ANNUAL REPORT REGARDING
LONG RANGE NEEDS FOR EXPANSION OF ELECTRIC GENERATION FACILITIES FOR SERVICE IN NORTH CAROLINA

REQUIRED PURSUANT TO N.C. Gen. Stat. § 62-110.1(c)

DATE DUE: DECEMBER 31, 2022
SUBMITTED: DECEMBER 30, 2022

RECEIVED BY
THE GOVERNOR OF NORTH CAROLINA; THE JOINT LEGISLATIVE OVERSIGHT COMMITTEE ON AGRICULTURE AND NATURAL AND ECONOMIC RESOURCES; THE CHAIRS OF THE SENATE APPROPRIATIONS COMMITTEE ON AGRICULTURE, NATURAL, AND ECONOMIC RESOURCES; AND THE CHAIRS OF THE HOUSE OF REPRESENTATIVES APPROPRIATIONS COMMITTEE ON AGRICULTURE AND NATURAL AND ECONOMIC RESOURCES

SUBMITTED BY
THE NORTH CAROLINA UTILITIES COMMISSION

ABBREVIATIONS AND ACRONYMS

ACE EPA's Affordable Clean Energy Rule
BSER best system of emissions reduction
CC combined-cycle
CECPCN Certificate of Environmental Compatibility and Public Convenience and Necessity
CIGFUR Carolina Industrial Group for Fair Utility Rates
COL combined construction and operating license
CPCN Certificate of Public Convenience and Necessity
CPP EPA's Clean Power Plan
CPRE – Competitive Procurement of Renewable Energy
CT combustion turbine/s
CUCA Carolina Utility Customers Association, Inc.
DEC Duke Energy Carolinas, LLC
DENC Dominion Energy North Carolina
DEP Duke Energy Progress, LLC
DOE U.S. Department of Energy
DSM demand-side management
EDF Environmental Defense Fund
EE energy efficiency
EGU electric generating unit
EMC electric membership corporation
EnergyUnited EnergyUnited EMC
EPA U.S. Environmental Protection Agency
EPAct 2005 Energy Policy Act of 2005
FERC Federal Energy Regulatory Commission
GreenCo GreenCo Solutions, Inc.
GridSouth GridSouth Transco, LLC
G.S. General Statute
GWh gigawatt-hour/s
Halifax Halifax EMC
IOU investor-owned electric utility
IRP integrated resource plan
kWh kilowatt-hour/s
LEE CC Lee combined-cycle plant in SC
Lee Nuclear William States Lee III nuclear station in SC
MAREC Mid-Atlantic Renewable Energy Coalition
MW megawatt/s
MWh megawatt-hour/s
NCDEQ North Carolina Department of Environmental Quality

ABBREVIATIONS AND ACRONYMS (continued)

NCEMC North Carolina Electric Membership Corporation
NCEMPA North Carolina Eastern Municipal Power Agency
NCMPA1 North Carolina Municipal Power Agency No. 1
NC-RETS North Carolina Renewable Energy Tracking System
NCSEA North Carolina Sustainable Energy Association
NCTPC North Carolina Transmission Planning Collaborative
NC WARN North Carolina Waste Awareness and Reduction Network
NERC North American Electric Reliability Corporation
NOPR Notice of Proposed Rulemaking
NRC Nuclear Regulatory Commission
OASIS Open Access Same-time Information System
OATT open access transmission tariff
OPSI Organization of PJM States, Inc.
PJM PJM Interconnection, LLC
PPA purchase power agreement/s
PURPA Public Utility Regulatory Policies Act of 1978
PV photovoltaic
REC renewable energy certificate/s
REPS Renewable Energy and Energy Efficiency Portfolio Standard
RFP request for proposals
ROE return on equity
RPS renewable portfolio standard
RTO regional transmission organization
SACE Southern Alliance for Clean Energy
SCC State Corporation Commission of Virginia
SCE&G South Carolina Electric & Gas
Senate Bill 3 Session Law 2007-397
SEPA Southeastern Power Administration
SERC SERC Reliability Corporation
SERTP Southeastern Regional Transmission Planning
TOU time-of-use
TRANSCO Transcontinental Gas Pipe Line Company, LLC
TVA Tennessee Valley Authority
VEPCO Virginia Electric and Power Company
VOWTAP Virginia Offshore Wind Technology Advancement Project
WPSA Wholesale Power Supply Agreement

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APPENDICES

1. EXECUTIVE SUMMARY

This annual report to the Governor and the General Assembly is submitted pursuant to N.C. Gen. Stat. § 62-110.1(c), which specifies that each year the North Carolina Utilities Commission shall submit to the Governor and appropriate committees of the General Assembly a report of its analysis of the long-range needs for the expansion of facilities for the generation of electricity in North Carolina and a report on its plan for meeting those needs. Much of the information contained in this report is based on reports to the Commission by the electric utilities regarding their analyses and plans for meeting the demand for electricity in their respective service areas. It also reflects information from other records and files of the Commission.

There are three regulated investor-owned electric utilities (IOUs) operating under the laws of the State of North Carolina and subject to the jurisdiction of the Commission. All three of the IOUs own generating facilities. They are Duke Energy Progress, LLC (DEP), whose corporate office is in Raleigh; Duke Energy Carolinas, LLC (DEC), whose corporate office is in Charlotte; and Virginia Electric and Power Company (VEPCO), whose corporate office is in Richmond, Virginia, and which does business in North Carolina under the name Dominion Energy North Carolina (DENC).

DEC and DEP, the two largest electric IOUs in North Carolina, together provide approximately 96% of the utility-supplied electricity consumed in the state. Approximately 22% of the IOUs' electric sales in North Carolina were to the wholesale market, consisting primarily of electric membership corporations and municipally-owned electric systems.

Table ES-1 shows the gigawatt-hour (GWh) sales of the regulated electric utilities in North Carolina.

Table ES-1:2020-2021 Electricity Sales of Regulated Utilities in North Carolina

	NC Retail GWh*		NC Wholesale GWh*		Total GWh Sales* (NC Plus Other States) [1]	
	2021	2020	2021	2020	2021	2020
DEP	37,402	36,298	21,083	20,590	66,882	65,240
DEC	56,916	55,675	4,984	4,631	87,797	84,574
VEPCO	4,222	4,169	50	46	83,600	86,992

*GWh = 1 Million kWh (kilowatt-hours)

[1] DEC and DEP are also in South Carolina. VEPCO is also in Virginia.

During the 2022 to 2035 timeframe, the average annual growth rate in summer peak demand for electricity in North Carolina is forecasted to be approximately between 0.7% - 2.04% compared to 0.7% - 2.3% for winter peak load growth. Table ES-2 illustrates the system wide average annual growth rates forecast by the IOUs that operate in North Carolina. Each uses generally accepted forecasting methods and, although their forecasting models are different, the econometric techniques employed by each are widely used for projecting future trends.

Table ES-2: Forecast Annual Growth Rates for DEP, DEC, and VEPCO (With Energy Efficiency (EE) Included) (2022 – 2035)

	Summer Peak	Winter Peak	Energy Sales
DEP	0.7%	0.7%	0.5%
DEC	0.8%	0.7%	0.7%
VEPCO	2.04%	2.31%	3.04%

As illustrated in Table ES-3, North Carolina's IOUs rely on a balanced mix of generating resources to ensure reliable energy to their customers.

Table ES-3: Total Energy Resources by Fuel Type for 2021

	DEP	DEC	VEPCO
Coal	10%	17%	10%
Nuclear	43%	49%	35%
Net Hydroelectric*	1%	2%	1%
Natural Gas and Oil	32%	21%	45%
Non-Hydro Renewable	9%	2%	2%
Other Purchased Power	5%	8%	7%

*See discussion of pumped storage in Section 6.

In 2007, North Carolina became the first state in the Southeast to adopt a Renewable Energy and Energy Efficiency Portfolio Standard (REPS). Under the REPS statute, codified at N.C. Gen. Stat. § 62-133.8, investor-owned electric utilities are required to increase their use of renewable energy resources and/or energy efficiency such that those sources meet 12.5% of their NC retail sales in 2021. EMCs and municipal electric suppliers are required to meet a similar requirement of 10% of their NC retail sales in 2018 and thereafter. The requirements under the law phase in over time, with the most recent increase in 2021, requiring investor-owned utilities to meet 12.5% of their prior year's NC retail sales through renewable energy and EE sources.

The electric utilities are subject to federal, state, and local laws and regulations with regard to air and water quality, hazardous and solid waste disposal and other environmental laws and regulations. Environmental compliance directly impacts existing generation portfolios and choices for new generation resources. For example, the utilities evaluate how robust their plans are relative to potential greenhouse gas regulations as well as their own sustainability goals.

North Carolina Governor Roy Cooper signed Executive Order No. 80 (EO80) on October 29, 2018, calling for a 40% reduction in statewide greenhouse gas emissions by 2030. The order tasked NCDEQ with developing a Clean Energy Plan (CEP) for North Carolina. After an extensive stakeholder engagement process, including meetings and public comment periods, the CEP was presented to Governor Cooper on September 27, 2019, and subsequently published in October 2019. The CEP includes Clean Energy Goals as follows:

- Reduce electric power sector greenhouse gas emissions by 70% below 2005 levels by 2030 and attain carbon neutrality by 2050;
- Foster long-term energy affordability and price stability for North Carolina's residents and businesses by modernizing regulatory and planning processes; and
- Accelerate clean energy innovation, development, and deployment to create economic opportunities for both rural and urban areas of the state.

NCDEQ established stakeholder groups tasked with providing policy designs to align with EO80 goals. Final reports from these efforts were published in early 2021.

In 2019, Duke Energy announced a corporate commitment to reduce carbon dioxide (CO_2) emissions by at least 50% from 2005 levels by 2030 and to achieve net-zero carbon emissions by 2050. According to Duke Energy, this is a shared goal important to the Company's customers and communities, many of whom have also developed their own clean energy initiatives. As one of the largest investor-owned utilities in the U.S., the goal to attain a net-zero carbon future represents one of the most significant reductions in CO_2 emissions in the U.S. power sector.

In February 2020, Dominion Energy announced its commitment to net zero CO_2 and methane emissions across its nationwide electric generation and natural gas infrastructure operations by 2050. The goal covers CO_2 and methane emissions, the dominant greenhouse gases, from electricity generation and gas infrastructure operations. According to Dominion Energy, the strengthened commitment builds on Dominion Energy's strong history of environmental stewardship, while acknowledging the need to further reduce emissions. According to the Dominion Climate Report, as Dominion works toward Net Zero emissions by 2050, Dominion Energy will focus on near-term progress. Under Dominion Energy's Net Zero strategy, Dominion is committed to reducing carbon emissions 55% by 2030 from their power generation business (compared to 2005 levels). Dominion Energy likewise expects to reduce methane emissions from their natural gas business by 65% by 2030 and 80% by 2040 (from 2010 levels).

The Virginia Clean Economy Act (VCEA) was signed into law on April 11, 2020. The VCEA includes provisions that institute a mandatory renewable portfolio standard, enhance renewable generation and energy storage development, require the retirement of certain generation units, establish energy efficiency targets, and expand net metering. The VCEA formalizes the administrative policy goals set by Virginia Governor Northam in September 2019 through Executive Order 43: Expanding Access to Clean Energy and Growing the Clean Energy Jobs of the Future (EO43). EO43 established statewide goals and targets for reducing carbon emissions. Specifically, EO43 included a goal that by 2030, 30% of the Commonwealth's electric system would be powered by renewable energy sources. By 2050, the goal is for 100% of Virginia's electricity to be produced from carbon-free sources such as wind, solar, and nuclear. In establishing a mandatory RPS, the VCEA sets forth a framework to meet the goals of EO43.

On October 13, 2021, Governor Cooper signed into law House Bill 951, also known as S.L. 2021-165 and later codified in pertinent part as N.C.G.S. § 62-110.9, directing the Commission to take all reasonable steps to reduce CO_2 emissions in this State resulting from electric generating facilities owned or operated by Duke Energy. The Commission is directed to achieve a reduction of 70% from 2005 levels by the year 2030, subject to certain discretionary extensions, and carbon neutrality by the year 2050. The Commission is directed to develop by December 31, 2022, a plan (the Carbon Plan) to achieve these emission reductions and to review the plan every two years thereafter. In addition to mandating carbon reduction, N.C.G.S. § 62-110.9 also authorizes the Commission to direct additional procurement of solar energy facilities in 2022 if needed to achieve the statutory carbon reduction goals. Finally, N.C.G.S. § 62-110.9 requires that the carbon emission reductions be met consistent with "current law and practice with respect to the least cost planning for generation[,]" and "maintain or improve upon the adequacy and reliability of the existing grid."

On November 19, 2021, the Commission opened Docket No. E-100, Sub 179, for the purpose of developing a Carbon Plan consistent with the provisions of N.C.G.S. § 62-110.9.

Consistent with N.C.G.S. § 62-110.9(1) and Commission directive, Duke Energy conducted three stakeholder engagement sessions between January 20, 2022, and February 25, 2022. The Commission also held three public sessions to receive updates on the sufficiency of the Duke Energy-led stakeholder process. Further the Commission held five public hearings to receive testimony from public witnesses across the State on the Carbon Plan.

On May 16, 2022, Duke Energy filed its proposed Carbon Plan as required by the Commission, which included four portfolios targeted at achieving the carbon emission reductions required by N.C.G.S. § 62-110.9 while balancing least cost and reliability considerations. An unprecedented number of parties have intervened and participated in the Carbon Plan proceeding, including the North Carolina Utilities Commission Public Staff, the Attorney General's office, and advocates for more discreet interest groups including large retail customers, renewable energy developers, low-income customers, wholesale customers of Duke Energy, environmental advocates, and local governmental entities. Intervenors were afforded an opportunity to file extensive comments, testimony, and alternative Carbon Plans.

The Commission commenced an expert witness hearing on September 13, 2022, for the purpose of hearing testimony from experts, including Duke Energy and the intervening parties. The hearing lasted the better part of three weeks, finally concluding on September 29, 2022. The Commission will issue a final order encompassing its initial Carbon Plan on or before December 30, 2022.

2. INTRODUCTION

The North Carolina General Statutes require that the Utilities Commission analyze the probable growth in the use of electricity and the long-range need for future generating capacity in North Carolina. The General Statutes also require the Commission to submit an annual report to the Governor and to the General Assembly regarding future electricity needs. North Carolina General Statute § 62-110.1(c) provides, in part, as follows:

> The Commission shall develop, publicize, and keep current an analysis of the long-range needs for expansion of facilities for the generation of electricity in North Carolina, including its estimate of the probable future growth of the use of electricity, the probable needed generating reserves, the extent, size, mix and general location of generating plants and arrangements for pooling power to the extent not regulated by the Federal Energy Regulatory Commission and other arrangements with other utilities and energy suppliers to achieve maximum efficiencies for the benefit of the people of North Carolina, and shall consider such analysis in acting upon any petition by any utility for construction . . . . Each year, the Commission shall submit to the Governor and to the appropriate committees of the Joint Legislative Oversight Committee on Agriculture and Natural and Economic Resources, the chairs of the Senate Appropriations Committee on Agriculture, Natural, and Economic Resources, and the chairs of the House of Representatives Appropriations Committee on Agriculture and Natural and Economic Resources a report of its analysis and plan, the progress to date in carrying out such plan, and the program of the Commission for the ensuing year in connection with such plan.

N.C.GS. § 62-110.1(c).

Some of the information necessary to conduct the analysis of the long-range need for future electric generating capacity required by N.C.G.S. § 62-110.1(c) is filed by each regulated utility as a part of the least-cost IRP process. Commission Rule R8-60 defines an overall framework for IRPs. Commonly called integrated resource planning, it is a process that takes into account conservation, energy efficiency, load management, and other demand-side options along with new utility-owned generating plants, non-utility generation, renewable energy, and other supply-side options in order to identify the resource plan that will be most cost-effective for ratepayers consistent with the provision of adequate, reliable service.

Prior to July 1, 2013, Commission Rule R8-60(b) specified that the IRP process was applicable to NCEMC and any individual EMC to the extent that it is responsible for procurement of any or all of its individual power supply resources. However, with the ratification of Session Law 2013-187 on June 26, 2013, the individual EMCs and NCEMC have been exempted from filing IRPs with the Commission, effective July 1, 2013.

This report is an update of the Commission's December 31, 2021 Annual Report. It is based primarily on reports to the Commission by the regulated electric utilities serving North Carolina, but also includes information from other records and Commission files.

3. OVERVIEW OF THE ELECTRIC UTILITY INDUSTRY IN NORTH CAROLINA

There are three regulated investor-owned electric utilities (IOUs) operating in North Carolina subject to the jurisdiction of the Commission. All three of the IOUs own generating facilities. They are Duke Energy Progress, LLC (DEP), whose corporate office is in Raleigh; Duke Energy Carolinas, LLC (DEC), whose corporate office is in Charlotte; and Virginia Electric and Power Company (VEPCO), whose corporate office is in Richmond, Virginia, and which does business in North Carolina under the name Dominion Energy North Carolina (DENC). A map outlining the areas served by the IOUs can be found at the end of this report.

DEC and DEP, the two largest IOUs in North Carolina, together provide 96% of the utility-supplied electricity consumed in the state. Approximately 22% of the IOUs' North Carolina electric sales were to the wholesale market, consisting primarily of EMCs and municipally-owned electric systems.

Based on annual reports submitted to the Commission for the 2020 reporting period, the gigawatt-hour (GWh) sales for the electric utilities in North Carolina are summarized in Table 1.

Table 1: 2021 Electricity Sales of Regulated Utilities in North Carolina

	NC Retail GWh*		NC Wholesale GWh*		Total GWh Sales* (NC Plus Other States) [1]	
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[1] DEC and DEP are also in South Carolina. VEPCO is also in Virginia.

EMCs are independent, not-for-profit corporations that operate distribution grids. There are 31 EMCs serving metered customers in North Carolina. EMCs serve approximately 25% of the State's population. Twenty-six EMCs are headquartered in the State, and these 26 EMCs served 1,115,274 metered customers as of December 31, 2021. The other five EMCs are headquartered in adjacent states and provide service in limited areas across the border into North Carolina. EMCs serve customers in 95 of the State's 100 counties.

Twenty-five EMCs are members of North Carolina Electric Membership Corporation (NCEMC), a generation and transmission services cooperative, centrally located in Raleigh, which provides its member EMCs with wholesale power and other services. All 25 NCEMC members are headquartered and incorporated in North Carolina.

Since 1980, NCEMC has been a part owner in the Catawba Nuclear Station located in York County, South Carolina. Duke Energy Carolinas (DEC) operates and maintains the station, which has been operational since 1985. NCEMC's ownership interests consist of 61.51% of Unit 1, approximately 700 megawatts (MW), and 30.75% in the common support facilities of the station. NCEMC's ownership entitlement is bolstered by a reliability exchange between the Catawba Nuclear Station and DEC's McGuire Nuclear Station located in Mecklenburg County, NC.

NCEMC is also a part owner in the Lee combined cycle (CC) plant located in Anderson, South Carolina. NCEMC's ownership interests consist of approximately 100 MW. DEC operates and maintains the plant, and NCEMC's ownership entitlement is bolstered by a reliability exchange between Lee CC and DEC's Dan River and Buck CC plants.

Additionally, NCEMC owns and operates approximately 680 MW of combustion turbine (CT) generation at sites in Anson and Richmond Counties, NC. These peaking resources operate on natural gas as primary fuel, with diesel storage on-site as a secondary fuel. NCEMC also owns and operates two diesel-powered generating stations on the Outer Banks of North Carolina (located on Ocracoke Island and in Buxton), with a combined capacity of 18 MW, which are used primarily for peak shaving and voltage support. Most EMCs also receive an allocation of hydroelectric power from the Southeastern Power Administration (SEPA).

NCEMC and the EMCs are deploying (or facilitating the deployment of) distributed energy resources/technologies (DER) on their grids as well as edge-of-the-grid programs to promote reliability, affordability, sustainability, and resiliency for the benefit of the communities they serve. These technologies and programs include but are not limited to the following:

1. Ten solar + energy storage sites totaling 18.5 MW/45.1 MWh in operation or under development;
2. Ten substation-based battery energy storage systems (BESS) totaling 40 MW/80 MWh in operation or under development;
3. Nineteen community solar facilities totaling 2,150 kW;
4. Energy efficiency (EE) programs that, in 2021, collectively produced 273,072 EE credits (the equivalent of 273,072 MWHs, or 2.0% of the prior year's retail sales, in reduced consumption by member-owners);
5. Approximately 49 MW of conservation voltage reduction capability with the feasibility of additional capability being actively studied; and
6. Ongoing development and operation of a Distributed Energy Resource Management System (DERMS) for the aggregated forecasting, notification, execution, analysis, and reporting of DR and DER programs.

NCEMC and its member distribution cooperatives have developed and implemented the NCEMC Distribution Operator (DO), a single entity that monitors, aggregates, and centrally coordinates distributed energy and demand response resources, bringing operational benefits to the distribution system, optimization to the market interface, and positive system impacts on the transmission systems upstream, including DEC, DEP, and DENC. The DO provides access to over half a gigawatt of distributed energy and demand resources, including solar, storage, microgrids, consumer devices, and behind-the-meter generation, and will continue to grow as additional resources are integrated into the DO system and processes become more automated. NCEMC continues to discuss the DO Platform with DENC, and with DEC and DEP to further evaluate how the DO Platform will interact with their Integrated System & Operations Planning (ISOP) process.

There are five NCEMC members that have assumed responsibility for their own future power supply resources. These "Independent Members" include Blue Ridge Energy, EnergyUnited, Piedmont EMC, Rutherford EMC, and Haywood EMC. Under a Wholesale Power Supply Agreement (WPSA), NCEMC supplies Independent Members from existing contract and generation resources. To the extent that the power supplied under the WPSA is not sufficient to meet the requirements of its customers, the Independent Members must independently arrange for additional purchases.

The service territories of NCEMC's member EMCs are located within the balancing authority areas of DEC, DEP, and DENC. The DENC control area is situated within the footprint of PJM Interconnection, the regional transmission organization (RTO) serving a portion of North Carolina. Six of NCEMC's members fall within that footprint, thus NCEMC is also a PJM member. Though NCEMC's system is spread across these three distinct control areas, NCEMC continues to serve all its members as a single integrated system using a combination of its owned resources, controlled resources, and purchases of wholesale electricity.

In addition to the EMCs, there are 73 municipal and university-owned electric distribution systems serving approximately 616,000 customers in North Carolina. Most of these systems are members of ElectriCities, an umbrella service organization. ElectriCities is a non-profit organization that provides many of the technical, administrative, and management services needed by its municipally-owned electric utility members in North Carolina, South Carolina, and Virginia.

New River Light and Power, located in Boone, and Western Carolina University, located in Cullowhee, are both university-owned members of ElectriCities. Unlike other members of ElectriCities, the rates charged to customers by these two small distribution companies require Commission approval.

ElectriCities is a service organization for its members, not a power supplier. ElectriCities' largest activity is the management of these two power agencies. The remaining members buy their own power at wholesale.

One agency, the North Carolina Eastern Municipal Power Agency (NCEMPA), is the wholesale supplier to 32 cities and towns in eastern North Carolina. Since April 1982, NCEMPA had jointly owned portions of five DEP generating units (about 700 MW of coal and nuclear capacity). On July 28, 2014, DEP filed notice with the Commission of its intent to file with FERC a request for approval to purchase NCEMPA's ownership in these generating facilities together with associated assets pursuant to a proposed Asset Purchase Agreement. As provided in the Agreement, the final purchase and sale was subject to approval by FERC, approval by the Commission, and enactment of legislation by the North Carolina General Assembly.

On May 12, 2015, in Docket Nos. E-2, Sub 1067 and E-48, Sub 8, the Commission issued an Order Approving Transfer of Certificate and Ownership Interests in Generating Facilities. The transaction between DEP and NCEMPA closed on July 31, 2015. On August 13, 2015, the Commission issued an Order Transferring Certificate of Public Convenience and Necessity.

The other power agency is North Carolina Municipal Power Agency No. 1 (NCMPA1), which is the wholesale supplier to 19 cities and towns in the western portion of the state. NCMPA1 has a 75% ownership interest (832 MW) in Catawba Nuclear Unit 2, which is operated by DEC. It also has an exchange agreement with DEC that gives NCMPA1 access to power from the McGuire Nuclear Station and Catawba Unit 1.

Both agencies purchase supplemental power as needed above their own generating resources, usually from investor-owned utilities and federally owned hydro-electric systems.

The Tennessee Valley Authority (TVA) sells energy directly to the Murphy Power Board and to three out-of-state cooperatives that supply power to portions of North Carolina: Blue Ridge Mountain EMC, Tri-State Membership Corporation, and Mountain Electric Cooperative. These distributors of TVA power are located in six North Carolina counties and serve over 35,000 households and about 9,000 commercial and industrial customers. The North Carolina counties served by distributors of TVA power are Avery, Burke, Cherokee, Clay, McDowell, and Watauga.

TVA owns and operates four hydroelectric dams in North Carolina with a combined generation capacity of 492 MW. The dams are Appalachia and Hiwassee in Cherokee County, Chatuge in Clay County, and Fontana in Swain and Graham counties.

4. THE HISTORY OF INTEGRATED RESOURCE PLANNING IN NORTH CAROLINA

Integrated resource planning is an overall planning strategy which examines conservation, energy efficiency, load management, and other demand-side measures in addition to utility-owned generating plants, non-utility generation, renewable energy, and other supply-side resources in order to determine the least cost way of providing electric service. The primary purpose of integrated resource planning is to integrate both demand-side and supply-side resource planning into one comprehensive procedure that weighs the costs and benefits of all reasonably available options in order to identify those options which are most cost-effective for ratepayers consistent with the obligation to provide adequate, reliable service.

Initial IRP Rules

By Commission Order dated December 8, 1988, in Docket No. E-100, Sub 54, Commission Rules R8-56 through R8-61 were adopted to define the framework within which integrated resource planning takes place. Those rules incorporated the analysis of probable electric load growth with the development of a long-range plan for ensuring the availability of adequate electric generating capacity in North Carolina as required by N.C.G.S. § 62-110.1(c).

Initial IRPs were filed with the Commission in April 1989. In May of 1990, the Commission issued an Order in which it found that the initial IRPs of Progress, Duke, and NC Power were reasonable for purposes of that proceeding, and NCEMC should be required to participate in all future IRP proceedings. By an Order issued in December 1992, Rule R8-62 was added. It covers the construction of electric transmission lines.

The Commission subsequently conducted a second and third full analysis and investigation of utility IRP matters, resulting in the issuance of Orders Adopting Least Cost Integrated Resource Plans on June 29, 1993, and February 20, 1996. A subsequent round of comments included general endorsement of a proposal that the two/three-year IRP filing cycle, plus annual updates and short-term action plans, be replaced by a single annual filing. There was also general support for a shorter planning horizon than the 15 years required at that time.

Streamlined IRP Rules (1998)

In April 1998, the Commission issued an Order in which it repealed Rules R8-56 through R8-59 and revised Rules R8-60 through R8-62. The new rules shortened the reported planning horizon from 15 to 10 years and streamlined the IRP review process while retaining the requirement that each utility file an annual plan in sufficient detail to allow the Commission to continue to meet its statutory responsibilities under N.C.G.S. § 62-110.1(c) and N.C.G.S. § 62-2(a)(3a).

These revised rules allowed the Public Staff and any other intervenor to file a report, evaluation, or comments concerning any utility's annual report within 90 days after the utility filing. The new rules further allowed for the filing of reply comments 14 days after any initial comments had been filed and required that one or more public hearings be held. An evidentiary hearing to address issues raised by the Public Staff or other intervenors could be scheduled at the discretion of the Commission.

In September 1998, the first IRP filings were made under the revised rules. The Commission concluded, as a part of its Order ruling on these filings, that the reserve margins forecast by Progress, Duke, and NC Power indicated a much greater reliance upon off-system purchases and interconnections with neighboring systems to meet unforeseen contingencies than had been the case in the past. The Commission stated that it would closely monitor this issue in future IRP reviews.

In June 2000, the Commission stated in response to the IOUs' 1999 IRP filings that it did not believe that it was appropriate to mandate the use of any particular reserve margin for any jurisdictional electric utility at that time. The Commission concluded that it would be more prudent to monitor the situation closely, to allow all parties the opportunity to address this issue in future filings with the Commission, and to consider this matter further in subsequent integrated resource planning proceedings. The Commission did, however, want the record to clearly indicate its belief that providing adequate service is a fundamental obligation imposed upon all jurisdictional electric utilities, that it would be actively monitoring the adequacy of existing electric utility reserve margins, and that it would take appropriate action in the event that any reliability problems developed.

Further orders required that IRP filings include a discussion of the adequacy of the respective utility's transmission system and information concerning levelized costs for various conventional, demonstrated, and emerging generation technologies.

Order Revising Integrated Resource Planning Rules – July 11, 2007

A Commission Order issued on October 19, 2006, in Docket No. E-100, Sub 111, opened a rulemaking proceeding to consider revisions to the IRP process as provided for in Commission Rule R8-60. On May 24, 2007, the Public Staff filed a Motion for Adoption of Proposed Revised Integrated Resource Planning Rules setting forth a proposed Rule R8-60 as agreed to by the various parties in that docket. The Public Staff asserted that the proposed rule addressed many of the concerns about the IRP process that were raised in the 2005 IRP proceeding and balanced the interests of the utilities, the environmental intervenors, the industrial intervenors, and the ratepayers. Without detailing all of the changes recommended in its filing, the Public Staff noted that the proposed rule expressly required the utilities to assess on an ongoing basis both the potential benefits of reasonably available supply-side energy resource options, as well as programs to promote demand-side management. The proposed rule also substantially increased both the level of detail and the amount of information required from the utilities regarding those assessments. Additionally, the proposed rule extended the planning horizon from 10 to 15 years, so the need for additional generation would be identified sooner. The information required by the proposed rule would also indicate the projected effects of demand response and energy efficiency programs and activities on forecasted annual energy and peak loads for the 15-year period. The Public Staff also noted that the proposed rule provided for a biennial, as opposed to annual or triennial, filing of IRP reports with an annual update of forecasts, revisions, and amendments to the biennial report. The Public Staff further noted that adoption of the proposed Rule R8-60 would necessitate revisions to Rule R8-61(b) to reflect the change in the frequency of the filing of the IRP reports.

With the addition of certain other provisions and understandings, the Commission ordered that revised Rules R8-60 and R8-61(b), attached to its Order as Appendix A, should become effective as of the date of its Order, which was entered on July 11, 2007. However, since the utilities might not have been able to comply with the new requirements set out in revised Rule R8-60 in their 2007 IRP filings, revised Rule R8-60 was ordered to be applied for the first time to the 2008 IRP proceedings in Docket No. E-100, Sub 118. These new rules were further refined in Docket No. E-100, Sub 113 to address the implementation of requirements imposed by the 2007 REPS legislation.

2019 IRP Update Reports and Related 2019 REPS Compliance Plans (Docket No. E-100, Sub 157)

In the 2019 IRP Update Reports and REPS compliance plans filed by DEP, DEC, and DENC; the IOU's provided their current IRPs (Docket No. E-100, Sub 157). The Commission held an Oral Argument on January 8, 2020, to discuss load forecast and reserve margin issues for DEC and DEP. A public hearing in this docket was held in Raleigh on March 9, 2020, for the purpose of receiving non-expert public witness testimony. Six public witnesses testified at the hearing.

In its review and evaluation of the 2019 Update Reports the Commission gave particular attention to four topics: (1) carbon dioxide emissions; (2) resource adequacy, expressed in terms of reserve margins for DEC and DEP; (3) the integrated systems and operations planning (ISOP) effort underway for DEC and DEP; and (4) utility statement of need.

Based upon the full record in the proceeding, the Commission issued an Order on April 6, 2020, accepting 2019 IRP Update Reports and REPS compliance plans.

2020 Biennial Integrated Resource Plan Reports and Related 2020 REPS Compliance Plans (Docket No. E-100, Sub 165)

The 2020 Biennial IRP Reports and REPS compliance plans were filed by DEP, DEC, and DENC in 2020. Public Hearings were held in April and May 2020 concerning the 2020 Biennial IRP Reports and REPS compliance plans.

On March 9, 2021, the Commission held a technical conference on Duke's initiative to develop and implement an Integrated Systems and Operations Planning (ISOP) project, and related ISOP topics (First Technical Conference). This technical conference was a follow-up to an ISOP technical conference held by the Commission in 2019 as part of the previous IRP process in Docket No. E-100, Sub 157.

Beginning on April 14, 2021, and continuing through May 26, 2021, the Commission held six public witness hearings in which it received testimony from 129 public witnesses. In addition to the witnesses who appeared at the public hearings, during the course of this docket, the Commission has received several hundred written consumer statements of position from interested persons.

On September 30 and October 1, 2021, the Commission held a technical conference (Second Technical Conference) to hear further presentations from the two Duke Utilities on the following three topics: (1) the proper methodology for evaluating economic retirement of coal-fired generating units, (2) potential use of an all-source procurement process, and (3) grid impacts of different resource portfolios.

Based upon the full record in the proceeding, the Commission issued an Order on November 19, 2021, that stated that the 2020 biennial IRP filed by DENC is reasonable for planning purposes, and the Commission hereby accepts DENC’s IRP, subject to adjustments based on its 2021 IRP Update; that DEC’s and DEP’s 2020 biennial IRPs are adequate to be used for short-term planning purposes as discussed in the Companies’ Short-Term Action Plans (STAPs); that the 2020 REPS Program Plans filed by DENC, DEC and DEP are hereby accepted; and that the 2020 CPRE Plan Updates filed by DEC and DEP are accepted.

2021 Biennial Integrated Resource Plan Reports and Related 2021 REPS Compliance Plans (Docket No. E-100, Sub 165)

On June 29, 2021, the Commission issued an Order Waiving in Part Rule R8-60(h)(2) and Giving Notice of Additional Proceedings (the Additional Proceedings Order), suspending certain IRP filing requirements and stating the Commission's intention to address additional issues in further proceedings in the docket. In summary, the Additional Proceedings Order (1) relieved DEC and DEP of the obligation to file updated 2021 IRPs under Rule R8-60; (2) required DEC and DEP to file on or before September 1, 2021, their REPS Compliance Plans as required by Rule R8-60(h)(4) and Rule R8-67(b), their CPRE Program Plan update as required by Rule R8-71(g)(1), and any material modifications to the short-term action plans identified in their 2020 biennial IRPs as would be required by Rule R8-60(h)(3); (3) denied pending motions for further evidentiary hearings; and (4) required DENC to comply with all requirements for filing an updated 2021 IRP under Rule R8-60.

On September 1, 2021, DENC filed its 2021 IRP Update report. In addition, DEC and DEP each filed their 2021 Update to 2020 Short-Term Action Plan, REPS Compliance Plan, and CPRE Plan Update.

On February 23, 2022, the Commission issued an Order Accepting Filing of 2021 Update Reports and Accepting 2021 REPS Compliance Plans, which found DENC’s 2021 IRP Update complete and in accordance with the requirements set out in Commission Rule R8-60. The Commission also accepted the REPS compliance plans submitted by DEC, DEP, and DENC. Finally, the Commission accepted DEC’s, and DEP’s CPRE Program Plan updates pursuant to Rule R8-71(g)(1) and modifications to the short-term action plans identified in their 2020 biennial IRPs.

2022 Integrated Resource Plan of Dominion Energy North Carolina (Docket No. E-100, Sub 182)

On February 11, 2022, DENC filed a motion requesting that the Commission delay requiring a full IRP pursuant to Commission Rule R8-60(i) until 2023, and in the interim, allow it to file an IRP Update in accordance with Commission Rule R8-60(j) by September 1, 2022. On February 28, 2022, the Commission issued an Order Granting Motion of Dominion Energy North Carolina to Revise Integrated Resource Plan Filing Schedule. Accordingly, DENC filed its 2022 IRP Update and REPS Compliance Plan on September 1, 2022.

On October 31, 2022, the Public Staff filed a report detailing its review of DENC's 2022 IRP Update and comments on DENC’s REPS Compliance Plan, stating that DENC’s IRP Update meets the requirements of R8-60(k), further that DENC should be able to meet its REPS obligations during the Planning Period without exceeding its cost caps and recommending that the Commission approve DENC’s 2022 REPS Compliance Plan.

2022 Duke REPS Compliance Plan & 2022 CPRE Program Plan Update
(Docket No. E-100, Sub 186)

On September 1, 2022, DEP and DEC each individually filed 2022 NC REPS Compliance Plans, and jointly filed a CPRE Program Plan Update.

On October 31, 2022, the Public Staff filed comments on DEP and DEC's REPS Compliance Plans opining that DEC and DEP should be able to meet their general and solar energy set-aside requirements during the planning period, and their poultry waste set-aside requirement in 2022, without exceeding respective cost caps. Further, the Public Staff notes that DEC and DEP's swine waste set-aside requirements will be difficult to meet during the planning period, and that meeting the poultry waste set-aside requirements for 2023 and 2024 will be dependent on the performance of waste-to-energy developers under current contracts. Finally, the Public Staff recommends that the Commission approve DEP and DEC's 2022 REPS Compliance Plans.

On November 8, 2022, the Public Staff filed comments on DEP and DEC's joint CPRE Program Plan Update stating that DEP and DEC's joint CPRE Program Plan meets the requirements of Commission Rule R8-71(g) and should be accepted by the Commission. CPRE Program procurements are slated to conclude following completion of the ongoing 2022 Solar Procurement. *See* Commission Docket Nos. E-2, Subs 1159 and 1297 and E-7, Subs 1156 and 1268.

Carbon Plan
(Docket No. E-100, Sub 179)

On November 19, 2021, the Commission opened Docket No. E-100, Sub 179, for the purpose of developing a Carbon Plan consistent with the provisions of N.C.G.S. § 62-110.9. The Commission's Order Requiring Filing of Carbon Plan and Establishing Procedural Deadlines notes in pertinent part that "the carbon reduction framework established by [N.C.G.S. § 62-110.9] and the analyses underlying Duke's IRPs overlap," and indicating the Commission's intent to eventually synchronize Carbon Plan and IRP proceedings, including undertaking a rulemaking proceeding to revise Commission Rule R8-60 to reflect the approach of syncing the Carbon Plan with the IRP proceedings. The Commission's initial Carbon Plan order, which will issue on or before December 30, 2022, will address consolidation of Duke Energy's traditional integrated resource planning process with ongoing Carbon Plan development and execution.

5. LOAD FORECASTS AND PEAK DEMAND

Forecasting electric load growth into the future is, at best, an imprecise undertaking. Virtually all forecasting tools commonly used today assume that certain historical trends or relationships will continue into the future and that historical correlations give meaningful clues to future usage patterns. As a result, any shift in such correlations or relationships can introduce significant error into the forecast. DEP, DEC, and VEPCO each utilize generally accepted forecasting methods. Although their respective forecasting models are different, the econometric techniques employed by each utility are widely used for projecting future trends. Each of the models requires analysis of large amounts of data, the selection of a broad range of demographic and economic variables, and the use of advanced statistical techniques.

With the inception of integrated resource planning, North Carolina's electric utilities have attempted to enhance forecasting accuracy by performing limited end-use forecasts. While this approach also relies on historical information, it focuses on information relating to specific electrical usage and consumption patterns in addition to general economic relationships.

Table 2 illustrates the system wide average annual growth rates in energy sales and peak loads anticipated by DEP, DEC, and VEPCO. These growth rates are based on the utilities' system peak load requirements.

Table 2: Forecast Annual Growth Rates for DEP, DEC, and VEPCO (With Energy Efficiency (EE) Included) (2021– 2035)

	Summer Peak	Winter Peak	Energy Sales
DEP	0.7%	0.7%	0.5%
DEC	0.8%	0.7%	0.7%
VEPCO	2.04%	2.31%	3.04%

North Carolina utility forecasts of future peak demand growth rates are in the range of forecasts for the southeast as a whole if not slightly higher. The 2021 Long-Term Reliability Assessment by the North American Electric Reliability Corporation (NERC) indicates a forecast of average annual growth in peak demand of approximately 0.65% through 2031.

Table 3 provides historical peak load information for DEP, DEC, and VEPCO.

Table 3: Summer and Winter Systemwide Peak Loads for DEP, DEC, and VEPCO Since 2016 (in MW)

	DEP		DEC		VEPCO	
	Summer	Winter*	Summer	Winter*	Summer	Winter*
2017	12,784	15,519	20,120	21,620	18,902	21,232
2018	13,090	13,669	20,379	19,286	19,244	19,930
2019	12,908	12,243	20,597	18,413	19,607	17,544
2020	13,233	12,258	20,398	17,830	20,087	17,867
2021	13,046	13,490	20,310	18,731	19,781	20,229

**Winter peak following summer peak*

6. GENERATION RESOURCES

Traditionally, the regulated electric utilities operating in North Carolina have met most of their customer demand by installing their own generating capacity. However, purchases including renewables now make up a significant percentage of summer load resources. Generating plants are usually classified by fuel type (nuclear, coal, gas/oil, hydro, renewable, etc.) and placed into three categories based on operational characteristics:

(1) Baseload – operates nearly full cycle;
(2) Intermediate (also referred to as load following) – cycles with load increases and decreases; and
(3) Peaking – operates infrequently to meet system peak demand.

Nuclear, combined-cycle natural gas units, and some large coal facilities, serve as baseload plants and typically operate more than 5,000 hours annually. Smaller and older coal and oil/gas plants are used as intermediate load plants and typically operate between 1,000 and 5,000 hours per year. Finally, combustion turbines and other peaking plants usually operate less than 1,000 hours per year.

All of the nuclear generation units operated by the utilities serving North Carolina have been relicensed so as to extend their operational lives. DEC has three nuclear facilities with a combined total of seven individual units. The McGuire Nuclear Station located near Huntersville is the only one located in North Carolina, and it has two generating units. The other DEC nuclear facilities are located in South Carolina. All of DEC's nuclear units have been granted extensions of their original operating licenses by the Nuclear Regulatory Commission (NRC). The new license expiration dates fall between 2033 and 2043.

DEP has four nuclear units divided among three locations. Two of the locations are in North Carolina. The Brunswick facility, near Southport, has two units, and the Harris Plant, near New Hill, has one unit. The Robinson facility, which also has one unit, is located in South Carolina. The NRC has renewed the operating licenses for all of DEP's nuclear units. The new renewal dates run from 2030 to 2046.

VEPCO operates two nuclear power stations, Surry and North Anna, with two units each. Both stations are located in Virginia. All four units have been issued license extensions by the NRC. For Surry, the licenses for Units 1 and 2 were renewed on May 4, 2021, permitting continued operation for Units 1 and 2 through 2052 and 2053, respectively, but approval by the Virginia State Corporation Commission will also be required for extending the licenses for Surry Units 1 and 2. North Anna's second license renewal was submitted to the NRC on August 24, 2020, and was accepted for review in October 2020. The issuance of the renewed license was expected by April 2022, but on February 24, 2022, the NRC Commission issued three orders (CLI-22-02, CLI-22-03, and CLI-22-04) and Staff Requirements Memorandum, SECY-21-0066, "Rulemaking Plan for Renewing Nuclear Power Plant Operating Licenses – Environmental Review," that impact the subsequent license renewal of various nuclear power plants including North Anna. As of now, the estimated date for the renewal has not been released. The renewal will preserve the option to continue operation of North Anna units 1 and 2 until 2058 and 2060, respectively.

Hydroelectric generation facilities are of two basic types: conventional and pumped storage. With a conventional hydroelectric facility, which may be either an impoundment or run-of-river facility, flowing water is directed through a turbine to generate electricity. An impoundment facility uses a dam to create a barrier across a waterway to raise the level of the water and control the water flow; a run-of-river facility simply diverts a portion of a river's flow without the use of a dam.

Pumped storage is similar to a conventional impoundment facility and is used by DEC and VEPCO for large-scale storage. Excess electricity produced at times of low demand is used to pump water from a lower elevation reservoir into a higher elevation reservoir. When demand is high, this water is released and used to operate hydroelectric generators that produce supplemental electricity. Pumped storage produces only two-thirds to three-fourths of the electricity used to pump the water up to the higher reservoir, but it costs less than an equivalent amount of additional generating capacity. This overall loss of energy is also the reason why the total "net" hydroelectric generation reported by a utility with pumped storage can be significantly less than that utility's actual percentage of hydroelectric generating capacity.

Some of the electricity produced in North Carolina comes from non-utility generation. In 1978, Congress passed the Public Utility Regulatory Policies Act (PURPA), which established a national policy of encouraging the efficient use of renewable fuel sources and cogeneration (production of electricity as well as another useful energy byproduct - generally steam – from a given fuel source). North Carolina electric utilities regularly utilize non-utility, PURPA-qualified, purchased power as a supply resource.

Another type of non-utility generation is power generated by merchant plants. A merchant plant is an electric generating facility that sells energy on the open market. It is often constructed without a native load obligation, a firm long-term contract, or any other assurance that it will have a market for its power. These generating plants are generally sited in areas where the owners see a future need for an electric generating facility; sometimes these are gas-fired plants but the majority have been solar photovoltaic plants in recent years.

The 2020 capacity mix for each IOU is shown in Table 4.

Table 4: Installed Utility-Owned Generating Capacity by Fuel Type (Summer Ratings) for 2020[1]

	DEP	DEC	VEPCO
Coal	24%	33%	19%
Nuclear	28%	26%	17%
Hydroelectric	2%	16%	11%
Natural Gas and Oil	45%	24%	52%
Non-Hydro Renewable	1%	<1%	1%

The actual generation usage mix, based on the megawatt-hours (MWh) generated by each utility, reflects the operation of the capacity shown above, plus non-utility purchases, and the operating efficiencies achieved by attempting to operate each source of power as close to the optimum economic level as possible.

Generally, actual plant use is determined by the application of economic dispatch principles, meaning that the start-up, shutdown, and level of operation of individual generating units is tied to the incremental cost incurred to serve specific loads in order to attain the most cost-effective production of electricity. The actual generation produced and power purchased for each utility, based on monthly fuel reports filed with the Commission for 2021, is provided in Table 5.

[1] The Commission's Order in Docket No. E-100, Sub 165 issued on June 29, 2021, waived DEC and DEP's obligation to file 2021 updated IRPs therefore, 2021 data is not available for DEC and DEP for Table 5. While VEPCO filed its updated IRP for 2021, the data in Table 5 would be skewed if only it included updated information solely from VEPCO.

Table 5: Total Energy Resources by Fuel Type for 2021

	DEP	DEC	VEPCO
Coal	10%	17%	10%
Nuclear	43%	49%	35%
Net Hydroelectric*	1%	2%	1%
Natural Gas and Oil	32%	21%	45%
Non-Hydro Renewable	9%	2%	2%
Other Purchased Power	5%	8%	7%

*See the paragraph on pumped storage in this section.

The Commission recognizes the need for a mix of baseload, intermediate, and peaking facilities and believes that conservation, energy efficiency, peak-load management, and renewable energy resources must all play a significant role in meeting the capacity and energy needs of each utility. In addition, the Commission is actively supporting efforts to expand the role of Distribution Planning into traditional IRP processes.

In 2020, DEP and DEC jointly initiated a multi-year Integrated Systems and Operations Planning Project (ISOP). This effort is an important and necessary evolution in electric utility planning processes to address the trends in technology development, declining cost projections for energy storage and renewable resources, and customer adoption of electric demand modifying resources such as roof-top solar and electric vehicles. The anticipated growth of Distributed Energy Resources necessitates moving beyond the traditional distribution and transmission planning assumption of on-way power flows on the distribution system and analysis based on limited snapshots of peak or minimum system conditions. As the grid becomes more dynamic, analysis of the distribution and transmission systems will need to account for increasing variability of generation and two-way power flows on the distribution system, which requires significant changes to modeling inputs and tools.

Merchant Generating Facilities

North Carolina General Statute § 62-110.1(a) requires that in addition to regulated public utilities themselves, all other persons who wish to construct or operate electric generating facilities in North Carolina obtain a CPCN in order to do so. When the Public Utilities Act was originally enacted, electricity generating facilities in North Carolina not owned or operated by public utilities predominantly consisted of two types – small scale hydroelectric facilities or facilities owned by large industrial companies or by universities or other governmental entities who generated electricity for their own use. After enactment of PURPA in 1978, North Carolina began to experience growth in the number of commercial, third-party developed, owned, and operated generating facilities, most of which sold their capacity and energy to regulated public utilities under the provisions of PURPA. Because of PURPA's "must purchase" requirements for qualifying facilities, the CPCN review process for these new "merchant" generating facilities was somewhat limited in scope. As the costs for development of new solar generating facilities continued to fall over the course of the first two decades of this century, the number of these qualifying facilities seeking to obtain CPCNs multiplied rapidly. After the enactment of HB 589 in 2017, this trend was amplified and reinforced by the new renewable energy competitive solicitation and procurement program codified in N.C. Gen. Stat. § 62-110.8.

Beginning in 2020, the Commission began to experience an increase in applications for CPCNs from merchant generating facilities not seeking to sell capacity and energy as qualifying facilities under PURPA and not participating in the competitive procurement process under N.C.G.S. § 62-110.8. These new merchant facilities are instead seeking to sell their capacity and energy output either by negotiated bilateral contracts with regulated public utilities or by selling into an organized RTO market such as PJM. Often this new type of merchant facility although located in North Carolina will be selling to buyers and consumers located outside North Carolina.

In 2022, the Commission approved an on-shore wind facility with a capacity of 189 MW. This facility would interconnect to the transmission grid owned by DENC. The Commission also conducted multiple hearings on a CPCN application for a solar facility with a capacity of 275 MW that would interconnect to the transmission grid owned by DEP. However, that facility withdrew its application. Applications for CPCNs for seven additional solar facilities, with a combined capacity of 1278 MW, are pending before the Commission. These solar facilities would also interconnect with DENC. From their applications, it appears that all of them would bid their power into the PJM market pursuant to contracts with corporate counterparties.

The increase in applications for merchant generating facilities seeking to sell their output outside of North Carolina may continue. As this was likely not anticipated when the Public Utilities Act was originally adopted, the provisions of Chapter 62 of the General Statutes do not directly address how the Commission should consider these CPCN applications. Prior to 2001 the Commission had no rule specifically addressing procedures for processing CPCN applications filed by merchant generating plants. To address this situation the Commission adopted Rule R8-63 by Order dated May 21, 2001 (Docket No. E-100, Sub 85). The Rule provides for a fact-specific, case-by-case consideration of the circumstances relating to each merchant plant CPCN application, comparable to the process the Commission follows in other types of CPCN applications. In its Order the Commission stated, “It is the Commission’s intent to facilitate, and not frustrate, merchant plant development. Given the present statutory framework, the Commission is not in a position to abandon any showing of need or to create a presumption of need. However, the Commission believes that a flexible standard for the showing of need is appropriate.” In the absence of different guidance, the Commission is continuing to apply the existing criteria, including those relative to such matters as the demonstration of need for the facility, the appropriateness of the proposed facility siting, and the effective management and containment of total project costs, that it uses for reviewing other CPCN applications under N.C.G.S. § 62-110.1(a).

7. RELIABILITY AND RESERVE MARGINS

Resource adequacy refers to the ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements. Utilities require a margin of reserve generating capacity in order to provide reliable service. Periodic scheduled outages are required to perform maintenance, inspections of generating plant equipment, and to refuel nuclear plants. Unanticipated mechanical failures may occur at any given time, which may require shutdown of equipment to repair failed components. Adequate reserve capacity must be available to accommodate these unplanned outages and to compensate for higher than projected peak demand due to forecast uncertainty and weather extremes. The Companies utilize reserve margin targets in their IRP processes to help ensure resource adequacy. Reserve margin is defined as total resources minus peak demand, divided by peak demand. The reserve margin target for planning is established based on probabilistic assessments. The Commission continues to evaluate in the IRP proceedings the appropriate reserve margins for planning.

DEP and DEC each utilize a minimum winter planning reserve margin of 17%. VEPCO is a PJM member and signatory to PJM's Reliability Assurance Agreement. The Company is obligated to maintain a reserve margin (11.7%) for its portion of the PJM coincident peak load. The PJM reserve requirement for years 2021-2032 for its adjusted load forecast is approximately 15%. Also, the Company participates in PJM's capacity auction which results in short-term reserves in excess of the target level.

