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, 2025
SUBMITTED: DECEMBER 19, 2025

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

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ABBREVIATIONS AND ACRONYMS

bcf billion cubic feet
CC combined-cycle
CEPS Clean Energy and Energy Efficiency Portfolio Standard
CPCN Certificate of Public Convenience and Necessity
CPIRP Carbon Plan Integrated Resource Plan
CPRE Competitive Procurement of Renewable Energy
CT combustion turbine/s
CTPC Carolina Transmission Planning Collaborative
DEC Duke Energy Carolinas, LLC
DENC Dominion Energy North Carolina
DEP Duke Energy Progress, LLC
DER Distributed Energy Resources
DERMS Distributed Energy Resource Management System
DO Distribution Operator
DOE U.S. Department of Energy
DR Demand Response
DSM demand-side management
EE Energy Efficiency
EMC electric membership corporation
EnergyUnited EnergyUnited EMC
EPA U.S. Environmental Protection Agency
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
kWh kilowatt-hour/s

ABBREVIATIONS AND ACRONYMS

LED light-emitting diode

LNG liquified natural gas

MW megawatt/s

MWh megawatt-hour/s

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

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

OATT Open Access Transmission Tariff

ORS South Carolina Office of Regulatory Staff

PJM PJM Interconnection

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

RTO regional transmission organization

SCPSC South Carolina Public Service Commission

SEPA Southeastern Power Administration

SERC SERC Reliability Corporation

SERTP Southeastern Regional Transmission Planning

STEM Science, Technology, Engineering and Mathematics education

Transco Transcontinental Gas Pipe Line Company, LLC

TVA Tennessee Valley Authority

TWh terawatt-hour/s

VEPCO Virginia Electric and Power Company

WPSA Wholesale Power Supply Agreement

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 on the retail market. 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. The service territory map in Appendix 1 provides an overview of counties in which some customers are served by either DEP, DEC, or DENC.

Table ES-1 depicts the sales of North Carolina Electricity IOUs.

Table ES-1: Electricity Sales of Investor-Owned Utilities in North Carolina for 2023-2024

	NC Retail Sales (GWh*)		NC Wholesale Sales (GWh*)		Total Sales (GWh*) (NC Plus Other States) [1]	
	2023	2024	2023	2024	2023	2024
DEP[2]	42,238	43,119	17,074	17,675	59,312	60,795
DEC	78,203	80,200	8,516	9,264	86,718	89,463
VEPCO[3]	3,976	3,988**	47	51**	4,024	4,040**

*GWh = 1 million kWh (kilowatt-hours)
** VEPCO's 2024 figures are estimates

[1] DEP and DEC sales represent combined totals for their service territories in both North Carolina and South Carolina. VEPCO sales reflect only the North Carolina portion of Dominion Energy's service area.

[2] DEP and DEC 2025 Biennial Consolidated Carbon Plan and Integrated Resource Plans (CPIRP), No. E-100, Sub 207, App. D at tbl.D-21, tbl.D-22 (Oct. 1, 2025).

[3] VEPCO sales figures updated from those provided on Table ES-1 in the 2024 Annual Report using VEPCO 2024 Integrated Resource Plan (IRP), No. E-100,Sub 204, App. 2B-3, (Oct. 15, 2024).

During the 2026 to 2040 timeframe, the average annual growth rate in summer peak demand for electricity in North Carolina is forecasted to be approximately between 1.2% – 2.74% compared to 1.7% – 2.58% for winter peak demand growth. Table ES-2 illustrates the system-wide average annual growth rates forecast by the IOUs in North Carolina. Each IOU 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 for Average Annual Growth Rates of Investor-Owned Utilities in North Carolina (with Energy Efficiency Included)[4]

	Summer Peak	Winter Peak	Energy Sales
DEP (2026-2040)	1.2%	1.8%	1.5%
DEC (2026-2040)	2.0%	1.7%	2.8%
VEPCO (2024-2039)	2.74%	2.58%	3.88%

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: Energy Generation by Fuel Type of Investor-Owned Utilities in North Carolina for 2024 Calendar Year [5]

	DEP	DEC	VEPCO
Nuclear	53%	41%	30%
Natural Gas & Oil	25%	34%	37%
Coal	9%	11%	8%
Net Hydropower[6]	1%	1%	3%
Renewables	3%	9%	1%
Other Purchased Power	9%	5%	22%

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 the appropriateness of planning reserve margins through its integrated resource planning proceedings. In its 2024 Carbon Plan and Integrated Resource Plan (CPIRP) Order, the Commission authorized DEP and DEC to implement a gradual increase of their minimum planning reserve margin to 22% by 2031 to maintain system reliability and reduce the likelihood of service interruptions

[4] Duke's 2025 CPIRP App. D at tbl.D-30, D-31; DENC's 2024 IRP App. 2B-1, 2B-3.

