tons of additional CO_2 emissions in 2032. Duke notes that they moved up the date of the nuclear units

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[24] Appendix L at 5.
[25] Appendix L at 10.
[26] Appendix L at 11

because doing so "could have a material impact on meeting the emissions reduction target,"[27] but they do not account for the potential impacts that a six-month delay in the schedule of the Nuclear SMR would have on meeting the Carbon Plan requirements.

Q. DO YOU AGREE WITH THE CHANGES TO SOLAR PAIRED WITH STORAGE AND THE DISPATCH OF BATTERY STORAGE?

A. Yes. Both of those changes in assumptions are an improvement over the previous assumptions that Duke used to develop P1 through P4.

Q. DO YOU HAVE ANY CONCERNS RELATED TO THE RESULTS OF THE SUPPLEMENTAL MODELING?

A. Yes. The final resource additions results for SP5, SP5A, SP6 and SP6A that are shown in Table SPA-12 of Exhibit 1 to the Modeling Panel testimony are misleading. In this table, the SP5 New Solar capacity (as of the beginning of 2032) is shown as 8,600 MW, which appears to be significantly greater than the 5,600 MW of New Solar that Duke listed for P2 in the Executive Summary of the Draft Carbon Plan. However, the two values are not comparable because they include cumulative solar additions over two different timeframes. The SP5 value includes all solar additions starting in 2024, while the P2 value includes solar additions starting in 2027. When put on a comparable basis, the amount of new solar additions in SP5 is 6.8 GW, as shown in the table below.[28] Notably, the higher solar

[27] Modeling Panel at 60.
[28] Solar additions based on the detailed EnCompass output provided by Duke. P1 and P2 are from the final production cost simulation results and P5 and P5 High Solar are from the capacity expansion results.

capacity limit set in the High Solar Interconnection case resulted in 1,665 MW of additional solar, or 8.5 GW of new solar by 2032.

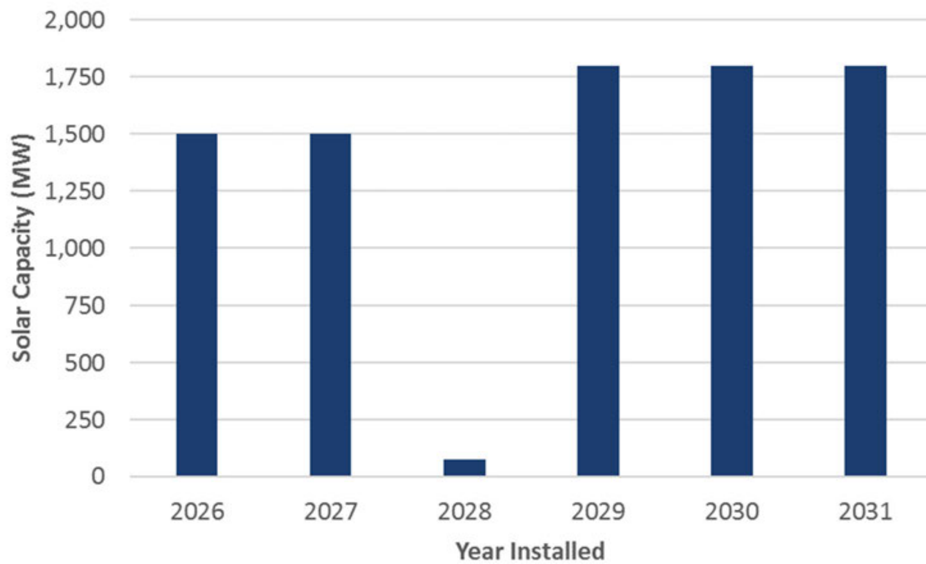
Table 2: Solar Interconnection Limits in Duke Portfolios

	Annual Solar Additions (BOY)						Cumulative Total	
Scenario	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**by 2030**	**by 2032**
P1	750	1,050	1,800	1,800	1,350	1,800	5,400	8,550
P2	375	1,050	1,050	1,050	1,050	975	3,525	5,550
P5	750	1,050	825	1,350	1,395	1,440	3,975	6,810
P5 High Solar	1,500	1,500	75	1,800	1,800	1,800	4,875	8,475

Source: Brattle analysis of Duke EnCompass modeling results

I also have several concerns related to the High Solar Interconnection case, in which Duke modeled the solar capacity additions limit as proposed by CPSA. First, their modeling selected the maximum amount of solar in each year except for 2028 when just 75 MW out of 1,800 MW of solar is installed, as shown in the figure below. I find this to be a surprising and counterintuitive result that has a significant impact on the total solar installed in this case. Long-term capacity expansion models like EnCompass minimize costs over the timeframe studied. Unless there is a significant difference in costs or a resource is unable to be built, the model is unlikely to make such a drastic change in a single year unless another constraint is limiting entry. This result seems to imply that Duke is including in its model an additional limit that is constraining solar additions in 2028. For example, Duke may be modeling the CO2 emissions to be *equal* to a certain cap in each year, instead of allowing the emissions to be *less than or equal* to that cap in each year. Applying such a limit would tend to increase the costs of achieving the Carbon Plan goals based on an arbitrary modeling assumption.

Figure 2: Annual Capacity Additions in High Solar Interconnection Case



Source: Brattle analysis of Duke EnCompass modeling results

Second, Duke reports in Table SPA-27 of Exhibit 1 to the Modeling Panel testimony that High Solar Interconnection Case selected an additional 700 MW of solar in 2035 and 300 MW in 2050 compared to the Supplemental Portfolio 5 ("SP5"). In fact, the High Solar Interconnection case results in an additional 1,665 MW of solar additions as of the beginning of 2032, which is more than 2x higher than shown in the table. By showing the lower values in 2035 instead of the much higher values in 2032, the compliance year, Duke is understating the potential benefits of a higher solar interconnection limit.

