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)

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RECEIVED BY
THE GOVERNOR OF NORTH CAROLINA
AND
THE JOINT LEGISLATIVE COMMISSION ON GOVERNMENTAL OPERATIONS

SUBMITTED BY
THE NORTH CAROLINA UTILITIES COMMISSION

ABBREVIATIONS AND ACRONYMS

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

ABBREVIATIONS AND ACRONYMS (continued)

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

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APPENDIX

1. EXECUTIVE SUMMARY

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

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

Duke and Progress, the two largest electric IOUs in North Carolina, together provide approximately 96% of the utility-supplied electricity consumed in the state. Approximately 22% of the IOUs' 2019 electric sales in North Carolina were to the wholesale market, consisting primarily of electric membership corporations and municipally-owned electric systems.

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

Table ES-1: 2018 Electricity Sales of Regulated Utilities in North Carolina

	NC Retail GWh*		NC Wholesale GWh*		Total GWh Sales* (NC Plus Other States)	
	2019	2018	2019	2018	2019	2018
Progress	37,894	38,362	21,613	21,914	68,357	69,333
Duke	58,458	59,157	5,662	6,892	89,921	92,280
VEPCO	4,281	4,401	1,203	1,158	88,238	88,038

*GWh = 1 Million kWh (kilowatt-hours)

During the 2020 to 2034 timeframe, the average annual growth rate in summer peak demand for electricity in North Carolina is forecasted to be approximately 1.1% compared to 1.0% for winter peak load growth. Table ES-2 illustrates the system wide average annual growth rates forecast by the IOUs that operate in North Carolina. Each uses generally accepted forecasting methods and, although their forecasting models are different, the econometric techniques employed by each are widely used for projecting future trends.

Table ES-2: Forecast Annual Growth Rates for Progress, Duke, and VEPCO (With Energy Efficiency (EE) Included) (2020 – 2034)

	Summer Peak	Winter Peak	Energy Sales
Progress	1.1%	1.0%	1.1%
Duke	1.0%	0.9%	0.9%
VEPCO	0.8%	0.8%*	0.9%

* 2019 – 2033

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

Table ES-3: Total Energy Resources by Fuel Type for 2019

	Progress	Duke	VEPCO
Coal	14%	22%	9%
Nuclear	41%	48%	36%
Net Hydroelectric*	1%	2%	1%
Natural Gas and Oil	30%	16%	50%
Non-Hydro Renewable	9%	2%	2%
Other Purchased Power	5%	10%	2%

* See discussion of pumped storage in Section 6.

In 2007, North Carolina became the first state in the Southeast to adopt a Renewable Energy and Energy Efficiency Portfolio Standard. Under the REPS statute, codified at N.C. Gen. Stat. § 62-133.8, investor-owned electric utilities are required to increase their use of renewable energy resources and/or energy efficiency such that those sources meet 12.5% of their NC retail sales in 2021. EMCs and municipal electric suppliers are required to meet a similar requirement of 10% of their NC retail sales in 2018 and thereafter. The requirements under the law phase in over time, with the most recent increase in 2018, requiring investor-owned utilities to meet 10% of their prior year's NC retail sales through renewable energy and EE sources. This issue is discussed further in Section 8.

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

North Carolina Governor Roy Cooper signed an executive order (EO80) on October 29, 2018, calling for a 40% reduction in statewide greenhouse gas emissions by 2030. The order tasked the Department of Environmental Quality with developing a Clean Energy Plan (CEP) for North Carolina. After an extensive stakeholder engagement process, including meetings and public comment periods, the CEP was presented to Governor Cooper on September 27, 2019, and subsequently published in October, 2019. The plan includes Clean Energy Goals as follows:

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

NCDEQ established stakeholder groups tasked with providing policy designs to align with EO80 goals. Final reports from these stakeholder groups will be available late in 2020 and the first quarter of 2021.

In 2019, Duke Energy announced a corporate commitment to reduce CO2 emissions by at least 50% from 2005 levels by 2030, and to achieve net-zero by 2050. According to Duke Energy, this is a shared goal important to the Company's customers and communities, many of whom have also developed their own clean energy initiatives. As one of the largest investor-owned utilities in the U.S., the goal to attain a net-zero carbon future represents one of the most significant reductions in CO2 emissions in the U.S. power sector. The development of the Company's IRP and climate goals are complementary efforts, with the IRP serving as a road map that provides the analysis and stakeholder input that will be required to achieve carbon reductions over time. All pathways included in the 2020 IRP keep Duke Energy on a trajectory to meet its carbon goals over the 15-year planning horizon.