[5] Estimates derived from DEP & DEC Monthly Fuel Reports and the 2024 DENC IRP. VEPCO generation percentages are for the 2023 Calendar Year. Percentages may not sum to 100% due to rounding.

[6] *See* paragraph on "pumped storage" in Section 6 under "Utility-Owned Generating Facilities."

during periods of extreme weather like those 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). This statute was amended in 2023 to include additional energy resources and renamed the Clean Energy and Energy Efficiency Portfolio Standard (CEPS). Under the CEPS statute, codified at N.C.G.S. § 62-133.8, IOUs are required to increase their use of clean energy resources and 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 use clean energy resources and energy efficiency to meet 10% of their North Carolina retail sales in 2018 and thereafter.

The Commission issued its most recent Carbon Plan order on November 1, 2024, pursuant to N.C.G.S. § 62-110.9. The law, as amended by Session Law 2025-78, which became effective July 29, 2025, directs the Commission to take all reasonable steps to achieve reduction in emissions of carbon dioxide from electric generating facilities owned or operated in this State by DEP and DEC that result in carbon neutrality by the year 2050, subject to certain discretionary extensions. The law further requires that the emission reduction 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." DEP and DEC filed the most recent CPIRP application for Commission consideration on October 1, 2025, and the Commission must issue an order approving a plan before the end of 2026.

Resource adequacy planning must account for shifting economic and policy dynamics and trends. Demand for electricity is projected to increase significantly more than previously expected across North and South Carolina. This increased demand is driven by a number of economic factors, including population growth, changing consumer use trends, and economic development, particularly economic development related to large-load factor customers such as data centers.

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 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. In developing such analysis, the Commission shall, as it deems necessary, confer and consult with the public utilities in North Carolina, the utilities commissions or comparable agencies of neighboring states, the Federal Energy Regulatory Commission and other agencies having relevant information and may participate as it deems useful in any joint boards investigating generating plant sites or the probable need for future generating facilities. In addition to such reports as public utilities may be required by statute or rule of the Commission to file with the Commission, any such utility in North Carolina may submit to the Commission its proposals as to the future needs for electricity to serve the people of the State or the area served by such utility, and insofar as practicable, each such utility, the Public Staff, and intervenors may attend or be represented at any formal conference conducted by the Commission in developing a plan for the future requirements of electricity for North Carolina or this region. In the course of making the analysis and developing the plan, the Commission shall conduct a public hearing on such plan in the year a biennial integrated resource plan is filed and may hold a public hearing on such plan in a year that an annual update of an integrated resource plan is filed. 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 IOU 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 16, 2024 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 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). The service territory map in Appendix 1 provides an overview of counties in which some customers are served by either DEP, DEC, or 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 on the retail market. Approximately 23% of the IOUs' North Carolina electric sales were to the wholesale market in 2024, consisting primarily of electric membership corporations (EMCs) and municipally owned electric systems.

Based on annual reports submitted to the Commission for the 2024 reporting period, sales for the IOUs in North Carolina are summarized in Table 1.

Table 1: Electricity Sales of Investor-Owned Utilities in North Carolina for 2023-2024

	NC Retail Sales (GWh*)		NC Wholesale Sales (GWh*)		Total Sales (GWh*) (NC Plus Other States)[7]	
	2023	2024	2023	2024	2023	2024
DEP[8]	42,238	43,119	17,074	17,675	59,312	60,795
DEC	78,203	80,200	8,516	9,264	86,718	89,463
VEPCO[9]	3,976	3,988**	47	51**	4,024	4,040**

* GWh = 1 million kWh (kilowatt-hours)
** VEPCO's 2024 figures are estimates

Electric Membership Corporations

EMCs are independent, not-for-profit corporations that distribute electricity to their member customers. The 32 EMCs serving customers in North Carolina serve approximately 25% of the State's population across 45% of the State's land mass. Twenty-seven EMCs are headquartered in the State, and these 27 EMCs serve approximately 1.05 million metered customers. The other five EMCs are headquartered

[7] *See* fn.1.

[8] *See* fn.2.

[9] *See* fn.3.

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 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); conservation voltage reduction capability; 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.

NCEMC and its member distribution cooperatives have developed and implemented the NCEMC Distribution Operator (DO), a single entity that monitors, aggregates, and centrally coordinates DER and DR 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.

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 (IRP) 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 DR and EE programs and activities on forecasted annual energy and peak loads for the 15-year period.

By order issued November 20, 2023, the Commission adopted Rule R8-60A, a revised version of the integrated resource planning rule specific to the CPIRP process. The rule, applicable to DEC and DEP, establishes filing dates for the utilities and intervenors and required information to be filed by the utilities.

DEP and DEC CPIRP

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 (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, directed the Commission to take all reasonable steps to achieve a reduction of 70% from 2005 levels by the year 2030, and directs the Commission to take all reasonable steps to achieve 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." 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.

