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, 2023
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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 Rule EPA's Affordable Clean Energy Rule

CC combined-cycle

bcf – Billion cubic feet

CPCN Certificate of Public Convenience and Necessity

CPIRP Carbon Plan Integrated Resource Plan

CPP Rule EPA's Clean Power Plan Rule

CPRE – Competitive Procurement of Renewable Energy

CT combustion turbine/s

DEC Duke Energy Carolinas, LLC

DENC Dominion Energy North Carolina

DEP Duke Energy Progress, LLC

DER Distributed Energy Resources

DO Distribution Operator

DOE U.S. Department of Energy

DSM demand-side management

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.

GWh gigawatt-hour/s

Halifax Halifax EMC

HVAC heating, ventilation and air conditioning

IIJA Infrastructure Investment and Jobs Act

IOU investor-owned electric utility

IRA Inflation Reduction Act

IRP integrated resource plan

ISOP Integrated System & Operation Planning

ABBREVIATIONS AND ACRONYMS

kWh kilowatt-hour/s

LED light-emitting diode

LEE CC Lee combined-cycle plant in SC

LNG liquified natural gas

MW megawatt/s

MWh megawatt-hour/s

NCDEQ North Carolina Department of Environmental Quality

N.C.G.S. North Carolina General Statute

NCTPC North Carolina Transmission Planning Collaborative

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

NERC North American Electric Reliability Corporation

NIETC National Interest Electric Transmission Corridors

NRC Nuclear Regulatory Commission

OASIS Open Access Same-time Information System

OATT Open Access Transmission Tariff

ORS South Carolina Office of Regulatory Staff

PPA power purchase agreement/s

PURPA Public Utility Regulatory Policies Act of 1978

PV photovoltaic

QF qualifying facility

REC renewable energy certificate/s

REPS Renewable Energy and Energy Efficiency Portfolio Standard

RFP request for proposals

RPS renewable portfolio standard

RTO regional transmission organization

SCPSC South Carolina Public Service Commission

SEPA Southeastern Power Administration

SERC SERC Reliability Corporation

SERTP Southeastern Regional Transmission Planning

ABBREVIATIONS AND ACRONYMS

STEM Science, Technology, Engineering and Mathematics education

TRANSCO Transcontinental Gas Pipe Line Company, LLC

TVA Tennessee Valley Authority

VEPCO Virginia Electric and Power Company

VCEA Virginia Clean Economy Act

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 investor-owned electric utilities (IOUs) 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.

Three IOUs operate in North Carolina subject to the jurisdiction of the Commission, all of which own generating facilities: Duke Energy Progress, LLC (DEP), headquartered in Raleigh; Duke Energy Carolinas, LLC (DEC), headquartered in Charlotte; and Virginia Electric and Power Company (VEPCO), headquartered in Richmond, Virginia, and doing business in North Carolina as Dominion Energy North Carolina (DENC).

DEP and DEC, the two largest electric IOUs in North Carolina, are owned by Duke Energy Corporation and together provide approximately 96% of the utility-supplied electricity consumed in the State. Approximately 23% of the IOUs' North Carolina electric sales were to the wholesale market, consisting primarily of electric membership corporations (EMCs) and municipally owned electric systems. Table ES-1 depicts the sales of the IOUs in North Carolina.

Table ES-1: Electricity Sales of Investor-Owned Utilities in North Carolina

	NC Retail Sales (GWh*)		NC Wholesale Sales (GWh*)		Total Sales (GWh*) (NC Plus Other States)[1]	
	2022	2021	2022	2021	2022	2021
DEP	38,640	37,402	25,586	21,083	70,435	66,882
DEC	56,950	56,916	4,881	4,984	90,915	87,797
VEPCO	4,078	4,222	47	50	89,989	85,169[2]

*GWh = 1 Million kWh (kilowatt-hours)

During the 2023 to 2038 timeframe, the average annual growth rate in summer peak demand for electricity in North Carolina is forecasted to be approximately between 1.5% – 4.6% compared to 1.2% – 4.0% for winter peak load growth. Table ES-2 illustrates the system-wide average annual growth rates forecast by the IOUs in North Carolina. Each uses generally accepted forecasting methods, and although their

[1] DEP and DEC serve customers in North and South Carolina. VEPCO also serves customers in Virginia.

[2] VEPCO updated the total sales figure of 83,600 GWh provided on Table ES-1 of the 2022 Annual Report.

forecasting models are different, the econometric techniques employed by each are widely used for projecting future trends.

Table ES-2: Forecast Average Annual Growth Rates for DEP, DEC, and VEPCO (with Energy Efficiency Included)[3]

	Summer Peak	Winter Peak	Energy Sales
DEP (2024-2038)	1.5%	1.2%	1.5%
DEC (2024-2038)	1.6%	1.5%	1.6%
VEPCO (2022-2035)	4.6%	4.0%	6.5%

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

Table ES-3: Total Energy Resources by Fuel Type for 2022

	DEP	DEC	VEPCO
Coal	9%	9%	8%
Nuclear	40%	47%	27%
Net Hydroelectric*	1%	1%	3%
Natural Gas and Oil	34%	30%	36%
Non-Hydro Renewable	9%	2%	2%
Other Purchased Power	7%	11%	23%

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 to provide reliable service. The Commission continues to evaluate in the integrated resource planning proceedings the appropriate planning reserve margins. DEP and DEC have proposed increasing their reserve margins in response to the customer outages experienced during Winter Storm Elliott in December 2022.