The Duke IRPs detail scenarios to achieve carbon reduction goals including the goal to achieve 70% greenhouse gas emission reductions from the electric sector by 2030, which is currently under evaluation as part of implementing the North Carolina Clean Energy Plan. Achieving these targets will require the addition of diverse, new types of carbon-free resources as well as additional energy storage to replace the significant level of energy and capacity currently supplied by coal units.

In February 2020, Dominion Energy announced its commitment to net zero CO2 and methane emissions across its nationwide electric generation and natural gas infrastructure operations by 2050. The goal covers CO2 and methane emissions, the dominant greenhouse gases, from electricity generation and gas infrastructure operations. According to Dominion Energy, the strengthened commitment builds on Dominion Energy's strong history of environmental stewardship, while acknowledging the need to further reduce emissions.

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

2. INTRODUCTION

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

> The Commission shall develop, publicize, and keep current an analysis of the long-range needs for expansion of facilities for the generation of electricity in North Carolina, including its estimate of the probable future growth of the use of electricity, the probable needed generating reserves, the extent, size, mix and general location of generating plants and arrangements for pooling power to the extent not regulated by the Federal Energy Regulatory Commission (FERC) and other arrangements with other utilities and energy suppliers to achieve maximum efficiencies for the benefit of the people of North Carolina, and shall consider such analysis in acting upon any petition by any utility for construction . . . Each year, the Commission shall submit to the Governor and to the appropriate committees of the General Assembly 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.

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

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

This report is an update of the Commission's December 31, 2019 Annual Report. It is based primarily on reports to the Commission by the regulated electric utilities serving North Carolina, but also includes information from other records and Commission files.

3. OVERVIEW OF THE ELECTRIC UTILITY INDUSTRY IN NORTH CAROLINA

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

Duke and Progress, the two largest IOUs, together provide approximately 96% of the utility-supplied electricity consumed in the state. Duke provided electricity to 2,005,000 North Carolina customers in 2019 and Progress to 1,402,000 customers. Each of the Duke utilities also has customers in South Carolina. Dominion supplies approximately 4% of the State's utility-generated electricity. It has 121,000 customers in North Carolina. The large majority of its corporate operations are in Virginia, where it does business under the name of Virginia Electric and Power Company. About 22% of the IOUs' North Carolina electric sales were to the wholesale market, consisting primarily of EMCs and municipally-owned electric systems.

Based on annual reports submitted to the Commission for the 2019 reporting period, the gigawatt-hour (GWh) sales for the electric utilities in North Carolina are summarized in Table 1.

Table 1: 2018 Electricity Sales of Regulated Utilities in North Carolina

	NC Retail GWh* 2019	NC Retail GWh* 2018	NC Wholesale GWh* 2019	NC Wholesale GWh* 2018	Total GWh Sales* (NC Plus Other States) 2019	Total GWh Sales* (NC Plus Other States) 2018
Progress	37,894	38,362	21,613	21,914	68,357	69,333
Duke	58,458	59,157	5,662	6,892	89,921	92,280
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*GWh = 1 Million kWh (kilowatt-hours)

EMCs are independent, not-for-profit corporations that operate distribution grids. There are 31 EMCs serving metered customers in North Carolina. EMCs serve approximately 25% of the State's population. Twenty-six EMCs are headquartered in the State, and these twenty-six EMCs served 1,075,622 metered customers as of December 31, 2019. The other five EMCs are headquartered in adjacent states and provide service in limited areas across the border into North Carolina. EMCs serve customers in 95 of the State's 100 counties.