The amount of energy provided by the three utilities utilizing gas technologies is greater than the energy provided by coal. This highlights the importance of the infrastructure that delivers natural gas to the generating stations. The State has historically been heavily dependent on one interstate pipeline, Transco for its natural gas requirements. While two other interstate pipelines (Columbia and Patriot) provide limited volumes, only Transco crosses the State, generally along the I-85 corridor, which means that long intrastate lines have had to be built to serve generating plants in other parts of the State. Pursuant to N.C. Gen. Stat. § 62-36.01, the Commission may, under some circumstances, order the State's natural gas local distribution companies (LDCs) to enter into natural gas service agreements (including "backhaul" agreements) with other pipeline suppliers to increase competition.

Transco historically delivered gas up from the Gulf Coast. Transco is reversing the flow on its pipelines to bring shale gas to the State from the north. While this provides North Carolina with another source of interstate gas, it has one significant negative impact. Historically, North Carolina customers have been able to contract for gas to be delivered to Transco north of the State, either from other interstate pipelines or from market-area storage facilities and have had that gas "backhauled" on Transco. The gas delivered upstream on Transco on behalf of N.C. customers would be physically delivered to other customers to the north and swapped for their gas out of Transco as it passes through North Carolina. Since Transco is physically reversing the flow on its pipelines, North Carolina customers can no longer count on cheap backhaul service and must pay for expensive firm forward-haul service on Transco or find other ways to get gas to the State.

The amount of firm capacity needed to replace backhaul is significant. North Carolina LDCs have been contracting with Transco to obtain some capacity to deliver supplies that were previously backhauled. They are also seeking capacity on new interstate pipeline projects into the State.

One major new interstate pipeline project into North Carolina is being built to serve both gas and electric generation customers. On October 13, 2017, FERC issued an order granting a Certificate of Public Convenience and Necessity to Mountain Valley Pipeline, LLC for the construction and operation of the Mountain Valley Pipeline Project (MVP). MVP includes approximately 303 miles of 42-inch-diameter greenfield natural gas pipeline, three new compressor stations, interconnections with new meter and regulator stations, taps, and other appurtenant facilities. FERC approved a Certificate of Public Convenience and Necessity for the MVP Southgate project on June 18, 2020. MVP Southgate is an extension of the MVP project. The proposed 75-mile long, 16 and 24-inch diameter natural gas pipeline would tie into Mountain Valley Pipeline (MVP) near Chatham, Virginia, and transport natural gas to delivery points in Rockingham and Alamance counties in North Carolina. In the Southgate Certificate Order, FERC directed the Office of Energy Projects to not issue any notice to proceed with construction of the Southgate Project until Mountain Valley receives the necessary federal permits for the Mainline System. MVP is currently 94% complete and is projected to be operational by late 2023. However, it is also facing long-running lawsuits. Until MVP Southgate can come on-line, LDCs will have to contract for short-term capacity. This capacity will be expensive and cannot be depended upon to meet long term needs. Further delays in MVP and MVP Southgate are a matter of serious concern.

Piedmont Natural Gas completed construction of the Robeson LNG plant during the fall of 2021. The Robeson LNG plant will help meet both gas and electric-peak demand.

8. RENEWABLE ENERGY AND ENERGY EFFICIENCY

Renewable Energy and Energy Efficiency Portfolio Standard (REPS)

In 2007, North Carolina became the first state in the Southeast to adopt a Renewable Energy and Energy Efficiency Portfolio Standard. Under the REPS statute, codified at N.C.G.S. § 62-133.8, investor-owned electric utilities are required to increase their use of renewable energy resources and/or energy efficiency such that those sources meet 12.5% of their NC retail sales in 2021 and thereafter. EMCs and municipal electric suppliers are required to meet a similar requirement of 10% of their NC retail sales in 2018 and thereafter. The requirements under the law phase in over time, with the most recent increase in 2021, requiring investor-owned utilities to meet 12.5% of their prior year’s NC retail sales through renewable energy and EE sources. Within the overall percentage requirements, electric power suppliers must meet a specified portion of their total REPS requirements by producing or purchasing electricity produced from solar, swine-waste, and poultry-waste resources. As detailed in the following section, these specified source requirements also increase over time, however the Commission has modified and delayed the swine and poultry waste requirements several times.

The REPS statute requires the Commission to monitor compliance with REPS and to develop procedures for tracking and accounting for renewable energy certificates (RECs), which represent units of electricity or energy produced or saved by a renewable energy facility or an implemented EE measure. In 2008 the Commission opened Docket No. E-100, Sub 121 and established a stakeholder process to propose requirements for a North Carolina Renewable Energy Tracking System (NC-RETS). On October 19, 2009, the Commission issued a request for proposals (RFP) via which it selected a vendor, APX, Inc., to design, build, and operate the tracking system. NC RETS began operating July 1, 2010, consistent with the requirements of Session Law 2009-475.

Members of the public can access the NC-RETS website at www.ncrets.org. The site's "resources" tab provides public reports regarding REPS compliance and NC RETS account holders. NC-RETS also provides an electronic bulletin board where RECs can be offered for purchase.

On October 1, 2021, the Commission submitted its Annual Report Regarding Renewable Energy and Energy Efficiency Portfolio Standard in North Carolina, which was required pursuant to N.C.G.S. § 62-133.8. The report detailed Commission implementation of the REPS statute since its enactment in 2007. The report is available on the Commission's web site at www.ncuc.gov. Pursuant to House Bill 217 (Session Law 2021-23), N.C.G.S. § 62-133.8(j) was repealed eliminating the requirement for this report.

Competitive Procurement of Renewable Energy (CPRE)

Pursuant to N.C.G.S. § 62-110.8 the Commission is tasked with oversight of the CPRE Program designed and implemented by Duke Energy for the competitive procurement and development of an aggregate amount of 2,660 MW of renewable energy facilities in North Carolina over a period of 45 months, which commenced on February 21, 2018, and concluded on November 21, 2021 (CPRE Program Procurement Period).

During the CPRE Program Procurement Period, Duke Energy was required to solicit a total of 6,160 MW of renewable energy through a combination of (1) CPRE Program procurement solicitations (CPRE MW) and (2) the execution of power purchase agreements (PPAs) for renewable energy capacity within the DEC and DEP balancing authority areas that are not subject to economic dispatch or curtailment and were not procured pursuant to the Green Source Advantage program authorized under N.C. Gen. Stat. § 62-159.2 (Transition MW). Under N.C.G.S. § 62-110.8(a) and (b)(1), 2,660 MW of this 6,160 MW total was targeted to be procured through the CPRE Program, and the remaining 3,500 MW was targeted to be Transition MW.

Section 62-110.8(b)(1) provides that, if during the CPRE Program Procurement Period, Duke contracts for Transition MW in excess of 3,500 MW, the Commission shall reduce the CPRE MW by the amount of such exceedance. Further, N.C.G.S. § 62-110.8(a) states that "[t]he Commission shall require the additional competitive procurement of renewable energy capacity by the electric public utilities in an amount that includes all of the following: (a) any unawarded portion of the initial competitive procurement required by this subsection . . . ."

During the CPRE Program Procurement Period, DEC and DEP collectively procured 1,185 MW via the CPRE Program. Further, during the CPRE Program Procurement Period, Duke procured a total of 4,378 Transition MW, an excess of 878 MW. Therefore, pursuant to N.C.G.S. § 62-110.8(b)(1), the Commission determined that it was appropriate to reduce the CPRE Program procurement target to 1,782 MW. As a result, the Commission concluded that Duke was 596 MW short of the adjusted CPRE Program procurement target at the end of the CPRE Program Procurement Period and on December 20, 2021, ordered DEC to initiate a third procurement solicitation (Tranche 3) of the CPRE Program to procure 596 MW.

On January 5, 2022, DEC issued the CPRE Tranche 3 request for proposals (RFP) seeking to procure 596 MW. The bid window for CPRE Tranche 3 closed on February 3, 2022. Only eight projects totaling 520 MW bid into CPRE Tranche 3. Following closure of the bid window, 365 MW withdrew from Tranche 3, citing market uncertainty and the rising costs of solar development as the cause of their withdrawal. Ultimately, only two projects totaling 155 MW completed the Tranche 3 bid evaluation process and have signed CPRE Program PPAs with DEC.

On September 1, 2022, Duke Energy filed a petition notifying the Commission that the CPRE Program was 441 MW short of meeting the target established by N.C.G.S. § 62-110.8 and requesting the Commission's approval to procure the shortage through the 2022 Solar Procurement, which was approved by the Commission on May 26, 2022, pursuant to Section 2(c) of S.L. 2021-165. By order dated November 1, 2022, the Commission authorized Duke Energy to seek the CPRE Program shortfall through the 2022 Solar Procurement.

The Commission's November 1, 2022 Order Permitting Additional CPRE Program Procurement And Establishing Target Procurement Volume For The 2022 Solar Procurement notes that, while the Commission has no ongoing obligation to target the CPRE Program shortfall "it is reasonable and consistent with the plain language of N.C.G.S. § 62-110.8(a) and the whole of the act to procced on a discretionary basis with regard to further conducting additional procurements aimed at the CPRE MW shortfall." The Commission further concluded that "regardless of whether the CPRE MW shortfall is procured in total through the 2022 Solar Procurement, the CPRE Program will be closed out upon the conclusion of the 2022 Solar Procurement."

Energy Efficiency

Electric power suppliers in North Carolina are required to implement demand-side management (DSM) and energy efficiency (EE) measures and use supply-side resources to establish the least cost mix of demand reduction and generation measures that meet the electricity needs of their customers. Energy reductions through the implementation of DSM and EE measures may also be used by the electric power suppliers to comply with REPS. DEC, DEP, DENC, EnergyUnited, Fayetteville Public Works Commission, Halifax, and NCEMC (which has assumed compliance responsibility from the now-dissolved GreenCo for REPS compliance for its member cooperatives) all administer EE and DSM programs.

NC GreenPower

NC GreenPower's mission is to expand public knowledge and acceptance of cleaner energy technologies to all North Carolinians through local, community-based initiatives. Founded in 2003 as a subsidiary of Advanced Energy Corporation, the nonprofit was launched by the NC Utilities Commission as a voluntary program to supplement the state's existing power supply with more green energy. NC GreenPower works to improve the state's environment by supporting renewable energy and carbon offset projects and by providing grants for solar installations at North Carolina K-12 schools.

Introduced on April 1, 2015, NC GreenPower Solar+ Schools uses donations to provide grants for educational solar PV packages at North Carolina schools. All K-12 schools are eligible, though preference may be given to those in economically distressed counties as defined by the NC Department of Commerce. Following a five-year pilot, the program was made official by the NC Utilities Commission in 2019 and offers top-of-pole mounted systems, roof-mounted systems, solar awnings, and other designs as needed to accommodate various structures.

The NC GreenPower Solar+ Schools program gives teachers valuable tools to educate students about renewable energy. NC GreenPower's grant pays for all of the project's construction costs requiring selected schools to raise only a small portion of the costs, approximately $3,500, to cover any operations and maintenance costs. NC GreenPower's partner, the State Employees' Credit Union (SECU) Foundation, will provide an additional grant of up to $600,000 over the next three years to assist with the installation costs for then selected public schools per year.

In 2022, NC GreenPower awarded 20 North Carolina schools a solar education package valued at $42,000. In addition to a 5-kW solar array, each school will receive donated SunPower solar modules, a weather station, data monitoring equipment, STEM curricula and training for educators.

By the end of 2022, the NC GreenPower Solar+ Schools program will have reached a total of 76 North Carolina schools in 46 counties, bringing solar energy and STEM education to nearly 57,000 students. To date, the schools have collectively produced an estimated 720,939 kilowatt hours of green energy, a savings of about $68,400.

Additionally, as part of the American Rescue Plan Act, NC GreenPower was awarded $798,436 in funding from NCDEQ's State Energy Office allowing NC GreenPower to purchase and install high-efficiency light-emitting diode (LED) fixtures in 60 qualifying North Carolina K-8 public school gymnasiums at no cost to the schools thereby reducing the schools' energy burden.

Contributions to NC GreenPower continue to help support the local generation of green energy and reduction of greenhouse gases but also help to install solar PV systems at schools across North Carolina. Statewide efforts of NC GreenPower also include community outreach and awareness. Voluntary donations to the program can be made by individuals or businesses through their electric bill or directly to NC GreenPower on their website: www.ncgreenpower.org. NC GreenPower is a 501(c)(3) nonprofit organization, and all current projects are located within North Carolina.

9. TRANSMISSION AND GENERATION INTERCONNECTION ISSUES

Transmission Planning

The North Carolina Transmission Planning Collaborative (NCTPC) was established in 2005. Its processes are intended to comply with the local transmission planning requirements imposed by FERC in Order Nos. 890 and 1000. The NCTPC participants consist of DEC and DEP which own transmission, and NCEMC and ElectriCities which represent transmission-dependent utilities. Through the NCTPC processes, the participants, create a local transmission plan that (a) identifies the electric transmission projects needed to maintain reliability, to integrate new generation resources or loads, for economic needs (i.e., to increase transmission access to potential supply resources inside and outside of the territories of DEC and DEP), and for public policy needs and (b) provides estimates of costs. The NCTPC's January 24, 2022 report (the "2021 Study") stated that 16 major transmission projects (greater than $10 million each) are needed in North Carolina by the end of 2031 at an estimated cost of $694 million. This compares to the original 2020 Study Plan estimate of $804 million for 17 reliability projects. In a mid-year update to the 2021 Plan, the NCTPC updated the costs of existing reliability projects from $694 million to $748 million. In addition, the mid-year update proposed adding 18 new projects with an estimated cost of $560.6 million "to integrate additional generation and to meet the public policy requirements of the Carbon Plan." After receiving input from stakeholders and after issuance of an order from the Commission, the NCTPC decided not to pursue to postpone approval of the new projects in the 2021 plan; although it expects many or most of them will be included in a future plan. For more information, visit the NCTPC's website at www.nctpc.org.

On July 21, 2011, FERC issued Order No. 1000, entitled "Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities."[2] This Order requires transmission owners to participate in regional and inter-regional transmission planning efforts. DEC and DEP have complied with Order No. 1000 by participating in the Southeastern Regional Transmission Planning (SERTP)[3] process.

On July 3, 2013, Session Law 2013-232 was enacted. This law states that only a public utility may obtain a certificate to build a new transmission line (except a line for the sole purpose of interconnecting an electric power plant). In this context, a public utility includes IOUs, EMCs, joint municipal power agencies, and cities and counties that operate electric utilities.

State Generator Interconnection Standards

On June 4, 2004, in Docket No. E-100, Sub 101, Progress Energy Carolinas, Duke Power, and Virginia Electric and Power Company jointly filed a proposed model small generator interconnection standard, application, and agreement to be applicable in North Carolina. In 2005, the Commission approved small generator interconnection standards for North Carolina.

In 2007 as part of REPS legislation codified at N.C.G.S. § 62-133.8(i), the General Assembly provided that the Commission shall "[e]stablish standards for interconnection of renewable energy facilities and other nonutility-owned generation with a generation capacity of 10 megawatts or less to an electric public utility's distribution system; provided, however, that the Commission shall adopt, if appropriate, federal interconnection standards."

In compliance, on June 9, 2008, the Commission issued an Order revising North Carolina's Interconnection Standard. The Commission used the federal standard as the starting point for all state-jurisdictional interconnections (regardless of the size of the generator) and made modifications to retain and improve upon the policy decisions made in 2005.

The Commission issued an Order Approving Revised Interconnection Standard on May 15, 2015. That Order made substantial changes to the procedures for requesting to interconnect a generator to the electric grid. Most of these changes were recommended by the stakeholders with the intent of addressing a backlog of interconnection requests. The more significant changes in the State's interconnection standards were the following:

[2] FERC issued Order No. 1000 on July 21, 2011, in its Docket No. RM10-23-000.

[3] For more information about the Southeastern Regional Transmission Planning process, see http://southeasternrtp.com/. Other sponsors of the SERTP are Southern Company, Dalton Utilities, Georgia Transmission Corporation, the Municipal Electric Authority of Georgia, PowerSouth, Louisville Gas & Electric Company, Kentucky Utilities Company, Associated Electric Cooperative, Inc., and the Tennessee Valley Authority.

(1) a project's ability to be expedited is now based not only on the project's size, but also on the size of the line it would connect to, and its distance from a substation; (2) a new process for addressing "interdependent" projects was added, where one generator needs to decide whether it is going to move ahead in order for the utility to determine that capacity exists to interconnect a second generator; (3) developers must provide a deposit of at least $20,000; (4) developers must demonstrate that they have site control; and (5) developers must pay for upgrades before the utility begins construction. The utilities are required to file a quarterly report to the Commission reporting on their progress in addressing the interconnection queue backlog.

On August 10, 2018, the Commission issued an Order Scheduling Hearing, Requesting Comments, and Extending Tranche 1 CPRE RFP Solicitation Response Deadline. The order established an evidentiary hearing to consider modifications to the NC Interconnection Standard. On October 5, 2018, the Commission issued an order approving modifications to the NC Interconnection Standard in order to accommodate Tranche 1 of the CPRE program.

On June 14, 2019, the Commission issued an order further modifying the NC Interconnection Standard that made fairly minor changes while establishing deadlines for considering more substantial changes. These include the following:

1. The utilities were required to file additional information explaining their need for generators' production profiles. The Commission subsequently approved this new requirement on September 23, 2019.
2. Duke was required to file a proposal for an expedited study process for battery storage being added to an existing solar generator. Duke made the required filing and on August 17, 2021, the Commission resolved several issues relative to adding storage at an existing solar site and required Duke to (1) provide a list of interconnection procedure waivers that would be needed to implement expedited storage retrofits at solar sites, and (2) propose a process whereby an existing QF that seeks to add storage could establish eligibility for a bifurcated avoided cost rate. Duke filed the required information September 29, 2021.Other parties have since filed comments on these issues, which remain pending.
3. Duke was required to consult with the Electric Power Research Institute as to ways to improve the fast track / supplemental review processes and file a report with the Commission. Duke filed that report on October 23, 2019.
4. The utilities were required to host stakeholder meetings about the adoption of Interconnection Standard IEEE-1547 and file a report with the Commission. This report was filed April 1, 2020. On March 2, 2021, the Commission issued an order requiring Duke and DENC to file by March 15 each year a report on the status of their implementation efforts.
5. Duke was required to establish a stakeholder process to discuss transitioning the interconnection process from a first-come first-served process to a grouping study process. Duke subsequently filed a queue reform proposal. In October of 2020, the Commission approved a queue reform proposal that had been developed by Duke with input from stakeholders. In 2021, the reforms were also approved by the

South Carolina Public Service Commission and FERC, and in August of 2021, the Commission ordered Duke to move ahead with implementation. In 2022, the utility conducted a Transitional Cluster Study as part of the transition to the new process, and is currently performing the 2022 DISIS (Definitive Interconnection System Impact Study) process.

FERC Transmission Planning and Cost Allocation Proceedings

In June 2021, the Federal Energy Regulatory Commission (FERC) established a Joint Federal-State Task Force on Electric Transmission and solicited nominations for state utility commission representation on the Task Force. (FERC Docket No. AD21-15) NC Commissioner Kimberly Duffley was appointed to the Task Force on August 30, 2021, and was renominated for a second one-year term on July 15, 2022. Commissioner Duffley has presented her views during the first five Task Force meetings. The Task Force will focus on topics related to efficiently and fairly planning and paying for electric transmission, including transmission to facilitate generator interconnection, and exploring opportunities for states to voluntarily coordinate to identify, plan, and develop regional transmission. The Task Force will expire in three years, but its term may be extended by agreement between FERC and state regulators.

In July 2021, FERC issued an advance notice of proposed rulemaking in which it sought comments on a wide range of proposals relating to planning and paying for regional transmission and facilitating generator interconnections. (FERC Docket No. RM21-17) The NCUC filed comments in that proceeding. A major focus of the Commission's comments was transmission cost allocation inequities that result in DEP customers paying for transmission upgrades that are needed due to electric generators interconnecting with DENC in order to export their power to the PJM Regional Transmission Operator that operates the power grid north and west of North Carolina. The NCUC also argued for the retention of "participant funding," wherein the generator that causes the need for a transmission upgrade should bear the full cost.

In April 2022, FERC issued a notice of proposed rulemaking in which it sought comments on proposals relating to long-term regional transmission planning, use of advanced technologies in regional transmission planning, seeking agreement of state entities within transmission planning regions related to cost allocation, and transparency requirements for local and regional transmission planning processes. (FERC Docket No. RM21-17) The NCUC filed joint comments in that proceeding with the North Carolina Public Staff. These comments expressed support for FERC's proposal to give states a greater role in transmission planning and cost allocation decisions.

In June 2022, FERC issued a notice of proposed rulemaking in which it sought comments on proposals relating to reforms to FERC's pro forma Large Generator Interconnection Procedures and Agreement and pro forma Small Generator Interconnection Agreement, to address interconnection queue backlogs, improve certainty, and prevent undue discrimination for new technologies. (FERC Docket No. RM22-14) The NCUC filed joint comments in that proceeding with the North Carolina

Public Staff. These comments gave the Commission another opportunity to describe to FERC how some of its policies tend to burden North Carolina ratepayers and violate the fundamental ratemaking principle that those who cause costs should pay for them. The Commission reported to FERC that many of its proposed reforms with respect to interconnecting new energy generation had already been implemented in North Carolina.

10. FEDERAL ENERGY INITIATIVES

Open Access Transmission Tariff (OATT)

In April 1996, the FERC issued Order Nos. 888 and 889, which established rules governing open access to electric transmission systems for wholesale customers and required the construction and use of an Open Access Same-time Information System (OASIS) for reserving transmission service. In Order No. 888, the FERC also required utilities to file standard, non-discriminatory OATTs under which service is provided to wholesale customers such as electric cooperatives and municipal electric providers. As part of this decision, the FERC asserted federal jurisdiction over the rates, terms, and conditions of the transmission service provided to retail customers receiving unbundled service while leaving the transmission component of bundled retail service subject to state control. In Order No. 889, the FERC required utilities to separate their transmission and wholesale power marketing functions and to obtain information about their own transmission system for their own wholesale transactions through the use of an OASIS system on the Internet, just like their competitors. The purpose of this rule was to ensure that transmission owners do not have an unfair advantage in wholesale generation markets.

Regional Transmission Organizations (RTOs)

Dominion filed an application with the Commission on April 2, 2004, in Docket No. E-22, Sub 418, seeking authority to transfer operational control of its transmission facilities located in North Carolina to PJM Interconnection, an RTO headquartered in Pennsylvania. The Commission approved the transfer subject to conditions on April 19, 2005, and the Commission relieved Dominion of compliance with most of the PJM conditions in the Commission’s order dated December 22, 2016.

The Commission has continued to provide oversight over Dominion by using its own regulatory authority. Additionally, the Commission engages with PJM and monitors its activities, including, through regional cooperation with other State commissions, and by participating in proceedings before FERC. Together with the other State commissions with jurisdiction over utilities in the PJM area, the Commission is involved in the activities of the Organization of PJM States, Inc. (OPSI). Commission Chair Charlotte Mitchell is currently the President of OPSI.

Southeast Energy Exchange Market (SEEM)

On December 11, 2020, DEC and DEP filed an advance notice with the Commission stating their intention to file with the Federal Energy Regulatory Commission revisions to their Open Access Transmission Tariff in order to establish an energy-only electricity market in the Southeast, known as the Southeast Energy Exchange Market (SEEM). Membership in the SEEM is not limited to investor-owned utilities, and NCEMC is also a member of SEEM. The market is designed to facilitate short-term, bi-lateral, automated energy sales across the region. The SEEM members have received clearance from FERC to enter into the SEEM agreements and modify their respective federal tariffs. Cost savings will flow to retail customers via the fuel rider, which the Commission adjusts annually. The SEEM initiated operations on November 9, 2022.

PURPA Reform

In July 2020, FERC issued a final rule which is the first major change to PURPA regulations since 1980. (Order No. 872, FERC Docket Nos. RM19-15 and AD16-16) In general terms, PURPA provides rights to certain non-utility power generators known as qualifying facilities or “QFs” to require electric utilities to purchase the QF’s output at the utility’s avoided cost. FERC is charged with ensuring that QF rates are just and reasonable to consumers and that the rates do not discriminate against QFs. Among its key revisions, the final rule grants additional flexibility to state regulatory authorities in establishing avoided cost rates for QF sales inside and outside of the organized electric markets. The rule also grants states the ability to require energy rates (but not capacity rates) to vary during the life of a QF contract.

FERC also changed the rules that determine whether facilities are located at the same site, replacing the “one-mile rule” with a “ten-mile rule.” Further FERC reduced the rebuttable presumption for “nondiscriminatory access” to power markets - from 20 MW to 5 MW - for small power production but not cogeneration facilities. Finally, in order for a QF to establish a legally enforceable obligation, the final rule requires that the QFs must demonstrate commercial viability and financial commitment to build under objective and reasonable state-determined criteria.

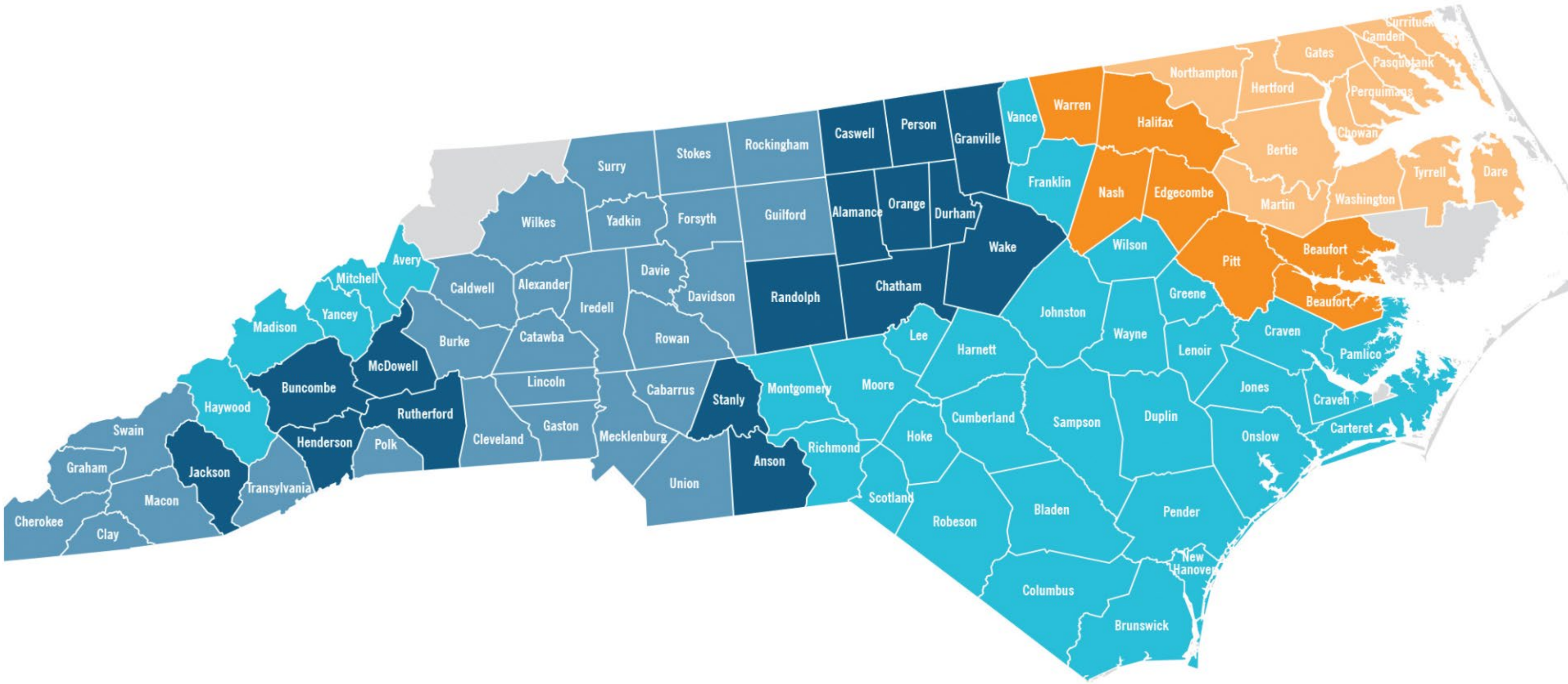
The final rule does not change other elements of the existing PURPA regulations that encourage QF development. These include regulations “requiring electric utilities to provide backup electric energy to QFs on a non-discriminatory basis and at just and reasonable rates; requiring electric utilities to interconnect with QFs; and providing exemptions to QFs from many provisions of the Federal Power Act and state laws governing utility rates and financial organization.”

Affordable Clean Energy Rule (ACE Rule)

Citing its authority under Section 1111 of the Clean Air Act, the Environmental Protection Agency (EPA) released the final version of the Affordable Clean Energy Rule (ACE Rule) on June 19, 2019, which replaced and repealed the Clean Power Plan. The

ACE Rule, which applied to existing coal-fired power plants greater than or equal to 25 MW, was a mechanism intended to provide achievable and realistic standards for reducing greenhouse gas emissions using heat rate improvement technologies. Appeals from this action eventually came before the United States Supreme Court, which applied the major questions doctrine and held that the EPA had exceeded its statutory authority in promulgating the ACE Rule. *West Virginia v. EPA*, 142 S. Ct. 2587 (2022). The Supreme Court's decision was issued on June 30, 2022.

APPENDIX 1



SERVICE TERRITORIES
(counties served)

- Duke Energy Carolinas
- Duke Energy Progress
- Duke Energy Carolinas/ Duke Energy Progress overlapping counties
- Dominion Energy North Carolina
- Dominion Energy North Carolina/ Duke Energy Progress overlapping counties

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	)	ORDER ADOPTING INITIAL
Carolinas, LLC, 2022 Biennial Integrated	)	CARBON PLAN AND
Resource Plans and Carbon Plan	)	PROVIDING DIRECTION FOR
	)	FUTURE PLANNING

HEARD: Monday, July 11, 2022, at 7:00 p.m., in Courtroom D7, Durham County Courthouse, 510 S. Dillard St., Durham, North Carolina 27701

Tuesday, July 12, 2022, at 7:00 p.m., in Courtroom 317, New Hanover County Courthouse, 316 Princess Street Wilmington, North Carolina 28401

Wednesday, July 27, 2022, at 7:00 p.m., in Courtroom 1-A, Buncombe County Courthouse, 60 Court Plaza, Asheville, North Carolina 28801

Thursday, July 28, 2022, at 7:00 p.m., in Courtroom 5350, Mecklenburg County Courthouse, 832 E. 4th Street Charlotte, North Carolina 28202

Tuesday, August 23, 2022, at 1:30 p.m. and 4:30 p.m. via Webex

Tuesday, September 13, 2022, at 9:00 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina 27603

BEFORE: Chair Charlotte A. Mitchell, Presiding; and Commissioners ToNola D. Brown-Bland, Daniel G. Clodfelter, Kimberly W. Duffley, Jeffrey A. Hughes, Floyd B. McKissick, Jr., and Karen M. Kemerait

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I. PRELIMINARY MATTERS AND CONTEXT

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IV. DEVELOPMENT OF LONG-LEAD TIME RESOURCES

V. GRID EDGE AND CUSTOMER PROGRAMS

BY THE COMMISSION: On October 13, 2021, Governor Cooper signed into law House Bill 951 (S.L. 2021-165). Section 1 of S.L. 2021-165, codified as N.C. Gen. Stat. § 62-110.9, directs the Commission to take all reasonable steps to reduce carbon dioxide emissions originating from electric generating facilities owned or operated by Duke Energy Progress, LLC (DEP), and Duke Energy Carolinas, LLC (DEC; together with DEP, Duke), in the state. More specifically, the statute directs the Commission to develop by December 31, 2022, a plan (the Carbon Plan) to achieve a 70% reduction in carbon dioxide emissions from 2005 levels (Interim Target) by the year 2030, subject to certain discretionary conditions, and carbon dioxide neutrality by the year 2050 (2050 Target). Section 62-110.9(4) affords the Commission flexibility in implementing the statute, including the ability to delay the achievement of the carbon dioxide emissions reduction mandates by up to two years, or longer if construction of a nuclear or wind energy facility requires additional time or if delay is necessary to maintain reliability of the grid. The statute further directs the Commission to review the plan every two years after the adoption of the initial Carbon Plan. In planning resources to achieve the carbon dioxide emissions reduction mandates, the statute requires that the Commission adhere to the principle of least cost planning and ensure the maintenance of reliability. Finally, N.C.G.S. § 62-110.9 requires that the development of the Carbon Plan include stakeholder input.

Relatedly, N.C.G.S. § 62-110.1(c) requires the Commission to analyze the long-range needs for expansion of facilities for the generation of electricity in North Carolina. To meet the requirements of this statute, Commission Rule R8-60 requires that all electric public utilities develop an Integrated Resource Plan (IRP) and provide details of that IRP to the Commission with a biennial report in even-numbered years. Given the overlap between the planning and execution components of N.C.G.S. § 62-110.9 and the planning requirements of N.C.G.S. § 62-110.1(c), the Commission finds good cause to synchronize proceedings advancing these two purposes, going forward, as the Commission further directs herein.

The findings of fact, supporting evidence, and resulting conclusions and directives presented in this Order represent the Commission's initial Carbon Plan, per N.C.G.S. § 62-110.9. The Commission has developed this initial Carbon Plan based upon competent, material, and substantial evidence Duke and the intervening parties presented, and upon the sworn testimony of public witnesses and public comment.

N.C.G.S. § 62-110.9 requires the Commission to direct and oversee the continued transformation of the electric system in North Carolina toward carbon dioxide neutrality. The guidance the General Assembly provided to the Commission for this task is clear: the Commission must find the least cost path to compliance with the carbon dioxide emissions reduction requirements while maintaining or improving the reliability of the electric system. Developing the path to least cost compliance with the carbon dioxide emissions reductions that the law requires is complex and will, necessarily, be an iterative process given the rapid pace of change of the electric industry. In fulfilling its obligation, the Commission has endeavored to balance the need for action in the immediate term against the deferral of actions when doing so is in the best interest of customers and the reliable operation of the electric system. In undertaking this task, the Commission has considered the need for urgency that certain circumstances related to the transition dictate but has been, and must continue to be, mindful of the rapid pace of change and associated potential benefits that could inure to customers in the future.

The least cost path to compliance has been and will continue to be squarely within the Commission's focus. To this end, the Commission expects and will direct Duke to investigate and to doggedly pursue every opportunity to apply downward pressure on rates and to optimize the use of the electric system to reduce system average cost. A reduced system average cost will benefit all customers. The work of the Low-Income Affordability Collaborative, presented most recently in its final report filed with the Commission, reveals, starkly, the magnitude of the challenges that a significant percentage of residential customers in North Carolina face and underscores the need for Duke, and this Commission, to pursue every chance to apply downward pressure on rates. Joint North Carolina Low-Income Affordability Collaborative Quarterly Progress Report, Docket Nos. E-7, Subs 1187, 1213, and 1214 and E-2, Subs 1219 and 1193 (Aug. 12, 2022). To this end, the Commission has expected and will continue to expect Duke to pursue every opportunity that may arise through tax incentives or federal funding to benefit its customers. In fact, even since the outset of this proceeding merely 14 months ago, we have experienced a bellwether for the significant escalation of the transformation and very likely a reduction in cost with the passage of the Inflation Reduction Act of 2022 (the IRA) on August 16, 2022. But the implications of the IRA on costs that Duke will incur and, therefore, the implications for Duke's customers remain mostly unknown. For this reason and others, the Commission must maintain the ability and flexibility to adapt, as necessary, to this dynamism.

The statute unambiguously directs the Commission to guard the reliability of the electric system. For many decades, the electric system has served North Carolina well. This record will continue. However, the transformation of the electric system — both in terms of the changing mix of generating resources and the changing ways in which customers are relying on the system — brings with it new challenges for system operators. As the system transitions to include more weather-dependent and time-limited resources, system operators must have an increasingly diverse and flexible set of tools to anticipate and address the challenges that arise. The increasing electrification of home heating influences (and, increasingly, so might the electrification of transportation) the timing and extent of peak demand in the winter, placing stress on the electric system. Additionally, extreme events — be they related to weather, cybersecurity, fuel supply, and the like — pose an additional risk to the electric system which the utilities and the Commission must navigate and account for amidst the transformation. Indeed, the North American Electric Reliability Corporation (NERC), the federal regulatory authority whose mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid, has acknowledged that traditional resource planning methods may not consider the real-world grid impacts and interactions of an evolving resource mix with less baseload generation and more variable generation, inverter-based resources, storage, and distributed energy resources (DERs), leading to potential generation or transmission insufficiencies. Tr. vol. 19, 133. Additionally, NERC's 2022-2023 Winter Reliability Assessment, which evaluates the generation resource and transmission system adequacy needed to meet projected winter peak demands and operating reserves as well as identifies potential reliability issues for the 2022–2023 winter period, notes that in the SERC-E region, which includes North Carolina, shrinking capacity and demand growth cause a risk of shortfall in extreme cold weather events. 2022–2023 Winter Reliability Assessment of the North American Electric Reliability Corporation at 21 (Nov. 17, 2022).[1] The emergency outage events experienced by some Duke customers in late December of this year during extreme cold temperatures provides a sobering example of the consequences to customers during times of stress on the electric system and underscores the vigilance with which the Commission must act in overseeing the utilities' planning efforts and implementation of the carbon dioxide emissions reductions to ensure that appropriate replacement generating units and associated transmission infrastructure are in service before existing generating units are retired.

PROCEDURAL HISTORY

Over the course of this proceeding, the Commission has issued numerous procedural orders, and the parties hereto have filed many pleadings, all of which are a matter of record herein. The following is a summary of only the most pertinent occurrences.

Stakeholder Process, Intervening Parties, Comments, and Expert Witness Hearing

On November 19, 2021, the Commission issued an Order Requiring Filing of Carbon Plan and Establishing Procedural Deadlines (November 19, 2021 Order) which states that, in developing the Carbon Plan, the Commission will look to, but will not strictly adhere to, Commission Rule R8-60. The November 19, 2021 Order acknowledges the overlap between the IRP process pursuant to N.C.G.S. § 62-110.1(c) and the analyses required to meet the carbon dioxide emissions reduction mandates of N.C.G.S. § 62-110.9, and further states an intent to eventually synchronize the IRP and Carbon Plan processes. Also, the November 19, 2021 Order delays DEC's and DEP's next comprehensive IRP filings that Commission Rule R8-60(h)(1) requires to September 2023 and forecasts that the Commission will undertake a rulemaking process separate from the Carbon Plan proceeding to revise Commission Rule R8-60 to synchronize the Carbon Plan and IRP proceedings. Finally, the November 19, 2021 Order directs Duke to conduct at least three stakeholder meetings consistent with the stakeholder input directive of N.C.G.S. § 62-110.9(1) before filing its Carbon Plan proposal.

The intervention and participation of the North Carolina Utilities Commission – Public Staff (Public Staff), an independent agency tasked with representing consumer interests before the Commission, has been recognized pursuant to N.C.G.S. § 62-15(d), and N.C.G.S. § 62-20 affords the North Carolina Attorney General's Office (AGO) intervention in Commission proceedings. In addition to the Public Staff and the AGO, the Commission granted numerous additional parties intervention in this proceeding: Appalachian Voices; Apple Inc., Google LLC, and Meta Platforms, Inc., (appearing jointly as Tech Customers); Avangrid Renewables, LLC (Avangrid); Brad Rouse; Broad River

[1] Available at: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2022.pdf.

Energy, LLC (Broad River); the Carolina Industrial Group for Fair Utility Rates II and the Carolina Industrial Group for Fair Utility Rates III (appearing jointly as CIGFUR); the Carolina Utility Customers Association, Inc. (CUCA); the Carolinas Clean Energy Business Association (CCEBA); the City of Asheville and Buncombe County (appearing jointly as Asheville et al.); the City of Charlotte (Charlotte); the Clean Energy Buyers Association (CEBA); the Clean Power Suppliers Association (CPSA); ElectriCities of North Carolina, Inc. (Electricities), the North Carolina Eastern Municipal Power Agency, and the North Carolina Municipal Power Agency Number 1 (appearing jointly as the Power Agencies); the Environmental Justice Community Action Network and the Down East Coal Ash Environmental and Social Justice Coalition (appearing jointly as EJCAN et al.); the Environmental Working Group (EWG); Fayetteville Public Works Commission (FPWC); Kingfisher Energy Holdings, LLC (Kingfisher); MAREC Action (MAREC); NAACP Charlotte-Mecklenburg County Branch #5376-B (Charlotte-Mecklenburg NAACP); NC WARN; the North Carolina Alliance to Protect our People and the Places We Live (NC-APPPL); the North Carolina Council of Churches (Council of Churches); the North Carolina Electric Membership Corporation (NCEMC); the North Carolina Pork Council (Pork Council); the North Carolina Sustainable Energy Association (NCSEA); Person County; Sean Lewis; the Southern Alliance for Clean Energy, the Sierra Club, and the Natural Resources Defense Council (appearing jointly as SACE et al.); the RedTailed Hawk Collective and the Robeson County Cooperative for Sustainable Development (appearing jointly, along with EJCAN et al., as RTHC et al.); TotalEnergies Renewables USA, LLC (TotalEnergies); Walmart Inc. (Walmart); and 350 Triangle.

The Commission held three conferences, occurring on February 7, 2022, March 7, 2022, and April 4, 2022, for parties to update the Commission on the sufficiency of the Duke-led stakeholder meetings as they occurred.

Consistent with the Commission's directive, Duke filed its Carbon Plan proposal on May 16, 2022. On July 15, 2022, the Commission received comments and alternative proposed Carbon Plans from certain intervenors. On July 29, 2022, the Commission scheduled a hearing to receive expert witness testimony into the record for the purpose of informing the Commission's analysis and development of the initial Carbon Plan. The Commission also allowed parties to file responsive comments on specific, designated legal issues by September 9, 2022. This matter came before the Commission for an expert witness hearing beginning on September 13, 2022, and continuing through September 29, 2022, during which the Commission received expert witness testimony and exhibits from the following parties: Duke, the Public Staff, the AGO, Appalachian Voices, Tech Customers, Avangrid, Brad Rouse, CIGFUR, CUCA, CCEBA and MAREC, jointly, CPSA, EWG, the Charlotte-Mecklenburg NAACP and NC WARN, jointly, NCEMC, and NCSEA and SACE et al., jointly. At the conclusion of the expert witness hearing, the Commission directed parties to file post hearing proposed orders and briefs by October 24, 2022.

Public Witness Hearings and Consumer Statements

In addition to the expert witness hearing, the Commission conducted five public witness hearings to receive testimony from members of the public, four at locations across the state and one remotely via two separate Webex sessions on Tuesday, August 23, 2022. The four in-person hearings took place as follows:

> Monday, July 11, 2022, at 7:00 p.m., in Courtroom D7, Durham County Courthouse, 510 South Dillard Street, Durham, North Carolina 27701
>
> Tuesday, July 12, 2022, at 7:00 p.m., in Courthouse Courtroom 317, New Hanover County Courthouse, 316 Princess Street, Wilmington, North Carolina 28401
>
> Wednesday, July 27, 2022, at 7:00 p.m., in Courtroom 1-A, Buncombe County Courthouse, 60 Court Plaza, Asheville, North Carolina 28801
>
> Thursday, July 28, 2022, at 7:00 p.m., in Courtroom 5350, Mecklenburg County Courthouse, 832 East 4th Street, Charlotte, North Carolina 28202

The following persons appeared and testified at the public witness hearings:

> Monday, July 11, 2022, in Durham: Gordon Phillip Allen, David Sokal, Tobin Freid, William Terry, Lieceng Zhu, Russ Outcalt, Jason Torian, Jessica Rowe, Montravias King, Bobby Jones, Hope Gattis, Aaron Hope, Robby Phillips, Peter Morcombe, Scott Cline, Rachel Woods, Katie Craig, William Scott, Dan Figgins, Dale Evarts, Lois Nelson, Daksh Arora, Denise Frizzell, Lib Hutchby, Claudia Berry Hill, Thomas Carlyle Dowd, Ziyad Habash, Betsy Bickel, Lauren Nadine Martin, Barry Strock, Michael Audie, Keval Khalsa, Maple Mary Ann Osterbrink, David Allen Kirkpatrick, Geraldine Nelson, and Gary Nelson
>
> Tuesday, July 12, 2022, in Wilmington: Alexander Brown, Esther Murphy, Ivan Bartley, Beth Hansen, Carl Parker, Deborah Dicks Maxwell, Rachel Mitchell, Robert Parr, M.D., Isabella Peadon, Lindsey Hallock, Paul Summers, Andy Wood, and Marcel McFadden
>
> Wednesday, July 27, 2022, in Asheville: Sherry Vaughan, Steven Norris, Lauren Steiner, Pam Brown, Rob Denton, Melanie Chopko, Gray Jernigan, Carlton Angell, Maggie Ullman Berthiaume, Shannon Bodeau, Steffi Rousch, Anne Craig, Clare Hanrahan, Phil Bisesi, Melody Shank, Elsa Enstrom, Shelby Cline, Maureen Linneman, Tim Birthisel, Sawyer Bryan, Cathy Scott, John Ager, Kendall Hale, Jodi Lasseter, Rachel Bliss, Mary Olson, Patrick Sawyer, Richard Fireman, Joe Beckham, Judy Mattox, Farah Ogletree, Michael Churchman, Ken Brame, Drew Ball, Ruffin Shackleford, Bruce Santorini, Don Nicholson, Holly Beveridge, Sophie Loeb, and Sara Tew
>
> Thursday, July 28, 2022, in Charlotte: Billie Anderson, June Blotnick, Majeed Ederer, Babak Mokari, Karen Hodges, Amy Brooks Paradise, Jennifer Roberts, Tina Katsanos, Hannah Stephens, Lisa Huntting, Tom Lannin, Meg Houlihan, Donna Durfee, Lawrence Toliver, Brenda Gasior, Faith Silva, Michelle Carr, Jill Palmer, Debbie Foster, Beth Henry, Susan Tompkins, Janet Palmer, John

Gaertner, Matthew Withrow, Jeff Robbins, Keith Banner, Mary Jo Klingel, David Walsh, Nancy Neely, Skip Hudspeth, John Rochester, Maria Portoue, Jerome Wagner, Martin Fiedler, and Bailey Scarlet

Tuesday, August 23, 2022, via Webex: William McNeil, Mary Abrams, David McGowan, Jane Barnett, Pam Hemminger, Kathleen Liebowitz, Jean Pudlo, Kay Reibold, Katherine Wyszkowski, Michael Totten, Barron Northrup, John Wait, Maren Mahoney, Peter Krull, and Nancy Carter

Public witness testimony covered a variety of topics relating to Duke's Carbon Plan proposal and the intervenors' alternative proposed Carbon Plans. Public witnesses represented the diversity of North Carolina's populace, ranging from retirees, doctors, physicists, college and high school students, and environmentalists. Additionally, public witnesses offered eclectic opinions varying from disapproval to approval of Duke's Carbon Plan proposal.

The Commission heard witnesses' criticisms of Duke's Carbon Plan proposal and the Commission's approach in developing the initial Carbon Plan. Witnesses expressed particular concern that the Commission tasked Duke with preparing the primary draft Carbon Plan proposal and urged the Commission to take a more active role in developing the Carbon Plan. Several witnesses noted that three of Duke's four proposed portfolios fail to achieve the Interim Target by 2030. Public witnesses expressed apprehension about the practicality of using unproven technologies such as small modular reactors (SMRs) and hydrogen-fueled turbines to produce energy. Witnesses questioned Duke's continued reliance on nuclear and natural gas-fired generation and the pace of the retirements of Duke's coal fleet.

Witnesses stated their preference for renewable generation, including wind, solar, and hydropower, and for more aggressive implementation of energy efficiency (EE) measures, battery storage, and improvements to the transmission grid. Further, public witnesses testified about the adverse impacts of climate change, such as the recent abnormal number of storms resulting in significant property damage throughout North Carolina, especially the coastal region. Witnesses testified about persons and communities often hardest hit by climate change, including those of low-to-moderate income levels and people of color, who because of excessive power bills and the cost of electric bills, often must make difficult decisions prioritizing basic necessities.

Some witnesses raised concerns about the potential for adverse impacts to their communities, such as those to Roxboro's local economy where Duke plans to retire coal plants. These witnesses requested that Duke site replacement generation in those communities or that the Commission defer coal plant retirements.

Witnesses also testified about the negative correlation between climate change and public health. Witnesses pointed to the increase in cases of asthma, post-traumatic stress disorder, and a person's lack of physical activity due to extreme temperatures.

Additionally, witnesses opined that climate change will have a profound effect on agriculture, resulting in a shortage of certain foods.

Witnesses expressed concern regarding Duke's lack of communication to the public about renewable energy education and information, specifically information about rebates and incentives encouraging customers to adopt renewable energy technologies.

Finally, a public witness at the Wilmington public hearing testified specifically that Duke's environmental justice outreach about its proposed Carbon Plan had been inadequate. Tr. vol. 2, 29-32.

In addition to receiving testimony from public witnesses, the Commission also accepted consumer statements from interested members of the general public. In total, members of the public filed more than 489 consumer statements in Docket No. E-100, Sub 179CS. Similar to the testimony received by the witnesses at the public hearings, the consumer statements covered a variety of topics relating to Duke's Carbon Plan proposal, including expressing support for renewable energy resources and stating opposition to new nuclear generation resources.

JURISDICTION

No party has contested the fact that DEC and DEP are public utilities subject to the Commission's jurisdiction pursuant to the Public Utilities Act. DEC and DEP are "electric public utility[ies] as defined in N.C.G.S. § 62-3(23) serving at least 150,000 North Carolina retail jurisdictional customers as of January 1, 2021[,]" and, therefore, are subject to N.C.G.S. § 62-110.9. Based upon the foregoing, the Commission concludes that it has personal jurisdiction over DEC and DEP and subject matter jurisdiction over the matters presented in this proceeding.

STANDARD OF REVIEW

The Public Utilities Act establishes state policy to promote adequate, reliable, and economical utility service. The Public Utilities Act further tasks the Commission with developing resource plans to ensure sufficient resources to meet future load growth and provide for adequate, reliable utility service achieved via the least cost mix of generation and demand-reduction measures. N.C. Gen. Stat. §§ 62-2 and 62-110.1(c).

As noted above, the Commission's November 19, 2021 Order states that the Commission will look to, but will not strictly adhere to, Commission Rule R8-60 in developing the Carbon Plan. Commission Rule R8-60 outlines the IRP planning process, in which the Commission investigates utility proposals to implement "the least cost mix of generation and demand-reduction measures" to meet electric power requirements in North Carolina. N.C.G.S. §§ 62-2(a)(3a) and 62-110.1(c). Pursuant to Commission Rule R8-60(g), the utility must consider all "potential resource options and combinations of resource options to serve its system needs." Furthermore, utility proposals "should take into account, as applicable, system operations, environmental impacts, and other qualitative factors." *Id.*

When fulfilling its resource planning duties, the Commission also acts in a legislative capacity. In *State ex rel. Utils. Comm'n v. N.C. Elec. Membership Corp.*, 105 N.C. App. 136, 412 S.E.2d 166 (1992), addressing the character of proceedings relating to utilities' IRPs, the Court of Appeals stated: "[T]he least cost planning proceeding should bear a much closer resemblance to a legislative hearing, wherein a legislative committee gathers facts and opinions so that informed decisions may be made at a later time." *Id*. at 144, 412 S.E.2d at 170. As a result, the Commission views information and data that it receives through comments, reply comments, consumer statements of position, and legal briefs as information the Commission should consider and use in its investigation and decision-making process when developing resource plans.

Further, "[f]or the purpose of conducting hearings, making decisions and issuing orders, and in formal investigations where a record is made of testimony under oath, the Commission shall be deemed to exercise functions judicial in nature . . . . " N.C.G.S. § 62-60. In developing the Carbon Plan, the Commission has acted in a judicial capacity by conducting hearings to receive evidence, including testimony under oath, consistent with its authority pursuant to N.C.G.S. § 62-60.

When acting as a court of record, the Commission must apply the rules of evidence "in so far as practicable" and must base its decision upon competent, material, and substantial evidence upon consideration of the whole record. N.C.G.S. § 62-65(a). The Commission may in its discretion exclude incompetent, irrelevant, immaterial, and unduly repetitious or cumulative evidence. *Id.* Further, "[a]ll evidence, including records and documents in the possession of the Commission of which it desires to avail itself, shall be made a part of the record in the case by definite reference thereto at the hearing." *Id.*

In addition to considering the record evidence, the Commission may take judicial notice of credible sources including its decisions, published reports of federal regulatory agencies, state and federal statutes, public information, data that official state and federal agencies publish, and generally recognized technical and scientific facts within the Commission's specialized knowledge. N.C.G.S. § 62-65(b).