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.G.S. § 62-133.8, IOUs are required to increase their use of renewable energy resources and/or energy efficiency such that those sources meet 12.5% of their North Carolina retail sales beginning in 2021. EMCs and municipal electric suppliers are required to meet 10% of their North Carolina retail sales in 2018 and thereafter.

[3] In their latest CPIRP filed in Docket No. E-100, SUB 179, DEP and DEC estimate energy sales to grow by 1.5% and 1.6% respectively, from 2024-2038.

The Commission issued its initial Carbon Plan order on December 30, 2022, pursuant to N.C.G.S. § 62-110.9. The law directs the Commission to take all reasonable steps to achieve carbon dioxide emission reductions from electric generating facilities owned or operated in this State by DEP and DEC of 70% from 2005 levels by the year 2030, subject to certain discretionary extensions, and carbon neutrality by the year 2050. The law further requires that the 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 March 15, 2023, the Commission opened Docket No. E-100, Sub 190 to begin its biennial review of the Carbon Plan consistent with the provisions of N.C.G.S. § 62-110.9. On August 17, 2023, DEP and DEC filed their proposed 2023 Carbon Plan consolidated with their 2023 integrated resource plan (CPIRP), as required by the Commission, which includes three energy transition planning pathways targeted at achieving the emission reductions required by N.C.G.S. § 62-110.9 while balancing least-cost and reliability considerations. The Commission scheduled and held a technical conference on October 12, 2023, and received an oral presentation from DEP and DEC. Intervenors will have an opportunity to file comments and analyses, and public and expert witness hearings will be held in 2024.

2. INTRODUCTION

The North Carolina General Statutes require that the 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. Section 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.G.S. § 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 investor-owned electric utility as a part of the least-cost integrated resource planning process. Commission Rule R8-60 defines an overall framework for this process, which 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 to identify the resource plan that will be most cost-effective for ratepayers consistent with the provision of adequate, reliable service.

This report is an update of the Commission's December 30, 2022 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

Investor-Owned Utilities

Three investor-owned electric utilities (IOUs) operate in North Carolina subject to the jurisdiction of the Commission, all of which own generating facilities: Duke Energy Progress, LLC (DEP), headquartered in Raleigh;[4] Duke Energy Carolinas, LLC (DEC), headquartered in Charlotte; and Virginia Electric and Power Company (VEPCO), headquartered in Richmond, Virginia, and doing business in North Carolina as Dominion Energy North Carolina (DENC). A map outlining the areas served by the IOUs can be found at the end of this report.

DEP and DEC, the two largest IOUs in North Carolina, are owned by Duke Energy Corporation (Duke) and together provide approximately 96% of the utility-supplied electricity consumed in the State. Approximately 23% of the IOUs' North Carolina electric sales were to the wholesale market, consisting primarily of electric membership corporations (EMCs) and municipally owned electric systems.

Based on annual reports submitted to the Commission for the 2022 reporting period, sales for the IOUs in North Carolina are summarized in Table 1.

[4] DEP was known as Progress Energy Carolinas after the merger of Carolina Power & Light Company (CP&L) with Florida Progress Corporation in 2000 and before its merger with Duke Energy Corporation in 2011.

Table 1: Electricity Sales of Investor-Owned Utilities in North Carolina

	NC Retail Sales (GWh*)		NC Wholesale Sales (GWh*)		Total Sales (GWh*) (NC Plus Other States)[5]	
	2022	2021	2022	2021	2022	2021
DEP	38,640	37,402	25,586	21,083	70,435	66,882
DEC	56,950	56,916	4,881	4,984	90,915	87,797
VEPCO	4,078	4,222	47	50	89,989	85,169[6]

*GWh = 1 Million kWh (kilowatt-hours)

Electric Membership Corporations

EMCs are independent, not-for-profit corporations that distribute electricity to their member customers. The 31 EMCs serving customers in North Carolina serve approximately 25% of the State's population. Twenty-six EMCs are headquartered in the State, and these 26 EMCs served 1,137,083 metered customers as of December 31, 2022. 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 North Carolina's 100 counties.

Twenty-five EMCs are members of North Carolina Electric Membership Corporation (NCEMC), a generation and transmission cooperative 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. 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 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, North Carolina.

NCEMC is also a part owner in the Lee combined-cycle (CC) plant located in Anderson, South Carolina. NCEMC's ownership interest consists 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, North Carolina. These peaking resources use natural gas as their primary fuel, with diesel storage on-site as a

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5 DEP and DEC serve customers in North and South Carolina. VEPCO also serves customers in Virginia.

6 VEPCO updated the total sales figure of 83,600 GWh provided on Table ES-1 of the 2022 Annual Report.

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-grid programs to promote reliability, affordability, sustainability, and resiliency for the benefit of the communities they serve. These technologies and programs include: Community solar facilities; solar plus storage facilities; substation-based battery energy storage systems; microgrids; demand response (DR) and energy efficiency (EE); electric vehicle charging; and the 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.

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 arrange for additional purchases.

The service territories of NCEMC's member EMCs are located within the balancing authority areas of DEP, DEC, and DENC. The DENC control area is situated within the footprint of PJM Interconnection, the regional transmission organization (RTO) serving a portion of northeastern 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.

Public Power

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 of North Carolina, Inc. (ElectriCities), a nonprofit 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 not a power supplier; however, it manages two power agencies: North Carolina Eastern Municipal Power Agency (NCEMPA), the wholesale supplier to 32 cities and towns in eastern North Carolina, and North Carolina Municipal Power Agency No. 1 (NCMPA1), 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 power agencies purchase supplemental power as needed above their own generating resources, usually from IOUs and federally owned hydroelectric systems. The remaining ElectriCities members buy wholesale power from other suppliers.