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

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

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

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

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

- 10 solar + energy storage sites totaling 18.5 MW/45.1 MWh in development;
- 19 community solar facilities;
- Operational microgrids located on Ocracoke Island, at Butler Farms in Harnett County, and in the Heron's Nest residential neighborhood in Brunswick County, as well as two microgrids in development, as of Q3 2020, at Eagle Chase in Wake County and at Rose Acre Farms in Hyde County;
- Aggregated demand response (DR) programs that, as of Q3 2020, reduce peak load via deployment of: over 4,500 member-owner Wi-Fi enabled thermostats, and over 1,300 smart controllers on existing electric resistance water heaters;
- Energy efficiency (EE) programs that, in 2019, collectively produced 271,820 EE credits (the equivalent of 271,820 MWHs, or 1.95% of the prior year's retail sales, in reduced consumption by member-owners);
- Approximately 50 MW of conservation voltage reduction capability with the feasibility of additional capability being actively studied;
- Cooperative-owned electric vehicle charging infrastructure including, as of Q3 2020: 9 DC fast chargers (with 9 charging ports) and 49 "level 2" chargers (with 91 charging ports);
- Approximately 220 MW of third-party-owned or member-owner-owned solar facilities that are operational and interconnected to the EMCs' grids as of October 2020; and
- Ongoing development and operation of a Distributed Energy Resource Management System (DERMS) for the aggregated forecasting, notification, execution, analysis, and report of DR and DER programs.

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

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

In addition to the EMCs, there are 72 municipal and university-owned electric distribution systems serving approximately 599,000 customers in North Carolina. Most of these systems are members of ElectriCities, an umbrella service organization. ElectriCities is a non-profit organization that provides many of the technical, administrative, and management services needed by its municipally-owned electric utility members in North Carolina, South Carolina, and Virginia.

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

ElectriCities is a service organization for its members, not a power supplier. Fifty-one of the North Carolina municipals are participants in one of two municipal power agencies which provide wholesale power to their membership. ElectriCities' largest activity is the management of these two power agencies. The remaining members buy their own power at wholesale.

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

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

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

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

The Tennessee Valley Authority (TVA) sells energy directly to the Murphy Power Board and to three out-of-state cooperatives that supply power to portions of North Carolina: Blue Ridge Mountain EMC, Tri-State Membership Corporation, and Mountain

Electric Cooperative. These distributors of TVA power are located in six North Carolina counties and serve over 34,000 households and 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 523 MW. The dams are Apalachia and Hiwassee in Cherokee County, Chatuge in Clay County, and Fontana in Swain and Graham counties.

4. THE HISTORY OF INTEGRATED RESOURCE PLANNING IN NORTH CAROLINA

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

Initial IRP Rules

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

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

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

Streamlined IRP Rules (1998)

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

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

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

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

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

Order Revising Integrated Resource Planning Rules – July 11, 2007

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

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

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

In the 2019 IRP Update Reports and REPS compliance plans filed by Progress, Duke and Dominion the IOU's provided their current IRPs (Docket E-100, Sub 157). The Commission held an Oral Argument on January 8, 2020 to discuss load forecast and reserve margin issues for Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP). A public hearing in this docket was held in Raleigh on March 9, 2020, for the purpose of receiving non-expert public witness testimony. Six public witnesses testified at the hearing.

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

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

The 2020 Biennial IRP Reports and REPS compliance plans were filed by Progress, Duke and Dominion in 2020. These are currently under review by the Commission.

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. Progress, Duke, and VEPCO each utilize generally accepted forecasting methods. Although their respective forecasting models are different, the econometric techniques employed by each utility are widely used for projecting future trends. Each of the models requires analysis of large amounts of data, the selection of a broad range of demographic and economic variables, and the use of advanced statistical techniques.

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

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

Table 2: Forecast Annual Growth Rates for Progress, Duke, and VEPCO (With Energy Efficiency (EE) Included) (2020– 2034)

	Summer Peak	Winter Peak	Energy Sales
Progress	1.1%	1.0%	1.1%
Duke	1.0%	0.9%	0.9%
VEPCO	0.8%	0.8%*	0.9%

* 2019 – 2033

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 2019 Long-Term Reliability Assessment by the North American Electric Reliability Corporation (NERC) indicates a forecast of average annual growth in peak demand of approximately 0.6% through 2029.

Table 3 provides historical peak load information for Progress, Duke, and VEPCO.

Table 3: Summer and Winter Systemwide Peak Loads for Progress, Duke, and VEPCO Since 2015 (in MW)

	Progress		Duke		VEPCO	
	Summer	Winter*	Summer	Winter*	Summer	Winter*
2015	12,849	13,298	20,003	19,377	18,980	18,948
2016	13,130	14,534	20,671	19,183	19,538	19,661
2017	12,784	15,519	20,120	21,620	18,902	21,232
2018	13,090	13,669	20,379	19,286	19,244	19,930
2019	12,908	12,243	20,597	18,413	19,607	17,544

**Winter peak following summer peak*

6. GENERATION RESOURCES

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

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

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

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

Progress 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 Progress's nuclear units. The new renewal dates run from 2030 to 2046.