Taking competency into consideration, the Commission determines the appropriate weight it will give to any particular piece of evidence or other information received during its analysis and development of the Carbon Plan. Ultimately, the Commission must base its decisions regarding the Carbon Plan upon competent, material, and substantial evidence it derives through consideration of the whole record. N.C.G.S. § 62-65(a).

SUMMARY OF PROPOSED CARBON PLAN PORTFOLIOS

Duke and the intervening parties have presented the Commission with a number of portfolios that aim to achieve the Interim Target as well as the 2050 Target. This section briefly summarizes the portfolios that Duke and the intervening parties have presented.

The following sections will provide additional detail and analysis of these portfolios, as necessary, in the context of specific resources and the related discussion and conclusions by the Commission.

Duke's Proposed Portfolios

Duke's Carbon Plan proposal includes four distinct portfolios designed to illustrate two potential pathways to achieving the Interim Target by replacing its coal fleet with new generation and other resources.

Presently, Duke relies upon approximately 9,294 megawatts (MW) of coal-fired generation, all sited within the state, representing roughly 25% of its total system[2] generating capacity. In order to meet the directives of N.C.G.S. § 62-110.9, Duke proposes to retire the vast majority of its coal fleet (8,445 MW).[3] Duke's proposed coal fleet retirements are mostly consistent across the four portfolios. Portfolios 1 through 4 (P1, P2, P3, and P4, respectively) commonly retire Allen Units 1 and 5 in 2024; Cliffside Unit 5 in 2026; Marshall Units 1 and 2, Mayo Unit 1, and Roxboro Units 1 and 2 in 2029; Marshall Units 3 and 4 in 2033; and Belews Creek Units 1 and 2 in 2036. Roxboro Units 3 and 4 retirements vary between portfolios, with retirement of those units effective in 2028 in P1, in 2032 in P2, and in 2034 in P3 and P4.

P1 achieves the Interim Target by 2030. Portfolios 2-4 take advantage of the Commission's limited discretion to extend the Interim Target compliance date. More particularly, P2 achieves the Interim Target by 2032; P3 achieves the Interim Target by 2034 by incorporating a 285 MW SMR; and P4 achieves the Interim Target by 2034 by incorporating a 285 MW SMR but with other resource selection variances from P3.

All of Duke's proposed portfolios incorporate demand response and EE measures, new solar generation, new natural gas-powered combined cycle (CC) and combustion turbine (CT) generation, battery storage capacity, and onshore wind to achieve the Interim Target. In addition to these baseline resources, P1 utilizes offshore wind generation to achieve compliance with the Interim Target by 2030. Compared to P1, P2 incorporates offshore wind generation, additional onshore wind generation, and slightly less battery storage capacity to achieve compliance with the Interim Target by 2032. P3 foregoes offshore wind but utilizes SMR capacity to achieve the Interim Target by 2034. Finally, P4 achieves the Interim Target by 2034 with offshore wind again in the mix but with slightly reduced CT capacity.

Duke's proposed portfolios range in projected costs through 2050 between $95 billion and $101 billion in present value revenue requirement (PVRR). Duke projects P1 to be the costliest of its proposed portfolios and projects P3 to be the least costly. P1

[2] As used herein, "total system" refers to the combined DEP and DEC North Carolina and South Carolina systems.

[3] Duke does not slate Cliffside 6, which is capable of operating 100% on natural gas, for retirement but assumes that it will cease coal operations by the beginning of 2036.

achieves the greatest carbon dioxide emissions reduction for the state, leading all portfolios in carbon dioxide emissions reductions by both 2030 and 2035, while P4 has the least impact on carbon dioxide emissions within the same timeframes. Finally, Duke assesses P1 as carrying the greatest level of risk to achieving the Interim Target, with P4 being the least risky.

Public Staff's Proposed Portfolios

During the proceeding, Duke developed two proposed supplemental portfolios (SP5 and SP6) based upon various recommendations by the Public Staff, the AGO, and CPSA. SP5 achieves the Interim Target by 2032, and SP6 achieves the Interim Target by 2034. The supplemental portfolios push back the retirement of Belews Creek Units 1 and 2 to 2037 with continued operation on both coal and gas. Both SP5 and SP6 primarily add new solar generation, onshore wind, and battery storage to achieve the Interim Target. SP6 uses pumped hydro storage, but SP5 does not do so until after Duke achieves the Interim Target. Neither SP5 nor SP6 rely on offshore wind to achieve the Interim Target. In modeling SP5 and SP6, Duke allowed the EnCompass model to optimize charging and discharging of battery storage paired with solar generation (Solar Plus Storage) facilities and removed cumulative limits on 4-hour and 6-hour batteries. SP5 and SP6 do not employ hydrogen (H_2) as a fuel blended with natural gas, and Duke's modeling allowed for the selection of both J-class and F-class CTs and CCs and used retirement dates for existing CTs that match the most recent depreciation studies. Also, SP5 and SP6 assume that Duke will not have access to natural gas from the Mountain Valley Pipeline (MVP) expansion. Finally, Duke modeled a higher limit on annual solar interconnections.

Intervenors' Proposed Portfolios

The AGO engaged Strategen, a consulting firm, to conduct a supplemental portfolio analysis. The AGO's proposed portfolio built upon the SP5 portfolio but included several modifications. Namely, the AGO's portfolio: (a) removed cumulative limits on Solar Plus Storage facilities; (b) set the useful life of new natural gas-fired facilities to 20 years; (3) economically selected coal retirement dates and converted Belews Creek Units 1 and 2 to 100% natural gas by 2028; (4) adjusted solar limits; (5) increased annual import limits using non-firm transmission; and (6) met the Interim Target by 2030. The AGO's proposed portfolio has a PVRR through 2050 of $100 billion.

CPSA engaged the Brattle Group to perform five alternative portfolio analyses: CPSA1-CPSA5. CPSA1 meets the Interim Target by 2030 and has no cap on solar capacity additions. CPSA2 and CPSA3 also meet the Interim Target by 2030 and are alternatives to Duke's P1: CPSA2 uses Duke's solar cap while CPSA3 uses a higher cap on solar interconnections. CPSA4 and CPSA5 meet the Interim Target by 2032 and are alternatives to Duke's P2: CPSA4 uses Duke's solar cap while CPSA5 uses a higher cap on solar interconnections.

NCSEA and SACE et al. (jointly referred to as NCSEA et al.) engaged Synapse to perform two portfolio scenarios: the “Optimized” scenario and the “Regional Resources” scenario. Synapse first created a “Duke Resources” scenario which it intended to provide a baseline and as such attempted to recreate the resources in Duke’s P1 portfolio. Compared with Duke’s P1, the “Optimized” scenario expanded EE and Net Energy Metering (NEM) forecasts, constrained SMR deployment, and allowed greatly increased solar, battery storage, and offshore wind deployments. The “Regional Resources” scenario additionally allowed the model to select power purchase agreements (PPAs) for Midwest wind imported through the PJM Regional Transmission Organization (PJM). Both of these scenarios met the Interim Target by 2030. These proposed portfolios have a PVRR through 2050 of $103.5 billion and $98.1 billion for the “Optimized” and “Regional Resources” portfolios, respectively.

Tech Customers engaged Gabel and Stratagen to create a “Preferred Portfolio.” This portfolio built upon Duke’s P1 but is characterized by: (1) significantly more Solar Plus Storage resources and behind-the-meter solar resources; (2) an EE forecast about twice that of Duke’s; (3) greatly reduced future natural gas-fired capacity; and (4) no future SMR resources. Tech Customers’ proposed portfolio meets the Interim Target by 2030 and has a PVRR through 2050 of $108.8 billion.

DISCUSSION AND CONCLUSIONS FOR THRESHOLD LEGAL ISSUES

Selection of No Single, Preferred Portfolio

One of the threshold matters on which the parties disagree is whether the Commission should or must select a single preferred portfolio as its initial “Carbon Plan” at this time.

Duke requests that the Commission affirm that its proposed suite of portfolios is reasonable for planning purposes and presents a reasonable plan for achieving the carbon dioxide emissions reduction directives in a manner consistent with both the law’s requirements and prudent utility planning. Duke Post Hearing Br. at 72.

In support of this request, Duke argues that its proposed “approach is consistent with the Commission’s historic approach to long-range planning,” and that N.C.G.S. § 62-110.9 does not require the selection of a single portfolio. *Id*. Duke further asserts that approving a single portfolio at this time would be premature, particularly with regard to further information about market costs and long lead-time supply-side resources. Duke Pre Hearing Comments on Non-Expert Track Legal and Policy Issues at 18.

The Public Staff requests that the Commission determine SP5 to be reasonable for planning purposes and as a foundation for the 2022 Carbon Plan and associated near-term procurement and development activities. Public Staff Proposed Order at 3.

NCSEA et al. contend that Duke’s “multi-pathway approach is not supported by H951.” NCSEA et al. Joint Comments at 15. NCSEA et al. argue that “Section 1 of Part 1 of H951 directs the Commission to develop 'a plan,' in the singular, to achieve the law's carbon reduction requirements." *Id*. While NCSEA et al. acknowledge the need for flexibility and revision to a long-term plan, they nonetheless characterize Duke's multi-pathway approach as a "request not to be held accountable to a plan that gives clear guidance for how [Duke] should proceed with meeting their carbon pollution reduction targets." *Id.* However, NCSEA et al. Joint Brief and Partial Proposed Order states that Duke's approach of presenting at least four portfolios in its Carbon Plan, in addition to a near term plan, is generally reasonable and appropriate for purposes of providing the Commission and stakeholders with a range of options and paths from which the Commission may choose towards the achievement of the carbon dioxide emissions reduction mandates of N.C.G.S. § 62-110.9 under a least cost framework. NCSEA et al. Joint Brief and Partial Proposed Order at 13.

At this time, the Commission concludes that it need not select a single portfolio as the basis for the initial Carbon Plan. The Commission has historically considered and accepted, as reasonable for planning purposes, multiple portfolios within its oversight of integrated resource planning. *See, e.g.*, Order Accepting Integrated Resource Plans, REPS and CPRE Program Plans with Conditions and Providing Further Direction for Future Planning, *2020 Biennial Integrated Resource Plans and Related 2020 REPS Compliance Plans*, No. E-100, Sub 165 (N.C.U.C. Nov. 19, 2021). Further, N.C.G.S. § 62-110.9 specifically directs the Commission to "take all reasonable steps" toward achieving the carbon dioxide emissions reduction mandates. Accordingly, the Commission views the development of the initial Carbon Plan pursuant to N.C.G.S. § 62-110.9 as a series of "reasonable steps" or actions in furtherance of the carbon dioxide emissions reduction mandates. As the compliance dates for the Interim and 2050 Targets get closer, the resource options available for the Commission to select will narrow and the Commission's selection or creation of a single portfolio may be reasonable at that time. Currently, however, it is reasonable for the Commission to decline to select a single portfolio, and instead, to focus on a series of near-term actions that support many of the portfolios the parties to this proceeding present. In the next Carbon Plan proceeding, the Commission expects parties to the proceeding to again present portfolios for the Commission's consideration that take into account the decisions the Commission makes in this initial Carbon Plan as well as up-to-date data and assumptions related to economic conditions, including developments such as the IRA, for example.

Further, as noted above, N.C.G.S. § 62-110.9 creates an Interim Target and provides the Commission flexibility to delay compliance with that Interim Target. The Commission finds that, at this time, it is not appropriate to determine whether it is reasonable or necessary to extend the Interim Target compliance date beyond 2030. The Commission expects Duke to continue to pursue compliance with the Interim Target, including proposing portfolios that comply with the Interim Target in future Carbon Plan proceedings. The Commission expects Duke to continue to consider the future recommendations of all stakeholders, which the Commission's decisions in this proceeding will presumably inform, in crafting a path to compliance with the Interim Target.

Approval of Supply-Side Activities to Be Undertaken in the 2023-2024 Timeframe

Duke requests that the Commission approve Duke's undertaking certain activities in the "near-term" 2023-2024 timeframe to advance the Carbon Plan components that are consistent across portfolios. Specifically, Duke requests Commission approval of its undertaking certain supply-side activities related to existing resources (the existing natural gas-fired fleet and nuclear fleet) and new resources (solar, battery storage, onshore wind, and new natural gas-fired generating resources). Tr. vol. 7, Duke Proposed Carbon Plan, Executive Summary, 23.

Duke also requests that the Commission approve certain initial development activities for Duke to undertake in the near term to support the future availability of certain supply-side resources — including offshore wind, new nuclear generation, and new pumped storage hydro at the Bad Creek facility — all of which Duke asserts are likely to be necessary in order to comply with the Interim Target and the 2050 Target. *Id.*

The table on the following page summarizes the near-term supply-side activities Duke proposes for the Commission's approval.

Table 3: Supply-Side Resources Requiring Actions in Near-Term

Resource	Amount	Proposed Near-Term Actions
Proposed Resource Selections: In-Service through 2029		
Carbon Plan Solar	3,100 MW	• Begin Public Policy Transmission projects in 2022[6] • Procure 3,100 MW of new solar 2022-2024 with targeted in service in 2026-2028, of which a portion is assumed to include paired storage
Battery Storage	1,600 MW	• Conduct development and begin procurement activities for 1,000 MW stand-alone storage and procure 600 MW storage paired with solar
Onshore Wind	600 MW	• Engage wind development community in preparation for procurement activities • Procure 600 MW in 2023-2024
New CT[1]	800 MW	• Submit CPCN for 2 CTs totaling 800 MW in 2023
New CC[2]	1,200 MW	• Submit first CPCN for 1,200 MW in 2023 • Evaluate options for additional gas generation pending determination of gas availability
Proposed Resource Development: Options for 70% Interim Target		
Offshore Wind[3]	800 MW	• Secure lease • Initiate development and permitting activities for 800 MW[7] • Conduct interconnection study • Initiate preliminary routing, right-of-way acquisition for transmission
New Nuclear[4]	570 MW	• Begin new nuclear early site permit ("ESP") for one site • Begin development activities for the first of two SMR units
Pumped Storage Hydro[5]	1,700 MW	• Conduct feasibility study for 1,700 MW • Develop EPC strategy • Continued development of FERC Application for Bad Creek relicensing

Note 1: CPCN for two CTs (800 MW) estimated for in-service 2027-2028
Note 2: CPCN for one CC (1,200 MW) estimated for in-service 2027-2028, CPCN for second CC (1,200 MW) will be evaluated for submittal in 2024 with estimated in-service 2030 as fuel supply is determined.
Note 3: Retaining optionality through early development activities, in-service date assumption dependent upon portfolio.
Note 4: New nuclear capacity represents first two SMR units, planned in-service date through 2034.
Note 5: Pumped storage hydro capacity represents second powerhouse at Bad Creek, planned in-service 2033.
Note 6: Projects subject to North Carolina Transmission Planning Collaborative (“NCTPC”) approval.
Note 7: Federal regulations require the lessee to submit in the preliminary term of 12 months: (i) a Site Assessment Plan (“SAP”); or ii) a combined SAP and Commercial Operation Plan.

Id.

Duke asserts that this proceeding "boils down to one simple question: what are the near-term 'reasonable steps' to be taken by Duke Energy to begin meaningful and substantial progress towards the 70% Interim Target on the path to Carbon Neutrality." Duke Post Hearing Br. at 11.

Other parties similarly have advocated for an initial Carbon Plan prioritizing actions that they characterize as "least regrets" or "no regrets." *See, e.g.,* Public Staff Witness Metz Testimony, tr. vol. 21, 142, 148; AGO Witness Burgess Testimony, tr. vol. 25, 236-38, 293, 295-96; NCSEA et al. Witness Caspary Testimony, tr. vol. 22, 232, 234-35, 247; CPSA Witness Norris Testimony, tr. vol. 26, 64; Tech Customers Post Hearing Br. at 8. For example, AGO witness Burgess testified in support of the solar, battery storage, and onshore wind procurements which Duke includes in its proposed near-term action plan and argues that Duke should pursue them as part of a "no regrets" approach. Tr. vol. 25, 295-96. As another example, Tech Customers advocate that the Commission should be looking for near-term, "no regrets" actions that keep open the potential to pursue multiple cost-competitive paths to a carbon-free grid, with due consideration given to the risks inherent in different generation technologies. Tech Customers Post Hearing Br. at 17.

Stopping short of recommending that the Commission adopt the AGO's proposed portfolio as its plan, the AGO proposes that the Commission's initial Carbon Plan should focus on the selection of resources and retirements that will achieve the Interim Target by 2030, the near-term actions to support those selections and retirements, and steps to prepare for longer lead-time resources that will continue reducing emissions over the next decades. The AGO notes that given the uncertainties of planning for later years, the AGO expects that the mix of resources and timing will evolve in subsequent Carbon Plan proceedings. AGO Post Hearing Br. at 24. While the AGO bases its recommendations primarily on its proposed portfolio, the AGO did point out that the range of portfolios parties presented to the Commission shared "a number of common features" as well as several distinctions. *Id*. at 25.

Duke's Modeling and Near-Term Actions Panel Rebuttal Table 1, which is shown on the following two pages, highlights Duke's proposed near-term supply-side resource activities and those that several intervenors propose, indicating at least some consistency in the resource types.

Rebuttal Table 1: Summary of the Companies' Proposed Near-term Actions with Intervenors' Suggested Modifications

	Solar (including SPS)	BESS Paired w/ Solar	BESS Standalone	Onshore Wind	CT	CC
Supporting deployment by:[1]	YE 2028	YE 2028	YE 2029	YE 2029	YE 2029	YE 2029
Duke Energy Proposal (MW)	**3,100**	**600**	**1,000**	**600**	**800**	**1,200**
Public Staff Proposal (MW)[2]	**2,630**	**820**	**1,130**	**600**	**800**	**1,200**
Alternative Proposals (MW)						
AGO[3]	3,100	600	1,000	600	0	0
Tech Customers[4]	3,450	1,600	2,900	1,200	400	0
CPSA[5]	4,800	1,650	*0*	*600*	*0 to 500*	*1,200*
NCSEA et al.[6]	4,000	0	4,000	600	0	0
Differences from Duke Energy Proposal						
Public Staff Proposal (MW)	**-470**	**+220**	**+130**	**0**	**0**	**0**
Alternative Proposals (MW)						
AGO	0	0	0	0	-800	-1,200
Tech Customers	+350	+1,000	+1,900	+600	-400	-1,200
CPSA	+1,700	+1,050	*-1,000*	*0*	*-800 to -300*	*0*
NCSEA et al.	+900	-600	+3,000	0	-800	-1,200

Note 1: Year End dates are selected based on the expected timeline from commencing development/procurement to project in service.
Note 2: Public Staff recommends including 440 MW of remaining CPRE capacity in the 2022 Carbon Plan solar procurement. CPRE amounts are excluded from the numbers in this table.
Note 3: Supports the Companies' proposed solar, storage, and onshore wind volumes as a "no regrets" floor for procurement. *See* AGO Burgess Direct Testimony at 69.
Note 4: Does not make a specific Near-Term Actions Proposal. Values used are based on Tech Customers' "Preferred" portfolio. *See* Tech Customers Roumpani Direct Testimony at 5.
Note 5: CPSA does not clearly advocate for specific volumes of resources for the near-term action plan other than solar and SPS. The volumes for other resources included in Rebuttal Table 1 reflect Portfolios CPSA3 and CPSA5, which "CPSA strongly recommends. . . inform Duke's near-term execution plan." *See* CPSA Norris Direct Testimony at 29. CPSA3 and CPSA5 both include two new CCs by 2030 totaling 2,400 MW, only one of which is reflected here, consistent with the Companies' approach to developing their own near-term action proposal.
Note 6: NCSEA et al. recommend beginning procurement of 4,000 MW each of solar and storage with target in-service dates of 2025-2028. Not shown above is additional recommendation for 2,500 MW of off-system onshore wind. NCSEA et. al Fitch Direct Testimony at 50-51.

Tr. vol. 27, 41, Duke's Modeling and Near-Term Actions Panel Rebuttal Tbl. 1.

Even though the parties have propounded specific portfolios for the Commission to consider or select in this initial Carbon Plan, no party has expressly opposed focusing on actions required in the near term to achieve the Interim Target, to avoid premature commitments, and to provide flexibility for longer-term decisions. The Commission concludes that an approach focused on near-term activities comprised of a number of reasonable steps needed to achieve the mandated carbon dioxide emissions reduction, which are generally supported as “no regrets,” is not only an appropriate course of action at this stage of implementation but is also well-supported by N.C.G.S. § 62-110.9, which contemplates review and adjustment of the Carbon Plan on an interim two-year basis. N.C.G.S. § 62-110.9(1). Accordingly, the Commission determines that it is properly within the Commission’s discretion to focus this initial Carbon Plan Order, in the context of supply-side resources, primarily, on a near-term plan, as discussed in greater detail in this Order.

Certificate of Public Convenience and Necessity Requirements

For clarification, Commission approval of, selection of, or support for a certain resource as part of the near-term plan does not constitute Commission approval for construction of a generating facility. The Commission agrees with Public Staff witness Thomas who notes that approval of a near-term action item should not be taken as approval of construction of generating plants or otherwise be controlling in a Commission certificate of public convenience and necessity (CPCN) proceeding. Tr. vol. 21, 98. More particularly, witness Thomas suggests that approval of a near-term action item provides clarification on what steps Duke is likely to need or should take in the planning horizon — here, the Commission’s immediate planning horizon is 2023-2024, which is the interim period between the issuance of this Order and the Commission’s next Carbon Plan which it is to issue on or before December 31, 2024. Parties should construe nothing in this Order as supplanting the Commission’s existing CPCN approval process. The Commission will consider and give appropriate weight to approval of a generation resource for planning purposes in a Carbon Plan proceeding in a future CPCN proceeding but will consider that factor in addition to all other evidence the law requires.

Cost Recovery Proceedings

Based on the commentary of Duke and other parties to this proceeding, the Commission deems it necessary to clarify the purpose of this Carbon Plan proceeding and subsequent combined Carbon Plan and IRP (CPIRP, as hereinafter defined) proceedings with regard to cost recovery for Carbon Plan execution costs. Duke seeks assurance that any decision to engage in initial project development activities for new nuclear facilities, offshore wind, and/or pumped hydro storage is a reasonable and prudent step toward Carbon Plan execution and that it will be assured future recovery of such initial project development costs. The Commission addresses this request for assurance and clarifies how this Carbon Plan proceeding, and subsequent CPIRP proceedings, relate to cost recovery.

Duke requests that the Commission make three determinations regarding Duke’s proposed project development activities for long lead-time activities: (1) that engaging in initial project development activities for new nuclear, offshore wind, and pumped hydro storage resources, in advance of receiving any required CPCN, is “a reasonable and prudent step” to enable future selection of those resources for the Carbon Plan; (2) that to the extent the Commission later finds the individual costs incurred to be reasonable and prudent, they will be recoverable in rates; and (3) that such reasonable opportunity for recovery will be available to Duke should any of these resources ultimately not be selected by the Commission in the future and the development activities, therefore, abandoned. Duke Post Hearing Br. at 82. On rebuttal, Duke witness Bateman confirmed that while in its initial Petition to the Commission, Duke requested the right to defer certain costs associated with the development of these resources, Duke has since modified its request to no longer seek any accounting deferral at this time. Tr. vol. 28, 88.

In support of these requests, Duke cites N.C.G.S. § 62-110.7, which authorizes the Commission to approve the decision to incur nuclear project development costs and provides that all reasonable and prudent nuclear project development costs thereby incurred shall be fully recoverable in a general rate case proceeding. Duke notes that in the event of cancellation of a project, all reasonable and prudently incurred nuclear development project costs are recoverable pursuant to N.C.G.S. § 62-110.7(d). With respect to the application of this special ratemaking treatment to other resources, Duke acknowledges that the statute only applies to nuclear facilities. Duke Post Hearing Br. at 83. Duke argues, however, that the Commission has previously granted the exact relief it now requests prior to the enactment of N.C.G.S. § 62-110.7, thereby demonstrating that the Commission has the authority and precedent to grant the requested relief outside of N.C.G.S. § 62-110.7 and for resources other than nuclear generation. *Id*. Duke explains that in 2006, it requested special ratemaking treatment for the proposed Lee Nuclear Station in Docket No. E-7, Sub 819. At the time, Duke expected to incur significant development costs prior to receiving its regulatory approval to construct, and the Commission, prior to enactment of N.C.G.S. § 62-110.7, found that it had the legal authority to grant the requested assurance of future cost recovery of initial development costs. Duke discusses the Commission’s decision in the Lee Nuclear Station proceeding and states, “[t]he exact same rationale underlying the Commission’s decision . . . applies in the context of the Carbon Plan.” *Id*.

Duke argues that the fact that N.C.G.S. § 62-110.7 is limited in scope to nuclear development costs does not change the fact that the Commission previously granted Duke’s requested relief without express statutory authority and does not indicate that the General Assembly believed the Commission should not have that authority for resources other than nuclear. Lastly, Duke points to the language in N.C.G.S. § 62-110.9 that directs the Commission to take “all reasonable steps” to achieve the emissions reduction targets in the legislation and argues that this should include pursuing new nuclear, offshore wind, and new pumped storage hydro at this early stage to ensure that these resources will be available when needed to meet the carbon dioxide emissions reduction mandates. Duke Post Hearing Br. at 84-85.

Relatedly, Duke contends that it has never been required to incur, prior to Commission approval, development costs of the magnitude that are required to ensure the availability of the long lead-time resources on the timelines contemplated by the Carbon Plan without some form of cost recovery assurance. Duke argues that this justifies its requested assurance in the present instance. Further, Duke states that it would be inconsistent with the regulatory compact to impose a legal obligation to perform substantial development work on Duke while denying any such assurance of future cost recovery. While it is possible that a long lead-time resource may not ultimately be selected as part of the Carbon Plan resource portfolio, Duke notes that this should not impact cost recovery for initial development activities deemed prudent for long-term planning purposes. Duke also argues that denial of its request will inequitably place all financial risk on Duke. Finally, Duke contends that in the absence of cost recovery assurance, customers could potentially lose the benefit of any resources Duke deems too risky to pursue. *Id*. at 85.

In response to the Public Staff's recommendation that requests for cost recovery assurances for nuclear development costs be addressed in a separate proceeding, Duke states that N.C.G.S. § 62-110.7 allows utilities to request special ratemaking treatment at any time prior to the filing of a CPCN application. Duke adds that it would be an inefficient use of regulatory resources to require it to initiate a separate proceeding to address the assurances being requested here. *Id*. at 86-87.

The normal regulatory mechanism for considering cost recovery is a general rate case proceeding; however, exceptions, both statutory and common law exist, including but not limited to statutorily authorized riders and Commission precedent authorizing accounting deferrals.[4] The immediate proceeding is neither a general rate case nor any other recognized cost recovery proceeding. Accordingly, absent an accepted regulatory exception, the Commission declines to make any determinations as to the reasonableness and prudence of specific Carbon Plan execution costs until such time that those specific costs are presented to the Commission in an authorized cost recovery proceeding. The Commission emphasizes that any approval of near-term development activities for the long lead-time resources or acknowledgment of Duke's proposed cost caps, discussion of which occurs in later sections of this Order, does not constitute a determination as to ultimate reasonableness and prudence of these specific costs.

The Commission finds that a detailed explanation of the timing of the Commission's decision to preauthorize the Lee Nuclear Station development costs and the enactment of N.C.G.S. § 62-110.7 is informative for the purpose of this discussion.

The pertinent facts, which are a matter of public record, are the following: On September 20, 2006, in Commission Docket No. E-7, Sub 819, DEC filed an Application for Authority to Recover Nuclear Generation Development Expenses, stating that "the evaluation and development of the Lee Nuclear Station also requires large sums of money. As noted above, the Development Costs through December 31, 2007, are anticipated to be as much as $125 million." DEC Appl. at 8-9. Following comments and

[4] Duke having withdrawn its request for deferral authorization, the Commission will not discuss its accounting deferral precedents herein.

oral arguments, on March 30, 2007, the Commission issued a Declaratory Ruling stating that "it is in the public interest for the Commission to issue a declaratory ruling which gives Duke a general assurance that its activities in assessing the development of the proposed Lee Nuclear Station through December 31, 2007, are appropriate activities." Order Issuing Declaratory Ruling, *Application of Duke Power Company LLC d/b/a Duke Energy Carolinas LLC, for Authority to Recover Necessary Nuclear Generation Development Expenses and Request for Expedited Treatment,* No. E-7, Sub 819, at 22 (N.C.U.C. Mar. 30, 2007). More particularly, the Commission found:

> It is appropriate in general for Duke to pursue preliminary siting, design and licensing of the proposed William States Lee II Nuclear Station (Development Work) through December 31, 2007, to ensure that nuclear generation remains an available resource option for Duke's customers, and such Development Work is generally consistent with the promotion of adequate, reliable, and economical utility service to the citizens of North Carolina and the policies expressed in G.S. 62-2.

Id. Moreover, future cost recovery was conditioned on "the specific activities involved in, and the costs of pursuing such Development Work" being found "to be prudent and reasonable (whether or not the Lee Nuclear Station is constructed)" "in a future general rate case proceeding[.]"[5] *Id.*

Shortly thereafter, on August 20, 2007, Session Law 2007-397 (also known as Senate Bill 3) became law, which in addition to enacting N.C.G.S. § 62-110.7 made other significant changes to the Public Utilities Act. In brief, N.C.G.S. § 62-110.7 provides that, prior to filing for a CPCN to construct a potential nuclear electric generating facility, a public utility may request that the Commission review the public utility's decision to incur project development costs,[6] and if the public utility demonstrates by a preponderance of the evidence that the decision to incur project development costs is reasonable and prudent, the Commission shall approve the public utility's decision to incur project development costs. In doing so, however, the Commission shall not rule on the reasonableness or prudence of specific project development activities or recoverability of specific items of cost. N.C.G.S. § 62-110.7(b). The statute continues that if the Commission deems the project development costs to be reasonable and prudent, the

[5] In a subsequent Order Clarifying Declaratory Ruling, the Commission stated "[c]learly this language has not pre-approved or denied any particular future ratemaking treatment for Development Costs regardless of whether the plant is never begun, abandoned, or completed. Instead, the Commission retains discretion to determine the appropriate ratemaking treatment in a future general rate case proceeding." Order Clarifying Declaratory Ruling, *Application of Duke Power Company LLC d/b/a Duke Energy Carolinas LLC, for Authority to Recover Necessary Nuclear Generation Development Expenses and Request for Expedited Treatment*, No. E-7, Sub 819, 6 (Aug. 6, 2007).

[6] "'[P]roject development costs' mean all capital costs associated with a potential nuclear electric generating facility incurred before (i) issuance of a certificate under G.S. 62-110.1 for a facility located in North Carolina or (ii) issuance of a certificate by the host state for an out-of-state facility to serve North Carolina retail customers, including, without limitation, the costs of evaluation, design, engineering, environmental analysis and permitting, early site permitting, combined operating license permitting, initial site preparation costs, and allowance for funds used during construction associated with such costs." N.C.G.S. § 62-110.7(a).

costs "shall be included in the public utility's rate base and shall be fully recoverable through rates in a general rate case proceeding . . . ." N.C.G.S. § 62-110.7(c). In the event that the project is cancelled, the statute also provides, "the Commission shall permit the public utility to recover all reasonable and prudently incurred project development costs in a general rate case proceeding pursuant to G.S. 62-133 amortized over a period equal to the period during which the costs were incurred or five years, whichever is greater." N.C.G.S. § 62 110.7(d). Accordingly, nothing in N.C.G.S. § 62-110.7 can be construed to supersede the Commission's oversight over a utility's cost of service in a cost recovery proceeding based upon the standard of whether the expenditures are reasonable and prudent, nor does the statute create an ultimate presumption of reasonableness and prudency. Rather, not inconsistent with the Commission's determination in the Lee Nuclear Station project development cost matter, N.C.G.S. § 62-110.7 codifies that in the limited case of highly capital-intensive nuclear development activities, where a utility can demonstrate by a preponderance of the evidence that the decision to incur project development costs is reasonable and prudent that it is in the public interest to give the utility limited and qualified assurance of cost recovery subject to standard review processes for cost recovery.

In light of the foregoing, the Commission concludes that N.C.G.S. § 62-110.7 is applicable only in the limited context of Duke's decision to incur development activities associated with new nuclear facilities and not in the context of non-nuclear resources. The Commission considers Duke's proposal to begin project development work on new nuclear facilities, including a fact-specific analysis, in its discussion related to Findings of Fact Nos. 40-43.

Further, consistent with the Commission's Lee Nuclear Station precedent, the Commission concludes that where it approves a request from Duke to incur initial project development costs for purposes of execution of the Carbon Plan, the Commission's approval constitutes reasonable assurance of recoverability in a future cost recovery proceeding, even if the resource is ultimately not selected by the Commission for the Carbon Plan. However, any such approval does not amount to the approval of the reasonableness or prudence of specific project development activities or the recoverability of specific items of cost. For the avoidance of doubt, any Commission approval of a request from Duke to incur initial project development costs does not constitute "preapproval" of cost recovery. Rather the approval is indicative that the Commission finds such actions to be a reasonable and prudent step in furtherance of the Carbon Plan, but that cost recovery will be conditioned on a full review for reasonableness and prudency during the appropriate cost recovery proceeding. With the exception of the Commission's approval of the nuclear project development costs pursuant to N.C.G.S. § 62-110.7, the Commission retains discretion to determine the appropriate ratemaking treatment for any authorized actions in a future general rate case proceeding.

Third-Party Ownership

The next issue before the Commission concerns a matter of statutory interpretation — whether third parties may own the resources that the Commission selects to achieve the mandates of N.C.G.S. § 62-110.9.

Well-established principles of statutory interpretation in North Carolina dictate:

> The intent of the General Assembly may be found first from the plain language of the statute, then from the legislative history, the spirit of the act and what the act seeks to accomplish. If the language of a statute is clear, the court must implement the statute according to the plain meaning of its terms so long as it is reasonable to do so. Courts should give effect to the words actually used in a statute and should neither delete words used nor insert words not used in the relevant statutory language during the statutory construction process. Undefined words are accorded their plain meaning so long as it is reasonable to do so. In determining the plain meaning of undefined terms, this Court has used standard, nonlegal dictionaries as a guide. Finally, statutes should be construed so that the resulting construction harmonizes with the underlying reason and purpose of the statute.

Midrex Techs. v. N.C. Dep't of Revenue, 369 N.C. 250, 258, 794 S.E.2d 785, 792 (2016) (internal citations omitted).

The statutory provision at issue, N.C.G.S. § 62-110.9(2), states that "[a]ny new generation facilities or other resources selected by the Commission in order to achieve the authorized carbon dioxide emissions reduction mandates for electric public utilities shall be owned and recovered on a cost-of-service basis by the applicable electric public utility . . . ." The provision then lists an exception to the preceding requirement: "To the extent that new solar generation is selected by the Commission, in adherence with least cost requirements, the solar generation selected" is subject to the following ownership conditions: (1) PPAs with third parties must supply 45% of the solar generation the Commission selects; and (2) solar generation "owned and operated and recovered on a cost of service basis by the soliciting electric public utility" must supply 55% of the solar generation the Commission selects. N.C.G.S. § 62-110.9(2)(b).[7] While the statute includes the term "solar generation" at the beginning of the provision, the final sentence clarifies that "[t]hese ownership requirements shall be applicable to solar energy facilities (i) paired with energy storage and (ii) procured in connection with any voluntary customer program." *Id.*

While Duke, the Public Staff, and CPSA assert that the plain language of these provisions provides a limited exception for third-party owned solar resources, including standalone solar and Solar Plus Storage, other parties contend that the Commission should construe the statute to allow an exception when a PPA arrangement is the least cost option over utility ownership. *See, e.g.*, Duke Post Hearing Br. at 72-81 ("There is no ambiguity in HB 951 with respect to ownership of new generating facilities and other resources selected by the Commission in the Carbon Plan: third parties shall own 45% of new solar and solar paired with energy storage, and Duke shall own all other Facilities selected by the Commission to achieve the Carbon Plan."); Public Staff Witness Thomas Testimony, tr. vol. 21, 62 ("Section 110.9(2) requires Duke ownership of new generation facilities for purposes of Carbon Plan compliance"); CPSA Initial Comments at 6-7 (N.C.G.S. § 62-110.9(2) "prohibit[s] this Commission from approving a Carbon Plan that relies on new non-utility-owned generating resources, other than solar and solar-plus-storage, in order to meet the decarbonization mandates of H.B. 951"); CUCA Initial Comments at 2 ("If utility ownership is not the least cost option, then Duke should be required to pursue alternative options that result in savings for ratepayers."); Tech Customers Initial Comments at 18 ("Duke's proposed Carbon Plan reflects the preference to build new generation rather than purchase power from energy suppliers or otherwise participate in the market. This approach is likely to result in greater costs to consumers . . . and the omission of purchased power as an alternative to new-build generation is contrary to the expectations of Session Law 2021-165.").

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[7] In its entirety, N.C.G.S. § 62-110.9(2)(b) provides:

> To the extent that new solar generation is selected by the Commission, in adherence with least cost requirements, the solar generation selected shall be subject to the following: (i) forty-five percent (45%) of the total megawatts alternating current (MW AC) of any solar energy facilities established pursuant to this section shall be supplied through the execution of power purchase agreements with third parties pursuant to which the electric public utility purchases solar energy, capacity, and environmental and renewable attributes from solar energy facilities owned and operated by third parties that are 80 MW AC or less that commit to allow the procuring electric public utility rights to dispatch, operate, and control the solicited solar energy facilities in the same manner as the utility's own generating resources and (ii) fifty-five percent (55%) of the total MW AC of any solar energy facilities established pursuant to this section shall be supplied from solar energy facilities that are utility-built or purchased by the utility from third parties and owned and operated and recovered on a cost of service basis by the soliciting electric public utility. These ownership requirements shall be applicable to solar energy facilities (i) paired with energy storage and (ii) procured in connection with any voluntary customer program.

N.C.G.S. § 62-110.9(2)(b).

As detailed above, the law is unambiguous in dictating the Commission's analysis of this matter, and the Commission must apply the plain language of the statute. First, in "determining generation and resource mix for the future," the Commission is bound to "[c]omply with current law and practice with respect to the least cost planning for generation." N.C.G.S. § 62-110.9(2). However, the Commission cannot construe the concept of "least cost" planning as a strict mandate wherein the Commission abandons all other concerns, including compliance with the plain language of N.C.G.S. § 62-110.9(2) in order to achieve the lowest possible cost for consumers. Rather, the concept is highly nuanced, and the Commission must reasonably balance least cost planning with other critical factors such as providing fair regulatory practices; assuring resource adequacy; promoting the provision of adequate, reliable, and economical service that is consistent with the level of energy needed for the public health and safety; promoting resource conservation and efficiency; and ensuring the overall public interest. *See* N.C.G.S. § 62-2.

While the first sentences of the provision at issue are clear that the Commission must economically select resources to replace retired coal generation, further provisions include more specific legislative caveats to this general requirement.

The first legislative caveat, that "[a]ny new generation facilities or other resources selected by the Commission in order to achieve the authorized carbon dioxide emissions reduction mandates for electric public utilities shall be owned and recovered on a cost of service basis by the applicable electric public utility[,]" is subject only to the limited exception for third-party owned solar, inclusive of standalone solar and Solar Plus Storage, contained in N.C.G.S. § 62-110.9(2)(b).[8] The Commission specifically notes that the statute's use of the word "and" dictates that the Commission must honor both the conditions of utility ownership *and* cost recovery on a cost-of-service basis. The second legislative caveat provided in N.C.G.S. § 62-110.9(3) is that "any generation and resource changes maintain or improve upon the adequacy and reliability of the existing grid."

The Commission interprets the preceding legislative caveats as specific provisions honing the more general directive for least cost planning for generation resources. Therefore, based on the foregoing, the Commission determines that while least cost, economic selection of resources is an important general factor that the Commission must consider, it must also balance such consideration with the General Assembly's more specific directives regarding utility ownership and reliability. More specifically, on this matter, the Commission determines that the plain language of N.C.G.S. § 62-110.9(2) dictates that new generation resources that the Commission selects to achieve the carbon dioxide emissions reduction mandates of N.C.G.S. § 62-110.9 must be utility-owned with

[8] The Commission notes that N.C.G.S. § 62-110.9(2)(a) provides that "[e]xisting law shall apply with respect to energy efficiency measures and demand-side management."

costs recovered on a cost-of-service basis, with the express exceptions of standalone solar and Solar Plus Storage.[9]

Methane Emissions

While acknowledging that "HB 951 is tailored to the reduction of carbon dioxide emissions and arguably does not address the emissions of other greenhouse gases, such as methane," intervenors NC WARN and Charlotte Mecklenburg NAACP contend that the Commission should nonetheless consider the impacts of methane emissions from natural gas facilities. NC WARN and Charlotte Mecklenburg NAACP Joint Initial Comments at 20. In response, Duke states that carbon dioxide and methane are "distinct chemical compounds" and observes that had the General Assembly desired to target methane emissions as it did with carbon dioxide emissions, it could have done so. Duke Post Hearing Br. at 59-60.

Absent such an exercise of its legislative powers, the Commission must assume that the General Assembly did not intend to address methane in N.C.G.S. § 62-110.9. In this statute, the General Assembly has vested the Commission with discrete and limited authority to regulate carbon dioxide emissions from electric generating facilities located in the state that are owned, operated by, or operated on behalf of Duke. Section 62-110.9 does not extend authority to regulate methane emissions to the Commission.

For the reasons explained herein, methane emissions are not within the Commission's authority under N.C.G.S. § 62-110.9. The Commission notes that Duke has outlined its voluntary corporate methane emissions reduction goals in its Post Hearing Brief, including a company-wide goal to achieve net-zero methane emissions from natural gas distribution by 2030 and net-zero methane by 2050 for upstream emissions related to purchased natural gas. Duke Post Hearing Br. at 62.

Consolidation of the Integrated Resource Planning and Carbon Plan Processes for Duke

For regulatory efficiency, the Commission deems it reasonable and necessary to consolidate its IRP planning function pursuant to N.C.G.S. § 62-110.1(c) and its Carbon Plan development and execution oversight function pursuant to N.C.G.S. § 62-110.9.

As evident from the filings on this issue, the parties have attempted to reach consensus on how the Commission conducts future Carbon Plan proceedings. The Commission is not persuaded that a 2023 Carbon Plan update proceeding is appropriate and will, accordingly, decline to take up the rulemaking recommendations parties propose on this issue. Instead, the Commission will, as set forth below, initiate a process that will put it in a position to adopt the second Carbon Plan by the end of 2024.

[9] For the avoidance of doubt, the Commission does not intend that its decision on this matter exhaustively define utility ownership nor extend to resources the utility selects for purposes other than compliance with the carbon dioxide emissions reduction directives of N.C.G.S. § 62-110.9.

One of the Commission's key takeaways from this initial Carbon Plan proceeding is that 14 months is far too brief a period to adequately model, review, and develop a carbon plan — particularly as we approach the Interim Target compliance deadline. The Commission interprets the provisions of N.C.G.S. § 62-110.9 to require that it review and adjust as necessary the Carbon Plan every two years, making the Commission's next biennial Carbon Plan due on or before December 31, 2024. Compliance therewith does not afford time for the proposed "update" proceeding as well as a full Carbon Plan proceeding before December 31, 2024. While Commission Rule R8-60 requires the filing of IRP updates, N.C.G.S. § 62-110.1(c) does not compel these updates, nor does N.C.G.S. § 62-110.9 contemplate an "interim Carbon Plan update." Therefore, the Commission deems it prudent to forego a Carbon Plan update proceeding in 2023. Instead, the Commission finds good cause to require Duke to file a proposed consolidated, full Carbon Plan and IRP (CPIRP) by no later than September 1, 2023.

Further, the Commission directs Duke to engage with the Public Staff and any interested stakeholders to draft a new proposed Commission rule governing the CPIRP proceeding, subject to the following enumerated parameters and to file the proposed rule with the Commission by no later than April 28, 2023, in a new and separate proceeding:

1. By September 1, 2023, and every two years thereafter, Duke shall file with the Commission its proposed biennial CPIRP, including the testimony and exhibits of expert witnesses. At the time of the filing, Duke shall provide complete modeling input and output data files to intervenors. Each proposed biennial CPIRP shall include a proposed near-term plan discussing the specific actions Duke recommends taking over the near term following the Commission's final order on the proposed CPIRP;

2. No later than 180 days after the later of either September 1 or the filing of Duke's proposed biennial CPIRP, the Public Staff or any other intervenor may file testimony and exhibits of expert witnesses commenting on, critiquing, or giving alternatives to Duke's proposed CPIRP;

3. No later than 45 days after the filing of intervenor testimony and exhibits, Duke may file its rebuttal testimony and exhibits of expert witnesses;

4. The Commission shall schedule an expert witness hearing to review the CPIRP proposals beginning on the second Tuesday in May following Duke's proposed biennial CPIRP, and shall schedule one or more hearings to receive testimony from the public at a time and place of the Commission's designation; and

5. The proposed rule filing shall also propose a separate mechanism for the filing and review of annual compliance plans that DEP and DEC previously filed with their respective IRP filings.

WHEREUPON, the Commission makes the following

FINDINGS OF FACT

The Commission has received expert and public witness testimony from numerous witnesses in this proceeding as well as voluminous exhibits, reports, comments, consumer statements, and briefs. In making the following findings of fact, the Commission has carefully considered all of the evidence in the record, as well as the comments and briefs of the parties and the consumer statements of position. The Commission has duly considered the credibility of each of these submissions and, accordingly, has given each the weight that it is due. The following findings of fact are based upon competent, material, and substantial evidence derived through consideration of the complete record.

Carbon Dioxide Emissions Assumptions and Calculations

1. In 2005, North Carolina electric generation facilities owned, operated by, or operated on behalf of DEP and DEC produced 75,865,188 short tons of carbon dioxide emissions. A 70% reduction of the 2005 carbon dioxide emissions produces an Interim Target of 22,759,556 short tons of carbon dioxide. Stated another way, achieving the Interim Target will require that Duke limit carbon dioxide emissions from electric generation facilities located in the state and owned, operated by, or operated on its behalf to 22,759,556 short tons of carbon dioxide.

2. It is appropriate to assume, for modeling purposes, that all new carbon-emitting resources selected in the Carbon Plan will be located in North Carolina.

Inflation Reduction Act of 2022

3. President Biden signed the IRA into law on August 16, 2022. The IRA includes $369.75 billion in tax incentives and is expected to have a major impact on the development of generating facilities, potentially offsetting significant cost.

4. Duke filed its Carbon Plan proposal on May 16, 2022, before enactment of the IRA but performed preliminary modeling sensitivity analysis based on an initial review of the IRA. This sensitivity analysis generally supports Duke's proposed near-term actions in its Carbon Plan modeling.

5. It is appropriate for Duke to incorporate the impacts of the IRA, the Infrastructure Investment Jobs Act (IIJA), other future legislative changes, and the impacts of other changing conditions such as inflationary pressures, into its modeling and analysis for future proposed biennial CPIRPs.

Modeling – Optimization Period

6. Portfolio development utilizes a series of optimization steps, primarily utilizing algorithms within specialized software, to ultimately seek the least cost solution

to meet customer energy and demand needs and carbon dioxide emissions reduction mandates over the planning horizon. The goal of this modeling process is to develop a portfolio of resources that will minimize overall system costs, including capital costs for new resources and ongoing operation, maintenance, and fuel costs.

7. Modeling over the longest possible optimization period, considering other factors such as modeling times, aids in determining the least cost path that meets the mandated carbon dioxide emissions reductions of N.C.G.S. § 62-110.9.

Modeling – Battery Storage

8. Modeling of storage resources with endogenous dispatch provides the most potential for adequately valuing these resources in the Carbon Plan.

9. Duke's endogenous dispatch of Solar Plus Storage caused modeling times to be in the range of 12 to 48 hours as opposed to 2 to 3 hours for fixed dispatch modeling.

Modeling – Battery-CT Optimization

10. Duke performed a "battery-CT optimization" in its resource modeling that resulted in the replacement of some battery capacity with some natural gas-fired capacity.

Modeling – Reliability

11. Ensuring ongoing system reliability and compliance with mandatory NERC Reliability Standards during the ongoing energy transition is consistent with prudent utility planning and the requirements of N.C.G.S. § 62-110.9 and is nonnegotiable for Duke and its customers.

12. The modeling approach Duke employed in developing its Carbon Plan proposal considers system reliability at each progressive step. While the use of the Strategic Energy Risk Valuation Model (SERVM), a reliability and hourly production cost simulation tool managed by Astrapé Consulting, occurs outside of the primary modeling tool, EnCompass, it is an appropriate action for the purpose of ensuring system reliability and compliance with the statutory mandates.

Coal Plant Retirements

13. Retirement of Duke's coal generation fleet is a critical step in in the path to compliance with N.C.G.S. § 62-110.9.

14. The approach Duke utilizes in planning for the retirement of its coal generation fleet achieves the carbon dioxide emissions reduction mandates of N.C.G.S. § 62-110.9 while maintaining adequacy and reliability of the existing grid.

15. Duke's modeling efforts consider least cost principles when determining the timeline for retirement of coal generation units.

16. In order to maintain adequacy and reliability of the existing grid while retiring its coal generation fleet, Duke must invest in replacement generation assets and upgrade its transmission network.

17. Undepreciated balances of certain of Duke's subcritical coal generation fleet are eligible for securitization at retirement pursuant to Section 5 of S.L. 2021-165 and Commission Rule R8-74.

Existing Resources – Subsequent License Renewals for Existing Nuclear Units

18. Duke currently operates 11 nuclear generating units that provide carbon-free baseload generation to Duke's customers in North Carolina and South Carolina.

19. Duke successfully obtained initial extensions of the operating licenses for all 11 of its existing nuclear generating units. To further extend the operating licenses for an additional 20 years beyond the initial extensions, Duke must pursue subsequent license renewal (SLR). Without SLR, the operating licenses for DEC's facilities will expire on the following dates: for the Catawba facility, located in York, South Carolina, Unit 1 and Unit 2 will both expire on December 5, 2043; for DEC's McGuire facility, located in Huntersville, North Carolina, Unit 1 will expire on June 12, 2041, and Unit 2 will expire on March 3, 2043; and for DEC's Oconee facility, located in Seneca, South Carolina, Unit 1 will expire on February 6, 2033, Unit 2 will expire on October 6, 2033, and Unit 3 will expire on July 19, 2034. Without SLR, the operating licenses for DEP's facilities will expire on the following dates: for the Robinson facility, located in Hartsville, South Carolina, Unit 2 will expire on July 31, 2030; for the Brunswick facility, located in Southport, North Carolina, Unit 2 will expire on December 27, 2034, and Unit 1 will expire on September 8, 2036; and for the Harris facility, located in New Hill, North Carolina, Unit 1 will expire on October 24, 2046.

20. Extending the retirement dates for the existing nuclear fleet an additional 20 years through SLR is foundational to Duke's Carbon Plan proposal, and all of Duke's proposed portfolios rely on SLR of the existing nuclear fleet.

Existing Resources – Natural Gas Fleet

21. Enhancing the flexibility of the existing natural gas fleet is one method to support renewable resource integration.

The Role of Natural Gas

22. The deliverability of natural gas for Duke's natural gas-fired generating resources faces sufficient current and future risks to warrant continued modeling of deliverability sensitivities in future resource modeling.

23. The natural gas price forecasting methodology utilized by Duke in its resource modeling relied on five years of natural gas market-based pricing and three years of transitioning from market-based pricing before fully utilizing fundamentals-based natural gas pricing forecasts beginning in year nine.

24. It is appropriate for Duke to plan for hydrogen fuel to replace natural gas and for the use of carbon dioxide offsets.

25. The 35-year operational life and capital cost assumptions for new CC and CT units are reasonable for planning purposes at this time.

26. Natural gas-fired generation is dispatchable; capable of providing baseload, intermediate, and peaking capacity; and supports system reliability during periods of high customer demand. Further, new natural gas-fired generation was selected by a number of the proposed portfolios submitted for the Commission's consideration.

27. Firm transportation capacity is essential to manage the natural gas supply security necessary for reliable, cost-effective generation and for the reliable operation of the electric system at this time.

Near-Term Development and Procurement Activities for New Standalone Solar Generation, Solar Plus Storage, Standalone Battery Storage, and Onshore Wind

28. Significant new solar generation must be added to Duke's resource mix in the short term to achieve the Interim Target.

