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October 24, 2022

VIA ELECTRONIC FILING

Ms. Shonta Dunston
Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, NC 27699-4300

RE: In the Matter of: Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plan and Carbon Plan, Docket No. E-100, Sub 179

Dear Ms. Dunston:

Please find enclosed for filing the Joint Brief and Partial Proposed Order of the North Carolina Sustainable Energy Association, Southern Alliance for Clean Energy, Natural Resources Defense Council, Sierra Club, Carolinas Clean Energy Business Association, Clean Power Suppliers Association and MAREC Action. By copy of this letter, I am serving a copy of the same on all parties of record by electronic delivery.

Under separate cover, the North Carolina Sustainable Energy Association, Southern Alliance for Clean Energy, Natural Resources Defense Council, and Sierra Club are also filing a separate partial proposed order.

Please do not hesitate to contact me if you have any questions.

Sincerely,

s/ Gudrun Thompson

Enclosures
cc: Parties of Record

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 179
BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plans and Carbon Plan	)	PARTIAL PROPOSED ORDER OF THE NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION, SOUTHERN ALLIANCE FOR CLEAN ENERGY, SIERRA CLUB, NATURAL RESOURCES DEFENSE COUNCIL, CLEAN POWER SUPPLIERS ASSOCIATION, CAROLINAS CLEAN ENERGY BUSINESS ASSOCIATION, and MAREC ACTION

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BY THE COMMISSION:

BY THE COMMISSION: On October 13, 2021, Governor Cooper signed into law House Bill 951. Section 1 of House Bill 951, which is now codified at Section 62-110.9 of Chapter 62 of the North Carolina General Statutes (the Statute) directs this Commission to take all reasonable steps to achieve by the year 2030 a 70 percent reduction from 2005 levels of carbon dioxide emitted in North Carolina by electric generating facilities owned or operated by Duke Energy, and to achieve carbon neutrality by the year 2050.

To this end, the Statute directs the Commission to develop a plan by no later than December 31, 2022, with Duke Energy and including stakeholder input to achieve the least-cost path to compliance with the carbon dioxide emissions reductions specified in the statute. Further, the Statute makes clear that this plan is to be reviewed by the Commission every two years and adjusted as necessary.

On November 19, 2021, the Commission issued an Order directing Duke to file a proposed Carbon Plan which complies with the requirements of the Statute by no later than April 1, 2022. The Order required Duke to conduct at least three stakeholder meetings before March 31, 2022, specifically for the purpose of gathering and incorporating stakeholder input on the Carbon Plan as well as to file a summary report identifying the participating stakeholders, outlining the process employed and identifying points of consensus after each of the three meetings.

The Order also directed the Public Staff to participate in the stakeholder process and to file a separate report after each stakeholder meeting, generally providing an overview of each of those three meetings. The Order made clear that the stakeholder process should take into account and reflect the collaborative work and the outputs of the stakeholder efforts associated with the 2019 North Carolina Clean Energy Plan, as well as the 2020 Integrated Resource Plan proceeding, and should build off the consensus achieved, and resources expended during those two efforts.

Finally, the Order set a deadline of May 31, 2022 for the filing of Petitions to Intervene in the proceeding, and gave parties 60 days from the filing of Duke's proposed Carbon Plan to file their own plans or comments on Duke's proposed plan.

On November 29, 2021, the Commission issued an Order on Duke's motion extending the deadline for Duke to file its proposed Carbon Plan to May 16, 2022, extending the deadline for intervention to July 15, 2022, and extending the deadline by which the stakeholder meetings were to be concluded to May 13, 2022.

On January 21, February 22, and March 22, 2022 the Commission issued orders requiring Duke and the Public Staff and allowing other parties to provide updates to the Commission after each of the three stakeholder meetings.

On February 7, March 7, and April 4, 2022 Duke and the Public Staff, and certain of the parties to this proceeding, provided those updates to the Commission.

On March 9, 2022, the Commission issued its Order scheduling hearings for the purposes of receiving public comment on the proposed Carbon Plan. These hearings, held in the evening, took place in Durham, Wilmington, Asheville, and

Charlotte. One hearing was also held virtually on August 23, 2022 and was split into two sessions, one in the afternoon and one in the evening.

In addition to receiving public comments at each of the public witness hearings, the Commission has received numerous statements of position from consumers, which have been filed in Docket Number E-100, Sub 179CS.

The following parties have been allowed to intervene in this proceeding by Order of the Commission: 350 Triangle; Appalachian Voices; Apple, Inc., Google LLC, Meta Platforms, Inc., jointly referred to as the Tech Customers; Avangrid Renewables, LLC; Brad Rouse; Broad River Energy, LLC; the Carolina Industrial Group for Fair Utility Rates II and the Carolina Industrial Group for Fair Utility Rates III, jointly referred to as CIGFUR; the Carolina Utility Customers Association, Inc., referred to as CUCA; the Carolina Clean Energy Business Association, referred to as CCEBA; the City of Asheville and Buncombe County jointly; the City of Charlotte; the Clean Energy Buyers Association; the Clean Power Suppliers Association; Electricities of North Carolina, Inc., North Carolina Eastern Municipal Power Agency, and North Carolina Municipal Power Agency Number 1, jointly referred to as the Power Agencies; the Environmental Justice Community Action Network and the Down East Coal Ash Environment and Social Justice Collision, jointly referred to as EJCAN, *et al.*; the Environmental Working Group; the Fayetteville Public Works Commission; Kingfisher Energy Holdings, LLC; Sean Louis; MAREC Action; NAACP; Charlotte-Mecklenburg County Branch Number 5376-B; NC WARN; the North Carolina Alliance to Protect Our People and the Places We Live; the North Carolina Council of Churches; the North Carolina

Electric Membership Corporation; the North Carolina Pork Council; the North Carolina Sustainable Energy Association; Person County; The Southern Alliance for Clean Energy, the Sierra Club, and the Natural Resources Defense Council, jointly referred to as SACE, *et al.*; the Redtailed Hawk Collective, and the Robeson County Cooperative for Sustainable Development, jointly referred to as RTHC, *et al.*; TotalEnergies Renewables USA, LLC; and Walmart, Inc.

The Public Staff, which represents the using and consuming public, is a party to this proceeding pursuant to Section 62-15(d) of the North Carolina General Statutes; and the Attorney General's Office, which represents the Using and Consuming Public as a party to this proceeding pursuant to North Carolina General Statute Section 62-20.

On May 16, 2022, Duke filed its initial Proposed Carbon Plan in this docket.

On July 15th, the intervening parties, including the Public Staff and the Attorney General's Office, made their initial filings as allowed by the Commission's Order.

On July 29, 2022, the Commission issued its Order Scheduling Expert Witness Hearings, Requiring Filings of Testimony, and Establishing Discovery Guidelines (Scheduling Order), which scheduled a hearing for the purpose of receiving expert witness testimony to begin Tuesday, September 13, 2022.

The Order also established deadlines for the prefiling of testimonies by the parties on certain specific issues, as well as allow the filing of responsive comments on other specified issues.

On August 19, 2022, Duke filed its direct testimony and exhibits.

On September 2, 2022, intervenors filed their testimony and exhibits.

On September 9, 2022, Duke filed its rebuttal testimony and exhibits.

On September 9, 2022, parties also filed responsive comments pertaining to topics not designated for the expert witness hearing.

On September 13, 2022, the Commission began the proceedings with the hearing of expert witness testimony. Duke called Kendal Bowman to testify followed by Duke's Modeling and Near-Term Actions Panel of Glen Snider, Michael Quinto, Bobby McMurry, and Matthew Kalemba.

On September 14 and 15, 2022, Duke's Modeling and Near-Term Actions Panel continued and its testimony.

On September 16, 2022, Duke called its Grid Edge Panel of Lon Huber and Tim Duff, to testify.

On September 19, 2022, Duke called its Carolinas Utilities Operations Panel of Nelson Peeler and Laura Bateman, and its Transmission Panel of Sammy Roberts and Maura Farver, to testify.

On September 20, 2022, Duke's Transmission Panel continued its testimony followed by testimony from Duke's Long Lead-Time Panel of Regis Repko, Steve Immel, Chris Nolan, and Clift Pompee, after which Duke's Transmission panel was recalled to continue its testimony.

On September 21, 2022, Duke's Transmission Panel was once again called to complete its testimony followed by testimony from Duke's Reliability Panel of John Samuel Holeman III, and Sammy Roberts.

On September 22, 2022, the Public Staff called its Panel 1 of Jeff Thomas, Dustin Metz, and David Williamson, to testify.

On September 23, 2022, CIGFUR's witness Michael Gorman, Brad Rouse (appearing on his own behalf), CCEBA and MAREC's witness Dinos Gonatas, NC WARN's witness William E. Powers, and Southern Alliance for Clean Energy, Sierra Club, and Natural Resources Defense Council (SACE et al.) and NCSEA's (together, CLEAN Intervenors) joint witness Jay Caspary were all excused from participating as expert witnesses in the hearing and their pre-filed direct testimonies were copied into the record. The Public Staff's Panel 1 was then recalled to complete its testimony followed by testimony from the Public Staff's Panel 2 of James McLawhorn and Michelle Boswell.

On September 26, 2022 CLEAN Intervenors called their witness Tyler Fitch, he was followed by the Tech Customer's panel of Michael Borgatti, Adrian Kimbrough, and Maria Roumpani, and that panel was followed by CUCA's witness Kevin O'Donnell, the Attorney General's Office's witness Edward Burgess, CIGFUR's witness Brandon Muller, and CPSA's witness John Michael Hagerty who were each called to testify in turn.

On September 27, 2022, CPSA's witness Tyler Norris, NCEMC's witness Lee Ragsdale, and CCEBA's witness Ron DiFelice were called to testify in turn; following those witnesses Duke called its Modeling and Near-Term Actions Panel of Glen Snider, Bobby McMurry, Michael Quinto, and Matthew Kalemba to give rebuttal testimony.

On September 28, 2022, Duke's Modeling and Near-Term Actions Panel was called to conclude its rebuttal testimony, after which Duke called its

Transmission and Solar Procurement Panel of Dewey S. Roberts, II and Maura Farver, its Long Lead-Time Resources Panel of Regis Repko, Chris Nolan, and Clift Pompee, and its Grid Edge Panel of Lon Huber and Tim Duff to each in turn give their rebuttal testimony.

On September 29, 2022 Duke's Grid Edge Panel was recalled to conclude its rebuttal testimony, after which Duke called its Reliability Panel of Sammy Roberts to give its rebuttal testimony. At the conclusion of these rebuttal witnesses' testimonies, the Commission closed the hearing.

On October 24, 2022, proposed orders and briefs were filed by the parties.

The written comments, responsive comments reports, and testimony and exhibits of the witnesses run to several thousand pages. The Commission has read and given due consideration to the entire record in this proceeding. In this Order, however, the Commission will not attempt to provide summaries or recitations of each of the points made by the parties in their filings, established during the expert witness hearing, or made at the public hearings or in consumer statements of position.

Based on the foregoing and the entire record in this proceeding, the Commission now makes the following:

FINDINGS OF FACT AND CONCLUSIONS OF LAW

Statutory Compliance Deadline

1. The Carbon Plan must include a reasonable range of portfolios designed to achieve Compliance with the requirements of N.C.G.S. § 62-110.9 at least cost under a wide range of scenarios, as well as a near-term execution plan

that supports execution of those portfolios.

2. The Carbon Plan must include portfolio(s) that are reasonably designed to achieve compliance in 2030, in keeping with the requirements of G.S. § 62-110.9.

3. The Commission's discretion in adjusting the compliance date does not extend to preemptively extending the deadline to 2032 (or later) except under specific, enumerated circumstances that have not been established at this time.

4. The Commission cannot preemptively authorize an extension of compliance past 2032 unless and until (a) construction of a particular wind or nuclear unit is authorized (consistent with least-cost planning) by the issuance of a CPCN and it is shown that the unit cannot achieve operation until after 2032 due to technical, legal, logistical, or other factors beyond the control of the electric public utility or (b) it becomes necessary to maintain the adequacy and reliability of the grid. Scenarios achieving compliance in 2034 may be considered for informational purposes but are not accepted as reasonable for planning purposes or an appropriate basis for near-term planning.

Inflation Reduction Act

5. The Inflation Reduction Act of 2022 P. Law 117-169, H.R. 5376) (IRA), which was signed into law by President Biden on August 16, will have immediate and far-reaching effects on the costs to the utility and thus, to ratepayers, for both supply-side and demand-side resources that are central to the energy transition mandated by N.C.G.S. § 62-110.9.

6. None of the modeling prepared in advance of the evidentiary hearing

fully captures the magnitude of the IRA because it was enacted after all of the initial modeling was conducted by Duke and intervening parties and because several relevant provisions require additional rulemaking or other implementation at the federal level. At this time, the record is not fully developed for the Commission to fully account for the effects of the IRA in the initial Carbon Plan.

7. There is broad consensus that the IRA will substantially reduce the costs to Duke Energy to deploy resources that are necessary to meet the near-term carbon emissions reduction requirements, such as solar, battery storage, and wind.

8. The IRA can also provide additional benefits relating to the early retirement of fossil fuel plants and for transmission investments that are necessary to integrate those zero-carbon resources.

9. While the IRA also provides financial incentives for nuclear and low- or zero-carbon hydrogen, those long lead-time resources are not integral to any of the short-term action plans considered by the Commission.

10. The modeling sensitivity analysis prepared by Duke and submitted by the Companies as a Modeling Panel Late-Filed Exhibit No. 1 on September 22, while informative, was only conducted in relation to Supplementary Portfolio P-5 (no Appalachian gas), was conducted only as a sensitivity to the Companies' Near-Term Action Plan and did not consider all aspects of the IRA. The P5 supplementary portfolio was not designed to meet the 2030 interim carbon emissions reduction requirements of G.S. § 62-110.9. The cost assumptions in this sensitivity were presented too late for review by other parties that conducted

EnCompass modeling.

Solar Interconnection Constraints

11. Constraints on the rate at which solar resources can be interconnected to Duke's system significantly increase the cost of compliance with the 70% reduction requirement, by requiring Duke to select higher-priced carbon free resources. Accordingly, it is in the interest of ratepayers for Duke to strive to achieve the highest rate of interconnection it reasonably can without compromising reliability.

12. Although there are practical limits on the rate at which Duke can interconnect additional solar resources, Duke has failed to demonstrate that it is unable to achieve solar interconnect rates in excess of its modeled Solar Interconnection Constraint. Although it is not possible to predict Duke's future solar interconnection rates with certainty, there is a reasonable possibility that Duke will be able to achieve interconnection rates in excess of the Solar Interconnection Constraint.

13. Given the uncertainty about future interconnection rates, it is not appropriate for Duke to include a modeling constraint in all portfolios based on its "most reasonable forecast" of likely interconnection rates. Given that higher solar interconnection rates would reduce the cost of compliance with the 70% reduction mandate, it is more appropriate to set an ambitious goal for solar interconnection and take affirmative steps to achieve that goal, while also planning for the possibility that Duke may not be able to achieve that goal.

14. It is reasonable to establish an independent technical advisory committee, with stakeholder participation, to study the achievability of higher interconnection rates in Duke's territory, and to advise the Company and the Commission on measures that can be taken to expedite interconnections; and to require Duke to report in the 2024 Carbon Plan filing on actions that have been taken and will be taken to improve interconnection rates.

Accepted Portfolios

15. The following portfolios generated from EnCompass capacity expansion and production cost modeling are, when considered collectively, reasonable for planning purposes for achieving carbon emissions reductions in a manner consistent with the requirements of G.S. § 62-110.9, prudent utility planning, and for informing the Commission’s near-term action plan: (1) Synapse Optimized and Regional Resources submitted on behalf of CLEAN Intervenors, (2) Gabel and Associates and Strategen Preferred Portfolio on behalf of the Tech Customers, (3) Strategen SP-AGO Portfolio on behalf of the Attorney General’s Office, and (4) Portfolio 1/P1-Alt conducted by Duke Energy. Portfolio CPSA3, modeled by Brattle on behalf of CPSA, though not using EnCompass, is reasonable for Commission consideration for planning purposes as an alternative resource portfolio that is consistent with the requirements of G.S. § 62-110.9 and prudent utility planning (the Synapse Optimized and Regional Resources portfolios, Gabel and Associates and Strategen Preferred Portfolio, Strategen SP-AGO Portfolio, Duke Portfolio 1/P1-Alt, and Brattle CPSA3 portfolio, collectively referred to herein as the Accepted Portfolios).

16. The Synapse Optimized and Regional Resources portfolios, the Tech Customers Preferred portfolio, the SP-AGO portfolio, and CPSA3 Portfolios all lay out pathways for reaching the 2030 interim carbon emissions reduction requirements at a lower relative PVRR than the Duke Portfolio 1 or P1-Alt.

17. The remaining portfolios modeled by Duke Energy, including the Supplemental P5 and P6 scenarios, provide useful information to the Commission, but because they do not meet the 70% reduction requirement by 2030, they are not reasonable for planning purposes at this time.

18. The Commission does not need to resolve all of the differences in inputs, assumptions, or other modeling decisions at this time for purposes of establishing a reasonable and prudent near-term action plan over the next three years.

19. The Commission finds that the following near-term actions are consistent with the modeling relied on for planning purposes, including for purposes of meeting the 2030 carbon reduction requirement, while maintaining the necessary flexibility and optionality that will allow the Commission the ability to check and adjust following the 2023 IRP update and 2024 Carbon Plan Update

Near-Term Execution Plan

20. The Commission finds that the following near-term actions are consistent with the Accepted Portfolios, including for purposes of meeting the 2030 carbon reduction requirement, while maintaining the necessary flexibility and optionality that will allow the Commission the ability to check and adjust following

the 2023 IRP update and 2024 Carbon Plan Update

RESOURCE	AMOUNT	PROPOSED NEAR TERM ACTIONS
Proposed Resource Selections		
Solar	2022 solar procurement of 1647 MW 2023 solar procurement of 1647 MW (with minimum 300 MW paired storage) 2024 solar procurement of 1947 MW (with minimum 450 MWr paired storage)	440 MW of 2022 Procurement consists of third-party CPRE MW (to roll over to HB951 if unfulfilled) If the RZEP are approved by the TPC, final DISIS cost allocations for RZEP will not be considered in bid evaluation, VAM calculation, or avoided cost cap compliance Revisit Volume Adjustment Mechanism for 2023-24 procurements Begin Stakeholder engagement on new contract language for solar-plus-storage, including properly valuing longer-duration storage to be presented for NCUC approval before the 2023 procurement
Battery Storage	850 MW (total minimum procurement for 2023 & 2024)	Finalize procurement strategy and initiate procurement activities to procure 850 MW minimum of stand-alone, battery-energy storage Build-Own Transfer Invest in operational capabilities for capitalizing on energy storage resources for grid service
Onshore Wind	900 MW	Initiate competitive procurements of Carolinas onshore wind with target volumes of 300 MW in 2023, 300 MW in 2024, and 300 MW in 2025 with target in-service dates of 2026, 2027, and 2028 respectively Begin necessary activities to support adding

		450 MW of imported onshore wind in both 2027 and 2028 Engage in inter-regional coordination with PJM for facilitating power purchase Integrate Midwest wind import into short-term transmission planning
Offshore Wind	---	Initiate study of costs of developing three distinct WEA leases
Pumped Storage Hydro	1700 MW	Conduct feasibility study for 1,700 MW, develop EPC strategy, and apply at FERC for re-licensing
Grid Edge-Energy Efficiency	1.5 percent of retail load	Step-up utility energy efficiency savings target to 1.5 percent of eligible retail load by 2027 and 1.5percent of total retail load by 2030
Grid Edge – Distributed Energy Resources	At least 1 GW by 2035	Develop and support programs to empower customer-owned energy resources to accelerate contribution to grid needs
RZEP		Begin construction in 2022 if approved by NCTPC

Solar Procurement

21. To comply with N.C.G.S. § 62-110.9, the near-term execution plan must include annual solar procurement target volumes that at least have the potential to achieve compliance with the 70% carbon reduction mandate by 2030, assuming that no volume adjustment (upward or downward) is triggered by operation of the Volume Adjustment Mechanism.

22. The procurement targets proposed by Duke and the Public Staff are

unreasonable because those targets would make it impossible to comply with the 70% requirement by 2030, even with optimistic assumptions about the availability of other carbon-free resources.

23. It is not reasonable to establish target procurement volumes that would achieve compliance by 2030 only if bid pricing came in significantly below modeled costs, such that the target volume would be adjusted upward by the Volume Adjustment Mechanism.

24. It is reasonable to establish ambitious targets for near-term procurement of solar resources because such targets increase the likelihood of compliance with N.C.G.S. § 62-110.9, mitigate execution risk in other aspects of the Carbon Plan, and create the possibility of achieving greater ratepayer savings. Establishing ambitious procurement targets (within the range proposed by intervenors) does not create significant risks to ratepayers.

25. In order to support compliance with the 70% reduction mandate of N.C.G.S. § 62-110.9 by 2030 and a reasonable range of Carbon Plan portfolios, it is reasonable to establish the following target volumes for solar procurements by Duke during the near-term execution plan: 1647 MW in 2022; 1647 MW in 2023; and 1947 MW in 2023.

26. It is reasonable to order that in the 2022 solar procurement, at least 440 MW of the solar capacity procured shall consist of projects designated to fulfill Duke's outstanding obligation under the CPRE program. In order to meet the requirements of HB 589, such CPRE MW must (a) consist solely of third-party PPAs; (b) be at or below avoided cost, inclusive of reasonable Network Upgrade

costs.

27. The Volume Adjustment Mechanism (VAM) is reasonable to use for purposes of the 2022 procurement but should be reviewed and revised in future procurements.

28. In order to avoid distorting the operation of the VAM, the pricing and volume of CPRE MW procured in the 2022 procurement must be considered in calculating solar pricing for the VAM; however, the volume of CPRE MW itself should not be subject to adjustment.

29. It is not reasonable or in the interest of ratepayers to allocate a specified amount of capacity in the 2022 procurement to projects located in DEC's service territory.

Energy Storage

30. Solar plus storage hybrid systems can harness carbon-free renewable generation in a dispatchable resource that is able to provide energy, capacity, and ancillary services to meet demand.

31. The modeling undertaken by Duke for the proposed Carbon Plan imposes significant limitations on the storage component of solar plus storage systems.

32. Adjustments to those limitations undertaken to produce supplemental portfolios SP5 and SP6 resulted in additional solar plus storage being forecast along with reductions in other resources that are less competitive with solar plus storage.

33. The Near-Term Execution Plan proposed by Duke recommends procurement of 1,600 MW of storage resources through 2024, including 1,000 MW

of standalone storage and 600 MW of storage plus solar.

34. All of the Duke Energy portfolios as well as all submitted alternative modeling and plans include substantial amounts of solar plus storage through 2030 and beyond and view solar plus storage as an important resource in achieving the mandated CO2 reductions in N.C.G.S. § 62-110.9

35. Duke's modeling limitations on solar plus storage, even after the development of the Supplemental Portfolios, is inconsistent with the market and unreasonable for determining the amount of solar plus storage needed to achieve the mandated reductions.

36. Duke's modeling limitations have the effect of rendering solar plus storage less competitive with other technologies in the proposed portfolios, in both the near and the long-term.

37. The Near-Term Execution Plan will benefit from greater procurement of solar plus storage than that requested by Duke.

38. Currently, Duke does not have contracting structures, such as PPAs, for the procurement of solar plus storage resources that adequately compensate third party developers for the energy and services provided by solar plus storage and provide rights to dispatch, operate, and control the solicited facilities in the same manner as the utility's own generating resources.

39. Models of such contracting structures do exist in other markets, and Duke should be able to develop such contracts with the engagement of stakeholders before the 2023 procurement.

40. It is in the best interest of ratepayers for solar plus storage to be

procured beginning with the 2023 procurement in the amount of at least 300 MW and in the 2024 procurement in the amount of at least 450 MW, with no restriction on amounts above those figures if solar plus storage is competitively procured.

41. As a rapidly maturing technology, standalone storage as a resource will play a vital role in achieving the carbon reduction mandates of HB951.

42. The effects of changes to the tax credits available to various storage technologies in the Inflation Reduction Act will likely change the economic analysis of storage and solar plus storage in the first two to three years following this Carbon Plan order.

43. Standalone storage offers numerous benefits to the grid, including voltage support and control, reliability enhancement, capacity deferral and peak shaving, reducing the need for transmission investments by boosting capacity and reducing overloading, transmission congestion relief, peak capacity deferral, bulk energy "time shifting", frequency regulation, spinning and non-spinning reserves, black start capacity, flexible ramping, and synthetic inertia to provide fast responses in a system where the share of variable renewables is high.

44. Standalone storage provides flexibility for location of storage capacity near load centers or at the sites of retiring thermal generation in order to minimize transmission and interconnection costs.

45. Duke Energy's Carbon Plan modeling inappropriately limits storage resources through the hard limits on battery storage in the initial four portfolios, and through Duke's Battery-CT Optimization process. This process should be adjusted and made more transparent before the next Carbon Plan update.

46. Duke Energy's calculation of Depth of Discharge inappropriately disadvantages storage in modeling by "double counting," because the cost projections used by Duke already account for depth of discharge, making Duke's additional adjustment unnecessary.

47. The procurement or construction of at least 850MW of standalone storage by 2024.

48. Duke Energy should, to the extent practicable, locate such standalone storage resources on the site of retiring thermal resources or near load centers to maximize use of existing transmission infrastructure.

49. Competitive procurement of standalone storage resources is consistent with least cost planning principles and will result in lower prices and protection of ratepayers.

50. Standalone storage resources should be procured through a competitive Build/Own/Transfer process to be developed by Duke Energy and stakeholders in time to be used for a procurement in 2023.

51. Any Build Own Transfer procurement process should be constructed to comply with LGIP 10.11.1 or NCIP 4.4.10.1 readiness requirements, such that the designation of a volume of standalone storage in the Carbon Plan is sufficient to comply with the requirement that "the Generating Facility has been selected by a Resource Planning Entity in a Resource Plan."

Onshore Wind

52. Onshore wind is a commercially available renewable energy technology with a proven track record. The generation profile of onshore wind

compliments solar resources. While there are geographic limitations on the availability of onshore wind in the Carolinas, there is no reason to conclude that significant amounts of onshore wind cannot be built in the Carolinas. Duke has not yet conducted a competitive solicitation for onshore wind in the Carolinas, nor has Duke held any stakeholder workshops with developers. By initiating a competitive procurement for Carolinas onshore wind that contains a volume adjustment mechanisms, Duke will ensure ratepayers benefit from the lowest cost resources available. If the availability of onshore wind is limited, the 2024 Carbon Plan will incorporate the results of such competitive procurement process and adjust accordingly.

53. Duke has long imported energy from neighboring areas to ensure reliability and meet peak demand. Even with annual limits and proxy costs, the SP-AGO, the Regional Resources portfolio, and Duke's modeling selected imported onshore wind when available. Duke has not provided a sufficient justification for limiting imports of onshore wind in light of the value that this resource provides to ratepayers, even when applying reasonable, objective limits on the amount that may be imported.

Offshore Wind

54. Offshore wind (OSW) is a commercially available renewable energy technology with a proven track record.

55. There is still a potential for OSW to form part of the least-cost path for complying with the 2030 carbon-reduction requirement.

56. The Kitty Hawk lease area is further along in its development process than the more recently auctioned Carolina Long Bay lease areas.

57. The wind resource and net capacity factor at the Kitty Hawk lease area appears to be superior to the wind resource and net capacity factor at the Carolina Long Bay lease areas.

58. There is insufficient information in the record to determine the relative overall value propositions for ratepayers presented by each of three Carolinas OSW lease areas .

59. Duke's plan to acquire the lease of its affiliate without a robust, independent comparison of the three available offshore wind lease areas may not lead to the least cost mix of generation resources

60. It is appropriate to hire an independent third-party consultant to evaluate and prioritize each North Carolina offshore wind lease and file its report in this docket within six months of the date of execution of its contract with the Commission. The Commission will endeavor to retain a consultant within 45 days of this Order.

61. Studying the various wind lease areas need not delay procurement of any necessary offshore wind resources, as there are certain development steps that must be taken in order for Duke's affiliate to maintain its lease that are not dependent on Duke acquiring the lease

62. In its evaluation, the third-party consultant's report should review levelized cost of energy (LCOE), viability, schedule, size, and overall plan, and

other parameters provided by the Commission in a subsequent order, discussed below.

63. It is appropriate to require the third-party consultant to hold at least one meeting with interested stakeholders before conducting its analysis and to submit a report summarizing their input; to hold a subsequent 15-day comment period during which stakeholders may comment on appropriate parameters, among other issues; and to issue an order on study parameters and any other important preliminary issues raised by commenters within 15 days after the comment period closes.

64. It is appropriate to require the third-party consultant to hold at least one meeting with interested stakeholders during drafting.

65. It is appropriate to require the third-party consultant to submit concise monthly status updates on the progress of the report.

66. It is appropriate to accept comments from Duke, the Public Staff, and intervenors on the report, including on the appropriate prioritization of offshore wind leases.

67. Following the close of the comment period on the third-party consultant's report, the Commission will endeavor to issue an order prioritizing wind lease areas within 30 days. Consistent with G.S. § 62-110.9, the Commission's prioritization will focus on the lease's contribution to a reliable least-cost path to the 2030 carbon-reduction goal as part of a comprehensive final Carbon Plan.

Pumped Storage Hydro/Existing Nuclear

68. Many of the Accepted Portfolios that support the near term execution plan assume continued operation of Duke's existing nuclear fleet and expansion of its Bad Creek facility, adding approximately 1700 MW of pumped storage hydro capacity.

Grid Edge

69. Expanding utility energy efficiency and demand side management is a necessary component of achieving the carbon reduction requirements of G.S. § 62-110.9 at least cost while maintaining the reliability of the grid. Duke Energy shall ramp up its cost-effective utility energy efficiency savings to 1.5% of eligible sales (net of industrial and commercial opt outs) by 2027 and work with the Duke Collaborative on a plan for achieving 1.5% of total retail sales by 2030.

70. In the event that non-utility energy efficiency savings made possible by the Inflation Reduction Act or other non-utility funded sources significantly reduces cost-effective utility EE savings opportunities, Duke shall work with the Collaborative to develop a different metric for the appropriate level of utility EE savings for Commission consideration in future Carbon Plan updates.

71. Modeling a range of utility energy efficiency savings levels as a decrement to total load, rather than one static assumption of utility EE savings levels, provides useful information for Commission consideration when developing its carbon plan. As a potential alternative, modeling utility EE as a selectable resource within EnCompass, rather than assuming a level of utility EE savings as a decrement to load, would provide additional useful information for Commission consideration.

72. Increasing opportunities for customer-owned distributed energy resources (DERs) is an important strategy for achieving the carbon reduction requirements of G.S. § 62-110.9 at least cost while maintaining the reliability of the grid. As with utility EE, DERs require the investment of customers' private capital in zero-carbon resources that have the aggregate effect of reducing the need for Duke Energy to invest in those same resources, mitigating carbon plan compliance costs for ratepayers as a whole

73. Modeling a range of DER adoption levels, rather than one static assumption of DER adoption, provides useful information for Commission consideration when developing its Carbon Plan.

Environmental Justice

74. Underserved community voices need to be included in the development of the Carbon Plan. Duke's Carbon Plan stakeholder process did not include specific outreach to or inclusion of environmental justice advocates and underserved communities before finalizing its May 15 Carbon Plan filing. Prior to beginning stakeholder processes for its 2024 proposed Carbon Plan, the Companies are expected to convene a more inclusive environmental justice stakeholder processes that will not be limited to members selected solely by Duke.

Red Zone Expansion Plan

75. Substantial upgrades to the transmission system will be required in order to meet requirements of N.C.G.S. § 62-110.9 .

76. In general, the so-called "Red Zone" is the area with the greatest potential for cost-effective development of solar projects in Duke's service

territories.

77. The Red Zone Expansion Plan projects represent a "no-regrets" set of upgrades to Duke's transmission system, and will be necessary to achieve compliance with N.C.G.S. § 62-110.9.

78. It is likely that additional upgrades may be needed to Duke's transmission system to achieve compliance with N.C.G.S. § 62-110.9, and it is reasonable to direct Duke, in the next IRP Update, to provide information relating to how it plans to identify further upgrades required for N.C.G.S. § 62-110.9 compliance.

Costs of the RZEP in the 2022 procurement

79. The current cost allocation methodology for Network Upgrades under the NCIP does not accurately reflect the costs and benefits of large-scale transmission upgrades like the RZEP, which will facilitate the construction of large volumes of solar resources that may not all be studied in the same DISIS cluster. As a result, using final DISIS cost allocation figures for purposes of bid evaluation and calculation of the Volume Adjustment Mechanism is inappropriate.

80. If the RZEP are approved by the NCTPC and reclassified as Contingent Facilities, then it would be unreasonable to use the final DISIS 1 cost allocations for RZEP upgrades for purposes of bid evaluation, avoided cost cap compliance, and VAM calculations in the 2022 solar RFP.

81. The cost allocations for RZEP upgrades at the conclusion of DISIS phase 1 provide a rough but reasonable approximation of the costs for those Upgrades that should be attributed to each project for the purposes of bid

evaluation, avoided cost cap compliance, and VAM calculation in the 2022 solar RFP.

Transmission Planning

82. Conventional transmission planning is fundamentally reactive because it is driven by responding to generator interconnection requests. Conventional reactive transmission planning is typically driven by the lowest initial cost transmission investments that can resolve reliability issues associated with new generator interconnection requests or other grid changes. Conventional reactive transmission planning can cost more than proactive planning over time as additional incremental investments continue to be required.

83. "Proactive" transmission planning looks forward in time across a range of future scenarios. The five core principles of proactive transmission planning are the following: (1) proactively planning for future generation and load using realistic projections for the life of the transmission asset; (2) using multi-value planning accounting for the full range of benefits provided by new transmission; (3) using scenario-based planning to address uncertainties and high-stress grid conditions across a range of possible futures and real-world system conditions; (4) using comprehensive transmission network portfolios to address system needs and cost allocation; and (5) jointly planning across neighboring interregional systems to increase resilience and improve economics and geographic diversification benefits.

84. Multi-value transmission planning analyzes the full range of benefits provided by new transmission investments, rather than limiting the analysis to the

production cost-derived valuation of the savings generated by new transmission. The range of benefits appropriate for multi-value transmission planning analyses is well captured in the NOPR in FERC's recent rulemaking RM21-17.

85. Proactive multi-value transmission planning is more likely than conventional reactive transmission planning to generate a least-cost path to the carbon-reduction requirements in Session Law 2021-165. Under the least-cost mandate in Session Law 2021-165, the Commission has the authority to require proactive multi-value transmission planning for Carbon Plans.

86. To be most efficient, proactive multi-value transmission planning must rely on synchronized resource planning and transmission planning, rather than iterating between siloed resource planning and siloed transmission planning.

87. Duke's proposed Carbon Plan does not rely on proactive multi-value transmission planning.

88. The existing NCTPC planning processes are insufficient to implementing proactive multi-value transmission planning. The opportunities for stakeholder input into the NCTPC's processes and studies, through the TAG, are insufficient Changes to the NCTPC planning processes such as shifting towards generator interconnection-type studies would improve the NCTPC's analyses but are insufficient to implementing proactive multi-value transmission planning.

89. It is appropriate to open a proceeding, within sixty days of the conclusion of the Carbon Plan proceeding, on the synchronizing resource planning and transmission planning and applying proactive multi-value transmission planning in Nort*h Carolina.*

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1-4
STATUTORY COMPLIANCE DEADLINE
(Scheduling Order ordering paragraph 6.c).

The evidence supporting these findings of fact and conclusions is contained in the Company's initial Carbon Plan filing on May 16, the comments filed by intervenors and the Public Staff, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

A threshold question this Commission must consider is whether it is both legally permissible and also prudent, in this initial Carbon Plan, to authorize Duke to delay compliance with the 70% carbon reduction requirement of H.B. 951 past 2030, or even past 2032. For the reasons below, we conclude that it is not.

Summary of the evidence and comments

N.C.G.S. § 62-110.9 requires the Commission to develop a plan to "achieve the least cost path…to achieve compliance with the authorized carbon reduction goals." G.S. § 62-110.9(1). The Commission must comply with current law and practice with respect to the least cost planning for generation in achieving the authorized carbon reduction goals, and the Commission retains discretion to determine optimal timing and generation and resource-mix to achieve the least cost path to compliance with the authorized carbon reduction goals. G.S. § 62-110.9(2), (4).

In the Carbon Plan, Duke presents four portfolios that include different combinations of supply-side resource to achieve the 70% interim target by 2030. Carbon Plan, Ch. 3, pp. 1-2. These different portfolios include variations in individual technology adoption rates and volumes, and the portfolios all incorporate the unique operational characteristics, cost projections, supply-chain dependencies, geographic limitations, and associated transmission and distribution grid dependencies. Duke explains that each portfolio results in different benefits and risks, and the consideration of these benefits and risks for each resource type demonstrates that implementation of the Carbon Plan will require a balanced approach across different demand-side programs and supply-side resources. Duke states that the two pathways and four portfolios presented in the Carbon Plan utilize least-cost planning to accomplish the energy transition contemplated by N.C.G.S. § 62-110.9. Duke also presents an Execution Plan that includes near-term activities and approvals required to pursue N.C.G.S. § 62-110.9 's emissions reductions targets, as well as intermediate-term and long-term actions and planning. Carbon Plan, Ch. 4, pp. 1-2.

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[.]" H.B. 951 Sec. 1(4).

G.S. § 62-110.9(4) states that the Commission shall:

> Retain discretion to determine optimal timing and generation and resource-mix to achieve the least cost path to compliance with the authorized carbon reduction goals, including 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.

Parties have presented differing views regarding the application of this provision, including how this language should influence the appropriate selection of a NTEP by the Commission.

In the proposed Carbon Plan, Duke includes one portfolio (P1) designed to achieve compliance with the 70% mandate in 2030; one portfolio (P2) that achieves compliance in 2032; and two portfolios (P3 and P4) that reach compliance after 2032. In its supplemental modeling, Duke included one 2032 portfolio (P5), one 2034 portfolio (P6), and no 2030 portfolio.

Duke argues that this is appropriate because the Commission has broad discretion to extend the interim target achievement date to 2032. Duke points to language in N.C.G.S. § 62-110.9(4), stating that "the plain language of the statute requires that the Commission retain its discretion to select the 'optimal' timing and resource mix…even where such timing and resource mix extends the Interim Target Achievement Date to 2032." (Duke Pre-Hearing Comments at 6-10.) Duke also identifies the specific circumstances under which the Commission is authorized to extend the compliance time frame, related to the construction of an authorized wind or nuclear facility or to maintain the adequacy and reliability of the grid. Duke disagrees with the interpretation of the AGO and other intervenors that the more general grant of authority to delay compliance beyond 2030 is only permissible if the delay is due to Carbon Plan implementation that results in a "more significant and material impact on carbon reduction." Duke argues that more significant and material impact on carbon reduction is only one factor that could lead the Commission to delay compliance to 2032, and that the Commission maintains broad authority to do so. *Id.*

Duke states that it is appropriate in this proceeding for the Commission to approve all portfolios presented by Duke as "reasonable for planning purposes" and that any reliance of the exception related to the construction of a wind or nuclear facility would only apply in "a later proceeding" in which Duke seeks authorization to construct any such facilities. *Id.* Duke requests the Commission "expressly state that it is retaining its discretion to adjust [resource plans] in the future so that it can better ensure that the least-cost plan to achieving the targeted carbon reduction milestones is achieved, as required by HB 951." *Id.* at 14.

The Public Staff's position on 2030 compliance is not entirely clear. On the one hand, the Public Staff states that "meeting the interim compliance goal of 2030 is a priority," and that it does not recommend that the Commission "preemptively authorize a delay in meeting the interim compliance goals." Comments of the Public Staff (Sept. 9, 2022) at 5. On the other hand, the Public Staff argues that the Commission "would be acting in accordance with its statutory authority should it find it in the public interest to extend the compliance deadlines set forth in Section 110.9." *Id.* at 6. The Public Staff also requested that Duke develop additional supplemental portfolios that would meet the 70% carbon emissions reduction requirements in 2032 and 2034, but none that would achieve that requirement by 2030.

The Public Staff goes on to state that "Section 110.9 provides for a balancing between the 2030 interim compliance timeline, least-cost planning, and adequacy and reliability," and appears to suggest (without "recommending") that the Commission should exercise its discretion to extend compliance past 2030 if doing so "would result in least-cost planning or improved adequacy and reliability of the grid." *Id.* The Public Staff further states that the Commission should consider several factors when determining the year in which Duke must comply with the 2030 compliance goal. The Public Staff argues that execution risk is the greatest determinant of whether the Commission should grant a delay in achieving interim compliance, because compliance will depend upon whether the required new resources are able to interconnect in a safe and reliable manner in the timelines proscribed by each portfolio. Public Staff Comments at 28-29. The Public Staff testifies that it is reasonable for Duke to model a delay in the interim compliance year beyond 2030 in order to evaluate the costs and generation resource mixes that would result. Tr. vol. 21,38-40. However, Public Staff witness Thomas clarified in his direct testimony and at the hearing that the Public Staff "is not recommending that the Commission preemptively authorize a delay in meeting the interim compliance goals." Tr. vol. 21, 40.

The AGO notes that N.C.G.S. § 62-110.9 provides 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" but that this discretion is limited to three scenarios: (1) delaying compliance by up to two years in order to allow for implementation of solutions that would have a more significant and material impact on carbon reduction, (2) delaying compliance by more than two years for the construction of an authorized wind or nuclear facility, or (3) delaying compliance more than two years in the event necessary to maintain the adequacy and reliability of the grid. AGO Comments, at 8-9. The AGO emphasizes that the Commission may only include a portfolio that delays compliance with the statutory deadline if the Commission determines that it provides “more significant and material impact on carbon reduction” than P1. The AGO also notes that a delay of more than two years is permissible only if factors beyond the control of the public utility necessitate additional time for completion of a previously authorized wind or nuclear facility but that it is inappropriate for the Commission to approve a portfolio that delays compliance by more than two years before a wind or nuclear facility included in the portfolio has been authorized. *Id.* at 10.

The CLEAN Intervenors came to the same legal conclusion as the AGO and noted that in the first instance, the Commission’s discretion to extend beyond the 2030 interim carbon emissions reduction deadline is limited to “the implementation of solutions that would have a more significant and material impact on carbon reduction”—meaning solutions that would result in faster or deeper carbon reductions. CLEAN Intervenors Joint Comments at 10-11 (July 15, 2022). With regard to statutory authorization for a delay in 2030 compliance relating to maintaining reliability or following Commission authorization to construct a nuclear or wind facility, CLEAN Intervenors noted that the “legislature’s use of the phrase ‘in the event’ makes clear that an extension pursuant to one of these triggering circumstances could be granted only if such a circumstance arises. *Id.* at 12. The

Tech Customers likewise noted that the "Companies have not presented any plan that would have a 'more significant and material impact on carbon reduction,' so section 62-110.9(4) does not permit an extension" of two years. Comments of Tech Customers on Non-Hearing Issues at 21. By the same token, Duke has not provided any evidence "of the circumstances necessary to justify an extension of more than two years." *Id.* CCEBA also noted that "the adopted Carbon Plan must achieve the 70% reduction by 2030 unless" specific findings are made relating to contingencies that have not yet occurred. CCEBA Comments at 6-8 (July 15, 2022).

CPSA states that although the statutory language is not a model of clarity, delays past 2032 are clearly not permitted, with two exceptions: (1) where it is necessary to maintain resources 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. CPSA points out that under North Carolina law the process by which the Commission authorizes the construction of electric generating facilities is through the issuance of a certificate of public convenience and necessity pursuant to N.C.G.S. § 62-110.1. AGO, CLEAN Intervenors and CCEBA came to the same conclusion that "authorizes construction of" in this context refers to the granting of a CPCN. CLEAN Intervenors Joint Comments at 11-12; CCEBA Comments at 7. CPSA notes that inclusion of a wind or nuclear facility in the Carbon Plan alone does not give Duke a "free pass" to delay 2030 compliance, and to the extent wind or nuclear generation is needed to maintain system reliability, the law independently allows for delays beyond two years "in the event necessary to maintain the adequacy and reliability of the grid," which CPSA notes that Duke has not asserted. Instead, CPSA argues, 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 bringing wind or nuclear resources online once their construction has been authorized through the issuance of a CPCN. CPSA Comments at 34-36.

CIGFUR describes the discretion afforded to the Commission regarding the time frame for compliance with N.C.G.S. § 62-110.9 's carbon reduction goals and states that the Commission may extend the time frame for compliance with the 2030 for "by two years for any reason" in addition to the potential extensions due to additional time needed to complete an authorized wind or nuclear facility or to maintain the adequacy and reliability of the grid. CIGFUR Comments at 8-9. CLEAN Intervenors noted that it is "difficult to square [CIGFUR's] assertion with the plain language of the statute." Joint Responsive Comments of CLEAN Intervenors at 7 (Sep. 9, 2022).

Discussion and conclusions

The Commission finds that Duke's approach of presenting at least four portfolios in its Carbon Plan, in addition to a NTEP, is generally reasonable and appropriate for purposes of providing the Commission and stakeholders with a range of options and paths that the Commission may choose from towards the achievement of the carbon reduction goals of N.C.G.S. § 62-110.9 under a least-cost framework. As discussed elsewhere in this order, the content of these portfolios and NTEP must ensure that the demand-side and supply-side resource mixes included in these portfolios are appropriate and reasonable. As discussed below, the Commission also finds that in this initial Carbon Plan proceeding, the portfolios and NTEP presented by Duke must target compliance with the 70% carbon reduction mandate by 2030. It is not appropriate, in this initial Carbon Plan proceeding, to plan around portfolios that would not achieve compliance by 2030.