On March 15, 2023, the Commission issued an Order Establishing Biennial Proceeding and Opening Dockets, requiring DEP and DEC (together, Duke) 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) on or before September 1, 2023. Duke filed the 2023 CPIRP, as ordered on August 17, 2023, with supporting testimony and exhibits filed on September 1, 2023.

The Commission issued its most recent CPIRP order on November 1, 2024, accepting the establishment of a plan that endeavors to balance the near-term needs of the electric system, including anticipated growth in demand for electricity in North Carolina, while preserving the flexibility to adapt to future dynamics, should they evolve, to ensure that Duke remains on a least-cost path and is in a position to operate the electric system in North Carolina reliably. The Commission's decision followed a nine-day hearing in which many parties to the proceeding presented expert witness testimony. In addition, the Commission conducted five hearings across the State to receive public witness testimony, including one virtual hearing via Webex, at which 117 public witnesses testified. Further, the Commission received more than 1,400 consumer statements from interested members of the public. Consistent with the initial Carbon Plan order, the Commission directed Duke to investigate and pursue every available opportunity, including tax incentives and federal funding, to reduce costs for the benefit of all customers. In the order, the Commission accepted a settlement agreement between Duke and the Public Staff, the State's consumer advocate, as well as Walmart and the Carolinas Clean Energy Business Association. Rather than approve a single portfolio of electric generating units, the Commission accepted the system modeling work conducted by Duke and the Public Staff as being reasonable for planning purposes and approved a series of actions for Duke to take in the near term, which are intended to facilitate Duke's continued efforts toward providing reliable, affordable electric service while advancing toward a carbon-free future. Those actions include:

(1) retiring the remaining coal-fired generating units;
(2) conducting additional competitive solar procurements;
(3) procuring standalone battery storage and battery energy storage paired with solar generation;
(4) procuring onshore wind and pursuing the development of offshore wind;
(5) pursuing the development of new natural gas-fired CT and CC generation;
(6) constructing additional pumped storage hydropower;
(7) conducting early development activities associated with advanced nuclear generation;
(8) continuing to work toward the extension of the operating licenses for Duke's existing nuclear fleet;
(9) continuing to plan for 1% load reduction through demand-side management (DSM) and energy efficiency (EE) measures; and
(10) working with large customers to develop programs aimed at managing and controlling large customer load for the benefit of all customers.

On February 12, 2025, the Commission issued its Order Establishing Biennial Proceeding and Operating Stakeholder Process Docket, requiring Duke 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) on or before September 1, 2025.

On July 29, 2025, the General Assembly enacted S.L. 2025-78, which, among other changes, removed the requirement for the Commission to take all reasonable steps to achieve a 70% reduction in Duke's North Carolina carbon dioxide emissions from 2005 levels by the year 2030.

On July 22, 2025, the Commission issued an order granting Duke's request for an extension of the filing deadline to October 1, 2025. Duke filed their 2025 CPIRP and supporting testimony and exhibits on October 1, 2025. The Commission will issue its next CPIRP order on or before December 31, 2026.

Dominion Energy North Carolina IRP

On July 7, 2025, the Commission issued an order accepting DENC's 2024 IRP. DENC filed its IRP on October 15, 2024. One party intervened and the Public Staff filed comments on March 14, 2025. After careful review of the comments, the Public Staff's independent review and recommendations, and DENC's responses thereto, the Commission concluded that DENC relied upon reasonable modeling assumptions sufficient for long-term planning purposes and that its short-term action plan is sufficient for planning purposes. The Commission further required DENC in its next IRP filing to develop additional analyses with different annual solar and storage limits and to model at least one scenario that includes the retirement of carbon-generating resources by 2045. The Commission additionally encouraged DENC to seek to produce hybrid solar plus storage resources in its next solar procurement cycles, including resources located in North Carolina, as recommended by the Public Staff.

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. Recent trends in the Carolinas and nationally show significant growth in projected electricity demand.[10] Although their respective forecasting models differ, 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 2025 Spring load forecast (filed on October 1, 2025, in docket E-100 Sub 207), DEP and DEC modeled four scenarios from low to high load forecasts. The total system net load growth rates from 2026-2040 range from 1.1% to 3.4%. DEP and DEC state that load growth over the next 15 years is forecasted to surge eightfold from the previous 10 years, with energy needs increasing by nearly 80 TWh. VEPCO is forecasted to grow faster than any other PJM zone during this planning horizon.

Table 2: Forecast for Average Annual Growth Rates of Investor-Owned Utilities in North Carolina (with Energy Efficiency Included) [11]

	Summer Peak	Winter Peak	Energy Sales
DEP (2026-2040)	1.2%	1.8%	1.5%
DEC (2026-2040)	2.0%	1.7%	2.8%
VEPCO (2024-2039)	2.74%	2.58%	3.88%

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

[10] NERC 2024 Long Term Reliability Assessment report found "Electricity peak demand and energy growth forecasts over the 10-year assessment period continue to climb higher than at any point in the past two decades."