Third, another counterintuitive result of the High Solar Interconnection Limit case (shown in Table SPA-27) is the reduction of battery storage additions (700 MW lower) and gas CTs (500 MW lower) in 2035. This outcome is counterintuitive because solar provides a limited contribution to meeting the winter reserve margin, while both battery storage and gas CTs provide greater contributions to the reserve margin. On net, this portfolio would appear to undershoot the winter reserve margin or reduce the reliability of the system.

Q. DOES THE HIGH SOLAR INTERCONNECTION CASE RESULT IN LOWER RATEPAYER COSTS COMPARED TO P5?

A. Yes. Although Duke did not include the costs of the High Solar Interconnection case in Exhibit 1 of the Modeling Panel testimony, the detailed EnCompass output results for the High Solar Interconnection case and P5 case show that on average from 2026 to 2032 the High Solar Interconnection cases results in $40 million of cost savings per year compared to P5.

Q. PLEASE PROVIDE YOUR OVERALL ASSESSMENT OF THE SUPPLEMENTAL MODELING AND ITS IMPLICATIONS FOR THE CARBON PLAN.

A. Overall, I found that the supplemental modeling runs, specifically SP5 and SP5 High Solar Interconnection, represent an incremental but insufficient improvement over Duke's pre-existing scenarios. The improvements primarily include selecting more solar resources by 2032 compared to the P2 portfolio and incorporating new configurations of solar paired with storage. In both cases, the results support CPSA's recommendation on higher near-term solar procurement.

The SP5 High Solar Interconnection case in particular demonstrates how larger solar procurements and a more reasonable solar interconnection constraint reduces cost and execution risk for achieving interim compliance (see Tyler Norris' testimony on the limited execution risk of solar development). The P5 High Solar Interconnection case identified 8,475 MW of solar by 2032, even with (1) the unreasonable assumptions that the first SMR is available by mid-2032 at Duke's unjustified low cost estimate, (2) the assumption that 1,200 MW of onshore wind will be available, and (3) the unreasonable one year drop in solar additions in 2028.

A more reasonable Supplemental Modeling approach would have included a scenario where the availability of Nuclear SMRs was not further accelerated (i.e. from late 2032 to mid 2032) and a higher solar cap was included (e.g., the CPSA cap or the solar cap applied to P1). If the NCUC does not accept the addition of CPSA's CPSA5 scenario for 2032 compliance, CPSA recommends that NCUC require Duke to run a P5 sensitivity (or a P7) that addresses these issues.

Finally, the Supplemental Modeling demonstrates that Duke should increase its near-term targets for procuring battery storage, primarily through solar paired with storage. Both of the P5 cases identified over 4 GW of battery storage by 2032, compared to about 2 GW in the initial portfolios. In addition, more than 50% of the new battery storage capacity is coming from paired storage.

(c) Modeling Conducted by Brattle

Q. PLEASE DESCRIBE THE PURPOSE OF THE MODELING YOU CONDUCTED IN YOUR EVALUATION OF DUKE'S CARBON PLAN.

A. Under my supervision, a team of The Brattle Group consultants and I modeled the optimal generation capacity expansion and dispatch of the Duke Energy system (including both Duke Energy Carolinas and Duke Energy Progress) to address the impacts of the aforementioned flaws I identified in Duke's modeling of resource portfolios in its Draft Carbon Plan. Specifically, we analyzed a more complete set of resource portfolios that achieve a 70% reduction of CO_2 emissions from Duke

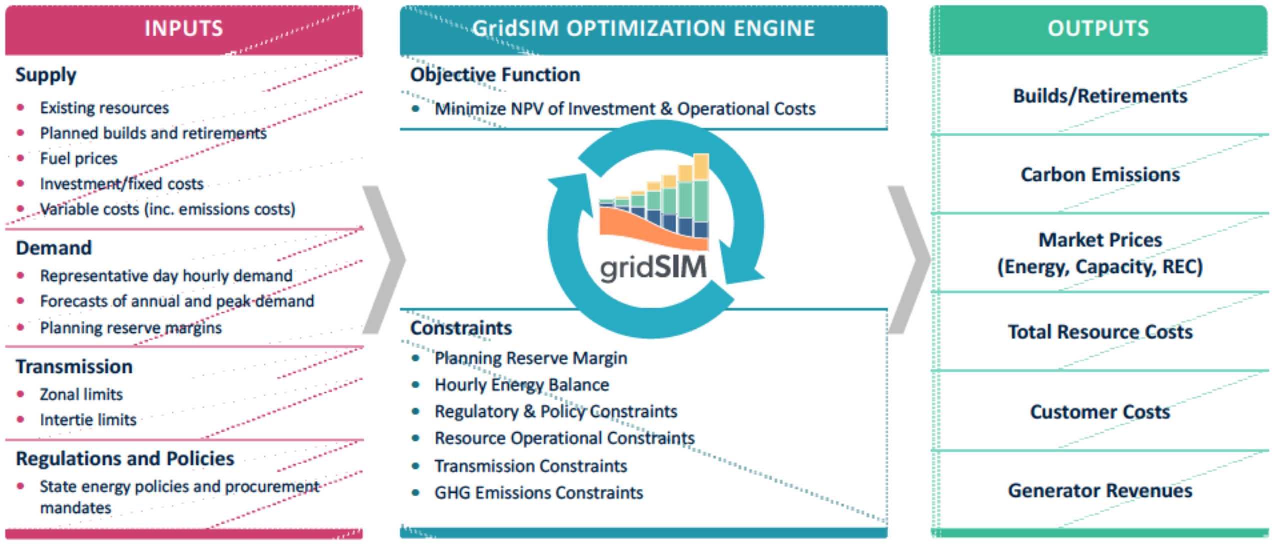
Energy's North Carolina power generation by 2030 or 2032 in order to inform the Carolinas Carbon Plan. We used an in-house capacity expansion and generation dispatch optimization model called GridSIM.