N.C.G.S. § 62-110.9(4) describes the discretion afforded the Commission regarding the optimal timing and generation and resource-mix to achieve the least cost path to compliance with the authorized carbon reduction goals. 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. However, this discretion is limited. The Commission may only exceed the dates specified to achieve the authorized carbon reduction goals by up to two years in limited circumstances, and the Commission may only exceed the specified dates by more than two years if one of two other conditions are met: first, in the event the Commission authorizes construction of a nuclear facility or wind 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 second, in the event necessary to maintain the adequacy and reliability of the grid.

With respect to the Commission's discretion to exceed the dates specified to achieve the authorized carbon reduction goals by no more than two years, the Commission finds persuasive the arguments of the AGO, CPSA, CLEAN

Intervenors, Tech Customers, and CCEBA that the Commission's discretion to exceed the dates specified by no more than two years applies only in the event that such delay is necessary "in order to allow for implementation of solutions that would have a more significant and material impact on carbon reduction." N.C.G.S. § 62-110.9 grants the Commission discretion to determine the optimal timing and generation and resource mix; however, with the exception of the implementation of solutions that would have a more significant and material impact on carbon reduction, such discretion is bounded by the statutory deadline of 2030. In other words, the Commission has discretion to choose the best path to achieve the statutory carbon reduction goals by 2030, but the delay not to exceed two years is permissible only in the event that such delay results in carbon reduction materially greater than portfolios that achieve 70% carbon reduction in 2030. No party argues that a delay past 2030 would result in more significant and material impacts on carbon reduction; to the contrary, there is ample evidence that P1, Duke's sole 2030 compliance portfolio, achieves greater carbon reductions than any other portfolio. See, e.g., Tr. vol. 12, 40-43 (discussing carbon reductions achieved under various portfolios). Moreover, while it may be generally true that delaying compliance past 2030 would be less expensive than complying in 2030 in PVRR terms (because delayed costs have a lower impact on present value), the statute does not give the Commission discretion to delay compliance past 2030 simply because it would be less expensive.

With respect to the Commission's discretion to exceed the dates specified to achieve the authorized carbon reduction goals greater than two years, the

Commission also finds persuasive the arguments of the AGO, CPSA, CLEAN Intervenors, Tech Customers, and CCEBA that the exception regarding an authorized wind or nuclear facility is intended to apply only after the construction of any such facility has been authorized by the Commission following a CPCN proceeding. N.C.G.S. § 62-110.9 permits the accommodation of limited construction delays in such facilities due to "technical, legal, logistical, or other factors beyond the control of the electric public utility," but the Commission finds it is inappropriate to adopt a plan that pre-emptively incorporates the assumption that such facilities will be delayed beyond the compliance deadline. No party has presented evidence that an extension of greater than two years is necessary in order to maintain the adequacy and reliability of the grid.

In sum, while the Commission has discretion to exceed the dates specified to achieve the authorized carbon reduction goals in certain scenarios, there is a clear statutory obligation to take all reasonable steps to achieve the carbon reductions goals by 2030. It is premature, in this first Carbon Plan proceeding, to approve a plan that will achieve anything other than compliance by 2030, and a NTEP that does not support 2030 compliance is therefore inconsistent with N.C.G.S. § 62-110.9. Further, no party has demonstrated that the conditions that would allow the Commission to exceed the dates by up to two years (or longer) have been met. Scenarios achieving compliance in 2034 may be included for informational purposes (in much the same way sensitivities are included to illustrate the impacts of various contingencies) but are not an appropriate basis for near-term planning.

Because the Commission finds that it is not appropriate to preemptively authorize Duke to delay compliance with the 70% reduction mandate past 2030 at this time, the Commission concludes that this initial Carbon Plan should orient around 2030 compliance (while preparing for the possibility that compliance in 2030 may prove impossible or impracticable). Accordingly, the Commission finds that (1) the Carbon Plan should include a robust range of portfolios that are designed to achieve compliance in 2030; (2) it is inappropriate to rely on the assumption that compliance will be delayed past 2032; and (3) the Near-Term Execution Plan should be designed to achieve compliance in 2030.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5-10
IRA
(Scheduling Order ordering paragraph 1.a., 1.c., 1.k.)

The evidence supporting these findings of fact and conclusions is contained in the Company's initial Carbon Plan filing on May 16, the comments filed by intervenors and the Public Staff, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

Summary of evidence

CLEAN Intervenors' witness Dr. Uday Varadarajan of RMI testified on the IRA. Because the carbon plan portfolios presented by Duke and the intervening modeling parties were completed before the enactment of the IRA in August, those portfolios do not reflect the full potential for "enormous savings for North Carolina ratepayers form IRA policies." Tr. vol. 23, 240. This risk is heightened for portfolios—like those from Duke—that rely on new gas generation or that keep existing coal plants running past their economically optimal retirement dates. *Id.* Because solar, wind, and battery storage are the commercially available resources that stand to benefit from "hundreds of billions of dollars in new and expanded federally funded incentives and key regulatory improvements," portfolios that rely more heavily on those resources present less risk of missing out on these new policies. The IRA "has the potential to radically alter the cost-effectiveness of clean resources, reduce the cost of retiring of fossil fuel assets, and change incentives for ownership structures of clean resources." Id. "Without considering the wide-ranging impacts of the IRA, the Commission risks selecting a near-term strategy for reaching the statutory carbon requirements that locks in extra costs for ratepayers and leaves savings opportunities untapped." *Id.* at 247.

According to Witness Varadarajan, the most important provisions of the $370 billion in federal funding and tax benefits in the IRA for reducing the cost of clean energy resources such as wind, solar, and battery storage are:

- A full decade (and potentially longer) of tax-credit certainty for solar, wind, and storage technologies (including for tax credits that were otherwise set to expire)
  - The existing Section 45 10-year Production Tax Credit is expanded to include solar as well as wind and extends credit eligibility at full value for projects deployed through the end of 2024.
  - The existing Section 48 Investment Tax Credit is continued at full value through the end of 2024 and now includes stand-alone energy storage projects.
  - Regulated public utilities may now opt-out of "tax normalization"

of the ITC for ratemaking purposes for storage investments, removing a federal legal barrier that has disadvantaged pricing (as flowed-through to customers) for utility-owned assets compared with technologically identical third-party-owned offerings.

- If newly implemented prevailing wage and apprenticeship “bonus” requirements are satisfied, the PTC for wind and solar is $26 per MWh (in 2022 dollars), while the ITC is sized at 30% of project cost.
- After 2022, an adder of 10% for the PTC and 10 percentage points for the ITC will apply if specific domestic materials requirements are met (phased in initially at 40%, though only 20% for offshore wind projects, and rising to 55% for onshore projects beginning construction in 2027 or later and offshore projects beginning construction in 2028 or later).

• Lifts the moratorium placed on renewable energy leases, easements, and right-of-way in areas of the outer continental shelf off the coast of North Carolina and other southeastern states that had been placed by the former administration.

• ITC and PTC enhancement for projects placed in service within an “energy community” defined to include brownfield sites; a census tract or any adjacent census tract in which a coal mine has closed after 1999, or a coal-fired electric generating unit has been retired after 2009; and a metropolitan or nonmetropolitan statistical area that (1) at any time after 2009 has had at least 0.17% direct employment or 25% local tax revenues from the extraction, processing, transport, or storage of coal, oil, or natural gas and (2) had an unemployment rate at or above the national average for the previous year, in each case as determined by the Secretary.

  - If prevailing wage and apprenticeship requirements are met, the amount of the base PTC is increased by 10% and the amount of any ITC is increased by 10 percentage points in energy communities (or 2% and 2 percentage points, respectively, if the wage and apprenticeship requirements are not satisfied).

- The various bonuses and adders are stackable, so that a PTC project garnering them all would receive $31 per MWh (in 2022 dollars) produced each year for ten years, while an ITC project would receive a 50% tax credit upon entering service.

- Allows for transferability of tax credits without the need for tax-equity financing.

- For the period after 2024, a new technology-neutral 10-year clean energy PTC (Section 45Y) and ITC (Section 48E).

  - This credit remains in full for projects that begin construction by the later of either (a) 2032 or (b) the year that electric power sector emissions are equal to or less than 25% of 2022 electric power sector CO_2 emissions.

  - A three-year phase-down of the credit level follows the relevant trigger year, with projects beginning construction in the first year of the phase-down period still eligible for 100% of the credit, which then reduces to 75% and 50% of full value over the next two years.

  - The bonus and adders are available as before.

Tr. vol. 23, 241-44.

In addition to these tax credit provisions, the IRA's Section 1706 provisions provides low-cost financing to reduce the rate impact of acerated phase-out and replacement of fossil assets that may be more advantageous to North Carolina ratepayers than the securitization provisions of N.C.G.S. § 62-110.9. *Id.* at 249. Section 1706 could allow for financing more than 50% of the undepreciated balance of an early retired coal plant, potentially at lower interest rates, and over longer periods of time. *Id.* at 236. "As with securitization under H951, ratepayer savings under Section 1706 would tend to increase in line with the size of the plant balances refinanced and duration of the refinancing period, with earlier retirements yielding larger consumer benefits." *Id.* In addition, "Section 1706 provides authority to extend the low-cost financing to environmental remediation, replacement with clean energy resources, and community reinvestment." *Id.* This provision expires towards the end of 2026.

When asked by the Commission whether Witness Varadarajan had any reason to believe that the Companies are not doing everything that they can to take advantage of the IRA to mitigate the upward pressure on costs, he replied that the only evidence he had reviewed with regard to the Companies approach to the IRA was Duke Modeling and Near-Term Actions Panel Late-Filed Exhibit 1. Tr. vol. 23, 266-69. In that Late-Filed Exhibit, Witness Varadarajan noted that the Companies had considered the extension of some of the tax credits, but the Companies had not discussed the tax normalization issue, transferability of tax credits, or the Energy Infrastructure Reinvestment Act provisions. *Id.* at 266. Nor had any seen a deep discussion of how the incentives relating to vehicle and fleet electrification or for energy efficient equipment and home retrofits might affect load growth. *Id.* at 267-69.

Witness Varadarajan concluded that "any resource decisions, near term execution plans, and relevant resource planning activity that occurs after the September 2022 Carbon Plan evidentiary hearing . . . should include an analysis of the full scope of the IRA cost implications." *Id.* at 250.

CLEAN Intervenors' witness Fitch testified that the passage of the IRA has significant implications "for power generation in the United States, and the IRA's tax incentive and electrification provisions would directly impact many of the factors that are used as inputs into capacity expansion analysis in this proceeding." Tr. vol. 24, 179. The wide-ranging impacts of the IRA have not been fully incorporated into any of the proposed carbon plans in this proceeding. *Id.* at 179-80. In light of the IRA, "plans that maintain flexibility in the short term and that are likely to take advantage of cost reductions facilitated by IRA provisions will be better able to adapt to changing circumstances." *Id.* at 180. By prioritizing flexible, modular solar and storage resources in their short-term execution plan, the Commission will best be able to maintain flexibility and avoid lock-in to more expensive resources. *Id.*

"Large-scale deployment of solar, in particular, is a common feature of not only the Carbon-Free by 2050 portfolios, but also the portfolios proposed by the Clean Power Suppliers' Association, Tech Customers and Duke." *Id.* Efforts to maximize the tax credits in the IRA in the short term are important because they have mostly had a ten-year window. *Id.* at 180-81. Pursuing other resource options that benefit from the IRA in the near term, such as wind, transmission, and coal retirement can unlock additional resource options. *Id.* at 181. Finally, avoiding investments in gas and nuclear can protect ratepayers from risk. *Id.*

CCEBA Witness Ron DeFelice testified that the "IRA greatly increases the value of both Solar+Storage and standalone storage because it allows energy storage to receive a 30% ITC regardless of method of charging and it allows for energy storage to be sited more optimally on the grid (instead of being tied to solar facilities)." Tr. vol. 26, 15. He also noted that the IRA extends of the 30% ITC for solar plus storage projects another 10 years. *Id.* The net result of these changes is to render Duke's cost assumptions of storage resources ""no longer valid because the costs of these resources are represented as too high during portfolio optimization." *Id.* Witness DeFelice stated that the passage of the IRA will accelerate deployment of storage in North Carolina and across the country. *Id.* at 16. Tech Customers Witness Borgatti testified that the "IRA significantly amplifies the value of the core recommendations" of the Gabel Associates Report. Tr. vol. 25, 67. The IRA extends the ITC and PTC for solar and wind resources, makes stand-alone storage eligible for an ITC equal to or upwards of 30% of the capital costs, and qualify solar and solar plus storage for the ITC or a new PTC that can significantly improve the economics of those hybrid resources that were already featured prominently Gabel's analysis. *Id.* Because the value of these credits will decline over time, there is an advantage to Duke's customers by "accelerating the deployment of these resources instead of new gas-fired generation." *Id.* at 67-68. Witness Borgatti also testified about the importance of the new funding opportunities under the IRA, "including federally guaranteed loans and other incentives for developing new carbon-free technologies at the sites of deactivating coal assets." *Id.* at 68. Witness Borgatti recommends that the Companies prioritize using those retiring fossil fuel generation sites for renewables and storage to combine the benefits of those funding sources with the ITC and PTC. *Id.* Finally, witness Borgatti testified that "if the Companies apply for financing with the Department of Energy and receive approval, the costs of Surplus Interconnection Service could be offset by federal financial incentives that further increase the value potential for ratepayers." *Id.* Tech Customers witness Ron DiFelice testified that the IRA "greatly increases the value of both Solar+Storage and standalone storage because it allows energy storage to receive a 30% ITC regardless of method of charging and it allows for energy storage to be sited more optimally on the grid." Tr. vol. 26, 248. If the cost reductions in these storage resources were to be taken into account, the portfolios that Duke presented would likely include much more of these resources. *Id.* at 248-49. These price reductions would be particularly significant for Duke's portfolios given the CT replacement step that was not sufficiently supported in their carbon plan proposal. *Id.* at 251-52.

AGO Witness Burgess testified that the IRA makes "significant and material" changes to key planning assumptions that will affect the results of carbon plan modeling results and near-term actions. Tr. vol. 25, 237. "To put it bluntly, the previous analysis was performed using assumptions that are now obsolete and do not reflect the current reality." *Id.* at 242. Given the statutory deadline in N.C.G.S. § 62-110.9, a complete reevaluation of all the previously submitted portfolios may not be feasible, but Witness Burgess nevertheless recommended that the Commission make every effort to take the IRA into account. *Id.* Witness Burgess anticipated that accounting for the IRA in Carbon Plan modeling would "very likely increase the economic selection of wind, solar, and (especially) battery storage resources." *Id.* at 243. By the same token, the IRA "would likely decrease the economic selection of natural gas due to reduced competitiveness." *Id.* While the IRA's incentives may also help to make nuclear and hydrogen resources more cost-effective over the long term, those technologies are not likely to be available for near-term selection. *Id.* at 243. The IRA could also "accelerate the replacement of coal plants with new generation through the availability of low-cost financing" from the DOE. *Id*. Witness Burgess testified that it would be unreasonable to approve a Carbon Plan that did not take into account the IRA, particularly if such a plan would later inform the determination of need in a future CPCN proceeding. *Id.* The IRA constitutes a material change in the facts and circumstances from the carbon plan assumptions that Duke used in its modeling analysis. *Id.* Witness Burgess provided a list of model assumptions that various IRA provisions change. *Id.* at 245-46. Witness Burgess also recommended that the Companies revise upward their cap on the amount of solar that it allowed EnCompass to select as a result of the IRA. *Id.* at 248-53.

Witness Tyler Norris testified on behalf of CPSA, noting that the IRA has so changed the landscape such that “most utilities can be expected to update their resource plans and proposal in the months and years ahead to procure and interconnect even more renewable and storage capacity to take advantage of the IRA on behalf of their customers.” Tr. vol. 26, 37. In addition, the IRA is likely to drive increased domestic production of solar modules, which should mitigate concerns that future trade policy could limit solar procurement. *Id*. at 54. Witness Norris testified that the IRA should provide an opportunity for utilities commissions generally to accelerate the pace of decarbonization of the electric power sector, principally by providing federal incentives. *Id.* at 84. But the IRA makes additional resources available to aid commissions, such as a Department of Energy fellows program and other technical assistance from the National Laboratories. *Id.* For purposes of near-term solar procurement, the downward-only price refresh in the 2022 solar procurement should provide an opportunity for companies to account for the incentives of the IRA in their bid prices. *Id.* at 98.

Witness Brad Rouse testified that the IRA’s passage should require updating the choices presented to the Commission by the portfolios modeled by Syanpse those modeled by Duke, which relied on inputs and assumptions that have been changed by the new federal law. Tr. vol. 22, 65. From a modeling perspective, Witness Rouse recommends requiring Duke to incorporate the IRA and other recent developments into their models. *Id.* at 108. In addition, Witness Rouse noted the major new incentives for EE in the IRA, including for low-income households, in addition to incentives that will facilitate continued growth of net energy metering, which both can reduce costs for the carbon plan compliance and to provide local resiliency. *Id.* at 88-89.

The AV Witnesses testified that as a result of not capturing the incentives for EE in the IRA, the Companies models likely underestimate the future of clean energy adoption rates by customers. Tr. vol. 24, 52. In addition, the utilities' low-income EE programs could be bolstered by IRA incentives. *Id.* at 54.

EWG Witness Dr. Makhijani testified that as a consequence of the enactment of the IRA, it would be reasonable to examine a diversity of alternative resource portfolios that do not contain nuclear power plants. Tr. vol. 24, 108-09. Witness Dr. Makhijani testified that "the extension of the investment tax credit under the Inflation Reduction Act and the low cost of solar plus storage increases the likelihood that currently planned nuclear projects will be abandoned." *Id.* at 120.

For Duke, Witness Bowman testified that the Companies "are excited that [the IRA] will enable a more affordable energy transition to the benefit of DEC and DEP customers." Tr. vol. 7, 57-58. Witness Bowman noted that the clean energy tax credits in the IRA "will enhance the Companies' ability to develop and procure more clean energy in a least-cost manner, including by mitigating recent inflationary and supply-chain pressures facing the industry." *Id.* at 58. Witness Bowman also pointed to the IRA and Infrastructure Investment and Jobs Act as supporting the development of hydrogen, which could help the Companies transition away from natural gas. *Id.* at 125.

The Duke Modeling Panel did not adjust their load forecast following the passage of the IRA. Tr. vol. 8, 31-33. The Modeling Panel noted, however, that the IRA also includes incentives for energy efficiency, which may offset the load growth that may follow from increased vehicle electrification. *Id.* The Modeling Panel was uncertain about the extent to which the IRA incentives would surpass or be somewhat offset by upward price pressure on the clean energy technologies that are eligible for those incentives. Tr. vol. 10, 42-46. The Modeling Panel did not adjust their natural gas price forecasts to account for the IRA provisions that regulate methane leaks in the gas extraction and transmission systems, which may have a downstream effect on prices. Tr. vol. 10, 40-41. The Grid Edge Panel for Duke noted that the Companies have not performed any detailed studies of how the IRA might impact the utility's EE programs. Tr. vol. 13, 174. In part, this is because the IRA is so new and the relevant federal agencies have not yet issued specific directives on how money relating to energy efficiency will be spent. *Id.* But the Grid Edge Panel recognized that the IRA would have a "huge impact" with regard to what the utilities can do with their EE programs. Tr. vol. 14, 78.

On rebuttal, the Modeling Panel testified that Duke agreed that the "tax credits and other incentives in the IRA will be beneficial for customers and may offset recent upward pressures on technology costs that have occurred since the development of the Plan" as a result of supply chain issues and inflation. Tr. vol. 27, 48-49. The Duke Modeling Panel acknowledged that "the IRA incentives will lower costs for solar, storage, wind, and nuclear, with potential compounding benefits if such resources can be optimally sited or meet other wage and domestic content requirements in the law." *Id.* at 49. The Companies also agreed with Public

Staff's testimony that it is appropriate use a consistent snapshot in time for fixing modeling inputs and assumptions. *Id.* The Modeling Panel testified that the Companies must "snap a chalk line" at a given point so that they can move forward with developing a plan. *Id.* In addition, the Companies acknowledged that the biennial schedule for the IRP and Carbon Plan updates, in addition to CPCN proceedings, will provide additional opportunities to update models. *Id.* at 49-50.

In addition, Duke Modeling and Near-Term Actions Panel Late Filed Exhibit 1 provided an overview of a supply-side resources IRA sensitivity analysis conducted by Duke on Supplemental Portfolio SP-5 (no Appalachian gas). In this sensitivity analysis, Duke considered near-term inflationary impacts on the prices of various supply-side resources, such as battery storage, solar, solar paired with storage, wind, and gas power plants. Duke Late-Filed Ex. 1, 1-2. In addition, they modeled the IRA's ITC provisions on standalone storage, and considered the PTC for other IRA-eligible resources, including SMRs. *Id.* at 2-3. The Companies noted that this sensitivity analysis is incomplete because of the complexity of the new legislation and the additional rulemaking and guidance that still needs to be issued by federal agencies. *Id.* at 3. The Companies found only a modest effect from this IRA sensitivity analysis on the SP-5 (no App. gas) portfolio, approximately 500 MW of additional solar, 600 MW of additional onshore wind, 200 MW less battery storage, 1,200 MW less gas CC, and 100 MW less gas CT by 2032 (the target compliance date for the 2030 70% carbon emissions reductions under SP-5). *Id.* at 6-7.

Discussion and conclusions

The IRA has an immediate, material influence on the most economical portfolio of near-term demand-side and supply-side resources that will be necessary for complying with the carbon emissions reduction requirements of G.S. § 62-110.9. Because the IRA was enacted after the modeling had been completed and submitted to the Commission, further supplemental modeling will be required before the next Carbon Plan update. The Commission gives substantial weight to the testimony of witnesses Varadarajan and Burgess, who testified about the likely impact of the IRA on driving down the costs of solar, wind, and battery storage, including in the near term. In addition, the Commission gives substantial weight to the testimony of witness Fitch that Carbon Plan portfolios that are likely to take advantage of cost reductions facilitated by IRA provisions will be better able to adapt to changing circumstances. Likewise, the Commission gives substantial weight to the testimony of witnesses Borgatti and DeFelice that the IRA will likely favor portfolios that rely more on solar and storage, particularly when the utilities can take advantage of provisions that provide additional incentives by locating these resources at retired or retiring fossil generating sites.

The modeling sensitivity analysis prepared by Duke and submitted by the Companies as a Modeling Panel Late-Filed Exhibit No. 1 on September 22, while informative, was only conducted in relation to Supplementary Portfolio P-5 (no Appalachian gas), was conducted only as a sensitivity to the Companies' Near-Term Action Plan and did not consider all aspects of the IRA. As previously discussed, the P5 supplementary portfolio was not designed to meet the 2030 interim carbon emissions reduction requirements of G.S. § 62-110.9 and thus, is not accepted for planning purposes by the Commission at this time. The cost assumptions in this sensitivity were presented after the expert witness hearing was underway, which was too late for review by other parties that conducted EnCompass modeling. As a result, the Commission did not get the benefit of a more thorough vetting of the inflation and IRA inputs used by Duke for this sensitivity analysis.

The Commission concludes that Duke must prepare new EnCompass modeling that takes into account both supply-side and demand-side impacts of the IRA to the costs of potential resources for Carbon Plan compliance as part of the 2023 IRP Update, with opportunity for intervenor comments and consideration of alternative modeling. In addition, the Companies must include the impacts of the IRA as part of any 2024 Carbon Plan modeling as well as for any CPCN applications for projects related to Carbon Plan compliance that are submitted by Duke prior to the 2024 Carbon Plan update. Without these efforts to consider the wide-ranging impacts of the IRA, ratepayers will be at risk of paying for suboptimal strategies for reaching the statutory carbon reduction requirements.

To mitigate against the risk that near-term Carbon Plan actions will lock-in extra costs to ratepayers, the Commission has concluded that the Companies' Near-Term Action Plan will consist of resource additions that are consistent with the new and extended federal incentives in the IRA. The 2022 solar procurement bid refresh in April of 2023 was specifically established to allow for the IRA incentives to be priced into those bids in the event federal clean energy legislation was enacted. In addition, the Commission concludes that the Companies shall take advantage of the additional incentives made available by the IRA for citing clean energy projects in energy communities, including at retiring or retired fossil fuel electric generating plants. In addition, the Commission concludes that the Companies shall explore opportunities under the Section 1706 provisions of the IRA.

To the extent not already addressed in Docket No. M-100, Sub 164, Duke should provide ongoing reporting to the Commission on its efforts to obtain funding under the Infrastructure Investment and Jobs Act and the Inflation Reduction Act. Any such funding received should inure to the benefit of ratepayers and not shareholders to the maximum extent possible.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15-19
ACCEPTED PORTFOLIOS
(Scheduling Order ordering paragraph 1.a.)

The evidence supporting these findings of fact and conclusions is contained in the Company's initial Carbon Plan filing on May 16, the filings of Public Staff and other intervenors, the testimony and exhibits of the witnesses, and the entire record in this proceeding.[1]

Summary of evidence

Synapse Modeling

CLEAN Intervenors' Joint witness Tyler Fitch, Senior Associate at Synapse, testified regarding the modeling that he and his team at Synapse conducted using the EnCompass capacity expansion and production cost model. Witness Fitch's testimony drew from a report entitled "Carbon-Free by 2050: Pathways to

[1] Note: The signatory parties have not attempted to summarize all evidence related to the Accepted Portfolios as modeled by Duke, the AGO, and Tech Customers.

Achieving North Carolina's Power-Sector Carbon Requirements at Least Cost to Ratepayers" (the Synapse Report), which Mr. Fitch's team at Synapse prepared for the CLEAN Intervenors, and which was filed with the Commission on July 20, 2022. Official Exhibits vol. 25, 145-212 [PDF]. Witness Fitch testified that the analysis used to develop the Synapse Report relies on the same underlying EnCompass database that Duke used to develop the portfolios in its proposed carbon plan filing, Tr. vol. 24, 131. Although Synapse experienced some technical difficulties working with the EnCompass data files that Duke produced, and was not able to validate Duke's files, witness Fitch testified in response to a question from Commissioner Brown-Bland that Synapse got "very, very close" to validating Duke's model and getting exactly the same result, and for that reason, he had confidence in the Synapse modeling. Tr. vol. 24, 251.

Witness Fitch testified on cross-examination by counsel for Avangrid that Synapse relied on Duke's inputs and assumptions as much as it could, subject to some reasonable revisions. Tr. vol. 24, 199. Similarly, with regard to model settings, witness Fitch testified that Synapse imitated as many Duke decisions as possible in order to maintain reliability. Synapse used the same assumptions or settings as Duke for the following: system topology (modeling the DEC, DEP-East and DEP-West BAAs individually); 17 percent planning reserve margin; coal price forecasts; carbon constraint; ancillary service requirements; gas distribution infrastructure and cost adders; effective load carrying capacity of all resources; and transmission adders. Official Exhibits vol. 25, 155-56 [PDF]. Notably, like Duke, Synapse also used a partial commitment setting in its capacity expansion modeling, and a full commitment setting for production cost modeling. Tr. vol. 24, 213. Duke witness Roberts testified that when Duke passed the Synapse Optimized portfolio through the reliability validation step using the SERVM model, the portfolio passed the reliability validation step in 2030, but did not pass in 2035. Tr. vol. 20, 88-89. Pro se intervenor witness Brad Rouse, an energy policy consultant with decades of experience in resource planning, testified that a number of options—batteries, flexible loads, overbuilding wind and solar—could be used to fill that reliability gap instead of adding a new CT. Rouse. Tr. vol 22, 104.

Witness Fitch further testified that Synapse modified several of Duke's model settings to better align with modeling best practices, and updated several inputs and assumptions to better represent current and likely future conditions. Tr. vol. 24, 132. Table 3 of the Synapse Report summarizes both Duke's inputs and Synapse's revised inputs to EnCompass for the following: gas prices; hydrogen prices; coal fixed operation and maintenance costs, gas plant book life and operational life; and capital costs for small modular reactors, gas plants, hydrogen new builds and retrofits, solar, solar-plus-storage, standalone storage, and onshore and offshore wind. Official Exhibits vol. 25, 156-57 [PDF]. According to witness Fitch, Synapse "deliberately sourced [its] capital cost inputs to maintain transparency and neutrality in resource selection." Tr. vol 24, 147. For resource capital costs, witness Fitch testified that Synapse's analysis used industry-standard, publicly available projections developed by expert U.S. government researchers. Synapse used the National Renewable Energy Laboratory's 2022 Annual Technology Baseline's (NREL ATB) capital cost projections for solar, solar plus storage, on- and off-shore wind, and battery storage. For gas resources and small modular reactors (SMR), Synapse used cost estimates from the Energy Information Administration's 2022 Annual Energy Outlook (EIA AEO). Tr. vol. 24, 145. In developing its gas price forecasts, Synapse used a methodology similar to Duke's, but 1) relied on a more recent (June 2022) set of NYMEX futures prices, and 2) used the more recent 2022 AEO instead of the 2021 AEO, and exclusively relied on the 2022 AEO instead of averaging the AEO with projections from proprietary sources. Tr. vol. 24, 148.

In addition to the assumptions and settings that Synapse revised, witness Fitch also acknowledged on cross-examination that using certain other assumptions different from Duke's could be reasonable and would produce different results. With regard to offshore wind, Mr. Fitch testified on cross-examination by counsel for Avangrid that Synapse used Duke's generic profile in modeling offshore wind but acknowledged that had Synapse modeled larger blocks of offshore wind, the model results would have been different, and that it would be reasonable to use 1300 MW blocks of offshore wind, rather than 800 MW blocks. Tr. vol. 24, 200. Further, on cross-examination by counsel for CCEBA, Witness Fitch testified that like Duke, Synapse used a fixed dispatch curve in modeling solar-plus-storage resources, but Witness Fitch acknowledged that he would expect that using a dynamic dispatch curve would result in more procurement of solar-plus-storage. Tr. vol. 24, 203.

One of the model settings that Synapse did not adopt was Duke's eight-year optimization period for the EnCompass model. Witness Fitch testified on cross-examination by counsel for EJCAN, *et al.* that because it is difficult for the model to optimize for a lengthy period, like the 28 years in this case, modelers divide the optimization period into segments. Tr. vol. 24, 207. Witness Fitch explained that modeling with a 15-year optimization period such as that Synapse used would produce lower costs over the total 2022-2050 planning horizon. Tr. vol. 24, 210. With use of a shorter period, such as the eight years used by Duke, the model could choose a gas CT or CC, but would not be accounting for what happens to that unit past the optimization period. Tr. vol. 24, 209. As explained by Public Staff witness Thomas, an eight-year optimization period indicates the model can only "see" costs and system conditions over an eight-year period (with a one-year extension) and is blind to any model inputs beyond the optimization period, and for that reason the eight-year optimization period is "problematic." Tr. vol. 20, 53.

Synapse also assumed a 20-year book life and 25-year operational life for new gas units rather than Duke's 35-year book and operational life. Official Exhibits vol. 25, 156 [PDF]. Attorney General's Office (AGO) witness Burgess testified that Strategen also used a 20-year life for new gas assets in its SP-AGO portfolio. Tr. vol. 25, 280. Witness Fitch explained that the purpose of the 20-year lifetime was to manage the risk that new gas resources would not become stranded assets if technology and infrastructure needed to convert them to zero-emissions resources did not materialize. Tr. vol. 24, 162. Tech Customer's witness Borgatti agreed that new gas plants could become stranded assets. Tr. vol. 25, 119. Public Staff witness Thomas likewise testified that the 20-year life for a new gas plant was a reasonable assumption, and represented a reasonable effort to identify the risk of stranded assets. Tr. vol. 22, 310-311. Witness Rouse disagreed with Duke that Synapse's shortened life assumptions for gas units should be seen as a problem. According to witness Rouse, Duke's own modeling shows very little use of these units once they are running on hydrogen in the 2040-2050 timeframe. Tr. vol. 22, 82.

With regard to solar interconnection, the Duke Modeling Panel testified that the question is "what specific limitation is the most reasonable forecast of the Companies' ability to interconnect solar in the future." Tr. vol. 7, 354. Synapse imposed a higher limitation on deployment of solar resources than Duke, based on the assumption that transmission upgrades, supportive policies, and improved procedures would increase Duke's ability to interconnect solar facilities. Official Exhibits vol. 25, 159 [PDF].

Like Duke, Synapse treated demand-side reductions in electricity usage as decrements to the load forecast, and used the same methodology as Duke to develop its UEE forecast. Official Exhibits vol. 25, 197 [PDF]. Synapse's EnCompass analysis assumed that incremental savings from Duke's energy-efficiency programs ramped up to 1.5% of total retail load—a level that, while more aggressive than the 1% of load net of opt-outs assumed by Duke, is in line with energy savings achieved by peer utilities. Official Exhibits vol. 25, 159, 198 [PDF], Tr. vol. 24, 197. Synapse used Duke's "High" net energy metering (NEM) projection as its assumption for rooftop solar adoption. Official Exhibits vol. 25, 159 [PDF]. Mr. Fitch testified that at the time the Synapse Report was developed, Synapse's use of the "High" NEM projection anticipated continued policy support for rooftop solar, an assumption that has been borne out by the extension of the Investment Tax Credit for rooftop solar in the Inflation Reduction Act (IRA). Tr. vol. 24, 184.

With regard to transmission, witness Fitch testified to the critical role of transmission in bolstering resource adequacy and enabling delivery of high-quality solar and wind resources to serve load. Tr. vol. 24, 154. According to witness Fitch, considering a broader range of transmission assumptions, such as increasing transmission capacity and allowing the utilities to buy and sell energy and capacity from neighbors over the planning horizon, will unlock lower-cost resource pathways. Tr. vol. 24, 195. Mr. Fitch therefore recommended that to the extent that the Commission deems that a distinct process from integrated resource planning is required (and that the existing public policy request function of the North Carolina Transmission Planning Collaborative is unable to fulfill this role), the Commission should initiate a new proceeding for pursuing long-term, prospective regional transmission planning and consideration of regional coordination. Tr. vol 24, 155.

Witness Fitch testified that the Synapse Report included three scenarios. The first, "Duke Resources," mimics Duke Energy's Portfolio 1 with Alternate Fuel (P1A), but with Synapse's revised inputs. Synapse selected the P1A portfolio as the basis for comparison because it is the only portfolio that was designed to meet the 2030 carbon-reduction requirement while assuming that firm transportation for Appalachian gas cannot be secured. Synapse also developed the "Optimized" scenario, which also used Synapse's revised inputs and allowed EnCompass to select the most cost-effective portfolio to meet carbon-reduction and reliability requirements. Finally, the “Regional Resources” scenario uses the same settings as the Optimized scenario, but also allowed the EnCompass model to select power purchase agreements (PPAs) for Midwest wind, imported through the PJM Interconnection (PJM). Tr. vol. 24, 132. These PPA resources were designed to imitate the Midwest wind resources identified in the North Carolina Transmission Planning Collaborative’s 2021 Public Policy Study. Official Exhibits vol. 25, 233 [PDF].

Witness Fitch further testified that compared to the Duke Resources portfolio, the Optimized and Regional Resources portfolios rely more on solar, storage, and energy efficiency resources, while avoiding investment in new gas, minimizing reliance on hydrogen and small modular nuclear technologies, maintaining the Companies’ reserve margin, and serving 100 percent of load in all modeled hours. In the Optimized and Regional Resources portfolios, the model did not select any new gas-fired resources, and opted for the retirement of some gas-fired units, rather than conversion to 100 percent hydrogen combustion. In addition, the Regional Resources scenario did not reach the 4-unit availability limit set for additional nuclear resources. Tr. vol. 24, 161.

The table below, reproduced from Table 8 of the Synapse Report, shows the NPVRR for the Duke Resources, Optimized and Regional Resources portfolios:

Results (2022-2050)	*Duke Resources*	*Optimized*	*Regional Resources*
2030 NPVRR ($B)	$36.7	$36.0	$34.3
2040 NPVRR ($B)	$77.7	$69.8	$65.8

2050 NPVRR ($B)	$121.2	$103.5	$98.1

Official Exhibits, vol. 25, 170 [PDF].

Witness Brad Rouse's testimony recommended that the Commission find the Synapse portfolio to be "reasonable," and that it or a similar plan should be added as an additional portfolio to be carried by the planning process. Witness Rouse further testified that the near-term actions requested by Duke as needed to preserve the "optionality" of portfolios should include the steps that would be required now to enable Duke to follow Synapse's proposed resource strategy going forward. Tr. vol 22, 73. Similarly, NCWARN witness William Powers testified that the Commission should adopt the Synapse portfolio, but with additional specificity on the development of the distributed generation solar-plus storage component of the portfolio. Tr. vol. 22, 189.

Witness Fitch testified that resource plans that maintain flexibility in the short term while capitalizing on cost-saving opportunities will be more adaptable to the changing energy landscape, particularly in light of the Inflation Reduction Act. Tr. vol. 24, 192-93. For example, solar and battery storage resources are modular, flexible resources that are eligible for tax credits under the IRA. Tr. vol. 24, 193. According to witness Fitch, robust transmission planning, retiring coal-fired generation, and enabling greater wind deployment now will expand the resource options available in the future. Id. On the other hand, investing in gas and nuclear resources now would commit ratepayers to financially supporting these resources (and to the carbon emissions from gas generation) for decades to come, tying up capital that could be more effectively spent elsewhere. Id.

Based on the capacity expansion and production cost modeling that Synapse completed using the EnCompass model and the resulting resource portfolios, witness Fitch recommended that the Commission approve the following set of near-term actions. The MW totals below are for the combined Duke Energy system, and unless otherwise specified, for in-service dates through 2030.

- Expand Utility Energy Efficiency to a minimum of 1.5% of total retail sales by 2030
- Develop and support programs that empower customer-owned energy resources to at least 1,000 MW by 2035
- Procure 4,000 MW of utility-scale solar in 2022-2024 with target in-service dates of 2025-2028, and a total of 7,200 MW of utility-scale solar to be in service by 2030
- Procure 4,000 MW of storage with target in-service date of 2028, and a total of 5,600 MW of battery storage to be in service by 2030
- Procure 900 MW onshore wind in NC
- Procure 2,500 MW of Midwest wind through PJM
- Procure at least 800 MW of offshore wind
- Order economically optimal coal plant retirements (considering any required operational transmission or replacement generation needs)
- Open a generic investigatory docket in early 2023 to examine options for integrating the FERC-jurisdictional NCTPC process, or other transmission planning reforms, with the Commission's carbon planning process

- Proceed with Bad Creek pumped hydro project for 1,700 MW of additional storage

Tr. vol. 24, 193-94.

Brattle Modeling of CPSA Portfolios

The evidence supporting these findings of fact is found in CPSA's Comments, Duke's Modeling and Near-Term Actions Direct and Cross Examination Testimony, Duke's Reliability Panel Direct Testimony and CPSA Witness Michael Hagerty Direct Testimony, and hearing testimony.

In its comments to the Carbon Plan, CPSA states that in response to Duke's Carbon Plan modeling, it retained the Brattle Group "to help understand and critique" Duke's models and to conduct modeling of its own. CPSA Comments, 31. Brattle used GridSIM, a capacity expansion modeling tool designed by Brattle to model low-carbon utility systems, and adhered closely to Duke's modeling assumptions and inputs. *Id.* at 31-32. Brattle modeled the years through 2035 rather than 2050 as Duke did, in order to focus the modeling on the interim compliance date of 2030 and to avoid reliance on "Duke's highly speculative assumptions regarding [SMRs] and green hydrogen." *Id.* at 32.

As discussed above, Brattle Group conducted modeled five portfolios using different compliance years and different solar interconnection constraints. It modeled a portfolio (CPSA1) that achieves 70% compliance in 2030, with no solar interconnection cap. This portfolio was included not for planning purposes, but to understand the cost impacts of interconnection constraints more fully. Second, it modeled two portfolios (CPSA2 and CPSA4) using the low Solar Interconnection

Constraint assumed by Duke in portfolios P2-P4. Finally, it modeled two portfolios (CPSA3 and CPSA5) using a solar interconnection constraint (1500 MW) that is higher than Duke's in 2026 and 2027, but that in 2028 and beyond is the same as the constraint assumed by Duke (1800 MW) in those years. CPSA Comments at 38.

In their direct testimony, Duke's Modeling and Near-Term Action Panel witnesses do not discuss CPSA's portfolios or findings, but argue that Brattle assumed that "an improbably rapid solar deployment" is possible in the near term. Tr. Vol. 7, 383. However, CPSA's solar interconnection assumptions are not the most aggressive of the intervenors, and in fact all "intervenors who modeled alternative Carbon Plan portfolios tended to favor solar resources by assuming new capacity can be connected to the system more rapidly" than Duke's models allow. *Id.,* 382. Duke's witnesses do not discuss any specific shortcomings of any particular portfolio from CPSA (or any other intervenor). See generally *Id.,* 382-396. Instead, Duke asserts generally that intervenor models "are not technically objective and tend to over-value renewables and storage and under value firm, dispatchable thermal resources." *Id.,* 396.

Duke's Reliability Panel testifies in its Direct Testimony that Brattle failed to "take the extra step the Companies' modeling did to ensure reliability of the Portfolios are maintained by modeling extended cold weather periods with high demand and lower solar capacity factors." Tr. Vol. 19, 196.

CPSA witness Michael Hagerty discusses Brattle's modeling methodologies in more detail. Tr. Vol. 25, 433. With regard to GridSIM, Mr.

Hagerty states that "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 CO2 limits." *Id.* at 434. Brattle attempted to replicate Duke's model as closely as possible while also correcting its flaws. *Id.* at 436-37. The modeling assumptions that Brattle adopted from Duke's models include "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." *Id.* at 436. Brattle attempts "to mimic Duke's assumptions in its draft Carbon Plan to ensure that [its] model results on the least-cost mix of resource portfolio does not cause any degradation of system reliability." *Id.* at 444.

CPSA's models reflected five significant differences from Duke's models. *Id.* at 437. First, CPSA only modeled through year 2035 so as to focus on achieving interim compliance no later than 2032. *Id.* Second, CPSA assumed higher capital costs for solar and natural gas CTs and CCs, but lower costs for onshore and offshore wind. *Id.* at 437. Third, Brattle ran models with various solar interconnection sensitivities, including Duke's assumed limits, CPSA's proposed limits, and a no limit case. *Id.* at 438. Fourth, CO2 emissions limits were consistent throughout all portfolios. *Id.* Fifth, it was assumed that no SMRs would be online before 2035 and only 600 MW of onshore wind would be added by 2032. *Id.* To test the impact of this assumption, Brattle performed two sensitivity analyses allowing for SMR selection in 2032, neither of which resulted in the selection of

SMRs in 2032. *Id.* at 440.

The results of Brattle's modeling simulations with higher solar interconnection limits were increased procurement of solar and lower overall costs to ratepayers. *Id.*, 452. The CPSA3 portfolio meets the 2030 carbon emissions reductions requirements and includes a solar interconnection limit higher than that assumed by Duke in its modeling. *Id.* Brattle found that using Duke's lower solar interconnection limit increase annual costs by about $860 to $930 million for 2030 compliance (based on conservative assumptions for future costs of solar that were 10% higher than Duke's estimates). *Id.*, 466. GridSIM also selected new gas, but not until 2029. By 2030, CPSA3 selects 7,500 MW of solar, 2,700 MW of BESS, 600 MW of onshore wind, and 400 MW of offshore wind. *Id.*, 465.

Mr. Hagerty rebuts the Duke Modeling and Near-Term Actions Panel's critiques of CPSA's portfolios on reliability and executability grounds. *Id.* at 446. With respect to resource adequacy, CPSA's models included similar results in resource additions to replace coal plants "including gas CCs . . . gas CTs . . . and battery storage." *Id.* The major differences in resource selection relate to solar interconnection, onshore and offshore wind, and SMR development. *Id.* Witness Hagerty also testifies that to align with Duke's modeling, he increased the planning reserve margin from 17% to 25%, although he notes that "the capacity expansion modeling alone however is not equivalent to additional detailed reliability modeling that Duke completed." *Id.* at 447-48. Witness. Hagerty recommends that Duke conduct additional reliability analysis of CPSA's portfolios. *Id.*

On Cross Examination Duke's Modeling and Near-Term Actions Panel testifies that CPSA and Brattle attempted to replicate Duke's modeling assumptions. Tr. Vol. 8, 86. When Brattle discussed its modeling with Duke it asked if Duke had any issues with its methodology. *Id.* On cross-examination Witness. Snider testifies that he does not recall if Duke did, in fact, have any issues with Brattle's methodology. *Id.*

Duke witness Holeman on the Reliability Panel testified at the hearing that one of his primary reliability concerns was the ability to serve load during extreme whether events. Witness Holeman further testified that gas-fired generation is the resource that the utility would rely on primarily to serve energy during such events. Tr. Vol. 20, 21:4-17. Witness Holeman also agreed that CPSA's proposed portfolios included almost exactly the same amount of new gas-fired resources as Duke's portfolios over the planning period. *Id.*, 21:18-22. When asked if he had identified any particular point in the planning period where he would expect reliability issues to arise if one of CPSA's portfolios were to be implemented, Witness Holeman did not identify any such period. *Id.*, 25:11-4.

Discussion and conclusions

Synapse Modeling

The Commission finds that the Synapse Optimized and Regional Resources portfolios are projected to achieve the carbon-reduction requirements of N.C.G.S. § 62-110.9 in a manner consistent with the law's requirements. For the reasons discussed below, the Commission concludes that the Synapse Optimized and Regional Resources portfolios are reasonable for planning purposes.

In making this determination, the Commission gives substantial weight to the testimony of witness Fitch regarding the modeling that he and his team at Synapse conducted in developing the Synapse Report. The Commission finds that Synapse's use of the same EnCompass model and database that Duke used renders its analysis particularly relevant and persuasive. Although the Commission recognizes that Synapse experienced some technical difficulties working with the EnCompass data files that Duke produced, those difficulties do not undermine the credibility or quality of Synapse's modeling, and the Commission accepts Witness Fitch's testimony that he has confidence in the Synapse modeling.