[11] *See* fn.4.

Reliability Assessment by the North American Electric Reliability Corporation (NERC) projects continued growth in electricity demand across the SERC-East subregion, driven largely by population increases and ongoing economic expansion in urban centers.

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

Table 3: Summer and Winter System-wide Peak Loads of Investor-Owned Utilities in North Carolina for 2018-2024 (MW)[12]

	DEP		DEC		VEPCO	
	Summer	Winter*	Summer	Winter*	Summer	Winter*
2018	13,029	15,876	17,779	19,077	16,528	17,792
2019	12,953	13,715	17,736	16,880	16,599	16,842
2020	12,966	12,196	17,405	16,132	16,356	14,661
2021	12,691	11,894	17,471	15,583	16,462	14,469
2022	12,896	13,149	18,098	16,282	17,131	17,813
2023	12,710	14,558	18,158	19,465	17,775	15,643
2024	12,864	14,181	18,641	18,689	18,023**	17,740**

*Winter peak following summer peak
**VEPCO's 2024 peaks are estimates

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, hydroelectric, renewable, etc.) and placed into three categories based on operational characteristics:

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

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 2041 and 2054.

[12] Duke 2025 CPIRP App. D at tbl.D-27; VEPCO's 2024 IRP App. 2B-7.

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 subsequent 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 finalized on August 28, 2024. The renewal preserves 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 2024 capacity mix for each IOU is shown in Table 4.

Table 4: Installed Generating Capacity by Fuel Type of Investor-Owned Utilities in North Carolina (Summer Ratings) for 2026[13]

	DEP	DEC	VEPCO
Nuclear	27%	27%	19%
Natural Gas/Oil	25%	41%	49%
Coal	28%	23%	14%
Hydropower	5%	2%	2%
Storage	12%	1%	10%
Renewables	3%	6%	6%

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 startup, 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 2023-2024, is provided in Table 5.

Table 5: Energy Generation by Fuel Type of Investor-Owned Utilities in North Carolina for 2024 Calendar Year[14]

	DEP	DEC	VEPCO
Nuclear	53%	41%	30%
Natural Gas & Oil	25%	34%	37%
Coal	9%	11%	8%
Net Hydropower[15]	1%	1%	3%
Renewables	3%	9%	1%
Other Purchased Power	9%	5%	22%

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

[13] DENC 2024 IRP; 2025 Duke CPIRP App. C.

[14] Estimates derived from DEP & DEC Monthly Fuel Reports and the 2024 DENC IRP. VEPCO generation percentages are for the 2023 Calendar Year. Percentages may not sum to 100% due to rounding.

[15] See paragraph on “pumped storage” in this section under “Utility-Owned Generating Facilities.”

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 forecast and modeling systems, evaluation of nontraditional solutions for the grid, grid hosting analysis, extensive stakeholder engagement, and new resource valuation methods to recognize contributions and value across the business segments.

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 from the Commission a certificate of public convenience and necessity (CPCN) to do so.

Merchant Generating Facilities

When the Public Utilities Act was originally enacted, electric 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.

The Commission therefore is continuing to apply the same criteria that it uses for reviewing other CPCN applications under N.C.G.S. § 62-110.1(a), 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.

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 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 2025, the Commission approved a CPCN for one merchant solar facility with a capacity of 70 MW. This facility will interconnect to the transmission grid owned by DENC.

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.

In 2024, the Commission ordered that DEP and DEC increase their minimum planning reserve margin from the current 17 % to 22% by 2031. 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 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 expected load growth in its service territory, i.e. to "self-supply" its capacity obligation. However, as of June 1, 2025, VEPCO has returned to PJM's capacity market. PJM recommends using an installed reserve margin of 17.8% for delivery year 2025/2026. In its 2024 IRP filing with the Commission, VEPCO reported that its summer reserve margin for 2024 was 25.6% of load, while its winter reserve margin was 27.1% 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. As Duke plans for the retirement of coal units, the need to acquire adequate natural gas supply to maintain least-cost and reliable operations will continue to increase.

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. On August 30, 2024, Transco filed a general rate case under Section 4 of the Natural Gas Act (Docket No. RP24-1035-000) seeking 13.74% return on equity, updating its transportation rates and implementing a modernization cost-recovery mechanism. The NCUC is an intervenor in this ongoing FERC proceeding.

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 securing transportation capacity and avoiding potential supply disruption. To mitigate these dynamics, the LDCs and Duke enter into contracts for firm transportation (FT) service and the highest transportation priority. Duke currently has a long-term portfolio of 447,560 dekatherms per day (Dth/day) of interstate FT service subscribed on Transco while the current peak burn of their baseload CC fleet is approximately 980,000 Dth/day.