Q. WHAT IS GRIDSIM AND HOW DID YOU USE IT IN THIS CASE?

A. GridSIM optimizes capacity expansion and system dispatch in order to minimize the present value of system costs over the timeframe modeled, subject to meeting various constraints including hourly demand, seasonal capacity requirements, and CO_2 limits. The timeframe modeled in this case was 2020 to 2035, with 2020, 2025, 2030, 2032 and 2035 modeled. The total system costs of achieving the specified constraints in each modeled year is assigned a weighting based on the number of years between modeled years. The annual system costs include the levelized fixed costs of new resources and the operating costs of existing and new resources, including fuel costs and operations and maintenance (O&M) costs. The variable operating costs of existing and new resources are calculated based on simulated chronological hourly dispatch of 49 representative days, including 4 representative days within each of the 12 months and the peak demand day. The 4 days within each month are selected by accounting for differences in demand and renewable generation within each month using a clustering algorithm. The operating costs of meeting hourly demand in each representative day is assigned a weighting based on the number of days within the month to which it is representative.

The following diagram summarizes the key features of the GridSIM model.

Figure 2: Summary of GridSIM Features



Q. HOW DOES YOUR MODELING ACCOUNT FOR RESOURCE ADEQUACY REQUIREMENTS?

A. Our GridSIM modeling added new generation and storage resources in order to maintain a 25% winter reserve margin, based on the results reported by Duke in Appendix E of its Carbon Plan for the resource portfolios P1 and P2. The amount of new resources required to meet the winter capacity requirement, referred to as the Capacity Shortfall, is based on our analysis of the projected winter peak demand, capacity of existing resources, and assumed contribution of each new resource to achieving the winter capacity requirement. The contribution of each new resource to achieving the winter reserve margin requirement (or effective load carrying capability, ELCC) is based on the values I estimated from Duke's Carbon Plan Appendix E for the representative range of capacity expected to be developed. For example, I assumed the new solar generation resources contribute only 2% to meeting the winter reserve margin requirement.

Q. PLEASE EXPLAIN HOW YOUR MODELING ENSURES COMPLIANCE WITH NORTH CAROLINA HOUSE BILL 951 REQUIREMENTS TO REDUCE CO_2 EMISSIONS BY 2030?

A. For each modeled year, I included separate CO_2 emissions limits for total emissions from Duke Energy's North Carolina-based resources (including all new gas-fired resources), and for total emissions from Duke Energy's South Carolina-based resources. The CO_2 limit on South Carolina-based resources is based on the annual CO_2 emissions of those resources reported in Duke's EnCompass output files for the P1 portfolio. The CO_2 limit on North Carolina-based resources is based on the assumed compliance year in which the 22.6 million short tons of emissions is achieved. For three of the portfolios I evaluated (CPSA1 through CPSA3), I assumed the compliance year is 2030. For the remaining two portfolios (CPSA4 and CPSA5), I assumed the compliance year is 2032. For CPSA4 and CPSA5, I estimated the 2030 CO_2 limit on North Carolina-based plants based on the difference between 2030 and 2032 limits reported in EnCompass input files. In all cases I modeled, I assumed the 2035 CO_2 limit is 16.9 million short tons, based on a linear reduction of the CO_2 limit from 22.6 million short tons in 2032 to achieve net zero by 2050.

Q. WHAT ARE THE MAJOR DIFFERENCES IN YOUR MODELING ASSUMPTIONS RELATIVE TO DUKE'S ENCOMPASS MODELING?

A. For the purpose of our modeling in this case, Brattle adopted most of Duke's modeling assumptions such as load growth, natural gas prices, timing of coal plant retirements, planning reserve margin requirements and contributions of each type of resource to meet seasonal resource adequacy requirements.

Our modeling assumptions differ from Duke's in five areas. First, our modeling timeframe covers the period through 2035 with the years 2020, 2025, 2030, 2032 and 2035 modeled. Duke's modeling timeframe covered all years until 2050. We have not modeled the years beyond 2035 because the modeling of those out years would have limited impact on the optimal types of resources needed to meet the 2030 or 2032 CO_2 reduction target.

Second, I assumed capital costs to install new generation and storage resources based on NREL's 2022 Annual Technology Baseline projections, with the exception of my reliance on PJM's 2026/2027 CONE Study for the cost of new gas CT. We adopted the lower capital costs of new gas CT based on the feedback I received from Duke when I presented my original assumptions and results to them prior to the release of the Draft Carbon Plan. In comparison to Duke's modeling, my capital cost assumptions in 2030 are higher for solar and natural gas CCs and CTs, and lower for onshore wind and offshore wind, as shown in the table below.

Table 3: Estimated 2030 Capital Costs (nominal dollars)

Resource	Brattle Capital Costs *$/kW*	Duke Capital Costs *$/kW*	Difference *$/kW*
Solar	$1,526	$1,380	$146
Onshore Wind	$1,325	$1,644	($319)
Offshore Wind	$3,865	$4,663	($798)
4-Hour BESS	$1,241	$1,233	$8
Gas CC	$1,422	$805	$617
Gas CT	$1,025	$711	$314

Third, our modeling evaluated sensitivities on various levels of capacity limits for model's selection of new solar generation plants. Those sensitivities include Duke's assumed limits for annual additions, CPSA's proposed limits for annual additions, and a no limit case.

Fourth, I assumed the 2035 CO_2 limit to be the same (at 16.9 million short tons) in all my cases. In contrast, as I explained above, Duke's modeling of resource portfolios assumed lower emission limits in its portfolio P1 compared to other portfolios in every year through 2050.