The Tennessee Valley Authority (TVA) sells energy directly to the Murphy Power Board and to three out-of-state electric 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. TVA has contracted for 19.2 MW of renewable solar and wind capacity in North Carolina.

4. OVERVIEW 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 to determine the least cost means 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 to identify those options which are most cost-effective for ratepayers consistent with the obligation to provide adequate, reliable service.

Development of IRP Rules

By order dated December 8, 1988, in Docket No. E-100, Sub 54, the Commission adopted Rules R8-56 through R8-61 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). In December 1992, Rule R8-62 was added to include information on the planned construction of transmission lines.

In April 1998, the Commission issued an order repealing Rules R8-56 through R8-59 and revising 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 62-2(a)(3a).

The Commission again revised its rules in July 2007 to provide for a biennial, as opposed to the previous annual or triennial, filing of IRP reports with an annual update of forecasts, revisions, and amendments to the biennial report. In addition to requiring an increased amount of information and level of detail, the rule extended the planning horizon from 10 to 15 years to identify the need for additional generation sooner and to 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.

2021 Biennial IRP 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 (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 DEP and DEC of the obligation to file updated 2021 IRPs under Rule R8-60; (2) required DEP and DEC 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 Competitive Procurement of Renewable Energy (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, DEP and DEC each filed their 2021 update to the 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 DEP, DEC, and DENC. Finally, the Commission accepted DEP and DEC'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 Dominion Energy North Carolina IRP and Related 2022 REPS Compliance Plans (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 Rule 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.

On October 18, 2023, the Commission issued an Order Accepting Filing of 2022 Update IRP and Accepting 2022 REPS Compliance Plan, which found DENC's 2022 IRP update complete and in accordance with the requirements set out in Commission Rule R8-60. The Commission also accepted DENC's 2022 REPS compliance plan.

2022 DEP and DEC REPS Compliance Plans and CPRE Program Plan Update (Docket No. E-100, Sub 186)

On September 1, 2022, DEP and DEC each 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 DEP and DEC should be able to meet their general and solar 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 noted that DEP and DEC'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 recommended 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.

On October 12, 2023, the Commission issued an Order Accepting REPS Program Plans, accepting the 2022 REPS compliance plans filed by DEP and DEC.

DEP and DEC Initial Carbon Plan
(Docket No. E-100, Sub 179)

On October 13, 2021, Governor Cooper signed into law House Bill 951 (S.L. 2021-165), Section 1 of which directed the Commission to develop by December 31, 2022, and to review every two years thereafter, a plan (the Carbon Plan) to achieve reductions in the emissions of carbon dioxide in this State from electric generating facilities owned or operated by DEP and DEC. The law, codified at N.C.G.S. § 62-110.9, directs the Commission to take all reasonable steps to achieve a reduction of 70% from 2005 levels by the year 2030 and carbon neutrality by the year 2050. The law further requires that the 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. 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 the 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 was issued on December 30, 2022, addressed consolidation of Duke Energy's traditional integrated resource planning process with ongoing Carbon Plan development and execution.

2023 DEP and DEC CPIRP
(Docket No. E-100, Sub 190)

On March 15, 2023, the Commission issued an Order Establishing Biennial Proceeding and Opening Dockets, requiring DEP and DEC to file a consolidated Carbon Plan pursuant to N.C.G.S. § 62-110.9 and IRP pursuant to N.C.G.S. § 62-110.1(c) (CPIRP) on or before September 1, 2023. DEP and DEC filed their 2023 CPIRP, entitled 2023 Carolinas Resource Plan, as ordered on August 17, 2023, with supporting testimony and exhibits filed on September 1, 2023.

The Commission scheduled and held a technical conference on October 12, 2023, and received an oral presentation from DEP and DEC on the 2023 CPIRP. Intervenors will have an opportunity to file comments and analyses, and public and expert witness hearings will be held in 2024.

2023 Dominion Energy North Carolina IRP and Related 2023 REPS Compliance Plans (Docket No. E-100, Sub 192)

On May 1, 2023, DENC filed its 2023 IRP and REPS compliance plan pursuant to Rule R8-60. Intervenors will have an opportunity to file comments and analyses, and public and expert witness hearings will be held in 2024.

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.[7] 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. For their 2023 Fall load forecast (filed on November 30, 2023, in docket E-100 SUB 190), DEP and DEC have collectively projected a load growth of 4 GW between 2024 and 2030. DEP and DEC state that this projected load growth is eight times higher than the growth they projected for the 2022 Carbon Plan and 2 GW higher than their 2023 Spring load forecast that they used to develop their 2023 CPIRP.

[7] As noted in Section 7 of this report, DEP and DEC have undertaken to improve their load forecasting in response to customer outages experienced December 24, 2022, during Winter Storm Elliott.

Table 2: Forecast Average Annual Growth Rates for DEP, DEC, and VEPCO (with Energy Efficiency Included)[8]

	Summer Peak	Winter Peak	Energy Sales
DEP (2024-2038)	1.5%	1.2%	1.5%
DEC (2024-2038)	1.6%	1.5%	1.6%
VEPCO (2022-2035)	4.6%	4.0%	6.5%

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 2024 Long-Term Reliability Assessment by the North American Electric Reliability Corporation (NERC) indicates a forecast of average annual growth in peak demand of approximately 0.7% through 2034 for the overall SERC Reliability Corporation (SERC) region.