Further, 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. The 304-mile, 2 billion cubic feet per day (bcf/day) MVP has provided another outlet for Appalachian Basin natural gas supplies since it was placed into service on June 14, 2024. The MVP extends the Equitrans transmission system in Wetzel County, West Virginia, to Transco's Zone 5 compressor station 165 in Pittsylvania County, Virginia. In June 2020, FERC approved a CPCN for the MVP Southgate Project (Southgate), which is an extension of the MVP Project. In December 2023, Mountain Valley's developer (Equitrans Midstream Corp) informed FERC that it was considering a revised version of originally planned 75-mile, 375-million cubic feet per day (MMcf/day) Southgate expansion that would shorten the route, increase the capacity, eliminate a compressor station, and cut the number of water crossings needed for the long-planned extension off the mainline. The revised scope would entail a 30 -inch -diameter pipeline with a capacity of 550,000 Dth/day stretching about 31 miles from the terminus of the Mountain Valley project in Pittsylvania County, Virginia, to new delivery points in Rockingham County, North Carolina. The developer has reached precedent agreements with PSNC and DEC for firm capacity commitments covering the full project for 20-year terms, with two potential five-year extensions. After the developer outlined the revisions, a coalition of environmental groups opposed to the project asked FERC earlier this year to cancel a late 2023 order that granted the developer more time to build the Southgate project. FERC rejected their request in April, standing by its decision to allow the developer until June 2026 to finish the proposed Southgate extension.

In February 2024, Transco initiated a prefiling review with FERC for the Southeast Supply Enhancement (SSE) project that would expand its existing gas transportation system in Alabama, Georgia, North Carolina, South Carolina, and Virginia. The Southeast Supply Enhancement project would involve the construction of approximately 55 miles of 42- inch diameter pipeline in total. More than half of it would be built between Pittsylvania County, Virginia, and Rockingham County, North Carolina. The rest of the line would be built across three other counties (Guilford, Forsyth and Davidson) in North Carolina. The project would also include compression facilities and upgrades to support the additional firm transportation across the Southeast into Alabama. Once approved by FERC, the expansion project will add approximately 1.6 million Dth/day of pipeline transportation capacity to the Transco system by the fourth quarter of 2027. DEC is one of the project shippers and accounts for about 63% of the project's capacity. When completed, SSE will enhance fuel security and reliability for existing and incremental natural gas generation in the Carolinas by providing new firm transportation capacity into Transco’s Zone 5.

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. In the 2024 CPIRP Order, the Commission also required Duke to evaluate and model LNG as part of its fuel-security strategy for natural-gas-fired generation, leading to the inclusion of Enhanced LNG (ELNG) storage modeling in the 2025 CPIRP.

Recognizing the importance of the dependencies and inter-dependencies between the gas and electric systems in North Carolina that could threaten electric operations or customer service during extreme cold weather or other emergencies, the Commission opened docket M-100 Sub 217 to monitor gas-electric coordination.

8. CLEAN ENERGY AND ENERGY EFFICIENCY

Clean Energy and Energy Efficiency Portfolio Standard

In 2007, North Carolina became the first state in the Southeast to adopt a Renewable Energy and Energy Efficiency Portfolio Standard, or REPS. On October 10, 2023, the North Carolina General Assembly enacted Session Law 2023-138, Part 1 of which amended the REPS by expanding it to be the Clean Energy and Energy Efficiency Portfolio Standard, or CEPS. Under the CEPS statute, codified at N.C.G.S. § 62-133.8, IOUs are required to increase their use of clean energy resources and EE 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 use clean energy resources and EE 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 CEPS requirements by producing or purchasing electricity produced from solar, swine-waste, and poultry-waste resources. These specified resource requirements also increase over time; however, the Commission has modified and delayed the swine and poultry waste set-aside requirements several times. On December 11, 2024, the North Carolina General Assembly enacted Session Law 2024-57, Section 3F.3 of which amended the CEPS statute to add a new section at N.C.G.S. § 62-133.8A providing for a one-time “enhanced credit” stimulus for renewable energy certificates (RECs) generated at clean energy facilities located in Tier 1 counties which use in-state sourced swine waste resources. These “enhanced credit” RECs (ECRs) can be used to meet swine waste set-aside requirements.

The CEPS statute requires the Commission to monitor compliance with CEPS 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 clean 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 CEPS 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 Program

Pursuant to N.C.G.S. § 62-110.8 the Commission was 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. 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 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 (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 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

Electric power suppliers in North Carolina are required to implement DSM and 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 CEPS. DEP, DEC, DENC, EnergyUnited, Fayetteville Public Works Commission, Halifax, and NCEMC (which has assumed compliance responsibility from the now-dissolved GreenCo for CEPS 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 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 EE 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, and 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 Science, Technology, Engineering and Mathematics (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-kilowatt (kW) top-of-pole and roof-mounted systems, solar awnings, and other designs as needed to accommodate various structures. In 2023, NC GreenPower had its largest Solar+

Schools year, awarding 15 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 and educational costs; the selected schools are no longer required to fundraise for any portion. Schools in Tier 1 and 2 counties are eligible to apply. NC GreenPower's partner, the State Employees' Credit Union (SECU) Foundation, provided NC GreenPower with a grant of up to $600,000 over three years to assist with the installation costs for selected public schools. The SECU Foundation grant was recently extended through the 2025 program year.