Fifth, and finally, I assumed that the new nuclear SMR plants would not be available to come online prior to 2035 and only 600 MW of onshore wind resources could be built by 2032. In contrast, Duke's modeling assumed new SMR plants could be available starting in year 2034 for P1 through P4, and in the middle of 2032 for its supplemental modeling (P5 and P6).

Q. HAVE YOU ALSO EVALUATED ALTERNATIVE RESOURCE PORTFOLIOS THAT DIFFER FROM THE PORTFOLIOS IN DUKE'S CARBON PLAN FILING?

A. Yes. I analyzed five alternative resource portfolios with varying limits on solar capacity additions and varying years to achieve 70% reduction in CO_2 emissions. For three of the portfolios I evaluated (CPSA1 through CPSA3), I assumed the compliance year is 2030. For the remaining two portfolios (CPSA4 and CPSA5), I assumed the compliance year is 2032.

I assumed no cap on solar capacity additions in the portfolio CPSA1, Duke's low solar cap assumptions (5,175 MW by the middle of 2030 and 7,875 MW by the middle of 2032) in portfolios CPSA2 and CPSA4, and CPSA's proposed cap on solar capacity additions (7,500 MW by the middle of 2030 and 11,100 MW by the middle of 2032) in portfolios CPSA3 and CPSA5.[29] Table 4 below shows the alternative solar caps considered by Duke and included in my simulations, showing the values in both the beginning of year ("BOY") and middle of year ("MOY") conventions.

Table 4: Duke and CPSA Annual Solar Addition Caps

Solar Cap	2026	2027	2028	2029	2030	2031	2032	2033+
Beginning of Year Convention								
Duke Low Cap	0	750	1,050	1,350	1,350	1,350	1,350	1,350
Duke High Cap	0	750	1,050	1,800	1,800	1,800	1,800	1,800
CPSA Cap	0	1,500	1,500	1,800	1,800	1,800	1,800	1,800
Middle of Year Convention								
Duke Low Cap	375	900	1,200	1,350	1,350	1,350	1,350	1,350
Duke High Cap	375	900	1,425	1,800	1,800	1,800	1,800	1,800
CPSA Cap	750	1,500	1,650	1,800	1,800	1,800	1,800	1,800

The following table summarize the key assumptions in my five alternative portfolios. Portfolios CPSA2 and CPSA3 are intended as alternatives to Duke's P1 portfolio, which assumes Duke's high cap on solar additions, with one version that is more conservative on solar additions (CPSA2 based on Duke's low solar cap) and one that is slightly more aggressive (CPSA3 based on CPSA's proposed rate of annual solar additions). Portfolios CPSA4 and CPSA5 are intended as alternatives to Duke's P2 portfolio, with CPSA4 assuming solar additions up to

[29] Note that I used the middle of the year convention as GridSIM assumes a constant amount of solar throughout the year. The middle of the year convention accounts for the average amount of solar that is forecasted to be online in a given year.

Duke's low solar cap and CPSA5 assuming solar additions up to the CPSA-proposed limit.

Table 5: Key Assumptions in Brattle Simulations

Portfolio	Compliance Year	Solar Cap
CPSA1	2030	No Cap
CPSA2	2030	Duke Low Cap
CPSA3	2030	CPSA Cap
CPSA4	2032	Duke Low Cap
CPSA5	2032	CPSA Cap

As a sensitivity to evaluate whether new SMR plants could be economic to be added to Duke's portfolio, I simulated two cases that allowed the selection of nuclear SMR plants starting in 2032. In the first case, I adopted Duke's lower capital and fixed O&M costs for nuclear SMR plants and also adjusted the solar costs to the Moderate case.[30] The second case increased the nuclear SMR costs to the EIA's capital and fixed O&M costs and increased solar costs to the ATB Conservative case. Neither case resulted in any entry of nuclear SMR by 2032.

Q. WHAT WAS THE PURPOSE OF MODELING ALTERNATIVE RESOURCE PORTFOLIOS?

A. As I explained in Section II, I have concerns about the assumptions Duke used in developing its resource portfolios. In order to illustrate the materiality of the impacts of Duke's flawed assumptions, I developed the five alternative resource portfolios.

[30] I assumed a 60 year book life for the nuclear SMRs and Duke's weighted average cost of capital to estimate the annual fixed costs for the nuclear SMRs. I allowed the unit to be fully dispatchable in GridSIM based on Duke's fuel cost assumptions.

Q. PLEASE DESCRIBE YOUR KEY FINDINGS FROM YOUR MODELING OF THE ALTERNATIVE RESOURCE PORTFOLIOS.

A. I find that restricting the amount of new capacity from solar plants in the model increases system costs. System costs increase due to the need to identify higher cost approaches to reduce CO_2 emissions, whether through the addition of alternative clean energy resources, such as offshore wind, or through shifting fossil generation away from higher emission rate resources, primarily coal. Comparing the resource portfolio in CPSA1 against CPSA2 and CPSA3 (all three of which assume the 70% reduction in CO2 emissions is achieved in 2030), I find that GridSIM selects new solar capacity additions through 2030 up to the assumed caps (7,900 MW in CPSA2 and 7,500 MW in CPSA3) and as economic in the uncapped case (9,500 MW in CPSA1). The results demonstrate that increasing solar additions reduces system costs in 2030, 2032 and 2035. Most of the solar capacity additions are paired with storage in the 4-hour at 50% of solar capacity configuration.

Second, the model selects 600 MW of onshore wind in all portfolios but offshore wind only in CPSA2 (800 MW by 2030 and 800 MW by 2032), CPSA3 (400 MW by 2030), and CPSA4 (1,100 MW by 2032). No offshore wind is selected in the case in which solar is uncapped with a 2030 compliance date (CPSA1) nor in the case with the higher CPSA cap and the 2032 compliance date (CPSA5).