The Commission further determines the inputs and assumptions that Synapse used in its modeling to be reasonable. Synapse's decision to rely on Duke's inputs and maintain Duke's model settings as much as possible was a reasonable and conservative approach. At the same time, the Commission also accepts as reasonable Synapse's revisions to certain settings and model inputs to better align with modeling best practices and better represent current and likely future conditions. These revised inputs included gas prices; hydrogen prices; coal fixed operation and maintenance costs, gas plant book life and operational life; and capital costs for small modular reactors, gas plants, hydrogen new builds and retrofits, solar, solar-plus-storage, standalone storage, and onshore and offshore wind. With regard to cost estimates, the Commission approves of Synapse's use of industry-standard, publicly available cost estimates developed by expert U.S.

government researchers. With regard to the operational and book life for new gas units, the Commission gives significant weight to the testimony of witnesses Fitch, Burgess, Rouse and Thomas, and determines that assuming a 20-year life for new gas plants was a reasonable way to take into account the risk that gas plants may become stranded assets. The Commission also takes note of witness Fitch's acknowledgment on cross-examination that using different assumptions regarding offshore wind and solar-plus-storage would be reasonable and would produce different results.

With regard to energy efficiency, Synapse's assumption of incremental savings from Duke's energy-efficiency programs ramping up to 1.5% of total retail load is in line with energy savings achieved by peer utilities, and, as discussed elsewhere in this order, also in line with the trajectory of Duke's own efficiency savings achievements. Accordingly, the Commission finds that Synapse's assumptions regarding energy efficiency are reasonable. Similarly, the Commission accepts Synapse's use of Duke's "High" NEM projection as its assumption for rooftop solar adoption as reasonable, particularly in light of the extension of the Investment Tax Credit for rooftop solar in the IRA.

Based on the evidence of Synapse's EnCompass modeling, the Commission recognizes that the Optimized and Regional Resources portfolios rely on new solar, storage, wind and energy efficiency resources, while avoiding investment in new gas, minimizing reliance on hydrogen and small modular nuclear technologies, maintaining the Companies' reserve margin, and serving 100 percent of load in all hours modeled in EnCompass. Although the Commission takes note of the testimony of Duke witness Roberts and others that Synapse's Optimized portfolio passed Duke's SERVM reliability validation step in 2030, but not in 2035, the Commission determines that this 2035 capacity shortfall does not undermine the reasonableness of the Optimized portfolio for planning purposes, particularly since there will be time to "check and adjust" the Carbon Plan portfolio every two years between now and 2035.

In light of the least-cost mandate in N.C.G.S. § 62-110.9, the Commission gives substantial weight to the evidence in the Synapse Report and the testimony of witness Fitch that the projected NPVRR of the Optimized and Regional Resources portfolios is lower than that of the Duke Resources portfolio in both 2030 and 2050. And given the dynamic nature of the energy landscape, underscored by enactment of the IRA, the Commission also finds that resource plans that maintain flexibility have lower risk to ratepayers.

For all of these reasons, the Commission concludes that the Synapse Optimized and Regional Resources portfolios are reasonable for planning purposes. The Commission does not need to resolve all of the differences in inputs, assumptions, or other modeling decisions in the various portfolios proposed by Duke and other intervenors at this time for purposes of establishing a reasonable and prudent near-term action plan for the next three years. In focusing on a near-term action plan, the Commission will be able to defer decisions that would commit Duke Energy to a certain level of carbon emissions or would preclude the ability to invest in more cost-effective resources which are not necessary to be made at this time.

Brattle Modeling of CPSA Portfolios

Based on the foregoing and the record, the Commission finds that CPSA's proposed portfolio CPSA3 is reasonable to include in the Carbon Plan for near-term planning purposes. CPSA3 achieves compliance with the 70% carbon reduction mandate in 2030, while appropriately reflecting more ambitious solar interconnection goals than Duke's portfolio P1.[2]

The Commission finds that CPSA's modeling methodology is sound and sufficiently reliable for near-term planning purposes in this initial Carbon Plan. The GridSIM model, which was used by Brattle Group to devise CPSA's proposed portfolios, was designed to simulate highly decarbonized systems and has been used by utilities and grid operators throughout North America. Brattle has relied on Grid SIM 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. CPSA Comments at p. 30. Brattle also adopted most of Duke's modeling assumptions. Duke's primary objection to Brattle's modeling is that it assumes significantly higher rates of solar additions than Duke permits in its modeling. As discussed above, there is significant uncertainty on that issue and the Commission concludes

[4] CLEAN Intervenors' July 15 Comments interpreted Table G-8, which Duke Energy included in its Appendix G, to include the total number of residential customers enrolled in NEM as of 2030, not the incremental number of new customers enrolled by 2030, because the chart is labeled "Number of Forecasted Customers and Incremental MWh Enrolled in Net Metering Rates..." Because the "incremental" was only used to modify MWh, CLEAN Intervenors interpreted the cart to list the total number of customers, and therefore subtracted the number of residential customers from Table G-7 to arrive at its annual average new residential solar NEM customer per year figure in its comments.

(for reasons discussed extensively above) that it is reasonable to include portfolios with more rapid solar interconnection rates in the Carbon Plan.

The other challenge Duke makes to Brattle's modeling methodology is to claim that Brattle "did not take the extra step the Companies' modeling did to ensure reliability of the Portfolios are maintained by modeling extended cold weather periods with high demand and lower solar capacity factors[.]"[3] Tr. Vol. 19, 196. The Commission is persuaded by Mr. Hagerty's assertion that by maintaining a reserve margin of 25% (equivalent to the average reserve margins observed in Duke's P1 and P2 portfolios), and by testimony elicited at the hearing, that Brattle's model sufficiently ensures resource adequacy during cold weather periods. Although Duke makes general assertions about the reliability of Brattle's portfolios, there is no evidence that it actually identified any reliability problems in Brattle's portfolios. As Witness Hagerty acknowledges, GridSIM is a capacity expansion model, which is not equivalent to the additional detailed reliability modeling that Duke completed. Mr. Hagerty suggests that Duke assess potential reliability issues and resource adjustments in resource portfolios with higher solar additions. Duke did not conduct any such analysis of portfolios with higher solar additions because the Solar Interconnection Constraint limited the amount of solar resources that could be added to its system over the planning period. The Commission

[4] CLEAN Intervenors' July 15 Comments interpreted Table G-8, which Duke Energy included in its Appendix G, to include the total number of residential customers enrolled in NEM as of 2030, not the incremental number of new customers enrolled by 2030, because the chart is labeled "Number of Forecasted Customers and Incremental MWh Enrolled in Net Metering Rates..." Because the "incremental" was only used to modify MWh, CLEAN Intervenors interpreted the cart to list the total number of customers, and therefore subtracted the number of residential customers from Table G-7 to arrive at its annual average new residential solar NEM customer per year figure in its comments.

agrees that ultimately, a more in-depth reliability analysis of high-solar portfolios like CPSA's is required. However, for the purposes of near-term planning in this initial Carbon Plan proceeding, Brattle's portfolios are sufficiently reliable for planning purposes.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 69-73
GRID EDGE
(Scheduling Order ordering paragraph 1.h.)

The evidence supporting these findings of fact and conclusions is contained in the Company's initial Carbon Plan filing on May 16, the filings of Public Staff and other intervenors, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

Summary of evidence

Duke Witnesses Bowman, Snider, Duff, and Huber provided testimony regarding the Companies' target of 1% of eligible sales. Public Staff Witness David Williamson provided testimony regarding the Public Staff's position on the appropriate level of utility EE savings to include in carbon plan modeling. CLEAN Intevenors' witness Tyler Fitch from Synapse Energy Economics provided testimony on alternative modeling that included the Companies ramping up utility EE savings to 1.5% of total load by 2030. The Tech Customers Witness Dr. Maria Roumpani and Michael Borgatti provided testimony on alternative modeling that included the Companies achieving increased savings from utility EE than modeled by the Duke. AGO Witness Edward Burgess provided testimony on the benefits of including utility EE as a selectable resource in EnCompass modeling. CIGFUR Witness Gorman provided testimony regarding the importance of realizing the maximum benefits from the Company's DSM and EE programs for industrial customers. EWG Witness Dr. Arjun Makhijani provided testimony about the need to consider additional resource portfolios, including portfolios that would rely more heavily on utility EE than Duke's proposed portfolios. Brad Rouse provided testimony regarding the role in increased energy efficiency in reducing costs of carbon compliance to ratepayers, particularly given the policies enacted in the Inflation Reduction Act. Appalachian Voices Witnesses Rory McIlmoil and Dr. Yunus Kinkhabwala testified about the importance of utility EE programs that reduce the energy burdens of low-income customers for affordably meeting the carbon reduction goals and the general importance of utility EE programs in helping to offset the need for new, more expensive supply-side resources.

As a cornerstone of their strategy for achieving the required carbon emissions in a least cost manner, the Companies put forward what they describe as an "aggressive" amount of utility energy efficiency (EE) and demand side management (DSM), amounting to 1% of "eligible" sales, meaning net of sales to those commercial and industrial customers that have opted out of Duke's EE/DSM programs. Tr. vol. 7, 43; 63-64. With the exception of the Public Staff, all parties that put forward evidence on EE/DSM's role in least-cost carbon plan compliance recommended that the Commission require a higher target than 1% savings of eligible sales. Tr. vol. 7. 310. In the instance of the Public Staff, its position was that for planning purposes, it would be unreasonable to assume any higher level of utility efficiency savings than was deemed achievable in the most recent Market Potential Study (MPS), prepared about three years ago, which has been the historic practice of Duke in IRP proceedings in the past. Public Staff Comments at p. 52; Tr. vol. 20, 180-90.

For the reasons set forth in more detail below, the Commission concludes that it is not necessary to rely on projections for achievable savings set forth in the MPS and that the Companies should be required to maximize reliance on cost-effective utility EE in order to shrink the challenge and achieve the required carbon emissions reductions at least cost to ratepayers while maintaining system reliability. In order to achieve "nation-leading" levels of EE savings, the Companies will need to achieve more than 1% savings of eligible sales. Tr. vol. 1, 68.

Duke Direct

Duke Witnesses Lon Huber and Tim Duff (Grid Edge Panel) provided evidence on Duke's plans for EE and DSM. The Grid Edge panel testified that "the first pillar of energy transition and the Carbon Plan process is to 'shrink the challenge' by reducing energy requirements and modifying load patterns through Grid Edge customer programs, allowing more tools to respond to fluctuating energy supply and demand." Tr. vol. 13, 30. The Grid Edge panel described the savings target of 1% of eligible load as an "aggressive but achievable target" that is built on the Companies' extensive experience in the Carolinas and engagement with stakeholders in the Carolinas EE/DSM Collaborative (Collaborative). *Id.* at 31. The Grid Edge panel noted that other intervenors have called on the Companies to achieve a higher amount of EE savings as part of the carbon plan, but the Companies do not believe that those higher savings targets are justified under existing legal frameworks and market conditions. *Id.* Nevertheless, consistent with the Companies' "check and adjust" framework, the Commission can make adjustments to the carbon plan as needed. *Id.* at 31-32. In addition to asking the Commission to approve the modeling assumption of 1% annual savings of eligible retail load as reasonable, the Companies ask the Commission to acknowledge that future changes would be needed to enable the achievement of that savings threshold over the long-term: updating the inputs underlying the determination of the utility system benefits; moving to an 'as-found' baseline; and expanding the pool of low-income customers." *Id*. at 32-33. These enablers are not required to achieve the savings target identified by the Companies in the near term, but would be necessary in order to achieve that target over a longer time horizon, particularly after 2030. Tr. vol. 14, 35-36.

The Companies also pointed to the savings that can be achieved from the pending tariffed on-bill financing programs and noted the importance of providing a more flexible and rapid framework for approval of EE/DSM pilots. *Id*. at 33. The Grid Edge panel discussed challenges to surpassing a 1% of eligible sales savings target, its progress on electric vehicle pilots, and responded to Intervenors' and Public Staff's comments on the Companies' savings target. *Id*. at 40-55. In addition, the Grid Edge panel discussed the possibility of expanding the pool of participants in the Companies' EE/DSM programs at the wholesale level and by reaching commercial/industrial customers who have previously opted out of the Companies' programs. *Id.* 63-65.

The Grid Edge Panel recognized that utility EE investments can represent both a least cost resource as well as a least-cost carbon-free resource. Tr. vol. 13, 82-83. They testified that the 1% of eligible sales target was modeled as a floor, and not as a ceiling, recognizing that the Companies may be able to achieve higher levels of savings. *Id*. at 181-84. The Grid Edge Panel testified that the Companies have identified a higher achievable efficiency savings potential than what had been included in the MPS as "achievable potential." *Id*. at 182. In response to Commissioner questions, the Grid Edge Panel noted that there is a strong relationship between utility rates and the attractiveness of participating in utility EE programs, noting that one reason why utilities in some other states achieve higher savings is because those utilities have significantly higher rates. Tr. vol. 14, 71. In response to questions from intervenors and the Public Staff, the Grid Edge Panel confirmed that the idea of raising the eligibility for participation in Companies' low-income utility EE programs up to 300% of the Federal Poverty Level was not raised with or considered by the Low-Income Affordability Collaborative. Tr. vol. 13, 113-14. In addition, the Grid Edge Panel confirmed that there remain a significant number of customers at or below 200% of the FPL who have not been directly served by the Companies' existing income-qualified utility EE programs. Tr. vol. 14, 42-49.

CLEAN Intervenors

The Synapse modeling sponsored jointly by CLEAN Intervenors assumed utility EE savings that would ramp up to 1.5% of total load by 2030. Tr. vol. 7, 314; vol. 24, 137, 178, 261. Witness Fitch from Synapse testified that "Duke's base and high energy efficiency targets are below many of its industry peers. Ratpayers could save as much as $2.9 billion through additional investment in energy efficiency." *Id.* (citing to the Synapse Carbon Free by 2050 Report, Table 10, 27). Synapse's analysis of Duke's baseline assumption of 1% of eligible sales shows that the Companies are anticipating a steady decline "in annual incremental energy efficiency savings over the long-term." *Id* at 182. Witness Fitch testified that "energy efficiency is a cost-effective resource for Duke ratepayers, and Duke should expand, rather than reduce, the impact of energy efficiency." *Id.* at 166-67. Even Duke's "High" utility EE forecast is below the average savings level achieved in 2018 by peer utilities as reviewed in the American Council for an Energy Efficient Economy's (ACEEE) 2020 Utility Energy Efficiency Scorecard. *Id* at 182-83; Appalachian Voices Grid Edge Panel Direct Cross Examination Ex. 2. Synapse's Carbon Free by 2050 Report used a 1.5% of retail sales an appropriate long-term savings target because it represented an "achievable increase in energy efficiency savings, in line with peer utilities." *Id.* at 183. Witness Fitch testified that "[m]ultiple policy developments since 2020, including decoupling via N.C.G.S. § 62-110.9 and the energy efficiency elements of the IRA, have also paved the way for more energy efficiency in the Carolinas." *Id.* Witness Fitch recommended that the Commission decline Duke's proposal to use the low 1% of eligible sales figure for planning purposes. *Id.* at 167.

Witness Fitch testified that setting a more ambitious utility EE savings target does not entail any additional risk to system reliability than does planning for supply-side resources. *Id.* at 211-12. Just as with supply-side resources, the Commission will be in a position to reevaluate the progress that Companies are making towards achieving higher levels of savings and be able to check and adjust in terms of whether any policy changes need to be made. *Id.* In contrast, if the Companies set a utility EE goal that is too low, they risk leaving "money on the table" that would otherwise have been to ratepayers' benefit. *Id.* at 213-14. In addition, Witness Fitch testified in response to Commissioner questions that the level of EE that Duke included in its model was static, locking in status quo as opposed to considering the possibility of further capitalizing on energy savings over time. *Id.* at 257-58. In addition, Witness Fitch noted that without setting a more ambitious utility EE savings target, it is harder to hold the Companies accountable to achieving those benefits to customers. *Id.* at 265-66. Duke did not ask any questions of Witness Fitch, including any questions regarding the appropriate level of utility EE for modeling purposes.

CLEAN Intervenors also jointly sponsored the testimony of Dr. Uday Varadarajan from RMI, who conducted a more detailed ratepayer impact analysis using RMI's Optimus model, which was based on the outputs of Synapses' EnCompass modeling. Witness Varadarajan concluded that a carbon plan "portfolio that invests more aggressively in the near term in energy efficiency," in addition to other zero-emitting supply side resources, "would be cheaper for ratepayers and better insulate ratepayers from the cost impacts of future fuel price spikes as well as unexpected increases in electricity demand…." Tr. vol. 23, 233. Duke did not ask any questions of Witness Varadarajan, including any questions regarding the benefits to ratepayers from a more aggressive investment in utility EE.

Tech Customers

The Gabel Associates Report sponsored by the Tech Customers recommended that efficiency savings alone could result in a 7.7% reduction in the load forecast by 2030. Tr. vol. 7, 314. The Gabel Report noted that such a reduction in load is conservatively achievable, noting that a 2020 ACEEE report, "How Energy Efficiency Can Help Rebuild North Carolina's Economy: Analysis of Energy, Cost, and Greenhouse Gas Impacts" (2020 ACEEE Study), concluded that an 11.1% reduction in load is achievable. Gabel Report at 12. Recent historic data shows that the Companies have regularly "reached the 1% incremental annual savings that the Carbon Plan seeks to achieve" *Id.* at 38. Data from EIA shows this level of EE savings would represent the 60th percentile of investor-owned utilities in 2020. *Id.* The Gabel Report concluded that "compared directly against the resource options proposed in Duke's Carbon Plan, energy efficiency would likely be dispatched to well beyond the technical potential identified in the Companies' market potential study." *Id.* at 37-38. The Gabel Report recommends merging the ideas put forward by Duke in Appendix G of its Carbon Plan filing with those offered by the 2020 ACEEE Study to significantly increase the level of energy efficiency savings achieved by the Companies. *Id.* at 40.

The Tech Customers reaffirmed the reasonableness of their assessment that a 7.7% reduction in the load forecast could be achieved with increased utility efficiency, but nevertheless updated its analysis to include a lower utility EE sensitivity, which comported with Duke's projections. Tr. vol. 25, 95-96. Witness Roumpani for the Tech Customers noted that this additional sensitivity resulted in an optimal portfolio that required additional imported onshore wind and an additional combustion turbine in 2030. *Id.* at 96. The costs to ratepayers and carbon emissions were higher from this lower utility EE sensitivity, which is unsurprising given that "[e]nergy efficiency is one of the most economic resource options that the utility could pursue." *Id.* Duke did not ask any questions of the Tech Customers' witnesses, including any questions regarding the appropriate level of utility EE to include as a decrement to load for carbon plan modeling or the costs to ratepayers from underutilizing achievable EE savings.

AGO

The Strategen Report sponsored by the Attorney General's Office recommended that Duke take a different approach to modeling utility EE. Instead of determining a set level of energy efficiency savings as a percentage of sales and including that as a decrement to load before running the EnCompass model, Strategen recommended making Utility EE a selectable resource in EnCompass itself, so that the model could select the most economically optimal EE in competition with other supply side resources. Tr. vol. 25, 311-12. The AGO noted that picking a predetermined amount of utility EE outside of the model is arbitrary. AGO Comments at 22, 32. Duke responded that it did not agree that it would be appropriate to model EE as a selectable resource because it is "almost entirely dependent on customer preferences." Tr. vol. 7, 316. AGO Witness Burgess disagreed that Duke has no ability to influence the outcome of customer decisions with regard to adoption of utility EE. Tr. vol. 25, 312-13. Increased rebates or incentives can help to drive increased adoption of such measures. *Id.*

AGO Witness Burgess testified that Strategen has experience running EnCompass models that treat utility EE as a selectable resource, and that doing so resulted in "more EE/DSM measures being selected than was previously assumed by the utility." Tr. vol. 25, 311. This result is not surprising given that utility EE is "often the lowest-cost resource available, let alone the lowest-cost carbon free resource." *Id.* Ultimately, Witness Burgess concluded that "it may be more cost effective to increase UEE rebate/incentive levels (even beyond those levels considered in the market potential studies) to achieve greater deployment of EE/DSM measures if doing so were able to avoid or defer more expensive carbon-free resources." *Id.* at 312. Relatedly, AGO Witness Burgess supported Duke's proposal to modify the cost-effectiveness test for utility EE programs so to compare the value of efficiency to zero-carbon marginal resource rather than a carbon emitting gas plant. *Id.* at 313. Duke did not ask any questions of AGO witness Burgess, including any questions regarding the appropriateness of allowing EnCompass to select utility EE.

Appalachian Voices

Appalachian Voices witnesses Rory McIlmoil and Dr. Yunus Kinkhabwala (AV Witnesses) testified that the Companies' proposed utility EE target of 1% savings of eligible retail sales is not aggressive, as characterized by Duke Energy witnesses. T. vol. 24, 48-50. Noting the utility EE savings achieved by Duke's peer utilities in other states, and Duke's own success in achieving the 1% savings of total retail sales in the recent past, a higher savings level needs to be set by the Commission. *Id.* AV Witnesses agreed with the AGO's position that utility EE should be a selectable resource in EnCompass for modeling purposes. *Id.* at 51-52. AV Witnesses testified that if:

> Duke achieved efficiency levels equal 1% of retail sales per year (which Duke Energy Carolina has achieved historically) . . . Duke would save an additional 4,700 GWh and reduce demand by 800 MW by 2030. Achieving 2% savings per year would provide 14,300 GWh of energy savings and 2,500 MW of demand reductions beyond Duke's current proposal. Such investments would greatly reduce the need to build new gas plants.

Id. at 47.

In addition, AV Witnesses testified that investments in energy efficiency that are targeted specifically at low-income households can prove to be a cost-effective method to lower energy demand while enhancing affordability for energy burdened households of whatever carbon plan is ultimately developed by the Commission. Tr. vol. 24, 26; 52-54. AV Witnesses, referring to information developed during the Low-Income Affordability Collaborative, testified that energy inefficiency is a primary driver of affordability challenges for the Companies' low-income customers. *Id.* at 30. Quoting from the LIAC report, AV Witnesses testified that "'improving a household's energy efficiency through air sealing, insulation, and energy efficient heating systems could substantially reduce a household's likelihood of experiencing a [disconnection for nonpayment].'" *Id*. Increasing the delivery of such comprehensive energy efficiency measures to low-income customers would both assist in achieving carbon plan emissions reductions while also mitigating the effects of potential rate increases from carbon plan compliance. *Id.* at 32-40; 47-48.

EWG

The Environmental Working Group (EWG) sponsored the testimony of Dr.

Arjun Makhijani, who recommended that the Commission require additional modeling that considers additional portfolios without new nuclear plants. Tr. vol. 24, 108-09. Proposed EWG Portfolio 2 would include higher levels of energy efficiency for existing loads (not including loads related to vehicle or building electrification) that would increase by 2% per year to 2030, 1.5% per year from 2031 to 2035, and 1% per year from 2036 to 2050, with the appropriate higher incentives and standards put in place to achieve the higher levels." *Id.* at 111-12. This portfolio would involve increased investments in efficiency for low and moderate-income households.

Brad Rouse

Witness Brad Rouse testified about the need to develop a short-term action plan for the utilities' EE and DER efforts that can help to avoid the need for new gas CC or CT plants over the next decade. Tr. vol. 22, 92. Such a plan would involve leveraging the EE incentives under the IRA as well as working with local governments to help in their efforts to engage with their communities on strategies for reducing energy waste that will help the Companies to achieve their carbon reduction requirements at least cost. *Id.* at 88-92.

Public Staff

Public Staff Witness Williamson recommended that the Commission not consider any utility EE savings beyond what was considered achievable savings in the most-recent Market Potential Study, included as Attachment IV to Duke's Carbon Plan application. Tr. vol. 20, 180-90. Witness Williamson relied on the fact that the Companies have historically relied upon the findings of "utility-specific market potential studies to establish a benchmark for new EE measures and savings in IRP proceedings. *Id.* at 182. Witness Williamson also noted that the Companies indicate that they would rely on future regulatory changes in order to achieve the 1% of eligible sales savings benchmark. *Id.* In support of relying on the achievable savings reflected in the MPS, Witness Williamson points to "headwinds" that have made it harder for the Companies to maintain or increase cost-effective EE savings, including "updates to codes and appliance standards; market transformation; and decreasing avoided cost rates that have lowered the economic value of EE benefits on a system basis." *Id.* In comments, the Public Staff set forth the difference between the achievable savings in the MPS (or base UEE sales), the 1% of eligible (or available) sales modeled by Duke, and 1% of total sales in Figures 7 and 8 (for DEC and DEP, respectively). Id. at 187 (citing PS Comments at p. 54). Those figures show that the savings that would come from 1% of eligible sales do not go well beyond what is considered achievable in the MPS for the next several years. *Id.* at 188. Nevertheless, Public Staff Witness Williamson expressed concern that projecting a savings level that is higher than what was deemed achievable in the MPS prepared about three years ago risks the utilities needing to meet a megawatt hour of energy in some manner that it is not least cost. *Id.*

On cross examination, Witness Williamson acknowledged that the Market Potential Study was concluded back in 2019, before N.C.G.S. § 62-110.9 was enacted. Tr. vol. 20, 348. Furthermore, Witness Williamson agreed that the MPS was based on business-as-usual assumptions, such as the market conditions, utility rates, technology, and economic conditions that existed at the time the MPS was conducted. *Id*. at 349. Witness Williamson agreed that changes in electricity rates can play a role in whether customer participate in energy efficiency programs. *Id.* at 351. Increases to customer rates from higher fuel costs and the pending proposed rate increases could send a different price signal about the value of utility EE than was the case when the MPS was prepared in 2019. *Id.* at 350-51. Witness Williamson also acknowledged that other policy changes have taken place since the MPS was conducted, for example, the Total Resource Cost (TRC) was the predominant measure of cost-effectiveness when the MPS was conducted, but since 2019, the Commission has adopted the Utility Cost Test (UCT) as the principal cost-effectiveness test. *Id.* at 351-54. The MPS found significantly higher economic potential from using that UCT as opposed to the TRC. MPS, Duke Carbon Plan Att. IV at 82. Another trend that informed the achievable savings identified in the MPS was declined avoided energy costs, which all other things being equal, makes it more difficult for utility EE programs to achieve cost-effectiveness. *Id.* at 354. Witness Williamson provided testimony in the most recent DEP DSM/EE Rider Docket No. E-2, Sub 1294 on August 24, 2022, in which he said that the Public Staff does not anticipate the trend of avoided cost rates declining to continue into the future. *Id.* at 355-56. Witness Williamson cited several factors as “likely to produce higher valuations of the benefits from DSM/EE programs,” including increases in fuel costs—which have a direct influence on avoided cost rates—the addition of renewable capacity, retirement of coal plants, and emphasis on grid improvement. *Id.* (quoting from Testimony of David

Williamson, Docket No. E-2, Sub 1294, Aug. 24, 2022). With regard to Witness Williamson's concern about Duke's 1% of eligible sales savings target going "well beyond" what was anticipated in the MPS, he acknowledged that those projections do not significantly diverge for several years, and that, as with any modeling exercise, the further out into the future a MPS projects, the more room for error in those projections. *Id.* at 364-65.

Duke Rebuttal

On rebuttal, the Grid Edge Panel discussed Duke Energy Late-Filed Exhibit 6, "Potential Ways to Increase Duke Energy's Annual Energy Savings Percentage to 1.5 Percent of Retail Sales for Utility Energy Efficiency," which was designated Grid Edge Panel Rebuttal Exhibit 1. This exhibit was prepared in response to the Commissioners' request to provide an overview of potential pathways for increasing utility EE from 1% of eligible sales to 1.5% of eligible sales. Grid Edge Panel Rebuttal Exhibit 1 included both new ways to count what could be included as utility EE savings and new ways to achieve greater utility EE savings. Tr. vol. 30, 43-44; 58-59.

The Companies cited the 2020 ACEEE State Energy Efficiency Scorecard, which ranks North Carolina 27 out of the 51 states plus the District of Columbia. Tr. vol. 30, 48. When asked, the Grid Edge Panel acknowledged that the first policy recommendation in the ACEE State Energy Efficiency Scorecard for improving utility EE savings is to establish an energy efficiency resource standard or similar savings target, but suggested that the REPS standard in North Carolina law establishes such a target. *Id*. at 48-49.

In addition, Duke Energy introduced Grid Edge Rebuttal Redirect Exhibit 1, which compares the baseline assumptions of utility EE savings to the target of 1% of eligible load that the Companies modeled for the carbon plan. Tr. vol. 30, 54-55. Redirect Exhibit 1 demonstrated that there is a negligible difference between the utility EE savings assumed in the most recent MPS and the Companies' 1% of eligible sales target modeled for the carbon plan for the next several years.

Comments

A number of local governments submitted comments that supported increased reliance on utility EE as part of a least cost Carbon Plan. In comments submitted in this docket, the City of Asheville and Buncombe County (Asheville/Buncombe Comments) asked the Commission to require Duke Energy to achieve utility EE savings "above and beyond 1.0% of full annual retail load." Asheville/Buncombe Comments, 5-6. EE and DSM programs are highly effective and cost-competitive grid resources that can benefit North Carolinians by saving customers money (by lowering customer energy bills) and decreasing energy burdens (by reducing emissions). *Id.* Asheville/Buncombe recommend that the Carbon Plan should enable increased access to EE for low-income households. *Id.* Asheville/Buncombe also criticized the most recent MPS because it wrongly finds little cost-effective savings available for HVAC measures, despite research showing that heat pumps and heat pump water heaters are two of the highest potential efficiency opportunities in the state. *Id.* at 6. Asheville/Buncombe recommend that Duke update its analysis to more fully value the benefits of EE, factor in technology development, take advantage of on-bill financing, and enhanced marketing, including taking into account recommendations form the NC Energy Regulatory Process and NC Energy Efficiency Roadmap. *Id.* Asheville/Buncombe have experience with community-utility partnerships in the design, development, and implementation of EE/DSM programs that have resulted in increased uptake and savings, including for low-income customers. *Id.*

The Durham Board of Commissioners comments note that Duke's target of 1% of eligible sales is significantly below the performance of many states. Durham Comments, 3. Durham County states that EE and DSM programs "must be considered as a serious strategy for reducing emissions, avoiding the construction of new generation and transmission infrastructure, and reducing costs for customers. These are cost-competitive grid resources that are undervalued in the proposed Carbon Plan." *Id*. Durham County recommends that EE programs focused on low-income households that require EE retrofits can have a high impact on energy use while bringing other community benefits. Durham County encourages the Commission to incorporate more strategies from the North Carolina Energy Efficiency Roadmap into the Carbon Plan modeling and future Market Potential Studies. *Id.*

The Town of Boone, Town of Chapel Hill, Chatham County, City of Durham, City of Greensboro, Town of Hillsborough, Town of Matthews, and the City of Raleigh filed joint comments as a consumer statement of position (Joint Local Government Comments) that highlighted the importance of EE and DSM for cost-effectively reaching carbon reduction requirements and helping to reduce customer bills, helping to ease energy burdens. Joint Local Government

Comments, 5. These local governments believe that "Duke Energy should achieve energy savings above and beyond 1.0% of the full annual retail load. Despite the relatively high per capita energy consumption of North Carolinians, the plan's target is significantly below the performance of many states and just barely meets the national average of states that have energy efficiency resource standards (EERS)." *Id.* at 6. These local governments "suggest that Duke consider new or enhanced customer engagement strategies, including increased collaboration with local governments. The undersigned believe local governments can be important partners to design, develop, and deliver EE and DSM programs to North Carolina residents and businesses in multiple ways, such as improving local ordinances, increasing the uptake and success of utility programs through local networks and targeted outreach, and supporting low-income weatherization." *Id*. These local governments highlighted the importance of utility EE investments in low-income households as a key strategy for helping to reduce unaffordable energy burdens. *Id.* at 5. In addition, Pam Hemminger, Mayor of Chapel Hill testified at the August 23 Public Hearing that the carbon "plan should base a more aggressive energy efficiency and demand-side management strategy to allow customers to save money and reduce emissions. This is particularly important for low-income residents facing a high energy burden." Tr. vol 5 at 29.

The NC Council of Churches and Interfaith Power and Light (NCIPL) submitted comments that encouraged the Commission, as part of its Carbon Plan, to "ensure that low-wealth communities have access to affordable electricity," have options for self-generation, opportunities for energy savings, and "reduced energy burdens." NCIPL Comments, 4. NCIPL recommend the Carbon Plan should "include elements that encourage low-income ratepayers to lower their consumption by eliminating wasted energy." *Id.* at 5. More specifically, NCIPL recommends that the Commission "adopt and implement: a Pay as You Save model for any energy upgrades or weatherization complemented by a Percent of Income Payment Plan (PIPP) to ensure that electric bills are affordable for low-income ratepayers. NCUC should also adopt and implement an Arrearage Management Plan to help customers pay off unpaid bills which serve as barriers to their investments in efficiency upgrades." *Id.*

In initial comments, the Red Tailed Hawk Coalition and RCCSD, urged the Commission to increase reliance on utility EE as part of its Carbon Plan. The Companies should work to expand the access and reach of its income-qualified programs and continue to develop tariffed on-bill financing for EE. The Commission should require clear implementation timelines and metrics to use to analyze projects, ensure their efficient implementation, and determine their potential to be scaled up as part of the Carbon Plan. *Id.* at p. 20. EJCAN and DECAESJC made substantially similar recommendations in their comments. pp. 14-15.

Public Witness Hearings

At the public hearings, a number of individuals called on the Commission to require Duke to achieve greater levels of EE savings that the Companies included in their Carbon Plan proposal. Members of the public testified about the importance of the Carbon Plan:

- Having higher goals for achieving greater conservation, energy efficiency and demand-side management gains. Tr. vol. 3, 31-32, 46, 92, 98, Tr. vol. 5, 60
- Creating more opportunities for customers to weatherize and insulate their homes, to install heat pumps, in order to increase EE and save themselves money and reduce demand. Tr. vol. 3, 45, 101; Tr. vol. 6, 58.
- Ensuring that the Carbon Plan takes into account the Inflation Reduction Act and the likelihood that customers in North Carolina will replace appliances and make energy-efficiency upgrades to their homes at a greater rate than Duke estimates. Tr. vol 5, 13.

Stakeholder Process

The importance of achieving significant energy efficiency savings was a consistent theme of the Carolinas Carbon Plan stakeholder process. Under the category of customer and community impacts, stakeholders listed considering "new or expanded customer-facing programs for energy efficiency, DSM, and renewables" as an important goal. Public Staff Report, Duke Energy "Carolinas Carbon Plan" Stakeholder Meeting 2 (Feb. 23, 2022) and Technical Subgroup Meetings (Feb. 18, 2022) (Mar. 2, 2022). In the first meeting, stakeholders asked Duke to consider "centering efficiency and demand-side management as first choice resources" for the Carbon Plan. *Id*.

DERs/NEM/Behind-the-Meter Distributed Generation

To account for distributed rooftop solar in its modeling, the Companies used projections based on existing net metering (NEM) regulatory policy coupled with adoption forecasts from Guidehouse that considered current and future payback periods. Tr. vol. 7, 316-17; Tr. vol. 20, 84-85. Even though the Companies have proposed changes to net metering policy and a new incentive for rooftop solar adoption, until there is more certainty about future policy, the Companies decided to base its projections on existing policy. Tr. vol. 7, 317-19; Tr. vol. 14, 17-18 (Duke Grid Edge panel confirming that new proposed solar NEM rates and incentives were not considered for the Carbon Plan forecasts).

CLEAN Intervenors also took issue with the solar projections used by Duke. CLEAN Intervenors July 15 Comments, 28. Looking at recent growth trends for NEM adoption in North Carolina alone, DEC and DEP each had more than 3,000 new customers enroll in NEM in 2021. *Id.* DEC's projections show an average of 4,808 new NEM customers per year in DEC and 2,605 new customers NEW customers per year in DEP in their combined North and South Carolina service territories.[4] Tr. vol. 7, 318-19.

For its modeling, Synapse used Duke's high NEM forecast for projecting future rooftop solar adoption as an input to its load forecast, which projects some acceleration in NEM deployment over time. Synapse Report, A-9-10. Synapse adopted Duke's high forecast because of existing market trends and the assumption that Duke policies "will continue to support the growth of distributed

[4] CLEAN Intervenors' July 15 Comments interpreted Table G-8, which Duke Energy included in its Appendix G, to include the total number of residential customers enrolled in NEM as of 2030, not the incremental number of new customers enrolled by 2030, because the chart is labeled "Number of Forecasted Customers and Incremental MWh Enrolled in Net Metering Rates..." Because the "incremental" was only used to modify MWh, CLEAN Intervenors interpreted the cart to list the total number of customers, and therefore subtracted the number of residential customers from Table G-7 to arrive at its annual average new residential solar NEM customer per year figure in its comments.

energy resources, including rooftop solar." Synapse Report, 12-13. CLEAN Intervenors witness Fitch testified that the policy supports in the IRA further support the use of the High NEM forecast. Tr. vol. 24, 184. Duke used its base NEM forecast, which projects a linear increase of 75 to 95 MW of incremental rooftop solar through 2050. The Public Staff agreed with Duke's approach to model behind-the-meter generation as a modification to load outside of EnCompass and agreed with Duke's NEM projections. Tr. vol. 20, 84-86. The Public Staff does not object to Duke including customer-sited generation as a selectable supply-side resource in future Carbon Plan modeling, that decision should be considered holistically to make sure that it does not overly complicate the model. *Id*. at 86.

Tech Customers Witness Borgatti testified that a distinguishing feature of the Gabel/Strategen Preferred Portfolio is that includes a more "robust investment in behind-the-meter (BTM) distributed generation. Tr. vol. 25, 108. The Gabel/Strategen Report noted multiple benefits that come with increased reliance on expanding opportunities for BTM generation, including rooftop solar:

> Increasing BTM solar is vital to a successful portfolio as it offers multiple benefits to hosts of the solar arrays, the Companies, and customers at large. BTM solar provides site hosts with bill savings through reduced consumption. This reduced consumption diminishes grid emissions, directly assisting the Companies in meeting their CO2 reduction targets. BTM solar also eases pressure on the need for wholesale grid-connected solar projects, reducing costs to ratepayers for interconnection and transmission. Finally, because site hosts bear many of the installed costs of BTM solar, this again provides savings to ratepayers at large. Because of these benefits, BTM solar should be increased within the Carbon Plan portfolios.

Gabel/Strategen Report, 43. Comparing other states that have achieved much faster rates of BTM distributed generation adoption than North Carolina, including states with worse solar irradiation, like New Jersey, Gabel/Strategen noted that there is much room for growth in this technology. *Id.* at 42-43. Using their modified growth rates for BTM generation adoption, Gabel/Strategen showed that "5% of electric load would be served by BTM solar by 2037." *Id.* at 44. Gabel/Strategen recommended that the Commission:

> direct Duke to develop and propose a best-in-class BTM renewable/storage program that accelerates Distributed Energy Resource deployment to the levels discussed above, with an emphasis on the use of onsite storage/hybrid resources. This includes revisions to net metering or the development of other incentive approaches

Id.

Witness Borgatti testified that the IRA could be a big factor in spurring increase behind the meter generation, because under certain conditions, the IRA can provide a tax benefit equal to about 70% of the value of the technology. Tr. vol 25, 153-54. Witness Borgatti noted that the Companies' Modeling and Near-Term Action Panel Late Filed Exhibit 1 did not take into account the IRA's impacts on behind-the-meter-generation. *Id.* Witness Borgatti recommended lifting the current MW cap on net metered facilities to allow larger projects to take advantage of NEM, which can be particularly important for large customers with corporate decarbonization goals. *Id.* at 156. As an additional NEM reform for Commission consideration, witness Borgatti mentioned New York's value of DER program, which has allowed more customers to participate in community solar programs. *Id.* at 156-57.

AGO witness Burgess recommended that the Companies evaluate the costs and benefits of different levels of rooftop solar deployment by varying the levels of incentives offered. Tr. vol. 25, 240. The AGO Strategen Report also found that distributed solar may present fewer barriers for interconnection, “which means distributed solar could serve as an important complement to large scale projects.” AGO Strategen Report at 44. Witness Burgess testified that the two scenarios considered by Duke for NEM adoption—base NEM and high NEM—represented a relatively narrow set of possibilities. Tr. vol. 25, at 319. In light of the incentives made available by the IRA, the Commission should seek to leverage any customer willingness to make significant personal investments in distributed generation. *Id*. at 320. Witness Burgess recommended modifying the Companies’ EnCompass model to make DERs like rooftop solar a selectable resource. *Id.* at 321. This approach could be taken with a larger variety of distributed generation options beyond just NEM. *Id.*

NCWARN *et al.* Witness William Powers testified that the Companies’ NEM growth projections for NEM have declined since the 2020 IRPs. Tr. vol. 22, 209-10. Witness Powers testified that the Companies did not explain why their NEM projections declined since the 2020 IRPs were filed. The Companies forecasts did not take into account the extended tax credits for rooftop solar in the IRA, which White House projections anticipate will add 170,000 rooftop solar systems in North Carolina over the next decade. *Id.* at 210.

AV Witnesses testified that the Companies did not adequately address the potential expansion of distributed energy resources (DERs), such as rooftop solar or demand response, noting that Duke did not allow EnCompass to treat these DERs as a selectable resource. Tr. vol. 24, 51. In addition, AV Witnesses noted that the incentives in the IRA are further evidence that Duke's modeling underestimates the adoption of rooftop solar. *Id.* at 52.

Discussion and conclusion

EE/DSM

The Commission concludes that, in light of the requirements of G.S. § 62-110.9, it is appropriate to set a minimum floor of energy efficiency savings that the Companies should achieve as part of the Carbon Plan. While the Commission agrees with Duke that this savings requirement should be aggressive, the Commission disagrees that 1% of eligible sales is a sufficiently aggressive target for purposes of achieving carbon reduction requirements at least-cost while maintaining system reliability. Consistent with the savings achieved by Duke's peers, as documented in the ACEEE Utility Scorecard, and consistent with the steps that the Companies set forth in Grid Edge Panel Rebuttal Exhibit 1, the Commission orders Duke to ramp up its cost-effective energy efficiency savings to 1.5% of eligible load by 2027 as part of its approved near-term action plan.

As noted by several intervenors, and as acknowledged by Duke witnesses, energy efficiency can be the lowest cost resource, and is foundational to any reasonable, least-cost carbon plan portfolio. A key difference in the assumptions made in the EnCompass modeling conducted by Synapse for CLEAN Intervenors and by Gabel Associates for the Tech Customers was a higher level of utility EE savings. These models resulted in resource portfolios that contained significantly lower costs to ratepayers while also meeting the 2030 carbon emissions reduction requirement.

The Commission has considered the broad support for expanding reliance on energy efficiency as a strategy for complying with the carbon emissions reductions required by law as expressed by many of the intervenors and commenters, including local governments from across North Carolina. With the exception of the Public Staff, every intervenor that provided evidence about energy efficiency as a component of the Carbon Plan recommended that Duke achieve greater utility EE savings that presented in the Companies' plan. The Commission also concludes that an increased reliance on utility EE is consistent with preexisting North Carolina law and policy. The existing Renewable Energy and Energy Efficiency Portfolio Standard established by Senate Bill 3 in 2007 does not itself place a floor on required utility EE savings, as would be the case with a stand-alone energy efficiency resource standard. Nevertheless, the supportive policy for achieving substantial savings that was put in place following the enactment of Senate Bill 3 provides a strong foundation for the Companies to expand their utility EE savings.

The Commission also concludes that the Companies should model various levels of efficiency savings as a decrement to load in future carbon plan modeling, including 1.5% savings of total load, 1.5% of eligible load, and 1% of total load. In addition, the Commission concludes that the Companies should work with the Collaborative and other stakeholders on finding an appropriate method for modeling utility EE as a selectable resource within EnCompass rather than only as a decrement to load to present the Commission with alternative strategies for identifying an optimal level of utility EE investments in future carbon plan proceedings.

As requested by the Companies, the Commission takes note of the enablers identified by the Grid Edge panel as policies that may facilitate greater utility EE savings, but it is premature to rule on any of those potential enablers at this time. As noted by the Grid Edge Panel for the Companies, those enablers are not required to achieve the Companies' proposed utility EE savings target in the near term. However, to the extent those enablers or other policies set forth in Grid Edge Panel Rebuttal Exhibit 1 would facilitate ramping up to the 1.5% of eligible sales savings requirement by 2027, the Companies should work with the Carolinas EE/DSM Collaborative to refine those proposals and submit them for Commission consideration as soon as is practicable. In particular, the Commission directs Duke to work with the Collaborative on a proposed change to the DSM/EE cost-recovery mechanism that would update the avoided cost value of utility EE programs that would be based on the levelized cost of the marginal zero-carbon supply-side resource for Commission consideration within 180 days of this Order. The Commission concludes that it is inappropriate, however, for the Companies to pursue expanding the eligibility for low-income programs to customers that are at or below 300% of the Federal Poverty Level (FPL). As part of the Low-Income Affordability Collaborative process which took place over the last year, no such recommendation was considered. The LIAC Report indicates that 200% or below of the FPL is an appropriate eligibility level for the Companies' income-qualified EE programs and the Companies have not put forward a compelling reason to change course.

The Commission concludes that the Companies need not pursue strategies identified the by the Companies in Grid Edge Panel Rebuttal Exhibit 1 that would only change the way that the existing efforts are counted towards savings. The fundamental purpose of increasing annual utility EE savings is to capture additional efficiency gains that will further reduce the need for more expensive power generation in the future. To achieve this aim, the Companies' solutions must deliver new savings and should not merely consist of modified accounting practices or ignore elements of forecasted energy demand, neither of which actually yield new efficiency savings.