29. On November 1, 2022, the Commission authorized Duke to procure 1,200 MW of new standalone solar resources via the 2022 Solar Procurement.

30. The 2022 Solar Procurement is subject to a Volume Adjustment Mechanism (VAM) which allows for an increase of up to 20% in the solar procurement target if the weighted average cost of the procured resources is less than or equal to 90% of the Carbon Plan Solar Reference Cost, meaning that if the weighted average cost of the procured resources is less than or equal to 90% of the Carbon Plan Solar Reference Cost, Duke may procure up to 1,440 MW of new standalone solar resources via the 2022 Solar Procurement.

31. Nearly all of the parties that performed modeling recommend the inclusion of Solar Plus Storage. Overall, proposed portfolios submitted to the Commission contemplate the addition of between 600 MW and 1,650 MW of new Solar Plus Storage by the end of 2028.

32. Nearly all of the parties that performed modeling recommend the inclusion of new standalone battery storage. Overall, proposed portfolios submitted to the Commission contemplate the addition of between 1,000 MW and 4,000 MW of new standalone battery storage by the end of 2029.

33. All proposed portfolios Duke submitted to the Commission include onshore wind capacity to achieve the Interim Target.

Development of Long Lead-Time Resources

34. Each of Duke's proposed portfolios and the Public Staff's proposed portfolios SP5 and SP6 select new nuclear resources and new pumped storage hydro (Bad Creek II) with the assumption that both resources in each portfolio will be in service no later than 2035.

35. Duke's proposed portfolios P1, P2, and P4 support the need to develop offshore wind either for compliance with the Interim Target or with the 2050 Target. Neither Duke's proposed portfolio P3 nor proposed portfolios SP5 and SP6 select offshore wind to achieve the Interim Target.

36. Bad Creek II is a second powerhouse that Duke proposes to construct at Duke's existing Bad Creek I pumped hydro storage facility located in Salem, South Carolina. Bad Creek I is currently undergoing work to expand its capacity from 1,360 MW to 1,700 MW with the project expected to be complete by 2023. Bad Creek II would include four new generating units that provide an additional 1,700 MW of capacity. The combined total capacity of Bad Creek I and Bad Creek II would be more than 3,300 MW. Bad Creek II would share the existing upper reservoir with Bad Creek I.

37. Bad Creek I operates as a daily-cycling facility, storing energy during low periods of demand and returning the energy to the grid at peak periods, which complements intermittent resources. Bad Creek I came online in 1991 and has been included in Duke's IRPs since that time, serving as a reliable asset for over 30 years. Bad Creek I is currently in the relicensing phase at the Federal Energy Regulatory Commission (FERC) with the opportunity to include Bad Creek II in the process if certain project development activities progress.

38. Pursuing a license with FERC for Bad Creek II separately from the Bad Creek I relicensing process would be unnecessarily duplicative and increase the in-service timeline by approximately five years.

39. Duke proposes the following near-term development actions for Bad Creek II for the period 2022 through 2024 for a total cost of $35,855,000: (a) conduct a feasibility study; (b) develop an engineering, procurement, and construction strategy; and (c) continue to develop the application to provide to FERC to relicense the Bad Creek I facility to incorporate operation of Bad Creek II.

40. New nuclear resources, including SMRs, advanced reactors (ARs), and microreactors, involve modular design and allow for offsite construction and potentially decreased production timelines.

41. ARs provide flexible operations that can support hydrogen production, thermal storage, and integration with variable renewable energy resources.

42. New nuclear generation is expected to provide firm, dispatchable, carbon-free electricity to the grid with greater operational flexibility than traditional nuclear generation.

43. Duke estimates that its proposed near-term development activities for new nuclear in 2022 through 2024 will cost $72,000,000 and include: (a) beginning new nuclear Early Site Permit (ESP) development; and (b) beginning development activities for the first two SMR units. The Commission finds that this authorization of initial development costs constitutes approval under N.C.G.S. § 62-110.7(b).

44. Offshore wind provides resource diversity to complement solar variability, especially in the winter months. Offshore wind's highest seasonal generation is in the winter mornings when solar generation output is not available.

45. Once an offshore wind lease for a Wind Energy Area (WEA) has been executed, it takes approximately 8 to 10 years to achieve commercial operation.

46. The Bureau of Ocean Energy Management (BOEM) to date has leased three WEAs near the coast of North Carolina for the potential development of offshore wind, including the Kitty Hawk, North Carolina WEA and two WEAs in the Carolina Long Bay (CLB) area near Cape Fear, North Carolina. Each WEA has a unique set of meteorological and geographical characteristics which will affect the WEA's cost of development and production profile, and therefore its economics.

47. All three WEAs would require cabling from the wind facility to onshore, with Kitty Hawk's having a significantly longer subsea cabling requirement due to its location near the North Carolina/Virginia border.

48. All three WEAs will require significant new transmission infrastructure in order to connect to the existing transmission system.

49. Duke Energy Renewables Wind, LLC, an affiliate of Duke, has acquired one of the two WEAs in the CLB Area. Duke remains open to pursuing other opportunities for ownership of cost-effective offshore wind WEAs.

50. Duke proposes the following offshore wind development activities for 2022 to 2024 at a total cost of $317,400,000: (a) enter into a lease ($155,400,000); (b) perform development activities ($62,000,000); and (c) construct transmission from landing site to point of injection ($100,000,000).

51. Avangrid Renewables holds the lease to the Kitty Hawk WEA and states that it is willing to negotiate for a sale of its interest to Duke.

Grid Edge and Customer Programs – Load Reduction

52. Reducing load through demand-side management and energy efficiency measures (DSM/EE), customer self-generation, and voltage management is a critical component of achieving the reductions in carbon dioxide emissions in a least cost manner as N.C.G.S. § 62-110.9 requires.

Grid Edge and Customer Programs – Electric Vehicles

53. Duke expects continued acceleration in electric vehicle (EV) adoption which requires planning and management by Duke in order to “do no harm” and to maximize potential system benefits.

Grid Edge and Customer Programs – New Regulatory Mechanisms

54. There is a need for new regulatory mechanisms for both DSM/EE and non-DSM/EE programs for Duke to reduce load through its Grid Edge programs.

Grid Edge and Customer Programs – Wholesale Customers and Dynamic Rate Design

55. Customer programs, including coordination with wholesale customers and dynamic rate design, may reduce load.

Transmission – Red Zone Expansion Projects

56. The 14 transmission projects listed on Transmission and Solar Procurement Panel Rebuttal Exhibit 3 under the heading “Acknowledge need for inclusion in the 2022 Local Plan” are necessary to enable the interconnection of solar generating capacity to meet the requirements of N.C.G.S. § 62-110.9 in a least cost manner.

Transmission – Planning

57. The addition of proactive transmission planning through the local transmission process, the North Carolina Transmission Planning Collaborative (NCTPC), integrated with resource planning, is reasonable and appropriate to meet the carbon dioxide emissions reduction mandates reliably and in a least cost manner.

58. To implement the Carbon Plan successfully, the NCTPC should evolve by expanding transparency and coordination to address the increasing complexity and potential cost of the addition of proactive transmission planning into the NCTPC process.

Transmission – Cost and Reliability Considerations

59. When proposing transmission projects as necessary for purposes of compliance with N.C.G.S. § 62-110.9, Duke should consider the full scope of the timing

and costs of the identified upgrades, any associated upgrades, Affected Systems costs, and coordination efforts with other load serving entities (LSEs).

60. Any transmission Network Upgrades Duke identifies as necessary for Carbon Plan compliance should not take priority over other transmission upgrade projects necessary to maintain reliability and service quality for Duke's retail and wholesale ratepayers.

Rate Disparity Between Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC

61. Based on rates effective August 1, 2022, a DEC residential customer consuming 1,000 kWh of electricity pays a monthly bill of $106.23, while a DEP residential customer with the same electricity consumption pays a monthly bill of $125.94, which is a rate difference of $19.71 or 19%.

62. The rate difference between DEC and DEP has existed since before the corporate merger of Duke Energy Corporation and Progress Energy, Inc., in 2012; however, the rate difference has increased consistently since the merger.

63. Numerous issues contribute to the rate difference between DEC and DEP; however, the significantly greater amount of solar generation in DEP's service territory compared to DEC's service territory, along with associated transmission and distribution upgrades, is one contributor to the rate disparity between DEC and DEP.

Present Value Revenue Requirements

64. Duke provided PVRR and bill impact calculations for the four proposed portfolios it presented as well as for the supplemental portfolios it prepared in response to the Public Staff's comments and others.

65. Various parties suggest that Duke should prepare analyses that include an "all-in cost" PVRR and bill impacts.

Environmental Justice and Impacted Communities

66. Successful execution of the Carbon Plan requires engagement by Duke on issues related to environmental justice and with frontline communities.

EVIDENCE AND CONCLUSIONS

As noted above, the Commission bases its findings of fact upon competent, material, and substantial evidence derived through consideration of the complete record. In providing the following evidence and conclusions in support of its findings of fact, the Commission does not exhaustively summarize the complete record.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-2

Carbon Dioxide Emissions Assumptions and Calculations

The evidence supporting these findings of fact is in Appendix A of Duke's Carbon Plan proposal, the direct testimony of Duke's Modeling Panel, the testimony of Public Staff witness Metz, and the entire record in this proceeding.

Duke states that in accordance with the provisions of N.C.G.S. § 62-110.9, it established the following parameters to calculate its 2005 carbon dioxide emissions baseline:

- The recommended 2005 baseline only considers carbon dioxide emissions;
- The recommended 2005 baseline only considers carbon dioxide emissions from electric generating facilities owned, operated by, or operated on behalf of Duke;
- The recommended 2005 baseline only considers carbon dioxide emissions from electric generation facilities located within the State of North Carolina; and
- The recommended 2005 baseline focuses on direct emissions from electric generation facilities.

Tr. vol. 7, Duke Proposed Carbon Plan, App. A, 1-2.

To set the 2005 carbon dioxide emissions baseline, Duke utilized the Environmental Protection Agency's (EPA) Emission and Generation Resource Integrated Database (eGRID), which is a publicly available, credible data source that the EPA manages. *Id.* at 3. Duke states that the EPA consistently publishes the data with results that are repeatable and consistent over time. *Id.* at 3-4. Duke states that eGRID's database compiles the EPA's Clean Air Markets Division (CAMD) Power Sector Emissions Data, which electric generating facilities report to the EPA to comply with regulations in 40 CFR Part 75 and 40 CFR Part 63. *Id.* at 4. Duke explains that most emissions data reported in eGRID is through Emissions Tracking Systems/Continuous Emissions Monitoring Systems (CEMS). *Id.* Further, Duke notes that emissions are quantified through actual measurements at the stack with systems regularly tested and calibrated to maintain accuracy. *Id.* Where CEMS data is not available, eGRID uses Energy Information Administration (EIA) reported fuel data (EIA-923) to estimate emissions based on fuel consumed and standard emissions rates for the applicable fuel type. *Id*. Duke notes that electricity generating facilities that the EPA's CAMD regulates must monitor and report carbon dioxide emissions annually. *Id.* Finally, Duke states that DEP and DEC (or predecessors) have used CEMS technology at their electric generation facilities for over 20 years to report actual stack emissions to the EPA. *Id.*

Using metrics from eGRID, Duke concludes that electric generation facilities located in the state, and owned, operated by, or operated on behalf of DEP and DEC (or their predecessors) emitted a total of 75,865,188 short tons of carbon dioxide in 2005. *Id.*; *see also id.* at Tbl. A-2.

Duke states that based on the 2005 baseline, to meet the Interim Target — defined by N.C.G.S. § 62-110.9 as a 70% reduction in carbon dioxide emissions from the 2005 baseline — it must reduce carbon dioxide emissions by 53,105,632 short tons.[10] *Id.* at 5. Accordingly, to achieve the Interim Target, Duke must limit carbon dioxide emissions from electric generation facilities it owns, operates, or that are operated on its behalf within the state to 22,759,556 short tons of carbon dioxide.

Duke further notes that N.C.G.S. § 62-110.9 applies solely to carbon dioxide emissions from electric generation facilities located within the State of North Carolina. Tr. vol. 7, Duke Proposed Carbon Plan, App. A, 1. As such, in calculating the 2005 carbon dioxide emissions baseline, Duke's carbon dioxide emissions calculations do not account for carbon dioxide emissions resulting from energy generated out of state and imported into the state. *Id.* Conversely, Duke included carbon dioxide emissions generated by in-state electric generation facilities but exported out of state. *Id.*

Duke acknowledges that stakeholders are concerned about the siting of new carbon dioxide-emitting resources outside the state as being counterproductive to achieving regional carbon dioxide emissions reductions. *Id.* at 6. "Recognizing the seemingly clear language of [N.C.G.S. § 62-110.9] and the questions raised by stakeholders," Duke requests that the Commission determine whether carbon dioxide emissions from out-of-state generating resources selected to be part of the Carbon Plan should be accounted for as if such emissions occurred in the state. *Id.*

On this point, Duke states that in modeling its Carbon Plan proposal it assumed that any new carbon dioxide-emitting resources would be sited in North Carolina. *Id.* However, Duke notes that to operate its dual-state systems reliably and cost-effectively for its North Carolina and South Carolina customers, it intends to site all new resources optimally based on several key parameters such as appropriateness of the site for the type of generation, access to fuel, ability to leverage existing infrastructure to reduce costs, and evaluation of community impacts, which could ultimately result in some new carbon dioxide-emitting resources being sited out of the state. *Id.* Duke further states that it committed to system-wide carbon dioxide emissions reductions and to carbon neutrality for the entire system by 2050. *Id.*

Public Staff witness Metz stated that Duke correctly accounted for the level of carbon dioxide output from its facilities in 2005 for purposes of complying with N.C.G.S. § 62-110.9. Tr. vol. 21, 108. In support of this conclusion, witness Metz testified that the Public Staff

[10] Interim Target = (1 – 0.7) x 2005 CO_2 Baseline [Short Tons CO_2]; N.C.G.S. § 62-110.9 Interim Target = 0.3 x 75,865,188 Short Tons CO_2; Interim Target = 22,759,556 Short Tons CO_2. Tr. vol. 7, Duke Proposed Carbon Plan, App. A, 5.

met with the North Carolina Department of Environmental Quality (NCDEQ) and Duke's staff multiple times to review historical emissions data and related information. *Id*.

No party disputes the 2005 baseline emissions calculation or the methodology Duke used to perform the calculation.

Public Staff witness Metz stated that the General Assembly intended for the emissions reduction targets to include only carbon dioxide "emitted in the State." *Id.* at 109. Witness Metz agreed with Duke's modeling assumption that all new carbon dioxide emitting resources will be located in North Carolina. *Id.* at 108. Moreover, witness Metz testified that he agrees with Duke's interpretation of N.C.G.S. § 62-110.9 that it should include only emissions from in-state (North Carolina) generation sources when calculating interim compliance and carbon neutrality. *Id*. at 109. However, witness Metz also testified that he recognizes the concerns stakeholders express that N.C.G.S. § 62-110.9's emissions boundary could lead to locating carbon dioxide-emitting resources outside of North Carolina as an "end-around" to the carbon dioxide emissions reduction mandates and stated that calculating carbon dioxide emissions on a system-wide basis reduces speculation regarding future asset locations and reduces modeling complexities. *Id*. Finally, Public Staff witness Metz encouraged the Commission to exercise oversight in further iterations of the Carbon Plan, IRP, CPCN dockets, and other proceedings to guard against this possibility. *Id*.

The Commission concludes that Duke's methodology for determining the 2005 baseline carbon dioxide emissions reasonably and appropriately relies on credible, widely-used data on emissions from the electric power sector. The Commission further concludes that Duke has correctly calculated the 2005 baseline and has correctly calculated the Interim Target. Additionally, the Commission concludes that it is appropriate for modeling purposes for Duke to assume that all new carbon dioxide-emitting resources will be located in North Carolina.

In response to Duke's request for guidance on the treatment of carbon dioxide emissions from facilities located outside of North Carolina, the Commission agrees with Duke and the Public Staff that the General Assembly intended for emissions reduction requirements to include only carbon dioxide emitted in North Carolina. The Commission is mindful of the concerns that the siting of new carbon dioxide-emitting resources outside the state could be counterproductive to achieving regional carbon dioxide emissions reductions. However, modeling all new carbon dioxide-emitting resources as if located in North Carolina mitigates this concern. The Commission confirms, though, that Duke must base ultimate siting of new resources optimally inside or outside of North Carolina on several factors — including, for example, the appropriateness of the site for the type of generation, access to fuel, ability to leverage existing infrastructure to reduce costs, and evaluation of community impacts — and not whether the resources will generate any associated carbon dioxide emissions inside or outside of North Carolina.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3-5

Inflation Reduction Act of 2022

The evidence supporting these findings of fact is in the direct testimony of Duke witness Bowman, the direct and rebuttal testimony of the Duke Modeling Panel, the testimony of Public Staff witnesses Thomas and Williamson, the testimony and Responsive Comments of RTHC et al., Brad Rouse, NCSEA et al., Tech Customers, AGO, CPSA, and CCEBA, and the entire record in this proceeding.

In her direct testimony, Duke witness Bowman stated that the IRA was enacted on August 16, 2022. She explained that Duke is actively continuing its analysis of the IRA, which contains many incentives associated with clean energy resources and electrification technologies. Tr. vol. 7, 57-58. She further stated that the clean energy tax credits in the legislation will enhance Duke's 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; also, the tax benefits for new generation resources will directly benefit Duke's customers. She stated that the new law will enable investment in new infrastructure, supporting the communities Duke serves.

The Duke Modeling Panel also addressed the IRA and testified that implementation of the IRA will be one of the key developments that will be influential in updating the Carbon Plan for the 2024 proceeding. *Id*. at 215. They explained that Duke did not account for the IRA in its original load forecast because Congress did not pass the IRA until after Duke had completed its initial modeling. Tr. vol. 8, 215. The Panel noted that the IRA is very complex with a multitude of incentive options for supply-side resources, generally solar, wind, storage, and nuclear, including potential stackable incentives based on other factors such as siting. The Panel stated that Duke is continuing to evaluate tax implications and applicability of the IRA and how the incentives offset the inflationary impacts to the cost of resources such as solar, wind, and storage. Tr. vol. 27, 70-71.

Public Staff witness Thomas, discussing more generally the appropriateness of updating commodity and generation resource price forecasts after the parties performed initial Carbon Plan modeling, stated that modeling inputs must be final at some point, lest the biennial IRP proceeding devolve into an endless cycle of updating assumptions and re-running the models. He further stated that procedural schedules that allow for frequent IRP updates and a reliance on robust portfolios that cover a range of scenarios temper the consequences of this reality. Tr. vol. 21, 72. With respect to the IRA specifically, witness Thomas stated that while the IRA has extended the Investment Tax Credit (ITC) for renewables and included energy storage as a qualifying resource for the ITC, the tax credits are dependent on new factors (such as industry prevailing wages, siting, and source of raw materials), can be replaced with a Production Tax Credit (PTC) once energy production begins, and may eventually become technologically neutral. He also stated that financing for new nuclear development, including PTCs for nuclear resources, also appears to be included in the legislation, but the capital costs for new nuclear facilities are speculative at best. *Id.* at 82.

In sum, witness Thomas testified that incorporating the impacts of the IRA into Duke's models would be complex, as it is dependent upon Internal Revenue Service guidance and renewable developers and utilities being able to capture bonus tax incentives to the benefit of ratepayers. Witness Thomas also acknowledged that the IRA could impact the supply chain for solar. However, he did not assert that the Commission should direct Duke to update its Carbon Plan proposal with the impacts of the IRA because the Public Staff's modeling suggests that the resource selection within the timeframe of the near-term action plan is less sensitive to capital costs and is largely dependent upon model constraints, such as the first available selection year, the amount that can be interconnected annually, and annual carbon dioxide limits. Witness Thomas further described how the IRA would not only impact the cost of certain renewable and energy storage resources but could also impact electrification and EE, and that the net impact on load is complicated and load forecasting experts would need to study it. *Id.* at 82, 242. Public Staff witness Williamson stated that when Duke begins to prepare for its subsequent Carbon Plan filing, it will incorporate these effects on load. Tr. vol. 22, 381.

Several intervenors emphasize that the IRA will have a significant impact on resource costs, least cost determinations, technologies, and other factors that impact Carbon Plan considerations. RTHC et al. Responsive Comments at 2-5; tr. vol. 22, 88-89, 114; tr. vol. 23, 236, 240-50; tr. vol. 24, 179-81; tr. vol. 25, 67-68, 241-47, 274-75, 293-94; tr. vol. 26, 37, 248-49. For example, in their responsive comments, NCSEA et al. note that the IRA has dramatically altered the policy landscape in ways that will significantly reduce the costs of resources that can help Duke achieve the state's carbon dioxide emissions reduction requirements. They therefore recommend that to the extent the 2022 Carbon Plan's near-term action plan does not take policies under the IRA into account, there be an opportunity to provide supplemental modeling to update the Carbon Plan in early 2023 for the limited purpose of determining whether any modifications to the near-term action plan would be in the public interest. NCSEA et al. Responsive Comments at 1-2. Likewise, the AGO argues that the Commission should update the 2022 Carbon Plan to incorporate the impact of the IRA before syncing the timing of the Carbon Plan update proceedings and Duke's IRP proceedings. AGO Responsive Comments at 4-5.

In their rebuttal testimony, the Duke Modeling and Near-Term Actions Panel stated that Duke agrees 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 Duke's Carbon Plan proposal. They added that the IRA incentives will lower costs for solar, storage, wind, and nuclear, and that in order to provide some preliminary high-level insight into the impact of the IRA and test the robustness of Duke's proposed near-term actions, they have conducted additional sensitivity analyses. The Duke Modeling Panel also stated that Duke must "snap a chalk line" at a specific point in time for purposes of fixing the modeling inputs and assumptions so that they can move forward with developing a plan. They argued that the modeling and analysis provided thus far in this proceeding are sufficient to support Duke's near-term actions. The Duke Modeling Panel also testified that the IRA is very complex, and that Duke is continuing to evaluate tax implications and the applicability of the new law and are confirming initial interpretations of the incentives for each resource. Tr. vol. 27, 48-

50, 70-71. Lastly, the Modeling Panel provided a description of the preliminary modeling sensitivity analysis they conducted based on their initial review of the IRA, as well as a description of the results of that preliminary modeling. Duke filed this IRA modeling sensitivity analysis as Duke Modeling and Near-Term Actions Panel Late-Filed Exhibit 1. *Id.* at 27, 72-75.

While the Commission agrees with the parties that the IRA will likely significantly impact the cost of compliance with N.C.G.S. § 62-110.9, it is also cognizant that Congress passed the IRA on August 16, 2022, three months after Duke completed its initial modeling in this proceeding, less than one month before the beginning of the evidentiary hearing, and a little over four months before the Commission's deadline for adopting the 2022 Carbon Plan. Such a timeline does not allow for the incorporation of the IRA into Duke's modeling or for a full review of the potential impacts of the legislation. The Commission further agrees with the Public Staff and Duke that modeling inputs must be final at some point, lest a proceeding "devolve into an endless cycle of updating assumptions and re-running the models." Tr. vol. 21, 72.

Therefore, based on the foregoing and the entire record in this proceeding, the Commission determines that it is appropriate for Duke to incorporate the impacts of the IRA, the IIJA, and other future legislative changes, as well as the impacts of other changing conditions such as inflationary pressures, into its first biennial CPIRP proposal that it will file with the Commission on or before September 1, 2023, and into any CPCN applications it files in the interim, so that Duke, the Public Staff, interested parties, and the Commission will have more comprehensive information on the IRA's impacts on Duke's execution and implementation of the Carbon Plan.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 6-7

Modeling – Optimization Period

The evidence supporting these findings of fact is in the testimony of the Duke Modeling and Near-Term Actions Panel, the testimony of Public Staff witness Thomas, the testimony of NCSEA et al. witness Fitch, the testimony of Tech Customers' witness Panel Borgatti, Kimbrough, and Roumpani, and the entire record in this proceeding.

Duke evaluated the period from 2023 through 2050, when it is required to achieve net zero carbon dioxide emissions. In selecting resources within capacity expansion, a full period optimization considers the costs of all resources and constraints through the entire study period. The Carolinas have a large number of resources and incorporating the additional constraint of achieving a declining carbon dioxide ton target made the problem size too large to solve within one full period in capacity expansion. Duke therefore did not study the entire 28-year period in one modeling run for each portfolio. Tr. vol. 7, 280-81.

Public Staff witness Thomas discussed the three eight-year optimization periods, and one five-year period, Duke used in its modeling. He explained that the optimization period is the length of time over which the model optimizes resource selection and dispatch, and that 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. He stated that an eight-year optimization period is problematic, particularly due to the hydrogen conversion costs in later model years. Tr. vol. 21, 25.

The Public Staff is satisfied with an eight-year optimization period for purposes of the 2022 Carbon Plan, although witness Thomas recommended that in future Carbon Plan proceedings, the Commission should direct Duke to utilize an initial optimization period of no less than 15 years and relax the Mixed Integer Programming (MIP) Stop Basis as necessary and within reason to reduce model run times. *Id.* at 53-54.

The Gabel Report, sponsored by the Tech Customers, used a single 28-year optimization period, and the Synapse Report, sponsored by NCSEA et al., used 15-year optimization periods. Both intervenors were able to complete their model runs by adjusting other settings to reduce run times, such as by increasing the MIP Stop Basis.

NCSEA et al.'s Synapse Report states:

> In the context of the current energy transition, where technology costs are changing rapidly and emissions are expected to decline over a multi-decadal time scale, longer planning horizons are important for integrating long-run industry transitions. Planning horizons that are too short may prevent resource planning tools like EnCompass from adequately taking long-term trends into account;" and "[c]apacity expansion modeling runs performed by Duke to develop its Carbon Plan proposed portfolios used a series of 8-year segments and a final 5-year segment . . . While 8-year planning segments are within the reasonable range of planning horizons used in detailed capacity expansion modeling, they also introduce risks that resources selected in the earliest segments may not be economical resource choices when viewed over the long term.

Tr. vol. 25, 205-06.

The Commission recognizes that certain modeling approaches, such as those that extend the optimization period, are likely to be more computationally intensive. Duke's Modeling and Near-Term Actions Panel stated that in response to Public Staff and intervenor recommendations to use longer optimization periods, Duke has committed to testing longer segmentation periods as it implements new versions of the model and will continue to engage with the Public Staff and other parties before the 2024 CPIRP filing.

Based on the foregoing, the Commission concludes that Duke's decision to use an eight-year optimization period for the capacity expansion modeling was appropriate, as it balanced model run times against the challenges associated with model foresight. However, the Commission directs Duke to test longer segmentation periods as it implements new versions of the model and to continue to engage with the Public Staff and other parties on this issue in preparation for its upcoming biennial CPIRP filing. The Commission concludes that it is reasonable for Duke to make all practicable efforts to maximize its modeling optimization period and to seek to model a 15-year, or greater, optimization period in its upcoming biennial CPIRP.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8-9

Modeling – Battery Storage

The evidence supporting these findings of fact is in the testimony of the Duke Modeling and Near-Term Actions Panel, the testimony of Public Staff witness Thomas, the testimony of NCSEA et al. witness Fitch, and the entire record in this proceeding.

Duke initially modeled Solar Plus Storage as “fixed-dispatch,” meaning that charge and discharge times were preset to align with on-peak and off-peak times in applicable rate schedules included in certain PPAs.

After receiving comments from intervenors, Duke updated its modeling to allow for more dynamic dispatch of storage; the supplemental analysis (SP5 and SP6) allowed the EnCompass model to endogenously dispatch Solar Plus Storage. Duke subsequently found that modeling dispatched storage in conjunction with solar added an extensive amount of time to the modeling process. Tr. vol. 8, 46.

The Commission notes that as of August 2022, the EnCompass software was not capable of allowing a storage resource at a Solar Plus Storage facility to charge from the grid; however, the ability to charge storage with both DC energy and grid energy is expected to be available in an update to the EnCompass model to be released later in 2022. Tr. vol. 7, 346. Thus, as of August 2022, constraints within EnCompass limited Duke’s ability to model the full functionality (or dynamism) of Solar Plus Storage.

Intervenors such as the Public Staff and NCSEA et al. agree that modelers should not model storage as fixed-dispatch and that dynamic dispatch is preferable, and Duke concedes the same, assuming that factors such as modeling times can be made to be reasonable. Tr. vol. 8, 47; tr. vol. 23, 54-56, tr. vol. 24, 165.

Duke’s fixed dispatch approach to modeling Solar Plus Storage is not unreasonable for purposes of this initial Carbon Plan. However, the Commission finds that, going forward, the mechanics of modeling storage resources will be a key element to enable least cost compliance. Accordingly, the Commission concludes that Duke’s first biennial CPIRP should model dynamic dispatch of Solar Plus Storage and, to the extent feasible, should incorporate bi-directional inverter capability. The Commission directs Duke and the Public Staff to work together closely on this issue during the next proceeding and, if they do not reach consensus on these modeling techniques, to each provide a robust explanation to the Commission as to the points of disagreement and agreement.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

Modeling – Battery-CT Optimization

The evidence supporting this finding of fact is in Appendix E of Duke's Carbon Plan proposal, the testimony of the Duke Modeling and Near-Term Actions Panel, the testimony of Public Staff witness Thomas, the testimony of AGO witness Burgess, and the entire record in this proceeding.

Appendix E of Duke's Carbon Plan proposal describes the portfolio verification steps Duke undertook in modeling its proposed Carbon Plan to ensure least cost compliance and to ensure that the selected resources maintain or improve upon the adequacy and reliability of the grid. The Modeling and Near-Term Actions Panel further testified that, as part of the overall modeling framework, Duke took a portfolio verification step, which included production cost modeling within the EnCompass model to confirm economic selection of resources by the capacity expansion model. The Modeling and Near-Term Actions Panel testified that due to the simplified simulations used in capacity expansion modeling, the capacity expansion model alone could not evaluate in-depth economic operation of resources to ensure economic resource selection, especially in the case of energy-limited resources such as storage. Therefore, Duke used the production cost model to produce a more detailed and realistic simulation of the system to more accurately account for the cost to operate the system with these resources. Tr. vol. 7, 227-28.

Duke describes this process as necessary to ensure the inclusion of a least cost set of resources. In further explanation, Duke explains that in order to quickly assess a wide range of resource options, the capacity expansion resource screening model makes necessary simplifications in hourly loads and system operations to find potential least cost resource portfolios that will minimize the cost of the system. Further, Duke explains that because of these simplifications, the model evaluates resources against load shapes that account for monthly peak and low load conditions for each "typical day," while maintaining total average daily energy to ensure that the model selects resources that can meet these crucial planning requirements. Duke explains that this simplification (while necessary in the capacity expansion resource screening model) has the side effect of distorting the load shape in a way that does not reflect actual hourly needs on the system, which results in the capacity expansion model over-valuing short duration energy storage. Because the capacity expansion model over-ascribes value to energy storage resources, Duke explains that it is important to use additional analyses to verify if at least a portion of the energy storage, especially in the near term, included in the initial capacity expansion results is economic relative to other peaking resources, in this case CTs. Tr. vol. 7, 229.

To this end, Duke states that it replaced approximately 35% of the batteries that the capacity expansion model selected with CTs and re-ran the detailed production cost model with the adjusted resource mix (the Battery-CT Optimization Process). Duke explains that removing batteries and adding CTs typically increased modeled production costs, but because CTs are lower capital cost to build than batteries, the adjustment reduced the total capital costs of the portfolio. Duke explains that so long as the capital cost savings are more than enough to offset the production cost increase and Duke can still meet carbon dioxide emissions reduction mandates, the CTs are the more cost-effective resource. *Id.* at 230. Duke cautions that omitting this step could result in the inclusion in the portfolio of greater amounts of energy storage than is cost-effective.

Public Staff witness Thomas stated that the Battery-CT Optimization Process may not be reasonable for planning purposes and stated that Duke should have allowed the model to economically select battery storage. He explained that if the reliability validation step identified reliability issues, Duke could add CTs at that point to meet reliability thresholds. Tr. vol. 21, 43-47. Regarding whether the Battery-CT Optimization Process step results in cost savings for ratepayers, as Duke argues, witness Thomas stated that he found the overall cost savings to be relatively minor and sensitive to assumptions regarding natural gas prices and battery storage capital costs. He further stated that the Public Staff tested the robustness of Duke's savings estimates under two sensitivities: a 30% reduction to battery storage capital costs, representing the ITC that is now available to standalone energy storage systems, and the use of Henry Hub natural gas prices forecasted in the 2022 Annual Energy Outlook, Low Oil and Gas Supply case. He stated that the PVRR savings decreased dramatically for each portfolio, and that in P2 and P3 the replacement of 35% of battery storage with CTs resulted in a cost increase under these assumptions. *Id.* at 47-49.

Public Staff witness Thomas' concerns are that the Battery-CT Optimization Process: (1) produces minimal ratepayer savings; (2) is not robust to changes in capital costs, fuel prices, or natural gas consumption relative to Duke's assumptions; (3) forces in CTs to serve as essentially capacity-only resources, resulting in elevated reserve margins; and (4) is potentially redundant to the more detailed reliability validation analysis Duke undertook. *Id*. at 51-52.

AGO witness Burgess stated that while not all out-of-model adjustments are necessarily unwarranted, these kinds of additional steps can introduce a new potential "black box" that is non-transparent and can be difficult for stakeholders to independently assess. Thus, witness Burgess believes it is generally preferable to minimize these additional steps. Tr. vol. 25, 257.

Based on the foregoing, the Commission concludes that the Battery-CT Optimization Process step performed by Duke is justified at this time, given that the overall battery energy storage contemplated in the initial Carbon Plan is untested at scale in North Carolina currently. However, as planning tools are updated and Duke gains system operations experience with energy storage, this out-of-model step may no longer be appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 11-12

Modeling – Reliability

The evidence supporting these findings of fact is in the testimony and exhibits of the Duke Modeling and Near-Term Actions Panel, the testimony of Public Staff witness Thomas, the testimony NCSEA et al. witness Fitch, the testimony of Tech Customers' witness Panel Borgatti, Kimbrough, and Roumpani, and the entire record in this proceeding.

Duke's Carbon Plan proposal specifies that reliability is one of its core objectives, along with carbon dioxide emissions reduction, affordability, and executability. Tr. vol. 7, Duke Proposed Carbon Plan, Ch. 2, 2. Chapter 2 to Duke's Carbon Plan proposal explains that N.C.G.S. § 62-110.9 requires that any generation and resource changes maintain or improve upon the adequacy and reliability of the existing grid and that the Commission may plan to achieve the Interim Target after 2030 if it is necessary to maintain the adequacy and reliability of the existing grid. Tr. vol. 7, Duke Proposed Carbon Plan, Ch. 2, 2; App. Q, 1; App. E, 5. Appendix Q explains that this core statutory objective recognizes Duke's public service obligation to plan and operate their generating fleets and transmission and distribution systems to continually provide reliable power system operations to their customers in accordance with federally mandated NERC Reliability Standards. Tr. vol. 7, Duke Proposed Carbon Plan, App. Q, 1.

Duke's Carbon Plan proposal includes multiple reliability inputs, including planning reserve margin, effective load-carrying capacity (ELCC) values for renewable and energy storage resources, and operational reserve requirements. Tr. vol. 7, Duke Proposed Carbon Plan, Ch. 2, 6-7. Duke's Carbon Plan proposal defines resource adequacy as "having sufficient resources available to reliably serve electric demand especially during extreme conditions," and explains that the planning reserve margin target is used in the planning process to ensure resource adequacy. Tr. vol. 7, Duke Proposed Carbon Plan, App. E, 9. The Carbon Plan proposal uses a 17% winter planning reserve margin to achieve a "one-day-in-10-year" industry standard Loss of Load Expectation (0.1 LOLE), or one firm load shed event every 10 years due to a shortage of generating capacity, as an acceptable level of physical reliability as determined by the 2020 Resource Adequacy Study conducted by Astrapé Consulting. Tr. vol. 7, Duke Proposed Carbon Plan, Ch. 2, 6; App. E, 9-10. Duke's Carbon Plan proposal uses a 2022 ELCC study developed in collaboration with Astrapé Consulting using the SERVM reliability and hourly production cost simulation tool to estimate the reliability capacity value attributable to variable solar and wind (seasonal contribution) and energy-limited storage resources. Tr. vol. 7, Duke Proposed Carbon Plan, Ch. 2, 6; App. E, 10-16. Finally, the Carbon Plan proposal uses a planning and reliability tool developed by the Electric Power Research Institute (EPRI) to calculate hourly operational reserves requirements to ensure that Duke will have sufficient flexible resources available to mitigate the risk of load and renewable output uncertainty. Tr. vol. 7, Duke Proposed Carbon Plan, Ch. 2, 6-7.

Duke's development of its Carbon Plan proposal includes simplified capacity expansion screening modeling in EnCompass with average representation of hourly system demand to determine optimal resource portfolios that meet reliability standards, carbon dioxide emissions reduction mandates, and least cost planning requirements. Tr. vol. 7, Duke Proposed Carbon Plan, Ch. 2, 25-26; App. E, 4. The output of the capacity expansion model is used to develop operational reserve requirements in the EPRI tool to ensure adequate flexible resources to mitigate load and variable resource uncertainty; the capacity expansion is then reoptimized with the operational reserve requirements. Tr. vol. 7, Duke Proposed Carbon Plan, Ch. 2, 6-7, 26.

Duke's Carbon Plan proposal explains that this capacity expansion, due to its computational and data simplifications, was further modeled in more detail in the production cost stage to validate and adjust resources across cost, reliability, and carbon dioxide emissions reduction mandates. Tr. vol. 7, Duke Proposed Carbon Plan, Ch. 2, 25; App. E, 4. The portfolio outputs from the preliminary identification of resources in the capacity expansion model were run through the detailed EnCompass production cost model that reflected more detailed hourly dispatch versus an "average" representation in capacity expansion, thus developing refined resource outcomes based on more realistic hourly loads. Tr. vol. 7, Duke Proposed Carbon Plan, Ch. 2, 26; App. E, 59.

The Battery-CT optimization step then considered hourly loads for each hour of the year to arrive at a portfolio that balanced carbon dioxide emissions reduction mandates while minimizing costs, and had the added benefit of enhanced system reliability by replacing shorter-duration batteries with CTs with longer duration capabilities to meet system needs 24 hours a day, every day of the year without limitation. *Id*.

Duke then performed resource adequacy and reliability verification using both the EnCompass production cost model and SERVM. Duke utilized the SERVM tool to assure that a portfolio with a high reliance on variable energy and energy-limited resources, which present risks that planning reserve margins do not adequately address, especially in severe weather events, would maintain system reliability. Tr. vol. 7, 228. DEC witness Roberts testified as to the importance of this additional reliability validation step, which reflects Modeling Team collaboration with the System Planning and Operations Team to ensure that the validation actually reflects realistic weather, demand, and outage operational patterns. Tr. vol. 19, 172.

The use of SERVM allows Duke to utilize 41 years of weather data, and other inputs, in order to perform a statistical determination of LOLE. Tr. vol. 9, 96. Duke has been using SERVM as its reliability tool for at least seven years. Tr. vol. 11, 150. The Public Staff reviewed the SERVM tool prior to these proceedings and expressed confidence in its ability to calculate LOLE. Tr. vol. 21, 374. NCSEA et al. witness Fitch argued that Duke's use of the SERVM tool is not commonly understood to be a necessary step in resource planning. Tr. vol. 24, 143. Witness Borgatti of Tech Customers expressed concern that intervenors cannot independently validate a proprietary tool such as SERVM. *Id.* at 354. While the Commission acknowledges the concerns of some intervenors as to the use of a reliability validation step outside of EnCompass, the Commission also gives significant weight to

Duke's arguments that a complete modeling exercise may consist of the use of more than one software tool. Based on the foregoing, the Commission concludes that Duke's use of a tool such as SERVM — to validate reliability — is appropriate.

Duke's Carbon Plan proposal explains that the power system transformation that the Carbon Plan portfolios contemplate raises many new challenges for managing the grid, as increasing levels of renewable generation will fundamentally change patterns of net load demand and increased uncertainty. Tr. vol. 7, Duke Proposed Carbon Plan, App. Q, 17. While traditional planning metrics of adequate day-to-day operating reserves and long-term planning reserves necessary to meet customer demands during cold winter morning and hot summer afternoons are necessary, the change in resource mix due to the energy transition creates new challenges. Tr. vol. 7, Duke Proposed Carbon Plan, Ch. 3, 17; App. Q, 1. The proposed Carbon Plan introduces six reliability risks and mitigating solutions of the energy transition that will create new challenges for managing the grid. *Id.* at App. Q, 1-2. Those risks include: (1) resource and energy adequacy from renewables and storage; (2) access to firm interstate transportation of natural gas and new natural gas-fired generating resources; (3) coal-fired generator reliability during the transition; (4) the need for new carbon-free load-following resources that are flexible and dispatchable; (5) the need for adequate and reliable flexible resources to manage the reliable integration of renewables; and (6) system resilience to withstand extreme events such as weather or cyber disruptions.

Duke witnesses provided extensive testimony on practical and operational experience that inform the positions Duke takes in the proposed Carbon Plan. For example, DEC witness Holeman explained that from a System Operator's point of view, there are real-world implications that must be factored in when maintaining grid adequacy and reliability during the energy transition. Tr. vol. 19, 114-15.

Duke's Reliability Panel discussed the criticality of resource planning resulting in an orderly, planned transition of the system, and stated that Duke "must strive to reduce risks, not heighten risks, for their customers and communities as their resource mix transitions through the Carbon Plan to achieve vital carbon dioxide emissions reduction targets" as intended by N.C.G.S. § 110.9 to maintain or improve upon the reliability of the grid. Tr. vol. 19, 129-30,140. The Reliability Panel further noted that NERC has identified the risks of energy transition as "merit[ing] the highest attention and mitigation efforts from regulators and grid operators," specifically citing resource adequacy during extreme weather events, appropriate sequencing of resource transitions (retirements and replacements), and having adequate flexible and dispatchable resources. *Id.* at 131, 133-34.

Based on Duke's system operational experience and trends across the industry, Duke's Reliability Panel underscored the need for a carefully planned transition to retire more than 8,400 MW of coal by 2035, with assurance that there is timely replacement with a robust mix of resources with operational capabilities that coal provides — particularly in constrained periods and prolonged weather events. *Id.* at 134, 154-55, 161, 182; tr. vol. 30, 105-06. In response to CIGFUR questions on coal retirements, witness Holeman punctuated this concept: "Replace before you retire. So I believe I'm confident after 38 years in this industry in the operations area that if we keep that order right, we'll be able to deliver what's mandated in House Bill 951." Tr. vol. 19, 208.

The Commission notes that N.C.G.S. § 62-110.9(3) provides expressly that the Commission, in developing the Carbon Plan, *must* "[e]nsure any generation and resources changes maintain or improve upon the adequacy and reliability of the existing grid." The Commission is persuaded by the testimony of the Duke and Public Staff witnesses supporting and underscoring the need for the various steps taken to assess and ensure the reliable operation of the system, and is persuaded that Duke, in developing its Carbon Plan proposal, appropriately focused on maintaining adequacy and reliability of the existing grid. The Commission takes special note of the six specific risks to reliability Duke identifies and directs Duke to address robustly each of those risks, with updated information and modeling where appropriate, in its upcoming CPIRP filing. The Commission agrees with Public Staff witness Metz and with Duke, that "[n]ot all system operational factors can be captured within a model," and directs Duke to work with the Public Staff in leveraging actual operational experience to continue to plan for the future, mitigate foreseeable risk, and prepare for the challenges ahead.

The Commission concludes that ensuring system reliability and compliance with mandatory reliability standards in the face of the ongoing energy transition is a requirement of state law, is an obligation uniquely held by Duke and overseen by this Commission, and is nonnegotiable for the continued health and well-being of all North Carolinians.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 13-17

Coal Plant Retirements

The evidence supporting these findings of fact is in Duke's Carbon Plan proposal, the direct and rebuttal testimony of the Duke Modeling and Near-Term Actions Panel and the Transmission and Solar Procurement Panel, the testimony of the Public Staff, NCSEA et al., and the AGO, the Initial Comments of the Public Staff, CIGFUR, Tech Customers, and Person County, and the entire record in this proceeding.

Duke's approach to modeling began with a constraint which decreased carbon dioxide emissions linearly to achieve the Interim Target and the 2050 Target. The model could then economically select a mix of assets subject to this constraint. In each of Duke's proposed portfolios P1-P4, Duke would retire all coal generation capacity by 2035 at the latest. Tr. vol. 7, Duke Proposed Carbon Plan, App. E, Tbl. E-47. In sensitivities SP5 and SP6 modeled at the request of the Public Staff, Belews Creek station is allowed to run as a coal-fired facility until the end of 2037. Tr. vol. 13, Official Exhibits, 30-31. The following table displays the amount of coal generation resources retired as of the date of achieving the Interim Target for each portfolio:

Portfolio	Interim Target Date	Coal Generation Retired
P-1	2030	4,900 MW
P-2	2032	4,900 MW
P-3	2034	6,300 MW
P-4	2034	6,300 MW

Tr. vol. 13, Official Exhibits, 38-39; tr. vol. 7, Duke Proposed Carbon Plan, App. E at 77. The Modeling Panel highlighted the scale of Duke's coal capacity reduction plans in the Carolinas, explaining that, including the coal-to-gas conversion of Cliffside Unit 6, Duke is planning to retire and/or replace 9,274 MW of coal capacity by the end of 2035. Duke asserts that compared to its southeastern peer utilities, Duke is reducing more coal capacity than any other utility surveyed. Tr. vol. 7, 335-36.

As explained in Duke's Carbon Plan proposal filing and through testimony, the timing of future coal retirements was first identified endogenously within Duke's EnCompass capacity expansion model. This is a significant enhancement over prior modeling and responds to criticisms made in connection with the 2020 IRP proceedings concerning Duke's methodology for determining coal unit retirement dates and to the directive the Commission gave in its Order accepting the 2020 IRPs. Order Accepting Integrated Resource Plans, REPS and CPRE Program Plans with Conditions and Providing Further Direction for Future Planning, *2020 Biennial Integrated Resource Plans and Related 2020 REPS Compliance Plans*, No. E-100, Sub 165, 12-13 (N.C.U.C. Nov 19, 2021). The capacity expansion model weighed the continued operational benefits to the system and costs to operate and maintain the coal units over time against the retirement and potential replacement of the coal units by available supply-side resources, while also meeting the operational and planning constraints of the system, including emissions reduction mandates. Tr. vol. 7, Duke Proposed Carbon Plan, App. E, 44. As the Duke Modeling Panel described, capacity expansion modeling does not provide an exact date for the optimal timing to retire a unit, and its ability to do so is inadequate due to necessary simplifications used in the model. Numerous factors which could influence optimal timing of retirements do not lend themselves to perfect integration into the model, but Duke must consider them in determining the optimal timing of coal retirements. Tr. vol. 7, 326-28.

Duke's modeling fixed retirement dates for each coal unit through its depreciable life with two exceptions. Duke modeled Belews Creek to cease operations at the end of 2035, consistent with Duke's target to be out of coal by 2035 and in an effort to mitigate fuel security risks related to coal supply. Additionally, Duke modeled Allen Units 1 and 5 to be retired by the beginning of 2024, coincident with the timing of a transmission project under construction in DEC to enable the retirement of these units. Tr. vol. 7, Duke Proposed Carbon Plan, App. E, 45.

In the 2020 IRP, and as directed by prior Commission orders, Duke evaluated coal retirements without regard to the remaining net book value (NBV) of the units. However, for the Carbon Plan, because N.C.G.S. § 62.110.9 and Commission Rule R8-74 provide for securitizing remaining NBV of accelerated retirements of subcritical coal units, Duke factored into the coal retirement analysis the benefits associated with securitization of the remaining net book value of subcritical coal units at the time of modeled retirement. *Id*. at 44-47.

The determination of optimal coal retirement dates was a multi-step process. Duke explains that while it used the capacity expansion model to endogenously identify retirement dates economically, on a level comparison with new resources and in keeping with carbon dioxide emissions reduction requirements, relying exclusively on results from the capacity expansion model would not be the best practice for resource planning. *Id*. at 44. Duke explains that while the capacity expansion and production cost models are sophisticated tools, capacity expansion modeling, in general, is not an exact indication of the optimal selection of resources or the optimal timing to retire a unit. Tr. vol. 7, 326-27. Additionally, Duke states that there are several factors which could influence the optimal timing of retirements — including the timing of new resource additions, transmission constraints, and the ability to leverage sites for future development — and that these factors do not lend themselves to perfect integration into the EnCompass model. *Id.* at 327. For these reasons, Duke notes that the coal retirement dates the model selected were subject to additional analysis and adjustment in certain, limited instances. Tr. vol. 7, Duke Proposed Carbon Plan, App. E, 48-49.

In response to NCSEA et al. witness Fitch, the Modeling and Near-Term Actions Panel testified that Duke reviewed the analysis that witness Fitch used as a basis for his assertions and concluded that Synapse's analysis is flawed and that the Commission should disregard it. Synapse's report indicates that Duke made manual changes to coal retirement dates, functionally overriding the conclusions of the endogenous retirement analysis performed with EnCompass. Synapse's conclusion is that Duke's manual adjustments would cost ratepayers an additional $1.4 billion. Tr. vol. 25 (Public), NCSEA et al. and SACE et al. Initial Comments, Synapse Report, 28-29. The Panel explained that the cost Synapse calculates does not account for net capacity changes on the system — that is, the replacement resources — essentially only factoring in one side of the ledger. Furthermore, Duke asserts that the cost estimates are based on a generalized industry study that does not specifically apply to Duke's coal units in question, whereas Duke's decades of experience operating these units inform a more appropriate estimate when evaluating the cost for continued reliable operation of these units. Tr. vol. 7, 333-34.

The Modeling and Near-Term Actions Panel also explained the adjustments Duke made to the endogenously identified retirement dates for Marshall Units 1 and 2 and Roxboro Units 3 and 4, as examples, pointing to transmission projects necessary to enable the retirements or to the optimal timing of new resource availability. Tr. vol. 7, Duke Proposed Carbon Plan, App. E, 48. The Panel provided additional context related to Duke's need to delay retirements of these assets in the modeling. The Panel stated that optimally timing the coal retirements to recognize the necessary transmission construction timelines is an appropriate consideration. Doing so further allows for the selection from a wider array of resources to meet the near-term and long-term system needs. The timelines additionally allow Duke to take advantage of continued cost declines for certain resources, such as batteries, if they are selected as a part of the collective optimal replacement resources. Tr. vol. 7, 327-28; tr. vol. 7, Duke Proposed Carbon Plan, App. E, 48.

Specifically, the Modeling and Near-Term Actions Panel continued, to retire Marshall Units 1 and 2 without replacement resources on site would require the completion of the McGuire – Marshall 230 kV transmission project. The Panel explained that the earlier deployment of batteries (prior to the completion of the transmission upgrade) as a replacement resource at the site is not a feasible alternative solution, as the replacement resources contemplated by the adjustment to the Marshall retirement dates must be fully dispatchable and capable of longer run times than are currently possible for batteries in order to satisfy grid reliability requirements. Energy-limited batteries do not allow for avoidance of the transmission project to enable these coal retirements. Tr. vol. 7, 328-29.

Similarly, the Panel explained that the accelerated retirement of Mayo that the capacity expansion model identifies, without replacement by dispatchable resources capable of longer run times, requires several potential transmission projects that push the feasible retirement date of Mayo to later in the current decade, at the earliest. *Id.* at 329-30.

Duke witness Roberts testified as part of the Transmission Panel that Duke must ensure that any transmission projects required to accommodate coal retirements are in place prior to the planned retirement dates. He echoed Appendix P to Duke's Carbon Plan proposal that considering the planned retirement dates for Duke's coal units, Duke has performed varying levels of transmission planning analysis and considerations based on different scenarios for generation replacement. He explained that several of these scenarios reveal the necessity of replacing the retiring generation onsite connected to the same electrical point of interconnection. He noted that a major consideration with respect to the timing for retirement is whether Duke can avoid long-term transmission upgrades and that this issue was a major driver in Duke's request for FERC approval to incorporate a Generation Replacement process into the Large Generation Interconnection Procedures (LGIP). He testified that FERC's approval of this process, which Duke obtained on September 6, 2022, will be critical to efficient, timely, and cost-effective replacement of retired coal-fired generation with new generation interconnected at the same switchyard. Tr. vol. 16, 94-96; tr. vol. 7, Duke Proposed Carbon Plan, App. P, 15-16.