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

Table 3: Summer and Winter System-wide Peak Loads for DEP, DEC, and VEPCO — 2018-2022 (MW)

	DEP		DEC		VEPCO	
	Summer	Winter*	Summer	Winter*	Summer	Winter*
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
2022	13,247	14,824	21,277	21,768	21,156	22,189

**Winter peak following summer peak*

6. GENERATION RESOURCES

Utility-Owned Generating Facilities

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,

[8] In their latest CPIRP filed in Docket No. E-100, SUB 179, DEP and DEC estimate energy sales to grow by 1.5% and 1.6% respectively, from 2024-2038.

hydroelectric, 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 for less than 1,000 hours per year.

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 two-unit McGuire Nuclear Station located near Huntersville is the only one located in North Carolina. 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 initial license extensions by the NRC. For Surry, the licenses for Units 1 and 2 were further renewed on May 4, 2021, permitting continued operation for Units 1 and 2 through 2052 and 2053, respectively. 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 in recent years have been solar photovoltaic plants.

The 2022 capacity mix for each IOU is shown in Table 4.

Table 4: Installed Utility-Owned Generating Capacity by Fuel Type (Summer Ratings) for 2022

	DEP	DEC	VEPCO
Coal	25%	28%	19%
Nuclear	29%	33%	17%
Hydroelectric	2%	16%	11%
Natural Gas and Oil	44%	22%	50%
Non-Hydro Renewable	1%	1%	3%

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 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 2022, is provided in Table 5.

Table 5: Total Energy Resources by Fuel Type for 2022

	DEP	DEC	VEPCO
Coal	9%	9%	8%
Nuclear	40%	47%	27%
Net Hydroelectric*	1%	1%	3%
Natural Gas and Oil	34%	30%	36%
Non-Hydro Renewable	9%	2%	2%
Other Purchased Power	7%	11%	23%

*See the paragraph on pumped storage in this section.

The Commission recognizes the need for a mix of baseload, intermediate, and peaking facilities and 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 System and Operations Planning (ISOP) project. 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 DERs necessitates moving beyond the traditional distribution and transmission planning assumption of one-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. DEP and DEC's approach to the development of ISOP builds on planning and stakeholder activities already accepted in their jurisdictions, including grid modernization under the Grid Improvement Plan and scenario-based generation and transmission planning in integrated resource planning. ISOP further expands on these elements in many areas related to integration of renewable generation and new distributed resources, including but not limited to new, more granular planning forecasts and modeling systems, evaluation of nontraditional solutions (NTS) for the grid, grid hosting analysis, extensive stakeholder engagement, and new resource valuation methods to recognize contributions and value across the business segments.

Merchant Generating Facilities

North Carolina General Statutes Section 62-110.1(a) requires that in addition to the regulated public utilities, other persons who wish to construct or operate electric generating facilities in North Carolina must also first obtain a certificate of public convenience and necessity (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 — (1) small scale hydroelectric facilities, and (2) facilities owned by large industrial companies, 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 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 House Bill 589 in 2017, this trend was amplified and reinforced by the new renewable energy competitive solicitation and procurement program codified in N.C.G.S. § 62-110.8.

By order dated May 21, 2001, in Docket No. E-100, Sub 85, the Commission adopted Rule R8-63 providing 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).

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. The Commission has determined that when considering the public convenience and necessity of a proposed generating facility, it is appropriate to consider the total construction costs of a facility, including the costs to interconnect and the costs to construct any necessary transmission network upgrades. The latter includes upgrades on neighboring systems that will be impacted by the interconnection of the facility, known as “affected systems.” This approach was recently upheld by the North Carolina Court of Appeals.

In 2023, the Commission approved CPCNs for five merchant solar facilities with a combined capacity of 877 MW. These facilities will interconnect to the transmission grid owned by DENC. Applications for CPCNs for three additional merchant solar facilities, with a combined capacity of 400 MW, are pending before the Commission. These solar facilities will also interconnect with DENC. From their applications, it appears that all of these will bid their power into the PJM market pursuant to contracts with corporate counterparties.

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 to provide reliable service. Periodic scheduled outages are required to perform maintenance, to inspect 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. 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. For DEP and DEC, the IRP process has been replaced by the CPIRP process, following the Commission’s Carbon Plan order issued on December 30, 2022.

DEP and DEC each utilize a minimum winter planning reserve margin of 17%.[9] VEPCO is a PJM member and signatory to PJM’s Reliability Assurance Agreement; thus, it participates in the PJM capacity planning process to ensure supply of capacity resources for its customer load. VEPCO has elected to meet its capacity requirements via the Fixed Resource Requirement. This is an alternative to participation in PJM’s capacity market which obligates VEPCO to obtain sufficient capacity for all load and

[9] DEP and DEC have proposed a 22% minimum winter planning reserve margin in their latest CPIRP filing in Docket No. E-100, Sub 190.

expected load growth in its service territory, i.e. to “self-supply” its capacity obligation. PJM recommends using an installed reserve margin of 14.9% for delivery year 2023/2024. In its 2023 IRP filing with the Commission, VEPCO reported that its summer reserve margin for 2023 was 14.9% of load, while its winter reserve margin was 29.8% of load.

Natural Gas Supply

More electricity is generated today by natural gas-fired generators than coal-fired generators, highlighting the importance of the infrastructure that delivers natural gas supply into North Carolina.