By the end of 2025, Solar+ Schools will have reached a total of 101 North Carolina schools in 52 counties, bringing solar energy and STEM education to nearly 67,000 students. Through June 30, 2025, the schools had collectively produced an estimated 1,814,000 kWh of clean energy, with a cumulative savings of about $172,400.

NC GreenPower recognizes that training and instruction will remain essential as North Carolina and the rest of the country continue to transition to a clean energy future. With this in mind, in summer 2024 NC GreenPower launched a new education-focused effort in partnership with the NEED Project (NEED).

The Clean Energy Education Program is a STEM-based initiative that brings energy curriculum to the classrooms of North Carolina teachers. Aligned with North Carolina State Science Standards, it combines energy workshops, hands-on activities, and outside community experts to enhance the experience of students and expose them to the energy field and STEM.

Participating educators — all K-12 educators in North Carolina are invited to apply — will take part in three energy education workshops organized by NEED. During these workshops, participants will receive STEM kits to help their students learn about energy and how it impacts their daily lives. The kits highlight four topics: the science of energy, solar energy, wind energy, and energy efficiency. As of August 2025, 39 teachers participated in the first round of the Clean Energy Education Program.

Both Solar+ Schools and the Clean Energy Education Program increase awareness of renewable energy, with the goal of preparing our future energy leaders and improving the environment. The Clean Energy Education Program, though, will allow NC GreenPower to reach more schools, teachers, and students. It will also provide broader coverage of energy topics (Solar+ Schools' curriculum focuses primarily on solar power) and allow students to take on an active role through participation in energy fairs and audits.

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. Businesses can also purchase in-state RECs and carbon offsets from NC GreenPower to reach their sustainability goals. NC GreenPower is a 501(c)(3) nonprofit organization, and all current projects are located in North Carolina.

9. TRANSMISSION AND GENERATION INTERCONNECTION

The Carolina Transmission Planning Collaborative (CTPC), formerly known as the North Carolina Transmission Planning Collaborative, 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 CTPC participants consist of DEP and DEC, which own transmission, and NCEMC and ElectriCities, which represent transmission-dependent utilities. The Transmission Advisory Group (TAG) of the CTPC ensures meaningful input from interested parties by allowing participation in the transmission planning process. Through the CTPC 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 CTPC's July 2025 mid-year report states that the total cost estimate of the "2024 Plan Reliability Projects" is $1.9318 billion and the total cost estimate of the "2024 Public Policy Projects" is $848.3 million. For more information, *see* https://carolinastpc.org/.

Since 2011, pursuant to FERC Order No. 1000, Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities,[16] transmission owners are required to participate in local and regional transmission planning efforts. DEP and DEC have complied with Order No. 1000 by participating in the Southeastern Regional Transmission Planning (SERTP) process.[17]

On July 3, 2013, Session Law 2013-232 was enacted providing 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.

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

[17] 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.

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 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 began 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 DER 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 DER that use inverter-based technology.

On June 28, 2024, the Commission issued an order approving Duke's request to offer provisional interconnection service for projects in the 2022 DISIS cluster, allowing them to export energy on a limited, non-firm basis while waiting for network upgrades to be completed. The Commission also granted limited waivers to reduce the financial burden on Interconnection Customers, permitting the use of letters of credit for up to 50% of upgrade costs. Additionally, the Commission required Duke to file an update on the status of the provisional interconnection service proposal by April 1, 2025, including a timeline for submitting its first report on the proposal. Duke filed a letter on April 1, 2025, providing a status update on the provisional interconnection service proposal and filed their report regarding the use of the provisional interconnection service option for the 2022 DISIS interconnection customers on April 30, 2025. On June 30, 2025, the Commission granted Duke’s motion to extend the provisional interconnection service option to interconnection customers in the 2023 and 2024 DISIS and Resource Solicitation Clusters (RSC).

10. FEDERAL ENERGY INITIATIVES

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.

Federal and State Current Issues Collaborative

After the Task Force ended in February 2024, FERC announced a new Federal and State Current Issues Collaborative in March 2024, which is comprised of all five federal Commissioners and ten state commissioner representatives selected from five regions. The Collaborative with the National Association of Regulatory Utility Commissioners will provide a venue for federal and state regulators to share perspectives, increase understanding, and identify potential solutions regarding challenges and coordination on a broad range of matters that impact specific and state and federal regulatory jurisdiction. In August 2025, Commissioner Karen Kemerait was selected for the Southeastern Association of Regulatory Utility Commissioners Representatives and has attended all meetings to date.