The Duke Transmission Panel testified that in planning for coal retirement, Duke must consider the adequacy of replacement resources and also plan for grid impacts such as voltage support, changing power flows, and the need for associated transmission investment. In defense of Duke's extension of the retirement dates for certain units, the panel testified that Synapse's critique ignores real-world execution and operations risks, and that scrutiny of model outputs is necessary to ensure that they reflect a reliable portfolio and consider these risks. The Synapse and Gabel reports both criticized Duke's manual changes to coal retirement dates, arguing that endogenous modeling only should drive coal retirements. Tr. vol. 25 (Public), NCSEA et al. and SACE et al. Initial Comments, Synapse

Energy Economics, 28-29; tr. vol. 25 (Public), Tech Customers Initial Comments, Gabel Report, 27-29. The panel's prefiled testimony outlines several of the upgrades that would be necessary to achieve the economic retirement dates, issues with which, the panel testified, Gabel and Synapse do not meaningfully engage, instead assuming that Duke can replace all retiring coal generation onsite. These necessary upgrades cause the panel to have significant executability concerns with the Synapse and Gabel proposed portfolios. Tr. vol. 16, 97-100.

As an example of the operational issues that Duke must address in settling upon retirement dates for coal units, witness Roberts testified concerning the critical role that coal and other dispatchable resources played during the extended winter peak event of 2018. Tr. vol. 19, 178-79. Witness Roberts provided a table which indicates that twelve of eighteen coal units in DEC and DEP operated at a 93% or higher capacity factor during the period January 2-8, 2018. He provided the Roxboro Plant as an example, which produced 392,786 MWh at 96% capacity factor during the 7-day period. Witness Roberts further testified that system operations must consider solar and wind facility performance to maintain reliability in extended cold weather periods, as well as how the planned retirement of the coal fleet impacts system operations reliability risks. *Id.* at 179-83. He further testified that Duke will need to carefully plan coal unit retirements to maintain resource adequacy and system reliability during the transition away from coal. Noting the actual customer demand and irradiance experience during January 2018, witness Roberts concludes that it would be impossible for him to agree with Synapse or Gabel that their portfolios could provide energy adequacy for reliably serving similar long duration winter events, as they over-rely on the weather-dependent resources of solar and wind. He added that the Synapse and Gabel proposed portfolios retire coal early without effectively providing replacement generation or resources that can achieve high-capacity factors for extended periods when needed as Duke's coal fleet did in January 2018. *Id.* at 182, 197-99.

With regard to the question of timing of coal retirements, Public Staff witness Metz testified that while maintaining the operation of any generating resource beyond its economic life is not preferable, there are operational and reliability implications that Duke must consider and manage as part of any coal exit strategy. He testified that the retirement schedule may need to reflect impacts of a range of factors including transmission, fuel supply, and system reserves to account for system abnormalities that occur outside of a model. Tr. vol. 21, 116-18.

Citing the need to maintain operational flexibility and reliability at a reasonable cost, witness Metz cautioned the Commission against ordering an overly prescriptive, inflexible retirement schedule for the entire coal generation fleet. *Id*. Witness Metz explained that Duke can use the coal generation assets that it does not retire before 2030 as capacity resources to meet reserve margin requirements while not dispatching them for daily system needs.[11] Duke would also use these units to account for system

[11] The Commission notes that a coal generation unit that Duke does not retire before 2030, may be idle but available when needed for purposes of responding to system anomalies or extreme contingencies. The coal

anomalies. *Id.* at 112-14. Witness Metz advised against a definitive coal retirement schedule and suggested the Commission's primary focus should be on maintaining operational flexibility and reliability at a reasonable cost. He recommended that Duke continue to update the Commission and stakeholders of any changes to the current retirement schedule on an ongoing basis. *Id*. at 116-17.

Public Staff Witness Boswell testified that Duke must comply with Commission Rule R8-74 and N.C.G.S. § 62-110.9 by securitizing 50% of the remaining NBV of all subcritical coal plants Duke retires early to achieve the carbon dioxide emissions reduction mandates in N.C.G.S. § 62-110.9. This securitization must be timely and maximize benefits to customers. Witness Boswell recommended that Duke maximize cost savings by assessing whether it would be in ratepayers' interest to securitize additional coal generation assets, including non-sub-critical coal units. Tr. vol. 23, 117-18.

In the Gabel Report, sponsored by Tech Customers witnesses, Tech Customers point out the undisputed fact that coal-fired generation is the largest source of carbon dioxide emissions in Duke's fleet. Tech Customers acknowledge that actual retirement decisions must consider factors outside those available in the model, though they insist that Duke make conclusions transparently and on the best available supporting data. Tr. vol. 25, Tech Customers Initial Comments, Gabel Report, 27-28. While the Gabel Report's alternate Carbon Plan modeling accelerates the retirement of Duke's coal fleet to before 2030, it also describes its analysis as a "modeling exercise to illustrate hypothetical results that may be possible." *Id.* at 28.

Person County desires that Duke locate replacement resources at the retiring coal unit sites currently operating in that county in order to minimize cost to customers. Person County Initial Comments at 9. Person County also advocates for maintaining the Mayo and Roxboro units for as long as possible to support N.C.G.S. §110.9's requirement to maintain or improve upon adequacy and reliability of the existing grid and offers that it is prudent planning for Duke to extend the operational lives of Roxboro and Mayo past the retirement dates Duke's Carbon Plan proposal identifies, but to use them only for emergency purposes. *Id*. at 12-13.

In his testimony, AGO witness Burgess disputed Duke's out-of-model adjustments to its coal retirement dates, which he stated lead to significant changes in those dates. Specific to Duke's proposed portfolio P1, witness Burgess testified that the economic retirement dates for Belews Creek Units 1 and 2, Marshall Units 1 and 2, and Mayo Unit 1 occur much sooner than what Duke has proposed, and that earlier retirement may be economic and feasible. Tr. vol. 25, 285-86. In summary, AGO witness Burgess criticized Duke's support for these adjustments as insufficient given the degree of delay. He also advocated alternatives to delayed retirement, including battery storage at the site of existing coal plants, to mitigate the need for transmission upgrades, and stated that by overriding the model's retirement date selection, Duke also crowds out other more economic resources that it would otherwise

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generation unit would no longer be regularly generating electricity, thus, it would produce decidedly less carbon dioxide emissions due to its limited operation.

consider earlier. In addition, witness Burgess critiqued the delayed retirement of Belews Creek from 2030 to 2036 due to necessary transmission upgrades and suggested there is ample time to complete any necessary upgrades by 2030. He also recommended that the Commission explore the feasibility of converting Belews Creek to 100% natural gas and direct Duke to include this as an option in all future scenarios.

AGO Witness Burgess also suggested increasing the natural gas co-firing at the Belews Station in lieu of accelerated retirement. AGO witness Burgess explained that in his alternate modeling, he modeled the conversion of Belews Creek to operate exclusively on natural gas starting in 2028. He stated that due to the complexities of modeling the Belews Creek gas conversion, this resource was assumed as an input for the 2028 timeframe rather than being a result of the model's resource selection process. While acknowledging that, ideally, modeling should support this scenario, he suggested that this is a reasonable approximation of the optimal outcome due to the considerably favorable economics of this conversion over a new natural gas plant addition. Tr. vol. 24, 281-83, 288.

Regarding the high gas price sensitivity scenarios, AGO witness Burgess cautioned that economic dispatch of the generation fleet could lead Duke to exceed its carbon dioxide emissions mandates by running relatively less expensive coal generation, specifically Belews Creek, more than it modeled. Giving weight to this sensitivity case increases the urgency of retiring Belews Creek and replacing it with cleaner resources. Tr. vol. 25, 290.

NCSEA et al. witness Fitch suggested that the adjustments to the endogenously identified coal retirements dates lack analytical justification and would result in additional costs to ratepayers. Witness Fitch asserted that the adjustments were not necessary to maintain reliability of the system and that Duke should have accepted the EnCompass optimization results as the most cost-effective retirement dates. He contended that the dates the model selected are the most optimal co-optimization of mix of resources. He argued that the reasoning Duke provided in its proposed Carbon Plan and in Duke witness Roberts' direct testimony rely too heavily on high level assumptions rather than detailed requirements and timelines. He presented Synapse's scenarios for coal unit retirement and recommends the Commission make all efforts to implement the most economic coal retirement dates. Tr. vol. 24, 171-77.

As an alternative to accelerating coal retirement and perhaps necessitating the deployment of replacement resources, in its Initial Comments the Public Staff recommends modeling Belews Creek as operating exclusively on natural gas post-2035 until the end of 2037, the end of the station's projected depreciable life. Public Staff Initial Comments at 21, 117-19.

In its initial written comments, CIGFUR contends that Duke failed to adequately consider, as a potentially more cost-effective alternative solution to reducing carbon dioxide emissions, retrofitting existing coal plants to burn natural gas as a means of extending the life of the assets. CIGFUR Initial Comments at 19-20.

With respect to the further conversion of coal units to operate primarily on natural gas and for longer periods of time, Duke responded that it evaluated the high-level business case of expanding natural gas co-firing beyond the current 50% at Belews Creek Units 1 and 2 and Marshall Units 3 and 4, and, while the expansions were potentially feasible (subject to detailed engineering studies to confirm), a recently completed evaluation did not indicate favorable economics for customers. Tr. vol. 7, 332; tr. vol. 27, 85.

Based on the foregoing evidence, the Commission finds Duke's coal retirement modeling and analysis, as well as the dates Duke targets for retirement and sets forth in Duke Table E-47 on the following page, to be reasonable for planning purposes.

Table E-47: Coal Unit Retirements (effective by January 1st of year shown)

Unit	Utility	Winter Capacity [MW]	Effective Year (Jan 1)
Allen 1[2]	**DEC**	167	2024
Allen 5[2]	**DEC**	259	2024
Belews Creek 1	**DEC**	1,110	2036
Belews Creek 2	**DEC**	1,110	2036
Cliffside 5	**DEC**	546	2026
Marshall 1	**DEC**	380	2029
Marshall 2	**DEC**	380	2029
Marshall 3	**DEC**	658	2033
Marshall 4	**DEC**	660	2033
Mayo 1	**DEP**	713	2029
Roxboro 1	**DEP**	380	2029
Roxboro 2	**DEP**	673	2029
Roxboro 3	**DEP**	698	2028-2034[3]
Roxboro 4	**DEP**	711	2028-2034[3]

Note 1: Cliffside 6 is assumed to cease coal operations by the beginning of 2036 and was not included in the Carbon Plan's Coal Retirement Analysis because the unit is capable of operating 100% on natural gas.

Note 2: Allen 1 and 5 retirements are planned by 2024 and were not re-optimized in the Carbon Plan's Coal Retirement Analysis.

Note 3: Retirement year for Roxboro Units 3 and 4 vary by portfolio, with retirement of those units effective 2028 in P1, 2032 in P2, and 2034 in P3 and P4.

Tr. vol. 7, Duke Proposed Carbon Plan, App. E, Tbl. E-47.

The coal retirement schedule Duke presents in its proposed Carbon Plan enables substantial reductions of carbon dioxide emissions that contribute to meeting the carbon dioxide emissions reduction mandates following least cost principles while maintaining system reliability. Duke employed a detailed multi-step modeling and analytical process to appropriately estimate the cost of continued operation and leveraged the results of the endogenous coal retirement analysis to inform and guide a coal retirement schedule that recognizes real-world operating constraints. The Commission recognizes the magnitude of the challenge Duke is undertaking over the next decade, including the significant fleet transition required to retire 8,400 MW of coal-fired units that are operating today by the end of 2035 and to replace more than 9,200 MW of coal capacity when also considering the Cliffside Unit 6 coal-to-gas conversion. While the Commission, too, is interested in Duke's considering all feasible options, such as converting the Belews Creek Station to operate 100% on natural gas, the Commission concludes that Duke is taking reasonable steps in this regard.

The Commission agrees with the Public Staff that planning for retirement of Duke's remaining coal fleet should continue to focus on maintaining operational flexibility and reliability at a reasonable cost. Retirements generally require replacement resources to maintain the resource adequacy of the system. Providing an overly prescriptive approach to coal unit retirement based solely on expansion planning model outputs is not prudent, and the Commission agrees with Public Staff witness Metz and Duke witness Roberts that accelerating coal unit retirements without enabling transmission or necessary replacement resources may risk the reliability of the grid. Duke's approach of an orderly transition provides time to evaluate transmission system needs, identify replacement resources, and pursue a holistic approach to an orderly transition of the fleet.

The Commission agrees with the Public Staff that it is appropriate for Duke to keep the Commission apprised of the timing of scheduled coal unit retirements. The Commission cautions that any slippage in the projected retirement dates set forth in Appendix E, Table 4-2 of Duke's Carbon Plan proposal has the potential to materially increase the risk of failure to meet the Interim Target by 2030. As stated above, the Commission understands and agrees on the need for Duke to retain a degree of flexibility with respect to the proposed retirement dates for purposes of reliability and cost management. However, Duke should not interpret that flexibility as open-ended. The Commission directs Duke to present a comprehensive analysis of the planned coal unit retirement schedule in its next CPIRP filing to specifically address the contingencies witnesses identified and discussed in this proceeding that may affect Duke's currently planned retirement dates of its coal-fired units, especially for the units Duke contemplates for retirement before 2030 (Cliffside Unit 5, Marshall Units 1 and 2, Mayo Unit 1, and Roxboro Units 1 and 2), and for Roxboro Units 3 and 4, which Duke retires in 2028 in its proposed portfolio P1. Duke shall further address steps it has taken and plans to take to ensure that those contingencies do not require delays to Duke's proposed retirement dates set forth in Appendix E, Table 4-2 of Duke's Carbon Plan proposal. The Commission will require Duke to show substantial justification for any delays and to present alternatives for reducing the additional carbon dioxide emissions that may result from delaying retirements beyond the dates currently proposed in its 2022 Carbon Plan filing.

Finally, the Commission notes that Duke conducted and completed its evaluation of the conversion of Belews Creek Units 1 and 2 from 50% natural gas capability to 100% capability before the passage of N.C.G.S. § 62-110.9 and not as part of the comprehensive analysis of Duke's overall resource portfolio that has been part of these proceedings or of the 2020 IRP proceedings. This evaluation did not, for example, consider whether Duke might justify the additional fuel source conversion at Belews Creek as an interim or bridge to a time when Duke could bring fully hydrogen-capable CT or CC generating units online, as an alternative to investing in new natural gas generating units now and then later incurring costs to convert those units to a zero-carbon fuel source. As another example, the earlier study did not evaluate whether the fuel source conversion might enable the Belews Creek units to provide additional, non-coal fired reserve capacity for the system and thereby help support the proposed retirement dates for others of Duke's coal-fired generating units. The Commission would benefit from additional review of such topics and others associated with the potential for fuel source conversion and directs Duke to re-study the potential costs and benefits of a further conversion of Belews Creek as part of its upcoming proposed biennial CPIRP.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 18-20

Existing Resources – SLR

The evidence supporting these findings of fact is in Duke's Carbon Plan proposal, the direct and rebuttal testimony of Duke's Long Lead-Time Resource Panel, the direct testimony of Duke's Modeling and Near-Term Actions Panel (Snider), the direct testimony of Public Staff witness Metz, the direct testimony of CIGFUR witness Gorman, and the entire record in this proceeding.

Duke's Long Lead-Time Resource Panel testified that Duke currently operates 11 nuclear generation units that provide a total capacity of approximately 11,100 MW, over 50 percent of Duke's total electric generating capacity. The Panel stated that the existing nuclear fleet provides baseload generation to Duke's customers in North Carolina and South Carolina and that the existing nuclear fleet provides approximately 83% of all Duke's carbon-free electric generation.

In Appendix D, Table D-14 of Duke's Carbon Plan proposal, Duke includes a list of its existing nuclear generating facilities that denotes each facility's jurisdiction (DEC or DEP), location, date of the original operating license expiration, date of the Nuclear Regulatory Commission's (NRC's) approval of the initial extended operating license, and date of the initial extended operating license expiration, which is the current operating license expiration for each facility. Duke's Long Lead-Time Resource Panel explained that each of Duke's existing nuclear facilities has obtained an initial renewal of the operating license, extending the operational life of each facility to their current expiration dates. Due to these initial license renewals, the earliest unit's license is set to expire in 2030 and the last unit's license will expire in 2046. The Panel contended that SLR will extend the operating life of each nuclear generating facility by 20 years beyond the current operating license expiration. With SLR approval, the retirements for the nuclear fleet will shift to 2050 through 2066.

Duke's Modeling and Near-Term Actions Panel (Snider) testified that continued operation of the existing nuclear fleet is essential to achieve the 2050 Target, and all of Duke's proposed portfolios rely on SLR of the existing nuclear fleet. The Panel asserted that SLR of the existing nuclear fleet is foundational to Duke's Carbon Plan proposal and that achieving the carbon dioxide emissions reduction mandates N.C.G.S. § 62-110.9 sets will not be possible from reliability, cost, and executability perspectives without the relicensing of the existing nuclear fleet. Tr. vol. 12, 16.

No party opposes Duke's pursuit of SLR for the existing nuclear fleet. Public Staff witness Metz testified that no intervenors engaged in a substantive discussion of the specifics of Duke's SLR proposal. Witness Metz asserted that the existing nuclear fleet can serve as a foundational component for compliance with the carbon dioxide emissions reduction mandates of N.C.G.S. § 62-110.9. However, he testified that the Public Staff is not advocating that Duke pursue SLR blindly. He stated that Duke must demonstrate that costs associated with SLR of the existing nuclear fleet are reasonable and prudent before Duke may recover those costs from ratepayers. Finally, witness Metz recommended that in future Carbon Plan filings Duke clearly lay out a schedule for pursuit of SLR for each existing nuclear unit and develop a contingency plan should any nuclear unit not achieve SLR in time to continue operations.

Both Duke's Long Lead-Time Resource Panel and Public Staff witness Metz detailed the regulatory process for SLR of nuclear facilities. They each explained that SLR requires regulatory approval by the NRC and is necessary to extend the operational life of each nuclear facility by 20 years. Witness Metz testified that in early 2022, the NRC reset the SLR applications of two nuclear facilities, neither of which Duke owns or operates. He stated that typically, SLR requests have taken approximately two years to complete but may take longer if the NRC triggers a re-evaluation of a SLR. He asserted that, because Duke's earliest nuclear license will not expire until 2030, Duke has adequate time to address this topic in future Carbon Plan updates. He also recommended that Duke review the SLR applications that the NRC reset in early 2022 and incorporate any lessons learned when preparing its SLR applications.

Regarding the operational timeline for the existing nuclear fleet, Duke's Long Lead-Time Resource Panel explained that if Duke successfully obtains SLR, the retirement dates for the existing nuclear fleet will shift to the earliest retirement occurring in 2050 and the last retirement occurring in 2066. Appendix D of Duke's Carbon Plan proposal notes that Duke's earliest nuclear operating license is set to expire on July 31, 2030, for Robinson Unit 2. Duke's last nuclear operating license is set to expire on October 24, 2046, for Harris Unit 1. CIGFUR witness Gorman pointed out that without SLR of the existing nuclear generation fleet, Duke will lose approximately 793 MW of capacity in 2030 and a total of approximately 4,400 MW of capacity by 2035.

Finally, Public Staff witness Metz discussed NC WARN's recommendation that Duke convert its existing nuclear fleet to synchronous condensers after 2035. Witness Metz asserted that NC WARN's idea is novel but is likely not the best utilization of Duke's nuclear fleet. He stated that NC WARN does not provide substantive discussion to support its recommendation and does not identify alternative resources that would be necessary to replace the approximate 11 GW of nuclear base load capacity. For these reasons, the Commission agrees with the Public Staff that it is not appropriate for Duke to consider conversion of the existing nuclear fleet to synchronous condensers at this time.

Given that Duke's existing nuclear generation fleet provides baseload electric generation for customers in North Carolina and South Carolina, that the existing nuclear fleet provides a significant portion of carbon-free electric generating capacity, and that no party contests Duke's pursuit of SLR for the existing nuclear fleet, the Commission concludes that it is reasonable and appropriate for Duke to pursue SLR of the existing nuclear fleet. Further, based on the recommendations of the Public Staff, the Commission directs Duke to develop a schedule detailing its plans for SLR of the existing nuclear fleet and provide this information in its upcoming CPIRP filing. The Commission also directs Duke to review the SLR applications that the NRC reset in early 2022 and to incorporate any lessons learned in the preparation of Duke's SLR applications for its existing nuclear fleet.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 21

Existing Resources – Natural Gas Fleet

The evidence supporting this finding of fact is in Duke's Carbon Plan proposal, the direct and rebuttal testimony of Duke's Modeling and Near-Term Actions Panel, the testimony of Duke's Reliability Panel, the direct testimony of Public Staff witness Metz, and the direct testimony of AGO witness Burgess.

Duke requests that the Commission approve Duke expanding the flexibility of its existing natural gas fleet, naming projects that support more flexible operational capabilities of the natural gas fleet, including increasing up and down ramp rates, improving minimum load capabilities, and reducing minimum up and minimum down time to increase a gas-fired plant's ability to cycle more often. Tr. vol. 7, Duke Petition for Approval, 10-11, 16.

Duke's Modeling and Near-Term Actions Panel testified that achieving increased flexibility of the existing gas fleet is critical to successfully achieving the carbon dioxide emissions reduction mandates that N.C.G.S. § 62-110.9 establishes. Tr. vol. 7, 325-26. Appendix Q to Duke's Carbon Plan proposal explains that in coordination with energy storage, operating the CC fleet more flexibly to meet the ramping and cycling demands of portfolios with significantly increased amounts of intermittent resources will be necessary to maintain system reliability in all portfolios to achieve N.C.G.S. § 62-110.9's carbon dioxide emissions reduction mandates. Tr. vol. 7, Duke Proposed Carbon Plan, App. Q, 10. Appendix Q further explains that Duke has historically designed and operated its CC fleet specifically for baseload operations and has faced a limited need to cycle given the flexibility of the remaining generators. *Id*. Duke's Modeling and Near-Term Actions Panel testified, however, that for some of the proposed Carbon Plan portfolios to meet the carbon dioxide emissions reduction requirements of N.C.G.S. § 62-110.9, the majority of the CC fleet will require daily cycling for certain periods of the year in order for the system to receive injections of zero-carbon energy. Tr. vol. 7, 367-68. This operational approach will be new to Duke's fleet and will likely require changes to operations and maintenance practices as well as investments and upgrades to increase unit flexibility. Tr. vol. 7, Duke Proposed Carbon Plan, App. Q, 10.

Duke's Reliability Panel testified that "[t]o maintain the grid, System Operators require adequate flexible and dispatchable operational reserves that can *persist* through prolonged extreme weather events." Tr. vol. 30, 106 (emphasis in original). This change in mission is particularly important as Duke retires remaining coal units and the system increasingly depends on intermittent renewable resources and limited duration storage technologies. Tr. vol. 7, Duke Proposed Carbon Plan, Chs. 3, 5; *see also* tr. vol. 7, 302 ("As the Companies reduce dependence on dispatchable fossil fuels and increase dependence on intermittent resources, prudent utility planning and HB 951 requires that this transition be planned and executed in a manner that does not impact reliability to customers."). The Reliability Panel testified that natural gas is "a bridge to integrate more renewables and batteries until hydrogen and long-duration storage and [zero emissions load following resources] are available and can replace at scale what gas contributes to the system." Tr. vol. 30, 106. The Modeling and Near-Term Actions Panel testified that expanding the flexibility of Duke's existing natural gas fleet "will allow the Companies to maintain system reliability and quality of service while integrating intermittent resources, such as wind and solar, that may not match customer demand." Tr. vol. 7, 325.

Public Staff witness Metz testified that the Public Staff supports expansion of the flexibility of the existing natural gas fleet provided that Duke identifies a targeted need for flexibility expansion on a project-by-project basis and that such projects prove to be least cost in order to meet required carbon dioxide emissions reductions. He testified that, as Duke's electric generation portfolio and load shapes change, Duke will be better able to identify specific flexibility expansion requirements for the existing natural gas fleet in future Carbon Plans. The Public Staff maintains that any expansion projects of the existing natural gas fleet to achieve flexibility in operations should demonstrate through cost-benefit analyses that the added benefits to flexibility justify the costs and that system flexibility cannot be achieved by alternative means. Public Staff Initial Comments at 159-60.

AGO witness Burgess testified that enhancing the flexibility of the existing natural gas fleet is one method to support renewable resource integration without the need to invest in construction of new generation. Tr. vol. 25, 303.

The Commission acknowledges that the ability to operate the fleet of natural gas resources to meet the ramping and cycling demands of portfolios with significantly increased amounts of variable and time-limited resources will be necessary to maintain system reliability while achieving the carbon dioxide emissions reduction requirements of the statute. Further, the transition of the generating fleet as well as the anticipated changes in load shapes will require system operators to have resources at the ready that are flexible in their ability to meet these new challenges. The Commission agrees with the Public Staff that the expansion of the existing natural gas fleet to allow for operational flexibility is necessary but expects Duke to identify targeted needs for expansion projects that will enhance flexibility and that meet the least cost path to compliance mandates. The Commission directs Duke to identify specific natural gas plants or regions of its service areas that would benefit from flexibility expansion projects and update the Commission on its analysis, including any change in carbon dioxide emissions from these changes, in future Carbon Plans.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 22-27

The Role of Natural Gas

The evidence supporting these findings of fact is in Duke's Carbon Plan proposal, the testimony of the Duke Modeling and Near-Term Actions Panel, the testimony of Duke's Reliability Panel, the Initial Comments of the Public Staff, the testimony of Public Staff witness Thomas, the testimony of Public Staff witness Metz, the testimony of AGO witness Burgess, the Initial Comments of Appalachian Voices, the Initial Comments of CUCA, the Initial Comments of CIGFUR, the testimony NCSEA et al. witness Fitch, the

Initial Comments of NCSEA, the testimony of Tech Customers witnesses Borgatti and Kimbrough, and the entire record in this proceeding.

Duke asserts that natural gas plays a vital role in its compliance with N.C.G.S. § 62-110.9. Duke witnesses Holeman and Roberts explained that to meet the statutory mandates to maintain or improve upon the reliability of the existing grid during the transition, firm, dispatchable natural gas-fired generating resources serve as a reliability "bridge" to achieving carbon neutrality while filling the resource adequacy needs created by the retirement of coal units. Tr. vol. 19, 164, 183. Duke further explains that it will design any new natural gas-fired generating units to transition to using hydrogen blended with natural gas and to ultimately be able to utilize 100% hydrogen. Tr. vol. 7, Duke Proposed Carbon Plan, App. M.

Duke used several fuel side assumptions and constraints in modeling new natural gas units as selectable resources, including access to natural gas supply, the price of natural gas, the potential for hydrogen fuel to replace natural gas, and the asset life of new natural gas facilities. Those assumptions and constraints are discussed in the following sections.

Access to Natural Gas Supply Assumptions

Duke's four proposed portfolios assume a limited amount of firm transportation capacity to provide natural gas from the Appalachian region. Tr. vol. 7, Duke Proposed Carbon Plan, Ch. 2, 24. Duke's Modeling and Near-Term Actions panel testified that using limited Appalachian natural gas accessibility follows the least cost planning principles and is in the best interest of ratepayers. The panel further testified that without this assumption Duke would face "increased fuel assurance risk, increased customer fuel cost exposure and increased risk of delayed coal retirements." Tr. vol. 7, 370.

DEC's and DEP's CC fleet is "currently deficient of interstate pipeline firm transportation capacity due to the cancellation of Atlantic Coast Pipeline (ACP)." Tr. vol. 7, Duke Proposed Carbon Plan, App. N, 7. Duke's Carbon Plan proposal indicates that "the major interstate pipeline supplying the Carolinas is fully subscribed, and during the coldest winter days, the gas demand for electricity generation coincides with peak Local Distribution Company demand. Currently, obtaining delivered gas supply into the Carolinas from the marketplace during these periods of high demand is constrained. The constrained market also leads to gas supply that can be cost prohibitive, if even available at volumes required." Tr. vol. 7, Duke Proposed Carbon Plan, App. Q, 5.

In the rebuttal testimony of its Modeling and Near-Term Actions panel, Duke clarifies that

> the Companies currently hold 434,560 Dth/day of Transco Firm Transportation capacity under long-term contracts that provides non-Zone 5 firm fuel supply. While this volume does not meet the natural gas needs of the entire CC fleet, this volume is greater than the peak day needs of the three gas-only combined

> cycles in the fleet. Additionally, the Companies contract with third parties to deliver firm fuel supply to the Companies in Zone 5.

Tr. vol 27, 87.

In response to concerns the Public Staff and other intervenors expressed, Duke performed supplemental modeling that assumed no access to Appalachian gas supply as the base planning scenario and utilized the Public Staff's recommendation to allow Transco Zone 4 to supply all existing CC units as well as incremental Transco firm transportation to supply for two large, or three small, CC units. Tr. vol. 7, 251. This supplemental modeling, identified as portfolios SP5 and SP6, also excluded the selection of hydrogen fuel and instead relied on up to 5% carbon offsets in 2050. *Id.* The supplemental portfolios also allowed the selection of between 1,200 MW advanced J-Class and smaller 800 MW F-Class CCs. Tr. vol. 7, Duke Modeling and Near-Term Actions Panel Ex. 1, 7-8.

Public Staff witness Thomas testified that Duke's assumptions regarding access to natural gas supply are not reasonable and emphasized concerns regarding the availability of Appalachian natural gas to electric generating facilities in North Carolina. He noted that SP5 and SP6 included natural gas assumptions that the Public Staff recommended and that the changes modeled in SP5 have resulted in a shift of the location of CC plants. In the original four portfolios of Duke's Carbon Plan proposal, one CC was selected to be located in DEC and one in DEP, both in 2029. However, in SP5, both CCs are located in DEC's territory, and the need for one of the CCs is delayed until 2030. Public Staff witness Thomas testified that even if Appalachian gas is made available to North Carolina via the MVP and/or the MVP Southgate Pipeline, it is unclear whether this gas will have a firm intrastate pathway to locations in DEC's territory. Witness Thomas concludes that the Public Staff supports the "No App Gas" supply assumptions Duke used in SP5 and SP6 and notes that developments related to the MVP and MVP Southgate projects will be a matter of debate in future CPCN and Carbon Plan proceedings. Tr. vol. 21, 73-74.

The AGO, NCSEA et al., Tech Customers, CUCA, and CIGFUR also raise concerns regarding Duke's assumptions associated with access to natural gas supply. AGO witness Burgess argues that Duke lacks sufficient access to firm transportation capacity for its existing fleet and that new natural gas-fired generating facilities will introduce a new reliability risk in cold weather. Tr. vol. 25, 267. NCSEA et al. witness Fitch and Tech Customers witness Borgatti make similar assertions. Tr. vol. 24, 158; Tr. vol. 25, 59.

CIGFUR supports the addition of new natural gas-fired generating facilities but also expresses concern regarding reliability impacts if Duke is unable to secure an adequate supply of natural gas or to access sufficient firm pipeline capacity, or if the MVP is not placed into service. CIGFUR Initial Comments at 19. CUCA also supports natural gas but likewise raises concern that Duke's Carbon Plan proposal does not adequately address how to obtain additional firm transportation capacity for natural gas. CUCA Initial Comments at 9-10.

Natural Gas Price Assumptions

Duke's natural gas price forecast method relies on five years of natural gas market-based pricing, followed by three years of transition from market-based pricing before fully utilizing a fundamentals-based natural gas pricing forecast starting in 2031 for the remaining period. Tr. vol. 7, Duke Proposed Carbon Plan, App. E, 39. Given the variation in natural gas price forecasts among fundamentals providers, Duke developed its fundamentals-based forecast by averaging four recent natural gas price forecasts: (1) EIA's Annual Energy Outlook Reference case (2021 AEO); (2) Wood Mackenzie North American Power Markets (Base Case) (2021); (3) EVA FuelCast (2021); and IHS Markit Long-Term Natural Gas Outlook (August 2021). *Id*. at 39-40. In addition to the alternate gas supply sensitivity analysis, Duke performed a natural gas price portfolio sensitivity analysis on certain portfolios to assess whether the selection of natural gas resources would be affected by the adoption of high price forecasts. Tr. vol. 7, Duke Proposed Carbon Plan, Ch. 3, 13. However, even under the high gas price case, the model selected new natural gas capacity as least cost under these portfolios. *Id*.

Public Staff witness Thomas stated that the natural gas price forecasts that Duke used in its Carbon Plan proposal are reasonable and an improvement over prior methods Duke used in IRPs. Tr. vol. 22, 67-68. He further noted that the Public Staff is concerned with the risk to ratepayers in overreliance on natural gas considering recent increases in natural gas commodity prices. However, witness Thomas noted that, as Duke's Carbon Plan proposal reflects, ratepayers' exposure to volatile natural gas prices is less due to the decline in natural gas fuel consumption, which peaks around 2026 in all four portfolios and steadily declines through the remainder of the planning period. *Id.* at 70-71.

Witness Thomas acknowledged that, similar to the IRP process, modeling for the Carbon Plan is a complex task and typically begins six to nine months in advance of a filing. *Id.* at 71. Witness Thomas noted that fuel price forecasts are typically "locked in" by that time and that procedural schedules that allow for frequent updates and a reliance on robust portfolios that cover a range of issues temper the consequences of unanticipated changes in the market. *Id.* at 72. For example, he testified, the 2024 Carbon Plan update proceedings will utilize updated natural gas price forecasts. If future gas prices appear elevated at that time, the revised near-term action plan will reflect that forecast. *Id.*

Witness Thomas noted that more recent natural gas price forecasts continue to predict gas prices declining between 2023 and 2029, well before natural gas plants are economically selected in Duke's Carbon Plan proposal. *Id.* Last, witness Thomas noted that Duke must also obtain a CPCN for any new gas resources and that the Commission and the Public Staff will evaluate in detail the reasonableness of proposed natural gas plants after Duke files the CPCN application, which will include an analysis of the most recent gas price forecasts and market conditions. *Id.* at 73. For all these reasons, witness Thomas explained, the Public Staff does not recommend any changes to Duke's natural gas forecasting methodology or that the Commission direct Duke to update natural gas price forecasts. *Id*. at 67, 70.

On behalf of the AGO, witness Burgess expressed concern that Duke developed its plan before the recent and significant increase in natural gas prices driven in part by Russia's invasion of Ukraine and that current spot prices are significantly higher than the "worst case scenario" that Duke modeled in its Carbon Plan proposal. Tr. vol. 25, 264. Witness Burgess argued that there is uncertainty regarding when or if current prices will eventually subside and "return to normalcy." *Id.* at 264-65.

Appalachian Voices, Tech Customers, CUCA, NC WARN, and NCSEA et al., similarly raise concerns that Duke's natural gas price forecasts do not reflect the recent surge in natural gas prices. Appalachian Voices Initial Comments, Attach. A - PSE Health Report at 4-5; Tech Customers Initial Comments, Gabel Report at 29-30; CUCA Initial Comments at 10-12; tr. vol 22, 196; NCSEA et al. Initial Comments at 5-6.

Hydrogen Fuel Assumptions, Asset Life of New Natural Gas Facilities, and Other Natural Gas Capital Cost Assumptions

Duke states that while it designed its existing fleet of natural gas-fired generators to operate by utilizing natural gas or fuel oil, hydrogen could potentially blend with or replace existing fuels with some modifications to the CTs. Tr. vol. 7, Duke Proposed Carbon Plan, App. N, 7-8. Duke's Carbon Plan proposal models hydrogen capable simple-cycle CT capacity additions with sufficient ultra-low sulfur diesel back-up to eliminate the need for interstate firm transportation natural gas capacity. Tr. vol. 7, Duke Proposed Carbon Plan, Ch. 2, 24. Duke represents hydrogen blending in its modeling with a starting point of 3% in 2035 and ramping up in several steps to 15% by 2041 and holding steady thereafter. Duke applies this blend to all natural gas assets existing or added before 2040. Duke's modeling assumes any new peaking CT units built in the 2040s are capable of being 100% hydrogen fueled. By 2050, the modeling assumes all existing CT and CC units continuing to operate on the system as well as all CTs and CCs Duke adds to the portfolios operate on hydrogen to achieve zero carbon dioxide emissions by the end of the planning horizon. *Id*. at 25.

Appendix E to Duke's Carbon Plan proposal explains that for planning purposes Duke assumed a 35-year asset life for new natural gas units selected under the model. Tr. vol. 7, Duke Proposed Carbon Plan, App. E, 31-32. For selectable CTs, Duke used a J-Class Frame CT with a selective catalytic reduction (SCR), with dual-fuel operations on natural gas and ultra-low sulfur diesel as the generic unit assumptions. According to Appendix E, this technology is a more efficient and flexible combustion technology than the F-Class Frame CTs that comprise the majority of Duke's existing peaking CT technologies. The J-Class Frame CTs also are currently more hydrogen capable than the F-Class Frame CTs and compatible with conversion to 100% operation on hydrogen in the future. *Id*. at 30. With respect to CCs, Duke used two configurations for the Carbon Plan: (1) a 2x1 J-Class CC with Duct Firing (CC-J) as the generic unit assumption; and (2) a 2x1 F-Class CC with dual fuel capabilities (CC-F), operating on both natural gas and ultra-low sulfur diesel (ULSD) in the alternate fuel supply sensitivity. *Id*. at 30-31.

Duke's Modeling and Near-Term Actions Panel's rebuttal testimony highlights that the IRA and IIJA provide potential funding and significant incentives to promote near-term development and scale up of the hydrogen economy. Tr. vol. 27, 76-77. The Modeling and Near-Term Actions Panel explained that these new policy incentives for developing hydrogen fuel further increase the likelihood of Duke's original planning assumption and reduce alleged stranded cost risk associated with the limited CC and CT capacity that Duke is recommending in its near-term actions. *Id.* at 77. During the hearing, witness Snider stated that Duke has other options to ensure that new natural gas assets will not be stranded, including offsets and sequestration. In addition, if no other technology comes to fruition, N.C.G.S. § 62-110.9 allows Duke to continue running natural gas resources on a limited basis if needed to maintain reliability. Tr. vol. 10, 100; Tr. vol. 27, 271.

The Modeling and Near-Term Actions Panel also acknowledged that, as part of the CPCN process, Duke will continue to evaluate the impact of changing resource technology costs, tax incentives, and commodity pricing with respect to the overall economics and need for a project, including project-specific cost estimates rather than generic cost estimates Duke uses in planning. *Id.* Duke also plans to update its IRPs soon to assess changing market conditions, including updated commodity price forecasts, technology cost projections based on prevailing market conditions, and a more comprehensive analysis of the tax benefits attributable to the IRA. The CPCN application will provide detailed updates to project costs, commodity costs and many other project and site-specific considerations while the 2023 IRP update will assess changing market conditions from a system perspective. Tr. vol. 27, 59-60.

The Public Staff expresses concern regarding the inclusion of hydrogen in the Carbon Plan modeling. The Public Staff notes that Duke bases its assumptions regarding the availability of hydrogen fuel on achieving United States Department of Energy (DOE) target electrolysis efficiencies and having sufficient excess renewable energy to produce the necessary quantities of hydrogen. Public Staff Initial Comments at 16. Accordingly, in the Public Staff's view, incorporating hydrogen fuel conversion assumptions for new natural gas CC and CT capacity represents a portfolio risk because if the production and blending of hydrogen does not materialize, meeting the carbon dioxide emissions reduction mandates will require substantial new generation to replace natural gas plants that would become stranded assets for which ratepayers would be responsible. *Id.* Accordingly, the Public Staff recommends that Duke not include hydrogen in base case modeling at this time. Tr. vol. 21, 47; Public Staff Initial Comments at 76. Nevertheless, the Public Staff acknowledges that Duke should consider hydrogen in an alternative portfolio analysis until Duke and the hydrogen industry resolve uncertainty around development risk, deliverability, and cost. *Id*.

Witness Thomas explained that the Public Staff finds Duke's modeling based on a 35-year useful life for natural gas-fired electric generating resources to be reasonable, and the Public Staff does not recommend any changes to either the capital costs or operable life assumptions in this proceeding. Tr. vol. 21, 81-82. Witness Thomas stated that the Public Staff is not persuaded by Tech Customers' Gabel Report or witness Kimbrough that Duke's capital cost assumptions for new natural gas resources are out of line with market benchmarks. While witness Thomas acknowledged that the publicly available sources the Gabel Report and witness Kimbrough cite were higher than Duke's assumptions, witness Thomas stated that Duke's assumptions are more reasonable for a number of reasons. *Id.* at 380. Public Staff witness Metz also highlighted that the Commission and the Public Staff extensively considered the issue of CT capital costs in recent avoided cost proceedings. *Id*. at 379.

AGO witness Burgess suggested that many of the cost assumptions Duke used to model hydrogen resources are speculative and that the feasibility of Duke's plan to utilize hydrogen is questionable. Tr. vol. 25, 271. Regarding Duke's cost assumptions, witness Burgess argues that the potentially significant future cost of hydrogen conversion of gas resources is largely missing because Duke only performed PVRR calculations through 2050. *Id.* Regarding the feasibility of hydrogen, witness Burgess noted that the availability of a robust hydrogen market by 2050 remains uncertain. *Id.* at 272.

Accordingly, AGO witness Burgess argues that Duke should model new CC and CT units assuming 20-year lifetimes, rather than the 35-year lifetimes that Duke has assumed, at least until there is more clarity on the future of the hydrogen market. According to witness Burgess, it may also make sense to delay a decision on new CC and CT additions as long as possible in order to monitor the development of clean hydrogen technologies, gain further clarity on costs, and avoid stranded asset risks for consumers. *Id.* at 273.

Tech Customers similarly argue that hydrogen generation is not commercially viable and is, therefore, too speculative for Duke to include in future planning. Tr. vol. 25, Tech Customers Initial Comments, Gabel Report, 4. As noted above, Tech Customers witness Kimbrough questions the reasonableness of Duke's capital cost assumptions for new natural gas-fired resources, suggesting they are out of line with a number of national industry publications that show higher costs for a single unit site. Tr. vol. 25, 79; *see also* tr. vol. 25, Tech Customers Initial Comments, Gabel Report, 8. According to witness Kimbrough, Duke assumes that natural gas-fired CC and CT units will be approximately 27% less expensive than market benchmarks for comparable resources, while capital cost assumptions for solar and battery storage resources is approximately 12% to 59% more expensive than market benchmarks. According to witness Kimbrough, the combined impact of these purported cost disparities means that the model is more likely to select new gas resources over new solar or battery storage resources. Tr. vol. 25, 249.

NCSEA et al. witness Fitch argued that it may not be technically feasible or cost-effective in the future to convert and operate combustion turbines on hydrogen. Tr. vol. 24, 158. Witness Fitch noted that if technical issues prevent cost-effective turbine conversion or a sufficient supply of zero-carbon hydrogen is not available, existing and planned gas plants risk becoming obsolete, and the burden of paying off stranded gas assets will fall on either shareholders or Duke's ratepayers. *Id.* at 158-59.

NCSEA et al. recommend several revisions to Duke's Carbon Plan proposal inputs and modeling assumptions, including increasing capital costs for new natural gas resources to align with the EIA's Annual Energy Outlook 2022, and reducing the operational and book life of gas CCs and CTs from 35 years to 25 years for operational life and 20 years for the purposes of natural gas plant depreciation. Tr. vol. 25, NCSEA et al. Initial Comments, Synapse Report, 10. According to NCSEA et al. witness Fitch, this approach avoids stranded asset risk as carbon requirements decline toward zero by 2050. Tr. vol. 25, 160.

Timing of Natural Gas Generation Additions

Multiple parties recommend that the Commission delay selecting new natural gas-fired generating resources. AGO witness Burgess argued that the Commission should delay a decision on new CT or CC additions in order to monitor costs and hydrogen development and in order to avoid the possibility of stranded costs. *Id.* at 271. AGO witness Burgess also noted that Duke did not include an evaluation of the conversion of Belews Creek to natural gas and recommends that conversion of Belews Creek to natural gas should be an option in the resource model. *Id.* at 290. At the hearing AGO witness Burgess further noted that there is already existing gas infrastructure at these units. *Id.* at 339.

In its Initial Comments, CIGFUR contends that Duke failed to adequately consider, as a potentially more cost-effective alternative solution to reducing carbon dioxide emissions, retrofitting existing coal plants to burn natural gas as a means of extending the life of the assets. CIGFUR Initial Comments at 19-20.

Regarding the conversion of coal units to utilize exclusively natural gas, Duke responds that it evaluated the high-level business case of expanding natural gas co-firing beyond the current 50% at Belews Creek and Marshall, but that while the expansions were potentially feasible, subject to detailed engineering studies to confirm, the evaluation did not indicate favorable economics. Tr. vol. 7, 332; tr. vol. 27, 85.

Tech Customers recommend that the Commission defer a decision to invest in new natural gas generation resources in this proceeding and eliminate new CCs as a selectable resource in their modeling. Tr. vol. 25, 57; tr. vol. 25, Tech Customers Initial Comments, Gabel Report. According to the Gabel Report, natural gas plants built in the early 2030s will survive well past 2050, and their cost-effectiveness is heavily reliant on Duke's assumptions regarding green hydrogen. Tr. vol. 25, Tech Customers Initial Comments, Gabel Report, 29. The Gabel Report also argues that new gas generation is not necessary until at least 2029 and may not be necessary at all given that investment in evolving technologies like battery storage could satisfy the capacity need. *Id*. at 30. To avoid the construction of new natural gas units and the risk of stranded assets, the Gabel Report suggests that Duke may be able to expand its contract capacity with existing North Carolina resources, including the Cleveland CT, Rowan CT, and Rowan CC, when those facilities' existing contracts with other purchasers expire. *Id.* at 30-31.

Duke argues that delay of the new natural gas-fired resources would limit its ability to retire its existing coal units. The Modeling and Near-Term Actions Panel's testified that Duke's planned coal unit retirements require replacement resources that can provide firm, dispatchable, and equally reliable capacity like peaking CTs and baseload CCs. Without such replacement resources, Duke cannot retire coal on an accelerated schedule. Tr. vol. 27, 80-81. The Panel noted that delaying a single natural gas CC and keeping an equivalent amount of coal online results in an increase of nearly two million tons of carbon dioxide on the system in the year 2030. *Id.* at 80.

Conclusions on Natural Gas

The assumptions related to natural gas and the role of natural gas-fired generating resources reflect one of the most significant resource planning decisions in this proceeding. Duke's near-term action plan includes 1,200 MW of new CCs and 800 MW of new CTs. Based upon the foregoing and the entire record in this proceeding, the Commission makes the following conclusions.

The Commission gives substantial weight to the fact that Duke's modeling across all portfolios, supplemental portfolios, and Duke's preliminary additional IRA sensitivity analysis demonstrate a need for new CCs as part of a least cost plan to continue the energy transition, to retire coal resources, and to meet the mandates of N.C.G.S. § 62-110.9. Selection of new CC capacity in Duke's Carbon Plan proposal's initial high gas sensitivity, supplemental modeling analysis, as well as preliminary IRA modeling provide further evidence of the need for limited new natural gas CC resources as part of least cost portfolio. Numerous modeling portfolios, including intervenor-sponsored modeling, also identified the need for new natural gas CTs by 2030. Additionally, the Commission recognizes Duke witness Roberts' testimony that generator replacement (natural gas replacing coal) on existing sites may obviate the need for investment in significant transmission upgrades at certain sites.

With respect to access to gas supply, the Commission agrees with Duke, the Public Staff, and other parties that there continues to be significant uncertainty around the sufficiency of interstate natural gas transportation capacity to deliver gas into North Carolina. However, Duke's Modeling and Near-Term Actions Panel has explained, in detail, a plan to obtain firm transportation of new natural gas to its system in a variety of contingencies. The Commission is persuaded that Duke will be able to pivot to an alternate plan if the MVP is never completed or not timely completed. However, the Commission concludes that the execution risk associated with fuel deliverability for Duke's natural gas-fired electric generating resources warrants, at least for the initial CPIRP filing, the modeling of portfolios with appropriate sensitivities to capture feasible fuel deliverability options for applicable future years. Thus, the Commission directs Duke to use natural gas pricing and supply assumptions that reflect the most recent developments that would impact natural gas access in North Carolina, including the development of natural gas pipeline capacity.

With respect to the method for developing the natural gas price forecast, the Commission concludes that the natural gas price forecast method Duke used in the Carbon Plan proposal is reasonable. Further, the Commission reiterates the following provision from its recent Order in the 2021 Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities proceeding:

> The Commission further notes that once the Commission approves the Carbon Plan, the natural gas forecasting method proposed by Duke in its Carbon Plan will be more appropriate for use in the subsequent avoided cost biennial proceeding. The Commission agrees with the Public Staff that consistency is appropriate and warranted.

Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, *2021 Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities,* No. E-100, Sub 175, 23 (Nov. 22, 2022). Accordingly, the Commission directs Duke to use the method approved herein in its proposed biennial CPIRP and in subsequent avoided cost proceedings.

With respect to the assumptions related to capital cost and operational life, the Commission gives substantial weight to the Public Staff's testimony that Duke's CC and CT capital cost assumptions and 35-year operational life assumptions are reasonable for planning purposes, even though the Public Staff believes it is premature to include hydrogen. The Commission notes that although the ability to select hydrogen was completely removed from SP5 and SP6 at the Public Staff's recommendation, those models allowed for the use of carbon offsets and selected a natural gas CT generating unit. Tr. vol 21, 75. While the Commission understands the Public Staff's and certain intervenors' position that there remains uncertainty in the development of a hydrogen market, the Commission does not believe it would be reasonable to reduce the operable life of new natural gas resources for modeling purposes or to exclude hydrogen as a selectable resource at this time. Duke witnesses stated that Duke intends to "check and adjust" these assumptions as part of the 2024 Carbon Plan proceeding, and the Commission will reassess the reasonableness of those assumptions at that time.

To reassess the reasonableness of the 35-year operational life assumption, the Commission directs Duke to provide additional information on the appropriateness of this assumption in its future filings. In response to a question on the options available for new natural gas generation resources after 2050, Duke witness Snider responded that the options are conversion to hydrogen, the offset market, sequestration, or long-duration storage. Tr. vol 27, 271. If Duke uses an operational life for any new natural gas generation facility longer than 20 years, the Commission directs Duke to provide additional information outlining why this assumption continues to be reasonable, including an analysis of its modeling inputs for the cost of the options witness Snider outlines for the natural gas generation facilities after 2050.

The Commission gives substantial weight to Duke's testimony that Duke's planned coal unit retirements require replacement resources that can provide firm, dispatchable, and equally reliable capacity like peaking CTs and baseload CCs and that without such replacement resources, Duke cannot retire coal on an accelerated schedule. The Commission also takes note that Duke argues that delay of the new natural gas resources would limit its ability to retire its existing coal units. The Commission likewise gives substantial weight to Duke's testimony that the limited new natural gas CC and CT resources Duke identifies in the near-term action plan are essential to achieving the Interim Target, while maintaining or improving reliability, and doing so along a least cost path. In particular, the Commission is persuaded by the testimony of Duke witnesses Holeman and Roberts that Duke needs flexible and dispatchable new gas resources on the system as Duke moves forward with retiring 8,400 MW of coal unit capacity by the end of 2035. Similarly persuasive was the Modeling and Near-Term Actions Panel's testimony that failing to develop new natural gas resources jeopardizes Duke's ability to achieve the mandated carbon dioxide emissions reduction, including witness Snider's testimony that new CC capacity resources are approximately 60% less carbon dioxide emitting per MWh compared to the coal they are replacing.

The Commission also gives substantial weight to Public Staff witness Thomas' testimony that almost all the proposed portfolios include natural gas CC in the near-term, and that if new natural gas facilities are not an option, then Duke may need to consider delaying its planned coal retirements. Tr. vol. 23, 47-48.

Finally, the Commission finds persuasive Duke's testimony that a failure to consider new natural gas resources may increase the cost of operating the system and curtail future longer-term development of the hydrogen economy or appropriately structure a North Carolina carbon offset market that may provide a pathway for continued operation of new CC and CT resources beyond 2050 in a manner consistent with N.C.G.S. § 62-110.9.