Utilities that use natural gas must subscribe to interstate transportation capacity so that natural gas can be delivered from supply areas or natural gas storage facilities outside of North Carolina to local distribution systems in North Carolina. The Transco pipeline, owned by the Transcontinental Gas Pipe Line Company, LLC (an affiliate of the Williams Company), is the primary interstate pipeline with which Piedmont Natural Gas (Piedmont) and Public Service Company of North Carolina (PSNC), two natural gas local distribution companies (LDCs) in North Carolina, directly interconnect. Transco delivers natural gas through a 10,000-mile interstate transmission pipeline system that extends from Texas to New York and transports approximately 15% of the nation’s natural gas. DEP, DEC, PSNC and Piedmont arrange for natural gas supply to be delivered to North Carolina receipt points on Transco. Neither DEP nor DEC directly interconnects with Transco, and, thus, both Piedmont and PSNC provide intrastate transportation service to DEP and DEC for power generation in North Carolina.

Historically, natural gas flowed on Transco from south to north, as supply from the Gulf of Mexico was injected into the pipeline. However, in 2018, the Federal Energy Regulatory Commission (FERC) authorized the reversal of flow along part of the pipeline, in light of the supply of natural gas emanating from the Marcellus region. The reversal of flow on Transco, as well as other dynamics such as an increase in use of natural gas for electricity generation within the Eastern Interconnection, have significantly impacted the dynamics of arranging for transportation capacity and for potential supply disruption. To mitigate these dynamics, the LDCs and DEP and DEC enter into contracts for firm transportation service and the highest transportation priority. In addition, North Carolina utilities are working to secure additional transportation capacity to meet customers’ growing needs. In late 2017, FERC issued a CPCN to Mountain Valley Pipeline, LLC, for the construction and operation of the Mountain Valley Pipeline (MVP) Project. 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. MVP is expected to provide 2 bcf/day[10] of firm transmission capacity from the Marcellus and Utica shale formations to markets in the Mid- and South Atlantic regions. In June 2020, FERC approved a CPCN for the MVP Southgate Project (Southgate), which is an extension of the MVP Project. The proposed 75-mile long, 16- and 24- inch diameter natural gas pipeline would tie into MVP near

[10] Billion cubic feet per day.

Chatham, Virginia, and transport natural gas to delivery points in Rockingham and Alamance counties in North Carolina. In its order approving Southgate, FERC directed the Office of Energy Projects to not issue any notice to proceed with construction of Southgate until Mountain Valley receives the necessary federal permits for the mainline. Construction of Southgate has been estimated to take at least two years once MVP has been placed into service. In October 2023, the developer of MVP pushed back the in-service target for MVP to the first quarter of 2024, from a previous target of year-end 2023.

Finally, off-system and on-system natural gas storage is used to supplement supply. Both PSNC and Piedmont own and operate liquified natural gas (LNG) storage facilities in North Carolina. Specifically, PSNC owns the Cary Energy Center, which is located in Wake County, and is planning for the construction of a second facility. Piedmont owns LNG facilities in Robeson County, Huntersville, and Bentonville. These facilities are available to supply natural gas service to customers during peak usage days when extreme low temperatures create a higher-than-normal demand for natural gas.

Winter Storm Elliott — December 2022

On the morning of December 24, 2022, DEP and DEC instituted customer outages in North and South Carolina in response to a cold weather event, Winter Storm Elliott. DEP and DEC appeared before the Commission on January 3, 2023, to present information regarding the load shed event. Subsequently, both the Commission and the South Carolina Public Service Commission (SCPSC) undertook investigations into the cause of the outages and the Companies' response.

The South Carolina Office of Regulatory Staff (ORS) engaged GDS Associates, Inc., and submitted a report on the outage to the SCPSC on August 25, 2023. DEP, DEC, and the Public Staff made presentations at a technical conference before the Commission on September 26, 2023, in Docket No. M-100, Sub 163.

In summary, the investigations by the ORS and the Public Staff found that the ultimate cause of the customer outages was an inadequate supply of power to meet demand on the morning of December 24, 2022. This inadequacy of supply resulted from a significant under-forecasting of expected demand, the failure of the Companies' generation resources, the failure of generation resources contracted for by the Companies, and the curtailment of purchases from other utilities. In addition, the Companies' software tool designed to automatically rotate customer outages and limit the duration of individual customer outages failed, resulting in the Companies resorting to manual load shed and restoration, causing extended outages for some customers.

At the September 26, 2023 technical conference, DEP and DEC reported on their own investigation and actions taken to reduce the risk of a future occurrence, including improved load forecasting, increased reserve margins, and improved operational preparedness and assessment.

On November 7, 2023, FERC and NERC released their final report on Winter Storm Elliott. Key recommendations of the report include that federal reliability standards identified after 2021's Winter Storm Uri need to be developed and implemented and that Congress, state legislators, and state regulatory entities with jurisdiction over gas infrastructure reliability should enact legislation to establish reliability rules for natural gas infrastructure.

The investigation of Winter Storm Elliott by the Commission is still ongoing.

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, IOUs are required to increase their use of renewable energy resources and/or energy efficiency such that those sources meet 12.5% of their North Carolina retail sales in 2021 and thereafter. EMCs and municipal electric suppliers are required to meet 10% of their North Carolina retail sales in 2018 and thereafter. 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. These specified source requirements also increase over time; however, the Commission has modified and delayed the swine and poultry waste set-aside 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. The Commission issued a request for proposals and selected APX, Inc., to build and operate the North Carolina Renewable Energy Tracking System (NC-RETS). 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.