Third, in all alternative resource portfolios, I find that the model economically selects a mix of gas CCs and CTs, including 2,400 MW of gas CCs in all cases with gas CTs ranging from new entry up to 1,100 MW.

Table 6: Summary of New Resource Additions and System Costs

Scenario	2030 New Solar	2032 New Solar	2030 New BESS	2032 New BESS	Onshore Wind	Offshore Wind	Gas CC	Gas CT	2030 System Costs	2032 System Costs	2035 System Costs
CPSA1 – No Cap 2030 Compliance	9,500	12,700	3,300	4,200	600 MW in 2030	---	2,000 MW in 2030	---	$6.97	$7.90	$9.13
CPSA2 – Low Solar Cap 2030 Compliance	5,200	7,900	1,800	2,700	600 MW in 2030	800 MW in 2030 and 800 MW in 2032	2,400 MW in 2030	900 MW in 2030	$7.90	$8.70	$9.84
CPSA3 – CPSA Cap 2030 Compliance	7,500	11,100	2,700	3,700	600 MW in 2030	400 MW in 2030	2,400 MW in 2030	---	$7.04	$7.97	$9.15
CPSA4 – Low Solar Cap 2032 Compliance	5,200	7,900	2,000	2,300	600 MW in 2030	1,100 MW in 2032	2,400 MW in 2030	1,100 MW in 2030	$6.78	$7.94	$9.87
CPSA5 – CPSA Cap 2032 Compliance	7,100	10,700	2,600	3,500	600 MW in 2030	---	2,400 MW in 2030	500 MW in 2030	$6.78	$7.75	$9.16

Q. DO YOUR MODELING SIMULATIONS ACCOUNT FOR THE CHANGES IN FEDERAL TAX CREDITS FOR RENEWABLE ENERGY AND STORAGE RESOURCES INCLUDED IN THE INFLATION REDUCTION ACT?

A. No, they do not. I did not incorporate any changes to our modeling following the passage of the Inflation Reduction Act due to the limited time available to do so, a desire to maintain an apples-to-apples comparison with Duke's modeling, and the need to better understand several of the provisions of the IRA related to the levels of tax credits that will be expected for each type of resource.

As a reminder, our modeling assumed the previous phase out of the federal production tax credit (PTC) and investment tax credit (ITC) with solar resources able to qualify for the 10% ITC after 2026 and offshore wind that is online by 2035 able to qualify for the 30% ITC. The IRA will significantly increase the value of tax credits for solar resources, as they now will be able to qualify for the higher value PTC. In contrast, offshore wind tax credits are expected to remain the same.

For this reason, I do not expect that the IRA would change the mix of clean energy resources selected in our modeling simulations. However, the higher value of the tax credits will further increase the cost savings of the solar capacity additions included in each portfolio and increase the cost savings that would occur by increasing the solar interconnection limits. In addition, the extension of the federal tax credits to standalone battery storage will continue to make it an attractive alternative to natural gas CCs and CTs.

Q. WHAT WERE DUKE'S CRITICISMS OF YOUR MODELING ASSUMPTIONS AND ALTERNATIVE RESOURCE PORTFOLIOS?

A. Duke Energy's witnesses Glen Snider, Bobby McMurry, Michael Quinto and Matt Kalemba criticized our modeling assumptions for allegedly failing to be technically objective, executable, and adequately reliable.[31] They indicated that our modeling assumptions "tend to unreasonably favor grid edge, renewable, and energy storage resources, and introduce bias against firm, dispatchable resource types."[32] Furthermore, they claimed that I assumed an "improbably rapid solar deployment" while not modeling any of the years 2026 through 2029 in my simulations.[33] Finally, they criticized our modeling results as yielding "unreasonably high levels of near-term energy storage procurement",[34] and my assumptions on capital costs for building new resources as biased.[35]

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31 Modeling Panel at 183-185.
32 Modeling Panel at 185.
33 Modeling Panel at 191.
34 Modeling Panel at 204.
35 Modeling Panel at 193-194.

Q. PLEASE SUMMARIZE YOUR RESPONSES TO DUKE'S CRITICISMS OF YOUR MODELING.

A. I do not agree with any of those criticisms. Most of our modeling assumptions were designed to mimic Duke's assumptions in its draft Carbon Plan to ensure that my model results on the least-cost mix of resource portfolio does not cause any degradation of system reliability. Prior to releasing the Brattle report with our modeling findings, we presented our approach and key assumptions to Duke and asked Duke to provide feedback on any concerns they may have; Duke did not raise any concerns about "technical objectivity" of our modeling at the time. Duke raised one issue regarding my assumptions, which was that the capital cost of new gas CTs seemed too high. I therefore reduced the assumed cost of a new CT, which improved the economic attractiveness of new gas CTs in my model relative to alternatives such as new battery (with or without paired solar).

In addition, Duke's criticisms about our modeling assumptions regarding the pace of adding new solar and storage resources do not have any strong basis. I provide my responses below to Duke's specific criticisms of our modeling.

Q. HOW DO YOU RESPOND TO DUKE WITNESSES' CLAIM THAT YOUR MODELING FAILS TO MEET "TECHNICAL OBJECTIVITY"?

A. Duke's claim concerning the technical objectivity of our analysis is unfortunate and based on their own analysis does not stand up to scrutiny. As noted above and in The Brattle Group report, the analysis we completed for the Carbon Plan relied on both publicly available assumptions as well as assumptions from Duke's own modeling. We used a well-established model that Brattle has used for several clients, including the Electric Power Research Institute, the U.S. Department of Energy, the New York Independent System Operator, and other utilities as a part of their resource planning efforts. Figure 17 in the Reliability Panel testimony highlights that our assumptions concerning solar costs are in fact higher than Duke's and other intervenors.[36]

In addition, the higher solar limit in CPSA3 and CPSA5 is based on Duke's estimate of the amount of solar it can interconnect but ramping up sooner due to the unreasonably low assumed rate of interconnections in the first two years, which is supported by CPSA Witness Watts' testimony and CPSA's analysis included in its previous comments.[37] These cases test the effects of Duke's thinly supported capacity limit and whether solar additions beyond the limits imposed by Duke would provide net benefits to ratepayers.