The Commission determines that planning for approximately 800 MW of CTs and a CC of up to 1,200 MW is a reasonable step for Duke to take at this time. This should include assessing replacement generation options at the sites of retiring coal units on the DEC and DEP systems. However, as multiple parties note, the availability of interstate pipeline firm transportation capacity is an ongoing concern. If and when Duke applies for a CPCN for any new natural gas-fired generating facility, the Commission will evaluate the need for the facility, using this 2022 Carbon Plan as one factor in determining the need. The Commission will also evaluate the projected costs of the facility, including all the costs associated with construction of the facility itself. The Commission will also consider the availability of firm transportation capacity to North Carolina, the status of any necessary pipeline expansion projects, and the availability of firm intrastate pipeline capacity. Due to uncertainty of interstate transportation as well as the very recent enactment of the IRA, it would not be appropriate to give the Commission's approval for planning purposes of 800 MW of CTs and 1,200 MW of CC dispositive weight in the future related CPCN proceedings. The Commission directs Duke to include in its initial CPIRP filing a detailed discussion of interstate transportation capacity and modeling analysis to demonstrate that any natural gas resource selected in future plans continues to be part of the least cost path to compliance.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 28-33

Near-Term Development and Procurement Actions for New Standalone Solar Generation, Solar Plus Storage, Standalone Battery Storage, and Onshore Wind

The evidence supporting these findings of fact is found in Duke's Carbon Plan proposal, the direct and rebuttal testimonies of the Duke Modeling and Near-Term Actions Panel, the direct testimony of the Duke Utilities Operations Panel, the direct testimony of the Duke Transmission Panel the direct testimony of Public Staff witnesses Thomas, Metz, and McLawhorn, AGO witness Burgess, CCEBA witness DiFelice, CPSA witnesses Norris and Hagerty, Tech Customers witness Borgatti, NCSEA et al. witness Fitch, and CIGFUR witness Muller; and the entire record in this proceeding.

Duke's proposed near-term plan for new supply-side resources includes: (1) 3,100 MW of solar generation (including the capacity targeted to be procured in the 2022 Solar Procurement Program[12]), of which a substantial portion is assumed to include Solar Plus Storage; (2) 1,600 MW of battery storage (comprised of 1,000 MW of standalone storage and 600 MW of Solar Plus Storage); (3) 600 MW of onshore wind; (4) 800 MW of CTs; and (5) 1,200 MW of CCs. Duke Proposed Order at 108 (citing to Duke Proposed Carbon Plan, Ch. 4, 3-5).

Having already addressed new natural gas-fired generation, the Commission now considers Duke's proposed actions related to standalone solar generation, Solar Plus Storage, standalone battery storage, and onshore wind.

Duke states that "the accelerated timeframe to deliver new resources, along with the interdependencies between generation and transmission needed to achieve the target in-service dates presented in the Carbon Plan, underscores the importance of Commission approval and support for near-term Execution Plan activities in this initial Carbon Plan." *Id*. Nonetheless, Duke also notes:

> [T]he dates and quantities in [Duke's Carbon Plan proposal portfolios] should be considered directional and not exact. The specific resources (technology, design, capacity) to be developed and optimal in-service dates will be refined through the development and siting processes as Plan components are executed. As more information is gathered through execution, [Duke] will keep the Commission apprised of material developments through future

[12] Duke requests in its proposed order that the Commission select 3,100 MW of solar generation, including 750 MW requested to be procured through the 2022 Solar Procurement Program. Duke notes the 750 MW amount to be procured through the 2022 Solar Procurement Program because Duke filed its proposed order on October 24, 2022, which is before the Commission authorized Duke to procure 1,200 MW in the 2022 Solar Procurement Program in its Order Permitting Additional CPRE Program Procurement and Establishing Target Procurement, Docket Nos. E-2, Sub 1297 and E-7, Sub 1268 (Nov. 1, 2022).

> biennial Carbon Plan updates, as well as through resource-specific regulatory processes or approvals (e.g., a CPCN proceeding).

Id.

While Duke has proposed a set of recommended near-term supply-side actions, the Commission is not obligated to accept the entirety of Duke's recommended actions. Rather, the Commission has considered each individual near-term action requested by Duke, along with the recommendations of the intervenors, to assess whether Duke's near-term supply-side plan will result in the least cost path to compliance with the carbon dioxide emissions reduction mandates in N.C.G.S. § 62-110.9 and is supported by competent, material, and substantial evidence.

New Solar Generation, Solar Plus Storage, and Standalone Battery Storage

As mentioned above, as part of Duke's proposed near-term plan, Duke recommends that the Commission select 3,100 MW of solar generation (including the MW targeted to be procured through the 2022 Solar Procurement Program), of which a substantial portion is assumed to include paired storage, and 1,600 MW of battery storage (1,000 MW of standalone storage and 600 MW of Solar Plus Storage). Tr. vol. 7, Duke Proposed Carbon Plan, Tbls. 4-6, 4-11; Duke Proposed Order at 108.

Duke states that from 2022 to 2030, approximately 5,980 to 7,930 MW of new solar resources will need to be added to its system in order to achieve the carbon dioxide emissions reduction mandates in N.C.G.S. § 62-110.9. Tr. vol. 7, Duke Proposed Carbon Plan, App. I, 1. Further, Duke notes that adding this significant amount of new solar resources to its system will require the accelerated interconnection of solar resources at a rate of approximately 2.5 times that of the historic maximum amount of utility-scale solar that Duke has ever connected in a single year in the Carolinas. *Id*. Duke also states that one of the key barriers to adding generation resources, particularly solar resources, to its system is the substantial transmission upgrades required to interconnect these new resources, as is discussed further in the "Transmission" section of this Order. *Id.*

Appendix K of Duke's Carbon Plan proposal states that battery storage will play an important role in meeting the carbon dioxide emissions reduction mandates. Tr. vol. 7, Duke Proposed Carbon Plan, App. K, 1. Each of Duke's proposed portfolios, including the supplemental portfolios, requires the addition of significant battery storage assets to achieve the Interim Target. *Id.* Duke states that new battery storage capacity is necessary to support the continued and increasing pace of interconnection of carbon-free intermittent resources, such as solar and wind, to the grid. *Id*. More particularly, Duke states that, as coal plants are retired and replaced with those intermittent resources, its need for firm capacity will grow. *Id*. Duke maintains that with the increased interconnection of solar and wind resources to the grid, battery storage, particularly long-duration battery storage, will become increasingly important to maintain the reliability of the grid. *Id.* Specifically, Duke proposes that long-duration battery storage will be an essential source of firm capacity in order to provide real time balance for the system and to maintain adequate frequency, voltage, and reliability of the grid. *Id*. Duke further asserts that battery storage is cost-competitive with other peaking generation resources over the planning horizon. *Id*.

As noted above, on November 1, 2022, the Commission authorized Duke to target a total 2022 Solar Procurement amount of 1,200 MW, which is inclusive of the 441 MW CPRE shortfall. *See* Order Permitting Additional CPRE Program Procurement and Establishing Target Procurement Volume for the 2022 Solar Procurement, *Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, Joint Petition for Approval of Competitive Procurement of Renewable Energy Program and Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Solar Procurement Pursuant to Session Law 2021-165, Section 2(c),* Nos. E-2, Sub 1159, E-2, Sub 1297, E-7, Sub 1156, and E-7, Sub 1268 (N.C.U.C. Nov. 1, 2022). The 2022 Solar Procurement Program includes a VAM to mitigate pricing risk to customers. Before selecting the portfolio of winning solar proposals, Duke must calculate the weighted average cost of the total portfolio of both utility-owned and third-party-owned solar resources along with their assigned transmission upgrade costs. 2022 Solar Procurement Program Final RFP and pro forma PPA Compliance Filing, *Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Solar Procurement Pursuant to Session Law 2021-165, Section 2(c),* Nos. E-2, Sub 1297, E-7, Sub 1268 at Attach. A, 2. If the weighted average cost of the solar resources to be procured is greater than or equal to 110% of the Carbon Plan Solar Reference Cost (the assumed cost of solar capacity, energy, and related upgrades used to develop the Carbon Plan), the target procurement amount may be decreased by as much as 20% (subject to the 700 MW minimum target), effectively eliminating the highest cost proposals from selection in the 2022 Solar Procurement Program and deferring some of the modeled procurement volume to future solar procurements. *Id.* Conversely, if the bid pricing is competitive because the weighted average cost of the solar resources to be procured is less than or equal to 90% of the Carbon Plan Solar Reference Cost, the target procurement amount may be increased by up to 20% above the volume targeted by the procurement request for proposals (RFP) (which is 1,200 MW in the 2022 Solar Procurement), thereby procuring more competitively priced, low-cost solar resources for customers through the 2022 Solar Procurement because they are less expensive than assumed in the Duke's Carbon Plan proposal and will provide savings to customers. *Id.* Thus, if the weighted average cost of the total portfolio of the 2022 Solar Procurement portfolio is less than or equal to 90% of the Carbon Plan Solar Reference Cost, the target procurement amount will be adjusted upwards by 20% — to procure a total of 1,440 MW of solar resources.[13]

Considering the Commission's November 1, 2022 decision on the targeted amount for the 2022 Solar Procurement, Duke recommends that the Commission authorize Duke to target a minimum of 2,350 MW[14] of new solar resources from 2023 to 2024 and allow Duke to "determine the optimal timing and mix of new standalone solar and solar paired with storage." Duke Proposed Order at 15. Duke further recommends that the Commission direct Duke to "consider volume adjustments or other mechanisms similar

[13] 1,200 MW x .20 = 240 MW. 240 MW + 1,200 MW = 1,440 MW.

[14] 3,100 MW – 750 MW = 2,350 MW.

to the 2022 Solar Procurement during this period to competitively procure additional solar at least cost." *Id.*

Also, when taking into account the targeted amount of capacity to be procured in the 2022 Solar Procurement, the Public Staff recommends that the Commission direct Duke to target the procurement of 950 MW of new solar generation in 2023 and 1,150 MW of new solar generation in 2024 (for a total targeted procurement of 2,100 MW between 2023 to 2024, which is 250 MW less than Duke's recommendation). The Public Staff also recommends that the Commission authorize the procurement of a minimum of 400 MW of at least 2-hour co-located storage in 2023 and also in 2024. Public Staff Proposed Order at 11. Public Staff witness Thomas states that its recommendation of solar resources and Solar Plus Storage in the near-term procurements is appropriate because procurement of these resources must appropriately balance the risks of waiting to procure solar resources with the risks of procuring them too early and placing the risk of additional cost on customers. Tr. vol. 21, 320. Also, witness Thomas recommends that 1,125 MW of standalone battery storage be procured as part of the near-term plan, which he states is consistent with SP5. *Id.* at 91.

AGO witness Burgess testified that Duke's proposed near-term solar and battery storage procurements should be pursued as part of a "no regrets" strategy and that greater quantities of these resources may be warranted due to the incentives provided in the IRA, which witness Burgess opined will significantly reduce the cost of the solar resources and battery storage. Tr. vol. 25, 296, 324. AGO witness Burgess further suggested that "it may be better to aim high and miss the mark by a year or two, rather than aim low out of an overabundance of caution and fail to meet the statutory requirements [for carbon dioxide emissions reductions.]" *Id*. at 323-24.

Tech Customers witness Borgatti testified that the Tech Customers' strategy in terms of near-term actions prioritizes near-term investment in infrastructure necessary for any Carbon Plan, including each of Duke's proposed portfolios, while avoiding or delaying investments that may not be needed or are reliant on speculative or unproven technology. *Id.* at 47. With regard to new solar resources, witness Borgatti testified that the Tech Customers' preferred portfolio includes no standalone solar before 2030. *Id.* Nonetheless, in information submitted after the hearing, Tech Customers support Duke's recommended near-term target of 3,100 MW of new solar resources through 2024 (inclusive of the amount of solar resources procured in the 2022 Solar Procurement). *See* Tech Customers Partial Proposed Order at 11. Further, Tech Customers' preferred portfolio recommends 1,000 MW of Solar Plus Storage with a 25% 4-hr battery ratio in 2027 to 2028, 3,750 MW of Solar Plus Storage with a 50% 4-hr battery ratio in 2027 to 2029, 2,850 MW of standalone 4-hr battery storage and 50 MW of standalone 6-hr battery storage in 2027 to 2029. Tr. vol. 25, 47.

CPSA witness Norris addressed the near-term procurement of new solar resources based on modeling performed by CPSA witness Hagerty. Witness Norris recommended that the Commission direct near-term procurement of 4,800 MW of new solar resources from 2022 to 2024 as follows: 1,500 MW in 2022, 1,500 MW in 2023, and

1,800 MW in 2024. Tr. vol. 26, 52. CPSA recommended that its alternate portfolios CPSA3 and CPSA5, which are based on more aggressive solar interconnection assumptions, be included in the 2024 CPIRP proceeding for further consideration and to inform Duke's proposed near-term plan. Witness Norris criticized Duke's excessive conservatism about the rate of solar interconnections and testified that Duke's proposed near-term procurement targets are insufficient to achieve compliance with the 2030 Interim Target, even under the most solar-reliant of Duke's proposed portfolios (portfolio P1). *Id*. at 28-29, 39. Witness Norris argued that Duke's proposed low amounts of early solar procurement are inconsistent with achieving the 2030 Interim Target. *Id*. at 49.

NCSEA et al. witness Fitch recommended that the Commission direct Duke to achieve the Interim Target by 2030, advising that such an approach would allow for flexibility in later CPIRP proceedings in the event that unforeseen delays occur and if the Commission determines that a delay is warranted. Tr. vol. 24, 157, 160. More specifically, witness Fitch argued that 7,200 MW of solar resources should be interconnected by 2030, 4,000 MW of which should be procured from 2022 to 2024 and in-service between 2025 and 2028. *Id.* at 177-78. Also, NCSEA et al. witness Fitch recommended that the Commission direct Duke to begin procurement for 4,000 MW of standalone storage with target in-service dates of 2025 to 2028. *Id.* at 178.

Public Staff witness Thomas contended that intervenors such as CPSA and NCSEA et al. are requesting solar procurement targets that rely on unrealistic near-term annual interconnection limits and high interconnection costs. Witness Thomas agreed that all portfolios eventually require the interconnection of 10 gigawatts (GW) of solar resources, but with different completion dates. However, he cautioned the Commission against procuring large amounts of solar resources too quickly. Tr. vol. 21, 320-21. Public Staff witnesses Thomas and Metz contended that there must be an orderly transition from fossil fuel resources to renewable resources and faults the CPSA and Brattle modeling for not considering transmission upgrades that might result in greater cost as they trigger affected system studies and create wide-ranging impacts beyond the local network. *Id*. at 319. Public Staff witness Thomas cautioned against only looking at solar resource interconnections when considering the challenges associated with interconnections

> So looking at it just in terms of how much solar can we interconnect is a bit myopic. And we need to look at the whole resource portfolio that we're trying to interconnect and realize that this is a challenge for Duke's transmission interconnection studies and Duke's transmission planners that I don't believe they've ever faced before, in term of interconnecting this volume of intermittent resources and dispatchable resource and energy storage simultaneously. So I think we need to temper this with some dose of reality.

Tr. vol 21, 249-50.

From a customer perspective, CIGFUR witness Muller testified that a more measured pace of transition enables North Carolina to be flexible and in a position to take advantage of new information, technology advancements, and other changed circumstances that could warrant altering the path forward in the future. Witness Muller similarly highlighted, from an affordability perspective, that a less accelerated pace of transition could make the year-to-year rate impacts for ratepayers more manageable and could also ensure that the least cost plan is selected. Tr. vol. 25, 364.

On rebuttal, the Duke Modeling and Near-Term Actions Panel explained that Duke seeks permission to procure significant Solar Plus Storage resources in future near-term procurements (procurements from 2023 to 2024). Tr. vol. 27, 57. While most of the recommended 2,350 MW of solar resources will include battery storage, the required amount of Solar Plus Storage should be based on the optimal configuration of the Solar Plus Storage that can be procured at least cost while recognizing system needs. *Id*. The Duke Modeling and Near-Term Actions Panel addressed the remaining 2,350 MW of solar resources (inclusive of 600 MW of Solar Plus Storage) to be procured, and explains that if all future Solar Plus Storage includes storage that is 25% of the solar nameplate capacity, then Duke would need to procure 2,400 MW of Solar Plus Storage to reach the 600 MW of Solar Plus Storage target, and thus no additional standalone solar would be required. *Id*. If all future Solar Plus Storage includes storage that is 50% of the solar nameplate capacity, then Duke would need to procure 1,200 MW of Solar Plus Storage to reach the 600 MW of Solar Plus Storage target. *Id*.

The Duke Modeling and Near-Term Actions Panel also noted that Duke's proposed near-term actions do not include solar and battery storage procurement targets for 2025 that would be assumed to come online in 2029, as procurement that far in the future should be further informed by the outcomes of the earlier solar procurements and the subsequent Carbon Plans. *Id*. at 67. According to the Modeling and Near-Term Actions Panel, this approach affords the Commission the time and flexibility to wait an additional two years to determine procurement targets for resources expected to come online in 2029 and in advance of the 2030 Interim Target. *Id*.

The Duke Modeling and Near-Term Actions Panel disputed CPSA witness Norris' claim that approval of Duke's proposed near-term actions would make the 2030 Interim Target unachievable. *Id.* at 56-60. The Modeling and Near-Term Actions Panel explained that Duke expects to procure 3,550 MW (inclusive of the 441 MW CPRE shortfall) in years 2022, 2023, and 2024, which leaves an additional 2,300 MW to be procured to reach P1 solar additions by 2029. *Id.* Assuming that a VAM similar to the 2022 Solar Procurement is included in future solar procurements, Duke could procure additional solar volumes in the near term to remain on track to meet the P1 solar volume. *Id.* at 58-59. The Panel also noted that there are numerous other considerations and aspects of an "all of the above" Carbon Plan that need to be considered to meet the carbon dioxide emissions reductions mandates; as such, the pace of solar procurements must be viewed in the broader context of other resources to be added to the system and the infrastructure needed to allow the interconnection of the new solar resources to achieve the required carbon dioxide emissions reductions in an orderly fashion. *Id*. at 60. The Modeling and Near-Term Actions Panel concluded that its near-term actions for 2022 to 2024 are appropriate and that pre-emptively selecting the significantly higher volumes of solar resources and battery storage recommended by CPSA and NCSEA et al. would significantly increase execution risk and is not a reasonable step. *Id.* at 67.

Duke's targeted near-term solar capacity addition is informed by what Duke deems as limits, based on engineering judgment, on its ability to interconnect solar capacity. Tr. vol. 7, Duke Proposed Carbon Plan, Apps. I, P; tr. vol. 7, 349-53. The Duke Utilities Operations Panel testified that its solar interconnection assumptions, including constraints on interconnections, within the model were supported by quantitative analysis and that it relied on its expert engineering judgment from transmission planning and transmission construction teams in formulating its positions. Tr. vol. 11, 75-76. The Panel additionally testified that the time period to interconnect solar resources — from executing an interconnection agreement to placing the solar resource in service has increased. At the time of the hearing, the time to place solar resources in service was averaging about 26 to 32 months for projects that do not require the construction of transmission upgrades. Tr. vol. 8, 39-41. Additionally, the Panel testified about the work on the electric system that is necessary to interconnect new generating facilities, including solar resources, and details the transmission line outages that must be coordinated to interconnect solar resources without jeopardizing Duke's ability to manage contingencies on its system and ensure that reliable service is provided to customers. Tr. vol. 16, 164-65.

With respect to battery storage, Public Staff witness Metz recommended that commercial terms be created so that dispatch of battery storage can occur and that those terms fairly compensate owners and protect ratepayers. Tr. vol. 21, 234-35. Also, CCEBA witness DiFelice testified that contract structures that allow the utility full control over third-party battery storage assets, within certain technical parameters, currently exist in jurisdictions such as the Tennessee Valley Authority, where a Solar Plus Storage procurement is underway. Tr. vol. 26, 278. Regarding witness Metz' recommendation for the development of commercial terms for contracts for Solar Plus Storage, the Duke Utilities Operations Panel testified that it is striving to replicate the same flexibility it has with utility-owned Solar Plus Storage assets for third-party-owned PPAs so that Duke's system operators will have the same operational flexibility for both utility-owned Solar Plus Storage assets and third-party-owned PPAs. Tr. vol. 12, 22. Duke witness Farver further testified that it is important to develop contracts for Solar Plus Storage resources that allow Duke to have control over the timing and use of the storage component of the Solar Plus Storage facilities in order to provide flexible uses beyond capacity. She also opined that third party developers should be appropriately compensated for the value they provide. Tr. vol. 16, 130-31, 133.

Public Staff witness Thomas indicated that he expects that Solar Plus Storage resources will be competitively procured through annual procurements that are similar to the 2022 Solar Procurement, albeit expanded to procure Solar Plus Storage resources in addition to standalone solar. Tr. vol. 21, 63. During these future procurements, witness Thomas opined that a wide variety of Solar Plus Storage configurations will be submitted for evaluation. *Id.* at 64. Witness Thomas stated that, assuming the first Solar Plus Storage procurement will take place during the 2023 Definitive Interconnection System Impact Study (DISIS), there should be sufficient time to incorporate common configurations and costs into a subsequent Carbon Plan. *Id.* As such, witness Thomas recommended that Duke file the preliminary 2023 Solar Procurement results in the 2024 Carbon Plan proceeding and explain how its Solar Plus Storage modeling is influenced by the results of the 2023 Solar Procurement. *Id.* Witness Thomas stated that the Public Staff supports CCEBA and CPSA's recommendation that Duke work with stakeholders in advance of the 2023 DISIS to develop appropriate Solar Plus Storage PPA structures that appropriately value third-party Solar Plus Storage resources. Tr. vol. 7, 264. Witness Thomas noted that Duke has agreed to this recommendation. *Id.*

Overall, the Commission notes that one of the few areas of consensus among Duke and the intervenors, as confirmed by the various modeled portfolios, is that a significant amount of solar resources and Solar Plus Storage must be included in Duke's resource mix in the near term to reach the Interim Target. More specifically, Duke states that up to 5.4 GW of solar resources needs to be added to the system to meet the 2030 Interim Target. Tr. vol. 7, Duke Proposed Carbon Plan, Ch. 3, Fig. 3-5; Duke Proposed Order at 27, 175, 179. The Brattle Group's modeling achieves the 2030 Interim Target by adding between 5.2 GW to 9.5 GW of solar resources by 2030. Tr. vol. 25, 438-39. Synapse's modeling achieves the 2030 Interim Target by adding 7.2 GW of solar resources by 2030. Tr. vol. 24, 178. The Gabel Report's Preferred Portfolio achieves the 2030 Interim Target by adding similar amounts of solar resources (but with more emphasis on Solar Plus Storage and behind-the-meter solar generation). Tr. vol. 25, 5.

The Commission gives weight to the substantial evidence of the need for the near-term procurement of new solar generation and complementary storage resources, the characterization by multiple parties of Duke's proposed 2022 to 2024 procurement targets as "no regrets" actions, and caution from the Public Staff and Duke that the near-term procurement of solar resources must appropriately balance the risks of waiting to procure solar resources with the risks of procuring them too early and placing the risk of additional cost on customers. The Commission recognizes the critical role that solar resources have and will continue to have in meeting the carbon dioxide emissions reduction mandates of N.C.G.S. § 62-110. However, the need to develop solar generating capacity must be balanced against the cost to customers as well as the risks to the electric system. Ultimately, it is critical that new solar resources, including Solar Plus Storage, must be interconnected and integrated in a manner that poses no risk to the reliability of the system and affords customers and the electric system as cost-effective a resource as possible.

Based on the foregoing and the entire record in this proceeding, the Commission directs Duke to target 2,350 MW of new solar resources in the 2023 to 2024 timeframe. The Commission directs Duke to design the future solar procurements to incorporate a VAM, similar to the VAM in the 2022 Solar Procurement, that would allow for the procurement of increased amounts of solar resources should the winning portfolios produce cost-effective bids.

The Commission also directs Duke to target procuring 1,000 MW of standalone battery storage and 600 MW of Solar Plus Storage in the 2023 to 2024 timeframe. Tr. vol. 7, Duke Proposed Carbon Plan, Ch. 4 – Execution Plan, 22-23; Duke Proposed Order at

236. In making this determination the Commission is mindful of the need to balance several considerations associated with rapidly developing battery technologies. The most widely commercialized and cost-competitive technology today uses lithium-ion cells in various configurations that yield storage capacity of relatively short duration. Both Duke and various intervenor parties have focused their attention in this proceeding on that readily available and cost-effective current storage technology. While such storage is undoubtedly a great benefit in addressing problems associated with intermittent energy resources such as solar PV and wind generation, cost-effective long duration storage solutions will be required in order to deal with larger issues of grid operations and stability and to provide reliable, dispatchable reserve capacity to meet extreme weather events or other anomalies creating abnormal demands on the grid.

The Commission notes that battery technologies and costs are evolving, if anything, even more rapidly than was the case with solar PV technologies in the past two decades. Many participants in this proceeding have expressed concern about investments in new natural gas generating facilities, which they fear will become outmoded before the end of their economically useful lives, leaving ratepayers to bear the costs of unrecovered investments made by the utilities. In the Commission's view, this same risk of potentially stranded costs is equally, if not more, present in the case of storage technology due to the pace of change in the development of alternatives to the prevailing lithium-ion model and in the costs of achieving longer duration storage capacities. The near-term investment in storage approved by the Commission in this proceeding will allow the utilities and ratepayers to reap the benefits current short-term storage technologies provide relative to the addition of more intermittent generating resources, but it will not, the Commission believes, incur an unreasonable risk of excessive near-term investment in technologies and systems that may very likely be superseded or surpassed in the intermediate and longer term.

Onshore Wind

Every portfolio in Duke's Carbon Plan proposal, as well as SP5 and SP6, selected 600 MW of onshore wind by 2030. Tr. vol. 12, 66. Likewise, modeling conducted by Tech Customers, CPSA, and NCSEA et al. selected onshore wind in modeling resource portfolios to achieve the Interim Target. More particularly, modeling conducted on behalf of Tech Customers selected 1,200 MW of onshore wind by 2028; CPSA's modelling scenarios each selected 600 MW of onshore wind by 2030; and modeling conducted on behalf of NCSEA et al. selected 900 MW of onshore wind by 2030. Tr. vol. 24, 177-178; tr. vol. 25, 88; tr. vol. 26, 46-47.

Consistent with the Commission's determination herein that pursuant to N.C.G.S. § 62-110.9(2), "Commission-selected" new generation resources must be utility owned (subject to specific exceptions for solar generation and Solar Plus Storage) and recovered on a cost-of-service basis, the Duke Utilities Operations Panel stated that Duke modeled onshore wind assuming it would be owned by DEP and paid for by DEP customers. Tr. vol. 15, 33. Public Staff witness Thomas also testified that Duke modeled onshore wind as a utility-owned resource consistent with the ownership requirements of N.C.G.S.

§ 62-110.9(2). Tr. vol. 22, 316.[15] The Duke Utilities Operations Panel further stated that if onshore wind is ultimately selected by the 2022 Carbon Plan, then Duke will consider whether DEP and DEC could jointly own wind generation. Tr. vol. 15, 14. For the avoidance of doubt, the Commission finds good cause to direct that all subsequent modeling of onshore wind resources should be compliant with the ownership requirements for Commission "selected" resources pursuant to N.C.G.S. § 62-110.9(2).

Public Staff witness Thomas found Duke's assumptions with respect to onshore wind interconnections to be reasonable for the development of the Carbon Plan, absent convincing evidence that large quantities of onshore wind will be available to Duke earlier than 2029 or that more than 300 MW could be interconnected annually. Tr. vol. 21, 59. As the Duke Near-Term Actions Plan Panel calls for the procurement of 600 MW of onshore wind in DEP's territory, Public Staff witness Thomas testified that should the 2022 Carbon Plan include onshore wind, Duke should work to procure these resources in accordance with the Commission's interpretation of the statute and provide updated assumptions in the 2024 CPIRP. *Id*. at 61. Public Staff witness Thomas further recommended that the 2022 Carbon Plan and the near-term plan include 600 MW of onshore wind, consistent with SP5. *Id*. at 63.

Duke witness Snider advised that it is important for Duke to strive to procure onshore wind in the near-term plan, as it has synergies with solar resources because the wind blows at different times than solar power is available, such as winter mornings and at night. Tr. vol. 11, 100. He also stated that developing onshore wind assets would provide additional diversification benefits from a technological, load profile, and supply chain perspective. *Id*. Witness Snider recommended that in the next CPIRP, Duke should report to the Commission about its efforts to procure onshore wind, and potentially adjust the amount of onshore wind that could be added at that time. *Id*. at 101-02. Further, witness Snider stated that there are a limited number of sites in North Carolina with

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[15] There is some disagreement among the parties as to whether Duke's onshore wind modelling assumptions include power purchased from third parties. *See, e.g.*, Tech Customers Partial Proposed Order at 23 ("Finally, [Duke] appear[s] to have modeled the purchase of onshore and offshore wind on a purchased basis. The offshore wind selected in Duke's proposed P1 is modeled based on a generic offshore wind block and not on a site-specific selection because Duke assumes it will have to "partner[]" with "on an offshore project that has already evolved beyond the leasing stage." *See* tr. vol. 7, Duke Proposed Carbon Plan, App. J, 6. Similarly, due to the various logistical and siting challenges identified by Duke in its plan, Duke's proposed plan for DEC is reliant on up to 600 MW of onshore wind "assumed to be sourced from PJM but could also be sourced from Midcontinental Independent System Operator, Electric Reliability Council of Texas, or other jurisdictions with strong wind profiles." *See* id. at 13). The Duke Transmission Panel testified that Duke considered importing Midwest onshore wind unfeasible at this time due to the needed transmission upgrades, the costs of those upgrades, and the time needed to complete the upgrades. Tr. vol. 16, 104. Duke also indicated that it has submitted a 1,000 MW first transmission service request to PJM to validate these results, which will be considered in future Carbon Plan iterations. *Id*. The Transmission Panel further states that the proposed Carbon Plan considered importing Midwest onshore wind onto Duke's system and used the PJM border rate for the transmission cost adder. *Id*. Duke had PJM conduct a feasibility study in 2019 for importing 300 MW into DEC, and the upgrades needed on the PJM side of the system were $411 million and expected to take up to 84 months to complete. *Id.* at 104-05. Witness Roberts further testified that if Duke were to import onshore wind from the Midwest, it would have to pay wheeling charges to PJM and potentially MISO, depending on where the resources were sited. Tr. vol. 17, 28.

significant onshore wind resource potential. *Id*. at 97. He testified that Duke must work with the communities and wind developers to determine if those sites are actually viable. *Id*. If those sites are determined to be viable, witness Snider added that Duke must determine the transmission plan to bring those resources to load centers. *Id*. Finally, witness Snider stated that while Duke has a proxy interconnection cost in the model for onshore wind, that price does not have the transmission study history that the solar interconnection cost does. *Id*. at 97-98.

Duke witness Pompee with the Long Lead-Time Resources Panel testified that onshore wind is considered a mature technology and that the only emerging technologies he is aware of that would increase the potential for onshore wind in North Carolina are "high hub height wind," which allows developers to place the wind turbines higher to achieve a bigger wind profile. Tr. vol. 18, 92. He admitted that the siting limitations in North Carolina would not necessarily change if the geographical area where a commercially viable wind turbine could be built were expanded. *Id*.

Duke witness Farver with the Duke Transmission Panel testified that Duke is excited about the opportunity to include onshore wind in its generation mix, but recognizes that there are challenges, particularly with siting. Tr. vol. 18, 125. She stated that Duke is ramping up internal preparations and capabilities for self-development and is also starting informal conversations with the onshore wind development community. *Id*. Witness Farver explained that onshore wind is a nascent technology in North Carolina. She stated that Duke is attempting to gather more information to determine if there is a pipeline of projects that would be interested in a 2023 RFP opportunity for acquisition, but there have not yet been any formal stakeholder meetings to gather that information. *Id*. As such, she concluded that Duke does not have sufficient market information to believe that the expense of an RFP would be worthwhile. *Id*.

Witness Roberts of the Duke Transmission Panel testified that since Carteret County is the area with the greatest onshore wind potential, there would most likely be transmission constraints that would need to be resolved due to the aggregation of solar, offshore wind, and onshore wind resources that could influence power flows in the area. While the main transmission line in Carteret County is not currently constrained, witness Roberts testified that she did not know how much headroom is available on that line. *Id*. at 127-28.

Public Staff witness Thomas testified that there are currently two onshore wind farms in North Carolina: the operational 208 MW Amazon Wind facility in Perquimans and Pasquotank Counties, and the planned 189 MW Timbermill Wind facility in Chowan County, both of which are in PJM's territory. He provided the history of the projects and describes the timelines under which they became permitted and, in the case of Amazon Wind, operational. He stated that given this history and the absence of any wind projects in Duke's interconnection queues, it is unlikely that any onshore wind projects in Duke's territory will be able to achieve operation prior to 2029. He added that onshore wind imported from PJM or other neighboring areas would require firm point-to-point transmission service and would be subject to the appropriate border or wheeling charge.

Public Staff witness McLawhorn also testified that the Public Staff is concerned about the transmission development required to interconnect onshore wind in DEP's service territory without a plan to allocate some of the costs to DEC. Tr. vol. 23, 96-97.

Several intervenors criticize Duke's assumptions of onshore wind availability in Duke's Carbon Plan proposal. CPSA argues that the Carbon Plan likely overstates the potential for onshore wind development, exclusive of imports, noting the 2016 to 2018 legislative moratorium and the fact that no onshore wind projects were in the recently completed DISIS queue. CPSA Initial Comments at 45-46. CPSA also stated that the development pipeline for new onshore wind farms and the timeline for such facilities in the Carolinas is "highly uncertain." Tr. vol. 25, 427.

AGO witness Burgess testified that Duke's proposed near-term wind procurements should be pursued as part of a "no regrets" strategy and that greater quantities of these resources may be warranted due to the IRA. Id. at 296.

AGO witness Burgess further testified that it is premature to assume both that no more than 300 MW of onshore wind can be procured and that a 2029 in-service date is required prior to testing the market through a competitive procurement solicitation. *Id.* at 254. He also argued that Duke should explore the potential for non-firm or "energy only" type of transmission service for wind imports. *Id*. at 255. Furthermore, NCSEA witness Fitch testified that the Synapse Report includes 2,500 MW of onshore wind from the Midwest and 900 MW "in-state" onshore wind by 2030. Tr. vol. 24, 178.

Modeling conducted by intervenors relied on lower cost, publicly available onshore wind technology costs. Tr. vol. 7, 384-86. Both Synapse and Brattle relied on 2022 NREL ATB costs while Strategen relied on 2022 EIA AEO costs. Tr. vol. 24, 145 (Synapse), 422 (Brattle); AGO Initial Comments, Attach. 1 at 23.

The Public Staff recommends that the Commission find that "it is appropriate to include 600 MW of onshore wind in the 2022 Carbon Plan for planning purposes at this time," and that the Commission direct Duke to continue gathering information as stated by witness Farver on the possible market for an onshore wind RFP and its ability to procure and place into service 600 MW of onshore wind capacity by 2030. Public Staff Proposed Order at 90. Finally, the Public Staff recommends that the Commission direct Duke to, within 60 days of the date of this Order, file a report proposing a plan to assess potential interest in an onshore wind RFP, including the potential inclusion of out-of-state wind resources; "determine the potential locations and timelines for procuring and placing into service onshore wind facilities[;] and estimate the potential transmission upgrade projects necessary to interconnect the facilities. *Id.* at 90-91. Further, the Public Staff recommends that, in the event that Duke determines than an onshore wind RFP would attract sufficient bids for a competitive procurement, the Commission should require Duke to submit a proposed timeline for submitting an RFP to the Commission for approval. *Id.* at 91. Finally, the Public Staff requests that the Commission require Duke to provide a cost allocation methodology for sharing the costs of the facilities and the requisite transmission upgrades between DEP and DEC.

Based on the foregoing and the entire record in this proceeding, the Commission finds that the characteristics of onshore wind make it a compelling complement to solar generation that could help foster system reliability, but whether Duke can reasonably put into service 600 MW of utility-owned onshore wind in order to achieve the Interim Target is uncertain based upon a number of variables. The Commission finds it reasonable to direct Duke to engage with onshore wind stakeholders and any others Duke finds are necessary to support its request that the Commission select onshore wind as part of its future preferred Carbon Plan portfolio as soon as practicable on the issues identified by the Public Staff. In formulating its first biennial CPIRP, Duke shall consider onshore wind and particularly any pertinent information gleaned from its stakeholder engagement, and, to the extent that future Encompass modeling economically selects utility-owned onshore wind resources, Duke should support that proposal in detail in its first biennial CPIRP.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 34-51

Development of Long Lead-Time Resources

The evidence supporting these findings of fact is in the testimonies of Duke witnesses Repko, Immel, Nolan, and Pompee (Long Lead-Time Resources Panel); the testimonies of Public Staff witnesses Metz and Thomas; the direct testimony of AGO witness Burgess; the testimonies of Avangrid witnesses Starrett and Gallagher; the testimony of NCSEA et al. witness Fitch; the testimony of Tech Customers witness Roumpani; the testimonies of Duke Modeling and Near-Term Actions Panel witnesses Snider, McMurry, Quinto, and Kalemba; the testimony of Duke Transmission and Solar Procurement witness Roberts; the testimony of EWG witness Makhijani; the testimony of NC WARN witness Powers; and the testimony of CPSA witness Hagerty.

As part of complying with the requirements of N.C.G.S. § 62-110.9, Duke contemplated utilizing a variety of low or zero carbon-emitting electric generating resources. Some of the contemplated resources will either take several years to develop or will require further evaluation for feasibility and cost. In particular, Duke focused on three categories of resources: (1) nuclear, including SLRs for its existing nuclear fleet and development of new nuclear facilities; (2) additional pumped storage hydro; and (3) offshore wind. Tr. vol. 7, Duke Petition for Approval, 9. Duke refers to these resources as “long lead-time resources.”

Duke explains that these resources have substantially long lead times and greater external dependencies than other resources discussed in the Carbon Plan proposal. As a result, Duke asserts that it will need to perform critical development work in the near-term to maintain optionality and the potential for in-service dates consistent with those Duke’s modeling contemplates. Duke is not requesting that the Commission “select” such resources at this time. Rather, Duke explains that it needs to do initial development work both to gather information to provide a more refined cost estimate to the Commission in future proceedings, and to allow Duke to position itself to implement such resources on a timeline consistent with the modeled portfolios. Duke asserts that if it does not undertake these development activities in the near-term for offshore wind, new nuclear, and additional pumped storage hydro, then these resources will not be available on the timelines the various portfolios contemplate. Tr. vol. 17, 77-78.

Duke witnesses testified that, in this proceeding Duke is asking for permission to incur the costs associated with the development of the three long lead-time items. Duke witness Repko explained that Duke would ask in another, separate proceeding for cost recovery, with the expectation that in that proceeding it would have to demonstrate the reasonableness and prudence of the costs associated with development of these resources. *Id.* at 155-56.

New Nuclear

Duke's existing nuclear fleet is composed of traditional, large-scale nuclear power plants typically with a nameplate capacity of approximately 1,000 MW or more. In the United States, new construction of these types of large nuclear facilities has been logistically problematic and has resulted in significant cost overruns and even cancelations of projects. Tr. vol. 21, 130-31. However, there are two additional types of nuclear generation Duke addresses in its Proposed Carbon Plan: ARs and SMRs.

ARs are nuclear generation facilities that do not use water as the primary coolant. Such ARs use liquid metal, molten salts, or high-temperature gas for cooling. *Id.* at 131. There are currently no commercially operating AR generating facilities in the United States. Tr. vol. 17, 183-84. While Duke believes that SMRs have a less challenging licensing path than ARs because the design for SMRs is based on existing large light-water designs, Duke states that the ESP they intend to pursue will be neutral to either technology. *Id.* at 97, 100.

SMRs are described by their name. They are physically smaller and generate less electricity than traditional nuclear plants, are modular in the sense that much of the construction can be completed offsite, and rely on nuclear reactors to generate electricity. Tr. vol. 21, 128. SMRs are smaller scale in terms of size, cost, and construction time due to their modular characteristics. In addition, the size and modularity provide for more flexibility in terms of siting and land requirements. *Id.* at 131. SMRs use water for cooling, just like the traditional nuclear fleet Duke presently operates. SMRs therefore use well-known and proven technology and as such should both have a more readily available supply chain and a less challenging licensing path than ARs. Tr. vol. 29, 97.

Duke is experienced with storing used nuclear fuel through its operation of its large, traditional nuclear fleet. Duke testified it is reasonable to expect that it would handle used nuclear fuel resulting from future operations of SMRs similar to Duke's current practices. *Id.* at 108.

Duke's modeling has demonstrated the need for nuclear generation for meeting the carbon dioxide emissions reduction mandates set forth in N.C.G.S. § 62-110.9. Tr. vol. 17, 176. Tech Customers' "Preferred Portfolio" also demonstrates the need for SMRs for reaching net zero carbon dioxide emissions. Tr. vol. 25, 47. SMRs are present in all six portfolios Duke modeled. Some portfolios selected SMR generation as early as 2032, but by 2035 all six portfolios include approximately 600 MW of SMRs. By 2050, models predict that new nuclear resources will provide generation comparable to that which Duke's traditional nuclear fleet currently provides. Tr. vol. 7, Duke Proposed Carbon Plan, App. E at 54-55, 86; tr. vol. 7, 262.

Although there is much interest in the utility sector in SMRs, Duke acknowledges that they are not a mature technology. Tr. vol. 18, 33-34. Presently, there are no SMRs in commercial operation. Tr. vol. 17, 183. Duke concedes that having SMRs in commercial operation by 2032 represents an "aggressive" schedule. *Id.* at 36.

Some intervenors oppose Duke's future use of SMRs, arguing that the technology is unproven, expensive, unlikely to be available, and will generate radioactive waste. *See, e.g.*, tr. vol. 22, 154-214; tr. vol. 24, 68-121. According to AGO witness Burgess, "[t]he Commission should use extreme caution in approving any development activities for new nuclear." Tr. vol. 25, 301.

Although SMRs are not a mature technology, they represent one of the "breakthrough technologies" that N.C.G.S. § 62-110.9(1) contemplates. In support of this point, Duke witness Nolan testified

> SMRs and ARs are distinctly different than the large light-water-cooled nuclear plants (i.e., Generation III/III+) that were planned to be built during the early 2000s. The next generation SMRs and ARs have significant advantages over their historical counterparts. The modular design of these new reactors allows for more off-site construction and decreases production and construction timelines. *Designs have become smaller, meaning units require less capital investment and are more flexible, allowing for greater ability to match power output to system loads. In addition, the new generation of nuclear plants have* [sic] *significant safety enhancements.* Inherent safety features, such as passive shut down and self-cooling through natural circulation, mean that the system can turn off and cool itself with no operator intervention. *This enhanced safety makes the plants less complicated (i.e., fewer systems needed), enabling easier construction and operation.* The ability to build these next generation advanced nuclear plants much quicker and with less financial risk, while providing always-on baseload power generation, will help enable Duke's transition to net-zero carbon dioxide emissions.

Tr. vol. 29, 106-07 (emphasis added). Duke witness Nolan testified that while none of the new nuclear reactor designs have been approved, this should not delay Duke's pursuit of near-term development activities. *Id*. at 107. He testified that the focus at this time is to pursue siting for an SMR by developing an ESP, allowing time for reactor technologies to develop.

Duke proposes to undertake certain near-term development activities between now and 2024 related to new nuclear facilities, as follows: (1) organize nuclear development staff for new nuclear builds; (2) perform new nuclear alternative siting study; (3) perform new nuclear technology selection; (4) begin new nuclear ESP development; (5) choose the advanced nuclear technology/company to build the first plant(s); and (6) develop a new nuclear construction and operating license application. The projected cost of the near-term development activities for new nuclear generation is $72 million. Tr. vol. 17, 102. Duke witness Repko testified that Duke proposes to limit the costs associated with the new nuclear near-term development actions to $75 million. Tr. vol. 29, 105.

The focus of the near-term development activities is to pursue siting for new nuclear facilities by developing an ESP. The multi-year process of obtaining such permits allows time for the reactor technologies to develop. Moreover, the NRC approves an ESP for up to 20 years, and Duke can renew the ESP. *Id.* at 107. Duke testified that it intends to be a "second mover" in the SMR field in an attempt to avoid first-of-a-kind costs. Tr. vol. 17, 105, 211.

Several SMR projects are expected to be operating in North America over the next decade. *Id.* at 98-99. Public Staff witness Thomas testified that 19 utilities across the country are planning to incorporate SMRs into their future generation plans. Tr. vol. 21, 77. The Public Staff testified that it is reasonable to include SMRs as a potential future generation resource since it is highly likely the technology will be approved and deployed. *Id.* at 258-59.

The Commission concludes that Duke's request to undertake limited development activities for new nuclear facilities is appropriate, and notes that Duke relies upon new nuclear technology in all of its modeled portfolios. Although new, commercial SMR technology relies on existing technology and represents an important developing field that has the potential to be executable and provide carbon-free, reliable power at least cost relative to other resources. This is the type of "breakthrough" technology N.C.G.S. § 62-110.9 contemplates. The Commission recognizes the risks of pursuing breakthrough technologies, but Duke's experience with existing nuclear technology, especially operating water-cooled nuclear reactors and managing spent nuclear fuel, mitigates the risk associated with new nuclear. The fact that Duke will review potential nuclear generation resources to determine the most viable and cost-effective technologies and provide the Commission with additional information and more refined cost estimates regarding new nuclear facilities in future proceedings further mitigates risk. The Commission concludes further that it should not view the risks of new nuclear in isolation from alternative portfolios that rely more heavily on other technologies, which place greater reliance on weather conditions, for example. Diversifying the risk of its generation portfolio is a prudent step which Duke has successfully managed over its history as it has reliably served North Carolina customers at reasonable rates. The Commission places great weight on Duke's pledge to be a "second mover" and allow time for reactor technology to develop and complete the NRC licensing phase. Finally, the Commission is mindful of the importance of monitoring the development activities related to this breakthrough technology.

Accordingly, the Commission orders Duke to provide updates on its progress, and any significant developments in the industry impacting Duke's plans, in its first CPIRP filing.

Consistent with its authority under N.C.G.S. § 62-110.7(b), the Commission determines that Duke, in this proceeding, has demonstrated by a preponderance of the evidence that the decision to incur the project development costs outlined in its proposed Carbon Plan, with respect to SMRs and ARs, is reasonable and prudent. The Commission is not ruling on the reasonableness or prudence of specific project development activities or on the recoverability of specific items of cost at this time. To the extent the Commission finds, in a future general rate case proceeding, the specific activities involved, and the costs of pursuing these limited development activities, to be prudent and reasonable (whether these nuclear resources are ultimately selected or not selected or canceled), Duke shall recover in rates the North Carolina allocable portion of Duke's share of such costs pursuant to N.C. Gen. Stat. § 62-133 and N.C.G.S. §§ 62-110.7(c) and/or (d). Further, the cost cap for the time period spanning 2022 through 2024 for expenditures related to SMRs and ARs, which Duke shall not exceed without Commission approval, shall be $75 million. In its first CPIRP filing, Duke is directed to report on its activities and costs incurred to date in pursuing such the authorized development work; this report shall be for informational purposes only, and Duke shall not use this report as support for an argument that the Commission has made any determination with respect to the reasonableness or prudence of the activities and costs reported therein.

Bad Creek II

Since 1991, Duke has successfully operated the Bad Creek I energy generation facility. Bad Creek I stores and generates energy by moving water between two reservoirs at different elevations. During times of low electricity demand, surplus energy is used to pump water to an upper reservoir while during periods of high demand, the stored water is released down through turbines. As with traditional hydroelectric stations, the flow of water through turbines generates electricity. Bad Creek I provides 1,360 MW of capacity. Presently, Duke is making upgrades to Bad Creek I that will increase its capacity to approximately 1,700 MW in 2023. Tr. vol. 17, 85-86; tr. vol. 21, 124.

The DEC system has benefited greatly from the operating reserves and flexibility provided by pumped storage hydro. Tr. vol. 19, 176. Duke has determined that an additional 1,700 MW of capacity can be added to the Bad Creek station through the addition of four new generating units and other improvements. Hereinafter, this pumped storage hydro resource expansion project is referred to as "Bad Creek II." Tr. vol. 17, 87.

Duke has already undertaken some development activities related to Bad Creek II, including retaining an engineering firm to perform a feasibility study scheduled for completion this year. Tr. vol. 17, 89; tr. vol. 21, 125-26. Duke has projected $35,855,000 in expenses related to Bad Creek II near-term development activities. Given the anticipated time involved in obtaining licensure and then completing construction, Duke projects Bad Creek II will be in service in 2033. Tr. vol. 17, 90. The Public Staff notes that this timeline may not be realistic and requests periodic reporting on the project's status. Public Staff Initial Comments at 98-99.

All six portfolios Duke modeled (P1 through P4, SP5, and SP6) include 1,700 MW of capacity from Bad Creek II coming online in the mid-2030s and remaining in service through at least 2050. Tr. vol. 7, Duke Proposed Carbon Plan, App. E, 86; tr. vol. 7, 262.

Duke opines that there appears to be substantial support for Bad Creek II. Tr. vol. 29, 91. Duke is correct that intervenors largely did not take issue with the near-term Bad Creek II development activities Duke proposed. Many included the capacity of Bad Creek II in their own proposals. *See, e.g.*, tr. vol. 25, 47; tr. vol. 27, 94-95. AGO witness Burgess finds pumped storage hydro to have "the most certainty" of the long lead-time resources. Tr. vol. 25, 300.

The Commission concludes that Duke's request to undertake limited development activities related to Bad Creek II is appropriate, as Bad Creek I presently serves as a unique and valuable system resource, and that Bad Creek II would add to that value. In making this decision, the Commission gives significant weight to the testimony of DEC witness Holeman, the Vice President of Transmission System Planning and Operations for Duke Energy Corporation who joined Duke in 1985 and has since that time held various engineering and management positions of increasing responsibility in system operations, regarding the value of Duke's operational experience with the long duration storage that the Bad Creek facility provides, as well as the operational potential of the long duration storage provided by the facility. Tr. vol. 19, 237-38. The Commission notes that all modeled portfolios rely on Bad Creek II's pumped storage hydro and that there was no substantial opposition to Bad Creek II among intervenors.

Based upon the foregoing, the Commission approves Duke's request to incur costs associated with the limited development activities it outlines in its Carbon Plan proposal for new pumped storage hydro capacity at Bad Creek II to ensure that these resources remain an available resource option for Duke's customers for purposes of Carbon Plan execution. To the extent the Commission finds, in a future general rate case proceeding, that the specific activities involved and the costs of pursuing these limited development activities are prudent and reasonable (whether or not this resource is ultimately selected for the Carbon Plan), Duke may recover in rates the North Carolina allocable portion of Duke's share of such costs at the time(s) and in the manner determined to be appropriate by the Commission and as otherwise allowed by North Carolina law. To further clarify, the Commission is not preapproving any particular future ratemaking treatment regardless of whether the plant is ultimately never begun, abandoned, or completed. Instead, the Commission retains full discretion to determine the appropriate ratemaking treatment in a future general rate case proceeding. Further, the Commission notes and places weight on Duke's estimate that its proposed activities shall cost $40 million. In its first CPIRP filing, Duke is directed to report on its activities and costs incurred to date in pursuing the authorized development work; this report shall be for informational purposes only, and Duke shall use the report as support for an argument that the Commission has made any determination with respect to the reasonableness or prudence of the activities and costs reported therein.

Offshore Wind

Duke witness Repko testified that Duke has requested that the Commission approve certain near-term development actions related to offshore wind. Tr. vol. 17, 81-82. Duke witness Pompee testified that while Duke has yet to develop an offshore wind facility, the deployment of the technology has a 25-year global track record. *Id*. at 110. Duke states that the domestic offshore wind market is growing, as there are over 30 GW of projects with leases in place to achieve the State's carbon dioxide emissions reduction mandates and economic policy goals. *Id*. at 110. Duke proposes to develop the CLB WEA, which is one of three currently available siting opportunities in the Carolinas (which includes CLB and the Kitty Hawk WEAs). *Id*. at 111-12. In May 2022, Duke Energy Renewables Wind LLC (DERW), an unregulated affiliate of Duke, entered into a lease for the CLB WEA, approximately 20 miles from Cape Fear. This wind lease area consists of approximately 55,000 acres and cost $155,000,000. *Id.* at 111; tr. vol. 29, 103.