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 May 2024, FERC issued a final rule in Docket No. RM21-17, Order No. 1920. This order builds on previous FERC orders (Order Nos. 888, 890, and 1000) requiring open access to the transmission grid as well as local and regional transmission planning. Order No. 1920 requires transmission providers to conduct regional planning by using a 20-year time horizon, develop at least three plausible and diverse scenarios using best available data, update the plans every five years, and collaborate with states on cost allocation with transparency in the process for all stakeholders. The rule requires transmission providers to assess seven key benefits when evaluating potential long-term regional transmission facilities, including avoiding infrastructure replacement, reducing loss of load probability, increasing production cost savings, lowering transmission energy losses, reducing congestion from outages, mitigating extreme weather impacts, and enhancing capacity cost benefits by reducing peak energy losses. FERC emphasized that considering all seven benefits is crucial for identifying and selecting efficient, cost-effective regional transmission solutions.

Lastly, Order No. 1920 requires transmission providers to submit cost allocation methods that fairly distribute the costs of transmission projects based on their benefits. FERC allowed state commissions and transmission providers an initial six-month period to reach agreement on a cost allocation method for future transmission projects, which may include an agreement to defer the decision until after specific projects are selected. In November 2024, FERC issued Order 1920-A, which enhanced the role of state regulators in the long-term regional transmission planning process, especially their role in shaping scenario development and cost allocation. This includes a requirement that transmission providers must include any long-term regional transmission cost-allocation method and/or state agreement process agreed to by Relevant State Entities, even if the transmission provider has an alternative proposal. In this case, FERC makes the ultimate determination on the cost allocation methodology. In April 2025, FERC issued Order 1920-B, which clarified that transmission providers are not obligated to plan for the long-term needs of unenrolled non-jurisdictional transmission providers though voluntary arrangements are allowed. The order otherwise upheld the requirement that transmission providers include Relevant State Entities' agreed-upon cost allocation methods in their compliance filings, sustained the consultation requirement with Relevant State Entities before amending cost allocation methods, and declined to expand the definition of Relevant State Entity.

DEC and DEP joined other southeastern utilities to form the Southeastern Regional Transmission Planning Collaborative (SERTP) to satisfy the FERC regional transmission planning requirement, and DENC is a member of PJM. Order No. 1920 compliance filings are due in December 2025, and costs allocation discussions between transmission providers and state commissions will take place over the next few months.

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.

In July 2023, FERC issued a final rule in Docket No. RM22-14, Order No. 2023, implementing reforms to its generator interconnection agreements and procedures aimed at alleviating the backlog of generation and storage projects pending in interconnection queues throughout the country. This order required a transition from a first-come, first-served (serial) study process to a first-ready, first-served process studying groups of interconnection requests that may be served by the same transmission upgrades (cluster studies), as had been implemented in 2021 by the Commission for state-jurisdictional generation interconnections in North Carolina. FERC Order No. 2023 also addressed issues such as firm study deadlines, evaluation of alternative transmission technologies, and public sharing of interconnection hosting capacity. Compliance filings were made in response to Order No. 2023 in May 2024.

Southeast Energy Exchange Market

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 Open Access Transmission Tariff (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. On March 14, 2025, FERC issued an order requiring SEEM members to change the market's tariff to allow market participation from outside its borders but otherwise reaffirmed the transmission rules that govern the SEEM.

Public Utility Regulatory Policies Act 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

Following the U.S. Supreme Court's 2007 decision in *Massachusetts v. EPA*, 549 U.S. 497, 127 S. Ct. 1438 (2007), that greenhouse gases come within the definition of air pollutants under Section 111 of the Clean Air Act, the U.S. Environmental Protection Agency (EPA) has proposed several regulations regarding emissions from utility generating facilities. The Clean Power Plan proposed in 2015 was replaced by the Affordable Clean Energy Rule in 2019, which was vacated and remanded to the EPA for further proceedings in 2021 by the U.S. Court of Appeals for the District of Columbia Circuit.

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, and on April 25, 2024, the EPA released its final rule. This rule sets emission standards for existing coal-fired power plants based on their expected retirement dates and for new natural gas-fired generators, but the EPA deferred final decision on requirements for existing natural gas-fired CT.

Multiple states and industry groups sued to block implementation of the new rule, and on June 17, 2025, the EPA proposed to repeal the rule. The EPA proposed to make a finding that greenhouse gas emissions from fossil fuel-fired power plants do not contribute significantly to dangerous air pollution. The EPA also proposed, as an alternative, to repeal a narrower set of requirements that includes the emission guidelines for existing fossil fuel-fired steam generating units, the carbon capture and sequestration/storage-based standards for coal-fired steam generating units undertaking a large modification, and the carbon capture and sequestration/storage-based standards for new baseload stationary combustion turbines.