Q. HOW DO YOU RESPOND TO DUKE WITNESSES' CONCERN THAT YOU "DID NOT MODEL ANY YEARS FROM 2026 TO 2029 WHEN DEVELOPING [YOUR] ALTERNATIVE PORTFOLIOS SO THERE IS NO MODELING JUSTIFICATION FOR THIS AGGRESSIVELY ACCELERATED PACE OF ADOPTION"?

A. The modeling I completed was intended to identify the least-cost mix of resources to achieve CO_2 emissions reductions goals by either 2030 or 2032. It is common modeling practice when running capacity expansion simulations not to include every year, especially when modeling over a longer timeframe. In this case, I

[36] Modeling Panel at 192.
[37] See CPSA Comments (July 15, 2022), Exhibit D, *Pathways to 1800 MW Annual Solar Capacity Additions*.

modeled 2030 and 2032, as well as 2025 and 2035, to identify resource capacity additions and retirements, as those are the years in which CO_2 emissions reductions must be achieved. I gave each modeled year a weighting to reflect the number of surrounding years that it represents. In addition, I developed limits on cumulative solar additions by 2030 and then from 2030 to 2032 and 2032 to 2035 to reflect the impact of annual limits and make sure that the solar builds cannot exceed those limits. I included similar capacity addition limits on other resources, including natural gas combined cycle plants, offshore wind, and onshore wind.

Q. DUKE'S WITNESSES EXPRESS CONCERN ON PAGES 197 TO 200 OF THE MODELING PANEL THAT YOUR MODELING "FAILS TO SUFFICIENTLY ADDRESS RELIABILITY AND EXECUTABILITY." DO YOU AGREE?

A. No, I do not. Although I did not complete all of the same detailed reliability analysis that Duke did, the resource additions identified in our modeling simulations (described above) result in similar resource additions by 2032 as Duke to replace retiring coal plants and maintain system reliability, including gas CCs (2,400 MW), gas CTs (up to 1,100 MW), and battery storage (2,300 – 4,200 MW). Instead, the differences in resource mix between our simulations are primarily due to differences in solar, onshore wind, offshore wind, and nuclear SMRs.

Duke faults intervenor modeling, including ours, for failing to conduct the "Portfolio Verification" steps detailed in Appendix E. These additional steps consisted of replacing battery storage with about 1,100 MW of gas CTs in 2030 and 2032 to ensure adequate capacity during extreme winter events. However, there are two important points that Duke does not mention. First, Duke's capacity expansion modeling that occurs prior to the Portfolio Verification step did not select any new gas CTs by 2030 or 2032 for P1 and P2. In contrast, the capacity expansion modeling I completed at a similar stage did identify the need for new gas CTs in certain scenarios, adding up to 500 MW in CPSA5, 900 MW in CPSA2, and 1,100 MW in CPSA4. This demonstrates that our modeling is accounting for the value that a dispatchable resource like a gas CT would provide to the system, while Duke's capacity expansion modeling does not.

Second, Duke makes the same level of adjustment to the capacity of gas CTs and battery storage in P1 and P2, as seen in Table E-54 of Appendix E, despite significant differences in the resource mix between the two portfolios. These results indicate that higher levels of solar penetration do not result in a less reliable system.

While our capacity expansion modeling alone does not include the same steps Duke completed through its Portfolio Verification process, I do not agree that the resulting portfolios from our simulations would be less reliable. I observed based on Duke's detailed reliability analysis, including the Portfolio Verification steps, that Duke achieved a much higher winter reserve margin than their target reserve margin of 17% based on the results Duke included in Figure E-12 of Appendix E. These figures show that in 2030 to 2035 the winter reserve margin for DEP and DEC is about 25% on average, with some years higher and some years lower, for P1 and P2. To best align our modeling with Duke's and incorporate the need for additional resources beyond the planning reserve margin, we increased the planning reserve margin in GridSIM from 17% to 25%, increasing the capacity needs in 2030 by 2,300 MW and in 2032 by 2,600 MW. By adopting the higher reserve margin that Duke identified after completing its full analysis, we implicitly accounted for the resource needs that Duke identified in later stages of its analysis.

The capacity expansion modeling alone however is not equivalent to additional detailed reliability modeling that Duke completed. Similar to other portfolios, Duke should assess potential reliability issues and resource adjustments in the higher solar resource portfolios we identified as least-cost in our simulations.

Q. DUKE TAKES ISSUE WITH ALTERNATIVE MODELING THAT USES A 17% WINTER RESERVE MARGIN TO ENSURE RELIABILITY. HOW DO YOU RESPOND?

A. As I noted in response above, we assumed a 25% winter reserve margin in our GridSIM modeling runs which approximated Duke's realized reserve margins shown in Appendix E. CPSA's comments on page 31 and initial response to data requests noted a 17% winter reserve margin, but we had included in the Brattle Report attached to the comments on page 22 and later clarified in a supplemental response that our simulations assumed a 25% winter reserve margin.

II. <u>TRANSMISSION PLANNING, PROACTIVE TRANSMISSION, RZEP</u>

Q. PLEASE PROVIDE A SUMMARY OF CPSA'S RECOMMENDATIONS WITH RESPECT TO PROACTIVE TRANSMISSION PLANNING.

A. CPSA and I believe 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. The benefits of proactive planning are discussed both in

CPSA' comments on the Carbon Plan[38] and in the Brattle Report.[39] In its Comments, CPSA recommends that the Commission initiate proceedings, including but not limited to the convening of a technical conference, with the goal of establishing a proactive, long-term transmission planning process consistent with applicable FERC requirements.