Duke witness Pompee testified that the three WEAs off North Carolina could produce approximately 4,800 MW of offshore wind energy. Tr. vol. 17, 111. Witness Pompee stated that offshore wind offers numerous benefits, such as "carbon [dioxide] emissions reduction, fuel cost savings, and increased renewable resource diversity in regions with high penetration of solar energy." *Id*. at 112. In addition, the relatively high capacity factors and lower intermittency compares favorably with other low carbon resources, and the distance from shore provides an opportunity to create larger and taller wind towers, thus resulting in site outputs that are measured in gigawatts. *Id*. at 112-13.

Duke testified that a variety of obligations and timing requirements accompany holders of leases for offshore wind energy areas. Duke agrees that under the applicable law and lease, DERW would have to submit a site assessment plan before June 1, 2023, and a construction operations plan before either December 2026 or June 2027, unless DERW seeks and is granted additional time from BOEM, the federal agency that regulates offshore wind development in federal waters. Tr. vol. 17, 113-14; tr. vol. 29, 127, 133. If DERW fails to comply with these obligations (in the absence of the grant of additional time), Duke agrees that DERW runs the risk of having BOEM cancel its CLB lease. Tr. vol. 29, 129-30.

Duke testified that after obtaining a lease for an offshore WEA, it can take eight to ten years to get to the point where electric power is commercially available. Tr. vol. 18, 80. In order to achieve offshore wind generation in this eight-to-ten-year timeframe, Duke outlines a series of steps that would be necessary, including: (1) obtaining BOEM's approval of a site assessment plan by 2024 for the CLB WEA; and (2) submitting a construction and operations plan to BOEM by 2027. Tr. vol. 7, Duke Proposed Carbon Plan, Ch. 4, 20-21.

Duke does not necessarily have to be the entity obtaining approval of a site assessment plan and submitting a construction and operations plan in order to keep offshore wind on the eight-to-ten-year timeframe. If DERW complies with the applicable law (without seeking extensions), it would meet the timeframe Duke proposes. Duke agrees that if DERW moved expeditiously, DERW's actions would keep Duke on the same timeframe as outlined in its near-term action plan. Tr. vol. 29, 134.

In fact, Duke believes its affiliate DERW is currently working on a site assessment plan that it targets for completion by mid-2023. Tr. vol. 17, 120; tr. vol. 18, 121. When asked if DERW would sell to Duke in five years, witness Repko testified: “I don’t know. I presume so.” Tr. vol. 18, 83.

Under the rules governing affiliates, Duke’s purchase from DERW would be made at the lower of cost or market. Duke asserts that because the auction was an independent, third-party process, the May 2022 auction necessarily set the market price. Tr. vol. 7, Duke Proposed Carbon Plan, Ch. 4, 19; tr. vol. 29, 103. Duke testified that its assertion regarding market price has not accounted for the IRA’s impact on the offshore wind moratorium. Tr. vol. 18, 83.

Duke projects the near-term costs associated with offshore wind development to be $317,400,000. It would use approximately half of the funds to purchase DERW’s CLB lease. Tr. vol. 17, 119. Duke was unaware of whether DERW would purchase its lease back if Duke acquired it from DERW and then did not move forward with offshore wind generation. Tr. vol. 18, 83-84.

Two intervenors in this case, TotalEnergies and Avangrid, have also leased offshore wind lease areas. TotalEnergies has leased approximately 55,000 acres in the CLB offshore WEA that is adjacent to that of DERW. Tr. vol. 17, 111. Avangrid has leased 122,405 acres approximately 27 miles from the Outer Banks (the Kitty Hawk lease area). Avangrid Initial Comments at 5.

Duke and Avangrid both support the need to develop offshore wind, as Duke witness Pompee testified that Duke’s modeling economically selected 800 MW of offshore wind energy in 2029 for both Portfolios 1 and 2. *Id*. at 123-24. Avangrid witness Starrett testified “that at least 1.3 GW of offshore wind can . . . serve as a cornerstone to meeting the 70% reduction target required by N.C.G.S. § 110.9. by 2030, with more offshore wind capacity available to follow thereafter.” Tr. vol. 23, 165. But testimony from Duke and Avangrid reveals differing views of the benefits of the various WEAs. Avangrid purchased the lease for the Kitty Hawk WEA. *Id*. at 177. Duke’s unregulated affiliate, DERW, purchased the lease for one of the CLB WEAs. Tr. vol. 29, 95. Avangrid states that the Kitty Hawk lease area is on a much more advanced permitting timeline than that of DERW. Avangrid Initial Comments at 15-17. Avangrid witness Starrett testified that — using publicly available data — the Kitty Hawk WEA provides a superior net capacity factor (NCF) of 43% versus the 36% for the CLB WEA. Tr. vol. 23, 181-82. Duke witness Pompee testified that Duke disagrees with Avangrid’s calculated NCF for the CLB WEA. As witness Pompee testified, “[d]etermining the NCF of any lease area requires detailed site assessment planning and, at this time, [Duke] does not believe that any party has performed the requisite analysis to definitively establish an NCF of 36% for the Carolina Long Bay WEA.” Witness Pompee concludes that the NCF for the CLB WEA that DERW owns is not known without further study, the kind that will occur if Duke pursues the development activities. Tr. vol. 29, 114.

Witness Pompee also testified that the Kitty Hawk WEA would require longer undersea cable than Avangrid claims. The shortest route for undersea cable for the Kitty Hawk WEA would have to traverse the Pamlico Sound, an environmentally sensitive area. According to Pompee, crossing the Pamlico Sound "introduces significant uncertainty due to challenges that could be encountered from a permitting, timing, and cost perspective, and it is likely that BOEM will require an assessment of multiple alternatives to a cable route through Pamlico Sound to reduce potential impacts." *Id.* at 111-13. Avangrid witness Starrett responded that the National Park Service and North Carolina Division of Marine Fisheries suggested crossing the Pamlico Sound as a potential preferred route but admitted permitting could complicate matters. Tr. vol. 23, 207. Witness Pompee testified that the less challenging undersea cable route for the Kitty Hawk WEA would require roughly 100 miles of additional cabling.[16] This longer route would add approximately $350 million to the cost of developing the Kitty Hawk WEA which could offset the lower NCF from the CLB WEA that DERW owns. Tr. vol. 18, 105 (transcript error; Pompee answering). Whether or not a route crossing the Pamlico Sound is ultimately feasible is unknowable at this time.

Avangrid testified that it "is open to any manner of transaction that is on reasonable terms and fairly values the Kitty Hawk lease area, including PPA transactions, or a sale of the lease area, in whole or in part." *Id.* at 173. However, testimony from Avangrid witness Starrett revealed that the ability to advance development of the Kitty Hawk WEA for the benefit of Duke's ratepayers is uncertain. *Id.* at 211-12; 217, 219. First, Avangrid witness Starrett admitted that the current iteration of the Construction and Operations Plan (COP) for the Kitty Hawk North WEA places its interconnection point at Virginia Beach, Virginia, and amending the COP to change that interconnection point to a point in North Carolina could add approximately 18 months to the site's development timeline. *Id*. Second, Avangrid witness Starrett also admitted that while the COP for Kitty Hawk South WEA lists North Carolina counties as possible interconnection points, they could easily amend the COP to list Virginia counties as interconnection points through PJM. Tr. vol. 23, 216-17. Third, Public Staff witness Thomas testified that development of the Kitty Hawk parcels is not as straightforward because "there is no guarantee that the more advanced Kitty Hawk offshore wind resource can be secured by Duke, as electric public utilities in Virginia also have stringent carbon reduction requirements under the Virginia Clean Economy Act." Tr. vol. 21, 62.

Duke's proposed portfolio P1 includes the addition of 800 MW of offshore wind to the generation mix in 2030 with no increase through 2050. Portfolio P2 includes the addition of 800 MW of offshore wind to the generation mix in 2030, the addition of 800 MW in 2032, and the total offshore wind capacity climbing to 3,200 MW by 2050. Portfolio P3 includes no offshore wind as part of the generation mix through 2050. Portfolio P4 includes the addition of 800 MW of offshore wind to the generation mix in 2032 with no increase through 2050. Portfolios SP5 and SP6 did not select offshore wind as part of the generation mix

[16] *See also* tr. vol. 29, 111 ("[Duke] disagrees with Avangrid's analysis that the export route differential is only 25 km. Our analysis of transmission routing indicates an estimate of a longer cable by about 170 km.").

until the 2040s but include at least 1,600 MW of capacity by 2050. Tr. vol. 7, Duke Proposed Carbon Plan, App. E, 73-77; tr. vol. 7, 262; tr. vol. 10, 133.

Offshore wind is selected in only half of the portfolios before the year 2040. Tr. vol. 18, 81. Public Staff witness Metz, therefore, recommended that Duke re-evaluate the need for offshore wind in the 2024 Carbon Plan. Tr. vol. 21, 221-22. Public Staff witness Metz recommended that, at this time, the Commission deny the request to begin the near-term development activities Duke seeks, especially the affiliate transfer from DERW to DEP. *Id.* at 127. Public Staff witness Thomas stated that DERW can undertake the development work for the offshore lease before transferring the lease to Duke. Witness Thomas asserted that this would help ratepayers by reducing risks, supports Duke's "check and adjust" plan, and provides the Commission with an opportunity to evaluate the other lease areas. Tr. vol. 22, 334-35.

For his part, Duke witness Repko testified that if the Commission were to adopt the Public Staff's position, it "would effectively eliminate the ability to keep offshore wind as an option to meet the 70% Interim Target of the Carbon Plan," and goes on to reemphasize Duke's "all of the above" strategy. Tr. vol. 29, 96.

While it is well established globally, with more than 30 GW installed capacity, primarily located in Europe and Asia, offshore wind development in the United States on the scale Duke proposes is nascent. Tr. vol. 7, Duke Proposed Carbon Plan App. J, 1; tr. vol. 21, 127. Presently, hurdles exist with offshore wind, including the lack of Jones Act-compliant seagoing ships needed for construction activities and the risk of strong hurricanes in the area. Public Staff Initial Comments at 91-92.

Offshore wind generation requires undersea cabling, landfall facilities, and overland routing to the point of interconnection to Duke's grid. The NCTPC performed a 2020 Offshore Wind Study which provided a comprehensive screening analysis for several potential points of interconnection. However, that study was not an official generator interconnection study responding to an interconnection request a facility submitted to the DEP Transmission Provider in accordance with the FERC-approved process in the Open Access Transmission Tariff (OATT). In order for offshore wind to appropriately connect to the grid, DEP would have to conduct such studies. Tr. vol. 16, 100.

The Commission concludes that at this time the facts do not support Duke's request for approval of an affiliate transfer of the CLB WEA lease. Given the uncertainty around the price and nature of any potential deal for the Kitty Hawk WEA, and the very early state of understanding of the CLB WEAs, the Commission cannot determine whether or not a transfer from DERW to DEP is consistent with least cost principles at this time. While Avangrid argues that Kitty Hawk will provide the most value to ratepayers, Duke counters that the price certainty of its proposed CLB-first approach outweighs Kitty Hawk's supposed advantages. Duke admits that it cannot determine yet the relative merits of the various WEAs. The Commission requires a better understanding of the variables in order to determine prudence. To the extent Duke chooses to pursue offshore wind development in the near-term, and views purchase of a WEA lease as necessary to furtherance of that objective, it should be prepared to support that decision in a future proceeding, including information showing that its course of action was in keeping with least cost principles.

The Commission supports offshore wind and agrees that Duke's "no regrets" and "all of the above" approaches are appropriate. However, the near-term development steps Duke outlines with respect to offshore wind first require identification of the appropriate WEA. Therefore, the Commission determines that Duke should commence evaluating the three alternative WEAs. The Commission directs Duke to study and consider each of the three WEAs off the coast of North Carolina before pursuing acquisition of a leasehold. This evaluation should include best estimates of all relevant costs to acquire and develop a WEA and deliver energy to the point of injection into Duke's grid. To the greatest extent practicable, this evaluation should compare the WEAs on a similar basis to one another, including a comparison of the levelized cost of energy to the point of injection into Duke's grid.

The Commission notes that offshore wind is not selected until the 2040s in SP5 and SP6 and is not selected at all in P3. However, offshore wind is selected in portfolios P1, P2, and P4, representing both pathways as Duke lays out in its proposed Carbon Plan. The Commission is not persuaded by the Public Staff's contention that because offshore wind is not selected until the 2040s, or ever, in half the portfolios modeled, the Commission should deny near-term actions at this time. Denying all the near-term actions would prevent Duke from using offshore wind within 8-10 years of any eventual decision to go forward, effectively nullifying the portfolios that rely upon offshore wind within that timeframe. On the other hand, even if Duke does not need offshore wind for interim compliance, the near-term actions would be foundational if it does eventually need offshore wind energy.

DERW is not a party to this proceeding, and it is not clear what actions DERW can or will take with respect to development of the CLB lease. The Commission notes for clarity that this Order in no way applies to DERW or any other wind lease holder that this Commission does not regulate, nor does this Order prevent their undertaking any work on or development of an offshore wind lease.

The Commission rejects Duke's assertion that Duke's failure to acquire DERW's lease in the near term will "effectively eliminate" offshore wind as an option for interim compliance. The Commission finds that holders of offshore wind leases may develop the offshore WEAs without Duke's ownership. In fact, both the applicable law and provisions of the BOEM lease require such activities. Should holders of offshore wind leases fail to move forward with the development of their areas for generation, they run the risk of cancelation. Bolstering the Commission's finding, Duke testified that it believes DERW is currently working on the required site assessment plan. Moreover, now that the Commission has clarified the issue of ownership, Duke may have additional options to purchase the other WEAs off the coast of North Carolina. Avangrid testified that it is willing to engage in discussions with Duke for the sale of its offshore wind lease.

The Commission directs Duke to report the findings of its evaluation of the WEAs to the Commission either in the first CPIRP filing or sooner for consideration. This study will permit more accurate modeling in the CPIRP proceeding and enable the Commission to better understand the costs and benefits of potential offshore wind resources. Both Avangrid and the Public Staff argue for an independent third party to conduct this study. While the Commission recognizes that third-party studies can provide benefits, the Commission determines that Duke is the proper party to make this evaluation and that a third-party study is not necessary. The Commission notes the potential that the sunk cost of the CLB WEA lease, from the parent company's perspective, may bias the outcome of the decision, and as such, directs Duke to adopt steps in its evaluation process to protect against this potential bias. Further, to the extent there are any near-term development activities common to all the WEAs under evaluation, including the related onshore transmission infrastructure needed from the point of injection into the Duke grid and thence inland to load centers, Duke may proceed with these activities. Also, the Commission directs Duke to investigate and pursue any federal funding that is available, through the IIJA or the IRA or any subsequent legislation, for offshore wind facilities and associated infrastructure. To the extent that Duke chooses not to pursue any such funding, the Commission expects Duke to provide sufficient justification for why doing so was prudent.

As is the case for pumped storage hydro, the Commission deems Duke's decision to incur costs associated with the limited development activities outlined in the preceding paragraph to be reasonable and prudent in furtherance of the Carbon Plan. To the extent the Commission finds, in a future cost recovery proceeding, the specific activities involved in, and the costs of pursuing these limited development activities to be prudent and reasonable (whether or not the Commission ultimately selects offshore wind for the Carbon Plan), Duke may recover in rates the North Carolina allocable portion of Duke's share of such costs at the time(s) and in the manner determined to be appropriate by the Commission and as otherwise allowed by North Carolina law. To further clarify, the Commission is not preapproving any particular future ratemaking treatment regardless of whether the plant is ultimately never begun, abandoned, or completed. Instead, the Commission retains full discretion to determine the appropriate ratemaking treatment in a future general rate case proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 52

Grid Edge and Customer Programs – Load Reduction

The evidence supporting these findings and conclusions is in Duke's Carbon Plan proposal, testimony and exhibits of Duke's Modeling and Near-Term Actions Panel and Grid Edge Panel, Appalachian Voices witnesses McIlmoil and Kinkhabwala, NCSEA et al. witness Fitch, Public Staff witness Williamson, and the entire record in this proceeding.

In its Carbon Plan proposal, Duke includes certain modeling assumptions that reduce its peak demand and load forecasts based on demand-side activities. Tr. vol. 7, Duke Proposed Carbon Plan, Ch. 2, 7. Duke characterizes this as the first prong of its three-step approach to maintaining reliability while reducing carbon dioxide emissions. Duke seeks to "shrink the challenge" through load reduction from these demand-side activities. *Id.* at 1. Duke groups Grid Edge and other customer programs into three categories: (1) programs that allow customers to reduce carbon dioxide emissions;

(2) programs that reduce carbon dioxide emissions by reducing demand; and (3) programs that allow the use of more resources that reduce carbon dioxide emissions. Tr. vol. 7, Duke Proposed Carbon Plan, App. G, 1.

Duke Grid Edge Panel described Duke's proposed Grid Edge programs as "certain rate designs, voltage control efforts, and other customer programs, such as EE and DSM programs, as well as renewable energy programs and electric transportation programs" where these programs allow customers to manage their use of electricity. Tr. vol. 13, 34. Duke Grid Edge Panel further explained that these programs allow Duke to reduce the amount of load they must serve in order to further the carbon dioxide emissions reduction requirements. Tr. vol. 13, 34-35.

The Modeling and Near-Term Actions Panel explained that Duke applied several load modifiers for its Carbon Plan proposal modeling to account for load projections that decrease load. These include Utility Energy Efficiency (UEE), dynamic rate designs, and behind-the-meter renewables including NEM. Tr. vol. 7, 308; Duke Proposed Carbon Plan, Ch. 2, Tbls. 2-1 to 2-4. Duke also included load modifiers to account for activities that could increase load including EV charging. *Id*.

The Duke Grid Edge Panel noted that Duke includes several categories of EE in its load forecast, including EE improvements customers install outside of UEE programs. Tr. vol. 13, 45. The Grid Edge panel also noted that the IRA could have an impact on EE programs going forward, and that at the time of the hearing Duke was still evaluating those impacts with a focus on UEE. *Id.* at 175. However, the Duke Grid Edge Panel noted that Duke plans to ensure that its customers are aware of the EE incentives, including non-utility EE, available in the IRA. Tr. vol. 14, 55. The Grid Edge Panel also noted that its current evaluation of its UEE programs seeks to isolate and remove the non-utility EE impacts from UEE. *Id.* at 59.

The Commission is persuaded that Duke's assumption that it can achieve a 1% reduction in eligible retail load through UEE programs is an "obtainable modeling assumption" as Duke characterizes the goal. Tr. vol 13, 37. Duke defines "eligible load" to mean the load attributable to retail customers except that portion of nonresidential customers who have elected to opt out of either EE or demand response (DR) programs or both. Tr. vol. 14, 93.

In past IRP proceedings, Duke used Market Potential Studies to identify the amount of EE load reduction that Duke could reasonably achieve. Tr. vol. 13, 38. Public Staff witness Williamson contends that Duke's assumption of 1% of load reduction through EE is too high and not reasonable and that the Commission should direct Duke to return to its use of Market Potential Studies as the basis for its EE forecast. Tr. vol. 21, 189.

Other parties argue that Duke's UEE forecast is too low. NCSEA et al. and their consultant Synapse's modeling utilized EE assumptions of approximately 1.5% of *total* load as opposed to eligible load as Duke modeled. Tr. vol. 25, NCSEA et al. Synapse Report, 24-25, 44. Tech Customers and their consultant, Gabel Associates, claim that a

7.7% reduction in the load forecast is achievable with EE alone. Tr. vol. 25, Tech Customers Initial Comments, Gabel Report, 12. The AGO similarly states that Duke's EE assumptions are "arbitrary" and that Duke should model EE as a selectable resource, while the City of Asheville/Buncombe County and City of Charlotte argue that EE targets based on 1% of retail sales are below other states' EE targets. AGO Initial Comments at 22, 32; City of Asheville and County of Buncombe Initial Comments at 5-6; City of Charlotte Initial Comments at 3, 12.

Both NCSEA et al. and Tech Customers rely in large part on a finding from the 2020 American Council for an Energy Efficient Economy (ACEEE) Report, "How Energy Efficiency Can Help Rebuild North Carolina's Economy: Analysis of Energy Cost and Greenhouse Gas Impacts" (ACEEE Report). In addition to the ACEEE Report, the ACEEE also released a Scorecard in 2020, which Tech Customers and NCSEA et al. also cite to as evidence that Duke can achieve more aggressive EE targets. Tr. vol. 25, Tech Customers Initial Comments, Gabel Report, 41. Duke asserts that the ACEEE Report ignores several factors relevant to North Carolina and assumes that certain legislative changes will occur in the future. Tr. vol. 13, 48-50.

NC WARN asserts that Duke's projection of growth for NEM has significantly declined between its filing in this proceeding and its forecast in the 2020 IRP Proceeding. Tr. vol 22, 209. The Modeling and Near-Term Actions Panel, referring to Appendix F of Duke's Carbon Plan proposal, describes how Duke determined the NEM forecast. The Panel explains that Duke derived the rooftop solar forecast from a series of capacity forecasts and hourly production profiles tailored to residential, commercial, and industrial customer classes, with each capacity forecast being the product of a customer adoption forecast and an average capacity value. Duke develops the adoption forecasts using economic models of payback, which is a function of installed cost, regulatory incentives, regulatory statutes, and bill savings. Tr. vol. 7, 316-17. The Public Staff notes that Duke bases the NEM forecast on the currently approved NEM tariffs, and that the current forecast does not reflect changes to Duke's NEM policies that are currently pending with the Commission. Tr. vol. 21, 175. The Duke Modeling and Near-Term Actions Panel acknowledges that future state and federal policy changes may change the NEM forecast but asserts that the forecast Duke used in its Carbon Plan proposal was appropriate at the time of filing. Tr. vol. 7, 319.

The Commission finds Duke's modeling assumption related to UEE to be reasonable. The Commission is not persuaded by the Public Staff's argument that Duke should limit its forecasts to the savings identified in Market Potential Studies. In response to a request made by Commissioner McKissick during the hearing, Duke identifies potential enablers that would allow it to be more of a leader in EE and obtain annual energy savings over the next five years that are closer to 1.5% of eligible retail sales. Duke provides a high-level list of potential enablers that could allow for the achievement of these aspirational levels over the next five years in Grid Edge Panel Rebuttal Exhibit 1 as informative as to what measures Duke believes would be necessary to meet a 1.5% of eligible retail sales target versus 1.0% of retail sales. Tr. vol. 14, 73-82; tr. vol. 29, Grid Edge Panel Rebuttal Exhibit 1.

The Commission finds that Duke's current forecast of 1% of eligible load is an appropriate bridge between the existing practice of using Market Potential Savings Studies to estimate UEE savings and the intervenors' UEE forecast goals. The Commission is persuaded that Duke can achieve greater load savings than what the Market Potential Savings Studies identify and encourages Duke to continue to improve its efforts and aim higher than the current 1% of eligible load forecast. In weighing the need for the load forecast to be as accurate as possible, the Commission is not persuaded by the intervenors' reliance on the ACEEE Report and will not direct Duke to increase the UEE forecast at this time. Therefore, the Commission directs Duke to seek an aspirational goal of 1.5% and further directs Duke to provide an alternative modeling scenario in its initial CPIRP filing that uses a UEE forecast of 1.5% of eligible retail sales in addition to its proposed UEE forecast of 1% of eligible retail sales.

The Commission is also not persuaded by the AGO's assertion that Duke should allow the model to select EE as a resource. Tr. vol 25, 311. The Commission finds persuasive Duke's assertions that EE is a unique resource, in that customer adoption levels restrain it, and that allowing the model to select EE may overstate the amount of EE that Duke may cost effectively implement. Tr. vol. 13, 43.

The Commission determines that Duke's proposal to reduce load through Grid Edge programs, including demand-side management, EE, customer self-generation, and voltage management, is a reasonable step towards achieving reductions in carbon dioxide emissions as required by N.C.G.S. § 62-110.9. The Commission further determines that the load modifiers Duke used for these programs in this proceeding are reasonable. The Commission directs Duke to utilize the Grid Edge programs to the greatest extent possible. However, the Commission gives substantial weight to Public Staff witness Williamson's testimony that the load forecast must be as accurate as possible in order to avoid creating shortfalls in the load forecast that will then need to be addressed in future proceedings. Tr. vol. 21, 365. Public Staff witness Williamson noted that if the forecasted reduction in load is overstated, Duke will have to take other actions to maintain reliability and serve actual load. Using accurate forecasts provides a greater likelihood that Duke will address future load and reliability in the least cost manner. *Id.* at 187. It is vital that Duke strive to achieve these ambitious goals while maintaining accurate load forecasts. To that end, Duke should seek to quantify the adoption of non-utility EE to accurately reflect the adoption of EE programs in its load forecasts. While Duke has noted that its load forecasts capture these "naturally occurring" EE impacts, due to the tremendous potential for increases in customer driven EE due to the IRA, it is imperative that Duke accurately reflect the adoption of EE — both UEE and non-utility EE — in its forecasts.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 53

Grid Edge and Customer Programs – EVs

The evidence supporting this finding of fact and conclusions is in Duke's Carbon Plan proposal; testimony and exhibits of Duke's Modeling and Near-Term Actions Panel and Grid Edge Panel, Appalachian Voices witnesses McIlmoil and Kinkhabwala, NCSEA et al. witness Fitch, Public Staff witness Williamson, and the entire record in this proceeding.

Duke testified that it continues to work with industry groups to understand the expected pace of EV adoption in its service territories. As of May 31, 2022, approximately 5,800 new EVs were registered year-to date in Duke's North Carolina and South Carolina service territories. This total outpaces the approximately 4,000 registrations for the same period in 2021, representing an increase of 45% year over year. In North Carolina specifically, the EV market has continued to grow. As of March 31, 2022, there were more than 36,000 EVs operating in Duke's North Carolina service territories compared to approximately 25,000 EVs in May 2021. Given the expected continued acceleration in EV adoption, Duke is developing programs to both encourage EV adoption and manage the impact of the new load associated with EVs. Tr. vol. 14, 31.

Appendix E to Duke's Carbon Plan proposal explains the base EV load forecast using trends and assumptions current as of Fall 2021. The base forecast did not include specific projections of future growth resulting from policies or trends from federal government incentive programs. Duke's EV forecast as it describes in Appendix F states that Duke incorporated recent goals from the Biden Administration providing that 50% of new United States passenger car and light truck sales will be electric by 2030. Additionally, major automakers have announced a goal of 40% to 50% of new vehicle sales being electric by 2030. Additionally, North Carolina Executive Order 246 directs the North Carolina Department of Transportation to develop a plan to achieve 1.25 million registered zero-emission vehicles on the road by 2030. Applying these assumptions, Duke used the Vehicle Analytics and Simulation Tool to produce hourly load shapes to determine the demand and energy requirements necessary to forecast the EV potential for the system over the planning horizon. Tr. vol. 7, Duke Proposed Carbon Plan, Apps. E, 18; F, 11.

The Modeling and Near-Term Actions Panel noted that a few potential variables could impact Duke's EV forecast. Examples of variables that may lead to higher adoption levels include increased consumer acceptance, automaker commitments, and strong public government support (policy and funding); examples of variables that may lead to reduced adoption levels include the current global chip shortage, supply chain issues, cost of EVs for the public, and manufacturing limitations. The Panel explained that the EV forecast in Duke's Carbon Plan proposal considered these variables when Duke developed the forecast. The Panel stated that Duke will continue to evaluate the EV marketplace and will continue to update the forecast and that if actual EV adoption differs from Duke's forecasts, Duke will reflect such changes in future Carbon Plan iterations. Tr. vol. 7, 320-21.

The Public Staff in its Initial Comments states that it does not dispute Duke's underlying forecast regarding EVs. The Public Staff acknowledges the nascent nature of the EV market, Duke's current efforts to research the EV market through EV-specific programs, and the EV market's potential to introduce significant amounts of additional load in the coming years. The Public Staff notes that rates and programs that Duke is implementing now can shape customers' charging behaviors and habits, rather than Duke waiting to implement new rates after EV adoption is more mature and customers have established charging behaviors. Although the Public Staff does not find it unreasonable that Duke did not include the impacts of EV-specific programs and rate schedules in its EV load forecast due to the uncertainty of customer response to these programs, it cautions that failure to properly manage new EV load could result in increased system peaks and acceleration of the need for new system resources in the future. Public Staff Initial Comments at 64-65.

Several intervenors, including the City of Charlotte, Durham County, and EWG, recommend that the Commission fully analyze the impact of EVs on load forecast. City of Charlotte Initial Comments at 10-11; Durham County Initial Comments at 6; EWG Initial Comments at 3.

With respect to taking action to optimize the potential electric system benefits of transportation electrification, Duke witness Huber testified that there are

> two parts that it is trying to solve for: 1) one is a do-no-harm piece to the rate design that says, hey, this as a time you don't want to charge, if you do, we'll have to have system upgrades, it's going to be expensive; and 2) another part of that rate design that says, hey, charge here, that will help the system with, you know, possible integration costs of higher renewables, for instance, so it's doing both.

Tr. vol. 14, 95-96. At the expert witness hearing, Duke also recognized that it must design rates to encourage EV charging at times that minimize harm and maximize benefit to the electric system and facilitate charging at locations on the grid that avoid the need for upgrade to the grid and, perhaps, facilitate operation of the grid. *Id*.

The Commission is persuaded that it is appropriate and critical for Duke to consider the impact of EVs on its load forecasts based on the regulatory environment at the time of its modeling. In addition, the Commission directs Duke to continue the two-pronged approach described above. Ultimately, load growth associated with EVs has the potential to reduce system average cost and possibly lead to more optimal system operation at times. Duke must pursue this opportunity to the fullest extent.

The Commission directs Duke, in its upcoming proposed biennial CPIRP, to include a separate and robust analysis of the electrification of transportation, including both load projections and actions Duke undertakes to encourage charging at off-peak times or during times of excess energy. The Commission further directs Duke to facilitate the location of charging infrastructure on the system that avoids or obviates the need for system upgrades or provides additional system benefit.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 54

Grid Edge and Customer Programs – New Regulatory Mechanisms

The evidence supporting this finding of fact and conclusions is in Duke's Carbon Plan proposal, testimony and exhibits of Duke's Grid Edge Panel, Appalachian Voices witnesses McIlmoil and Kinkhabwala, Public Staff witness Williamson, and the entire record in this proceeding.

In identifying the load reduction that Duke can achieve through the Grid Edge programs, Duke also identifies several enablers that would be necessary to continue to meet the load reduction through EE on a long-term, annual basis. The Grid Edge Panel requested that the Commission approve several enablers that Duke identifies in its Carbon Plan proposal. Tr. vol. 7, Duke Proposed Carbon Plan, App. G. Duke asserts that there is value in the Commission acknowledging and affirming at this time the enablers Duke identifies in order that the work on the Grid Edge programs can begin. The enablers the Grid Edge Panel identifies include: (1) updating the inputs underlying the determination of the utility system benefits; (2) moving to an "as-found" baseline; (3) expanding the pool of low-income customers; (4) obtaining approval of Duke's proposed tariff on-bill programs; and (5) adopting new flexibility and rapid prototyping guidelines to ensure timely regulatory approval of new DSM/EE pilots and rate designs. Tr. vol. 13, 32-33.

Generally, the Public Staff asserts that it is not appropriate or necessary for the Commission to acknowledge in this proceeding that the enablers Duke identifies are necessary to achieve targeted UEE savings. The Public Staff asserts that acceptance of these enablers would require either public policy decisions by the Commission, legislative action, or proceedings in separate dockets to investigate the impacts of any proposed enablers. Tr. vol. 21, 208-09.

Other intervenors also criticize specific enablers that Duke requests. AGO witness Burgess argues that Duke's proposal to shift to an as-found baseline would include "fictitious" energy savings and would not be reasonable. Tr. vol. 25, 316. AGO Strategen Report, 44-45. Appalachian Voices witnesses McIlmoil and Kinkhabwala disagree with Duke's proposal to expand the pool of low-income customers and argue that DSM/EE programs for low-income ratepayers are insufficiently funded. Tr. vol. 24, 43-44.

The Commission acknowledges that Duke identifies certain enablers that would allow it to achieve greater load reduction through its Grid Edge programs. While the Commission encourages Duke to utilize its Grid Edge programs, the Commission is persuaded by the Public Staff that all enablers related to the DSM/EE mechanism should be discussed within the context of a full DSM/EE mechanism review. The Commission approved the most recent DSM/EE mechanism for each company in October 2020 in Dockets No. E-2, Sub 931, and E-7, Sub 1032. Tr. vol. 13, 39. The Commission is persuaded by the Public Staff's assertion that "any modifications to individual components of the Mechanisms must take place in the context of a full, formal review of the entire Mechanisms, so that any impacts of other components of the Mechanisms can be analyzed at the same time." Tr. vol. 21, 193. With one exception, the Commission determines that it is not reasonable to make any determination on the specific enablers in this proceeding but directs Duke to initiate a review of DEC's and DEP's DSM/EE Mechanisms within 120 days of the issuance of this Order.

The Commission is also persuaded that the adoption of new flexibility and rapid prototyping guidelines to ensure regulatory approval of new customer programs, pilots and rate designs in a timely manner would be appropriate at this time. Tr. vol. 13, 32-33. The Grid Edge Panel explained that other states have expedited implementation processes for customer programs and that Duke believes that similar guidelines in North Carolina can help enable timely implementation of the energy transition and the Carbon Plan. The Grid Edge Panel noted that the current "Flexibility Guidelines" the Commission has approved as part of Duke's Mechanisms for DSM/EE programs is an example of such a guideline, and that a similar expedited approval process for new customer programs and pilots for non-DSM/EE programs would better allow Duke to innovate, shrink the challenge, and timely implement the Carbon Plan. The Commission is receptive to this approach and directs Duke to file a formal proposal with the Commission.

In addition, the Commission finds that Duke can also reduce load by decreasing the number of nonresidential customers that elect to opt out of its DSM/EE programs. As Duke witness Duff noted a "significant portion" of Duke's nonresidential customers, representing approximately 30% of its load, have opted out of participation. Tr. vol. 14, 93-94. Duke witnesses testified that "to achieve the aggressive long-term energy efficiency projection necessary for energy transition and included in the Carbon Plan, the Companies recognize that they must increase the efficiency savings from customers that are participating in the Companies' portfolio *and* obtain savings from customers not participating in its portfolio of EE/DSM programs or, as the Companies call it, expanding the pool for savings." Tr. vol. 13, 65 (emphasis added). Duke witness Huber outlined some of the actions Duke has taken to reduce the number of customers that opt out of participating in the portfolio of DSM/EE programs including working with CIGFUR to develop new DR programs and streamlining the way for customers to opt in. Tr. vol. 13, 128; tr. vol. 30, 64. Duke's Grid Edge Panel further noted that Duke has "a long history of working with stakeholders in the DSM/EE Collaborative to ensure that their portfolios of nonresidential programs are both attractive and comprehensive." The Commission directs Duke to focus on expanding the pool for savings by developing programs aimed at reducing the number of DSM/EE opt outs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 55

Grid Edge and Customer Programs – Wholesale Customers and Dynamic Rate Design

The evidence supporting this finding of fact is found in the testimony of NCEMC, Power Agencies Initial Comments, Duke's Initial Comments, and the entire record in this proceeding.

Coordination with Wholesale Customers

The Power Agencies contend that the Carbon Plan cannot comply with N.C.G.S. § 62-110.9's least cost mandate without taking full advantage of as much load-side management as its wholesale customers can possibly provide. The Power Agencies claim that Duke's current plan "effectively ignores the potential for demand reduction associated with as much as 30% of DEP's load" and recommend that the Commission direct Duke to take full advantage of as much load side management as wholesale customers can provide. Power Agencies Initial Comments at 4-5.

NCEMC witness Ragsdale testified that NCEMC and its 26 member-distribution cooperatives[17] have developed and implemented the NCEMC Distribution Operator (DO), a single entity that monitors and coordinates DER and DR resources for the electric membership co-ops across the State. Tr. vol. 26, 207-08. Witness Ragsdale noted that the Commission has previously recognized the value of the DO in contributing reliability benefits to Duke's system, and that coordination of such efforts between Duke and NCEMC was consistent with least cost planning. *Id*.

Duke Transmission Panel witness Roberts described Duke's coordination with NCEMC and its DO platform. He indicated that Duke included in its General Load Reduction Plans the fact that it is able to coordinate operating instructions to utilize NCEMC's DO capabilities for emergency purposes, and that Duke continues to have collaborative meetings with NCEMC to coordinate the utilization of the DO function from a reliability perspective. Tr. vol. 26, 120-21.

Duke argues that the Power Agencies' request would be outside the bounds of the Carbon Plan proceeding. Duke explains that, as the North Carolina Court of Appeals has recognized, "exclusive jurisdiction over interstate wholesale electric power transactions is conferred upon FERC."[18] Duke further notes that Duke's wholesale requirements contracts with multiple entities in the Carolinas are on file with FERC and subject to its jurisdiction, including as they relate to how the wholesale customers' DSM/EE programs interact with wholesale charges. Duke Pre Hearing Comments at 63.

As NCEMC witness Ragsdale noted, the Commission has previously recognized the growing relationship between resource and distribution planning between the electric public utilities and their load serving entity customers. In its April 6, 2020 Order Accepting Filing of 2019 IRP Update Reports and Accepting 2019 REPS Compliance Plans in Docket No. E-100, Sub 157, the Commission recognized the benefits of including the electric membership cooperatives in the Integrated Systems and Operations Planning (ISOP) process.

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[17] For clarity, NCEMC notes that its 25 participating and independent members, as well as French Broad EMC, a member of the North Carolina Association of Electric Cooperatives, Inc., participate in the DO platform.

[18] *State ex. rel. Utils. Comm'n v. N.C. Electric Membership Corp.*, 105 N.C. App. 136, 142 (1992) (affirming that issues affecting wholesale rates were appropriately not addressed in IRP proceeding as "such an issue is more appropriately addressed to FERC"); *see also Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 964 F.3d 1177, 1181 (2020).

The Commission recognizes that contractual arrangements between Duke and its wholesale customers associated with the operation of DER, demand reduction measures, and any compensation mechanisms associated with such resources are FERC-jurisdictional. However, the Commission acknowledges the very real potential that coordinated use of these resources has to influence a lower-cost path to compliance with N.C.G.S. § 62-110.9. Therefore, the Commission directs Duke to continue to coordinate with NCEMC and other LSEs in both its ISOP process and the Carbon Plan stakeholder process regarding the utilization of the capabilities of their DER programs and the ability of such programs to contribute to Duke's ability to comply with the carbon dioxide emissions reduction mandates of N.C.G.S. § 62-110.9 in a least cost manner that at a minimum maintains or improves the reliability of the entire grid network in North Carolina. Duke in its upcoming proposed biennial CPIRP shall include a report on the discussions between it and the other LSEs in the state, provide an estimate of the future potential of those coordinated DER resources to contribute to future Carbon Plan compliance, and make reasonable efforts to incorporate those measures in its 2024 CPIRP filings. Duke shall also include a discussion of progress with the wholesale customers, as well as any impediments it identifies regarding the capability of these coordinated DER resources to contribute to low cost, reliable Carbon Plan compliance in such filings.

Dynamic Rate Design

Chapter 4 of Duke's Carbon Plan proposal briefly discusses some of the possible near-term rate design actions to encourage customers to change their load profiles to better support lower- and zero-carbon resources. These include updating pricing structures for distributed solar resources, developing new real-time pricing tariffs for large business customers, and piloting subscription rates to encourage customers to actively manage their charging behaviors. Duke intends rate programs such as critical peak pricing and peak-time programs to send signals to customers to incentivize reduction of their energy consumption during peak hours. Duke captures the effects of these and other rate programs in the load forecast and models them as a reduction in load. Tr. vol. 7, Duke Proposed Carbon Plan, Ch. 4, 32; App. E, 24.

The Grid Edge Panel explained that Duke engaged a third-party facilitator to support a broad stakeholder process covering both DEC and DEP rate designs over the course of 12 months, concluding in March 2022. The Grid Edge Panel described the collaborative process as including participation from more than 50 organizations including commercial and industrial customers, EV companies and advocates, environmental advocates, government agencies, public advocates, renewable/distributed energy companies, and legal/consulting companies covering a comprehensive number of topics. The Grid Edge Panel explained that this stakeholder engagement resulted in Duke's crafting an informed vision and direction for future pricing and rate design options in the form of a Roadmap, which Duke filed with the Commission in Docket Nos. E-7, Sub 1214 and E-2, Sub 1219 on March 31, 2022. Tr. vol. 13, 67.

The Grid Edge Panel also provided examples of specific program concepts that Duke has discussed with stakeholders including a revised Green Source Advantage

(GSA) program, a "Clean Energy Impact" program for residential and business customers who want to support the advancement of renewables by purchasing locally generated renewable energy certificates (RECs) from Duke-owned renewable resources, and the Clean Energy Connection Program, which is a subscription solar program for all customer types to support renewable energy in North Carolina. *Id.* at 69-71.

The Public Staff recommends that the Commission explore the proposals stemming from the Comprehensive Rate Design Study and that Duke at a minimum offer them on a pilot basis if they improve system efficiency and avoid significant cost shifts between customer classes. The Public Staff notes that it does not oppose specific rate design proposals at this time but also does not recommend any of the specific rate design proposals in the proposed Carbon Plan given its view that the Commission should review any such proposals as part of a program application. Public Staff Initial Comments at 67-68.

CIGFUR also asserts that Duke should explore rate design options that could potentially reduce load. Tr. vol 22, 43.

The Commission finds the proposal for Duke to pursue dynamic rate design reasonable but is persuaded by the Public Staff that the Commission must fully review and evaluate all programs within the proper proceeding. The Commission directs Duke to engage with stakeholders to develop dynamic rate designs and to propose such rate designs in future rate cases.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 56

Transmission – RZEP

The evidence supporting this finding of fact is in Appendix P to Duke's Carbon Plan proposal, the direct and rebuttal testimony and exhibits of the Duke Transmission and Solar Procurement Panel, the testimony of Public Staff witness Metz, CPSA witness Norris, and NCSEA witness Caspary.

The "Red Zone" consists of several non-contiguous geographic areas in DEC and DEP territories where transmission constraints exist, as depicted in Figure P-1 of Appendix P. As Public Staff witness Metz testified, the Red Zone is highly suitable for solar development due to its flat terrain, relatively low land costs, and relatively high solar insolation; however, historical load requirements and, more recently, increased solar development highly constrain the transmission in this area. Tr. vol. 21, 140. The historic success of solar development interconnected to Duke's distribution and transmission systems in these areas has contributed to the transmission system reaching a saturation point, i.e., the system has too much generation and not enough load in discrete line segments of the distribution and transmission system. *Id.*

Duke witness Roberts explained how Duke identified four transmission upgrade projects in the DEC territory and 14 transmission upgrade projects in the DEP territory, which Duke calls Red-Zone Transmission Expansion Plan (RZEP) projects. In March of

2022, prior to its Carbon Plan filing, Duke presented the RZEP projects to the Oversight Steering Committee (OSC) of the NCTPC. The NCTPC is the local transmission planning body in which Duke participates in order to satisfy its obligations under FERC orders. Tr. vol. 16, 67; Transmission Panel Exhibits 1 and 2. Class 5 estimates for all of the 18 RZEP projects exceed $560 million. Tr. vol. 7, Duke Proposed Carbon Plan, App. P, 14-15. In June 2022, the NCTPC distributed a draft of the 2021 Mid-year Update Report to the Transmission Advisory Group (TAG) of the NCTPC for review prior to the June TAG meeting; the draft 2021 Mid-Year Update Report proposed adding the RZEP projects to the Local Transmission Plan. Tr. vol. 16, 68. Duke planned to seek approval of the 2021 Plan Mid-Year Update Report, including the 18 RZEP projects, from the OSC by mid-August, pending feedback from TAG stakeholders. *Id*.

However, on June 10, 2022, the Commission directed Duke not to include RZEP projects in the 2022 DISIS baseline, concluding that doing so would be premature because "no party has presented competent evidence that the RZEP projects are necessary to achieve the Carbon Plan." Order Approving Request for Proposals and Pro Forma Power Purchase Agreement Subject to Amendments, *Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Solar Procurement Pursuant to Session Law 2021-165, Section 2.(c)*, Nos. E-2, Sub 1297, E-7, Sub 1268 (N.C.U.C. Jun. 10, 2022). Duke witness Roberts testified that, based on the Commission's directive as well as feedback the NCTPC received from TAG stakeholders, the NCTPC communicated that it would no longer consider the RZEP projects for inclusion in the 2021 Plan Mid-Year Update Report. Tr. vol. 16, 69.

In its Issues Report filed in this proceeding on July 22, 2022, Duke agreed to perform supplemental analysis for the Public Staff to address the need for RZEP projects. Tr. vol. 21, 140. Accordingly, Duke performed a revised transmission study to address some of the concerns the Public Staff raised in the NCTPC process, such as isolating solar facilities that were extraneous and required substantial line upgrades that primarily benefited one interconnection request. Tr. vol. 21, 142-43. Duke's recent supplemental transmission studies show the need for 11 of the original 14 RZEP projects in DEP, in order to enable 2,778 MW of solar projects to interconnect in the DEP Red Zones, and 981 MW of solar project to interconnect in the DEC Red Zones, all 4 of the original RZEP projects in DEC.

More specifically, Duke concludes that the supplemental studies demonstrate that it can delay DEP Projects #9 (Rockingham-West End 230 kV West), #11 (Erwin-Milburnie 230 kV line), and #12 (Sutton-Wallace 230 kV line) until future studies again show a reliability need or generation addition need. This would reduce the RZEP project group from 18 to 15 projects. Tr. vol. 16, 74-75.

Looking to the original 18 proposed projects, Public Staff witness Metz recommended against construction of DEC Project #4, the Clinton 100 kV line, because there were relatively few generator facilities impacting that line and the relationship between future solar generation and that upgrade is unclear. Tr. vol. 21, 145-46. Witness Metz similarly recommends against construction of DEP Projects #7, #9, #11, #12, and #14 because relatively fewer interconnections impact them as compared with the other

RZEP projects. At the same time, Witness Metz opined that interconnection requests are likely to increase in the Red Zone after completion of the upgrades, potentially leading to more congestion. Tr. vol. 21, 149. If the Commission were to adopt the Public Staff's recommendations, it would reduce the RZEP project group from 18 to 12 projects.

In rebuttal, Duke Transmission Panel witnesses agreed that Duke could postpone Project #14 — the Camden-Camden Dupont 115 kV line upgrade — at this time. However, Duke testified that that prior generator interconnection studies and the supplemental studies demonstrate that DEC Project #4 (Clinton 100 kV line) and DEP Project #7 (Erwin – Fayetteville 115 kV line) will be necessary to integrate hundreds of MW of generation in the Red Zone area. Tr. vol. 28, 130-32. Furthermore, Duke estimated that DEC Project #4 will take 48 months to build, and that DEP Project #7 will take 54 months. *Id.* at 132-33. If the Commission adopts the recommendations in Duke's rebuttal testimony, it would restore two projects that the Public Staff recommends postponing and increase the RZEP project group from 12 to 14 projects.

Duke witness Roberts described the Red Zone as "fertile ground" for development of utility-scale solar projects and testified that these are areas in which Duke would develop solar on its own, even if it were not purchasing from third parties. Tr. vol. 19, 60-62.

Duke notes that all of the portfolios the parties to this proceeding propose require interconnection of at least 5 GW of solar over the next decade, including solar combined with storage. *See* tr. vol. 21, 142. Without completion of the RZEP projects, Duke concludes it would be "extremely challenging" if not impossible to meet the Interim Target. Tr. vol. 16, 187; tr. vol. 19, 61. Duke has completed no significant development work for the RZEP projects, and certain RZEP projects have lead times of up to 4.5 years. Tr. vol. 16, 68-69.

Duke sees benefits flowing from the RZEP projects, aside from the requirements of N.C.G.S. § 62-110.9. Duke assessed the reliability benefits of the RZEP projects, using two different methodologies, and determined that the projects had cost-benefit ratios ranging between 5.1 to 22.5 as many of the projects will be replacing aging facilities with newer and more efficient and resilient components. Id. at 78-79. Duke also identifies additional benefits from the RZEP projects, such as increased ability of solar in the Red Zones to charge standalone battery storage located close to load centers and discharge during net demand peak periods. *Id.* at 71.

CPSA witness Norris testified that "Duke has amply demonstrated that the RZEP upgrades are needed to achieve compliance with HB 951." Tr. vol. 26, 25. Based on the additional analysis the supplemental studies provide, he describes them as a "no-regrets" set of upgrades. He noted that the supplemental study is consistent with CPSA members' experience in developing solar projects in the Carolinas. *Id*. at 63-64. Likewise, NCSEA witness Caspary testified that the RZEP projects are necessary to achieve the Interim Target by 2030. He endorsed the efficiency of planning resources and transmission at the same time and agrees with Duke that the risk of underutilization of the RZEP projects is low. Tr. vol. 22, 13-15.

Based on the foregoing, including the fact that the Public Staff is overall supportive of the majority of the RZEP projects, the Commission concludes that the fourteen 2022 RZEP projects are necessary to achieve the carbon dioxide emissions reduction mandates of N.C.G.S. § 62-110.9 in a least cost manner. The Commission's conclusion is in keeping with the directive from the North Carolina General Assembly that the Commission consider transmission as an element of the Carbon Plan. N.C.G.S. § 62-110.9(1).

The Commission gives substantial weight to Duke's testimony regarding the necessity of the fourteen 2022 RZEP projects, including DEC Project #4 and DEP Project #7, given their long lead times and the fact that they should allow hundreds of megawatts of solar energy to interconnect to Duke's system. The Commission finds that the risk of those upgrades being underutilized is low. Even the Public Staff expects interconnection requests in the Red Zone to increase after construction of the upgrades.

Completion of the 2022 RZEP projects is a necessary first step to interconnect the solar volumes necessary to execute the Carbon Plan, both in terms of carbon dioxide emissions reductions and in terms of the timelines N.C.G.S. § 62-110.9 mandates. The 2022 RZEP projects will allow the interconnection of approximately 3,759 MW of solar generating facilities in Duke's territory — 2,778 in DEP and 981 in DEC — as the aforementioned supplemental transmission studies evidence.

The 2022 RZEP projects are appropriate for Duke to construct as a reasonable early step to meet with the requirement of N.C.G.S. § 62-110.9 that the Carbon Plan must constitute the least cost path that meets the carbon dioxide emissions reduction mandates of N.C.G.S. § 62-110.9 and provides additional operation and resiliency benefits.

In regard to bids for solar facilities that are dependent on the RZEP projects in the 2022 Solar Procurement, the Commission notes that NCSEA et al. seek to alter the assignment of RZEP project costs to those bids if the NCTPC approves the RZEP projects and, therefore, includes them in the Local Transmission Plan. Once in the Local Transmission Plan, the RZEP projects would be part of Duke's "baseline" for interconnection studies going forward. Tr. vol. 29, 33. Specifically, NCSEA et al. request that if the NCTPC approves the RZEP projects in 2023, the Commission order Duke to use the DISIS Phase 1 Upgrade cost allocations for the bids for solar projects that depend on the RZEP, as opposed to the DISIS Phase 2 results, for purposes of the 2022 Solar Procurement final bid evaluation, VAM calculations, and assessment of compliance with the CPRE avoided cost cap. *See* NCSEA, SACE et al., CCEBA, CPSA, and MAREC Joint Br. and Partial Proposed Order at 231. They point out that Duke witness Farver stated that Duke is in the process of seeking approval from the NCTPC to include the RZEP projects in the 2022 Local Transmission Plan that will be finalized in early 2023, and that the 2022 Local Transmission Plan will likely include the RZEP projects by the time the Step 2 evaluation of the 2022 Solar Procurement is conducted. Tr. vol. 29, 72-73; NCSEA, SACE et al., CCEBA, CPSA, and MAREC Joint Br. and Partial Proposed Order at 228. They argue that bids for solar projects that depend on the RZEP projects present a "particular problem" with regard to assignment of Network Upgrade costs in the 2022 Solar Procurement. NCSEA, SACE et al., CCEBA, CPSA, and MAREC Joint Br. and Partial Proposed Order at 228. They state that because Duke did not include the RZEP projects in the baseline for the DISIS Phase 1 study, the full costs of the RZEP projects will be assigned to any projects that trigger those upgrades in the DISIS study and those assigned upgrade costs will influence the evaluation of projects in the 2022 Solar Procurement RFP. *Id.* NCSEA et al. contend that assignment of the full cost of the RZEP projects to bids for solar projects that depend on the RZEP projects in the 2022 Solar Procurement RFP is likely to have "undesirable and problematic consequences." *Id.* They argue that because the number of solar projects being procured in the 2022 Solar Procurement is smaller than the total number of solar projects that will benefit from the RZEP projects, it would be inappropriate to assign the full cost of the RZEP projects to a smaller number of solar projects and thus drive up the apparent cost of the 2022 Solar Procurement. *Id.* at 227, 229. They are concerned that assignment of the RZEP projects to bids for solar projects that depend on the RZEP projects could result in rejection of those bids in the 2022 Solar Procurement. *Id.* at 229. They state that even if the bids that depend on the RZEP projects are selected in the 2022 Solar Procurement, Duke should not assign the full cost of the RZEP projects in calculating the cost for purposes of the VAM and for purposes of determining whether projects selected to fulfill the CPRE capacity allocation in the 2022 Solar Procurement meet the avoided cost cap. *Id.* at 229-30.