National Interest Electric Transmission Corridors

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.

On December 15, 2022, FERC 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.

On May 8, 2024, DOE released a preliminary list of ten NIETCs totaling more than 3,500 miles. DOE designated NIETCs in areas of the country where it has determined the lack of adequate transmission harms consumers and that the development of new transmission would advance important national interests in that area, such as increased reliability and reduced consumer costs. Of the ten, one (Mid-Atlantic) was designated in the geographic area served by PJM, and none were designated in the Southeast.

On May 13, 2024, FERC issued a final rule in Docket No. RM22-7, Order No. 1977, approving revised backstop transmission siting procedures. As recommended by the Commission and Public Staff, the rule does not adopt the proposal to allow simultaneous processing of state and FERC siting applications.

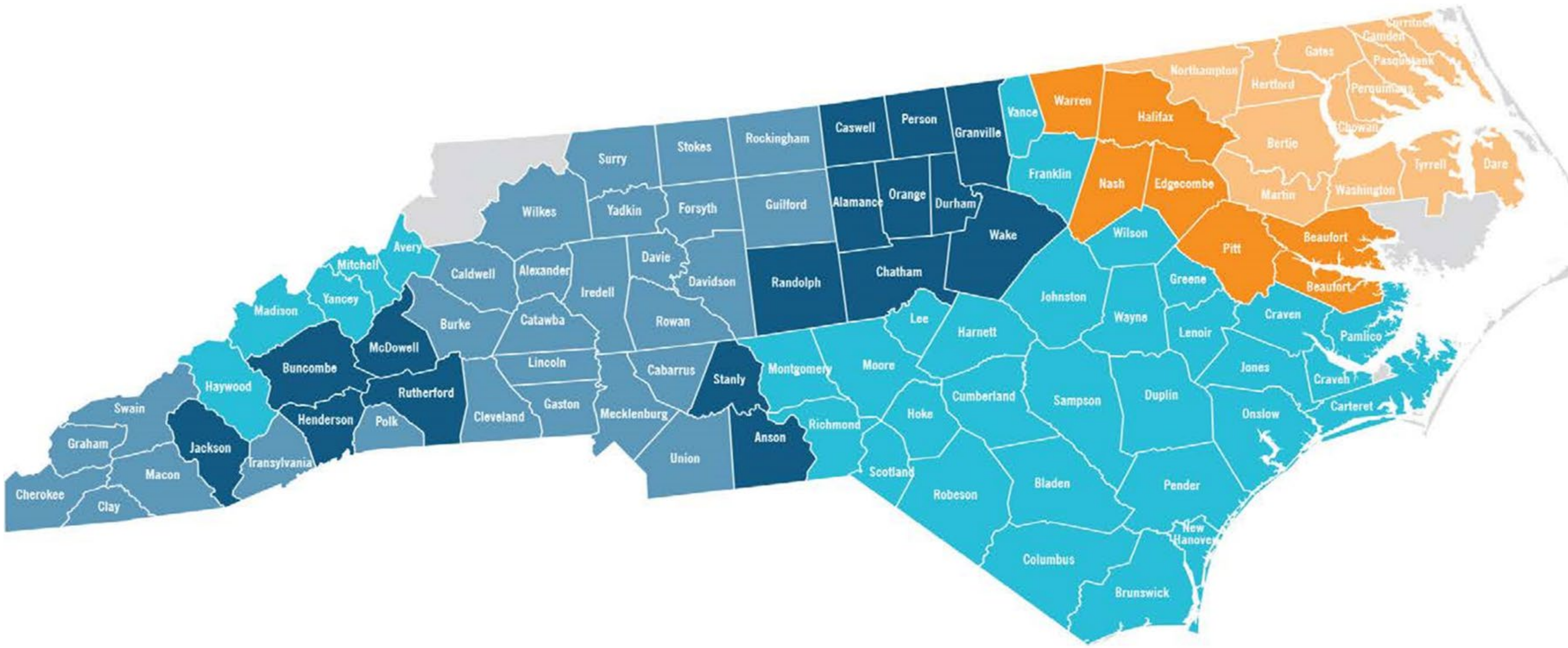
Infrastructure Investment and Jobs Act and Inflation Reduction Act

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 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 also 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.

On July 4, 2025, the One Big Beautiful Bill Act became law, which rescinds numerous provisions supporting investment in energy infrastructure contained in the IRA. Specifically, the legislation: (1) revised the types of projects eligible for energy infrastructure reinvestment financing, specifically; (2) shortened the eligibility window for wind or solar tax credit availability; and (3) eliminated financing for projects that avoid or reduce air pollutants or greenhouse gas emissions. Under this new legislation, certain fossil fuel projects are also no longer required to have controls or technologies to avoid or reduce air pollutants or greenhouse gas emissions.

APPENDIX 1



Service Territory Map of Investor-Owned Electric Utilities
(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**