Q. HOW DOES DUKE RESPOND TO THIS RECOMMENDATION?

A. Duke does not respond directly to CPSA's recommendation. Instead, Duke focuses narrowly on the North Carolina Transmission Planning Collaborative ("NCTPC"), stating that it is "supportive of the NCTPC initiating a review to evaluate changes to the local transmission process and to consider changes" to the provisions of Duke's Open Access Transmission Tariff ("OATT") that govern the NCTPC. Duke also indicates that it is open to a stakeholder process "to gather feedback on improvements to the local transmission planning process."[40]

Q. WOULD A CHANGE TO THE NCTPC PROCESS BE SUFFICIENT TO IMPLEMENT PROACTIVE TRANSMISSION PLANNING?

A. Probably not. As discussed in the Brattle Report, transmission planning must be combined with integrated resource planning in order to achieve maximum benefit for customers. The NCTPC as currently conceived is strictly a transmission planning entity. Although (as required by FERC) it can study public policy driven transmission improvements, it is not integrated with resource planning, a function that is under the jurisdiction of the Commission. Although it is a complex

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[38] CPSA Comments at 54-58

[39] Brattle Report at 9, 37-52.

[40] Transmission Panel at 41-42.

undertaking to integrate transmission and resource planning, RTOs and utilities across the country have implemented proactive transmission planning approaches that identify cost effective upgrades for their changing resource mix. I noted several approaches to doing so above in Section II and The Brattle Report includes several additional examples of such processes.[41]

Because the stakes are so high, it is also not sufficient for Duke to simply "gather feedback" on changes to the transmission planning process and come up with its own proposal for a revised process. Devising a new transmission planning process for North Carolina should be a truly collaborative process that ideally would reflect consensus among interested stakeholders.

Q. FERC HAS EXERCISED JURISDICTION OVER TRANSMISSION PLANNING. WHAT ROLE CAN THE NORTH CAROLINA UTILITIES COMMISSION PLAY IN SUCH A PROCESS?

A. In establishing local and regional transmission planning processes, FERC was careful to clarify that it did not intend to infringe on states' traditional authority over resource planning – and indeed, FERC believed that an open transmission planning process "can provide useful information which will help states to coordinate transmission and generation siting decisions, allow consideration of regional resource adequacy requirements, facilitate consideration of demand response and load management programs at the state level, and address other factors states wish to consider."[42] Indeed, FERC has said that it "strongly encourages state

[41] Brattle Report at 38-41, 45-47.

[42] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 FR 12266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241 at P 479 n. 274.

participation in the transmission planning process," and "encourage states to determine their own level of participation [in the transmission planning process], consistent with applicable state law."[43]

California provides one example of state involvement in the transmission planning process. During its biennial IRP cycle, CPUC identifies optimal resource portfolios needed to meet state policy goals over next 10 years, including resource type and zone. CAISO then studies whether there are reliability, economic, and/or policy needs for new transmission under each portfolio in its annual Transmission Planning Process. Stakeholders play a key role in reviewing assumptions and preliminary results, and submitting transmission upgrades for CAISO to study.[44] North Carolina could consider a similar model.

In a similar way, the New York Public Service Commission ("PSC") in 2015 identified the need for a more comprehensive approach to transmission planning than the FERC-approved planning approach completed by the New York Independent System Operator ("NYISO"). The PSC order specifically identified constraints on their system that were not being addressed and a much broader range of transmission benefits that should be considered in future planning processes to reduce costs to New York ratepayers, including longer term benefits of transmission upgrades in a decarbonizing system.[45] This example demonstrates that state commissions have a critical role to play in developing proactive transmission

[43] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 574.
[44] Brattle Report at 39.
[45] https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={6E1E021D-FD28-4F2B-84AC-35ADEE19A22C

planning processes in their state to ensure a reliable and cost effective transmission system.

III. COST EVALUATION

Q. WILL INCREASING THE SOLAR INTERCONNECTION LIMIT REDUCE COSTS TO RATEPAYERS?

A. Yes. Based on our modeling of alternative solar interconnection limits, I find that increasing the solar interconnection limit will reduce costs to ratepayers. Solar is the least-cost clean energy resource available to Duke to reduce its emissions. Even under conservative estimates of future solar costs that I included in our modeling that account for differences in contributions of resources to achieving winter reserve margin requirements, I find that raising the solar interconnection limit reduces costs. Allowing for more solar additions reduces costs by (1) avoiding the need for higher cost alternative clean energy resources, such as offshore wind and nuclear SMRs, and (2) reduces the need to dispatch higher operating cost but lower emitting fossil generation resources, such as natural gas-fired resources instead of coal-fired resources.

Duke's supplemental modeling supports this finding. Although they do not include the results in their testimony, the detailed cost information for the SP5 and SP5 High Solar Interconnection cases included in the EnCompass output spreadsheet indicates that the portfolio with higher solar capacity will reduce total system costs. While I am hesitant to rely too heavily on the results of the SP5 High Interconnection case due to the counterintuitive results I explained above, the results provide an indication that Duke's own analysis shows that an increase in the solar interconnection limit, while holding all other assumptions constant, will reduce costs to ratepayers.

IV. RELIABILITY

Q. DUKE CLAIMS ON PAGE 81 OF THE RELIABILITY PANEL TESTIMONY THAT THE INTEGRATION OF RENEWABLES CREATES RAMP RATE ISSUES THAT HAVE NEGATIVELY IMPACTED RELIABILITY IN OTHER JURISDICTION. PLEASE RESPOND.