The Commission finds that NCSEA et al. are effectively asking the Commission to modify the Commission's orders regarding the 2022 Solar Procurement, along with the 2022 Solar Procurement RFP, while the bid evaluation process is underway.[19] In response to this request, the Commission notes Duke witness Farver's explanation of the effect of any NCTPC approval of the RZEP projects — that Duke will classify the RZEP projects as "Contingent Facilities" and include them in Duke's "baseline" and will not assign costs of the RZEP projects in Interconnection Agreements coming out of the 2022 DISIS process and in subsequent DISIS processes. Tr. vol. 29, 29, 33, 34. Duke witness Farver, who cautioned against making any changes to the 2022 Solar Procurement process at this point, testified about her concerns regarding the NCSEA et al.'s request. Tr. vol. 29, 29-30, 77. She stated that if the costs of the RZEP projects were not assigned to the bids for solar projects that trigger the need for the RZEP projects, then the ranking of projects in the 2022 Solar Procurement could change. *Id.* She also testified, in support of not making a change to the 2022 Solar Procurement process at this point in spite of the NCSEA et al. concern, that "we don't know if all of those upgrades identified in [DISIS] Phase 1 will still be necessary in Phase 2, so as there are fewer projects, perhaps there are fewer upgrades needed." Tr. vol. 28, 183.

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[19] *See* Order Approving Request for Proposals and Pro Forma Power Purchase Agreement Subject to Amendments, *Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Solar Procurement Pursuant to Session Law 2021-165, Section 2.(c)*, Nos. E-2, Sub 1297, E-7, Sub 1268 (N.C.U.C. Jun. 10, 2022) and Order Permitting Additional CPRE Program Procurement and Establishing Target Procurement Volume for the 2022 Solar Procurement, *Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, Joint Petition for Approval of Competitive Procurement of Renewable Energy Program and Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Solar Procurement Pursuant to Session Law 2021-165, Section 2(c),* Nos. E-2, Sub 1159, E-2, Sub 1297, E-7, Sub 1156, and E-7, Sub 1268 (N.C.U.C. Nov. 1, 2022).

The Commission agrees with Duke witness Farver that it is not appropriate to "change the evaluation process mid-flight in the current 2022 RFP." Tr. vol. 29, 77. Not only would it be inappropriate to change the rules of the 2022 Solar Procurement "mid-flight" and potentially unfair to bids for solar projects that are not dependent on the RZEP projects, the Commission has made it abundantly clear in its 2022 Solar Procurement Orders that "the [2022 solar] procurement process must evaluate bids that takes into account all costs for the proposed facilities, including Network Upgrades . . . Duke is directed not to include the RZEP projects in the 2022 DISIS baseline." The Commission reiterated its direction to Duke and the parties to allocate Network Upgrade costs in the bid evaluation process in its November 1, 2022 Solar Procurement Order. However, to again be clear, the Commission denies the request of NCSEA et al. to modify the Commission's 2022 Solar Procurement orders and the Solar Procurement Program RFP and directs Duke to comply with the procedure the 2022 Solar Procurement Program RFP requires (i.e., to include the Network Upgrade cost estimate in the Part B Price for bids for solar projects that depend on the RZEP).

Duke witness Farver also stated that it is unclear how Network Upgrades that solar projects trigger and that Duke also includes in the baseline (assuming, again, NCTPC approval) would be assigned to the bids for solar projects that depend on the RZEP projects in the 2023 Solar Procurement and subsequent solar procurements. Tr. vol. 29, 28. While she opined that designing an appropriate RFP for the 2023 Solar Procurement will be "new territory" for Duke, she testified that the 2023 Solar Procurement RFP might be designed "such that it's not just zero assigned to those Red Zone projects, but that there's some cost reflected in the evaluation process to recognize that there was a transmission cost associated with it." Tr. vol. 29, 28. Duke witness Farver further testified:

> I think for future solar procurements we should have further discussion about how best to account for transmission costs assigned to projects — I should say transmission costs assigned to projects for evaluation purposes if those transmission costs are not being borne by the generator in the DISIS interconnection process. So for a Red Zone upgrade, how are we making sure that we're not assigning a zero transmission cost to a project that's benefiting from Red Zone upgrades that were approved through a different mechanism [the NCTPC], but also not assigning one project the full cost of all of the Red Zone upgrades because that also is not an accurate reflection of the — I suppose the project's cost.

The Commission agrees with Duke witness Farver that it is important that the 2023 Solar Procurement RFP ensure that bids for solar projects that depend on the RZEP projects are assigned an appropriate percentage of RZEP project costs since those solar projects have caused the need, in part, for the RZEP projects but will not have to pay for it. As Duke witness Farver noted, bids for solar projects that depend on the RZEP projects should be evaluated in solar procurements' RFPs based upon the projects' costs, including the Network Upgrades. The Commission points out that the necessity of evaluating bids for solar projects considering the projects' total costs is not confined to the RZEP projects; instead, any projects triggering Network Upgrades that the NCTPC has approved, and that Duke has included in the "baseline" should be evaluated based upon the projects' total costs. Accordingly, the Commission directs Duke to prepare a mechanism for the 2023 Solar Procurement that evaluates bids for solar projects that depend on the RZEP that includes an appropriate cost for the RZEP projects.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 57-58

Transmission – Planning

The evidence supporting these findings of fact is in Appendix P and Appendix S to Duke's Carbon Plan proposal, the direct and rebuttal testimony and exhibits of the Duke Transmission Panel, the testimony of Public Staff Witness Metz, CCEBA witness Gonatas, CPSA witness Norris, and NCSEA witness Caspary, and the entire record in this proceeding.

Duke explains in Appendix P that executing the Carbon Plan will require a transformation of the DEC and DEP transmission system in the near-term and long-term to interconnect the unprecedented amount of new supply-side resources that will be necessary to retire significant amounts of coal-fired generation and achieve the carbon dioxide emissions reduction mandates of N.C.G.S. § 62-110.9.

Duke requests the Commission to direct Duke to continue to study future transmission needs and to reliably implement the Carbon Plan primarily through the NCTPC, whose transmission planning procedures are set out in Attachment N-1 of Duke's OATT and are designed to meet the requirements of FERC Order Nos. 890 and 1000. Tr. vol. 7, Duke Proposed Carbon Plan, App. P, 7-8. The members of the NCTPC are DEC, DEP, ElectriCities, and NCEMC. Tr. vol. 16, 53, Tr. vol. 7, Duke Proposed Carbon Plan, App. P, 7. The Duke Transmission Panel provided an overview of the NCTPC process and explained that the NCTPC solicits input and recommendations from stakeholders through the TAG. Tr. vol. 16, 54-57; Tr. vol. 7, Duke Proposed Carbon Plan, App. P, 6-9. State public utility commissions may receive periodic status updates and progress reports on the NCTPC process. *Id.* at 8. Duke participates in regional transmission planning in compliance with FERC Order Nos. 890 and 1000 through the Southeastern Regional Transmission Planning (SERTP) process. *Id*. at 9.

Duke witness Roberts opined that to meet the N.C.G.S. § 62-110.9 carbon dioxide emissions reduction mandates, Duke must integrate transmission planning with resource planning, consistent with the Commission's and FERC's respective authorities. Tr. vol. 16, 59. He explained that failure to do so could lead to insufficient timely transmission development and that the lack of transmission infrastructure to reliably support coal retirements and integrate significant amounts of new generation would put Carbon Plan execution at risk. *Id.* at 61-62.

Duke witness Roberts also explained that Duke embraces least regrets planning and expects to identify future transmission upgrades in a variety of ways, including generator interconnection requests, DISIS studies, and scenario-based planning, in order to identify holistically the transmission upgrades necessary to provide the most benefits for the least cost. *Id.* at 168-69.

The Public Staff supports, as does Duke, the need to evolve and move away from a solely reactive transmission upgrade approach, where upgrades are constructed in response to generation interconnections, to a proactive approach that also considers upgrades in anticipation of future generation needs. *Id.* at 63-66.

Duke witness Roberts stated that "[a]n effective transmission planning process is necessary for system adequacy and reliability . . . and Duke views the transmission planning process as a key enabler of achieving the goals of the Carbon Plan." *Id.* at 59. He noted that the Commission's Final Order on the Duke's 2020 IRP highlighted the Commission's focus on transmission planning and the transmission Network Upgrades necessary to retire coal facilities and integrate new resources to achieve the least cost energy transition N.C.G.S. § 62-110.9 requires. *Id*. at 60.

Duke agrees with the Public Staff and other intervenors that the NCTPC planning process must evolve to meet the needs of executing the Carbon Plan. *Id.* at 86. Duke commits to working with NCTPC OSC members and stakeholders to consider changes to the local transmission planning processes reflected in Attachment N-1 of Duke's OATT that would improve coordination with Carbon Plan execution and ensure timely and robust review of transmission projects necessary to meet generation needs. *Id.* at 85-87.

Public Staff witness Metz testified that a transformation in the generation fleet cannot be considered in isolation from the impact on the transmission system. Tr. vol. 21, 139. The Public Staff states that proactive transmission upgrades require a balance of least cost and least-regrets planning, coupled with a robust, forward looking planning process. The Public Staff further states that a least-regrets approach for proactive transmission is reasonable because Duke will add solar and other low or no carbon resources in later years, likely exceeding the 5 GW amount by the late 2030s. *Id.* at 142.

NCSEA witness Caspary recommended that the scope of studies the NCTPC and SERTP perform needs to better inform regional and interregional plans to ensure least regrets plans which maximize net benefits and address the decarbonization requirements of N.C.G.S. § 62-110.9 through 2050. Tr. vol. 22, 247.

Witness Caspary stated that for its Carbon Plans, the Commission should direct Duke to incorporate the results of long-range joint studies with other utilities and stakeholders to determine optimal expansion plans in lieu of Affected System studies. Tr. vol. 22, Ex. 2, 10. He further testified that the Commission should encourage Duke to provide some leadership to expand the current SERTP and NCTPC processes, while at the same time leveraging the DOE-funded Atlantic Offshore Wind Transmission Study, to better identify long-term needs of Duke and its neighbors. Finally, he stated that it is imperative that neighboring systems work together to identify and address future system needs in an open and transparent manner, implementing the best solutions to improve grid performance. Tr. vol. 22, 240.

Based on the foregoing, the Commission concludes that it is reasonable for Duke to engage in the process of making changes to transmission planning to reliably implement the Carbon Plan through the NCTPC, SERTP, and other transmission planning forums that Appendix P identifies, and witness Roberts discussed. The Commission supports Duke's acknowledgement that changes to the NCTPC are necessary and strongly advises Duke to initiate a review of its processes and quickly implement any improvements that FERC may require in a final rule resulting from the Notice of Proposed Rulemaking in FERC Docket RM21-17-000. The Commission agrees with witness Roberts that Duke must integrate transmission planning with resource planning to maintain the reliability of the electric system and to ensure a least cost path to compliance with N.C.G.S. § 62-110.9.

Furthermore, based upon the potential magnitude of future transmission expenditures, the Commission urges Duke to explore all possible efficiencies and to be vigilant in its participation in SERTP and in its coordination with PJM to assure a least cost path to achieve the carbon dioxide emissions reduction requirements while maintaining and improving reliability.

In addition, the Commission notes that there are important linkages between the work of Duke's ISOP teams relative to distribution level Grid Edge programs and impacts on the design and operation of the bulk power system that may result. The Commission encourages Duke, in its future transmission planning efforts, to support ISOP's strengthening these linkages between the bulk power system and distribution level DER programs.

Although the Commission will not dictate any specific changes to the NCTPC, the Commission encourages Duke to engage with stakeholders and the other members of the NCTPC immediately to improve the NCTPC process and address requests to increase transparency and coordination and to provide more opportunities for stakeholder input.

Further, due to the increasing significance of transmission and potential increased investment in transmission pursuant to this Order, the Commission will avail itself of Section 2.5 of Attachment N-1 of Duke's OATT and require periodic status updates and progress reports on the NCTPC process. The Commission shall open a sub docket to the CPIRP process in order to receive these updates and reports pursuant to the FERC OATT.

States, and not the federal government, have responsibility for resource adequacy, determining the generation mix, and siting of transmission, distribution, and generation facilities. *See, e.g.,* Federal Power Act § 201(b)(1), 16 U.S.C. § 824(b)(1); Federal Power Act § 211(d)(1); *Pac. Gas & Elec. Co. v. State Energy Res. Conservation & Dev. Comm'n*, 461 U.S. 190, 205, 103 S. Ct. 1713, 75 L. Ed. 2d 752 (1983)("[n]eed for new power facilities, their economic feasibility, and rates and services, are areas that have been characteristically governed by the [s]tates."). Meeting the requirements of N.C.G.S. § 62-110.9 in a least cost manner will mean holistically considering the costs and benefits of the generation mix in the context of the costs and benefits of the associated transmission needs. For instance, there will be times when the most cost-effective solution to a constraint on the transmission system is not more transmission, but rather generation assets located near load. Moreover, the Commission is ultimately responsible for ensuring fair and reasonable retail rates, including bundled transmission rates. Finally, given the Commission's role in ratemaking and issuing CPCNs and, where appropriate, certificates of environmental compatibility and public convenience and necessity (CECPCNs) for transmission facilities, and given the interface between the issues considered in the NCTPC process and proceedings pending before the Commission, the Commission finds it necessary to receive robust information in this newly created sub docket.

In other words, because the Commission retains certain jurisdiction over transmission facilities under N.C.G.S. § 62-101, over bundled retail rates, and over resource adequacy and generation mix, which is dependent on transmission facilities needed to interconnect generation resources, Duke must keep the Commission informed of its transmission planning by means of filings in the Commission's sub docket.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 59-60

Transmission – Cost and Reliability Considerations

The evidence supporting these findings of fact and conclusions is set forth in Duke's Carbon Plan proposal, the direct and rebuttal testimony of Duke's Transmission Panel, the testimony of NCEMC witness Ragsdale, and the entire record in this proceeding.

Duke witness Roberts stated that the initial RZEP projects would be "the first phase" with respect to executing the Carbon Plan, but that there would likely be the need for more upgrades in the future on top of the initial RZEP projects. Tr. vol. 17, 37-38.

NCEMC witness Ragsdale testified that Duke indicated in the supplemental studies that it did not conduct an analysis of Affected Systems. Witness Ragsdale therefore concluded that there may be additional costs and potential execution risks associated with the RZEP projects to consider and recommends that the Commission require Duke to not only coordinate with other transmission providers, but also with LSEs in North Carolina to ensure consideration of all Affected Systems. Tr. vol. 26, 204-05. These efforts should include both an evaluation of any costs associated with equipment upgrades on the LSE systems resulting from the RZEP upgrades, as well as increased coordination of the outages and other scheduled maintenance work on NCEMC delivery points. Witness Ragsdale noted that NCEMC's members have 45 delivery points within the DEP RZEP areas located in North Carolina that the proposed upgrades would potentially impact. *Id*. at 219. These could include impacts on substation equipment at those delivery points that should also be considered in evaluating the systems the RZEP projects affect. *Id*.

In addition, NCEMC witness Ragsdale testified that NCEMC currently has multiple delivery point repairs and upgrade requests to service its member-consumers it is coordinating with Duke that if delayed, could result in impacts to the reliability and service quality to electric cooperative member-consumers. Therefore, witness Ragsdale stressed that Duke's expedited timeline for RZEP projects should not result in the RZEP projects having priority over other transmission or distribution projects necessary for reliability and maintaining service quality for retail and wholesale ratepayers. *Id*. at 205. To the extent that Duke seeks to accelerate the RZEP project timelines, there should be no delays to Duke's traditional transmission provider obligations, including managing the network reliably, serving current load, and expanding the network to meet load growth and long-term service requests.

In response to Commission questions, witness Roberts and witness Farver indicated that it is their understanding that the RZEP projects by themselves should not cause an Affected System upgrade, and that any Affected System costs resulting from the RZEP projects would not occur until new generation interconnected to those upgrades. Tr. vol. 29, 82-83. Witness Roberts further stated his understanding that the upgrades that witness Ragsdale is referring to is short-circuit availability, and that as Duke adds more inverter-based resources and retires more synchronous generation, one would likely see less fault current and short-circuit availability. Therefore, it is likely there would be fewer issues or upgrades resulting to EMC points of delivery than the EMCs anticipate as a result of the RZEP upgrades themselves. *Id*. at 84.

As noted by NCEMC witness Ragsdale, N.C.G.S. § 62-110.9(3) requires that any resource changes "maintain or improve upon the adequacy and reliability of the existing grid." This provision does not apply solely to Duke's transmission grid or the grids of other transmission providers, and Duke must as a primary step ensure that any transmission or distribution upgrades it undertakes to interconnect the significant amounts of new resources called for in its recommended Carbon Plan pathways do not in any way negatively impact the adequacy or reliability of the existing grid across the Carolinas. Affected Systems studies for these projects will confirm the impact these projects have on LSE facilities and maintaining the adequacy of the grid. Prioritizing these upgrades over other necessary upgrades could shift cost and/or reliability risk to Duke's retail and wholesale ratepayers and is, therefore, unsustainable and incompatible with Duke's obligation to plan and operate its system in a safe and reliable manner for all ratepayers.

As noted by Duke's witnesses, the goal of the RZEP projects is to facilitate an aggressive timeline for the interconnection of a significant number of new resources for Carbon Plan compliance, and those additional resources will potentially impact the transmission and distribution systems of other LSEs in the state. To ensure that any resource changes maintain or improve upon the adequacy and reliability of the existing grid, the Commission directs Duke, in any future transmission upgrades proposed as necessary for Carbon Plan compliance, to ensure that it has evaluated the potential Affected System impacts on all LSEs in North Carolina, from both a cost and coordination perspective, and appropriately consider those impacts in its evaluation of the necessity for those upgrades, as well as the potential for execution risk associated with those projects. This also includes the coordination with Affected Systems both at the time of consideration of transmission upgrades, as well as at the time when new generation requests to interconnect to the upgraded facilities to ensure that the additional generation would not negatively impact delivery substations or other equipment LSEs operate in the state. Duke shall include a discussion of its efforts to coordinate the timing, cost, and scheduling of those resources in its future Carbon Plan biennial filings.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 61-63

Rate Disparity Between DEP and DEC

The evidence supporting these findings of fact is set forth in Duke's Carbon Plan proposal, the testimony of Duke's Carolinas' Utilities Operations Panel, the testimony of the Modeling and Near-Term Actions Panel, the rebuttal testimony of Duke witness Bateman, the testimony of Public Staff witness McLawhorn, the testimony of AGO witness Burgess, the testimony of NCEMC witness Fall, the testimony of CUCA witness O'Donnell, the testimony of CIGFUR witnesses Gorman and Muller, the Initial Comments of the Public Staff, CIGFUR, and CUCA, and the entire record in this proceeding.

Appendix R to Duke's Carbon Plan proposal explains that DEC and DEP currently operate as separate NERC registered Balancing Authorities (BA), Transmission Operations (TOP), and Transmission Service Providers (TSP) and plan as separate NERC-registered Transmission Planners. Tr. vol. 7, Duke Proposed Carbon Plan, App. R, 1. As registered BAs, DEP and DEC separately integrate unit commitment plans ahead of time, maintain generation-load-interchange-balance within each BA Area and contribute to interconnection frequency in real time. DEC has one BA Area, and DEP has two BA Areas. As registered TOPs, DEP and DEC are responsible for the real-time operating reliability of the transmission assets in their separate TOP Areas. Dukes' TOPs have the authority to take certain actions to ensure that they operate reliably. As registered TSPs, Duke administers the FERC-approved OATT for the separate Duke transmission zones and provides transmission service to transmission customers under applicable transmission service agreements. *Id*. In response to a question from Chair Mitchell, Duke witness Peeler explains that Duke developed and modeled the Carbon Plan assuming consolidation of these system operations. Tr. vol. 16, 25; *see also* tr. vol. 7; Duke Proposed Carbon Plan, App. E, 8.

On behalf of the Carolina Utilities Operations Panel, witness Peeler explained that Duke proposes to consolidate system operations — including the BA, TOP, and TSP operating functions — through a merger of DEC and DEP. Tr. vol. 15, 24. Witness Peeler explained that consolidated operations provide a number of customer benefits, including lowering reserve requirements, improving dispatch efficiencies, reducing carbon dioxide emissions, and allowing more solar generation to serve Duke's customers. *Id.* According to witness Peeler, combining into a single BA to manage load and resources produces savings annually for customers, helps accommodate expanded levels of variable renewable energy resources, substantially reduces forced solar curtailment, and eliminates several hundred annual CT starts that increase fleet maintenance costs. Tr. vol. 7, Duke Proposed Carbon Plan, App. R, 2; tr. vol. 15, 24. Witness Peeler explained that each of these improvements provides annual direct benefits to customers in the form of lower fuel costs and reduced carbon dioxide emissions. *Id.* Accordingly, the Modeling and Near-Term Actions Panel confirmed that the Carbon Plan assumes consolidated system operations in its modeling. Tr. vol. 7, 292; Tr. vol. 7, Duke Proposed Carbon Plan, App. E, 8.

Witness Peeler explained that Duke believes a merger of DEP and DEC is the best long-term path to achieve the benefits of consolidated operations for a number of reasons, including addressing rate differences between DEC and DEP over time, helping to moderate rate impacts by spreading new investments over a larger customer base, reducing complexity, and achieving regulatory efficiency. Tr. vol. 15, 25.

Importantly, witness Bateman explained that a merger is the most straightforward and direct way to address rate differences between DEC and DEP. *Id.* at 29. According to witness Bateman, if stakeholders and regulators can agree on an approach that is equitable to all jurisdictions, customer classes and Duke, and a merger receives the necessary approvals, there are various approaches to preventing further rate divergence and addressing historical differences between DEP and DEC. *Id.* at 30. Duke could adopt the approach taken by Florida Power & Light, conducting cost of service studies for both the standalone and merged entities, and proposing a rider that would move the rates from the standalone cost of service study for each utilities' customers to the combined one over a five-year period. *Id*. In the alternative, Duke could create a combined cost of service study with one rate base and combined accounting records but maintain the separate legacy rate schedules. In each rate case, the combined utility could apply the new rate increase for each customer class to the legacy rate schedules within the class and then also make further adjustments to move the rate schedules closer together over time. This approach leaves more flexibility to consider other factors in each rate case rather than committing to a fixed five-year schedule and is consistent with how Duke currently addresses rate schedules that vary from the cost of service within a rate class. This is similar to the approach that DEC took after the merger with Nantahala Power & Light Company. *Id.* at 31.

Witness Bateman noted that these two options address base rates, but Duke will also have to propose how to combine the riders, the most impactful of which will be the fuel riders. As witness Bateman explained, the jurisdictional shifts in cost would happen right away, but the Commission would have discretion on how quickly to merge the DEC and DEP rates within the retail jurisdiction. *Id.* at 22.

In addition to merging the rates, witness Bateman noted that there are numerous complexities that Duke will need to be worked through before fully merging the rate schedules. For example, DEC currently offers voltage differentiated rates for commercial and industrial customers while DEP does not. DEC's fuel rates are differentiated between commercial and industrial, not by rate schedule. DEP fuel rates follow the rate schedules and are not different between commercial and industrial. These are just a few examples. *Id.*

Duke is also evaluating alternatives to achieve equitable allocation of Carbon Plan costs if Duke cannot achieve the proposed merger. *Id.* at 32-33. For example, witness Bateman explained that Duke is evaluating whether DEC could own solar generation in DEP's service territory and whether DEP and DEC could jointly own offshore wind generation. *Id.* at 33-34.

Witness Bateman explained that Duke is also looking at the allocation of transmission investments. Even without a merger of DEC and DEP, CSO would require a combination of the BAs and a combined OATT rate for wholesale customers. Duke could take a similar approach in retail rates and combine the transmission costs for DEP and DEC and then allocate them back to the separate utilities based on a transmission allocation method. *Id.* at 34-35.

Public Staff witness McLawhorn testified that, on average, DEP's customers pay rates that are substantially higher than those of DEC's customers even though the Commission has found the rates of both utilities to be just and reasonable. Tr. vol. 23, 91-92. Witness McLawhorn acknowledged that some amount of rate difference is normal given that DEC and DEP are separate utilities, each possessing a unique service territory, customer base, and generation, transmission, and distribution assets. *Id.* at 92. However, witness McLawhorn expressed concern that such rate differences have grown significantly since the 2012 merger. *Id.* Witness McLawhorn noted that there are many issues that could have contributed to this growing disparity over time, but points to the impact of the significantly greater amount of solar generation developed in DEP's service territory, along with associated transmission and distribution system upgrades, as a likely significant driver of the current disparity. *Id.* at 93.

Witness McLawhorn noted that N.C.G.S. § 62-110.9 presents a state-wide mandate to achieve a 70% reduction in carbon dioxide emissions from 2005 levels by 2030 and carbon neutrality by 2050, including through the development of additional significant amounts of solar and other renewable generation. According to witness McLawhorn, DEP's service territory will continue to be the likely location for much, if not all, of the solar, Solar Plus Storage, and onshore wind resource development, and any offshore wind generation will require significant transmission development and upgrades on DEP's system. *Id.* at 96. Witness McLawhorn expressed concern that DEP's retail customers will absorb a disproportionate share of the costs to achieve statewide compliance with the Carbon Plan without action to address the growing rate differences. Witness McLawhorn further noted that it may become increasingly difficult to recruit new economic development into DEP's service territory, and the higher electricity costs will likely drive out existing business. *Id.* at 97.

To address these concerns, witness McLawhorn stated that "the most efficient way to achieve a least cost Carbon Plan is through a full merger of DEC and DEP." *Id.* at 91. Witness McLawhorn stated that the Public Staff recommends that the Commission order the utilities to begin implementing plans to merge DEC and DEP into a single utility as soon as reasonably practicable. *Id*. at 102. In addition, the Public Staff recommends that the Commission instruct Duke to take immediate steps to allocate all Carbon Plan costs proportionately between DEC and DEP to ensure that DEP customers to not disproportionately bear costs Duke incurs to achieve system-wide carbon dioxide emissions reduction. Finally, the Public Staff recommends that the Commission require Duke to work with the Public Staff and other interested intervenors to develop a plan for this allocation. *Id.* At the hearing, witness McLawhorn stated that the merger timeline presented by Duke appears reasonable. *Id*. at 145.

On behalf of the AGO, witness Burgess stated that he supports the proposal to consolidate Balancing Authorities (BAs) for a variety of reasons, including that it will aid in the integration of variable resources, improve operational efficiency, reduce related operating costs, and enhance reliability. Tr. vol. 25, 303. NCEMC witness Fall similarly stated that NCEMC supports the proposed consolidation of DEC and DEP system operations. Tr. vol. 23, 308. Witness Fall noted that consolidation of system operations presents a broad range of customer benefits, including operational efficiencies and cost savings benefiting transmission customers. Witness Fall further acknowledged that a merger of DEC and DEP presents even greater overall potential benefits to Duke's retail and wholesale customers. *Id.* Further, witness Fall stated that the merger timeline Duke witness Bateman presents appears reasonable. Ultimately, witness Fall stated that NCEMC recommends that the Commission issue a procedural order to establish a process for stakeholder engagement and reporting timelines consistent with the schedule Duke proposes. *Id.* at 308-09.

In her rebuttal testimony, witness Bateman reiterated that one of the primary reasons for the current and historic rate differences between DEC and DEP is fuel costs. Tr. vol. 28, 54. DEC has a higher percentage of low fuel cost nuclear generation than DEP has. In addition, due to its geographic location, DEP has higher fuel transportation costs than DEC does. These fuel differentials have led to DEP having higher avoided cost rates than DEC, which has contributed to DEP's higher volume and cost of Public Utility Regulatory Policies Act (PURPA) contracts, and to a higher DSM/EE rate. *Id.* Witness Bateman agreed with Public Staff witness McLawhorn that these types of differences can be expected based on unique characteristics of each utility. Witness Bateman additionally noted that while DEP's rates are higher than DEC's, they are still below the national average. *Id*. In response to a question from Commissioner Clodfelter, witness Bateman explained that the existing rate difference is not the result of something that Duke has done wrong or that Duke should have been working to remediate since the time of the merger. *Id.* at 100. Instead, as Public Staff witness McLawhorn acknowledged, the disparity is the result of a variety of regulatory requirements with which DEP had to comply, such as the purchase of solar PPAs under PURPA. *Id.* at 100-01. In response to questions from Chair Mitchell at the hearing, witness Bateman stated that Duke has sought to make DEC's and DEP's rates as low as possible, not more even. According to witness Bateman, one utility subsidizing the other would violate Duke's Regulatory Conditions Code of Conduct. In other words, Duke does not charge DEC customers more to make the rates more even. *Id*. at 111. Witness Bateman agreed with witness McLawhorn that because N.C.G.S. § 62-110.9 is a statewide policy, the cost of complying should be spread more evenly across DEC and DEP. *Id*. at 102. Witness Bateman explained that four of the six Carbon Plan portfolios reduce the rate difference in 2026, and the other two increase the rate difference by just 8 cents per MWh and 55 cents per MWh, respectively. *Id.*

Looking to the future, witness Bateman stated that Duke agrees with witness McLawhorn that merger is the most straightforward way to address rate differences. Nevertheless, witness Bateman explained that Duke does not believe an interim cost allocation is necessary given the timing of the Carbon Plan investments and the timing of the merger. *Id.* at 56. Witness Bateman explained that the projected impact of Carbon Plan investments on current rate differences prior to the targeted merger date of the end of 2026 is “minimal to non-existent.” *Id.* Given that, Duke believes that attention and resources should be devoted toward pursuing the potential merger rather than pursuing a stop-gap method for cost allocation that is not necessary at this time. *Id*.

Based upon the foregoing and the entire record in this proceeding, the Commission finds that it may be appropriate for Duke to pursue a merger of DEC and DEP according to the timeline set forth in the panel testimony of Duke witnesses Peeler and Bateman; however, the Commission will not prematurely judge the prudency of such a merger proposal and will only consider such when an application is properly before the Commission. Until such a time, the Commission directs Duke to take reasonable steps to mitigate further exacerbation of the rate disparity between DEC and DEP attributable to the Carbon Plan by presenting solutions where appropriate, including but not limited to in its pending general rate case applications.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 64-65

Present Value Revenue Requirements

The evidence supporting these findings of fact and conclusions is in Duke’s Carbon Plan proposal, the testimonies of Duke’s Modeling and Near-Term Actions Panel, Duke witness Bateman, Public Staff witnesses Metz and McLawhorn, CUCA witness O’Donnell, and CIGFUR witness Muller, and the entire record in this proceeding.

In its Carbon Plan proposal, Duke presented the PVRR and bill impact calculations it used to compare the relative costs of the various Carbon Plan portfolios. Tr. vol. 7, Duke Carbon Plan, App. E, 81-83. Duke witness Quinto with the Modeling and Near-Term Actions Panel stated that the PVRR is a comparison metric only and is not useful for nor intended to be useful for evaluating the total cost of serving customers. Tr. vol. 7, 289. Witness Quinto further stated that the bill impact estimate, like PVRR, is a metric for comparing the cost of alternate Carbon Plan portfolios and that Duke did not develop it for the purpose of estimating the future total cost of serving customers. *Id.* at 289-90. Finally, witness Quinto stated that including costs that are common across all portfolios would obscure differences that do exist across portfolios and make them appear less significant. *Id.* at 290.

Public Staff witness Metz disagreed with the exclusion of SLR costs from the bill impact calculations. Tr. vol. 21, 138. Public Staff witness McLawhorn testified that the Public Staff does not have concerns with Duke’s calculations of PVRR and retail bill impacts. Witness McLawhorn stated that because Duke did not include costs that are common across all portfolios in the bill impact analysis, he believes it is likely that Duke substantially understated the rates. He further stated that in the future, Duke should provide bill impacts in two ways — a comparative analysis between portfolios as Duke has provided, as well as “all-in cost” bill impacts. Tr. vol. 23, 106-08.

CUCA witness O’Donnell and CIGFUR witnesses Gorman and Muller agreed with the Public Staff’s request for an all-in cost bill impact analysis. Tr. vol. 22, 43-44; tr. vol. 25, 220, 352-56.

In rebuttal testimony, Duke witness Bateman testified that Duke's presentation of the rate impacts with only revenue requirements the individual portfolios cause was consistent with how it had traditionally presented PVRRs in its IRPs. She also noted that all-in cost forecasts of future bill impacts would inevitably be incorrect due to the many factors over which Duke has no or limited control, such as interest rates, inflation, fuel costs, government regulations, amortization periods for deferred costs, etc. Witness Bateman stated that she is not aware of any utility in the country that develops such long-term, all-in cost forecasts. She testified that in discovery, Duke asked the Public Staff, CIGFUR, and CUCA to provide any all-in cost forecasts that they are aware of from other utilities. Witness Bateman commented that Duke did not receive any such forecasts from these intervenors in response to the discovery request. Tr. vol. 28, 57-60.

The Commission finds that the PVRR and bill impact calculations provided by Duke in this proceeding are reasonable for planning purposes and provide a helpful tool to compare the relative benefits of the different portfolios. The Commission notes that the focus of this proceeding and future Carbon Plan proceedings is on evaluating various portfolios in order to determine the least cost path, subject to other statutory mandates, to achieve the carbon dioxide emissions reduction mandates. Although the Commission understands the Public Staff's, CIGFUR's, and CUCA's desire for Duke to provide all-in cost PVRR and bill impacts in its Carbon Plans that present the total cost of electricity ratepayers will pay as Duke implements the Carbon Plan, the Commission gives significant weight to the testimony of Duke witness Bateman that there are substantial uncertainties associated with projecting all-in costs for an extended future period. Further, neither Duke nor any other party was aware of any other utilities providing such all-in forecasts. Thus, the Commission determines that Duke does not have all the information that it would require to provide the Commission realistic and meaningful long-term, all-in cost bill impact projections. The Commission also gives significant weight to the testimony of Public Staff witness McLawhorn in which he states that the Public Staff does not have any concerns with Duke's calculations of PVRR and bill impacts in this proceeding and consequently concludes that the PVRR and bill impact analyses provided by Duke are sufficient for evaluating and comparing the relative benefits of the various portfolios Duke presents in the Carbon Plan proposal.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 66

Environmental Justice and Impacted Communities

The evidence supporting this finding of fact and conclusions is in the direct testimony of Duke witness Bowman and the entire record in this proceeding.

In recognition of the impact the provision of electric service and the transition to carbon dioxide neutrality will have on communities, Duke conducted targeted stakeholder engagement. Specifically, Duke convened a small group of environmental justice – focused stakeholders on May 3, 2022, and August 2, 2022, to discuss how to engage North Carolina communities and to understand what issues are important to low-income ratepayers and communities of color. Tr. vol. 7, 49. Each meeting included approximately ten stakeholders, representing a variety of interests, including health, environmental, and economic impacts of the Carbon Plan. *Id*. Duke explains that the stakeholder engagement effort will be ongoing and will involve a select number of individuals committed to working together with Duke to explore these complex issues and identify areas for potential partnership and progress. *Id*.

RTHC et al. express significant concern regarding the sufficiency of Duke's outreach towards — or accessibility to — low-income, minority, and rural communities, both in terms of quality of the outreach as well as timing of the outreach. They highlight for the Commission that "that only those living in impacted communities can capture the full range of the lived experience." RTHC et al. Partial Proposed Order at 6-7, 10.

Duke also held an Impacted/Frontline Communities stakeholder meeting on May 5, 2022, to initiate engagement with communities that Duke expects future coal retirements to impact. Tr. vol. 7, 49. Person County advocates that the Commission require Duke to provide community support, including workforce development and charitable contributions, to communities like Person County, which the transition will likely impact. Person County Partial Proposed Order at 11-12.

The Commission recognizes the extent of the stakeholder outreach Duke conducted in conjunction with this initial Carbon Plan proceeding and recognizes that the limitation of time was a very real constraint on Duke's ability to expand its engagement to all potentially impacted stakeholders. Duke understands that continued and expanded engagement will be necessary going forward, in order to hear from and respond to those communities uniquely impacted by the transition to a carbon neutral electric system. Tr. vol. 7, Duke Proposed Carbon Plan, App. B, 22-23. Accordingly, the Commission directs Duke to continue to develop targeted engagement plans for impacted communities, to enact these plans in the near term and to report to the Commission on these plans and the ensuing engagement with stakeholders in its upcoming CPIRP filing.

IT IS, THEREFORE, ORDERED as follows:

1. That Duke shall file its first proposed biennial CPIRP by no later than September 1, 2023;

2. That Duke shall engage with the Public Staff and any interested stakeholders to draft a new proposed Commission rule governing CPIRP, subject to the following parameters, and file the proposed rule with the Commission by no later than April 28, 2023, in a new and separate proceeding:

a. By September 1, 2023, and every two years thereafter, Duke shall file with the Commission its proposed biennial CPIRP, including the testimony and exhibits of expert witnesses. At the time of the filing, Duke shall provide complete modeling input and output data files to intervenors. Each proposed biennial CPIRP shall include a proposed near-term action plan discussing the specific actions Duke recommends taking over the near term following the Commission's final order on the proposed CPIRP;

b. No later than 180 days after the later of either September 1 or the filing of Duke's proposed biennial CPIRP, the Public Staff or any other intervenor may file testimony and exhibits of expert witnesses commenting on, critiquing, or giving alternatives to Duke's proposed CPIRP;

c. No later than 45 days after the filing of intervenor testimony and exhibits, Duke may file its rebuttal testimony and exhibits of expert witnesses;

d. The Commission shall schedule an expert witness hearing to review the CPIRP proposals beginning on the second Tuesday in May following Duke's proposed biennial CPIRP filing, and shall set one or more hearings to receive testimony from the public at a time and place of the Commission's designation; and

e. The proposed rule filing shall also propose a separate mechanism for the filing and review of annual compliance plans that DEP and DEC previously filed with their respective IRP filings;

3. That to meet the Interim Target, Duke shall be required to reduce the carbon dioxide emitted by the electric generating facilities sited within North Carolina that it owns, operates, or that are operated on its behalf to 22,759,556 short tons of carbon dioxide;

4. That Duke shall incorporate the impacts of the IRA, the IIJA, and other future legislative changes, as well as the impacts of other changing conditions such as inflationary pressures, into its first biennial CPIRP that it will file with the Commission on or before September 1, 2023, and into any CPCN applications it files in the interim;

5. That in its first proposed biennial CPIRP Duke shall make all reasonable efforts to maximize its modeling optimization period, and seek to model a 15-year, or greater, optimization period;

6. That in its first proposed biennial CPIRP Duke shall model Solar Plus Storage resources using dynamic dispatch and bi-directional inverter capability, subject to modeling limitations. Furthermore, Duke and the Public Staff shall work together closely on modeling Solar Plus Storage resources during the next proceeding and, if they do not reach consensus on modeling techniques, each shall provide a robust explanation to the Commission as to the points of disagreement and agreement;

7. That in its first proposed biennial CPIRP Duke shall make all reasonable efforts to model storage resources in the capacity expansion and production cost modeling steps without manual adjustments, subject to modeling limitations, and if such limitations remain, that Duke shall develop robust cost sensitivity analyses that clearly demonstrate the cost impacts of potential resource replacement;

8. That Duke shall proactively address risks to system reliability in its upcoming first proposed biennial CPIRP, including but not limited to engaging with the Public Staff in leveraging actual operational experience to continue to plan for the future, mitigate foreseeable risk, and prepare for the challenges ahead;

9. That Duke shall take appropriate steps to optimally retire its coal fleet on a schedule commensurate with its Carbon Plan proposal filed on May 16, 2022;

10. That in determining the least cost path for ratepayers, Duke shall evaluate whether securitization of eligible costs related to subcritical coal-fired units will maximize ratepayer savings;

11. That Duke shall re-study the potential costs and benefits of a further conversion of Belews Creek and provide the results in its initial CPIRP filing;

12. That Duke shall continue to pursue SLR for its existing nuclear fleet and shall develop a schedule detailing its plans for SLR of the existing nuclear fleet and provide this information in its upcoming CPIRP filing;

13. That Duke shall continue to review the NRC SLR regulatory process, paying particular attention to the two nuclear licenses that the NRC reset in early 2022, and shall incorporate any lessons learned from its review into its first proposed biennial CPIRP;

14. That Duke shall pursue expansion of flexibility of its existing natural gas fleet and target specific natural gas plants or regions of its service areas that would benefit the most from flexibility expansion projects. In its planning for the expansion of the flexibility of the existing natural gas fleet, the Commission directs Duke to identify least cost flexibility expansion projects that will improve or maintain system operability and reliability;

15. That Duke shall analyze and incorporate, in future modeling efforts, realistic assumptions regarding the availability of firm natural gas transportation capacity and shall work with the Public Staff in achieving those assumptions;

16. That Duke shall use the natural gas price forecast method approved herein in its proposed CPIRP and in subsequent avoided cost proceedings;

17. That Duke, in its CPIRP filing, shall include in its modeling efforts the costs and assumptions for natural gas-fired generating facilities operating after 2050;

18. That in any future CPCN filing for natural gas-fired generating resources, Duke shall provide an analysis of the sufficiency of firm natural gas transportation capacity for the proposed facility;

19. That during the 2023-2024 period Duke shall target the procurement of 2,350 MW of new solar;

20. That Duke shall hold stakeholder discussions regarding a competitive, least cost 2023 Solar Procurement and shall file, by than no later than February 15, 2023, a proposal to procure new solar generation to be placed in service by 2028, subject to a VAM, including a targeted procurement of Solar Plus Storage in alignment with the 2023 DISIS. Duke's proposal shall include proposed terms and conditions, operational conditions, and a pro forma PPA to be used for Solar Plus Storage resources;

21. That Duke shall file, no later than February 15, 2024, a proposal to procure the remainder of 2,350 MW of new solar generation to be placed in service by 2028, subject to a VAM, including a targeted procurement of Solar Plus Storage in alignment with the 2024 DISIS;

22. That Duke is authorized to conduct the initial development and procurement activities for 1,000 MW standalone storage and 600 MW of Solar Plus Storage, consistent with those activities outlined for the 2022-2024 timeframe in Table 4-11 of Duke's Carbon Plan proposal;

23. That Duke shall engage with onshore wind stakeholders as soon as practicable and in formulating its first biennial CPIRP, Duke shall consider onshore wind and particularly any pertinent information gleaned from its stakeholder engagement, and, to the extent that future Encompass modeling economically selects utility-owned onshore wind resources, Duke should support that proposal in detail in its first biennial CPIRP;

24. That with respect to near-term development actions for small modular and advanced nuclear reactors, Duke is hereby authorized to take steps it outlines in its proposed Carbon Plan and this authorization constitutes approval under N.C.G.S. § 62-110.7(b). Duke shall report in its first CPIRP filing on the specific activities and costs incurred to date;

25. That the Commission approves Duke's decision to incur project development costs associated with the initial project development activities proposed for new pumped storage hydro at Bad Creek II and requires Duke to report in its first CPIRP filing on the specific activities and costs incurred to date;

26. That Duke shall study and consider each of the three currently available WEAs off the coast of North Carolina, adopting steps in its evaluation process to protect against any potential affiliate bias, and report the findings of its evaluation of the WEAs to the Commission in its first CPIRP filing;

27. That Duke shall investigate and pursue any federal funding that is available, through the IIJA or the IRA or any subsequent legislation, for offshore wind facilities and associated infrastructure;

28. That, in addition to Duke's proposed UEE forecast of 1% of eligible retail sales, Duke shall provide an alternative modeling scenario in its next CPIRP filing that uses a UEE forecast of 1.5% of eligible retail sales. Further, Duke shall continue to

explore avenues to increase load reduction by implementing new DSM/EE programs, implementing EE and load reduction programs for wholesale customers, and reducing the number of non-residential customers that that have opted out of the DSM/EE program;

29. That Duke should continue to explore rate design as a load shaping tool to encourage customers to change their load profiles to support the use of new generation facilities;

30. That Duke should include, in its CPIRP filing, a separate and robust analysis on the electrification of transportation, both in terms of load projections and actions undertaken to encourage charging at off-peak times or during times of excess energy and to facilitate the location of charging infrastructure on the system that avoids or obviates the need for system upgrades;

31. That Duke shall initiate a docket to review the DEC and DEP DSM/EE cost recovery mechanisms to consider the enablers Duke proposes, including: (i) updating the inputs underlying the cost benefit test in the mechanisms; (ii) using the as-found baseline for EE measures; (iii) changing the definition of low-income customer; and (iv) developing guidelines for expedited regulatory approval of DSM/EE pilot programs;

32. That Duke shall engage with stakeholders to develop guidelines for expedited regulatory approval of customer programs and pilots for non-DSM/EE customer programs that enable load reduction or load management consistent with the Carbon Plan including rate design programs and EV programs;

33. That Duke shall take all reasonably necessary steps to construct the fourteen 2022 RZEP projects further identified herein;

34. That Duke shall make all reasonable efforts in accordance with state and Federal law to update and improve its local transmission planning process including increasing transparency and coordination;

35. That Duke shall make semi-annual reports in the CPIRP sub-docket regarding the status of transmission upgrades including timing milestone completion, and cost estimates to the Commission pursuant to Section 2.5 of Attachment N-1 of the OATT;

36. That Duke shall make all reasonable efforts to comply with the carbon dioxide emissions reduction mandates of N.C.G.S. § 62-110.9, but shall not alter, delay, or modify any scheduled maintenance, asset management operations, or upgrades on its system or to the delivery points of other LSEs that would negatively impact the reliability or service quality of the customers of those LSEs;

37. That to the extent Duke proposes future transmission Network Upgrades to support its Carbon Plan compliance for consideration by the NCTPC, Duke shall include an assessment of the timing, costs, and benefits of the Network Upgrades on its system as well as the systems of other LSEs, in its future CPIRP filings, and shall also include

documentation of its efforts to coordinate with all LSEs in North Carolina on these upgrades;

38. That Duke shall address the rate disparity between DEC and DEP in its upcoming DEC general rate case application in Docket No. E-7, Sub 1276, in any update filing made in its DEP general case proceeding in Docket No. E-2, Sub 1300, and shall provide an update on rate disparity in its first biennial CPIRP filing along with an update of recent actions taken to pursue the recommended merger; and

39. That Duke shall continue to develop targeted engagement plans for impacted communities, as are further discussed in conjunction with Finding of Fact No. 66, shall enact these plans in the near term, and shall report to the Commission on these plans and the ensuing engagement with stakeholders in its initial CPIRP filing.

ISSUED BY ORDER OF THE COMMISSION.

This the 30th day of December, 2022.

NORTH CAROLINA UTILITIES COMMISSION

A. Shonta Dunston

A. Shonta Dunston, Chief Clerk

Commissioner Daniel G. Clodfelter concurs.

DOCKET NO. E-100, SUB 179

Commissioner Daniel G. Clodfelter, concurring:

I am in full agreement with and join in the Commission's order issued today. I write separately only to underscore one point I believe deserves emphasis. Some may be concerned that the Commission does not select or settle upon one of the various 2030 resource portfolios offered by Duke, by the Public Staff, or by several intervenor parties and members of the public. They may even think that in not doing so the Commission has failed to prepare and adopt a Carbon Plan as directed by N.C.G.S. § 62-110.9. It would be a mistake to think this.

A proposed configuration of generating and transmission resources is not a plan. It is instead simply a snapshot of how the generating and transmission resources of the electricity system might look at some instant in time — now, next year, 2030, or perhaps 2050 — whatever point in time may be selected. Looking at a proposed resource portfolio tells one nothing about how it came to be configured in just such a way at just such a point in time, in the same way that looking at a photograph tells one absolutely nothing about what it took for the image in the photograph to appear in exactly the way it did at the instant the camera's shutter clicked. But that question — "how did this come to look this way?" — is exactly the question planning must answer. Said another way, a "plan" is not the same as an "outcome." Rather, it is the organized series of actions that are required to produce an outcome. That is why I believe the Commission has correctly centered its initial response to the directive in N.C.G.S. § 62-110.9 on the series of actions that must be undertaken today and in the succeeding two years before the next biennial review in order to achieve the targeted reductions in carbon dioxide emissions mandated by the General Assembly in N.C.G.S. § 62-110.9.

Anyone not persuaded that this is so might try thinking about planning in a more familiar context. Suppose you are intending a vacation to Europe, and I ask you to tell me about your travel plan. In response you excitedly pull out and show me a photograph of the Eiffel Tower, and then one of Big Ben, and perhaps also one of the Colosseum in Rome. That's my plan, you say. I would certainly reply that I understood *where* you are going, but I really want to know something about your plan for the trip. Will you fly or will you take a longer and more exotic ocean voyage? If you are flying, will you be able to get a direct flight or will you have to make connections? Will you be staying in hotels or perhaps in private bed and breakfasts? Are you travelling with a group and a guide or will you make up your own itinerary? Will you have time for any side excursions, or will you just visit the main tourist sites? And so on and so on. I know your destination, I would say, but I am interested in how it will all work out along the way so that you enjoy your trip once you get there.

This same dialogue translates to the case of a Carbon Plan. We know the destination — a 70% reduction in carbon dioxide emissions by 2030 and no net carbon dioxide emissions by 2050. That has already been set by the General Assembly. But merely picking a mix of resource and transmission assets for 2030 and then another set for 2050 is not planning and does not constitute a plan; it is no different from your showing me your picture of the Eiffel Tower and calling it the “plan” for your trip to Europe. The General Assembly understood this. It did not direct the Commission to select a portfolio of resources and call it a “carbon plan”; instead, it directed the Commission to “take all reasonable steps” to achieve specific reductions in carbon dioxide emissions by the target dates, and it is those “reasonable steps” that constitute the Carbon Plan. Certainly, if the Commission and the utilities succeed in fulfilling their charge, the mix of generation and transmission resources will have a particular configuration in 2030 and another in 2050. Those will be the “resource portfolios” as of those dates. But as the record amply demonstrates, there is no single, unique resource portfolio that satisfies the required emissions reduction goals, just as there is no single picture — not the Eiffel Tower alone or the Colosseum alone — that is “Europe.”

The travel analogy is apt for a second reason. You intend your vacation in Europe to be an extended one, perhaps several weeks long. Over that time many things will unfold that you cannot presently foresee. Depending on the time of year or your choice of destinations, you may have to pack clothes for highly variable weather conditions. Depending on such things as weather, public health concerns, labor disputes, or similar causes, you may have to deal with cancellations, delays, reschedulings, or closures. Depending on the vagaries of business cycles or financial markets, you may have to be prepared for price increases since the time you made your initial bookings and reservations or for currency fluctuations that will affect the cost of things once you arrive at your travel destinations. Your first steps in planning your trip should be those that will best preserve the flexibility you will need to accommodate those uncertainties and deal with unanticipated events if and when they arise over the course of your travels. You must think, for example, about whether you want to book the cheaper ticket that is nonrefundable and cannot be changed, or whether instead you want to purchase a more costly but more flexible fare option. You must decide whether you want to risk driving in what could be difficult mountain terrain and in possibly bad weather, or whether perhaps a more relaxed rail pass is a better way to see Switzerland. The more distant your actual departure date is from the time you are making your plan, the more likely such uncertainties must be taken into account in your planning.

For the first, 2022, iteration of the Carbon Plan the Commission has likewise chosen to emphasize those initial steps that are foundational to every possible itinerary and every possible route to the ultimate carbon-free destination, the ones that offer the most flexibility as the journey progresses and present the least risk of later, and perhaps costly, disappointment. I believe this is the most responsible way, and indeed the only responsible way, to proceed on a journey that starts today and will span the next twenty-eight years until 2050. I fully concur in the Commission’s order issued today.

/s/ Daniel G. Clodfelter
Commissioner Daniel G. Clodfelter