Instead, the Companies should put their efforts towards those strategies that will actually increase cost-effective utility EE savings. The Commission directs the Companies to work with the Collaborative on identifying concrete steps for ramping up the Companies' cost-effective utility EE programs to achieve 1.5% of eligible sales. This could include hiring an outside expert consultant to work with the Companies and the Collaborative on developing such a plan. Such an action plan should include steps that the Companies plan to take in order to increase savings for low-income customers who meet the existing income eligibility criteria (200% or below of the Federal Poverty Level). Strategies for delivering additional savings to low-income customers could include further expanding deployment of the Income Qualified Weatherization program, increased delivery of Neighborhood

Energy Saver 2.0 measures, and enhanced incentives for low-income customers in Duke's non-income qualified program offerings (including for the Tariffed On-Bill Financing program). An action plan that reflects the Collaborative's efforts should be filed in this docket no later than 120 days following this Order.

The Commission does not agree with the Public Staff that the most recent Market Potential Study, from approximately three years ago, is a reasonable baseline for efficiency savings levels for purposes of complying with carbon reduction requirements. The MPS was based on business-as-usual assumptions from before the enactment of N.C.G.S. § 62-110.9, which creates a new policy framework for utility EE. In addition, the savings assumptions in the MPS did not take into account rate increases, which have already occurred due to increased fuel prices, and which are being sought by the Companies in the pending and upcoming PBR rate cases. In addition, the trend of declining avoided cost values for energy efficiency are not likely to continue given the increases in fuel prices and the requirements of the energy transition, as the Public Staff has acknowledged in the most recent DEP DSM/EE rider docket. While in the past the Commission has relied on the findings of the most recent MPS for planning purposes in IRP dockets, this Carbon Plan docket is not equivalent to prior IRP dockets. The energy transition required by G.S. § 62-110.9 is different in kind than prior resource planning dockets and requires new strategies to achieve the required carbon reduction goals at least cost and while maintaining system reliability.

In addition, the Commission concludes that there is not a significant difference between the utility EE savings deemed as achievable in the most recent MPS and the Companies' proposed target of 1% of eligible sales over the next several years. The Commission will be able to adjust as necessary in future carbon plan update dockets. Ramping up to 1.5% of eligible sales by 2027 provides an appropriate balance between the savings targets identified by various intervenors and what the Companies suggested is a reasonable target. Ramping up cost-effective utility EE savings is a foundational component of achieving the required carbon reduction goals at least cost to Duke's ratepayers.

DERs/BTM Distributed Generation

Increasing opportunities for customer-owned distributed energy resources (DERs) is an important strategy for achieving the carbon reduction requirements of G.S. § 62-110.9 at least cost while maintaining the reliability of the grid. As with utility EE, DERs require the investment of customers' private capital in zero-carbon resources that have the aggregate effect of reducing the need for Duke Energy to invest in those same resources, mitigating carbon plan compliance costs for ratepayers as a whole. Duke should continue to develop cost-effective and reasonable support for private investment in and customer adoption of DERs.

All of the Companies portfolios included the same assumption about future NEM adoption as a proxy for future behind-the-meter distributed solar adoption and as an adjustment to load. Modeling a range of behind-the-meter generation adoption levels, rather than one static assumption of NEM adoption, would provide more useful information for Commission consideration when developing the Carbon Plan. In the next Carbon Plan, the Companies should model various compound annual growth rates of distributed solar adoption.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 11-14
SOLAR INTERCONNECTION CONSTRAINT
(Scheduling Order ordering paragraph 1.c.)

The evidence supporting these findings of fact is found in Duke's Modeling and Near-Term Actions Panel Direct and Rebuttal Testimony, and Cross-Examination and Commissioner Questions, Duke's Transmission and Solar Procurement Panel Rebuttal Testimony, Comments of the Public Staff, Cross Examination and Commissioner Questions for Public Staff Panel 1, Corrected Comments of Clean Power Suppliers Association on Proposed Carolinas Carbon Plan (CPSA Comments), and the Direct Testimony of CPSA witnesses Ryan Watts, Tyler Norris, and Michael Hagerty.

Summary of the evidence

In their proposed Carbon Plan, Duke states that because of "'real-world' limitations on the ability of Duke Energy (or any utility or transmission operator) to interconnect projects," the Companies limited the amount of solar that could be selected by the EnCompass model on an annual basis. Carbon Plan Appx. I, 3-4) Duke further notes that "there are several factors that are unknown or outside of utility control that will ultimately impact the actual amount of the annual interconnections achievable," including in particular the size of projects that seek interconnection. *Id*. According to Duke, "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. 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." *Id*.

Duke adopts a different limit on annual solar interconnections (the "Solar Interconnection Constraint") in different portfolios. In portfolio P1 (the only portfolio to achieve compliance with the 70% carbon reduction mandate in 2030), Duke modeled annual solar interconnection limits of 750 MW in 2026, 1050 MW in 2027, and 1800 MW in successive years. In all other portfolios (P2-P4), Duke assumed solar interconnection limits of 750 MW in 2026, 1050 MW in 2027, and 1350 MW in successive years. Carbon Plan Appx. I, 6) The Companies' proposed Carbon Plan goes on to discuss the factors that informed Duke's annual Solar Interconnection Constraint.

In Comments, CPSA notes that Duke's Solar Interconnection Constraint significantly increases the cost of compliance with H.B. 951. Because solar is generally the least-expensive and most available carbon free resource available to Duke, limitations on solar adoption prevent the model from selecting least-cost solar resources and result in the selection of other, more expensive resources.

CPSA's comments describe the results of modeling conducted by Brattle Group on behalf of CPSA. Brattle Group conducted capacity expansion modeling of portfolios using three alternative approaches to solar interconnection. First, it modeled a portfolio (CPSA1) that achieves 70% compliance in 2030, with no solar interconnection cap. This portfolio was included not for planning purposes, but to understand the cost impacts of interconnection constraints more fully. Second, it modeled two portfolios (CPSA2 and CPSA4) using the low Solar Interconnection Constraint assumed by Duke in portfolios P2-P4. Finally, it modeled two portfolios (CPSA3 and CPSA5) using a solar interconnection constraint (1500 MW) that is higher than Duke's in 2026 and 2027, but that in 2028 and beyond is the same as the constraint assumed by Duke (1800 MW) in those years. CPSA Comments at 38.

Based on this modeling, CPSA contends that such strict limitations on solar interconnection could end up increasing "the annual system cost . . . by $900 million in 2030 and $800 million in 2032." CPSA Comments at 12. This is based on a comparison between the 2030 and 2032 system costs of portfolios modeled using Duke's low interconnection cap and CPSA's higher cap. CPSA Comments at 38.

CPSA further argues that Duke's modeling limits on solar interconnection to be unsupported by data. Solar is one of the least cost and most readily available new generation resources available in the Carolinas, yet Duke's portfolios, including SP6, place unnecessarily stringent limits on solar interconnections. *Id.* at 10-12. CPSA notes that Duke's portfolios show a willingness to take risks on uncertain or less established technologies such as SMRs, green hydrogen, and onshore and offshore wind, while being much more conservative with solar interconnection caps. *Id.* at 10. Duke sets high goals for these riskier resources and claims it will "check and adjust" when it fails to meet those goals. *Id*. at 20. However, for solar interconnection, Duke sets strict limits because of "uncertainty about the rate of future interconnections." *Id.* at 14.

Because of the potential for higher solar interconnection rates to accelerate compliance with the 70% mandate, and to reduce costs, CPSA recommends that Duke be required 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. *Id*. at 69.

The Public Staff in its comments states that the "average pace of interconnection . . . represents a significant risk" because it must occur at an "unprecedented [rate] in Duke's history in North Carolina." Public Staff Comments at 88. Still, the Public Staff "believes it is not appropriate to use historical interconnections as a gauge or limit on future interconnections." *Id.* at 146.

In direct testimony, Duke's Modeling and Near-Term Actions Panel testifies that in its modeling of interim compliance by 2030, solar interconnections are capped at 750 MW for the beginning of 2027, 1,050 MW for 2028, and 1,800 MW for 2029 and beyond; and for interim compliance by 2034 the limitations on interconnection for 2029 and beyond are reduced to 1,350 MW. Tr. vol. 7, 348 Table 11. While the Public Staff and several intervenors disagree with Duke's interconnection limits, Duke contends that the disagreement "is not whether a limitation or constraint is appropriate, but what specific limitation is the most reasonable forecast of the Companies' ability to interconnect solar in the future." *Id.* at 354.

The Modeling and Near-Term Actions Panel explains that the forecasted limits on solar interconnection used in its modeling are "based on engineering judgment taking into account a variety of factors." *Id.* at 348. Duke lists seven "factors" that contributed to its interconnection caps: (1) solar interconnections are increasingly complex as solar facilities are located farther away from existing infrastructure *Id.* at 348; (2) the most viable land for use in solar is located in the "Red Zones" *Id.* at 349; (3) increased levels of renewable resources requires transmission expansion and time for construction *Id.* at 350; (4) upcoming transmission expansion projects will enable greater interconnection over time *Id.* at 351; (5) there are finite interconnection resources, some of which are allocated to non-solar resources *Id.* at 352; (6) Duke's historic solar interconnection rates; and (7) the likelihood that there will be larger solar projects in the future compared to historic project sizes *Id.* at 353.

Duke concedes that including a restraint on solar interconnections will "will increase costs when compared to an unconstrained solution," *Id.* at 359 but disagrees that these constraints will necessarily increase costs for consumers or that intervenors' unconstrained models will ultimately cost less. *Id.* 359-360. In addition, Duke claims 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." *Id.* at 360.

The Modeling and Near-Term Actions Panel also describes the results of supplemental modeling performed by Duke in consultation with the Public Staff. This reflected a number of changes to modeling assumptions and yielded to sets of supplemental portfolios: SP5 and SP5A, which achieve compliance in 2032; and SP6 and SP6A, which achieve compliance in 2034. Id., 246. For the SP5 portfolio, Duke also performed an additional sensitivity reflecting higher interconnection rates proposed by CPSA and supported by other intervenors including the AGO and CCBEA. Id., 246-47. Consistent with Brattle's modeling, the "High Solar Sensitivity" economically selects significantly more solar in the early years of the Carbon Plan, adding solar up to the interconnection limit in five of the first six years solar is eligible for selection ahead of the targeted compliance year. Id., 265. Duke's direct testimony does not include any analysis of the cost impacts of the portfolio changes resulting in the High Solar Sensitivity.

In direct testimony, CPSA witness Ryan Watts points out several issues with Duke's limits on solar interconnection. Primarily, Watts believes that Duke's Carbon Plan is "questionable" because of a lack of "demonstrable evidence of their claimed limitations to integration of solar resources[.]" Tr. vol. 23, 277. In response to Duke's claim that the unknown size of future solar projects contributes to the limitation on solar interconnection in its modeling, Witness Watts argues that while some transmission upgrades may be needed to accommodate larger projects, "uncertainty is an inherent feature" of transmission planning and is not "a basis for slowing down interconnection rates." *Id.* at 280. Likewise, finite interconnection resource availability "stresses the importance of utilizing" those resources efficiently and should not be used as an excuse to limit solar interconnection. *Id.* at 283. Siding with the Public Staff, Witness Watts agrees that reliance on Duke's historic interconnection is not appropriate when forecasting future interconnection. *Id.* at 284. Several recent changes could lead to significant improvements in interconnection rates including "significant increase in project size and shift from distribution to transmission interconnection; the implementation of queue reform; and a shift . . . to a more proactive approach" to transmission planning. *Id.* at 285. Witness Watts also believes that allowing self-builds and the deployment of temporary transmission lines (referred to as shooflies) would help decrease the time needed for outages and increase the rate of solar interconnection. *Id*. at 282-83.

CPSA witness Tyler Norris criticizes Duke's solar interconnection caps saying they are "imprudent and inconsistent with the requirements of H.B. 951" because they are focused on "setting a *limit* to how much [Duke] will model . . . rather than a *goal* for how much solar it will try to interconnect[.]" Tr. vol. 26, 30 (emphasis in original) Witness Norris argues that a more "ambitious" approach to solar interconnection will ultimately save ratepayers money by avoiding "higher cost resources that will benefit Duke's shareholders at the expense of customers." *Id.* at 43. And while Witness Norris concedes that there is a "possibility of solar project costs declining" that risk "is not significant enough for it to be prudent to delay" solar procurement. *Id.* at 44.

Witness Norris testified that lutimately, Duke's strict limits on solar interconnection will make it unlikely to achieve interim compliance by 2030 or even by 2032, increase the likelihood that higher risk and higher cost resources will be relied upon, increase execution risk, and lessen the opportunity for performance improvement from historic levels. *Id.* at 39. To ensure that Duke takes the necessary steps to maximize annual interconnection rates, Norris and CPSA urge the Commission to order Duke to retain "an independent technical review committee" as it did with the Solar Integration Services Charge (SISC). *Id.* at 45 (citing Order Establishing Standard Rates and Contract Terms For Qualifying Facilities, Docket No. E-100, Sub 158 (Apr. 15, 2020) at 95). Acting now, Duke would have ample time to employ the review committee and receive results of the review prior to the 2024 Carbon Plan update. *Id.* at 46. Based on those results, it may also be appropriate for "a qualified independent monitor to regularly report back" to the Commission on "interconnection activities and progress" of the Carbon Plan. *Id.* at 46.

CPSA witness Michael Hagerty, who conducted CPSA's alternative models, testifies that increasing the solar interconnection limit will reduce costs to ratepayers. Tr. vol. 25, 452. These savings occur because solar additions avoid the need for higher cost alternative resources such as offshore wind and SMRs. Solar also reduces the need for "higher operating cost but lower emitting" resources like natural gas-fired resources. *Id.* at 452. In fact, "Duke's own analysis shows" that higher solar interconnection reduces costs to ratepayers. *Id.* at 452. Duke's SP5 High Solar Interconnection Sensitivity shows that average savings could be as high as $40 million per year as compared to P5. *Id.* at 432.

In its rebuttal testimony, Duke's Transmission and Solar Procurement Panel testifies that CPSA fails to include "the specific considerations of [Duke's] systems and interconnection procedures." Tr. vol. 28,143-144. The Panel also argues that Duke's interconnection caps are reasonable because CPSA's claims are based on Duke being able to improve on its historic interconnections. *Id.* at 144. Those historic numbers, however, are based on projects that "were distribution level connections" which are simpler connections than will be required to reach compliance with H.B. 951. *Id.* at 144. Not only are the distribution level connections simpler they also require less time than transmission level projects (less than a year versus 26-32 months). *Id.* at 144. Transmission line outages are significant reason for the delay on solar interconnections on transmission level projects. *Id.* at 145. The Transmission Panel maintains that Duke has set a "reasonable but aggressive target" for solar interconnections in its portfolios. *Id.* at 145.

In its testimony Duke does not object to CPSA's recommendation to commission a third party to review the achievability of Duke's solar interconnection rates. Rather, it emphasizes certain prior and planned steps by the company to increase interconnection efficiencies. Tr. vol. 16,87-88. Duke also emphasizes that "the Companies understand that the interconnection of sufficient volumes of solar is critical to execute the Carbon Plan[.]" *Id.* at 88. Witness Roberts elaborated during cross examination that the Company would like to further develop its interconnection process improvements and present that to stakeholders. *Id.* at 186.

Duke's witness Kendal Bowman testifies on cross examination that the rate of solar interconnection is the most contested issue with respect to Duke's near-term plans. Tr. vol. 7, 145.

On cross-examination and Commissioner Questions, Duke witness Matthew Kalemba confirmed that Duke's interconnection caps are not based "specific underlying calculations" but instead rely on "engineering judgment and experience." Tr. vol. 8,125. Glen Snider of the Modeling and Near-Term Actions Panel acknowledged that in each model once the solar cap is reached the model will have to select another, higher-cost resource. *Id.* at 74. As a result, constrained portfolios are typically more expensive than unconstrained portfolios. *Id.* at 75. Duke's witness Michael Quinto also testified during cross-examination that in

Portfolio 1 (P1), the only one of Duke's portfolios to achieve interim compliance by 2030, hit the solar interconnection limit each year. *Id.* at 76. However, Duke did not run any sensitivities on portfolios P1-P4 to see how much more solar would have been selected with a higher interconnection cap. *Id.* at 77- 78. And although Duke (at CPSA's request) performed a sensitivity on analysis on supplemental portfolio P5 with a higher solar interconnection limit, it did not conduct any PVRR analysis to determine how a higher solar interconnection cap might impact revenue requirements. In fact, Witness Snider conceded that Duke had not performed <u>any</u> analysis whatsoever to determine how achieving higher solar interconnection rates might impact the costs of Carbon Plan compliance. *Id.* at 79. Witness Quinto conceded, however, that higher solar interconnection limits would likely reduce costs *Id.* at 90.

Discussion and conclusions

Based on the foregoing and the record, the Commission finds that Duke's approach to the real-world constraints on its ability to interconnect solar and other resources is unreasonable, for several reasons. As discussed below, rather than constraining solar additions in all of its portfolios and the near-term execution plan based on the company's "most reasonable forecast" of its future interconnection rates, Duke should (1) conduct modeling to determine what cost savings could be achieved with higher interconnection rates; (2) take definitive steps to explore options for increasing interconnection rates; and (3) set near-term procurement volumes based on more aggressive solar interconnection goals.

Modeling conducted by Brattle and introduced in the comments of CPSA and the testimony of Witness Hagerty amply demonstrate that limitations on solar interconnection rates not only make timely compliance with the 70% reduction mandate more difficult, but also increase costs to ratepayers. Duke does not dispute that higher interconnection rates, if achievable, would lower costs to ratepayers and make timely compliance more difficult. Duke does not contend that higher interconnection rates would be impossible to achieve, but claims that they more execution risk than is reasonable.

Duke's argument concerning execution risk is unpersuasive. In this context, the only "execution risk" posed by modeling higher solar interconnection rates is the risk that those rates will not be achieved and compliance with carbon reduction requirements would be delayed. However, if the alternative is to <u>deliberately</u> delay compliance (e.g., by planning to achieve compliance in 2032 instead of 2030), the risk is illusory. As long as Duke does not forego development of other resources in reliance on achieving higher solar interconnection rates (which no party suggests it should), ratepayers are no worse off if Duke tries and fails to achieve higher interconnection rates than if it never tried at all.

In any event, the Commission does not believe that Duke has sufficiently justified its solar interconnection constraint. One of the primary justifications articulated by Duke for the Solar Interconnection Constraint is the need to construct major transmission upgrades (such as the RZEP) to relieve congestion on its network. No party contested the need for major transmission upgrades. However, Duke's own studies show that construction of the RZEP will be sufficient to enable the connection of more than 3.6 GW of additional solar resources in the Red Zone alone (although some additional, smaller upgrades may also be required). Tr. vol. 8,134, 138; Tr. vol. 16,160-161. And those upgrades are designed to provide "headroom" to interconnect additional solar beyond that volume, although Duke could not say how much. Tr. vol. 16, 162-163. This is well in excess of the 3.1 GW of solar Duke proposes to add via procurement in 2022, 2023, and 2024. Those upgrades, if approved by the NCTPC, will almost all be completed by the end of 2026, the target interconnection year for the 2022 SP. Tr. vol. 16, 163-164; CPSA Modeling Panel Direct Cross Examination Ex. 1.

Duke's testimony that it could likely interconnect 14-15 transmission scale projects "in the near term" also undermines its claimed Solar Interconnection Constraint. As Mr. Roberts acknowledged at the hearing, based on the size of projects in the current DISIS study, 15 interconnections could equate to anywhere from 1260 to 1838 MW of solar capacity in a single year. Tr. vol. 28, 192. Although this testimony does not demonstrate unequivocally that such interconnection rates will be obtained, it does suggest that they are potentially achievable.

The Commission also finds persuasive the testimony of CPSA Witness Watts, who described measures that Duke could take to accelerate interconnections, including the use of shooflies to reduce the need for outages, and allowing state-jurisdictional interconnection customers to self-build Standalone Upgrades and Interconnection Facilities, as FERC-jurisdictional customers can (thus easing the strain on Duke's limited interconnection resources). Tr. vol. 23, 282-83. Duke did not attempt to rebut Mr. Watts' testimony about the use of shooflies; and at the hearing Duke Witness Roberts acknowledged that state-jurisdictional customers could be permitted to self-build Standalone Upgrades and Interconnection Facilities without undermining reliability. Tr. vol. 28,189-90. ("Q. So I take it from your testimony that you agree that interconnection customer construction of standalone network upgrades does not put the system at reliability risk? A. Right.")

Uncertainty about future interconnections is unavoidable because the rate of interconnection will depend on a variety of unknown factors, including but not limited to the location and size of generating facilities seeking to interconnect; the approval and construction of major transmission upgrades; and Duke's own efforts to expedite interconnection processes. Duke witness Kalemba acknowledges (and other Duke witnesses agree) that the Solar Interconnection Constraint represents no more than Duke's "most reasonable forecast" of its future interconnection rates. Witness Kalemba acknowledges that the Solar Interconnection Constraint, like any forecast, may be "too low or too high." Tr. vol. 8, 129. The Public Staff also acknowledges that the Solar Interconnection Constraint is simply a forecast. Tr. vol. 21, 313.

Fortunately, the Commission is not called upon to resolve that uncertainty now, or even to decide whose forecast of future interconnections (Duke's, CPSA's, or some other party's) is most reasonable. Rather, the Commission must decide how best to proceed in the face of that uncertainty. In so doing the Commission must weigh the risks and benefits of the parties' proposed approaches.

The Commission is persuaded that CPSA's proposed approach of setting an ambitious goal for solar interconnection, rather than a more modest cap as Duke and the Public Staff suggest, is the more prudent approach. Analysis conducted by the Brattle Group and presented by CPSA witness Hagerty (which was not challenged or refuted by Duke or by any other party) shows that achieving higher interconnection rates than Duke forecasts has the potential to reduce costs to ratepayers by hundreds of millions of dollars on an annual basis, by allowing lower-cost carbon-free resources to be deployed. It follows that if Duke is only able to achieve lower interconnection rates – or does not attempt to achieve higher rates – this will increase the costs of compliance or delay compliance with the 70% reduction requirement (or both). Duke does not dispute this. (Even in supplemental modeling in which it prepared a sensitivity analysis looking at higher interconnection rates, Duke did not conduct any of its own analysis to consider the impacts of higher or lower interconnection rates.)

In addition to potentially reducing costs, higher levels of solar adoption would (if achieved) mitigate the risk that other new carbon-free resources relied on in the carbon plan (e.g. onshore and offshore wind and SMRs) may come online later than expected, may not be available in the volumes modeled by Duke, or may cost more than expected. Duke acknowledges that its goals for deployment of all carbon-free resources are ambitious; onshore wind and SMRs in particular face strong headwinds that will make deployment on the schedule assumed by Duke challenging. Tr. vol. 7, 359. Consistent with the "all of the above" strategy touted by Duke, the utility should set ambitious goals for deployment of all of these resources, with the understanding that some resources are likely to be delayed or more costly than expected.

N.C.G.S. § 62-110.9 requires this Commission to "take all reasonable steps" to achieve compliance with the 70% reduction mandate by 2030, and to establish a least cost path for achieving those goals. G.S. 62-110.9. As Duke witness Bowman acknowledges (Tr. vol. 7, 100), it follows that Duke must explore all reasonable avenues for mitigating the cost of compliance with N.C.G.S. § 62-110.9. The Public Staff also agrees that if there is the potential to achieve greater ratepayer savings, the Commission should be investigating whether Duke can achieve higher solar interconnection rates. Tr. vol. 21, 371.

While it is possible that Duke ultimately will not be capable of interconnecting new projects more quickly than its forecast, that is far from certain. And if the utility is able to exceed its modest expectations with regard to interconnection, modeling shows that this is likely to result in significant savings for ratepayers. It would be unreasonable to pass up this opportunity[5].

<u>Promoting improvement in interconnection rates</u>

Due to the complex nature of interconnection related issues within utility operations, and the magnitude of potential cost savings for customers if Duke's assumed rate of solar interconnections can be improved upon, the Commission agrees with CPSA that an independent technical review committee should be initiated to review current interconnection practices within Duke and to document

[5] As discussed further below in relation to the procurement goals in the Near-Term Execution Plan, the Commission is not persuaded that setting more ambitious interconnection goals will expose ratepayers to meaningful risks if those goals cannot be achieved.

any recommended improvements within a report to be filed with this Commission prior to the 2024 Carbon Plan update.

There is general agreement among the parties that Duke and this Commission should explore every reasonable avenue for reducing the costs of compliance with H.B. 951. It is also undisputed that real-world limitations on the rate at which new generation can be interconnected not only increase costs, but are a significant source of interconnection risk across all portfolios.

The Commission commends Duke for initiating internal "process improvements" to improve interconnection performance. However, due to the complex and often contentious nature of interconnection related issues, and the magnitude of potential cost savings for customers if Duke's assumed rate of solar interconnections can be improved upon, the Commission agrees with CPSA that an independent technical review of Duke's interconnection practices is reasonable. The potential benefits to ratepayers have already been addressed; however, the Commission concludes that it would benefit from the results of an independent assessment to inform future Carbon Plan proceedings where similar issues will be reviewed. In its response to CPSA's comments and testimony, Duke does not oppose CPSA's recommendation.

Therefore, the Commission concludes that an independent technical review committee should be engaged to review current interconnection practices within Duke, consider steps that can be taken to improve the rate of interconnection, and to document any recommended improvements within a report to be filed with this Commission prior to the 2024 Carbon Plan update. The creation of an independent technical review committee will complement the ongoing efforts at Duke to create additional efficiencies in the interconnection process and will assist this Commission in future considerations related to this highly complex and consequential issue, and that no substantive objection to this proposal exists in the record. This directive is also consistent with the Public Staff's recommendation that "The Commission should direct Duke to take all reasonable steps to streamline its interconnection processes" in order to meet the 70% reduction mandate. Tr. vol. 21, 42.

The technical review committee shall be constituted of individuals, not otherwise affiliated with Duke or any of its affiliates or organizations in which Duke is a member, who have technical expertise, knowledge, and experience related to the integration of solar generation as well as the development of complex research, development, and modeling. The review committee shall include a representative of the Public Staff, as well as at least one technically qualified representative designated by independent developers of renewable generation.

The technical review committee shall consider the following issues, as well as any others it deems relevant to assessing and improving Duke's interconnection performance:

- Use of temporary lines or "shooflies" to reduce the need for line outages
- Authorizing state-jurisdictional customers to self-build interconnection facilities and standalone upgrades;
- The potential for grid enhancing technologies, such as dynamic line ratings, topology optimization, and advanced power flow control, which have the potential to reduce costs, enhance benefits, and expedite interconnection timelines; and
- Review of Duke interconnection study criteria to determine whether changes can be made that would reduce the need for Upgrades without undermining reliability.

The technical review committee should provide specific comments or feedback to Duke in the form of a report, which report is to be included in the initial filing made in Duke's next Carbon Plan filing.

It is striking that, notwithstanding its obligation to find the least cost path to compliance, Duke conducted no modeling or analysis to determine what the cost impacts of its modeled interconnection constraint.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 21-29
SOLAR PROCUREMENT
(Scheduling Order ordering paragraph 1.c.)

Summary of the evidence

Carbon Plan

In its proposed Carbon Plan, Duke proposes to procure 3100 MW of new solar in 2022-2024 with targeted in-service dates of 2026-2028, with a portion of the procurement for 2023 and 2024 assumed to include paired storage. Carbon Plan Ch. 4, 5. As required by H.B. 951, 45% of procured solar capacity would come from third-party power purchase agreements (PPAs) and 55% would come from utility-owned projects, which could be procured in several ways. *Id.* at 12-13.

The proposed year-by-year target volumes for solar procurement during the NTEP are as follows:

Year	Target Volume	Target In-service date
2022	750 MW	2026
2023	1000 MW	2027
2024	1350 MW	2028

Duke Carbon Plan at 17. The procurement target for each year is exactly equivalent to the amount of solar added in Duke's P1 portfolio four years later. As such, the procurement targets are equivalent to Duke's modeled Solar

Interconnection Constraint for the targeted in-service year. *Id* at 16.

The Companies' proposed Carbon Plan also states that the 2022 solar procurement (2022 SP) program design includes a volume adjustment mechanism (VAM) to mitigate pricing risk if bid prices exceed 110% of the Carbon Plan's assumed solar cost and to enable up to 20% more solar to be procured if bid prices are 10% below the Carbon Plan's assumed solar cost. *Id*.

Intervenor Comments

In its comments, CPSA argues strenuously that in order to preserve ability to execute a least-cost portfolio that achieves compliance with the 70% carbon reduction mandate by 2030, it is essential that the NTEP call for substantially more solar procurement than has been proposed by Duke. CPSA Comments at 3. CPSA proposes that the NTEP should be revised to include solar procurements of 1500 MW in 2022 and 2023, and 1800 MW in 2024. *Id.* at 6. In addition, 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. *Id.*

As discussed above, in its Comments CPSA takes issue with the Solar Interconnection Constraint that drives Duke's proposed procurement targets. *Id.* at 15-19. CPSA also takes issue with Duke's decision to key its proposed 2022 procurement volume (750 MW) to the amount of solar Duke's Carbon Plan portfolios add in 2026. Even assuming those solar addition amounts are reasonable, Duke acknowledges that 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. *Id.* at 52.

With respect to near-term procurement, CPSA argues that 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. *Id.* at 20.

CPSA notes that 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 it is certain that this 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. *Id.* at 21. However, this assumption is not reasonable and does not provide a sufficient basis to delay procurement of solar resources. While it is uncertain whether module prices will rise or fall over the next several years, 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.

Id. at 53-54. Any "over-payment risk" associated with earlier procurement of solar is counterbalanced both by the risks that solar costs will in fact rise, and by the possibility that delaying procurement will force Duke to rely on higher-cost resources to achieve compliance. *Id.*

The procurement targets proposed by CPSA for 2022-2024 support the portfolios modeled by Brattle (CPSA2-5) and described in CPSA's comments. CPSA Comments, 50. CPSA discusses why these procurement levels are reasonable and achievable when compared to past Duke procurements, as well as procurements underway in other jurisdictions. *Id.* at 51.

CPSA's comments also include a geographic analysis of potential solar project combinations and locations that might achieve approximately 1800 MW in aggregate annual solar capacity additions across DEP and DEC. CPSA Comments at 50 and Ex. D. 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.

Duke Direct Testimony

In its direct testimony, Duke's Modeling and Near-Term Actions Panel (Modeling Panel) requests that the Commission affirm the target procurement volumes presented in the Carbon Plan. Tr. vol. 7, 213. The Modeling Panel asserts that the supplemental modeling performed by Duke after submittal of the Carbon Plan supports those targeted procurement volumes (with the addition of 441 MW of additional capacity to meet Duke's outstanding CPRE obligation, as discussed below). *Id*. at 267.

Duke Witness Kalemba discusses the fact that Duke's Carbon Plan modeling assumed Duke would successfully procure the entire volume of solar resources required in the Competitive Procurement of Renewable Energy (CPRE) program authorized under N.C. H.B. 589. *Id*. at 269. However, Witness Kalemba testifies that the Companies must procure an additional 441 MW of solar capacity (the CPRE Program Remainder) to meet its obligations under the CPRE program, and to bring Duke's solar capacity to the baseline assumed by Duke's modeling. Witness Kalemba states that Duke proposes to add the CPRE Program Remainder to the proposed procurement target for 2022, bringing the total target to 1200 MW. *Id.* at 366.

Duke's Modeling Panel testifies that relying on higher levels of solar interconnections will increase execution risk. *Id*. at 383. The panel further 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. *Id*. at 360. It also asserts that "the solar interconnection constraints will evolve as more information becomes known through the current 2022 Solar Procurement, as well as future procurements." *Id.*

Witness Farver on Duke's Transmission and Panel provides testimony about the market response to the 2022 SP. Witness Farver testifies that more than 5000 MW of proposals have been received for the 2022 SP, over 70% of which (from the standpoint of MW) is located in known red-zone areas. Tr. vol. 16, 81.

Intervenor Direct Testimony

CPSA

CPSA Witness Hagerty testifies that Duke's supplemental modeling runs, specifically SP5 and SP5 High Solar Interconnection, select more solar resources compared to Duke's P2 portfolio (the other portfolio modeled by Duke to achieve 70% compliance in 2032), and support CPSA's recommendations on higher near-term solar procurement. Tr. vol. 25, 432. 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. *Id*.

CPSA Witness Norris criticizes Duke's approach to establishing a 2022 solar procurement target based on the solar additions called for in 2026 in Duke's P1 portfolio. Tr. Vol. 26, 48-49. Witness Norris states that even if the Solar Interconnection Constraint were justified, near-term solar procurement volumes should be determined independently of the forecasted solar interconnection constraints for 2026-2028.

Witness Norris also testifies that Duke's proposed solar procurement volumes do not actually support achievement of Duke's P1 portfolio, and are inconsistent with achieving 70% compliance in 2030, even if all the assumptions about other resources made in P1 are borne out. *Id.* at 49. Witness Norris explains that P1 requires a total of 5400 MW of solar to be online by the beginning of 2030 to achieve compliance. If Duke procures only 3,100 MW in 2022-2024 (as proposed in the Carbon Plan), Duke would have to procure at least 2,300 MW of additional solar in 2025 alone, and achieve an annual solar interconnection rate of

2,300 MW in 2029, in order to ensure that 5,400 MW of solar is online by early 2030. *Id.* at 49-50. Witness Norris further testifies that the least-cost scenario for 2032 modeled by Brattle for CPSA (which call for the additions of more solar than Duke's portfolios) would be extremely difficult to achieve with the low near-term procurement targets proposed by Duke.

Witness Norris provides testimony concerning the benefits of ambitious near-term procurement of solar and solar-plus-storage facilities, which are the most mature, affordable, and scalable zero-carbon resources available to Duke's system for purposes of compliance with H.B. 951. These benefits include: (1) decreasing solar execution risk; (2) mitigating the risk of network upgrade delays and rising costs; (3) better enabling assessment of interconnection limits; (4) reducing the need to rely on higher cost alternative resources with greater execution risk; (5) mitigating the risk of higher electricity load; and (6) accounting for project attrition in procurements. *Id.* 56-61.

Witness Norris clarifies that higher near-term solar procurement would not adversely affect the development of alternative carbon-free resources, as authorized by the Commission. *Id.* at 61. Witness Norris also rebuts Duke's argument that larger initial procurement targets may cause ratepayers to lose the opportunity to capture additional savings if solar or solar-plus-storage costs decline more quickly than forecasted for projects procured after 2024. *Id.* At 53. Witness Norris testifies that based on NREL conservative cost projections, it is just as likely that costs will increase as decrease. In addition, he rebuts Duke's speculation that "accelerating solar deployments based on today's technologies could crowd out future, unknown solar or other technologies that are more efficient or more cost-effective than today's solar." *Id.* at 55. (citing Modeling Panel Direct Testimony at 168). Witness Norris explains that crystalline silicon will remain the dominant technology for U.S. utility-scale solar PV projects through the 2020's, and it is highly unlikely that an unforeseen solar technology will emerge at commercial scale in this timeframe that results in a significant impact on NREL's cost forecast. *Id.*

Witness Norris provides CPSA's response to incorporating the CPRE shortfall into the 2022 SP. Witness Norris testifies that although CPSA supports Duke's proposal in concept, given the limited information provided by Duke, "it is impossible even to guess whether the proposal would actually result in any signed [CPRE] contracts." *Id.* at 62.. If the Commission elects to take action on Duke's proposal in this docket, CPSA recommends that any approval be contingent upon: (1) "upsizing" the target procurement to account for expected attrition; and (2) providing some assurances that there are sufficient bids that may fall under avoided cost, after consideration of any network upgrade costs. *Id.* at 63.

AGO

AGO Witness Mr. Burgess testifies that he believes, based on modeling conducted by Synapse, that there is a sufficient basis to move forward with a minimum amount of solar, storage, and onshore wind procurements, which he characterizes as "a 'no regrets' strategy for any Carbon Plan." Tr. Vol. 7, 293, 295. Witness Burgess testifies (and clarified on cross-examination) that the 3,100 MW of solar procurement recommended by Duke represents a minimum, "no regrets" procurement volume. *Id.* at 296. He goes on to state that because of cost decreases due to the IRA, even greater quantities of solar, storage and wind procurements may be warranted. *Id.*.

CLEAN Intervenors

CLEAN Intervenors Witness Fitch recommends, based on his modeling, that Duke begin procurement of 4 GW of new solar in 2022-2024 with target in-service dates of 2025-2028. Tr. vol. 24, 178. Witness Fitch also recommends that in order to achieve compliance by 2030, Duke develop at least 1 GW of distributed energy resources by 2035; procure 900 MW of onshore wind and 800 MW of offshore wind by 2030; and import 2500 MW of onshore wind from the Midwest by 2030. *Id.*

Public Staff

In direct testimony, Public Staff Witness Thomas questioned why Duke did not modify its proposed near-term procurement activities as a result of supplemental modeling results, stating that "the Public Staff is concerned that near-term procurement activities are insufficient to meet the resource procurement needs identified by the results of SP5 in order to comply with Section 110.9." Tr. vol. 21, 90-91.

Witness Thomas testifies that in his view, the amount of solar Duke proposes to procure in the NTEP (3100 MW) is generally aligned with the amounts of solar to be added by 2030 in portfolios P3 and P4 – both of which do not achieve compliance with the 70% mandate until 2034. *Id.* at 91. In order to support supplemental portfolio SP5 (which achieves compliance in 2032), 4250 MW of solar would need to be procured during the NTEP. *Id.*

In direct testimony that was subsequently amended at the hearing, Witness Thomas responds to Duke's proposal to procure remaining CPRE capacity in the 2022 SP. Witness Thomas recommends that the Commission approve Duke's request to procure a portion of the CPRE shortfall through a CPRE set-aside "and include those megawatts in determining whether the volumetric adjustment mechanism is triggered in the 2022 solar procurement." Tr. vol. 21, 23-25. This recommendation is based in part on the fact that capacity consisting entirely of third-party PPAs at below avoided cost are likely to be less expensive for ratepayers than the 45% PPA / 55% utility-owned solar capacity otherwise required by H.B. 951. *Id*. Witness Thomas also states that because "the CPRE projects that have withdrawn to create the CPRE shortfall have primarily been located in DEC's territory; the Public Staff would therefore expect at least some portion of the 2022 Solar Procurement to be procured in DEC." *Id.* at 68.

With respect to the 2022 procurement target, Witness Thomas notes that dividing the 4250 MW required under SP5 by four procurements and adding the 441 MW CPRE shortfall "yields a 2022 Solar Procurement volume of approximately 1,500 MW." *Id.* at 67. Alternatively, Witness Thomas notes that only 22% of the near-term solar identified by SP5 (950 MW) is standalone solar, while the entire 441 MW CPRE shortfall is standalone solar. Adding these two capacities together for the 2022 SP (which is seeking only standalone solar) yields a volume of approximately 1400 MW. *Id.* at 68.

Despite these recommendations, Witness Thomas recommends that the

Commission approve a 2022 SP target volume of 1200 MW. The Public Staff does not include recommended procurement volumes for 2023 or 2024.

Duke rebuttal Testimony

On rebuttal, Duke's Modeling Panel notes that intervenors advance a variety of proposals for near-term solar procurement. Tr. vol. 27, 37. Duke characterizes CPSA's and others' more ambitious solar procurement targets as "overly-aggressive," and states that "Over-procuring solar through even larger initial procurements than planned creates increased cost risk and execution risk for the Companies and customers and is not a reasonable step." *Id.* at 37, 46.

Witness Snider claims that Duke's proposed solar procurement target volumes are consistent with achieving compliance in 2030, because the volume adjustment mechanism approved by the Commission for the 2022 SP (and potentially similar mechanisms in later procurement) could allow for those target volumes to be increased, if solar bid pricing comes in lower than expected. *Id.* at 59.

Witness Snider also asserts that "over-procurement" of solar resources carries risk for customers: specifically, the risk of "losing out" on technology maturation and development that would be captured by later procurements. *Id.* at 61. Witness Snider also asserts that if procurements exceed Duke's annual interconnection capability, this will "extend[] the period of time between when the PPA is executed and when the facility actually begins delivering energy to customers," which "leads to increasing risk for customers that the value of the solar being delivered does not reflect the price accepted many years prior." *Id.* at 63.

Witness Snider does not explain, however, why a deviation between price and "value" (however that may be defined) is problematic for customers.

Hearing Testimony

At the hearing, Duke's witnesses acknowledged that for a near-term execution plan to be reasonable, it must actually support the achievement of the portfolios included in the Carbon Plan. Duke acknowledges this see, e.g., Tr. vol. 7,101; Vol. 8,102.

Witness Quinto acknowledged that in procurements to date, there has been significant attrition of projects after selection. Tr. vol. 8, 93-94.

In response to cross-examination questions about the degree to which Duke's solar procurement targets actually support P1, Witness Snider acknowledged that Duke's procurement targets are only "generally aligned" with P1, and that they would support that portfolio only if the Volume Adjustment Mechanism (or Commission discretion) acted to "flex those volumes" upward to meet P1 requirements. Tr. vol. 8, 111-112.

In response to questions about Duke's claim that by procuring more solar earlier, the utility could be missing out on future technological advances, Witness Snider could not identify any coming technological advance with respect to solar that is not already in use in the Carolinas. Tr. vol. 12, 53, 55.

At the hearing, Duke's modeling panel also described (for the first time) their concern that by setting larger procurement targets, Duke would have to accept less-competitive bids in each procurement. [*cite]

With regard to the 2022 SP that is already underway, Duke Witness Farver stated that the company had received approximately 3500 MW of bids in the Red Zone alone. Tr. vol. 16, 172. However, Witness Farver declined to provide any information about the pricing of bids received (even in the aggregate), stating that it was confidential. *Id.* at 175.

At the hearing, Public Staff witness Thomas stated that, in the Public Staff's view, near-term procurement targets must be established based on a balance of cost, execution, reliability, and carbon reduction. Tr. vol. 21, 310-311.

Witness Thomas also stated his view that it would be appropriate for Duke to take on greater execution risk related to solar interconnection if that creates opportunities for ratepayer savings. Tr. vol. 21, 311.

On cross examination, Witness Thomas acknowledged that the proposed NTEP is not consistent with compliance in 2030, but puts Duke on a path towards compliance "no later than <u>2032.</u>" Tr. vol. 21, 292-294.

With respect to the Volume Adjustment Mechanism, Witness Thomas confirmed that, based on the Public Staff's modeling, even if solar prices were 30% less than the Solar Reference Cost, this would not affect the amount of solar selected by the model. Tr. vol. 21,308-309. Nor would a 10% upward change in the cost of solar change the amount selected, because in either case the model selects the maximum amount of solar allowable under the Solar Interconnection Constraint. *Id*.

CPSA witness Norris testified extensively at the hearing concerning the potential benefits of more ambitious procurement goals and the potential risks of "over-procurement," and explained his view that the potential benefits substantially outweigh the risks. Tr. vol. 26, 143-44. However, “procrastinating on procurement” – setting low procurement and interconnection targets in early years – will increase execution risk, by increasing the rate of interconnection required in later years to meet carbon reduction targets. *Id.* at 151-152.

With respect to Duke’s concerns about solar over-procurement, Witness Norris noted that under current contracting structures (including in the RFP), bidders bear all of the financial risk that project construction will be delayed by interconnection, and that bidders have very strong financial incentives not to withdraw their projects based on such delays, because they will be liable for millions of dollars in liquidated damages if they do. Tr. vol. 26, 86-87. The primary risk of delayed interconnection of solar resources, Witness Norris testified, is simply that compliance will be delayed. The primary economic risk to ratepayers is that solar resources will not be available and that Duke will have to rely on higher-priced non-solar resources to meet carbon reduction requirements. *Id.* at 103-104, 108.

Witness Norris, a solar developer, also confirmed that solar photovoltaic generation is a “mature technology” and that there are no technological advances on the horizon that might result in substantial cost reductions over the near term. Tr. vol. 26, 154. Witness Norris also noted that the risk of over-payment is much less for mature technologies like solar PV than it is for emergent technologies like SMRs or offshore wind. *Id.* at 118-119.

Discussion and conclusions

Based on the foregoing and the record, the Commission finds and concludes that the target solar procurement volumes proposed by Duke in the Carbon Plan and in testimony are unreasonably low and inconsistent with the goals and requirements of H.B. 951. The Commission concludes instead that it is appropriate and reasonable to set more aggressive near-term procurement target volumes for solar and solar plus storage resources during the NTEP. Specifically, the Commission concludes that the following target volumes for the procurement of solar and solar plus storage resources are appropriate during the NTEP: 1647 MW in 2022, 1647 MW in 2023, and 1947 MW in 2024.

These target procurement volumes correspond approximately to the total procurement volume recommended by CPSA for the 2022-2024 procurements (4800 MW), plus the 441 MW CPRE shortfall (a total of 5241 MW). The Commission concludes that it is appropriate set a higher procurement target in 2024, to allow for implementation of steps (including the construction of transmission upgrades) that will facilitate the interconnection of higher volumes of solar in later years.

<u>Duke's proposed procurement targets are unreasonably low.</u>

As discussed above, H.B. 951 requires that Duke at least attempt to meet the 70% carbon reduction requirement by 2030, unless and until it can be demonstrated that timely compliance is either impossible or unreasonable. No such demonstration has been made, and there is no reason to give up on timely compliance in the initial Carbon Plan.[1] The need to include additional portfolios that achieve compliance by 2030 is discussed above.