Competitive Procurement of Renewable Energy (CPRE) Program

Pursuant to N.C.G.S. § 62-110.8 the Commission is tasked with oversight of the CPRE Program designed and implemented by DEP and DEC 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, DEP and DEC were 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 DEP and DEC 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.G.S. § 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, DEP and DEC contract 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, DEP and DEC collectively procured 1,185 MW via the CPRE Program. Further, during the CPRE Program Procurement Period, DEP and DEC 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 DEP and DEC were 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.

As described above, on October 13, 2021, Governor Roy Cooper signed Session Law 2021-165 into law, establishing a new framework for the Commission to set a least cost path to carbon neutrality. Section 1 of the law, codified at N.C.G.S. § 62-110.9, directed the Commission to develop a Carbon Plan that specifically plans for the addition of "new solar generation" by establishing a new framework for the balanced development and procurement of utility owned and of third-party-owned controllable solar facilities that supply power to the utility through the execution of PPAs under N.C.G.S. § 62-110.9(2)b.

Section 2(a) of Session Law 2021-165 also amended N.C.G.S. § 62-110.8(a) by eliminating future procurements of renewable energy under the CPRE Program framework based upon a showing of need. Additionally, Section 2(b) of Session Law 2021-165 repealed N.C.G.S. § 62-110.8(h)(5), which previously provided the Commission discretion to modify or delay compliance with the statutory CPRE Program requirements.

Additionally, Section 2.(c) of Session Law 2021-165 authorized the Commission to direct DEP and DEC to procure solar energy facilities in 2022 "if, after stakeholder participation and review of preliminary analysis developed in preparation of the initial

Carbon Plan, the Commission finds that such solar energy facilities will be needed in accordance with the criteria and requirements set forth in Section 1 of [Session Law 2021-165] to achieve the authorized carbon reduction goals."

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, DEP and DEC 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 DEP and DEC 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."

On June 30, 2023, DEP and DEC filed a Notice of Completion of 2022 Solar Procurement Contracting Phase (the Notice) in Docket Nos. E-2, Sub 1297 and E-7, Sub 1268. As stated in the Notice, in the 2022 Solar Procurement, DEP and DEC contracted with 286 MW of controllable CPRE PPA solar resources.

On September 1, 2023, DEP and DEC filed a Motion to Conclude the CPRE Program in Docket Nos. E-2, Sub 1159 and E-7, Sub 1156.

On December 12, 2023, the Commission issued an Order approving DEP and DEC's Motion and closing the CPRE.

Energy Efficiency (EE)

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. DEP, DEC, 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 the North Carolina Advanced Energy Corporation, the nonprofit was launched by the Commission as a voluntary program to supplement the state's existing power supply with more renewable, or 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 and energy efficiency upgrades (like heating, ventilation, and air conditioning (HVAC) equipment and light-emitting diode (LED) fixtures) at North Carolina schools.

NC GreenPower's Solar+ Schools program was introduced on April 1, 2015. Solar+ Schools uses donations to provide grants for educational solar photovoltaic (PV) packages at North Carolina K-12 schools. In addition to a solar array, awarded schools receive a weather station, data monitoring equipment, teacher training, and valuable STEM curricula and materials.

Originally, all schools were eligible to apply to Solar+ Schools, though preference was given to those in Tier 1 counties — the most economically distressed counties as defined by the North Carolina Department of Commerce. Following a five-year pilot, the program was made official by the Commission in 2019 and offered 5 kW top-of-pole and roof-mounted systems, solar awnings, and other designs as needed to accommodate various structures.

In 2023, NC GreenPower announced its largest grant award yet for Solar+ Schools, awarding 15 North Carolina schools a package valued at approximately \$55,000 – \$75,000, with the solar arrays increasing to 20 kW. Solar+ Schools covers the entirety of each project's construction costs, and the selected schools are asked to raise a small portion, approximately \$3,500, for any future operations and maintenance expenses. Schools located in Tier 1 and 2 counties are eligible to apply. NC GreenPower's partner, the State Employees' Credit Union Foundation, also provides NC GreenPower with a grant of up to \$600,000 over three years to assist with the installation costs for selected public schools each year.

By the end of 2023, Solar+ Schools will have reached a total of 82 North Carolina schools in 45 counties, bringing solar energy and Science, Technology, Engineering and Mathematics (STEM) education to more than 58,000 students. Through August 31, 2023, the schools had collectively produced an estimated 1,151,000 kilowatt-hours of green energy, with a cumulative savings of about \$108,800.

In 2022, NC GreenPower implemented North Carolina Department of Environmental Quality State Energy (NCDEQ) Office grant funding to install LED fixtures and HVAC equipment in 61 North Carolina K-8 school gymnasiums. In 2023, NC GreenPower used that prior experience to completely replace inefficient lighting with LEDs (interior and exterior) at nine additional schools. NC GreenPower is also exploring ways to expand its education focus to enhance Science, Technology, Engineering and Mathematics (STEM) curricula and materials for students even further.

Contributions to NC GreenPower continue to help support the initiatives outlined above, as well as statewide community outreach and awareness. Voluntary donations can be made by individuals or businesses through their electric bill or directly to NC GreenPower at www.ncgreenpower.org. NC GreenPower is a Section 501(c)(3) nonprofit organization, and all current projects are located in 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 DEP and DEC, 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 DEP and DEC), and for public policy needs, and (b) provides estimates of costs. The NCTPC's July 2023 mid-year report states that the total cost estimate of the 24 "2022 Plan Reliability Projects" is $936 million and that the total cost estimate of the 14 "2022 Public Policy Projects" is $567 million. For more information, visit the NCTPC's website at www.nctpc.org.