A. The addition of more and more renewable energy resources into the power system will change the operation of the system and the dispatch of non-renewable generation resources. The daily generation profile of solar resources is predictable and results in the need for a significant increase in resources as the sun goes down and demand increases. Duke will need to have flexible resources on its system, including BESS and natural gas-fired CCs and CTs, that can ramp up during these hours to serve the daily peak demand hours. Other markets are further along in terms of wind and solar adoption and thus can provide valuable experience to Duke for preparing for the coming shift in its generation fleet.

In this case, Duke relies on market conditions in California from August 14, 2020 during a historic, once-in-35-years heatwave across several Western U.S. states and in a very different electric power system and market than the Carolinas. It is unclear how this event is applicable to Duke's system. Duke must run their own analysis of specific market conditions in the Carolinas and the Southeast to identify concerns that need to be addressed in Carbon Plan, similar to the studies completed by Astrape during the Carbon Plan analysis.

Q. DUKE CONTENDS ON PAGE 86 OF THE RELIABILITY PANEL TESTIMONY THAT THE BRATTLE STUDY DID NOT ACCOUNT FOR PERIODS OF LIMITED OUTPUT FROM SOLAR RESOURCES IN WINTER MONTHS. PLEASE RESPOND.

A. Infrequent renewable droughts like those identified by Duke can occur and would require having sufficient dispatchable capacity available to fill in the gaps. As explained in our response to CPSA DR 2-8b, my simulations did in fact account for periods in the winter in which demand is high, but solar capacity factors are only 2 – 4%. For example, the highest demand day in December coincides with the lowest solar output of only 4% (compared to average monthly capacity factor of 13%). By including a day with high demand and low solar generation, I am accounting for the periods of limited output that the Duke witnesses claim I did not.

V. <u>EXECUTION RISKS</u>

Q. DOES THE CARBON PLAN PROVIDE A FAIR AND ACCURATE ASSESSMENT OF THE EXECUTION RISK OF DIFFERENT RESOURCES AND PORTFOLIOS?

A. No. There are a number of ways in which Duke constructs and compares its portfolios to create the false impression that portfolios that rely more heavily on solar resources present more execution risk than portfolios that rely on resources that are new to the Carolinas, like offshore wind, and resources that are completely untested in the United States, such as SMRs. Duke's misleading assessment of execution risk is discussed at length in CPSA's comments and in the direct testimony of CPSA Witness Norris.[46] However, I would make a few points about execution risk from a resource planning standpoint.

First, a plan that relies on a number of resources that present different execution risks should take reasonable steps to mitigate those risks. Duke seems to recognize this fact, emphasizing an "all of the above" strategy of that aggressively pursues development of many different resource types – and seeking authorization from the Commission for recovery of development costs even for resources that are ultimately not selected for a resource plan.[47] Unfortunately, as discussed in Mr. Norris's testimony, Duke's approach to solar execution risk is not to mitigate it, but to strictly limit the amount of solar it will even try to add to its system. This approach is particularly notable as the execution risk that Duke has identified for adding more solar resources are their own interconnection and transmission upgrades processes. As such, Duke has the ability to better understand, manage, and mitigate this risk.

Second, although solar interconnection rates are uncertain, it is more advantageous for ratepayers to set ambitious interconnection goals for the least-cost clean energy resource, understanding that they may not be met (with contingency plans in place if that turns out to be the case) than to set modest goals from the beginning that will not be exceeded.

Q. WHAT WOULD BE THE POTENTIAL CONSEQUENCES OF SETTING AMBITIOUS SOLAR INTERCONNECTION GOALS AND FAILING TO MEET THEM?

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[46] CPSA comments at 43-47.

[47] Modeling Panel at 18; Bowman Ex. 2 ¶ 2(c)(2)(i)-(iii).

A. Ratepayers would be no worse off than if Duke had pursued a resource plan based on a solar interconnection constraint. CPSA does not argue that the Carbon Plan should *only* include portfolios that assume higher rates of interconnection – a prudent Carbon Plan should include portfolios that reflect lower solar interconnection rates, just as it should include portfolios reflecting the possibility that SMRs might not be available by mid-2032 for compliance with the 70% carbon reduction mandate. So long as the near-term execution plan supports the entire range of modeled portfolios, then Duke can "check and adjust" its plan once Duke shows just how much solar it actually can interconnect to its system. The Commission also retains discretion to adjust compliance timelines if there are insufficient resources to achieve 70% reduction in 2030.

Q. MR. KALEMBA TESTIFIES THAT "ACCELERATING SOLAR DEPLOYMENTS BASED ON TODAY'S TECHNOLOGIES COULD CROWD OUT FUTURE, UNKNOWN SOLAR OR OTHER TECHNOLOGIES THAT ARE MORE EFFICIENT OR MORE COST-EFFECTIVE THAN TODAY'S SOLAR."[48] HOW DO YOU RESPOND TO THIS?

A. While there are likely to be significant developments in technology over the coming decade, Duke must plan today to achieve the 2032 or 2032 CO_2 emissions reduction goals. Duke should not foreclose an approach to reducing emissions in the near-term in the hope of significant technology breakthroughs over the longer-term. As a part of that, Duke should be staying on top of technology and policy developments

[48] Modeling Panel p. 168.

in the industry and assess during each planning cycle whether new technologies are ready for primetime.

The only potential downside of procuring more solar in the near term is that customers could miss out on paying less if solar prices decline. Of course there is also the risk that prices will increase. Moreover, any cost savings that ratepayers might enjoy due to delaying solar would be more than offset by the increased costs of the non-solar resources that would need to be added to make up the shortfall in generation that results from procuring less near-term solar.’

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

PUBLIC (REDACTED) VERSION

CERTIFICATE OF SERVICE

I certify that a copy of the foregoing, has been served by electronic mail, hand delivery, or by depositing a copy in the United States mail, postage prepaid, properly addressed to parties of record.

This the 2d day of September, 2022

/s______________
Benjamin L. Snowden
Counsel for Clean Power
Suppliers Association