For a near-term execution plan to be reasonable, it must actually support the achievement of the portfolios included in the Carbon Plan. Duke acknowledges this. see, e.g., Tr. vol. 7,101; vol. 8,102. Nevertheless, Duke's proposed procurement targets for the NTEP are insufficient even to support its sole 2030 compliance portfolio (P1). As Witness Norris explains in his testimony, P1 requires the addition of 5400 MW of solar capacity (plus the CPRE shortfall) by the beginning of 2030. Tr. vol. 26, 144) In addition, in order to achieve compliance in 2030, Duke's P1 portfolio requires the deployment not only of the 5400 MW represented in the Carbon Plan by the beginning of 2030, but of approximately 700 additional MW of solar by mid-year 2030. *Id.* at 144-145. So the total volume of solar required to achieve timely compliance in P1 is actually closer to 6100 MW – to which 441 MW of additional solar capacity will need to be added due to the CPRE shortfall.

Duke's proposed procurement volumes, however, only target the addition of 3100 MW of solar by the beginning of 2029 (at the earliest), requiring 2300 MW to be added in 2029 to reach 5400 MW – far above Duke's modeled Solar Interconnection Constraint, and well in excess of what any party claims can be interconnected in a single year. Tr. vol. 16, 161. In other words, if the Commission were to approve Duke's proposed procurement volumes, it would almost ensure that the company would be unable to comply by 2030. The almost inevitable attrition of projects that are selected in RFPs (which Witness Quinto acknowledges, and which has been a significant factor in the CPRE process) makes compliance with Duke's procurement targets even less likely. Tr. vol. 8, 93-94.

For the same reasons, the Public Staff's recommendation that the Commission approve 4250 MW of solar procurement in the near-term action plan (to which 440 MW of additional solar would need to be added due to the CPRE shortfall) (Tr. vol. 21, 91) is inadequate to achieve compliance in 2030. Witness Thomas acknowledges this, testifying at the hearing that the proposed NTEP puts Duke on a path towards compliance "no later than 2032." *Id*. at 292-294.

The Commission is not persuaded by Witness Snider's argument that Duke's procurement targets are "generally aligned" with P1 because the Commission "has discretion to flex those volumes" using the Volume Adjustment Mechanism or a similar method for increasing procurement above the targeted volume. Tr. vol. 8, 111-112. As authorized in the 2022 SP, the VAM results in an upward adjustment of procurement volume only if bids come in significantly below the price of solar assumed by Duke in its modeling (the Solar Reference Cost). However, Duke's modeling selected the volume of solar in P1 based on the assumption that solar would be procured at the Solar Reference Cost. Modeling conducted by the Public Staff confirms that even if solar prices were 30% less than the Solar Reference Cost, this would not affect the amount of solar selected by the model. Tr. vol. 21, 83, 308-309. Nor would a 10% upward change in the cost of solar change the amount selected, because in either case the model selects the maximum amount of solar allowable under the Solar Interconnection Constraint. *Id*. There is no reason to procure less solar than called for by Carbon Plan portfolios (and thus abandon the possibility of compliance in 2030) just because RFP bids aren't lower than Duke expects them to be.

Duke's procurement targets for 2022, 2023, and 2024 are also unreasonable because they rely on the modeled solar additions in P1 in 2026, 2027, and 2028, respectively. Those amounts are, in turn, based on Duke's modeled Solar Interconnection Constraint, which Duke (as discussed above) has failed to justify. As previously discussed, the Commission finds that it is unreasonable for Duke to cap solar additions based on its forecast of likely interconnection rates. It is more prudent to set an ambitious goal for solar interconnection, which not only increases the likelihood that Duke will be able to achieve compliance in 2030, but also has the potential to result in significant savings for ratepayers if additional solar deployments allow Duke to reduce reliance on more expensive carbon-free resources.

The Commission is also not persuaded by the Public Staff's recommendation that only 1200 MW of solar be procured in 2022. Tr. vol. 21, 97. The analytical basis for this recommendation is unclear: in his testimony, Mr. Thomas first provides analysis that supports a target of 1500 MW (*id.* at 95), then another analysis that yields 1400 MW (*id.* at 96), before recommending (without further explanation) 1200 MW of procurement in 2022 (*id.* at 97).

Although the Public Staff does not include recommended procurement volumes in 2023 or 2024, the Commission notes that a 1200 MW procurement in 2022 will not put Duke on a robust path to compliance in 2030. As discussed above, the NTEP must support all portfolios, including intervenor portfolios that achieve compliance in 2030.

<u>Benefits and risks of ambitious near-term solar procurement targets</u>

The Commission generally agrees with the Public Staff's view that in establishing near-term procurement goals, the Commission is called on to balance cost, execution, reliability, and carbon reduction. Tr. vol. 21, 310-311. The Commission also agrees with Public Staff witness Thomas that it is appropriate for Duke to take on greater execution risk related to solar interconnection if that creates opportunities for ratepayer savings. Tr. vol. 21, 311. Based on the record evidence, the Commission concludes that the target procurement volumes proposed by CPSA represent a reasonable balance of those factors.

As an initial matter, the Commission notes that every portfolio proposed by Duke or any other party in this docket includes the deployment of large volumes of solar, well in excess of the amount contemplated by any proposed near-term procurement target. So the question is not whether Duke may be procuring more solar than it can use in the near-term; rather the question is <u>when</u> Duke should be attempting to put that solar on its system.

The primary benefits of more ambitious early procurement targets – allowing for possibility of achieving timely compliance, and creating the potential for cost savings – are discussed above. The Commission also finds that establishing more ambitious procurement goals will actually test Duke's ability to achieve higher interconnection rates, and may mitigate the execution risk associated with other carbon-free resources, including onshore and offshore wind and SMRs.

The Commission finds that these benefits (actual and potential) far outweigh the supposed risks of "over-procurement" (i.e., procuring more solar than can be interconnected on an annual basis) cited by Duke.

The first of these is the possibility that by procuring more solar resources earlier, Duke will lose out on future declines in the cost of solar. Tr. vol. 27, 62-63. However, this is offset by the possibility that solar costs will increase, in which case it would be more expensive to delay procurement, not less. In any event, the magnitude of any potential cost changes (which Duke estimated to be less than ten percent either way) is far outweighed by the potential savings that could result from larger procurements. It would be imprudent indeed to hold out for the possibility of modest cost savings on solar if doing so results in Duke having to procure even more expensive resources.

The Commission also affords little weight to Duke's speculation that by procuring more solar earlier, the utility could be missing out on future technological advances. The Company's witnesses could not identify any coming technological advance with respect to solar that is not already in use in the Carolinas. Tr. vol. 12, 53, 55. Witness Norris, a solar developer, confirmed that solar photovoltaic generation is a "mature technology" and that there are no such technological advances on the horizon. Tr. vol. 26, 154. This concern is speculative.

The final concern articulated by Duke is that by setting larger procurement targets, Duke will necessarily have to accept less-competitive bids in each procurement. The Commission is not persuaded that this concern justifies reducing near-term procurement goals.

Duke did not discuss this concern in its prefiled testimony, but volunteered it for the first time at the hearing. As a result, other parties had no opportunity to conduct discovery or otherwise respond to this concern prior to the hearing. For this reason the Commission gives this concern less weight than it otherwise might if it had been raised at the appropriate time. The Commission further notes that Duke is the only party in possession of information – the actual bids received in the 2022 RFP – that would allow the Commission to understand just how significant this concern is, from an economic perspective. However, Duke has declined to provide this information to other parties or to the Commission.

In any event, Duke's concern is adequately addressed by the RFP's Volume Adjustment Mechanism. If increasing the procurement target were to increase the per-MW price of the procurement significantly over the solar costs modeled by Duke, the VAM would be triggered, and would reduce the size of the total procurement by up to 20%. This is, it should be noted, the whole purpose of the VAM.

The Commission also has reason to doubt that increasing the target procurement volume for 2022 from 1200 MW (as proposed by Duke) to 1647 MW (consistent with CPSA's recommendation) would result in meaningfully higher costs for ratepayers. The 2022 solar RFP received more than 5,000 MW of bids for a procurement that (at the time bidding closed) was only guaranteed to include 700 MW of capacity. Tr. vol. 16, 81. Given the very large volume of bidding relative to the announced target capacity, the Commission finds it reasonable to infer that bids were competitive, and increasing the target volume as proposed by CPSA would not meaningfully increase costs.

It is not possible to predict with any degree of certainty whether accelerating solar procurement or delaying it will result in that solar capacity being procured at a lower cost. But it is clear that delaying procurement will materially increase the risk that Duke will not achieve timely compliance with the 70% carbon reduction mandate, and may significantly increase costs to ratepayers by forcing reliance on more expensive carbon-free resources.

CPSA procurement recommendation

Balancing the obligation to achieve timely compliance with H.B. 951, the potential cost savings for ratepayers, and the other risks and benefits of more and less aggressive procurement targets, the Commission concludes that the following procurement targets are reasonable during the NTEP: 1647 MW in 2022, 1647 MW in 2023, and 1947 in 2024. These amounts are equal to CPSA's recommended procurement volumes (1500, 1500, and 1800 MW), plus the remaining CPRE megawatts. As noted in the Commission's Order on the 2022 procurement volume in the 2022 solar procurement and CPRE dockets (Docket Nos. E-2, Subs 1159 & 1297 and E-7, Subs 1156 & 1268), 441 MW of the 2022 SP shall consist of third-party PPAs below avoided cost, as described therein. The remaining capacity shall be split 45%/55% between third-party PPAs and utility-owned projects, as required by H.B. 951. There shall be no set allocation of capacity in the 2022 SP among projects in DEC and DEP territory.

[1] Nor has Duke or any other party shown that delaying compliance past 2030 would "allow for implementation of solutions that would have a more significant and

material impact on carbon reduction," as required by G.S. § 62-110.9(4). To the contrary, a delay in compliance past 2030 would likely result in less significant carbon reductions.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 30-40
SOLAR PLUS STORAGE PROCUREMENT
(Scheduling Order ordering paragraph 1.c.)

The evidence supporting these findings of fact and conclusions is contained in the Companies' initial Carbon Plan filing on May 16, the comments filed by Intervenors and the Public Staff, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

Summary of evidence of application and initial comments of Public Staff and intervenors

<u>Duke Carbon Plan Application</u>

In its proposed Carbon Plan, Duke states that "[f]uture procurements will solicit both utility-owned solar and solar paired with storage resources as well as third-party owned resources that provide the Companies right to dispatch, operate and control the facilities in the same manner as utility-owned resources." Duke Carbon Plan, Ch. 4, p. 17. In the Near-Term Execution Plan proposed by Duke, it requests that the Commission approve the procurement of 1,600 MW of storage, of which 1,000 MW is standalone and 600 MW paired with solar through 2024. *Id.* at 23.

Duke states that it "will utilize established and evolving procurement practices for battery paired with solar resources that align with the Companies' plans for procuring and self-developing new controllable solar resources." *Id.*

Duke's modeling of solar plus storage is discussed in detail elsewhere in this Order. In short, the Companies originally modeled solar plus storage in two configurations: 75MW solar plus 20 MW / 80MWh battery and 75MW solar plus 40MW / 80 MWh battery. *Id.* at Appx. K, 6-7. "The Companies originally intended to only model a 4-hour battery that was sized at 25% of the solar facility but based on feedback, the Companies included a 2-hour storage option that was paired with solar, sized at 50% of the solar capacity." *Id.* at 7.

Duke further notes that "[t]here are several impacts that the supply chain can have on the overall cost and availability of energy storage technologies, such as raw materials, freight, and competition with other industries dependent on batteries such as cellular communications and electric transportation." *Id.* at 8.

<u>Attorney General's Comments</u>

Relying on analysis by Strategen, the AGO identified a "number of problematic inputs that Duke inserted into the EnCompass modeling" including, among others, "cumulative limits on solar plus storage additions" and "limited configurations of solar plus storage additions." Attorney General's Comments at 15. The AGO identified Duke's fixed storage dispatch profile in its modeling of solar plus storage resources, the limited battery configurations of solar plus storage, and Duke's cumulative 50% limit imposed on the battery ratio in solar plus storage configuration as problematic and "arbitrary." *Id.* at 20-21. The AGO stated that these limitations "may have significantly decreased the amount of solar plus storage that would have otherwise been selected." *Id.* The AGO recommended that Duke "be directed to model a scenario that allows storage resources to be dispatched flexibly, includes additional solar plus storage configurations with larger batteries, and has no cumulative limit on the amount of solar plus storage that can be selected. *Id.* The AGO further requested that the Carbon Plan adopted in this proceeding "include only portfolios developed without arbitrary limits on solar plus storage additions." *Id.* at 32.

<u>CCEBA Comments</u>

CCEBA addressed a portion of its July 15, 2022, comments to arguing that the Commission should "select a larger amount of standalone and solar+storage for procurement in the near term." CCEBA Comments at 31. After discussing the numerous benefits that storage can provide to the grid, as referenced in the highly detailed 2018 Report of the NC State Energy Storage Team Attached to CCEBA's comments at Exhibit H, CCEBA addressed how "to different extents, these benefits can be provided either by stand-alone (and thus under HB951 utility-owned) storage or by hybrid systems in which the storage component is combined with PV solar (or other variable renewable resources)." *Id.* at 32.

In discussing the differences between the two types of storage, CCEBA noted that "embedded storage is combined with other resources such as solar, wind or other non-base load power plants." *Id*. at 32. CCEBA stated that "[i]n systems with a lot of solar generation, typical operating challenges relate to the sudden drop-off of supply in the late afternoon and early evening period, which can force additional fast-start thermal generation to come online, and to the lack of supply from solar for night-peaking systems." *Id.* at 32-33. CCEBA then detailed the ways in which storage can smooth those solar peaks by allowing some of the generation to be stored and then sued later to smooth out the peaks and reduce the drop-off rate. *Id.* These advantages also operate to the financial benefit of ratepayers, by lowering the need for peaking thermal resources. *Id.* at 33. Thus, CCEBA concludes that "storage, when combined with solar, enhances the value of the solar generation and can provide substantial operational and cost-saving benefits to the grid and end users." *Id.*

CCEBA takes issue with Duke's modeling of solar plus storage, noting that the Carbon Plan "does not adequately describe the different performance and cost characteristics applied to standalone storage vs. [solar plus storage]." *Id.*at 35. Among the failures CCEBA points out are that while Duke concedes that solar plus storage resources can be charged from the grid, and not solely from the solar facility, in producing the portfolios Duke did not include this capability in its modeling. *Id.* CCEBA notes that "this difference is important because the ability to grid-charge should increase the ELCC of a [solar plus storage] resource, with the ELCC values of the solar and storage being 100% additive, thereby rendering it more competitive against other technologies in a model without these constraints." *Id.* at 36. CCEBA also criticized Duke for excluding AC-coupled solar plus storage as a possible configuration, noting that AC and DC-coupled systems have their respective advantages and disadvantages. For instance, both solar and storage of an AC-coupled solar plus storage asset could be dispatched at max capacity simultaneously because AC-coupled systems generally do not have a shared interconnection limit, while DC-coupled systems tend to have higher round-trip efficiency. *Id.* at 37.

CCEBA also disputes Duke's assumptions about depth of discharge of battery resources, which CCEBA contends double count the constraint, resulting in higher costs per kWh and a competitive disadvantage for storage in Duke's portfolios. *Id.* at 39. Because manufacturers already build the depth of discharge constraint into their battery pricing, further adjustment is not necessary. *Id.*

CCEBA urges the Commission to increase solar and solar plus storage procurement by 2030 by more than that set forth in Duke's proposed portfolios and to remove the cap on solar integration in the near term. *Id.* at 52. CCEBA recommends "that all solar procurements after the completion of the 2022 Procurement be of [solar plus storage] resources, provided that an acceptable rate design for such facilities that adequately incentivizes the inclusion of storage can be developed." *Id.*at 40.

With regard to contracting, CCEBA notes that the most recent CPRE tranches under HB 589 did not generate successful bidders who incorporated solar plus storage into their bids. *Id.* at 42. CCEBA attributes this to the structure of the PPA used in those solicitations, which "included a rate and bidding structure that tracked the avoided cost rate structure, minus the bid decrement" but "failed to recognize the value of storage and restricted its use such that the benefits that adding storage to a project provides were undercompensated." *Id.* The structure limited sellers to two ways to use storage: first, to time-shift some of its production to higher-rate periods, and second, to "smooth" its output to avoid the application of the Solar Integration Service Charge. *Id.* CCEBA points out that the second approach requires the battery to remain charged during all generating hours, which limits the amount available for time shifting and results in the extra revenue over the lifetime of the PPA being insufficient to cover the costs. *Id.*

CCEBA does note that there are models of PPAs and other contracting structures elsewhere that do provide payment for the full range of services provided by storage in a solar plus storage facility, such as the TVA 2022 RFP for Carbon Free Resources, and also notes that a properly-set tolling payment for batteries could also incentivize bidder participation. *Id.* at 42-43.

CCEBA also notes provisions in the CPRE Tranche 2 PPA that had the effect of lowering the value of storage resources in a combined system by limiting the allowable depth of discharge and adjusting the nameplate capacity of the battery to accommodate that limit. *Id.* at 44. CCEBA maintains that this is an unnecessary provision that any PPA arising from the Carbon Plan should avoid.

CCEBA requests that the Commission direct Duke Energy to work with stakeholders on appropriate Solar+Storage PPA structures to be used in the 2023 procurement and thereafter.

CPSA's Corrected Comments

In corrected Comments filed on August 17, 2022, CPSA argues that Duke's modeling assumptions related to issues, including solar plus storage, are "unreasonable and unjustified." CPSA Corrected Comments at 5. CPSA states that Duke's request for 1,000 MW of standalone storage and 600 MW of solar plus storage in its Near-Term Execution Plan is "counterintuitive" because solar plus storage "enjoys significant economic advantages over standalone storage." *Id.* at 25. CPSA notes that paired storage benefit from shared interconnections and upgrades, cost efficiencies, tax credit eligibility, lower development expenses, mitigated solar curtailment, and the potential relief of interconnection restraints through load-shifting. *Id.* CPSA argues that Duke has limited the competitiveness of solar plus storage in its modeling through limited configurations, limitations on battery size, and not allowing the model to assume that DC-tied hybrid solar and storage facilities could charge from the grid in addition to charging from the solar generating facility. *Id.* at 26.

Relying on alternative portfolios prepared by the Brattle Group, CPSA calls for significantly increased procurement of solar and battery storage compared to the portfolios in Duke's proposed Carbon Plan, and requests that the Commission "[d]irect that all solar procured after 2022 be paired with storage until the storage requirements of the Carbon Plan are met." *Id.* at 73.

CPSA further requests the Commission to "engage stakeholders in the development of appropriate contract structures for the procurement of solar plus storage facilities." CPSA Corrected Comments, 73.

<u>NC WARN and Charlotte-Mecklenburg NAACP Comments</u>

NC WARN and Charlotte-Mecklenburg NAACP (herein "NC WARN") noted in their comments that all portfolios of the proposed Carbon Plan have a "relative lack of battery storage." NC WARN Comments, 2. NC WARN attributes this lack of storage to "several artificial and unnecessary constraints which had the effect of lowering the reliability value of solar plus storage." *Id.* NC WARN argues that Duke lags behind its peer utilities in deployment of battery storage, and states that the proposed Carbon Plan portfolios would exacerbate that deficit. *Id.*

NC WARN states that the proposed Carbon Plan portfolios prefer natural gas CTs and CCs over storage, despite what NC WARN's expert Witness Powers says is solar plus storage's lower production cost. *Id*. at 10-11. NC WARN lays out two primary "flaws" it sees in Duke's analysis of solar plus storage:

First, Duke uses "an incorrect definition of the number of hours of battery storage relative to the nameplate capacity of the solar array." *Id.* at 12. According to Witness Powers "[t]he generally accepted industry definition of the number of hours of battery storage relative to the nameplate capacity of the solar array is the number of hours of storage at the capacity rating of that solar array." *Id.* NC WARN states that Duke instead modeled "a 75 MW solar array coupled with a 20 MW battery with four (4) hours of storage at 20 MW." *Id.* This approach, NC WARN maintains, understates the value of storage to the grid.

Second, NC WARN states that by limiting the modeled solar plus storage facility to only 80MW or battery storage over four hours, Duke's analysis also misstates the ELCC value of solar plus storage, because "the ELCC score is largely driven by the size of the storage component accompanying a solar array." *Id.* at 13 -14.

NC WARN requested in their comments that the Commission order Duke to "model three new solar plus storage profiles, solar plus 4-hour storage, solar plus 6-hour storage, and solar plus 8-hour storage, and provide the ELCCs" and to "vastly increase" the implementation of battery storage. *Id.* at 15.

Public Staff Comments

The Public Staff criticized Duke's modeling of solar plus storage as well, noting that the Carbon Plan includes only two available configurations of solar plus storage: "(1) a 75 MW AC solar photovoltaic (PV) facility co-located with a DC-couple 40 MW / 80 MWh battery; and (2) a 75 MW AC solar PV facility co-located with a DC-coupled 20MW / 80 MWh battery." Public Staff Comments at 119. Like CCEBA and other Intervenors, the Public Staff also criticized the Duke modeling of solar plus storage for assuming "the storage to be DC-coupled and only chargeable from the coupled solar resource." *Id.* at 119. Further, the Public Staff took issue with Duke modeling the solar plus storage resource with a predetermined output file that did not take full advantage of solar plus storage actually being two resources, thus preventing their model from dispatching the storage resource independently of solar and limiting the value of solar plus storage. *Id* at 121. In addition, the Public Staff criticized Duke for relying on pricing periods established for solar resources in the 2018 IRP proceeding to calculate profiles through 2050, noting that "it is unlikely that these pricing periods will continue to accurately reflect the actual marginal system costs so far in the future." *Id.* at 122.

The Public Staff found that Duke's assumptions about solar plus storage were "unreasonable" and, when combined with the "questionable" assumption that all solar plus storage resources are only chargeable from the solar component and not from the grid, unreasonably limits the amount of solar plus storage deployed in the proposed portfolios. *Id.* at 123.

As a result of these stated flaws, the Public Staff found that "Duke modeled the S+S resources too rigidly and has failed to accurately capture the benefits of S+S beyond it having a higher ELCC value than standalone solar," which "may be leading to material impacts on resource selection." *Id.*at 125. requested that Duke run additional modeling with changes made to the dispatchability of storage as well as changes to the battery configurations. The Public Staff agreed that changing the modeling to allow charging from the grid, as requested by CCEBA, would result in long modeling run times which were not achievable under the current pressing time restrictions, but stated that this change should be made in future Carbon Plan proceedings. *Id.* at 125-126.

<u>CLEAN Intervenors Comments</u>

In their Supplemental Comments, CLEAN Intervenors rely on the report prepared by Synapse. In that report, Synapse produces an "Optimized" portfolio, which when compared to a portfolio modeled to represent Duke's Portfolio 1, "retires the same amount of coal and focuses capacity deployment on solar plus storage." Synapse Report at 15. Synapse also incorporated a "Regional Resources" portfolio in which "more of Duke's coal fleet can retire because of additional cost-effective Midwest wind resources." *Id.* Regardless of the portfolio, Synapse states that all "contemplate an expansion of solar and energy storage resources" to meet the 70 percent reduction requirement by 2030. *Id.* at 16. Synapse states that past 2030, the Duke portfolio relies increasingly on the development of new resources such as advanced nuclear and hydrogen, which its alternative portfolios do not do. *Id.* at 17.

In the Synapse Report, Synapse discusses the benefits of solar plus storage technology, including “shifting low-cost renewable energy around to meet load.” *Id.* at 23. Ultimately, Synapse recommends that, regardless of the long-term path chosen by the Commission, “Duke Energy should move ambitiously to integrate battery storage resources and build out operational capabilities for capitalizing on their services to the grid.” *Id.* at 44. Synapse’s future proposed resource tables do not specifically delineate standalone storage from solar plus storage, but all significantly increase the recommended amount of battery storage resources to be brought online between 2022 and 2050. *Id.* at C-1 to C-3.

<u>Tech Customers Comments</u>

The Tech Customers critiqued the Carbon Plan because “the Companies restrain – and even remove – solar and battery storage from the model, while forcing natural gas, offshore wind, and pumped storage into the model.” Tech Customers Comments at 11. The Tech Customers rely on the Gabel Report which urges corrections to the modeling of solar and solar plus storage. Gabel Report at 9. Noting that “solar plus storage hybrids provide a unique opportunity to harness carbon-free renewable generation in a dispatchable resource that is better able to provide energy, capacity, and ancillary services to meet demand,” the Gabel Report criticizes Duke for “elect[ing] to override the capacity expansion model’s economic dispatch optimization and manually selecti[ing] internally developed assumptions that eliminated the ancillary services and flexibility benefits that the storage portion of hybrids provide." Gabel Report at 9.

The Gabel Report adjusted those limitations and allowed the model to "capture the full value that hybrid resources provide." *Id.* As a result, the Gabel Report "Preferred Portfolio" expanded the amount of storage and hybrid resources by "about 6 GW more than Portfolio 1 of the Companies' Carbon Plan." *Id.* The "Preferred Portfolio" engages significantly more solar plus storage, particularly after 2027. *Id.* at 51-52, Figures 29 and 30. Further, the Tech Customers "Preferred Portfolio" calls for more solar plus storage and less standalone solar than the Duke Portfolio 1, increasing solar plus storage by around 6 GW and reducing standalone solar by approximately the same amount through 2035. *Id.* at 52, Figure 31.

The Tech Customers urge the Commission to be "cautious" in addressing Duke's requested Near-Term Execution Plan, noting that solar and battery storage "have been proven at commercial scale and have "no risk of becoming obsolete because of fuel-price escalation or carbon emission constraints." Tech Customers Comments, 12. The Tech Customers contrast this to gas investments, which they say bear substantial risk and uncertainty in the current environment. *Id.* at 13. The Tech Customers maintain that the Gabel Report "shows that Duke can rely on solar and storage to avoid the immediate need for investments in gas plants while technology evolves and markets mature." *Id.*

Summary of evidence of presubmitted and live testimony

There is a substantial amount of agreement among the parties as to the importance of solar plus storage as a resource. The parties mentioned above produced expert direct testimony which largely supported their comments and, except for the testimony of the Duke witnesses , there was little cross-examination on these issues. Therefore, this review of testimony will focus on the areas of disagreement, which are primarily related to the pace and amount of adoption of this resource.

Duke Direct Testimony and Supplemental Modeling

The Modeling Panel in its direct testimony outlined the steps Duke undertook to develop supplemental portfolios in response to the request of the Public Staff that Duke review the effect of no Appalachian gas availability. The results of the supplemental modeling were discussed in detail by the Modeling Panel (Witnesses Snider, Quinto, and Kalemba) (*See* Tr. vol. 7, beginning at 244:12.)

In so doing, Duke "developed two additional portfolios, each with two fuel supply assumption scenarios." *Id.* at 245. The first portfolio, SP5, assumes a 2032 interim 70% compliance year. The second, SP6, targets a 2034 interim 70% compliance year. *Id.* at 245 – 246. Each also had two alternates (SP5A and SP6A) which assumed an "alternate fuel" to replace Appalachian gas. *Id.*

Witness Kalemba testified that as part of additional sensitivity analysis of these portfolios and in response to intervenor comments, SP5 and SP6 also adjusted the available solar plus storage battery configurations, adding an additional configuration for 4-hr, 50% battery to solar ratio. *Id.* at 248-250, Table 2; 343. Witness Kalemba further testified that while "the Companies see merit in the issue" identified by intervenors and the Public Staff that allowing the model to economically dispatch storage as opposed to following a fixed dispatch profile would be preferable, he stated that EnCompass model runtimes were too long when this capacity was attempted. *Id.* at 344 – 345. Nevertheless, he said this capacity was include solely in the SP5 and SP6 modeling runs, resulting in substantially longer time for each run. *Id.* The additional capacity was described in Modeling and Near-Term Actions Panel Exhibit 1 as "model functionality for the Supplemental Portfolio analysis to allow the Encompass model to optimize the charging and discharging of the resource to best meet system needs." Modeling and Near-Term Actions Panel Ex. 1,t 5.

Witness Kalemba also stated that in "adding an additional SPS configuration, the Companies discovered the fixed operations and maintenance (O&M) costs for the combined solar sites were improperly reflected in the model. The resulting correction resulted in a lower FOM for all solar plus storage resources." Tr. vol. 7, 259. He testified that "the [solar plus storage] revised modeling uses increased modeling functionality at this step in the analysis to identify the mix of standalone solar, standalone storage, and [solar plus storage]." *Id.* at 255. However, Witness Kalemba stressed that Duke did not support all the implications of such changes:

> … as explained by the Companies in the Carbon Plan, the use of the capacity expansion model alone is insufficient for selecting the optimal configuration of storage resources given simplifications to the load shape at this step in the analysis framework. Furthermore, the additional burden on the model to determine this optimization increases time required to sole and continues to limit the Companies' ability to perform modeling quickly and efficiently. The Companies will work in the coming months to continue to review how future resources added to the system impact the operation of storage on the system and look to find simplifying, though representative,

> assumptions to decrease model run times while accurately capturing the changes in dispatch due to other resource changes on the system.

Id. at 255:9-19.

Witness Kalemba testified that he agreed with CCEBA's conclusion that the modeling in the Carbon Plan did not allow solar plus storage to charge from the grid *Id.*at 346, but he maintained that while Duke would "acknowledge that hybrid [solar plus storage] assets are being designed with bidirectional inverters to enable" grid charging, the EnCompass model was not capable of modeling that approach as of August 2022. *Id.* Later testimony confirmed that newer versions of EnCompass will be able to perform this function.

Witness Kalemba testified to the changes to the resource additions output by the supplemental portfolios and concluded that:

> [t]he inclusion of the additional SPS option that included a 50% battery-to-solar ratio with 4-hour duration, along with the revised SPS modeling resulted in more storage paired with solar and less standalone storage being selected in SP5 and SP5A. Most of the increase is due to a shift from standalone storage and standalone solar to SPS as the model recognizes some synergistic capital cost benefits of pairing larger storage with solar versus standalone storage."

Id. at 263:4-9.

Despite the modeled increase (reflected in Modeling and Near-Term Actions Panel Exhibit 1, Tables SPA-4 to SPA-11), Witness Kalemba testified that the new figures "validate the total storage needs identified in the Companies' proposed near-term actions" and Duke would "continue to support the 1,000 MW of standalone storage and 600 MW of storage paired with solar as reasonable in the Companies proposed near-term actions." *Id.* at 263. He identified several concerns, including that the larger battery size's ELCC had not been studied, that Duke's current contract structures "do not enable the flexibility and operation control modeled here." *Id.* at 263. In his testimony, he committed Duke to "work with stakeholders in advance of the 2023 procurement to assess potential commercial contract terms and conditions for leasing third-party owned [solar plus storage] assets" consistently with Duke-owned assets. *Id.* at 263-64 He also testified that transmission costs were peculiar to sites and particular assets and that the effects of "stacked" benefits to the bulk system that may or may not be added by [solar plus storage] resources depending on the design. *Id.* at 264.

On rebuttal, Witness Snider testified that "[b]ased upon the panel's review of the testimony filed by the Public Staff and other parties, there is *substantial consensus that pursuing solar, battery energy storage, and onshore wind resources is consistent with a 'no regrets' strategy and that these resources should be 'selected' by the Commission for development and procurement in the near-term*." Tr. vol. 27, 43.

Witness Snider disagreed with CCEBA and CPSA's recommendation that all solar procurement after the 2022 Procurement be of solar plus storage resources. While he agreed that "a significant portion of future procured solar will be paired with storage" he stated that "there is no benefit to pre-determining in this hearing that all future solar must be paired with solar." *Id.* at 57. He further stated that if there were a requirement that all future solar include storage at 25% of the solar nameplate capacity, then to procure 600 MW of storage, 2,400 MW of new solar would need to be procured within the near-term execution plan and no additional standalone solar would be procured. If the battery is sized at 50%, then only 1,200 MW of solar would need to be procured, leaving 1,150 MW of standalone needed to meet Duke's suggested total acquisition of solar in the near-term. *Id.* at 57-58 He stated that with uncertainty as to the procurement profiles and functionality of solar plus storage, the result could be a delay in the procurement of solar. *Id.* at 58.

Also in their rebuttal, the Modeling and Near-Term Actions Panel discussed Duke's review of effects of the Inflation Reduction Act and concluded that based on that preliminary analysis "significant quantities of solar (standalone and SPS) and standalone battery storage continue to be selected." *Id.* at 73.

<u>Reliability Panel (Witnesses Roberts and Holeman)</u>

Duke presented the testimony of Witnesses Dewey S. Roberts II and John Samuel Holeman III as the "Reliability Panel." On the whole, the Reliability Panel testified to the need for Duke to maintain a reliable and consistent electricity supply to its customers in the DEC and DEP territories. They discussed the standards against which Duke is measured and the difficulties posed by a transformation away from thermal resources to renewable generation and storage.

Witness Roberts noted in his direct testimony that the proposed Carbon Plan was designed to meet the requirement of N.C.G.S. § 62-110.9 that "any generation and resource changes ***maintain or improve upon*** the adequacy and reliability of the existing grid." Tr. vol. 19, 162. He discussed the reliability risks posed by increased integration of renewable resources, including that "As intermittent renewable energy becomes an increasingly large share of generation capacity in

DEC and DEP, the remaining electricity demand that must be met by dispatchable resources—that is, the electric load net of renewable energy contributions, commonly referred to as “net load”—will change in timing, shape and magnitude in ways that will place new stresses on the power system” *Id.* at 165.

As part of this analysis, Witness Roberts noted that, “[a]s the Companies consider the amounts of renewables and energy- limited storage in all Carbon Plan portfolios along with the observations that System Operators are already experiencing today, volatility and ramping, resource and energy adequacy analyses will be critical as DEC and DEP move further into decarbonizing their fleets.” *Id.* at 170. He continued that increased renewable generation poses risks related to extreme weather events, where load could outstrip the supply of energy generated by such assets and affect reliability.

With regard to storage, Witness Roberts testified that, even balancing for such concerns, “[t]he Carbon Plan portfolios . . . plan to rapidly add battery energy storage – approximately 2,000 MW to over 4,000 MW of battery storage by 2035, some paired with renewables.” *Id.*at 176. This is an amount, Witness Roberts testified, that is “very significant from the perspective of the System Operator.” *Id.* at 176. He further testified that systems were just being developed to manage battery storage on a grid, and that “as battery storage technology stands now, scale and time limitations do not make battery storage an operational equivalent for dispatchable gas.” *Id.* at 177.

On the whole, the Reliability Panel urged caution in reliance on storage, stating that it is and would become and even more important “tool” in the system operations toolbox, but arguing that storage, including solar plus storage, was not yet mature enough to play the role of dispatchable thermal assets in Duke's system.

CCEBA Witness DeFelice

CCEBA presented the testimony of Dr. Ronald DeFelice, Managing Partner of Energy Intelligence Partners. Witness DeFelice provided testimony supporting the comments filed by CCEBA, including the criticism of the way solar plus storage was modeled for configuration, dispatch, and charging by Duke. Tr. vol. 26, 242, 245-48, 249-50.

He testified as to the roles that front of the meter storage could play in North Carolina, making reference to the 2018 report of the NC State University Energy Storage Team. *Energy Storage Options for North Carolina*, (December 2018) [hereinafter NC State Storage Report] https://energy.ncsu.edu/storage/wp-content/uploads/sites/2/2019/02/NC-Storage-Study-FINAL.pdf (Attached to CCEBA Comments as Exhibit H)) and his own experience in describing the ability of storage, particularly when paired with solar, to meet the needs of the grid. Tr. vol. 26; 237-38. He also detailed the effect that solar plus storage resources have on the integration of solar into the grid, noting that pairing storage with solar can address the ramping and drop-off issues discussed by Witnesses Roberts and Holeman. Speaking of drop off and lack of supply for early-morning or evening-peaking systems, he stated that "Solar+Storage addresses both issues by allowing time-shifting of the solar generation to reduce the drop-off rate, which reduces the ramping requirement from thermal resources, and to deliver more power for the evening or morning peak." *Id.* at 239. He noted that a recent NREL study, attached to CCEBA's Comments as Exhibit I, emphasized that "storage, when combined with solar or other renewables, can replace conventional peaking capacity. And this relationship is somewhat symbiotic, as the narrower load peaks caused by high penetrations of solar PV, for instance, enables shorter duration batteries to serve that peak load, thus reducing combined portfolio costs." *Id.* at 239-40; Exhibit I to CCEBA Comments (Nate Blair, *et al.*, 2022. *Storage Futures Study: Key Learnings for the Coming Decades*. Golden CO: National Renewable Energy Laboratory, NREL/TP-7A40-81779. https://www.nrel.gov/docs/fy22osti/81779.pdf) at p. 16 ("The ability of storage to provide firm capacity is a primary driver of cost-competitive deployment.")).

In light of the value and functions storage and solar plus storage bring to the grid, Witness DeFelice testified that "larger and faster near-term procurement of storage – both standalone and paired with solar – is needed for the integration of more solar in the near-term to achieve carbon emissions reductions and to reduce the need for thermal resources both as baseload and peaking resources." Tr. vol. 26, 241-42. Witness DeFelice agrees with CCEBA's recommendation that the Commission order that all solar procurements after the completion of the 2022 Procurement be of Solar + Storage resources, which must include development of a commercially sound contract structure and proper valuation metrics for such facilities." *Id.* at 253. He then recommends further modeling to determine the optimum ratio of storage capacity to solar generating capacity. *Id.* at 253.

Witness DeFelice then testified to the necessity for those new contract structures. He noted that sellers of energy from solar plus storage projects need to be adequately and appropriately compensated in order to "maximize the opportunity for [solar plus storage] procurement." *Id.* at 255. He discussed the PPA structures of Tranche 2 of the CPRE process and why they failed to generated solar plus storage bidders because they relied on the avoided cost rate alone, without accounting for the other uses and benefits of storage. *Id.* at 255. He then discussed options for such PPA structure, including the TVA 2022 RFP for Carbon Free Resources, attached to CCEBA's comments as Exhibit O. Witness DeFelice stated that the TVA example "highlights the value of energy storage to TVA's system and the material system benefits beyond energy time shifting – not limited to primary frequency response, operating reserves, and reactive power support" it enables. *Id.* at 256-57.

Witness DeFelice was asked by Commissioner McKissick what the typical maximum battery storage capacity for used by electric utilities was "today." He responded that "SMUD just announced an eight-hour contract with a company called ESS" and stated that for non-pumped hydro "that's about as high as I've seen. There are several companies working on 10-hour storage solutions." *Id.* at 268.

When asked by Commissioner McKissick how battery storage would replace the generation from solar if it were lost due to severe weather conditions that last several days, Witness DeFelice noted that the question highlights why it is important to understand that solar plus storage systems can also charge from the grid itself and not solely from the solar component. He said, “I believe most of the portfolios have some assets that generate 24/7, and because you have demand going up and down, you could run those assets 100 percent and charge the batteries up if you have a period of bad weather for recharging the batteries.” *Id.* at 270. Asked to clarify, he responded “but there are some instances where still, maybe have you a couple of days of bad solar, or just one really dark day, we have to account for that. And typically, we do that through contracting where we have the ability to charge the battery from the grid, if it's not recharged from the solar facility the day before.” *Id.* at 272. He then noted that the Inflation Reduction Act makes the investment tax credit available to batteries that charge from the grid some or all of the time, which he stated removed a problematic barrier to such functionality. *Id.*

Chairwoman Mitchell asked Witness DeFelice to clarify “what it would do to the economics of solar plus storage to allow for charging from the grid versus solar only?” He responded: “Asked what the functionality of charging from the grid “it generally increases the value of the storage. So, if you put a constraint that it can only charge from the solar -- and as the Commissioner was just asking, if there's not enough solar the day before, that battery is not gonna be able to provide the value the next day. By being able to charge from the grid without penalty, it opens up the value and the utility of that storage.” *Id.* at 275. When asked how such a system would function, he noted that the TVA PPA would give the utility the right to “actually control the asset” and within the contract parameters the utility “has full control of the battery. You're monitoring it, you're controlling it, you know what the state of charge is at all times. You know when you want to use it." *Id.* at 278.

Asked whether he was aware of any solar plus storage in service anywhere where the utility had such control, he replied that there "certainly" were. *Id.* at 279.

CLEAN Intervenors Witness Tyler Fitch

CLEAN Intervenors presented the testimony of Synapse Energy Economics, Inc. Senior Associate Tyler Fitch. Mr. Fitch's testimony was wide-ranging and his critiques of the modeling performed by Duke in its proposed Carbon Plan, as well as his defense of the findings of Synapse, are discussed elsewhere in this Order. For the purposes of the issue of the deployment of solar plus storage, the Commission notes that Witness Fitch testified as to the alternative portfolio developed by Synapse which includes no incremental solar plus storage, as reflected in Duke Public Staff Panel 1 Direct – Cross Examination Exhibit 1.

When asked why there was no solar plus storage in the Synapse study result, Witness Fitch responded that Synapse had applied the same static dispatch constraints as were applied in the initial Duke portfolios. Tr. vol 24, 201-02. Asked what would happen if he had changed that constraint and modeled solar plus storage with variable or dynamic dispatch, he responded that while he could not state with specificity in terms of number of megawatts, "I would expect more procurement of those resources." *Id.* at 203.)

Public Staff Witness Jeff Thomas

The Public Staff presented the testimony of Jeff Thomas, Dustin Metz and David Williamson as a panel, addressed in live testimony as "Public Staff Panel 1." The testimony of this panel was also wide-ranging and addressed issues of modeling, transmission, and other topics that are addressed in this Order. With regard to solar plus storage, Witness Thomas supported the critiques by the Public Staff in their comments. He testified that the cumulative limits on solar plus storage and standalone storage in the proposed Carbon Plan were unreasonable. Tr. vol. 7, 58. He further testified that the Public Staff does not believe that Duke appropriately modeled solar plus storage resources and detailed the ways in which that modeling could be improved. *Id.* at 64-67.

Despite these concerns, Witness Thomas testified that Duke's decision to limit the economic selection of solar and solar plus storage is based primarily on interconnection concerns, and the Public Staff found the forecast limitations included in P2 through SP6 to be reasonable for planning purposes. *Id.* at 54-55. The interconnection limits themselves are discussed in this Order.

Discussion and conclusions

<u>Procurement of Solar plus Storage Resources</u>

Based upon all of the testimony, comments and evidence submitted to the Commission, the Commission concludes that solar plus storage systems are and will remain a vital resource to be applied to the achievement of the CO2 reduction mandates of N.C.G.S. § 62-110.9. The Commission notes the near-universal agreement that such systems increase the flexibility and usefulness of the solar resources to which they are attached and can aid in the successful integration of other intermittent or variable resources into the grid. The Commission finds that solar plus storage as a resource enables a system to harness carbon-free renewable generation in a dispatchable resource that is able to provide energy, capacity, and ancillary services to meet demand.

The Commission accepts the critiques of Duke's modeling of solar plus storage advanced by the Public Staff, CCEBA, CPSA, CLEAN Intervenors, Tech Customers and NC WARN. The Commission finds that the constraints placed on the economic modeling of solar plus storage, to include fixed dispatch, non-charging from the grid, and limited battery/solar configurations unduly and unreasonably restricted the model from considering the value of these resources in the near and long-term. This is seen most clearly in the additional solar plus storage resources that were modeled in the Supplemental Portfolios once some of these constraints were eased, as detailed in the testimony of Witness Thomas and the Modeling Panel on Direct and Rebuttal. With those Supplemental Portfolios, Duke effectively provided telling evidence against its own initial modeling.

In light of the above considerations, the Commission agrees with Witness Thomas that cumulative limits on the amount of Battery Electric Storage, both standalone and solar plus storage, are unreasonable. Future updates of the Carbon Plan should not include such limits. Further, the Commission finds that all of the portfolios and models submitted by the various parties in this case rely extensively on solar plus storage as a resource and add substantial amounts of solar plus storage through 2030 and beyond.

The Commission finds that the inability to model charging of solar plus storage resources from the grid is a significant limitation on the value and validity of the modeled results. Based upon the testimony of Witness DeFelice, the Commission understands that the state of the technology is such that bidirectional charging is the current state of the art and that control systems exist to allow such systems not only to charge bidirectionally, but for that charging to be monitored, predicted, and controlled by the utility, given proper contracting authority. As a result, the Commission requires that in all future Carbon Plan updates, solar plus storage shall be modeled with bidirectional charging

In light of the usefulness of solar plus storage and the existence of a current market for such resources, the Commission finds that the Near-Term Execution Plan through 2024 would benefit from greater solar plus storage procurement than the 600 MW forecast by Duke. The Commission also finds merit in CCEBA and CSPA's recommendation that all solar procurement after 2023 be entirely solar plus storage. The Commission strongly suspects that, properly contracted and incentivized, the competitive procurement of resources will likely trend in the direction of solar plus storage over standalone solar in the next few years.

However, the Commission is mindful of the arguments stated by Duke that setting a hard benchmark and *requiring* all solar procurement to be solar plus storage would be problematic given that contracting documents have not yet been developed, and that variance in the configuration of solar plus storage procured may result in wide variances in the required remaining megawatts to be procured through standalone solar.

Therefore, the Commission finds that it is reasonable and prudent to set a minimum amount of standalone storage to be procured in 2023 and 2024 without limiting the amount of solar plus storage that may be included in procurements in those years. The Commission finds that the minimum over 2023 and 2024 should be more than the 600 MW in the Near-Term Execution Plan, due to the pressing need for development of this resource and its acknowledged ability to assist in the integration of solar. Therefore, the Commission will set a minimum of 300 MW of solar plus storage to be procured as part of the solar procurement in 2023, and 450 MW of solar plus storage to be procured as part of the solar procurement in 2024. These should not be understood to be caps or limits on the amount of solar plus storage to be procured.