In its initial Carbon Plan order, the Commission directed DEP and DEC to 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. On November 1, 2023, after seeking stakeholder input, DEP and DEC filed proposed changes to their federal tariffs relating to the local transmission planning process.

Since 2011, pursuant to FERC Order No. 1000, entitled "Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities,"[11] transmission owners are required to participate in regional and inter-regional transmission

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

planning efforts. DEP and DEC have complied with Order No. 1000 by participating in the Southeastern Regional Transmission Planning (SERTP) process. [12]

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, the State's IOUs 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 procedures. 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:

(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

[12] For more information about the SERTP 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.

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.

In 2019, the Commission issued an order directing DEP and DEC to establish a stakeholder process to discuss transitioning the interconnection process from a first-come first-served process to a grouping study process. DEP and DEC subsequently filed a queue reform proposal. In October of 2020, the Commission approved a queue reform proposal that had been developed by DEP and DEC with input from stakeholders. In 2021, the reforms were also approved by the SCPSC and FERC, and in August of 2021, the Commission ordered DEP and DEC to move ahead with implementation. In 2022, DEP and DEC conducted a Transitional Cluster Study as part of the transition to the new process and is currently performing the 2022 Definitive Interconnection System Impact Study (DISIS) process.

On August 17, 2021, the Commission resolved several issues relative to adding storage to an existing solar generation facility. On May 12, 2022, the Commission issued an order that (1) granted waivers to the North Carolina interconnection procedures to implement expedited storage retrofits at solar sites, and (2) approved a process whereby an existing nonutility generator that seeks to add storage could establish eligibility for a bifurcated avoided cost rate.

On March 2, 2021, the Commission issued an order requiring DEP, DEC, and DENC to file by March 15 each year a report on the status of their efforts to implement IEEE Standard 1547, a technical standard published by the Institute of Electrical and Electronics Engineers, relating to the uniform interconnecting and interoperability of distributed energy resources with electric power systems. On April 13, 2023, the Commission required electric public utilities to also report annually on their plans to mitigate the reliability risk of distributed energy resources that use inverter-based technology.

10. FEDERAL ENERGY INITIATIVES

Open Access Transmission Tariff (OATT)

In April 1996, 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, FERC also required utilities to file standard, non-discriminatory OATTs under which service is provided to wholesale customers such as EMCs and municipal electric providers. As part of this decision, 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, 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 using 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.

Joint Federal-State Task Force on Electric Transmission

In June 2021, 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. The Task Force focuses 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 expires in three years, but its term may be extended by agreement between FERC and state regulators.

Commissioner Kimberly W. Duffley was appointed to the Task Force on August 30, 2021, and has been subsequently renominated for two additional one-year terms. Commissioner Duffley has presented her views during all seven Task Force meetings that have occurred to date. Commissioner Duffley currently serves as the co-Chair of the Task Force, along with FERC Chairman Willie L. Phillips. Commissioner Duffley, along with Chairman Phillips, presided over the seventh meeting of the Task Force on July 16, 2023, which explored the topic of grid-enhancing technologies.

FERC Transmission Planning and Cost Allocation Proceedings

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 Commission 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 to export their power to PJM. The Commission 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 Commission filed joint comments in that proceeding with the Public

Staff expressing 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 to prevent undue discrimination for new technologies. FERC Docket No. RM22-14. The Commission filed joint comments in that proceeding with the 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.

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. 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 by order dated December 22, 2016.

The Commission continues to exercise jurisdiction over Dominion's retail rates and services. Additionally, the Commission engages with PJM and monitors its activities, including as a member of the Organization of PJM States, Inc. (OPSI), an entity comprising the retail regulators of the 14 jurisdictions within the PJM footprint, and by participating in proceedings before FERC.

Southeast Energy Exchange Market (SEEM)

On December 11, 2020, DEP and DEC filed an advance notice with the Commission stating their intention to file with the FERC revisions to their OATT 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 IOUs, and NCEMC is also a member of SEEM. The market is designed to facilitate short-term, bilateral, automated energy sales across the region. Cost savings will flow to retail customers of DEP and DEC via the fuel rider, which the Commission adjusts annually.

The SEEM members received clearance from FERC to enter into the SEEM agreements and modify their respective federal tariffs. The SEEM initiated operations on November 9, 2022. On July 14, 2023, the U.S. Court of Appeals for the District of Columbia Circuit issued an order remanding back to FERC the orders related to the establishment of the SEEM and vacating orders in which FERC accepted tariff rates for the transmission service facilitating SEEM transactions. SEEM continues to operate pending further action from FERC.

Public Utility Regulatory Policies Act (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 (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, 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 111 of the Clean Air Act, the U.S. 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. On January 19, 2021, the U.S. Court of Appeals for the District of Columbia Circuit vacated the ACE Rule and remanded to the EPA for further proceedings.

In 2022, the United States Supreme Court applied the major questions doctrine and held that the CPP Rule exceeded EPA's statutory authority under the Clean Air Act when it implemented "generation shifting," i.e., shifting electricity production from higher-emitting to lower-emitting producers. *West Virginia v. EPA*, 142 S. Ct. 2587 (2022). Although the decision involved the CPP Rule, which the EPA had already voluntarily withdrawn, it has broad implications for the EPA's authority to regulate emissions from electric generation plants.

On May 23, 2023, the EPA proposed a new rule that would set greenhouse gas emission standards and provide guidelines for fossil fuel-fired power plants. The rulemaking process is ongoing.