Contracting

Part I, Section 1(2)b of N.C.G.S. § 62-110.9 requires new solar and solar plus storage resources procured by Duke in compliance with the Carbon Plan to allow Duke "rights to dispatch, operate, and control the solicited solar energy facilities in the same manner as the utility's own generating resources." Despite Duke's commitment in its proposed Carbon Plan to "utilize established and evolving procurement practices for battery paired with solar resources," Duke has acknowledged in discovery responses as well as in the testimony of Witness Snider and Witness Roberts that no such PPA or other contracting document has yet been developed.

The Commission finds that the procurement of solar plus storage resources must be conducted in a way that will adequately compensate third party developers and sellers for their investment in these resources and for the energy and services provided by solar plus storage to the grid. Conversely, and consistent with

N.C.G.S. § 62-110.9 , that procurement must also provide the utility with rights to dispatch, operate, and control the solicited facilities in the same manner as the utility's own generating resources.

The Commission notes that there are examples of such contracting structures in other jurisdictions. The Commission finds that it is reasonable to require Duke to work with stakeholders to develop such contracts before the 2023 Procurement. The Commission further finds that it is reasonable for such contracting structures to be submitted to and approved by this Commission as part of the 2023 Procurement Docket.

EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NO. 41-51
STANDALONE STORAGE PROCUREMENT
(Scheduling Order ordering paragraph 1.c)

The evidence supporting these findings of fact and conclusions is contained in the Companies' initial Carbon Plan filing on May 16, the comments filed by Intervenors and the Public Staff, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

Summary of evidence of application and initial comments of Public Staff and intervenors

<u>Duke Carbon Plan Application</u>

Duke discusses Energy Storage in Appendix K of its Proposed Carbon Plan, including long term storage (pumped hydro) and a brief discussion of other storage technologies. Duke states that "Today, energy storage systems primarily provide regulation and reserve ancillary services," Carbon Plan, Appx. K, 1. Duke then states, "With the growing market for long-duration storage, the development of new storage technologies that have more flexible siting than pumped storage hydro (PSH) and are cost competitive to existing lithium-ion technologies at extended durations are essential to making the clean energy transition affordable." *Id.*

In Appendix K, Duke evaluates Advanced-Compressed Air Energy Storage, Flow Batteries, Lithium-Ion Batteries, and Pumped Storage Hydro Carbon Plan, Appx. K, 4-6. and states that it is "actively tracking funding opportunities and evaluating their relevancy to the Companies' decarbonization journey" before committing to explore funding in Docket No. M-100, Sub 164 through the Infrastructure and Investment Jobs Act (IIJA) for long-duration storage.

Energy storage technologies included in the Carbon Plan "include both stand-alone storage and solar paired with storage (SPS) across a range of durations." Carbon Plan, Appx. K, p. 6. In Table K-2, Duke set forth the "Energy Storage Options in the Carbon Plan Modeling":

Table K-2: Energy Storage Options in the Carbon Plan Modeling

Stand-alone Storage	Solar paired with Storage
50 MW / 200 MWh	75 MW solar + 20 MW / 80 MWh battery
50 MW / 300 MWh	75 MW solar + 40 MW / 80 MWh battery
50 MW / 400 MWh	

In discussing the design assumptions assumed for battery storage in the Carbon Plan, Duke noted that it made certain assumptions related to Depth of Discharge: "The cost of the battery storage assets in the Carbon Plan assumes that the asset is designed to include a 90% depth of discharge (DoD) constraint. This means that if a battery is designed with 100 megawatt-hours (MWh) of usable energy, the total energy of the battery would be 111.1 MWh. The depth of discharge is included to reflect requirements of the original equipment manufacturer to maintain the warranty on most batteries." Carbon Plan, Appx. K, 7.

In its Near-Term Execution Plan, Duke requests approval of the following Near-Term Actions (2022-2024):

- Submit interconnection requests for battery energy storage projects at strategic grid locations supporting Carbon Plan needs through 2029
- Design controls, dispatch and software tools for a fleet of battery energy storage systems
- Test and study non-lithium technologies at the R&D scale.
- Finalize procurement strategy and initiate procurement activities relative to procurement strategy for 1,600 MW of battery energy storage (1,000 MW standalone storage, 600MW storage paired with solar.

Carbon Plan, Ch. 4 – Execution Plan, 22-23.

Duke states that the value of energy storage "is maximized for the grid and its customers if the assets are strategically located on the Companies' system" Carbon Plan, Ch. 4 – Execution Plan, 23. In its original Carbon Plan filing, Duke stated that the need for storage can best be met through "self-development" and that "when cost-effective," EPC services would be opened to "qualified vendors, ensuring the best value for customers." *Id.*

<u>Appalachian Voices Comments</u>

Appalachian Voices notes that the proposed Carbon Plan "does not consider significant levels of demand response and energy efficiency, nor how distributed resources combined with energy storage can meet peak demand needs." *Initial Comments of Appalachian Voices*, p. 21 (July 15, 2022). Appalachian Voices relies on the work of its expert consultant PSE Health Energy (PSE) to contend that "the proposed combustion turbine could be replaced with

512 MW of energy storage, 1,820 MW of energy efficiency, and 2,411 MW of demand response." *Id.; see* PSE Health Energy, Elena Krieger, et al, "Review and Comments on Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's 2022 Proposed Carbon Plan" (PSE Report), attached as Attachment A to Appalachian Voices Comments. Appalachian Voices states that "Duke currently proposes to add 1.7-2.1 GW of battery storage by 2030-34 and 2.0-4.2 GW by 2035, alongside an additional 1.7 GW of new pumped storage" but notes that "New York, which has similar total electricity consumption to North Carolina, recently doubled its 2030 storage target from 3 GW to 6 GW and already has 12 GW o storage in its interconnection queue." *Id.* at 21-22. Appalachian Voices states that a similar commitment of 1 GW of storage for every 23,500 GWh of current annual demand "would lead to a target of 6.8 GW of storage by 2030." *Id*. at 22.

Attorney General's Comments

The Attorney General's Office had little comment on the standalone storage aspects of Duke's proposed Carbon Plan other than to note that Duke's near-term proposal to procure at least 1,000 MWs of new standalone storage and 600MW of solar paired with storage "can safely be pursued." Comments of the Attorney General's Office, 26 (July 15,2022).The AGO also criticized the Carbon Plan for the "Battery-CT Optimization" which it said "resulted in between 1,600 and 2,000 MWs of batteries being replaced with 1,500 to 1,900 MWs of CT units. *Id.* at 25. According to the AGO, relying on the report of its expert Strategen Consulting, LLC (Strategen), this process, under which Duke attempted to address what it said was over-valuation of short duration storage due to the load shape that the EnCompass model assigned as a “typical day,” was problematic because it occurred outside the EnCompass modeling and was “difficult to analyze.”

CCEBA Comments

CCEBA noted that “Storage, whether standalone or paired with solar (Solar + Storage), offers numerous benefits to the grid.” *Comments and Issues of the Carolinas Clean Energy Business Association* CCEBA Comments and Issues, p. 31 (July 15, 2022). Referring to a December 2018 study published by the NC State Energy Storage Team, CCEBA set forth the multiple roles that can be played by in front of the meter storage on the North Carolina energy grid, including voltage support and control, reliability enhancement, capacity deferral and peak shaving, reducing the need for transmission investments by boosting capacity and reducing overloading, transmission congestion relief, peak capacity deferral, bulk energy “time shifting”, frequency regulation, spinning and non-spinning reserves, black start capacity, flexible ramping, and synthetic inertia to provide fast responses in a system where the share of variable renewables is high. *See* North Carolina State Energy Storage Team, Energy Storage Options for North Carolina, at 10-11 (Dec. 2018) (NC State Storage Report) https://energy.ncsu.edu/storage/wp-content/uploads/sites/2/2019/02/NC-Storage-Study-FINAL.pdf (Attached to CCEBA Comments and Issues as Exhibit H).

CCEBA further stated that the Carbon Plan’s discussion of storage was inconsistent and confusing, noting that different sections of the Carbon Plan referred to differing amounts of storage proposed to be brought on-line, and those numbers were less than those proposed in Duke Energy's last IRP. CCEBA Comments and Issues, 34-35. In addition, CCEBA noted many issues with the modeling of solar plus storage systems, as discussed in this Order, noting that the inaccurate modeling of solar plus storage "makes it impossible to understand if the mix of standalone storage vs Solar+Storage is accurate." *Id.* at 35.

CCEBA then noted that Duke's treatment of Depth of Discharge is problematic, noting that the 90% depth of discharge assumption noted on page 7 of Appendix K of the proposed Carbon Plan "appears to be double counting" because "original equipment manufacturers and energy storage integrators already factor in this depth of discharge constraint when pricing and procuring assets for developers and purchasers. For example, NREL's Cost Projections for Battery Storage: 2021 Update utilizes BloombergNEF cost projections for "usable" kWh of battery storage, which "means that round trip efficiency and depth of discharge are accounted for in the price of the battery pack in dollars per kWh." CCEBA Comments and Issues, 39-40 (internal citations omitted). CCEBA argues that because Duke uses the NREL Cost Projections in its modeling, its further adjustment for depth of discharge by costing battery storage at 110% of capacity adds expense and unfairly prejudices storage in Duke's modeling. *Id.*

CCEBA urges the Commission to order the procurement of both standalone and solar plus storage resources in the near term. *Id.* at 40. Because standalone resources are, under N.C.G.S. § 62-110.9 , to be 100% owned by Duke, CCEBA argues that the Commission should further direct Duke Energy to procure all stand-alone storage resources, through competitive procurements that allow participation by build-own-transfer bidders, to ensure that all such procurement occurs at least cost." *Id.* at 41. In addition, CCEBA asks that "the Build Own Transfer procurement process should be constructed to comply with LGIP 10.11.1 or NCIP 4.4.10.1 readiness requirements, such that the designation of a volume of standalone storage in the Carbon Plan is sufficient to comply with the requirement that 'the Generating Facility has been selected by a Resource Planning Entity in a Resource Plan.'" *Id.*

CLEAN Intervenors

CLEAN Intervenors filed comments on July 15, 2022 and then, pursuant to this Commission's Order, filed supplemental Comments on July 20, 2022 supported by modeling work performed by Synapse Energy Economics, Inc. *See* Tyler Fitch, Jon Tabernero, Divita Bhandari; Synapse Energy Economics, Inc., Carbon-Free by 2050, Pathways to Achieving North Carolina's Power-Sector Carbon Requirements at Least Cost to Ratepayers (July 20, 2022) (Synapse Report).

In their initial comments, CLEAN Intervenors discuss the value and services that storage technology can deliver. They state:

> Storage deployment has suffered in Duke's proposed near-term mini-portfolio as a result of deliberate replacement with CTs. But battery storage in particular will complement the massive solar deployment required under any least-cost path to the H951 carbon reduction requirements, shifting energy delivery from times of peak solar generation to times of peak demand. Storage also offers multiple additional grid values besides energy arbitrage, including providing ancillary services and functioning as a transmission asset (SATA). The value of storage to integrating low-cost zero-emitting resources including solar and wind, as well as its other values difficult to capture using traditional methods, have allowed it to out-compete gas economically and it should form a cornerstone of the least-cost

path to 2030.

Joint Comments of CLEAN Intervenors (Initial CLEAN Intervenor Comments), 18-19 (internal citations omitted) (July 15, 2022).

In their Supplemental Comments, CLEAN Intervenors state that Synapse modeled two alternative portfolios utilizing Duke's EnCompass database the *Optimized* scenario and the *Regional Resources* scenario. Based upon the findings of those Synapse scenarios, CLEAN Intervenors made different near-term recommendations from those made by Duke, regardless of the path chosen by the Commission. Supplemental Joint Comments of the North Carolina Sustainable Energy Association, Southern Alliance for Clean Energy, Sierra Club and Natural Resources Defense Council (CLEAN Intervenor Supplemental Comments), 3-5 (July 22, 2022). Relative to Standalone Storage, CLEAN Intervenors Supplemental Comments call for 5,600 MW of battery storage, including 4 GW of stand-alone storage with target in-service dates of 2025-2028. *Id.* at 4, Table 2.

CLEAN Intervenors criticize Duke's modeling of storage, stating that "Duke chose to restrain generation choices and even override EnCompass's selections by 'forcing' it to make certain resource choices." *Id.* at 5. They note that "[t]he cumulative effect of these changes was to force nearly 1 GW of new nuclear generation and nearly 2 GW of new gas generation while removing roughly 2 GW of battery storage from the generation mix." *Id.*

<u>CIGFUR Comments</u>

The Carolina Industrial Groups for Fair Utility Rates II and III (collectively "CIGFUR") field comments which criticized the Duke Carbon Plan for, among other things, not addressing power quality and failing to accurately forecast bill impacts related to the implementation of the Carbon Plan by underestimating or not counting cost-adders. Comments of CIGFUR I and II, 10, 14-21. In evaluating the Near-Term actions proposed by Duke, CIGFUR encouraged Duke to "offer new voluntary non-residential customer renewable programs, including incentives for adoption of behind-the meter distributed generation and storage resources, as well as front-of-the meter programs." *Id.*at 28. CIGFUR further recommends that the Commission "direct Duke in its next general rate cases to propose rate designs that will encourage and incentivize increased adoption of behind-the-meter renewable energy resources and storage for non-residential customers, as well as increased participation in front-of- the-meter renewable energy programs." *Id.*at 32.

<u>CPSA Comments</u>

The Clean Power Suppliers Association CPSA) filed Comments on July 15, 2022 and corrected Comments on August 17, 2022. Corrected Comments of Clean Power Suppliers Association on Proposed Carolinas Carbon Plan (CPSA Comments) (Aug. 17, 2022). In those comments, CPSA noted that Duke's portfolios "add between 1.7 and 2.2 GW of battery storage to meet the 70% decarbonization mandate" in addition to the 1.7 GW of proposed additional capacity at the Bad Creek pumped storage facility. CPSA Comments at 24. Stating that Duke "proposes to procure 1,000 MW of standalone storage and 600 MW of storage paired with solar," CPSA notes that the amounts chosen by Duke are "arbitrary" and "counterintuitive" because storage paired with solar has numerous economic advantages over standalone storage, including shared capital and interconnection costs, cost efficiencies due to independent ownership, and the benefits of certain tax advantages. *Id.* at 25.

Consistent with CCEBA's critiques, CPSA noted errors in Duke's modeling of solar plus storage resources resulted in the model preferring standalone resources over solar plus storage. *Id* at 26.; see CPSA Comments, Ex. A, Brattle Report Relying on its expert consultant, the Brattle Group, CPSA stated that fixing these errors in Duke's modeling would result in "the more economic outcome of prioritizing hybrid over standalone storage facilities." *Id.* at 27._CPSA requested that Duke be required to remodel using adjusted assumptions in line with those modeled by Brattle. *Id.*

<u>CUCA Comments</u>

Like CIGFUR, the Carolinas Utility Customers Association, Inc. (CUCA) primarily directed its standalone storage-related comments at Duke's customer programs, noting that Duke's plan "fails to take advantage of ratepayers' willingness to help in reducing carbon emissions." CUCA's Comments Regarding Carbon Plan, p. 15 (June 15, 2022). CUCA points out that while the Companies state that the "large-customer clean-energy programs 'revolve around' self-sourced energy, utility-sourced energy, and battery storage… they offer no details for future programs to address the large customers' demand for new programs." *Id.* at 15-16. CUCA recommends the development of voluntary customer programs "to allow industrial customers to contract with renewable-energy sources and pay for transmission service through the Duke system." *Id.* at 16.

<u>ElecriCities and Power Agencies' Comments</u>

ElectriCities of North Carolina, Inc. (ElectriCities), North Carolina Eastern Municipal Power Agency (NCEMPA), and North Carolina Municipal Power Agency Number 1 (NCMPA1, together with NCEMPA, the Power Agencies) filed comments on July 15, 2022. While most of the comments from ElectriCities and the Power Agencies were directed to issues related to Energy Efficiency and Demand Side Management, the Power Agencies did note that N.C.G.S. § 62-110.9 directs the Commission to "at a minimum, consider power generation, transmission and distribution, grid modernization, storage, energy efficiency measures, demand-side management, and the latest technological breakthroughs to achieve the least cost path" to compliance. Power Agencies' Filing Regarding Significant Carbon Plan Issues to be Considered at Expert Witness Hearing (Power Agencies Comments)*,* 2 (July 15, 2022).

The Power Agencies noted that "[i[f properly incentivized NCEMPA could add Battery Energy Storage Systems (BESS) and other DSM/DR programs designed to managed the NCEMPA/DEP system load, which would allow DEP to avoid having to add the highest cost capacity resources." *Id.* at 7. The agencies argue that investments in such programs in the near term will enable Duke to "offset higher future costs in more expensive non-emitting generation resources in the long term." *Id.* Because the Proposed Carbon Plan does not "take advantage" of such investments, the Power Agencies state, it does not comply with N.C.G.S. § 62-110.9 's least cost mandate.

<u>NC WARN and Charlotte Mecklenburg NAACP</u>

NC WARN and the Charlotte NAACP addressed standalone storage in their comments. Joint Comments of NC Warn and the Charlotte Mecklenburg NAACP (NC WARN Comments), (July 15, 2022). They note that the Companies "lag far behind their peers in implementing battery storage technology" and note that the proposed plan targets "a mere 350 MW of cumulative operational storage by the end of 2027." NC Warn Comments, 2. NC WARN contends this level of storage is "completely divergent from the fact that battery storage is a rapidly expanding technology." *Id.* at 9.

NC WARN attributes the levels of storage in the proposed Carbon Plan to errors in Duke Energy's modeling of storage, particularly solar plus storage, which are discussed in the report of its expert William E. Powers and set forth in the recitation of facts in this order, NC WARN concludes that Commission "should require the Companies to vastly increase their future implementation of battery storage." *Id* at 48.; William E. Powers, P.E., Report on Assumptions Used in Duke Energy May 2022 Carbon Plan (July 15, 2022) (attached to NC WARN Comments as Attachment A) ((Powers Report).

<u>Person County Comments</u>

In *Comments of Person County, North Carolina* (Person County Comments) (July 15, 2022), Person County stressed the "importance" of Duke Energy to Person County as an employer at its Roxboro coal plant since 1966 and at the Mayo plant since 1983. Person County Comments, 7. Person County stated that without the energy capacity provided by the Roxboro plant, DEP customers face a risk of rolling blackouts due to reduced reserve margins. *Id.* at 10-12. Person County argues that the coal burning generators at Mayo and Roxboro should be replaced by gas generation, noting that "[w]hile Person County generally supports the use of carbon-free renewable resources to meet the requirements of House Bill 951, the Commission must be realistic in recognizing that to-date, renewable resources, even when paired with energy storage, have not shown an ability to completely replace fossil fuel generation." *Id.* at 17. While Person County urges the Commission to maintain the operation of the Mayo and Roxboro plants until they can be replaced with gas units with a firm supply of natural gas, the county also requests that the Commission locate new generation and storage assets at the Mayo and Roxboro sites to maximize the advantage from existing transmission infrastructure. *Id.* at 23-24.

Public Staff Comments

The Public Staff makes several recommendations regarding the modeling of solar plus storage, which are discussed in this Order. Regarding standalone storage, the Public Staff recommends that the Commission require Duke to "remove limits on the total amount of 4-hour and 6-hour battery capacity that can be added" noting that "[t]hese limits were implemented in recognition of the declining capacity value of storage resources, but the EnCompass model already includes declining capacity value constraints for solar, battery storage, and wind resources." Comments of the Public Staff, 22 (July 15, 2022); *see also Id.* at 130. The Public Staff also suggested that Duke should be required to provide an update in 2024 regarding any changes to its modeling resulting from the replacement of battery storage resources at the end of their operable lives. *Id.* at 24.

The Public Staff, in examining the execution risk of various proposed portfolios, notes that "with respect to batteries, while some utilities across the country have been installing significant quantities of battery storage, Duke is still in the early stages of battery storage adoption. Each portfolio calls for less total battery storage capacity than solar capacity, but interconnection will still likely present issues." Comments of the Public Staff, 89. They further state that "it is also not clear whether battery storage projects can be dispatched by Duke in order to mitigate transmission congestion issues, or if they will instead contribute to congestion issues." *Id.* The Public Staff continues by stating that the "need for battery storage is clear in the Proposed Carbon Plan portfolios, but until Duke has proven its battery storage development capabilities, a more ambitious interconnection schedule presents significant challenges." *Id.* at 90.

<u>Tech Customers Comments</u>

The Tech Customers filed Comments along with a report by their expert consultant Gabel Associates, Inc. (Gabel). See Gabel Associates, Inc., Review of the Duke Carbon Plan and Presentation of a Preferred Portfolio (July 15, 2022)(Gabel Report). The Tech Customers note that the Companies "restrain – and even remove – solar and battery storage from the model, while forcing natural gas, offshore wind, and pumped storage into the model." Tech Customers Comments, at 11. The Tech Customers discuss Duke's proposed Near-Term Execution Plan and caution the Commission that "some of these energy resources present greater risk than others," while noting that "[s]olar generation and battery storage, for example, have been proven at commercial scale and have no risk of becoming obsolete because of fuel-price escalation or carbon emission constraints." *Id.* at 12.

Relying on the Gabel Report, the Tech Customers recommend that sites of retiring coal generation "should not be reserved for future gas plants, but should be eligible for solar and storage" in order to make use of existing transmission capacity and avoid expensive transmission improvements. *Id.* at 15. The Tech Customers urge the Commission to require Duke to use existing sites and "the Generator Replacement Request process to accelerate renewable resource deployment" and the "use of Surplus Interconnection Service to deploy clean energy and storage at the sites of its existing thermal generators." *Id.* at 24.

The Tech Customers further urged the Commission to require Duke to revise its modeling "consistent with the law and the recommendations set forth in the Gabel Report," including the storage recommendations above. *Id.*

Summary of evidence of presubmitted and live testimony

During the evidentiary and expert witness hearings, most all witnesses who testified on the subject agreed that storage, both standalone and solar plus storage, was an important resource for the transformation of the grid in North Carolina. (*See e.g.*, Testimony of Kendal Bowman, Tr. vol. 7, 120-21; Testimony of Ron DeFelice, Tr. vol. 26, 237-38. The differences arose in the recommended pace of adoption and in the manner in which standalone resources should be procured.

Duke's Modeling Panel testified as to the modeled role of standalone storage. In responding to critiques from Intervenors and the Public Staff of how Duke modeled storage, specifically regarding the cumulative battery limits

EnCompass was allowed to assume, Duke's Modeling Panel testified that supplemental portfolios had modeled 4 hour and 6 hour batteries without MW caps, but allowed the model to account for decline in storage capacity value. Tr. vol. 7; 248-250, Table 2. However, the Companies did not adjust the CT-Battery Optimization step criticized by several intervenors. The Modeling Panel testified that "the use of the capacity expansion model alone is insufficient for selecting the optimal configuration of storage resources given simplifications of the load shape at this step in the analysis framework." Tr. vol 7, 255.

The Modeling Panel did concede that making changes to the modeling of solar plus storage, to include a 50% battery-to-solar ratio with 4-hour duration, and revised modeling of solar plus storage dispatchability "resulted in more storage paired with solar and less standalone storage being selected in SP5 and $SP5_A$." Tr. vol. 7, 263. The Modeling Panel further testified that "most of the increase is due to a shift from standalone storage and standalone solar to SPS as the model recognizes some synergistic capital cost benefits of pairing larger storage with solar versus standalone storage." *Id.* Nevertheless, the Modeling Panel testified that Duke "continued to support the 1,000 MW of standalone storage and 600 MW of storage paired with solar as reasonable in the Companies' proposed near-term actions." *Id.*

In regard to competitive procurement of resources under the Carbon Plan, under cross-examination by counsel for Kingfisher Holdings, Duke Witness Bowman agreed that Duke had in the past "expressed support for competitive procurement as providing benefits to the utility and to customers." Tr. vol. 7, 169-

70. Witness Bowman maintained that, even without procurement through PPAs for resources that N.C.G.S. § 62-110.9 restricts to Duke ownership, Duke "will still go out to competitively procure the resources." *Id.*, at 170.

Duke's Reliability Panel of Witnesses Holeman and Roberts testified "Additional storage can help with managing the net demand ramp or the excess energy during the net demand valley; however. it can't perform both functions unless you have separate storage assets for both functions." Tr. vol. 19, 167. Witness Roberts further cautioned that while "the Companies agree with stakeholders that storage is an essential tool to assist in reliably transitioning to a low carbon future . . . battery storage is not yet scaled, does not have the necessary duration, and should not be viewed as a panacea." *Id.* at 177.

Tech Customers Witness Michael Borgatti, Vice President of Gabel Associates, took issue with the way in which Duke modeled storage, noting that Duke relies heavily on natural gas CCs and CTs to provide flexible, dispatchable resources to the grid while "NERC recognizes that stand-alone battery storage (SAS) and dispatchable solar plus storage (SPS) hybrids can also mitigate energy shortfall when conventional renewable resources are curtailed." Tr. vol. 25, 21.

CCEBA Witness DeFelice testified to the benefits that storage resources could bring to the grid, including those benefits noted by CCEBA in its Initial Comments. *Id.* at 237-38. He stated that standalone storage, which is "not co-located with another resource, . . . draws from the grid and stores energy for later discharge to the grid." *Id.* at 238. He stated that "the basic operating mode is to charge when demand is low and to discharge when demand is high." *Id.* He further testified that in market systems prices for stored energy would rise or fall based on demand and allow arbitrage, and that batteries typically operate on a daily (or diurnal) cycle "completing a roundtrip full charge and discharge within 24 hours." *Id.* Nevertheless, he testified most lithium-ion batteries were capable of multiple charging cycles per day, and that additional operating modes beyond arbitrage would allow storage resources to be applied "as a response to certain system conditions to reduce curtailment or to provide other ancillary services to the system." *Id.*

Witness DeFelice testified that after review of Duke's Carbon Plan, he concluded that Duke's proposed procurement of 1,600 MW of total storage, including 1,000 MW of standalone and 600 MW of solar plus storage "in service through 2029" was insufficient and not consistent with the forecasts in the Carbon Plan itself for 2030 and 2035. *Id.* at 241. He stated that "larger and faster near-term procurement of storage – both standalone and paired with solar – is needed for the integration of more solar in the near-term to achieve carbon emissions reductions and to reduce the need for thermal resources both as baseload and as peaking resources." *Id.* at 241-42.

As to procurement of standalone storage, Witness DeFelice testified that "it is highly unlikely that their proposed self-development of all standalone energy storage resources represents the least cost / best value for rate-payers. There should be competitive procurement for standalone energy storage to allow third parties to develop and offer projects through a Build-Own-Transfer (BOT) structure (also called Build Transfer Agreements (BTA's))." *Id.* at 242. He went on to explain that such agreements allow construction-related risk and cost overruns to be borne by the developer, and through such agreements "more storage can be deployed more quickly from projects already under development in North Carolina by third parties." As a result, "ratepayers benefit from the selection of the lowest cost / highest value projects." *Id.*

Witness DeFelice further testified that the passage of the IRA "greatly increases the value of both Solar+Storage and standalone storage because it allows energy storage to receive a 30% ITC regardless of method of charging and it allows for energy storage to be sited more optimally on the grid." *Id.* at 248. As a result, he testified, the cost assumptions used by Duke in modeling storage are too high no longer valid. *Id.*

Witness DeFelice disagreed with the Operations Panel's statement that storage resources could not perform multiple functions at the same time. He described the testimony as "simply not accurate," noting that "there are many storage and [solar plus storage] Energy Management Software (EMS) tools and plant controllers that allow for energy storage to perform several functions simultaneously." *Id*. at 250. As an example, in Exhibit 5 to his testimony, Witness DeFelice showed a sample of a commercially available EMS software which has the ability to manage ramping and charge simultaneously, noting that "this is just one example of commercially available software, and this particular software currently operates over 3 GWh of energy storage globally." *Id.* at 250-51, Exhibit 5. He noted that "application stacking is common, and if Duke Energy is not allowing for the fact that energy storage assets can perform multiple functions like ramp control, energy-shifting, Volt/Var support, and frequency regulation, among others, then the Company is under-valuing the energy storage assets in the portfolios." *Id*. at 251. Witness DeFelice further took issue with the CT-Optimization step described by Duke. *Id*. at 251-52.

Public Staff Witness Jeff Thomas took issue with the CT-Battery Optimization approach pursued by Duke and defended by the Modeling Panel. Witness Thomas testified that the Public Staff found the comments of CLEAN Intervenors, and the Synapse Report to be "persuasive," noting that while Duke had properly identified the "needle peak" issue with the EnCompass model's selection of typical days, it's method of resolving that issue by removing 35% of battery storage and replacing it with CTs "may not reasonable for planning purposes." , Tr. vol. 21, 43-47.. Rather, Witness Thomas testified, "Duke should have allowed the model to economically select battery storage without replacing 35% of battery capacity with CTs, and if reliability issues were identified during the LOLE Validation step, CTs could be added at that point to meet LOLE thresholds." *Id.* at 46-47.

In discussing competitive procurement, Witness Thomas agreed with Intervenors who recommended competitive procurement of energy resources, noting that the NC Energy Regulatory Process (NERP) released a report in 2020 finding that "competitive solicitations benefit customers by ensuring the most cost-effective generation resources are selected." *Id.* at 79. He stated that "the Public Staff agrees and has consistently supported the development of competitive procurement processes for generation resources in North Carolina, and such procurement is consistent with least cost planning principles." *Id.* at 41-43. Noting that all-source procurements may not be proper with the stated requirements of , Witness Thomas nevertheless concluded that "Solar, wind, and battery storage will be needed in great quantities over the next ten to 15 years, and Duke should procure these resources via competitive procurements." *Id.* at 80. .

On Rebuttal, Duke's Modeling Panel testified in its summary of testimony that "The Battery-CT Optimization step was a reasonable economic assessment in advance of the reliability valuation step. The concerns expressed by Witness Thomas do not address the ability of the capacity expansion model to accurately evaluate energy storage, and the sensitivities and uncertainties he references reinforce the need to validate capacity expansion model results rather than undermine this reasonable and necessary verification step." Tr. vol. 27, 39. The Panel went on in direct testimony to detail the reasons behind its disagreement with Witness Thomas and the Intervenors critical of this step. Tr. vol. 27, 104-05.

Witness Snider of the Modeling Panel also testified on Rebuttal under cross-examination from Commissioner Brown-Bland that calling storage a mature technology "would be a misrepresentation" because "there's a lot of dynamic changes happening in the battery market" and "I think there's room for technology improvement." Tr. vol. 27; 203-04. On further questioning from counsel for CCEBA, Witness Snider acknowledged that a 2022 NREL report called Storage Futures Study: Key Learnings for the Coming Decades, which had been introduced as Exhibit I to CCEBA's Initial Comments stated that "the ability of storage to provide firm capacity is a primary driver of cost competitive deployment" (Tr. vol.

28, 21) and that "Storage provides firm capacity,· the ability to meet demand during system peak and replace conventional generators such as gas turbines," "energy time shifting," and can "provide multiple services either simultaneously or at different times, often referred to as value stacking." *Id.* at 22. When asked if he agreed with those statements, WitnessSnider stated "if placed properly and evaluated properly, yes" *Id.* at 22. and acknowledged that storage was "integral in all – of the 12 portfolios, all had storage as part of those 12 portfolios." *Id.* at 24.

The Modeling Panel also again disagreed that Duke's Depth of Discharge calculations double counted the adjustment discussed by Witness DeFelice, stating that while they were not aware that the NREL 2021 Annual Technology Baseline used the BloombergNEF cost projections mentioned by Witness DeFelice, Duke's costs were similar to those used by other modelers. Tr. vol. 28, 25-29.

Finally, on rebuttal, the Transmission and Solar Procurement Panel (Witnesses Roberts and Farver) discussed standalone storage procurement. Witness Farver stated that she did not believe that "standalone storage should be procured in the same manner as solar and solar paired with storage." Tr. vol. 28, 158. Witness Farver described the Companies' RFPs for engineering, procurement and construction (EPC) as a competitive process that ensures low costs. *Id.* at 158. She distinguished between EPC and procurement from third party developers by noting that EPC companies are also used by third party developers and often "do not perform the early-stage activities of battery development, such as handling project identification or evaluation, buying/selling any of the land, preparing engineering designs or interconnection agreements, obtaining permits, or establishing off-take sales agreements." *Id.* at 159. For self-developed projects, she stated, Duke would perform these early stage activities. *Id.* at 160.

Witness Farver flatly disagreed with Witness DeFelice, stating that there is "no compelling evidence to suggest that a developer stepping in as an intermediary to create a build-own-transfer structure for batteries is more cost-effective than a utility self-developing the battery project." *Id.* at 160. She further disagreed with Witness DeFelice that third party developers could increase the speed of deployment of storage projects. *Id.* at 160-61. She also testified that through self-development, Duke could maintain standards of safety and quality and would best know where to locate storage projects. *Id.* at 161-62.

Nevertheless, Duke amended the panel's Rebuttal testimony to include the acknowledgement that "the Companies support all available avenues to keep customer costs low, and would be open to further exploring options for a future build-own-transfer RFP for standalone storage. In such a scenario, the RFP would be subject to Duke Energ-directed siting based on system needs, benefits, timing, and other requirements." *Id.* at 163.

Discussion and conclusions

Based upon the entire record, including the evidence and arguments discussed above, the Commission agrees with all parties that standalone solar is an integral resource to the success of any Carbon Plan portfolio, whether those proposed by Duke or those proposed by the various Intervenors. The Commission accepts Witness DeFelice's testimony regarding the roles that standalone storage can play in providing both time-shifting of energy as well as other ancillary services to the grid. Furthermore, standalone storage is a key resource in allowing the integration of larger amounts of variable renewable energy which will be necessary to accomplish the mandates of HB 951.

The Commission is further persuaded that Duke inappropriately limited storage technologies in its modeling, as shown by the increase in modeled storage in the supplemental portfolios that removed those restrictions and the modeling performed by Synapse, Brattle and others. Future Carbon Plan updates should be modeled without those hard restrictions on storage.

The Commission further agrees with the Public Staff and intervenors that the CT/Battery Optimization process undertaken by Duke in the development of its portfolios as presented in the proposed Carbon Plan unduly restricted the model in choosing both standalone and solar plus storage assets. Future IRP and Carbon Plan updates should adapt this process in the manner suggested by Public Staff witness Thomas rather than assuming before the LOLE analysis that the model has overprocured storage.

The Commission finds that at least 850 MW of standalone storage should be included in the 2022-2024 Near-Term Execution Plan (in addition to the solar plus storage resources also included in this Order) and that, to the extent possible, Duke should attempt to locate standalone storage at retiring thermal generation sites or near load centers in order to capitalize on existing transmission infrastructure.

The Commission is persuaded by testimony from CCEBA and the Public

Staff that it is in the public interest and consistent with least-cost planning principles that standalone storage resources included within the Carbon Plan be procured through competitive RFP or BOT process. While Duke argues that through self-development it is better able to control siting, safety, and quality, the same argument could be made in any procurement of any generation asset, and is similarly unavailing here. The Commission finds that such concerns will be met through Duke establishing the terms, conditions, and requirements to be met by any competitive bidder, and that the competitive process is best able to keep costs low and protect ratepayers. Duke is therefore directed to work with stakeholders and the Public Staff to develop a competitive process for the competitive procurement of standalone storage assets, and that such RFPs shall be subject to the approval of the Commission.

The Commission is also persuaded by CCEBA's request that any Build Own Transfer procurement process should be constructed to comply with LGIP 10.11.1 or NCIP 4.4.10.1 readiness requirements, such that the designation of a volume of standalone storage in the Carbon Plan is sufficient to comply with the requirement that "the Generating Facility has been selected by a Resource Planning Entity in a Resource Plan." Such a requirement will help ensure that third party projects are evaluated on an equal footing with bids controlled by Duke or its affiliates.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 52-53
Onshore Wind
(Scheduling Order ordering paragraph 1.c.)

The evidence supporting these findings of fact and conclusions is contained in the Company's initial Carbon Plan filing on May 16, the comments filed by intervenors and the Public Staff, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

There was general agreement that onshore wind is a mature generation resource that has been developed in the United States. Tr. vol. 25, 254 (AGO Witness Burgess); Tr. vol. 17, 92 (Duke Witness Pompee). Witness Burgess testified that over 2,400 MW of onshore wind projects are currently being developed in the PJM territory with development times of 2 to 3 years. Tr. vol. 25, 255. Duke Witness Snider testified that wind energy has a "synergistic effect" with other resources, which gives it a unique value to the system. Tr. vol. 11, 100.

Duke's modeling imposed a combined limit of 300 MW per year on the amount of onshore wind in DEP or imported onshore wind in DEC that EnCompass could select, delayed when those resources could be selected, and imposed a cumulative limit on onshore wind procurement. Tr. vol. 7, 366; vol. 11, 101. Public Staff Witness Thomas testified that onshore wind is not made available in Duke's model until 2029. Tr. vol. 20, 59. Duke witness Snider acknowledged that the 300 MW target was a conservative start for modeling on-shore wind resources. Tr. vol. 11, 101. No competitive solicitation for onshore wind has occurred in the Carolinas. Tr. vol. 18, 124-25. Duke has not yet held stakeholder workshops with developers. *Id.*at 125.

Witness Thomas noted that Duke may have inconsistently applied the ownership provisions of G.S. § 110.9(2) because it allowed EnCompass to select onshore wind for DEC acquired from PJM, the Midwest, or Texas through PPAs.

Tr. vol. 20, 78. Likewise, the Synapse Regional Resources scenario allowed EnCompass to select onshore wind power purchase agreements from the Midwest, transferred to Duke through PJM. Tr. vol. 24, 150. Synapse recommended procuring 900 MW of onshore wind and importing 2,500 MW of Midwest wind by 2030. *Id*. at 177-78. The Gabel/Strategen Preferred Portfolio selected 1,200 MW of onshore wind before 2030, including imports. Tr. vol. 25, 47, 88. The SP-AGO portfolio called for importing 450 MW of onshore wind in 2027 and an additional 450 MW in 2028. Duke witnesses Roberts and Farver testified that Duke determined that acquiring Midwest wind as not being "economically feasible at this time." Tr. vol. 16, 105.

As noted by Witness Thomas, several parties raised concerns about the model constraints that Duke placed on onshore wind resources, including the AGO, MAREC, CCEBA, and Avengrid. Tr. vol. 20, 59. The Public Staff found that Duke's assumptions are reasonable at this time. *Id.* at 61. In its modeling for the AGO, Strategen removed the cumulative limit on the availability of onshore wind, but retained the annual limit. Tr. vol. 25, 280. This resulted in the Strategen SP-AGO portfolio selecting an additional 300 MW—a total of 900 MW by 2030—of onshore wind. Official Exhibits, vol. 25, Corrected Burgess Exhibit 2. The Strategen-AGO modeling reflected the transmission challenges that may come with added onshore wind. A proxy cost was added in the modeling to reflect any transmission upgrades needed to enable onshore wind. Tr. vol. 11, 97. This transmission cost used for onshore wind was $0.24/W, which was higher than any other land-based resource. Duke Carbon Plan, Appendix E, Table E-44; Tr. vol. 7,

33. Even including this transmission cost adder, the SP-AGO continued to economically select onshore wind.

To model imported onshore wind resources, Duke witness Roberts testified that the Companies included a firm point-to-point transmission cost adder based on PJM's Firm Point-to-Point Transmission Service. Tr. vol. 17, 27-28. Witness Burgess compared Duke's assumption of Firm Point-to-Point Transmission Service of $67,625/MW-year for imports from PJM or approximately $26/MWh for a wind resource with a 30% capacity factor and found that it may increase the resource costs by over 30%. Strategen AGO Report at 22; Tr. 25, 345, 66. This cost was included in the SP-AGO modeling. *Id.* at 281. Synapse's Regional Resources portfolio used an input for imported wind that imitated Midwest wind resources identified in the North Carolina Transmission Planning Consortium's 2021 Public Policy Study, and included the PJM border charge for firm point-to-point transmission service. Tr. vol. 25, 27-28; Synapse Report, 14. CLEAN Intervenor Witness Fitch testified that this cost included "any upgrades needed to the transmission system plus the wheeling charges[.]" *Id.* at 28. The modeling continued to select high volumes of imported onshore wind as an economic resource. Tr. vol. 24, 264. By including imported Midwest wind, the CLEAN Intervenor's Regional Resources portfolio resulted in a decrease in 2050 PVRR of nearly $5 billion when compared to the otherwise identical Optimized portfolio. *Id.* a*t* 132, 151.

AGO witness Burgess testified that Duke's reliance on Firm Point-to-Point transmission service for wind may be overly limiting. Tr. vol. 25, 254-55. The SP-

AGO allowed the model to import using non-firm transmission, but assumed that the imports provided no capacity value. *Id.* at 281-82. This was consistent with Astrapé recommendations in Duke's 2020 resource adequacy study. *Id.* at 59. For comparison, PJM's Non-Firm Point–to-Pont Transmission Service is discounted to just $0.67/MWh, significantly less than $26/MWh used by Duke. Strategen AGO Report at 22; *Id.* at 345.

In addition to cost concerns, Duke Witnesses Roberts and Farver testified about technical feasibility concerns with importing Midwest wind. They indicated that the required transmission upgrades necessary to enable importing Midwest wind would take "up to 84 months." Tr. vol. 16, 105. Duke has submitted a 1000 MW firm transmission request to the PJM queue and is waiting for the results of that request. *Id*. The report considered by Duke in this instance looked only at imports via PJM. *Id*. at 224-25. Additional power could be procured via the Tennessee Valley Authority, Southern Company, or any other neighboring balancing area. *Id.* at 225-26. Duke witness Snider testified that Duke has a history of importing power from neighboring areas to ensure reliability and meet peak demand. Tr. vol. 9, 18-19. According to Tech Customers witness Borgatti, imports of power have also helped Duke to reduce resource requirements and decrease reserve margins. Tr. vol. 25, 59-61.

Discussion and conclusions

The Commission concludes that onshore wind is a mature generation resource that has been developed at scale in the United States. While there likely are some limitations on the total amount of available onshore wind resources in the Carolinas over the next several years, that limit should not be predetermined at this time. Duke's modeling included a cumulative limit on onshore wind additions that was not justified. As a result, the 600 MW cumulative limit in Duke's modeling does not represent what is commercially available. It is premature to implement a cumulative cap before testing the market to see what volumes are reasonably obtainable.

It is thus probable that substantially more onshore wind can be developed in a shorter timeframe than Duke has assumed for purposes of its modeling. Accordingly, the Commission concludes that Duke should initiate a competitive procurement for 900 MW of in-state onshore wind with a volume adjustment mechanism consistent with the VAM developed for next round of solar procurements. Beginning the procurement process for onshore wind helps to ensure that ratepayers can benefit from the lowest cost resources available for meeting the requirements of G.S. § 62-110.9.

On the subject of imported onshore wind, G.S. § 62-110.9 allows for the inclusion of imported resources in the Commission's Carbon Plan. Duke has long imported wind energy from neighboring areas to ensure reliability and meet peak demand. Imports can help to reduce resource requirements and decrease reserve margins. All of Duke's proposed portfolios include some imported wind. However, Duke implemented cumulative caps on the amount of wind that could be imported. The modeling results that allowed for importation of Midwest wind demonstrate tremendous potential for ratepayer savings. Despite Duke's assertion to the contrary, economics do not appear at this time to be a reason for imposing limits on imported onshore wind in Carbon Plan modeling. Even with annual limits and proxy costs, the SP-AGO portfolio, the Synapse Regional Resources portfolio, and Duke's modeling selected onshore wind when it was made available to the model.

Instead, the only rationale identified for potentially limiting imports of onshore wind is technical feasibility. Duke witnesses indicated that the required transmission upgrades necessary to enable importing Midwest wind would take up to 84 months. However, the study Duke used to justify that estimate was not comprehensive. It looked only at imports via PJM. Additional power could be procured via the Tennessee Valley Authority, Southern Company, or any other neighboring balancing area. Duke has not provided a sufficient justification for limiting imports of onshore wind.

Duke should take a more comprehensive approach to studying the most cost-effective way for importing Midwest wind and begin inter-regional coordinate with PJM and other bordering balancing areas to facilitate power purchases of Midwest wind.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 54-67
Offshore Wind
(Scheduling Order ordering paragraph 1.d.)

The evidence supporting these findings of fact and conclusions is contained in the Company's initial Carbon Plan filing on May 16, the comments filed by intervenors and the Public Staff, the testimony and exhibits of the witnesses, and the entire record in this proceeding

Summary of evidence

Duke witness Pompee testified that offshore wind (OSW) is relatively new to the U.S., with two projects in operation and 30 GW of projects with leases in place, and has a 25-year track record globally. Tr. vol. 17, 110. Witness Pompee testified that there are currently three siting possibilities, or wind energy areas (WEAs), in the Carolinas: the Kitty Hawk parcel of approximately 127,000 acres approximately 27 miles offshore from Corolla, purchased by Avangrid Renewables (Avangrid) in 2017; and the Carolina Long Bay lease area comprising approximately 110,000 acres divided into two individual lease areas of approximately 55,000 acres each, located approximately 20 miles offshore from Cape Fear, one of which was purchased by Total Energies Renewables USA, LLC (Total) and the other of which was purchased by Duke Energy Renewables Wind, LLC (Duke Wind), both in May 2022. *Id.* at 111. He testified that all lease areas would require cabling from the wind farm to shore and network upgrades and new transmission infrastructure. *Id.* at 111-12.

Witness Pompee testified that OSW could provide resource diversity to a future system likely to be heavily reliant on solar because its generation profile complements the generation profile of solar both daily and seasonally. *Id.* at 112. As more solar is added, the summer peak planning hour shifts to the early evening as solar generation decreases and offshore winds increase. *Id*. In winter, OSW is especially valuable because the peak planning hour for the system is currently the early winter morning and OSW's highest seasonal generation is in the winter mornings. *Id.* In addition, OSW has high capacity factor and low intermittency relative to other zero-carbon resources. *Id.* Locating OSW at any of the three leases above, more than 20 miles offshore, allows for very large wind farms, large turbines, and tall towers, all of which increases the capacity and capacity factor of OSW. *Id*.

Witness Pompee testified that OSW leasing is managed by the Bureau of Ocean Energy Management (BOEM), which is part of the U.S. Department of the Interior. *Id.* at 113. He testified that it typically takes approximately eight (8) to ten (10) years from leasing a WEA to commercial operation. *Id.* at 113, 123; Tr. vol. 18, 80. He Duke recommended beginning development of OSW in order to refine Duke's cost estimates and to preserve the potential for OSW to be available on a timeline matching Duke's modeling. Tr. vol. 17, 114-15. He testified that OSW could reduce Duke's reliance on other technologies, new gas pipelines, and solar. *Id.* at 115.

Witness Pompee testified that Duke's modeling did not assume that OSW would come from a particular WEA. *Id.* at 115. However, he testified that it is Duke's position that legally it must own any OSW selected by the Commission as part of the Carbon Plan. *Id.* at 116. This requires sole ownership, precluding a joint venture and other options. *Id.* at 175. Duke is willing to purchase WEAs from other entities. *Id.* at 116-17. However, unless Avangrid or Total expresses a clear desire to sell their respective WEAs Duke will pursue affiliate approval to transfer the WEA owned by Duke Wind to Duke. *Id.* at 117. Witness Repko testified that, as he understands an affiliate transfer, it is a legal transaction between Duke and a commercial affiliate, and would need to be accepted by the Commission and later approved by BOEM. *Id.* at 154-55.

Witness Repko later explained that Duke had not received an explicit statement from Avangrid that it was willing to sell. *Id.* at 168. He stated that Avangrid's testimony that it was open to any manner of transaction that is on reasonable terms and fairly values the Kitty Hawk WEA included too many subjective terms and did not provide certainty that Avangrid would sell. *Id.* at 170-71. Witness Repko testified that build-own-transfer is an option but Duke believes it is appropriate that it develop the Carolina Long Bay parcel due to ease and simplicity and timeframe. *Id.* at 174; Tr. vol. 18, 61. Duke's position is that if Duke does not own the lease then there is no guarantee that it will be developed on a pace to meet the necessary timeline. Tr. vol. 18, 59. Duke proposes that DEP would develop the OSW under H951, although DEP has never developed OSW. *Id.* at 82.

Witness Pompee testified that the near-term activities associated with OSW development include paying rent to BOEM, development of a stie assessment plan (SAP), various site surveys, and preliminary engineering, followed by development of a construction and operations plan (COP) and later by transmission. Tr. vol. 17, 117-19. BOEM requires these activities of any OSW leaseholder. *Id. a*t 133.

Duke estimated the following near-term development costs: $155,000,000 to purchase the lease from unregulated affiliate Duke Wind, $62,000,000 in development expenses, and $100,000,000 in transmission construction. *Id.* at 119-20. Duke's cost figures are specific to Duke Wind's WEA. *Id.* at 151-52. Duke Wind purchased its WEA for $155,000,000 and Avangrid purchased Kitty Hawk WEA for approximately $9,000,000. Tr. vol. 18, 62-63. Witness Pompee explained that these are high-level estimates based on indicative pricing, industry data, and multiple sources, and that uncertainty could be mitigated through front-end design and would be updated over time. Tr. vol. 17, 125. He later testified that the estimates were not precise and Duke did not have indicative pricing and had not done procurements. *Id.* at166. Witness Repko testified that the cost of OSW should be evaluated as part of the whole portfolio. Tr. vol. 18, 81. Duke has not studied whether wind leases might be less expensive in light of the removal of the moratorium on OSW in the Southeast under the IRA. *Id.* at 83.

On cross examination by counsel for Avangrid, Witness Pompee testified that the higher the capacity factor of an OSW asset the more energy you can get out of the WEA. Tr. vol. 17, 145. He did not know the relative net capacity factors available at the different Carolinas WEAs because the currently available wind data is for coastal waters outside of the WEAs, making further meteorological study necessary. *Id.* at 145-46. He disagreed that wind speed is the most important factor in determine a facility's net capacity factor because another factor is optimizing the turbine for the given wind speed. *Id.* at 146-47. However, he testified that according to publicly available data the Kitty Hawk WEA has higher wind speed than the Carolina Long Bay WEAs and he would therefore expect it to have a higher capacity factor. *Id.* at 147-48.

Witness Pompee testified that he understands that Avangrid has submitted a SAP that was accepted and a COP that has not yet been approved. *Id.* at 157. He would agree that Duke Wind has had less time to do its SAP and COP than Avangrid has had. *Id.* at 158. And that the Carolina Long Bay WEA permitting has not been completed. *Id.* at 163. Witness Repko testified that if 2030 is deadline the date that the Commission chooses to comply with for the 2030 deadline established in H951 then a parcel that is further along in development would be the most likely course of action, and that parcel would be the Kitty Hawk WEA. *Id.* at 160; *see id.* 163. He testified that the Carolina Long Bay WEAs could be developed if the Commission chose a deadline of 2032 or later. *Id.* at 160-61.

Public Staff witness Thomas testified that Duke prevented the selection of OSW prior to 2030, although Avangrid has stated that it can achieve commercial operation as early as 2029. Tr. vol. 21, 61. The Public Staff views 2029 as a reasonable first year of operation for OSW. *Id.*at 62.

Public Staff witness Metz recommended that the Commission deny Duke's request to begin near-term resource development activities for OSW because supplemental model portfolios SP5 and SP6 did not select the resource in the next ten (10) years, but recommended that Duke reevaluate OSW in its proposed 2024 Carbon Plan. *Id.* at 127,383-84. Witness Thomas explained that the reason for this position is that the Public Staff does not think the Commission should approve DEP to spend $155,000,000 to acquire a lease plus another $156,000,000 on development when the resource might not be needed until 2040, particularly when a lot of the development work could be done by entities that are not DEP. Tr. vol. 22, 333-35.

Witness Metz testified that waiting until the 2024 Carbon Plan to reevaluate the need for OSW absolutely would not mean that the earliest time OSW would be available for North Carolina customers would be 2034, because Duke Wind presumably would be continuing to develop its lease. *Id.* at 32. Witness Thomas added that he expected Avangrid and Total would do the same. *Id.* at 332-33.

Witness Thomas testified that it would have value in the 2024 Carbon Plan to look at all three WEAs. Tr. vol. 21, 226. Witness Thomas testified that portfolios SP5 and SP6 did not select OSW prior to 2040 because it was not a least-cost resource because the model was evaluating a suite of alternatives. *Id.* at 274. He would not say necessarily that OSW is not part of a least-cost solution. *Id.* at 275. He testified that it can be an expensive resource but it provides benefits in terms of its output profile. Tr. vol. 22, 352-53.

Witness Thomas explained that modeling thus far modeled OSW as a generic resource, whereas if the Commission were to order a third-party study that could receive information from each of Avangrid, Total, and Duke Wind related to key inputs such as capacity factors and output profiles and network upgrades, including confidential information, it could come up with a least-cost option, and the information also could go into the 2024 Carbon Plan. *Id.* at 347-50. Participation in the study by the three unregulated entities could be voluntary. *Id.* at 350-51. Witness Thomas testified that with a competitive market—albeit limited to three competitors—it would be inappropriate to simply pick Duke Wind's Carolina Long Bay lease as a winner. *Id.* at 352. Witness Thomas also opined that based on the results of the study the Commission could order Duke to open a competitive procurement for OSW that would be open to the three leaseholders and through an independent administrator or independent evaluator DEP could pick the most competitive regardless of who owns it. *Id.* at 352.

Witnesses Michael Starrett and Becky Gallagher testified for Avangrid. Tr. vol. 23, 159. Witness Starrett testified that OSW provides a benefit in terms of the shape of its generation, both daily and annually, and has a high capacity factor. *Id.* at 166-67. He also testified that OSW's different supply chain from other renewables can be a benefit. *Id.* at 168. He disagreed with Duke's assumption that OSW necessarily requires a 500kV grid expansion. *Id.* at 169. He testified that Avangrid's Vineyard Wind 1 project is on track to come online within nine (9) years. *Id.* at 176. Avangrid has been developing its Kitty Hawk WEA since its purchase in 2017. *Id.* at 179.

Discussion and conclusions

Offshore wind is a commercially available zero-carbon resource that likely can form part of a least-cost path to compliance with the 2030 carbon-reduction requirement as part of a portfolio of resources due primarily to its daily and annual generation profile and high-capacity factor, which complements solar generation particularly well.

There is evidence that the Kitty Hawk WEA likely has a higher capacity factor than the Carolina Long Bay leases due to its higher wind speed, although other factors such as transmission costs could weigh in favor of Carolina Long Bay and offset the difference. The modeling to date, relying on a generic OSW resource, is not sufficiently granular to allow the Commission to determine the relative values of the lease areas in terms of energy production, nor are the transmission costs, both to bring power onshore and any necessary upgrades, sufficiently clear. Accordingly, the Commission cannot make a determination at this time as to which lease area would provide North Carolina customers with the best value. Further, the Commission does not have the benefit of an analysis of the effect of the IRA's lifting the OSW leasing moratorium in the Southeast, nor its other effects on the cost of OSW and other zero-carbon resources.

The Commission is mindful of the relatively long development timeline for OSW from leasing to commercial operation and the need to move expeditiously if OSW is to play a role in meeting the 2030 carbon-reduction requirement. However, there is evidence in the record that OSW at one or more of the three Carolinas lease areas could be operational before 2030, and in any case the Commission simply does not have sufficient information to select a lease area at this time. Accordingly, in recognition of the tight timeline the Commission will commission a third-party study of the three Carolinas OSW lease areas, which will be carried out as described in the Findings of Fact. Depending on the results of the study and other factors, the Commission might choose to direct Duke to take further action such as to have DEP initiate a competitive procurement of OSW, overseen by an independent administrator, and at the latest expects the results of the study to inform Duke's proposed 2024 Carbon Plan.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 74
Environmental Justice Outreach
(Scheduling Order ordering paragraph 6.a.)

The evidence supporting these findings of fact and conclusions is contained in the Company's initial Carbon Plan filing on May 16, the comments filed by intervenors and the Public Staff, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

Summary of evidence

In their comments, the Comments of Environmental Justice Community Action Network and Down East Coal Ash Environmental and Social Justice Coalition (collectively, EJCAN *et al.*) noted that

> Duke Energy convened a small group of environmental justice-focused stakeholders on May 3, 2022, to begin discussing how to engage North Carolina communities and understand what issues are important to low-income and communities of color." Though Duke Energy claims this effort will be ongoing, this was their only effort to substantively engage with justice and equity perspectives before the release of their draft plan and it occurred less than two weeks before that date.

EJCAN *et al.* at 11 (quoting Duke Energy, Carolinas Carbon Plan, Appendix B: Stakeholder Engagement at 22 (2022)). EJCAN *et al.* had concerns with Duke's design and scheduling of this limited environmental justice outreach. EJCAN *et al.* at __. See also Comments of NCWARN *et al.* at 42.

At the Wilmington public hearing, NC NAACP President Deborah Dicks Maxwell spoke about the Companies environmental justice outreach. Tr. vol. 2, 29-32. Public Witness Maxwell testified that after one meeting with Duke Energy on May 3, which included participation from multiple individuals who are Latinx, African American, and Indigenous, she heard soon thereafter that there would not be further discussions about Duke's proposed Carbon Plan because it had already been submitted to the Commission. *Id.* at 29. Witness Maxwell characterized this meeting as an afterthought and as unacceptable. *Id.* at 30. Noting the challenges of climate change and energy affordability, witness Maxwell testified that the Carbon Plan is very important for the future of her community and state. *Id*. at 30-31.

Citing the requirements of Title VI of the Civil Rights of 1964, EJCAN *et al.* called on the Commission to consider the disparate and cumulative impacts of environmental harms from Duke's existing and planned fossil generation units when developing the Carbon Plan. EJCAN *et al.* at 11-13. AAPPL noted the environmental justice concerns and disproportionate harms that air and water pollution have caused to local communities where fossil fuel generating plants are located. At 3. NCWARN and the Charlotte-Mecklenburg NAACP (NCWARN *et al.*) raised environmental justice concerns with regard to relying on new fossil fuel infrastructure, such as gas pipelines, as part of any Carbon Plan. *Id.* at 38.

In their comments, Asheville/Buncombe encouraged Duke "to incorporate equity and environmental Justice concerns in the transmission planning process and ensure historically underrepresented communities are included in this process." At 13. The NC Council of Churches and Interfaith Power & Light called on the Commission to "ensure racial and economic equity and justice are centered meaningfully during every step of the process going forward," noting the importance of affordability as a component of reliably affording essential electric utility service to low-income customers. At 2. NCIPL noted that a lack of adequate notice or public engagement during the development of the Carbon Plan can "result in the neglect of historically overburdened and underserved communities," adding that the stakeholder process conducted by Duke and the outside facilitator were not inclusive for those not well-versed in utilities proceedings. At 5. NCIPL recommended that the Commission conduct its own outreach and engagement with low-income communities, which would include a dedicated staff position, making materials available in Spanish, creating a new web portal that is easier to access, and more. At 6. EJCAN *et al.* also called the Commission's attention to the lack of broadband infrastructure in many rural parts of the state, which further limit public participation by people who will be directly impacted by the Carbon Plan. *Id*. at 13-14.

A number of intervening parties referenced Governor Cooper's Executive Order 246, issued on January 7, 2022, which notes that "[M]eaningful, fair, and equitable public engagement in state agency decisionmaking is necessary to avoid and remedy harmful impacts on communities most severely and frequently impacted…" EJCAN and DECAESJC at 10. The Redtailed Hawk Collective and Robeson County Cooperative for Sustainable Development (RHC *et al.*) also lifted up the importance of including environmental justice and Indigenous communities' voices in the Carbon Plan development process, noting some of the same concerns with Duke's limited environmental justice outreach as EJCAN *et al.*. RHC *et al.* at 14. In addition to noting the authority of Title VI and EO 246, RHC *et al.* asked the Commission to embrace the principle of free, prior, and informed consent when it comes to consultation with the State's Indigenous Tribes. *Id*. at 15. Appalachian Voices (AV) raised the environmental justice provisions of EO 246 as support for its comments focused on the need to consider low-income affordability when developing the Carbon Plan. AV at 5-6.

Stakeholder Meetings

Following the initial Carbon Plan Stakeholder meetings, under the category of considering customer and community impacts, participants identified centering "environmental justice communities in the development of the carbon plan" as desired outcome. Public Staff Report, Duke Energy "Carolinas Carbon Plan" Stakeholder Meeting 2 (Feb. 23, 2022) and Technical Subgroup Meetings (Feb. 18, 2022) (Mar. 2, 2022). In addition, stakeholders noted the importance of supporting communities that will be impacted by the transition away from coal and considering "the siting of new facilities, avoiding areas already disproportionately impacted by energy generation and other industrial facilities" under the topic of environmental justice. Public Staff Report, Duke Energy "Carolinas Carbon Plan" Stakeholder Meeting 1 (Jan. 25, 2022) (Feb. 1, 2022). Following the third Carbon Plan Stakeholder meeting, Duke reported that it was planning to schedule a meeting focused on community and environmental justice impacts in April. Duke Energy, Third Stakeholder Meeting Summary Report, Att. 1, 40 (Mar. 29, 2022).

Discussion and conclusions

The Commission concludes that the environmental justice outreach conducted by the Companies was insufficient because it occurred too late in the process for participants to have any meaningful impact on Duke's Carbon Plan proposal. While the Commission recognizes the Companies' efforts to respond to the stakeholder feedback that it received on this issue, its effort to convene such a group on May 3 were not aligned with receiving environmental justice stakeholder feedback in a way that allowed for substantive engagement prior to Duke's submittal of its Carbon Plan proposal on May 15. The Commission is mindful of the large number of participants in the Carbon Plan stakeholder process and recognizes that it is impossible to reach all potentially interested parties across Duke's extensive footprint in North Carolina. The Commission nevertheless places substantial weight on the testimony of public witness Maxwell on the limited nature of the environmental justice outreach conducted prior to the Companies' proposed Carbon Plan filing on May 15.

The Commission orders Duke to remedy these shortcomings in its stakeholder outreach to and inclusion of environmental justice advocates and underserved communities prior to beginning stakeholder processes for its 2024 proposed Carbon Plan. Participation in future stakeholder processes should not be limited to members selected solely by Duke.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 75-78
RZEP
(Scheduling Order ordering paragraph 1.f.)

Summary of the evidence

In the Carbon Plan, Duke describes the inclusion in the Execution Plan of near-term action to initiate public policy transmission projects necessary to allow for substantial incremental solar resource interconnections in existing "Red Zone" areas of DEC and DEP. Carbon Plan, Ch. 4, 25-26. Duke describes the Red Zone as five separate transmission lines needing to be upgraded to allow for substantial incremental resource interconnections in the southern and southeastern portions of North Carolina and the Pee Dee region of South Carolina. *Id*. at 12. Duke indicates that existing transmission lines will not be sufficient to interconnect later phases of incremental resources associated with Carbon Plan implementation, creating the need for the Red Zone upgrades. Duke states that it has presented the Red Zone upgrades to the NCTPC for assessment and that Duke hopes to incorporate an initial set of Red Zone upgrades into the Local Transmission Plan by mid-year 2022. *Id*. at 13. Duke emphasizes that a more proactive approach to transmission planning and expansion is needed to meet the Carbon Plan objectives and that the failure to construct these needed transmission upgrades will likely adversely impact the Carbon Plan implementation timeline. *Id*.

In its comments, CPSA states that it supports the proposal by Duke to construct the Red Zone upgrades to alleviate congestion in the Red Zone and facilitate the interconnection of renewable generation needed to comply with HB 951. CPSA Comments, 54. CPSA comments that 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 that will create additional benefits and cost savings beyond just facilitating the interconnection of more generation, and that planning and constructing those upgraded proactively is far more efficient and cost-effective than doing so piecemeal, in response to generator interconnection requests. *Id.* at 55. CPSA notes that the benefits of proactive transmission planning are a central component of the current FERC Notice of Proposed Rulemaking related to transmission planning and was a key conclusion of the North Carolina Clean Energy Plan prepared in 2019. *Id.* at 56. CPSA states that given the urgency of adding new resources to meet the 2030 mandate of HB 951, and the 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. *Id.* at 57-58. CPSA describes the history of the Red Zone upgrades, including their inclusion in numerous generator interconnection studies for projects that ultimately did not move forward due to the high cost of the upgrades allocated to individual interconnection customers. *Id.* at 59-60. CPSA explains why the Red Zone upgrades are necessary to achieve the carbon reduction targets of HB 951, including why land within the Red Zone upgrades is particularly suitable for the development of solar energy facilities. *Id.* at 61-62. CPSA describes why "market testing" transmission upgrade costs is impractical, and CPSA states that the Commission should consider the benefits as well as the costs of transmission upgrades. *Id.* at 63-65. CPSA also recommends that Duke should be required to study grid enhancing technologies, such as dynamic line ratings, topology optimization, and advanced power flow control, which have the potential to reduce costs, enhance benefits, and expedite interconnection timelines for new generation and load, all of which can take place separate from or in parallel to the construction of new transmission upgrades. *Id.* at 66.

In its comments, the Public Staff recognizes the challenges of executing the Carbon Plan and finds that "Duke should move from a purely reactive transmission upgrade approach, where it constructs transmission only after a generator has requested interconnection, to a planning process that also considers proactive upgrades in anticipation of future generation required by the Carbon Plan adopted by the Commission." Public Staff Comments, 114. The Public Staff identified concerns regarding Duke's proposed transmission planning, including timeline, cost efficiencies and allocation, and selection of appropriate transmission projects. *Id.* at 112-114.

In their direct testimony, Duke witnesses Roberts and Farver testify that the integration of resource planning and proactive transmission planning will mitigate execution and timeline risk associated with the construction of necessary transmission upgrades. Because, under the current interconnection process, transmission upgrades identified through the DISIS process would only begin construction following execution of an interconnection agreement, the 3-7 year construction timeline for such transmission upgrades would create substantial risk to Carbon Plan execution. Tr. Vol. 16, 62-64. To mitigate this timeline and execution risk, Duke believes that proactive transmission planning is necessary to meet the requirements of the Carbon Plan in the specified timeframes.

Duke describes recent developments in the NCTPC Local Transmission Planning process to consider the Red Zone upgrades, stating that in March, April, and June 2022 Duke introduced to the NCTPC OSC information regarding the potential Red Zone upgrades, including the mapping of generator interconnection studies that have identified the need for the Red Zone upgrades, and a draft 2021 Mid-Year Update Report and final Mid-Year Report proposing the addition of the Red Zone projects to Duke's Local Transmission Plan. *Id.* at 67-68. Duke states that due to feedback received from TAG stakeholders and the Commission's directive in the 2022 Solar Procurement dockets for Duke to exclude the Red Zone upgrades from consideration in the baseline of the 2022 DISIS Phase I Study, the NCTPC communicated that the Red Zone projects would be removed from consideration to be included in the 2021 Plan Mid-Year Update Report.

Duke describes subsequent supplemental studies developed to further evaluate the need for the Red Zone upgrades, which reinforce the need for the majority of the Red Zone projects. *Id.* at 69-70, 73-76. Duke states that it plans to reintroduce the Red Zone projects through recommended inclusion in the 2022 Local Transmission Plan that will be reviewed by the TAG and considered for approval by the OSC later in 2022. *Id.* at 70.

Duke also testifies that it views the Red Zone projects as a prudent and necessary first step to interconnect to the DEC and DEP systems the volume of solar needed to execute the Carbon Plan. The Red Zone upgrades will also provide secondary benefits, including increasing the ability to charge stand-alone battery storage located close to load centers to meet customer demand during peak periods, as well as replacing aging, less resilient transmission equipment with new, more resilient equipment. *Id.* Duke testifies that the Commission's acknowledgement of the need for the Red Zone projects will provide strong evidence to the NCTPC that approval of the Red Zone projects in the 2022 Local Transmission Plan is a reasonable and prudent step. *Id.* at 84.

Witness Roberts testified that the RZEP projects are a necessary first step towards proactive transmission planning. Tr. vol. 28, 126. He testified that the projects are essential to the Carbon Plan and there is widespread agreement among parties accordingly. *Id*. at 126-27. He agreed with the Public Staff that one project could be delayed, but not the other two that the Public Staff recommended delaying. *Id*. at 130-32. An updated list of RZEP projects was attached to his pre-filed rebuttal testimony as Exhibit 3. *Id*. at 135. He testified that the RZEP projects will help to interconnect more solar generation. *Id*. at 146-47.

In direct testimony, CPSA states that proactive transmission planning is critical to facilitating the achievement of the decarbonization mandate of HB 951 and will ultimately reduce costs to ratepayers. Tr. vol. 25, 448. CPSA notes that the additional analysis provided in Duke's direct testimony further demonstrates that the Red Zone projects represent a "no-regrets" set of upgrades that will be required to cost-effectively achieve HB 951's carbon reduction mandates. Tr. vol. 26, 64. CPSA further notes that it would be extremely helpful for the Commission to provide additional guidance regarding its expectations for justifying a set of transmission upgrades for inclusion in the Carbon Plan or future revisions, given that it is likely that additional upgrades will eventually be needed to fully achieve the goals of HB 951. *Id.* at 66. CPSA also recommends that the Commission initiate proceedings with the goal of establishing a proactive, long-term transmission planning process consistent with applicable FERC requirements, separate and in addition to the NCTPC process. Tr. vol. 25, 449.. CPSA emphasizes the need to coordinate proactive transmission planning with integrated resource planning, and CPSA described the critical that both state utility commissions and FERC play in the transmission planning process. *Id.* at 449-51.

In its direct testimony, the Public Staff describes Duke's supplemental planning process as "a valid effort to refine the study process to determine potential proactive upgrades." *Id*. The Public Staff described updates to assumptions regarding circuits of certain voltages and generation of solar facilities and land availability. Public Staff Testimony, pp. 39-40. The Public Staff concludes that the supplemental transmission studies support the need for the requested Red Zone upgrades with certain exceptions. The Public Staff did not recommend that DEC build Project #4 at this time, based on the relatively few generator facilities impacting that line. Public Staff Testimony, p. 42. The Public Staff also recommended that DEP Projects #7 and #14 be removed from the Red Zone plan. Public Staff Testimony, pp. 43-44. The Public Staff also raised concerns regarding the cost assumptions included in Duke's supplemental study (Public Staff Testimony, p. 45), and it described proposed next steps regarding the proposed Red Zone upgrades in the context of both the Carbon Plan proceeding and the 2023 NCTPC planning process. (Public Staff Testimony, p. 47.)

In rebuttal testimony, Duke notes that other parties identify proactive transmission planning as key to reliably executing the Carbon Plan. Tr. Vol. 16, 49, 51-52. Duke states that it plans to continue to engage the NCTPC OSC members, NCEMC, and Electricities in reviewing and improving NCTPC Local Transmission Planning processes, as well as engagement through the Southeastern Regional Transmission Planning Process that will adopt FERC orders resulting from the FERC Transmission Planning NOPR. *Id.* at 49-50. Duke describes the Public Staff's reactions and recommendations to Duke's proposed Red Zone upgrades and states that Duke maintains its original recommendation regarding the Red Zone upgrades that are appropriate to proactively pursue at this time, with the exception of one project. *Id.* at 59-61.

Discussion and Conclusions

Based on the evidence presented, the Commission concludes that least-cost compliance with H.B. 951 will be unachievable without substantial improvements to Duke's transmission system. The Commission is persuaded by the evidence and studies presented by Duke and intervenors that the RZEP represent necessary, "no regrets" upgrades that will help to interconnect large amounts of additional new solar resources, which all proposed Carbon Plan portfolios have identified as necessary to a successful Carbon Plan. The projects have high benefit-to-cost ratios, which are likely to be even higher under a multli-value analysis. The risk that they will be under-utilized is low given high historic interest in the "red zone" regions and high solar viability in those regions. It is appropriate to find all of the RZEP projects identified in Duke's final list—Exhibit 3 to its Transmission Panel rebuttal testimony—necessary to the Carbon Plan. The Commission further urges the NCTPC to include those RZEP projects in its next LTP.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 79-81
COST ALLOCATION FOR THE RZEP
(Scheduling Order ordering paragraph 1.f)

<u>Summary of the evidence</u>

In its comments and testimony, CPSA describes the current cost allocation structure of interconnection network upgrades under the NCIP. CPSA notes that under the current system, the allocation of upgrade costs in the interconnection process either to single customers or small cluster 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. CPSA Comments, 60. CPSA states that the Red Zone upgrades provide a textbook example of the dynamic FERC is concerned with in its NOPR – upgrades 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. *Id.* at 61.

Duke notes that based on the Commission's directive in the 2022 Solar Procurement dockets, Duke will exclude the Red Zone upgrades from the 2022 DISIS Phase 1 study baseline. Tr. vol. 16, 69. Duke explains that the Red Zone contains many of the solar facilities included in the 2022 DISIS and that the Red Zone upgrades proposed by Duke would provide upgraded transmission capability to move the carbon-free solar energy from these facilities to meet customer demand and to supply carbon-free energy for storage for peaking capacity and other system needs. *Id*. at 80.

Duke witnesses acknowledged that under Duke's existing interconnection process, the full cost of the Red Zone upgrades would be allocated to the DISIS projects that triggered those upgrades. *Id*. at 179. Duke states that to date, the Red Zone upgrades have created insurmountable cost hurdles for developers of one or two projects being asked to bear the upfront burden of that cost. Tr. vol 28,26. Duke witnesses agreed that despite the fact that completion of the Red Zone upgrades would create interconnection capacity for approximately 5,400 MW of projects, when evaluating RFP bids, the exclusion of Red Zone upgrades in the

DISIS Phase 1 baseline requires Duke to evaluate bids based on the assumption that Red Zone upgrades will be allocated the generator assigned the upgrade under the DISIS Phase 1 process. Tr. vol. 16, 179. Duke witnesses explained that the timing of NCTPC approval of Red Zone upgrades would inform whether the DISIS Phase 2 study lists the Red Zone upgrades as contingent facilities or whether the cost of the upgrades is allocated to the interconnection customer. *Id.* at 180. Duke also acknowledged that the allocation of Red Zone upgrade costs to bidders in the RFP could increase the apparent cost of the procurement for evaluation purposes and that a larger number of projects in the Red Zone would allocate the cost of those upgrades to a greater number of projects. *Id.* at 181. Duke further explained that Duke considers the Red Zone to be an efficient investment if the entire amount of generation that the Red Zone upgrades will allow to interconnect is considered. Tr. vol 28, 178.

Duke confirmed that based on their supplemental study, the Red Zone upgrades could accommodate approximately 3,500 MW of projects. *Id.* at 179. Duke also confirmed that in DISIS Phase 1, the cost of the Red Zone upgrades would be spread across approximately the same volume of projects that would be facilitated by the construction of the Red Zone projects. *Id.* at 180. Duke witnesses agreed that the allocation of cost to Red Zone projects in DISIS Phase 1 would provide a rough approximation of the cost that would be allocated to those projects if the costs were allocated across all the projects that would benefit from the Red Zone upgrades. *Id.* at 181.

With respect to DISIS Phase 2, Duke witnesses acknowledged that because the number of projects in Phase 2 was likely to be lower than in Phase 1 given that projects may withdraw following Phase 1, the Phase 2 study will identify and allocate costs based on a smaller number of projects than in Phase 1. *Id.* at 182. As a result, Duke witnesses agreed that if the Red Zone upgrades are triggered in Phase 2, the costs would be allocated to whichever projects were remaining. *Id.* Duke also noted that future projects that were not allocated costs of the Red Zone upgrades would also benefit from those upgrades. *Id.* at 183.

Duke witnesses agreed that with respect to providing an appropriate price signal for developers that may wish to develop projects in the Red Zone, the DISIS Phase 1 cost allocations for the Red Zone upgrades would provide a rough approximation of cost that could be used in bid evaluations. *Id.* at 186. Duke witnesses explained that it is important for Duke to avoid assigning a zero transmission cost to a project that is benefitting from Red Zone upgrades that were approved through a different mechanism, but also to avoid assigning one project the full cost of all of the Red Zone upgrades, which would be an inaccurate reflection of the project's cost. *Id.* at 187.

At the hearing, Mr Roberts and Ms, Farver provided testimony about the RZEP in the context of the 2022 SP. Mr. Roberts opined that any projects bidding into the 2022 SP from the Red Zone would likely trigger the RZEP, the full cost of which would be allocated to those projects in the DISIS interconnection study process. Tr. vol. 16, 179. Ms. Farver testified that if the RZEP are approved by the NCTPC, Duke will classify them as "Contingent Facilities" and not allocate costs for those upgrades in Interconnection Agreements for projects coming out of the 2022 DISIS process (although that would not happen until after the conclusion of the DISIS process). Tr. vol. 62, 180. Nevertheless, Ms, Farver testified that for purposes of bid evaluation process in the 2022 RFP, Duke plans to use to the full DISIS allocation of RZEP upgrade costs. *Id.* She acknowledged that this would drive the "apparent cost" of the 2022 solar procurement up. *Id.* at 181. However, spreading the costs among a larger number of projects would reduce the "distorting impact" of this phenomenon. *Id.*

Ms. Farver further testified that the RZEP would create benefits for a large number of projects, somewhere in excess of the 3600 MW of red zone projects on which Duke's supplemental study of the RZEP was based. However, the historic allocation of the costs of the RZEP to much smaller number of projects has made the economics of those projects untenable. Tr. vol. 16, 177.

Ms. Farver acknowledged that in the DISIS 1 study, the costs of the RZEP would be spread among about 3600 MW of red zone projects -- approximately the minimum amount of solar capacity that Duke estimates will be facilitated by those Upgrades. Tr. vol. 16, 180. The DISIS Phase 2 study results (which represent the final results of the DISIS process, and which Duke intends to base RFP evalutions on) will allocate costs across a much smaller group of projects, depending on the procurement target established for the 2022 SP. This is likely to be a much smaller group of projects than will ultimately benefit from the RZEP. *Id.* at 183. Ms. Farver testified that the DISIS Phase 1 cost allocations for the RZEP would provide a “rough approximation” of how the costs of the RZEP could be spread among the number of projects that would ultimately benefit from those Upgrades. *Id.* at 186.

Discussion and conclusions

The RZEP present a particular problem with regard to cost allocation and the 2022 solar procurement. As directed by the Commission in its June 10, 2022 Order in docket nos. E-2, sub 1297 and E-7, sub 1268, Duke did not include the RZEP in the baseline for the DISIS 1 study. It has also withdrawn the RZEP from consideration for including in the mid-year update to the 2021 Local Transmission Plan. As a result, the full costs of the RZEP will be allocated to any project(s) that trigger those Upgrades in the DISIS study. Duke has stated that it intends to use those DISIS cost allocations in evaluating projects in the 2022 RFP.

Duke is in the process of seeking approval from the NCTPC to include the RZEP in the 2022 Local Transmission Plan, which will be finalized in early 2023. If the RZEP are approved by the NCTPC, then to the extent the RZEP are assigned to projects in the DISIS 1 study, those Upgrades will be designated as “Contingent Facilities” in the Interconnection Agreements for those projects, as required in Duke's OATT, and no costs for the RZEP will ultimately be assigned to them. This creates a disconnect between the way in which the costs of the RZEP are considered in the RFP process and the way in which they will ultimately be handled in the interconnection process.

The allocation of the full cost of the RZEP to projects in the 2022 RFP is likely to have undesirable and problematic consequences. Duke witness Roberts testified that Red Zone projects participating in the 2022 SP are very likely to trigger the need for the RZEP in DISIS 1. Because the volume of projects being procured in the 2022 SP is much smaller than the total volume of projects that will benefit from the RZEP, this will (under the current study process) result in the full cost of the RZEP being allocated to a relatively small number of projects. (Tr. Vol. 16 p. 179-180) As Witness Farver acknowledged, the full allocation of RZEP costs in this manner for bid evaluation would significantly drive up the apparent cost of those projects for bid evaluation purposes, distorting the results of the RFP evaluation. (This has already been observed in the results of the Transitional Cluster Study, where the allocation of the RZEP costs to a small number of projects led to all Red Zone projects dropping out.) Depending on the costs assigned, this could result in Red Zone projects (which comprise the significant majority of projects that bid into the 2022 SP) not being selected in the 2022 SP, even though they would, if selected, ultimately not be allocated costs for those Upgrades, to the extent the RZEP is approved by the NCTPC and included in the 2023 LTP. This could, perversely, result in the RZEP—the costs of which (if they are approved by the NCTPC) are likely to be allocated to ratepayers—not actually being utilized by projects in the 2022 SP.

Even if projects in the Red Zone are selected in the 2022 SP, it would be inappropriate to include the full cost of the RZEP in calculating the cost of the procurement for purposes of the Volume Adjustment Mechanism. The VAM is intended, in part, to adjust procurement volume upward in years when the bids costs of solar projects are lower than expected, and to adjust volumes downward when costs are higher than expected. The Commission has concluded that the

RZEP ultimately will be required for least-cost compliance with the 70% carbon reduction requirement, and if they are approved by the NCTPC, they will almost certainly be constructed. To assign the full cost of the RZEP to the 2022 SP, or to any other particular procurement year (likely reducing the size of that procurement), is arbitrary and does not accomplish the goals of the VAM. For the same reasons, the full costs of the RZEP should not be considered when determining whether projects selected to fulfill the CPRE capacity allocation in the 2022 SP comply with the avoided cost cap. As discussed above, the projects most likely to be priced under the avoided cost cap are located in the Red Zone. But the allocation of the full RZEP costs to those projects would most likely put them over avoided cost, and make it much more difficult for Duke to fulfill its CPRE obligation in 2022.

At the same time, the Commission concludes that it would be inappropriate to give no consideration to the costs of the RZEP in the 2022 SP. As discussed at the hearing, to do so risks sending inappropriate price signals to solar developers about locating projects in the Red Zone. The ideal solution would be to allocate the cost of the RZEP across all the projects that will ultimately benefit from them. Unfortunately this is not possible, both because it is uncertain what projects (or indeed, what volume of projects) will ultimately benefit from those upgrades; and also because neither the North Carolina Interconnection Procedures nor Duke's OATT permit the allocation of upgrade costs to interconnection customers in future clusters.

Fortunately, Duke is not limited to using the DISIS Phase 2 study results for purposes of RFP bid evaluation, VAM calculation, and avoided cost cap evaluation. At the hearing, Ms. Farver testified that the DISIS Phase 1 study results would allocate the costs of the RZEP among the approximately 3600 MW of Red Zone projects in the DISIS study. This approximates the minimum volume of solar capacity that Duke estimates will be facilitated by the RZEP. Tr. vol. 28, 180. As a result, the allocation of costs for the RZEP at the conclusion of DISIS Phase 1 provides a rough, conservative approximation of the costs those projects would be responsible for if the costs of the RZEP could be allocated across the whole volume of projects that could benefit from them. *Id.* at 181. Although there is no ideal way to allocate the costs of the RZEP under the current state and federal regulatory structure, this rough approximation is far better than the alternatives, which are either to allocate either the full costs of the RZEP to projects in the 2022 SP, or to allocate no RZEP costs at all.

Accordingly, the Commission concludes that if the RZEP are approved by the NCTPC, then it is appropriate, for purposes of the 2022 SP, to use the DISIS Phase 1 allocation of Upgrade costs for approved RZEP. Specifically, Duke shall use the Phase 1 cost allocations for approved RZEP for purposes of final bid evaluation, VAM calculations, and assessment of compliance with the CPRE avoided cost cap. For any Upgrades not approved by the NCTPC for inclusion in the 2022 Local Transmission Plan, Duke shall use the final DISIS cost allocation.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 82-89
Transmission Planning
(Scheduling Order ordering paragraph 1.f.)

The evidence supporting these findings of fact and conclusions is contained in the Company's initial Carbon Plan filing on May 16, the comments filed by intervenors and the Public Staff, the testimony and exhibits of the witnesses, and the entire record in this proceeding…

Summary of reports from stakeholder meetings

Participants in the stakeholder processes convened by Duke Energy at the Commission's direction supported improving transmission planning.

At the first stakeholder meeting, participants recommended considering regional transmission coordination and incorporating transmission needs into resilience evaluations, modeling solar interconnection forecast sensitivities based on existing transmission constraints, progressive improvements, and an "enhanced transmission policy" that could improve interconnections further by alleviating constrained areas. First Stakeholder Meeting Summary Report at 1, In the Matter of: Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plans and Carbon Plan, Docket No. E-100, Sub 179 (N.C.U.C. Feb. 1, 2022) (Duke Report on Meeting 1). Duke represented that it was developing an enhanced transmission policy. Id. at 27. Stakeholders asserted that transmission improvements are critical and asserted that the Carbon Plan must take into account future transmission needs and siting of resources. Id.; Public Staff Report: Duke Energy "Carolinas Carbon Plan" Stakeholder Meeting at 4, In the Matter of: Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plans and Carbon Plan, Docket No. E-100, Sub 179 (N.C.U.C. Feb. 1, 2022) (Public Staff Report on Meeting 1). Stakeholders recommended setting up a working group on the issue and Duke took the request under consideration. Duke Report on Meeting 1 at 27; Public Staff Report on Meeting 1 at 3.

Duke held a technical subgroup meeting on modeling assumptions related to its solar interconnection forecast shortly before the second stakeholder meeting. Duke solicited input on the appropriate limits in an “Enhanced Transmission Policy” scenario, as well as the appropriate transmission cost adders to apply within the model. Stakeholders requested an unlimited interconnection sensitivity, better integration between the Carbon Plan and the North Carolina Transmission Planning Collaborative (NCTPC), integration with neighboring utilities, more detail as to estimated network upgrade costs for wind and solar, and cost sharing of network upgrades. Public Staff Report: Duke Energy “Carolinas Carbon Plan” Stakeholder Meeting 2 at 5, In the Matter of: Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plans and Carbon Plan, Docket No. E-100, Sub 179 (N.C.U.C. Mar. 2, 2022) (Public Staff Report on Meeting 2). Duke held that transmission investments were outside of the scope of the workgroup because they were being considered through a FERC process and should be left to that process. Carolinas Carbon Plan - Second Stakeholder Meeting Summary Report at 37, 40, 44, In the Matter of: Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plans and Carbon Plan, Docket No. E-100, Sub 179 (N.C.U.C. Mar. 2, 2022) (Duke Report on Meeting 2). Duke discussed the challenge of transforming the transmission system and acknowledged that the pace of transformation must accelerate to reliably meet clean energy objectives. Duke Report on Meeting 2 at 38. Duke recommended exploring solutions including the already-completed revisions to the interconnection process, reducing the delay between an interconnection agreement and a COD, and using the local transmission planning process to evaluate public policy needs. Id. at 39. Stakeholders recommended allowing the model to select solar first and then determining the transmission necessary to interconnect it and pointed out that a recent study showed that proactively building transmission to support renewables could reduce electricity rates by a third.

At the second stakeholder meeting, Duke noted the stakeholder interest in a technical subgroup that would work on the cost of transmission upgrades and ongoing efforts to relieve transmission and distribution congestion. Stakeholders raised questions about how output from the NC Transmission Planning Collaborative will feed into the Carbon Plan (and vice versa).

At the third and final stakeholder meeting, Rich Wodyka with the NCTPC gave an overview of the NCTPC and its work, including its goals, organizational structure, and various transmission study processes. At the conclusion of the meeting, many transmission issues remained in dispute, including how Duke will ensure that upgrades will be sufficient for future needs; whether Duke would model the effect of joining PJM or forming an RTO; whether joining PJM would result in cost savings; the effects of changes within PJM on North Carolina; how the cost of transmission upgrades will be allocated among rate classes and across DEC/DEP; whether Duke is considering proactive transmission and distribution upgrades;

how the NCTCP and Carbon Plan processes will interact; whether North Carolina's existing transmission planning processes are adequate to support the Carbon Plan or a more proactive transmission planning process is needed. Public Staff Report: Duke Energy "Carolinas Carbon Plan" Stakeholder Meeting 3 at 4-5, In the Matter of: Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plans and Carbon Plan, Docket No. E-100, Sub 179 (N.C.U.C. Mar. 29, 2022).

Summary of initial comments

CCEBA Initial Comments

CCEBA recommended comprehensive transmission planning reform, including directing Duke to take steps to reform the NCTPC process to advance the Carbon Plan through long-term, proactive and holistic transmission planning that will allow for the least-cost, timely integration of new low carbon resources. It supported the RZEP projects in the interim, along with near-term transmission investments necessary to allow for the development of offshore wind resources. It also supported Duke's proposal to consolidate system operations across DEP and DEC in the near term (2022-24).

CCEBA pointed out that North Carolina's historic incremental transmission planning process has become outdated partly as a result of the growth of distributed generation, and the Commission should require Duke to undertake proactive resource planning that combines resource planning under the Carbon Plan with proactive transmission planning. CCEBA proposed an iterative parallel process between the NCTPC and the Commission, allowing the Commission's resource decisions to drive transmission planning over 10 to 20-year terms, reducing costs and risks, and improving reliability through scenario-based planning. CCEBA recommended modeling the process on those in other listed regions. Comments And Issues Of The Carolinas Clean Energy Business Association at 28-31, In the Matter of: Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plans and Carbon Plan, Docket No. E-100, Sub 179 (N.C.U.C. July 15, 2022).

CEBA Initial Comments

CEBA supports a comprehensive and well-planned regional transmission buildout to support cost-effective emissions reductions. CEBA found Duke's proposals insufficient to that end, relying too heavily on the status quo. CEBA cited multiple studies showing that a well-planned and robust transmission system is crucial to least-cost decarbonization, two to three times the current transmission capacity is needed, and increase transmission capacity brings various economic benefits, facilitates renewable integration, and increases reliability. CEBA opposed fracturing transmission planning along state lines and supported meaningful interregional transmission planning. It requested the Commission encourage Duke to join an RTO or ISO if Duke cannot reliably plan transmission to meet regional needs cost-effectively. Initial Comments And Proposed Issues Of Clean Energy Buyers Association at 7-9, In the Matter of: Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plans and Carbon Plan, Docket No. E-100, Sub 179 (N.C.U.C. July 15, 2022).

City of Asheville and Buncombe County's Initial Comments

The City of Asheville and Buncombe County argued that proactive, large-scale, long-term transmission planning driven by future generation needs can lower costs by offering economies of scale and scope, citing multiple studies. This could reduce the costs of offshore wind. Planning for high-capacity lines that would enable access to large renewable resource areas would be more efficient than an incremental approach. And interregional coordination would further reduce costs. The city and county recommended Duke integrate transmission planning into resource planning and procurement, plan jointly with neighboring grids, and incorporate equity and justice concerns into transmission planning. City Of Asheville And Buncombe County Initial Comments On Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Carbon Plan at 13, In the Matter of: Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plans and Carbon Plan, Docket No. E-100, Sub 179 (N.C.U.C. July 15, 2022).

CLEAN Intervenors' Initial Comments

CLEAN Intervenors requested that the Commission develop a Carbon Plan that relies on proactive multi-value portfolios of transmission expansion planning, incorporates the results of existing collaborative planning efforts, leverages existing transmission corridors using advanced transmission technologies, and relies to the extent possible on regional projects that can reduce costs and improve reliability. They further requested the Commission open a docket to synchronize grid planning and transmission planning processes with Carbon Plan process and direct Duke to synchronize the two in its future proposed Carbon Plans. CLEAN

Intervenors opposed Duke's request for relief concerning transmission planning, which relied solely on existing processes outlined in Duke's Open Access Transmission Tariff (OATT) and planning through the North Carolina Transmission Planning Collaborative (NCTPC). Joint Comments of The North Carolina Sustainable Energy Association, Southern Alliance for Clean Energy, Sierra Club, and Natural Resources Defense Council at 29-30, In the Matter of: Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plans and Carbon Plan, Docket No. E-100, Sub 179 (N.C.U.C. July 15, 2022).