National Interest Electric Transmission Corridors (NIETC)

The Federal Power Act authorizes the U.S. Department of Energy (DOE) to designate as a national interest electric transmission corridor (NIETC) any geographic area that is experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers, or that is expected to experience such energy transmission capacity constraints or congestion. Recent amendments to the Federal Power Act broadened the definition of NIETCs and expanded FERC's authority to issue permits to construct electric transmission facilities in NIETCs if a state commission with transmission siting authority either denies a permit or withholds approval for more than a year.

FERC has initiated a rulemaking procedure to implement its expanded authority. FERC Docket No. RM22-7-000. The Commission, jointly with the Public Staff, filed comments with FERC, educating FERC on North Carolina's transmission siting process and recommending that FERC allow state transmission siting processes to fully play out before initiating federal transmission siting proceedings.

DOE proposed a process for it to designate applicant-driven, route-specific NIETCs. The Commission joined with several other state commissions in submitting comments to DOE advocating close coordination with state public utility regulators in designating NIETCs and advising that any such designations should be carefully reviewed to ensure they benefit only well-planned, cost-effective transmission projects that will serve the public interest.

Infrastructure Investment and Jobs Act (IIJA) and Inflation Reduction Act (IRA)

On November 15, 2021, the Infrastructure Investment and Jobs Act (IIJA) became law. The Inflation Reduction Act of 2022 (IRA) was enacted on August 16, 2022. Both of these federal statutes contain provisions supporting investment in energy infrastructure through federal grants, loans, and tax incentives.

With respect to the IIJA, the Commission opened Docket No. M-100, Sub 164 to facilitate sharing of information about funding opportunities between and among the Commission and North Carolina's public utilities and to direct public utilities to take all reasonable and prudent efforts to obtain benefits available under the IIJA to enhance their ability to provide utility services at just and reasonable rates for the benefit of customers.

The Commission has directed DEP and DEC to incorporate the impacts of the IRA and the IIJA into their CPIRP. The legislation is complex, and North Carolina's electric public utilities are still analyzing the impacts, but they expect the laws to directly benefit their customers.

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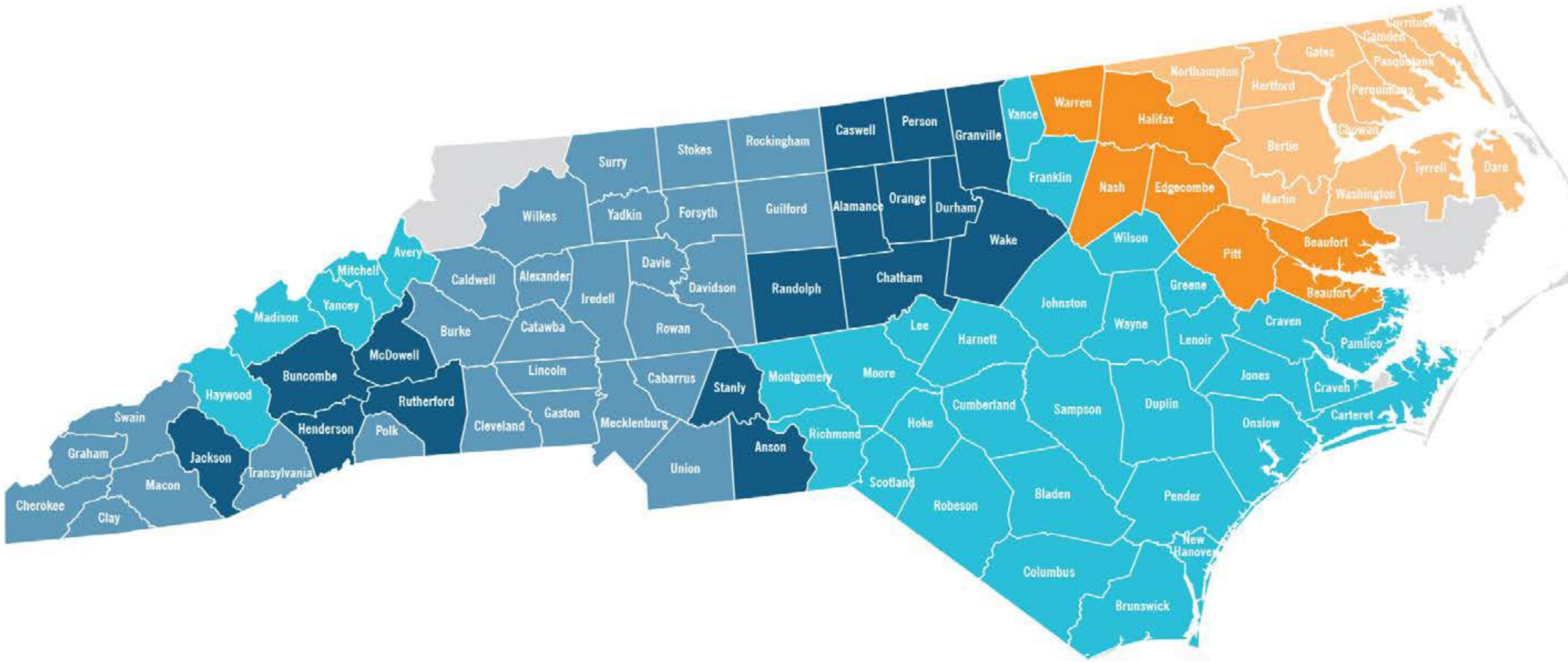
APPENDIX 1



SERVICE TERRITORIES
(counties served)

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