CLEAN Intervenors anchored their requests in an expert report prepared by Jay Caspary, Vice President of Grid Strategies LLC (Caspary Report). Witness Caspary made five recommendations for any future Carbon Plan. First, it should rely on proactive, scenario-based, multi-value portfolios of transmission expansion projects to identify bulk transmission upgrades. He recommended the multi-value approach because the actual value of transmission expansion typically is much larger than is projected in economic planning assessments that rely on production cost modeling. Second, it should incorporate the results of improved collaborative planning efforts with neighboring systems, as well as incorporate affected system studies, which can identify "backbone" transmission upgrades that will benefit the system as a whole. Third, it should leverage existing transmission corridors for future transmission needs. He opined that this will require greater transparency from Duke concerning its asset management practices, use of advanced transmission technologies or grid-enhancing technologies, and right-sizing appropriate projects. Fourth, it should rely on rigorous analysis of potential regional projects that would support future resource needs, such as enabling Midwest wind and offshore wind. Finally, witness Caspary recommended the Commission synchronize the development of its Carbon Plan with transmission planning processes, and direct Duke to plan resource and transmission additions at the same time for future proposed Carbon Plans. *Id.* at 7-9.

CPSA's Initial Comments

CPSA requested that the Commission initiate proceedings, including a technical conference, with the goal of establishing a proactive, long-term transmission planning process. It also requested the Commission direct Duke to immediately begin studying using grid-enhancing technologies. CPSA cited the benefits of planning and constructing the significant upgrades necessary for the Carbon Plan proactively rather than piecemeal and reactively, citing examples from PJM and MISO, FERC's Notice of Proposed Rulemaking relating to transmission planning, the North Carolina Clean Energy Plan, and the interconnection proceeding. CPSA recommended establishing a proactive transmission process, but not waiting for the process to be established before proceeding with necessary upgrades. CPSA also recommended the Commission consider the full benefits of transmission upgrades and not only their costs, and require Duke to study the use of grid-enhancing technologies. Corrected Comments Of Clean Power Suppliers Association On Proposed Carolinas Carbon Plan at 58-61, 68-72, 73-74, In the Matter of: Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plans and

Carbon Plan, Docket No. E-100, Sub 179 (N.C.U.C. Aug. 17, 2022).

CPSA retained The Brattle Group, Inc. (Brattle) to review Duke's proposed Carbon Plan and prepare a report on its findings (Brattle Report), which was attached as Exhibit A to CPSA's August 17 corrected comments. Corrected Comments Of Clean Power Suppliers Association On Proposed Carolinas Carbon Plan, Exhibit A, Duke Energy Resource Mix to Meet 70% CO2 Reduction by 2030 in NC, In the Matter of: Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plans and Carbon Plan, Docket No. E-100, Sub 179 (N.C.U.C. Aug. 17, 2022). Brattle explained that concerns about interconnecting the solar resources necessary for a successful Carbon Plan are caused by the piecemeal just-in-time approach of the existing transmission planning process. Brattle opined that employing system-wide proactive planning would identify no-regrets upgrades with multiple benefits; reduce the cost, time and complexity of interconnecting new resources; and better connect least-cost resources. Id. at 9. Employing a proactive long-term transmission planning process that studied potential resource mixes and the necessary transmission infrastructure simultaneously would further improve interconnection of solar. *Id.* at 9, 50.

Brattle argued that Duke must analyze the effect of proactively building transmission upgrades to improve interconnection in order to select the least-cost resource mix. *Id.* at 37. It cited industry experience and examples of other grid operators such as PactifiCorp, the California ISO, ERCOT, and MISO that analyze resources portfolios as well as the transmission needs for each. *Id.* at 38-42, 45-

46. Brattle recommended drawing from the experiences of these other regions and applying five planning best practices—the same as the five core principles identified by witness Caspary in his report and testimony, discussed below. *Id.* at 44. Brattle identified the transmission benefits used in different existing multi-value planning analyses and the very significant savings that applying multi-value frameworks have identified. *Id.* at 47-49. Brattle recommended employing proactive multi-value transmission planning as a way to identify the least-cost resource mix for the final Carbon Plan. *Id.* at 52.

MAREC Initial Comments

MAREC supported CCEBA's position on the need for comprehensive transmission planning reform. MAREC Action's Initial Comments, In the Matter of: Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plans and Carbon Plan, Docket No. E-100, Sub 179 (N.C.U.C. July 15, 2022).

North Carolina Electric Membership Corporation's (NCEMC) Initial Comments

NCEMC commented that Duke's proposed transmission and distribution investments must be reviewed through the current transmission planning process in North Carolina to determine their reliability and enhanced capacity values and whether they are needed to meet carbon-reduction goals. NCEMC expressed concern that although investing in new generation assets sited primarily in DEP might prove to be the lowest-cost path to the carbon reduction requirements of H951 it could result in disproportionate transmission and grid investments in DEP, further resulting in larger rate impacts in DEP, exacerbating rate differentials. NCEMC recommended reviewing for least-cost compliance in each service territory and reviewing cost allocation methodologies so that savings are distributed equitably, recommending an approach taken in New York. Comments of North Carolina Electric Membership Corporation at 10-15, In the Matter of: Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plans and Carbon Plan, Docket No. E-100, Sub 179 (N.C.U.C. July 15, 2022).

The Public Staff's Initial Comments

According to the Public Staff, successfully implementing Session Law 2021-165 will require substantial changes to the current method of transmission planning, particularly with the significant volume of coming generation asset retirements and additions. The Public Staff made three recommendations concerning future transmission. First, it recommended extending long-term transmission planning to 20 years and completing the first such plan prior to the 2024 Carbon Plan proceeding. It recommended the long-term plan identify long-term needs, the potential for proactive upgrades, and all upgrades required to maintain NERC compliance. Second, it recommended Duke continue to provide updated locational guidance maps in future DISIS and procurement solicitations, including known upgrades and planned proactive upgrades. Third, it recommended that in future Carbon Plan filings Duke clearly identify and justify any proactive transmission upgrades and provide the lead times necessary to construct them.

With respect to proactive transmission planning, the Public Staff again noted that the requirements of Session Law 2021-165 have created a need to re-evaluate current transmission planning processes given the risks in each Proposed Carbon Plan portfolio. The Public Staff advocated developing a least-reasonable-cost and least-regrets plan. It identified the central question to be whether to build proactive upgrades in anticipation of future interconnections or reactive upgrades in response to interconnection requests. The Public Staff then noted that all of Duke's proposed portfolios anticipated that power flows across the transmission interties from DEP to DEC would approximately double by 2030, likely increasing beyond 2030, and noted that Duke assumed that intertie capacity would never increase.

The Public Staff identified two main risks associated with future transmission construction. The first was insufficient time to build large scale transmission upgrades to allow economically selected generation. The Public Staff identified this as an increased risk based on current timelines.

The second risk the Public Staff identified was wasted proactive transmission assets, which it further divided into two categories: (1) building transmission that is either not utilized or underutilized; and (2) building transmission only to have it replaced by future upgrades in the first 10 to 15 years of the original asset's 40- to 60-year asset life. The Public Staff recommended beginning proactive transmission upgrades as soon as possible, as long as these two risk factors were addressed.

The Public Staff also recommended addressing the allocation of Carbon

Plan costs between DEC and DEP by allocating the cost of DEP's required transmission assets allocated to DEC proportional to DEC's reliance on those assets in order to meet its allocable share of CO_2 reduction requirements. It also recommended including cost allocation among DEC and DEP as part of any future proactive transmission upgrades, until DEC and DEP are merged.

The Public Staff supported Duke's proposed proactive transmission upgrades—meaning the RZEP—and stated Duke from a purely reactive transmission upgrade approach, where it constructs transmission only after a generator has requested interconnection, to a planning process that also considers proactive upgrades in anticipation of future generation required by the Carbon Plan adopted by the Commission. However, noting that past interconnection requests did not necessarily predict future development, the Public Staff stated it needed more information before it would recommend a plan identifying specific upgrades. The Public Staff requested Duke file the results of its then-pending study of the RZEP projects. The Public Staff requested the Commission delay considering cost recovery for the RZEP projects until allocation between DEC and DEP had been resolved. Comments of the Public Staff at 107-16, In the Matter of: Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plans and Carbon Plan, Docket No. E-100, Sub 179 (N.C.U.C. July 15, 2022).

Tech Customers' Initial Comments

Tech Customers requested the Commission require Duke to revise its proposed Carbon Plan to incorporate improvements to its transmission planning, including a coordinated portfolio-based transmission plan with the NCTPC. Tech Customers anchored this request in their expert report prepared by Gabel Associates, Inc. (Gabel Report), submitted with Tech Customers' initial comments. The Gabel Report discussed the benefits of a coordinated, portfolio-based transmission planning strategy as a proven means of increasing renewable generation resources, facilitating decarbonization, and reducing consumer costs. It further suggested that failing to take this approach would risk failing to achieve the optimal least-cost path to meeting carbon-reduction requirements. It cited recent prospective planning initiatives in the Mid-Continent ISO (MISO) and Southwest Power Pool (SPP) examples of successful planning efforts. The Gabel Report also recommended combining holistic transmission planning and resource procurement in a way that maximizes imports from neighboring regions. Tech Customers' Comments on Proposed Carbon Plan at 24, In the Matter of: Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plans and Carbon Plan, Docket No. E-100, Sub 179 (N.C.U.C. July 15, 2022).

Summary of testimony at public witness hearings

Witness David Sokal, on behalf of the Citizens Climate Lobby, recommended supporting improvements to the transmission grid necessary to improve efficiency and support distributed generation. Tr. vol. 1, 22. Witness Will Scott, on behalf of the North Carolina Conservation Network, recommended the Commission work with stakeholders to create a new, forward-looking transmission planning process that rather than reacting to generator interconnection requests would result in investments that would allow timely interconnection of solar and wind resources. Tr. vol. 1, 74. Witness Gray Jernigan, on behalf of MountainTrue, testified that transmission is the bottleneck limiting North Carolina's access to renewable resources and opined that the final Carbon Plan must order Duke to build sufficient transmission capacity to access the full potential of offshore wind, onshore wind, and solar power in a timely manner. Tr. vol. 3, 32. Witness Judy Mattox testified that transmission must be timely built to provide capacity for robust renewable energy. *Id.* at 92. Similarly, witness Ken Brame opined that North Carolina needs to invest more in transmission lines to connect new solar and wind farms. *Id.* at 102. Witness Drew Ball testified that transmission is a bottleneck limiting North Carolina's access to renewable resources and recommended making significant investments in transmission in order to deliver clean energy. *Id.* at 105. Witness Nancy Donley opined that Duke has historically underinvested in transmission and supported increasing investment in clean energy. Tr. vol. 6, 11-12.

Summary of direct testimony Duke witnesses Sammy Roberts and Maura Farver reviewed the directives in the Commission's November 19, 2021 final order in the 2020 IRP proceeding and Duke's response, provided in Appendix P to Duke's proposed Carbon Plan. They testified that resource planning guided by the Commission and the South Carolina commission must be coordinated with FERC-jurisdictional transmission planning, as well as forward-looking, or insufficient transmission infrastructure could put the Carbon Plan and energy transition at risk. They testified that integration would mitigate execution risk because the reactive, generator interconnection request-based approach to transmission planning entails significant delays. They testified that Duke must work within the existing NCTPC framework to evolve from reactive to proactive planning. Tr. vol. 16, 59-65.

Witness Roberts and witness Farver testified that Duke's approach to using proactive transmission planning in the Carbon Plan process was discussed in Appendix P to the document. They added that Duke will not be able to wait for solar procurements and the DISIS process to drive transmission upgrades before it will need to work on upgrades like the RZEP. They testified that Duke planned to follow the NCTPC processes for the RZEP. *Id.* at 65-69.

Witness Farver testified that Duke agrees with other parties that the NCTPC planning process needs to evolve to meet the needs of executing the final Carbon Plan. She testified that Duke will work on changes with other members of the NCTPC's OSC and stakeholders. Duke also believes that the NCTPC local planning processes could improve by conducting studies that more closely align with current generator interconnection studies. Duke also believes there's a need to clarify the process for obtaining feedback from the NCTPC's TAG. Witness Farver committed Duke to considering the request made by the Public Staff and others to move to a twenty-year planning horizon, but identified some methodological and administrative challenges with the proposal. *Id.* at 85-90.

Duke opposed CPSA's proposal to initiate a proceeding to develop a proactive long-term transmission planning process, in favor of the NCTPC process under attachment N-1 of Duke's OATT. Duke also opposed CPSA's recommendation to engage a third party to evaluate solar interconnection rates and measures to expedite interconnection. Duke also opposed a requirement to consider GETs on the grounds that Duke already does and will continue to investigate new technologies and deploys them when prudent. *Id.* at 85-90.

AGO – Edward Burgess

AGO witness Edward Burgess supported many of the Public Staff's recommendations concerning transmission planning, including using a twenty-year planning horizon, but he opined that the Public Staff and Duke were too focused on transmission upgrades within Duke's territory rather than improving connections to neighbors. He cited Strategen's report concerning the value of regional coordination. Tr. vol. 25, 226.

CCEBA/MAREC – Dinos Gonatas

CCEBA/MAREC witness Dinos Gonatas provided an overview of the need for an improved transmission planning process in North Carolina, and opined on four specific improvements: (1) increased interregional and intraregional transmission capacity; (2) the connection between transmission constraints at existing coal plants and constraints on new renewable resources; (3) application of multiple transmission planning scenarios in the long term; and (4) planning process reforms aimed at increasing responsiveness to stakeholders. Tr. vol. 22, 118-21.

In his overview, Witness Gonatas proposed evaluating transmission planning scenarios according to a multi-value framework. He simplified the metrics used by FERC and MISO to four: (1) value of congestion relief or fuel savings; (2)

avoided capital cost of local resources and other transmission upgrades that otherwise would be done anyway; (3) resource adequacy savings and reduced occurrence of load shedding; (4) decarbonization benefits. He opined that transmission constraints were a primary driver of Duke's generation choices in its proposed Carbon Plan, particularly concerning coal retirements, and further, that Duke was not transparent about the transmission requirements that it believed required coal plants to remain online longer than economic modeling would suggest. *Id.* at 121-25.

Concerning interregional planning, Witness Gonatas testified that Duke should clarify its modeling of the cost to interconnect to other systems because there can be great value in improved interconnection. He reviewed the current status of interregional transfer capability and discussed the benefits of interregional transfers, such as smoothing differences in generation and load through increased diversity, and over the long term improved renewable integration. He recommended a set of interconnection studies examining costs and benefits to optimize existing facilities and assess expansion potential to PJM and Southern Company. *Id*. at 125-30.

Concerning transmission's effect on coal retirements, witness Gonatas reviewed the constraints identified in the direct testimony of Duke witnesses Roberts and Farver. He testified that Duke had failed to enable transmission planning that would overcome those constraints and recommended a transparent planning process to achieve that outcome. He also testified that a lack of detailed technical information available from Duke prevented stakeholders from independently assessing transmission constraints and supported CPSA's call for independent evaluation. He also reviewed the operations of Duke's must-run coal plants and concluded that there are operating conditions that allow turning those plants down or off entirely, which in turn suggests that transmission constraints are less rigid than Duke concluded. He also opined that intraregional transfer limits between DEC and DEP were problematic and warranted further study. He testified that advanced grid technologies could be part of the solution. *Id.* at 125-36.

Witness Gonatas testified that the connection between resources scenarios and different transmission planning scenarios in Duke's proposed Carbon Plan was unclear, making it difficult to evaluate cost differences between Duke's portfolios. He opined that transmission scenarios should EnCompass a broad range of potential futures, such as constructing the RZEP, earlier coal retirements, higher renewables, and increased interconnection with neighboring regions. He recommended against considering Duke's scenarios heavily due to their heavy reliance on technologies that are not commercially ready, and instead using an open stakeholder process with equal access to planning information. *Id.* at 136-39.

Witness Gonatas discussed multi-value transmission frameworks and applied his version, noted above, to Duke's proposed Carbon Plan. He concluded that (1) if Duke had developed significantly different transmission build-outs then it could have captured congestion benefits and fuel-cost reductions; (2) in direct testimony Duke identified laudable grid modernization and safety projects but did not sufficiently identify potential synergies and savings through integration into the proposed Carbon Plan; (3) Duke's resource adequacy analysis performed by Astrape in 2020 appeared missed the efficiency of optimizing a system as a whole rather than islanded sub-systems and resource adequacy should be revisited in the Carbon Plan proceeding under new assumptions; and (4) carbon benefits could be captured through a dollar-per-ton price such as was used for the RGGI sensitivity in the Synapse Report. *Id.* at 139-44.

Concerning planning process recommendations, witness Gonatas referred to figure P-3 from Duke's proposed Carbon Plan—a map identifying the RZEP projects—and identified ambiguities such as references to prior system impact studies, contrasting that with a straightforward approach taken by MISO. He also recommended early engagement with stakeholders concerning transmission constraints, more frequent stakeholder meetings than are convened by the NCTPC Transmission Advisory Group (TAG), and a more meaningful role for stakeholders such as through merging the TAG with the Oversight Steering Committee (OSC), and greater participation by the Commission in NCTPC planning activities. He recommended the Commission consider whether Duke should revise its OATT attachment N-1. *Id.* at 144-49.

CIGFUR – Michael P. Gorman

CIGFUR witness Michael P. Gorman testified that transmission planning should be done hand-in-hand with production resource planning because each can affect the other and combining planning should result in the least-cost path. Tr. vol. 23, 41-42.

CLEAN Intervenors – Jay Caspary

In his testimony, CLEAN Intervenors' witness Jay Caspary discussed his report, Transmission Issues and Recommendations for Duke's Proposed Carbon Plan, filed as Exhibit 2 to CLEAN Intervenors' July 15 comments. *Id.* at 270. He focused on six issues: 1) proactive multi-value transmission planning, 2) the "Red Zone Transmission Expansion Plan" (RZEP), 3) collaborative planning studies, 4) advanced transmission technologies, 5) regional integration, and 6) synchronizing development of Carbon Plans with transmission planning processes. Tr. vol. 22, 228.

Witness Caspary explained that proactive transmission planning uses several future scenarios to frame decisions and better manage uncertainties. It looks forward at new resources that could be enabled by new transmission; the farther forward in time the more proactive the planning. Witness Caspary recommended following five core principles of proactive planning, which are (1) proactively planning for future generation and load using realistic projections for the life of the transmission asset; (2) using multi-value planning accounting for the full range of benefits provided by new transmission; (3) using scenario-based planning to address uncertainties and high-stress grid conditions across a range of possible futures and real-world system conditions; (4) using comprehensive transmission network portfolios to address system needs and cost allocation; and (5) jointly planning across neighboring interregional systems to increase resilience and improve economics and geographic diversification benefits. *Id.* at 230-31. Multi-value transmission planning looks beyond the production cost-derived valuation of the savings generated by new transmission at the full range of benefits, which are well captured in the NOPR in FERC's recent rulemaking RM21-17. According to Witness Caspary, proactive multi-value planning is central to developing a least-cost resource mix to meet future needs, but Duke has not truly employed it in its proposed Carbon Plan. *Id.* at 232-36. As discussed in Section X concerning the RZEP, witness Caspary supported the RZEP as necessary to but not sufficient for the Carbon Plan. *Id.* at 22, 236-40.

According to Witness Caspary, coordinated and collaborative planning is critical to transmission planning for a future grid. He recommended the Commission engage more heavily in collaborative planning processes such as Southeastern Regional Transmission Planning (SERTP), and the NCTPC. *Id.* at 240-41.

According to Witness Caspary, advanced transmission technologies (ATTs) and grid-enhancing technologies (GETs) are non-traditional hardware and software solutions which incorporate capabilities driven by sensors and advanced technologies to improve the performance and utilization of existing transmission assets. ATTs and GETs can improve efficiency by reducing losses and allow higher operating temperatures. According to witness Caspary, employing ATTs and GETs can be a low-cost way to increase transmission capacity, by increasing the capacity available on existing infrastructure and rights of way. He opined that Duke's proposed Carbon Plan did not appear to rely on ATTs and GETs. *Id.* at 241-44.

According to witness Caspary, improving regional integration and interregional transmission can provide large economic, reliability, and public policy benefits that can lower electricity costs. Further, conventional planning tends not to capture the full value of interregional transmission. Witness Caspary stressed that employing least-cost transmission planning does not mean lowest-initial-cost planning, and the latter can end up costing more in the long run as additional investments continue to be required. Witness Caspary opined that Duke's proposed Carbon Plan does not rely on sufficient regional integration and the Commission should require Duke to synchronize development of its proposed Carbon Plans with transmission planning processes and extend the transmission planning horizon to twenty or thirty years. *Id.* at 244-47.

Witness Caspary finally recommended synchronizing development of Carbon Plans with transmission planning. He opined that co-optimizing resource and transmission expansion will result in better decisions. *Id.* at 244-49.

CPSA – Michael Hagerty

CPSA witness Michael Hagerty testified that it is critical to establish a comprehensive and proactive transmission planning process for the Carolinas in order to meet the carbon-reduction requirements in H951 and reduce costs. He referred to CPSA's comments on the Carbon Plan and the Brattle Report for a discussion of the benefits of proactive planning and a request for a proceeding including a technical conference. Witness Hagerty noted that Duke proposed to work through the NCTPC and opined that a change to NCTPC probably would not be sufficient to implement proactive transmission planning since as discussed in the Brattle Report it must be combined with integrated resource planning for maximum benefit. Given FERC's jurisdiction over transmission planning, he discussed FERC's support for open transmission planning processes and several state commission's successful involvement in planning processes. Tr. vol. 25, 448-52.

The Public Staff – Dustin R. Metz

Public Staff witness Dustin R. Metz summarized the Public Staff's initial comments concerning long-term transmission planning and proactive planning. The bulk of his testimony about transmission concerned the RZEP, discussed above. Tr. vol. 21, 139-40.

Tech Customers – Michael Borgatti

Tech Customers retained Gabel Associates, Inc. (Gabel) to review Duke's proposed Carbon Plan and prepare a preferred portfolio (Gabel Report). Official Exhibits, Vol. 25 (Tech Customers - Gabel Report /A). Gabel recommended developing a holistic portfolio-based transmission expansion plan through the NCTPC. *Id.* at 15. Gabel determined that Duke had not taken a holistic scenario-based approach, instead developing transmission and interconnection piecemeal before integrating them into the proposed Carbon Plan. *Id.* Gabel warned that Duke's failure to take this approach risked selecting something other than the least-cost pathway to carbon-reduction requirements. *Id.* Gabel contrasted Duke's proposed investments with proposals in MISO and SPP that were developed using a coordinated strategy and resulted in savings many times greater than the investment by unlocking low-cost renewable resources. *Id*. at 16-17. Gable recommended the Commission direct Duke to develop a coordinated portfolio-based transmission plan with the NCTPC. *Id*. at 17.

Gabel also opined that Duke's proposed Carbon Plan did not meaningfully consider increasing firm long-term supply from other regions despite the availability of seventy-eight tie-line circuits with additional transfer capacity. *Id.* at 17. Gabel noted the large quantity of renewable resources in the PJM interconnection queue indicated that greater interconnection to PJM, which could accelerate decarbonization, connected through existing transmission and new transmission capacity being studied. *Id.* at 18. It opined that importing more renewable power from external resources could improve Duke's ability to achieve the carbon-reduction requirements, would be likely to save customers money, and would improve reliability and resilience. *Id.* at 19. It recommended the Commission require Duke to revise its planning and procurement processes to consider the benefits of procuring external assets. *Id.* at 19-20.

Tech Customers' witness Michael Borgatti, of Gabel, testified that among the challenges with Duke's plan that his team identified was reliance on the conventional generator interconnection process to install new resources. He noted that the Gabel Report recommended developing a comprehensive transmission expansion and interconnection plan that leverages experience from other regions. Tr. vol. 25, 51-52. Witness Borgatti also testified that Duke's conclusion that renewable imports would be cost prohibitive was not reasonable, pointing out that PJM's border rate is significantly higher than the cost to import from other regions through other interfaces. *Id.* at 65-66. He also testified that a comprehensive transmission and generator interconnection planning process at the NCTPC could capture overlooked transmission-related opportunities associated with coal retirements. *Id.*at 66-67.

Summary of rebuttal testimony – Roberts and Farver

In their rebuttal testimony, Duke witness Roberts agreed with other parties in the proceeding that proactive transmission planning is key to reliably executing a Carbon Plan. Witness Roberts testified that it is necessary to employ proactive transmission planning that is scenario-based and that coordinates transmission network upgrades, greenfield transmission expansion, and explores alternatives. Witness Roberts testified that in response to the possible FERC orders that will follow its transmission planning NOPR, Duke plans to implement any necessary changes to its OATT, engage with the NCTPC and its stakeholders, and continue to participate in SERTP. Tr. vol. 28, 123-36.

Summary of testimony on cross examination

Duke – Roberts and Farver - Direct

In response to CCEBA's attorney, witness Roberts agreed that it is important to integrate transmission planning with resource planning, that proactive planning is an important part of the Carbon Plan process, that if the two are misaligned it could put the Carbon Plan and energy transition at risk, and that alignment can help to mitigate execution risk and reduce the cost of upgrades. Tr. vol. 16, 134-36. He disagreed that the NCTPC's current local transmission planning process is insufficient, contending some processes needed refinement. *Id.* at 136. He agreed that the time required for interconnection under the current process, takes approximately two-and-a-quarter years. *Id.* at, 136-37.

Asked to describe Duke's proposal for proactive transmission planning reform at the NCTPC, witness Roberts stated that Duke wants to look at having studies like the NCTPC study be more like true generator interconnection studies, in which case the results would better reflect real life, and having studies look out longer-term. *Id.*at 137-38. He stated that not all changes, such as shifting towards generator interconnection-type studies, would need to wait until after FERC issues an order on the pending transmission planning NOPR, which could take years to finalize. *Id.* at 138-39. He was sure there is an avenue for Commission input into the NCTPC's local transmission planning process. *Id.* at 139-40. He reaffirmed that Duke plans to work with NCTPC OSC members and stakeholders on reforms, and confirmed that the OSC comprises Duke and the other load-serving entities Electricities and NCEMC with no role for third-party developers or sellers of power, or customers. , *Id.* at 140-42.

Witness Roberts testified that the NCTPC has an indirect role in resource planning because it plans for generation additions, but Duke does not run its IRP or Carbon Play by the NCTPC for approval, it receives the outputs of those documents. *Id.* at 142.

Witness Roberts confirmed that the NCTPC could include stakeholder input from TAG conversations and meetings in its refinements to existing processes. The TAG provides advisory input to the NCTPC. TAG members may make up to three public policy study requests before they must pay for the cost of studies. *Id.* at 142-44.

In response to CIGFUR's attorney, witness Roberts testified that it would be imprudent to incorporate the costs associated with the hypothetical transmission build-out described in the Carbon Plan into the Carbon Plan transmission cost adder because they are derived from a hypothetical example of a long-range transmission plan whereas actual generator siting could be drastically different, and because baseline costs already captured future ongoing upgrade costs because they were escalated with inflation, and the cost adder would be adjusted over time. *Id.* at 145-46. He testified that cost savings from brownfield development at retiring coal sites could be determined by transmission studies. *Id.* at 156.

In response to CPSA's attorney, witness Roberts agreed that the RZEP upgrades are unlikely to be the last set up upgrades necessary to comply with H951, and for future upgrades Duke will not have the same amount of information about interconnection requests. Tr. vol. 16, 168:2-16. He testified that besides DISIS studies, Duke will look to transmission planning scenarios to find synergistic and least-cost upgrades to connect resources like solar. Tr. vol. 16, 168:17-169:1. A scenario-based analysis could be performed within the NCTPC process. *Id.* at 16869.

Witness Roberts confirmed that the current interconnection process takes two-and-a-quarter years from the time the request is made to the time an interconnection agreement (IA) is signed, although it could be close to a year and a half if the request was made toward the end of the DISIS enrollment window. *Id.* at 169-70. A project that did not require thermal upgrades past the point of interconnection likely would take a year or two between signing of the IA and completion of construction, for a total time from request to completion of two-and-a-half to three-and-a-half years. *Id. a*t 170-71. Witness Roberts later revised his estimate of the time to interconnect solar projects to twenty-six to thirty-two months. Tr. vol. 17, 55.

Witness Roberts was aware that CPSA had recommended establishing an independent technical advisory committee to study achieving higher solar interconnection rates, but opined that the internal process improvements presented at stakeholder meetings would save time. Tr. vol. 16, 182. He testified that Duke had already begun implementing some of the improvements and was surprised solar developers had not heard that. *Id.* at 184-86.

In response to counsel for CLEAN Intervenors, Witness Roberts testified that it will be impossible to achieve the 2050 carbon-reduction requirement without additional upgrades beyond the RZEP projects. *Id.* at 188. He confirmed that Duke believes shifting to proactive transmission planning is necessary. *Id.* at 194. He also confirmed that the NCTPC declined to include the RZEP in its 2021 midyear update and the Commission cannot be sure that the RZEP will be included in the next NCTPC update. *Id.* at 197. Duke is planning to submit a public policy request of long-range transmission needs for the Carbon Plan, but the Commission also cannot be sure that the NCTPC will grant that request or approve all of the upgrades that it contains. *Id.* at 199-200.

Witness Roberts confirmed that the final coal retirement dates in Duke's proposed Carbon Plan depend on replacement resources and transmission upgrades and some were delayed accordingly. *Id.* at 207. He discussed the revisions to Duke's large generator interconnection procedures (LGIP) that Duke recently proposed to FERC, which FERC granted on September 6, 2022. *Id.* at 207. He testified that the purpose of Duke's revision to the LGIP was to allow customers who have paid for transmission to retain the rights to that transmission, and acknowledged that the revised procedures could be to make it easier and faster to connect new generation where generation is retired. *Id.* at 210-11. He agreed that multiple generation technologies could qualify for the revised LGIP procedure, including standalone storage and solar-plus-storage. *Id.* at 214-16.

In response to counsel for Tech Customers, witness Roberts acknowledged the recommendations in the Gabel Report to establish a new planning process with the NCTPC. *Id.* at 222. He confirmed that Duke had reviewed three studies concerning imports from neighbors, one for 1,500MW from PJM to DEP, a 2019 study for onshore wind through PJM, and a transmission service request to PJM. *Id.* at 223-24. He confirmed a lack of studies of transferring power from the Tennessee Valley Authority or Southern Company, despite Duke's seventy-eight tie-line circuits connecting to ten different transmission operators. *Id.* at 225-26.

In response to the Public Staff's attorney, witness Roberts again confirmed the conclusions of the PJM transfer studies noted above, discussed calculation of the PJM border rate, and confirmed a number of transmission upgrades not included in the PJM-related studies. Tr. vol. 17, 25-28.

Witness Roberts testified that TAG stakeholder input is taken to the OSC—of which he is a members—which votes on whether or not to approve a local transmission plan. *Id.* at 42. He reviewed Public Staff Transmission Panel Direct Cross Examination Exhibit 2, a scoping document for the OSC, similar to

Attachment N-1 to Duke's OATT. *Id.* at 42-44. He confirmed that Duke has half of the voting members of the OSC, that the OSC is governed by majority vote failing consensus, and in the event of a tie would retain an independent third party, although to his knowledge the voting members had never failed to reach consensus. *Id.* at 44-45. He confirmed that any NCTPC participant or TAG participant could dispute a decision of the OSC at the NCUC, although to his knowledge that had never happened. *Id.* at 45-46. He confirmed that the investor-owned utilities were not bound by the decisions of the OSC to the extent that they reasonably determined they would violate reliability standards or least-cost principles. *Id.* at 46.

Witness Roberts testified that the resources in an approved IRP or Carbon Plan would be studied in the base reliability model in the NCTPC process. *Id.* at 49-50. Reviewing Public Staff Transmission Panel Direct Cross Examination Exhibit 3, the NCTPC's 2022 study scope document, witness Roberts confirmed that it reflected the current resource plan—prior to a final Carbon Plan—including coal replacements. *Id.* at 50-52.

In response to questions from Commissioner Clodfelter, witness Roberts testified that the RZEP projects in South Carolina had not yet been reviewed by the Carolinas Transmission Collaborative Arrangement (CTCA)—the South Carolina sister to the NCTPC. Tr. vol. 18, 130-:1-131:2. He believed that the RZEP projects would require CPCNs in South Carolina and if those were not granted Duke would continue to pursue approval, attempting to persuade the South Carolina commission. Tr. vol. 18, 131:2-133:2. He later clarified that the NCTPC handles local transmission planning for North Carolina and South Carolina. Tr. vol. 19, 90:4-16.

In response to questions from Commissioner Hughes, Witness Roberts testified that transmission upgrades absolutely have resilience benefits in addition to reliability benefits. Tr. vol. 18, 143:5-145:11.

In response to questions from Chair Mitchell, witness Roberts walked through the process that the NCTPC employs to approve an annual local transmission plan, from a scope document through TAG input, TAG, OSC, and Planning Working Group (PWG) meetings, the midyear update, annual reliability study, the report on the annual reliability study, and the OSC vote on that report. Tr. vol. 19, 17:24-21:7. The scope document will begin with the prior year's approved local transmission plan and identify transmission upgrades necessary as a result of interconnection agreements, generator retirements, additional resources, and additional load. Tr. vol. 19, 21:8-22:4. The inputs concerning changes to be studied come from the load-serving entities, while the PWG actually performs the studies. Tr. vol. 19, 23:4-13. He reaffirmed that going forward, studies should look at public policy requests more like generator interconnection studies, including looking at maximum generation scenarios in local areas and ensuring firm deliverability. Tr. vol. 19, 23:13-24:21. At the end of the process, the report will identify specific transmission projects considered and state that there were no reliability issues encountered in the studies. Tr. vol. 19, 24:22-26:7. Projects identifies as needed in the NCTPC local transmission plan would be translated into the base models in the DEC and DEP transmission planning models and added to Duke's transmission additions plan, which is akin to an execution plan. Tr. vol. 19, 27:2-12. The outputs from NCTPC planning feed into SERTP. Tr. vol. 19, 91:15-92:6.

In response to questions from Commissioner Duffley, witness Roberts confirmed that if Duke were selecting sites for a large quantity of solar it would choose the areas of high solar viability identified in Figure 3 of the Transmission Panel's testimony due primarily to land availability. Tr. vol. 19, 60:20-61:63:1.

CPSA – Tyler Norris

In response to questions from Commissioner McKissick, CPSA witness Tyler Norris discussed CPSA's request for a technical advisory committee with stakeholder participation that would look at expediting interconnections, explaining that the committee could look into improving interconnection study methodology, customer self-build, and proactive transmission planning. Tr. vol. 26, 132:2-134:8. In response to Chair Mitchell, witness Norris testified that there had been limited engagement on proactive transmission planning, beyond the RZEP projects. Tr. vol. 26, 181:12-182:1.

Duke – Roberts and Farver - Rebuttal

In response to CCEBA's counsel, witness Roberts testified that the RZEP projects are an example of the proactive multi-value transmission network upgrades that will need to be added in order to execute the final Carbon Plan. Tr. vol. 28, 170:14-22. He testified that he believed that the current avenue for stakeholder involvement in the NCTPC process, by way of the TAG, is sufficient and the entities ultimately responsible for paying for transmission should be the ones making decisions. Tr. vol. 28, 170:23-172:13. He testified that the TAG process was not necessarily reactive because the NCTPC could respond to stakeholders' proposals. Tr. vol. 28, 172:14-23. He reiterated that he believed the NCTPC did need to change its studies to be more similar to generator interconnection studies. Tr. vol. 28, 172:24-173:5. Witness Roberts testified that generation planning could be incorporated into the NCTPC process through public policy requests, including from the Commission itself. Tr. vol. 28, 173:6-18.

In response to CPSA's counsel, witness Roberts testified that a proactive transmission planning approach looks at the transmission needed to facilitate a resource plan and maximizes overall benefits holistically. Tr. vol. 28, 175:8-176:11. The portfolios used in this process would come from the Carbon Plan, either a set of near-term actions or a certain portfolio or range of portfolios, if those are approved. Tr. vol. 28, 176:12-177:10. Witness Farver testified that it is impossible to tell the full number of megawatts that will be enabled by upgrades under proactive transmission planning, and witness Roberts agreed. Tr. vol. 28, 185:2-186:3.

Public Staff - Metz

Witness Metz agreed with witness Roberts for Duke's Transmission Panel that it is important that North Carolina develop a process to integrate resource planning and transmission planning. Tr. vol. 23, 76.

Discussion and conclusions

Developing a least-cost path to achieving the carbon-reduction requirements in Session Law 2021-165 will require proactive multi-value transmission planning. Conventional transmission planning is fundamentally reactive because it is driven by generator interconnection requests and the reliability issues that they create. It is typically driven by the lowest-initial-cost transmission investments that will resolve reliability issues. This approach can cost more than proactive planning over the long term because additional incremental transmission investments continue to be required.

Proactive multi-value transmission planning is more likely than conventional, reactive transmission planning to lead to the least-cost path to the carbon-reduction requirements in Session Law 2021-165. Proactive transmission planning looks forward in time across a range of future scenarios and employs five core principles: (1) proactively plan for future generation and load using realistic projections for the life of the transmission asset; (2) use multi-value planning accounting for the full range of benefits provided by new transmission; (3) use scenario-based planning to address uncertainties and high-stress grid conditions across a range of possible futures and real-world system conditions; (4) use comprehensive transmission network portfolios to address system needs and cost allocation; and (5) jointly plan across neighboring interregional systems to increase resilience and improve economics and geographic diversification benefit. Multi-value transmission planning analyzes the full range of benefits provided by new transmission investments, rather than limiting the analysis to the production cost-derived valuation of the savings generated by new transmission. The Commission has the authority to require proactive multi-value transmission planning for Carbon

Plans, as a means of carrying out the mandate in Session Law 2021-165 to develop the least-cost path to its carbon-reduction requirements.

As discussed above, the RZEP projects are an important first step towards proactive transmission planning and are necessary though not sufficient to a successful final Carbon Plan. However, the development of the RZEP projects, discussed above, does not reflect true proactive multi-value transmission planning, nor does Duke's proposed Carbon Plan as a whole. There is no evidence that Duke synchronized resource planning with transmission planning or applied the five core principles or multi-value analysis discussed above. Duke proposes to move towards proactive transmission planning by reforming existing NCTPC processes, such as by shifting towards generator interconnection-type studies. This would represent an improvement but also would not constitute true proactive multi-value transmission planning. Nor is stakeholder participation in NCTPC processes sufficient. Stakeholders, including the Commission, may participate in the NCTPC's TAG. Stakeholders should inform the analysis each of the five core principles and the values in multi-value analyses.

While the RZEP projects represent an important first step towards proactive transmission planning and form an essential part of the 2022 Carbon Plan, future Carbon Plans must be based on proactive multi-value transmission planning. Accordingly, it is appropriate to open a proceeding on proactive multi-value transmission planning. The proceeding will also analyze synchronizing resource planning and transmission planning. The Commission will establish this proceeding within sixty days of this Order.

IT IS, THEREFORE, ORDERED as follows:

1. The following Accepted Portfolios, considered collectively, are reasonable for planning purposes for achieving carbon emissions reductions in a manner consistent with the requirements of G.S. § 62-110.9, prudent utility planning, and for informing the Commission's Near-Term Execution Plan: Optimized and Regional Resources portfolios modeled by Synapse on behalf of CLEAN intervenors, the Preferred portfolio modeled by Gabel and Strategen on behalf of the Tech Customers, SP-AGO portfolio modeled by Strategen on behalf of the Attorney General's Office, Portfolios 1 and P1-Alt modeled by Duke Energy, and CPSA3, modeled by Brattle on behalf of CPSA.

2. Duke's request to find its proposed Carbon Plan portfolios P2 through P4 as well as Supplemental Portfolios 5 and 6 to be reasonable for planning purposes is denied.

3. Consistent with Accepted Portfolios, the Companies shall pursue the following Near-Term Execution Plan as part of the Commission's approved Carbon Plan:

- Solar Procurment
    - 2022 solar procurement of 1647 MW, of which 440 MW consists of third-party CPRE (which will roll over to future HB951 procurements if unfulfilled); 2023 solar procurement of 1647 MW (with a minimum of 300 MW of paired storage); 2024 solar procurement of 1647 MW (with a minimum of 450 MW of paired storage);
    - If the RZEP are approved by the TPC, final DISIS cost allocations for RZEP will not be considered in bid evaluation, VAM calculation, or avoided cost cap compliance for solar procurements;
    - Revisit Volume Adjustment Mechanism for 2023-24 procurements before the 2023 procurement;
    - Begin Stakeholder engagement on new contract language for solar-plus-storage, including properly valuing longer-duration storage, to be presented for NCUC approval before the 2023 procurement;

- Standalone Battery Storage
    - Finalize procurement strategy and initiate procurement activities to procure 850 MW minimum of standalone, battery-energy storage
    - Allow for Build-Own Transfer of standalone battery-energy storage
    - Invest in operational capabilities for capitalizing on energy storage resources for grid services

- Onshore Wind
    - Initiate competitive procurements of Carolinas onshore wind with target volumes of 300 MW in 2023, 300 MW in 2024, and 300 MW in 2025 with target in-service dates of 2026, 2027, and 2028 respectively. Duke will also begin the necessary activities to support adding 450 MW of imported onshore wind in both 2027 and 2028
    - Engage in inter-regional coordination with PJM for facilitating power purchase of imported onshore wind
    - Integrate Midwest wind import into short-term transmission planning

- Offshore Wind
    - Initiate study of costs of developing three distinct WEA leases

- Pumped Storage Hydro
    - Conduct feasibility study for 1,700 MW at Bad Creek, develop EPC strategy, and apply at FERC for re-licensing

- Grid Edge
    - Step-up utility energy efficiency savings to 1.5 percent of eligible retail load by 2027 and 1.5 percent of total retail load by 2030
    - Develop and support programs to empower customer-owned distributed renewable energy resources to accelerate contribution to grid needs with a target of 1 GW of distributed energy resources on-line by 2035.

- RZEP
    - Begin construction in 2022 if approved by NCTPC

4. No findings with respect to the reasonableness or prudence of Duke's proposed initial project development activities for long-lead time resources as set forth in Table 3 of the Executive Summary of Duke's Proposed Carbon Plan are made at this time.

5. Duke shall conduct new EnCompass modeling that takes into

account both supply-side and demand-side impacts of the IRA to the costs of potential resources for Carbon Plan compliance as part of the 2023 IRP Update, with opportunity for intervenor comments and consideration of alternative modeling.

6. Duke shall include the impacts of the IRA as part of any 2024 Carbon Plan modeling as well as for any CPCN applications for projects related to Carbon Plan compliance that are submitted by Duke prior to the 2024 Carbon Plan update.

7. Duke shall provide ongoing reports to the Commission on its efforts to obtain funding under the Infrastructure Investment and Jobs Act in Docket No. M-100, Sub 164 and shall supplement those reports with its efforts to obtain funding or financing under the Inflation Reduction Act. Such reports shall demonstrate how such funding or financing inures to the benefit of ratepayers and not shareholders to the maximum extent possible.

8. <u>Duke shall 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. The technical</u> advisory<u> committee should provide specific comments or feedback to Duke in the form of a report, which report is to be included in the initial filing made in Duke’s next Carbon Plan filing, along with a detailed description by Duke of the steps it has taken and intends to take to improve interconnection performance.</u>

9. In its next carbon plan update filing, Duke Energy shall include a range of utility energy efficiency savings levels as a decrement to total load as part of its modeling: 1% of total sales, 1.5% of eligible sales, and 1.5% of total sales.

10. The Companies shall work with the Collaborative and other stakeholders on finding an appropriate method for modeling utility EE as a selectable resource within EnCompass as an alternative method for considering utility EE as a decrement to load.

11. Deny Duke's request to change the definition of low-income customers for purposes of its income-qualified EE programs to 300% of the Federal Poverty Level.

12. Duke shall work with the Carolinas EE/DSM Collaborative to revise the inputs underlying the benefits to the utility system in the EE/DSM cost-recovery mechanism so that those customer-sited programs are evaluated on par with zero-carbon supply-side alternatives and submit a proposal for Commission consideration within 180 days of the Commission's Final Order.

13. The Companies shall adopt more reasonable assumptions for customer adoption of NEM and other distributed energy resources for carbon planning purposes, which may include modeling DERs as a selectable resource in EnCompass, and shall continue to offer reasonable support for private investments in distributed renewable energy resources.

14. Duke's request to begin near-term resource development for offshore wind at the Carolina Long Bay lease site obtained by Duke's affiliate is denied at this time. Instead, the Commission will hire an independent, third-party

to undertake a study to evaluate the three available offshore wind lease areas located off the coast of North Carolina to compare the offshore wind lease areas and determine which, if any, could potentially assist in meeting the least-cost mandate to lower carbon emissions consistent with the language in HB 951. The parameters of the study will be determined through a stakeholder process to immediately proceed undertaking the study. The results of the study should be reported as soon as possible, but no later than the 2024 Carbon Plan update.

15. The Commission will open a generic investigatory docket within 60 days to examine how best to synchronizing resource planning and transmission planning and apply proactive multi-value transmission planning in North Carolina, including by integrating the FERC-jurisdictional NCTPC process with the Commission's carbon planning process or other transmission planning reforms.]

16. Approve Duke's approach to accounting for the emissions from new out-of-state resources.

17. Duke shall provide an annual update, along with statistics, that illustrate any progress made towards meeting carbon reduction requirements to effectively track compliance.

ISSUED BY ORDER OF THE COMMISSION.

This the ___ day of __________, 2022.

NORTH CAROLINA UTILITIES COMMISSION

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A. Shonta Dunston, Chief Clerk