VEPCO operates two nuclear power stations with two units each. Both stations are located in Virginia. All four units have been issued license extensions by the NRC. The new license expiration dates range from 2032 to 2040. On October 16, 2018 Dominion Energy Virginia filed an application with the U.S. Nuclear Regulatory Commission to renew its operating licenses for the Surry nuclear plant for an additional 20 years which would keep the plant on line beyond 2050.

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 Duke 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, often near a natural gas pipeline, and are owned by developers willing to assume the economic risk associated with the facility's construction.

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

Table 4: Installed Utility-Owned Generating Capacity by Fuel Type

(Summer Ratings) for 2019

	Progress	Duke	VEPCO
Coal	28%	33%	18%
Nuclear	28%	26%	17%
Hydroelectric	2%	16%	11%
Natural Gas and Oil	42%	25%	53%
Non-Hydro Renewable	<1%	<1%	1%

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

Generally, actual plant use is determined by the application of economic dispatch principles, meaning that the start-up, shutdown, and level of operation of individual generating units is tied to the incremental cost incurred to serve specific loads in order to attain the most cost effective production of electricity. The actual generation produced and power purchased for each utility, based on monthly fuel reports filed with the Commission for 2018, is provided in Table 5.

Table 5: Total Energy Resources by Fuel Type for 2019

	Progress	Duke	VEPCO
Coal	14%	22%	9%
Nuclear	41%	48%	36%
Net Hydroelectric*	1%	2%	1%
Natural Gas and Oil	30%	16%	50%
Non-Hydro Renewable	9%	2%	2%
Other Purchased Power	5%	10%	2%

* See the paragraph on pumped storage in this section.

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

In 2020, Progress and Duke jointly initiated a multi-year Integrated Systems and Operations Planning Project (ISOP). This effort is an important and necessary evolution in electric utility planning processes to address the trends in technology development, declining cost projections for energy storage and renewable resources, and customer adoption of electric demand modifying resources such as roof-top solar and electric vehicles. The anticipated growth of Distributed Energy Resources necessitates moving beyond the traditional distribution and transmission planning assumption of on-way power flows on the distribution system and analysis based on limited snapshots of pea 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. Duke anticipates implementing the basic elements of ISOP in the 2022 IRPs for the Carolinas.

The following highlights from utility generation planning exercises reflect information contained in the 2020 IRPs filed with the Commission.

Progress Generation

As of January 2020, Progress had 14,343 MW of installed generating capacity (winter rating). This does not include purchases and non-utility owned capacity.

NCEMPA previously owned partial interest in several Progress plants, including Brunswick Nuclear Plant Units 1 and 2, Mayo Plant, Roxboro Plant Unit 4 and the Harris Nuclear Plant. The Power Agency's ownership interest in these plants represented approximately 700 MW of generating capacity. The boards of directors of Duke Energy and the NCEMPA approved an agreement for Progress to purchase the Power Agency's ownership in these generating assets. All required regulatory approvals were completed and the agreement closed on July 31, 2015. Progress is now 100% owner of these previously jointly owned assets. Under the agreement, Progress will continue meeting the needs of NCEMPA customers previously served by the Power Agency's interest in the Progress plants.

As part of the Western Carolinas Modernization Project (WCMP), the combined 350-MW Asheville 1 and 2 coal units were retired in January 2020. The retired units were replaced with two 280-MW natural gas combined-cycle (CC) units. Additionally, an undetermined amount of solar generation is planned for installation at the same site.

Other capacity additions include:

- Planned Brunswick nuclear uprates totaling 20 MW in 2025 through 2030.
- Addition of 481 MW of storage capacity in December 2030 and 539 MW in December 2034.
- Addition of 2,448 MW of combined-cycle capacity in 2027 through 2028.
- Addition of 1,827 MW of combustion turbine capacity in 2025 through 2028.

- Addition of 300 MW (1,200 MW nameplate) of solar + storage in 2030 through 2035.

Other planned retirements include:

- Darlington combustion turbine units 1-4, 6-8 and 10 were retired in March 2020 (514 MW).

- Blewett combustion turbine units and Weatherspoon combustion turbine units in December 2025 (329 MW).

- Roxboro coal units 3-4 in December 2027 (1,409 MW).

- Roxboro coal units 1-2 in December 2028 (1,053 MW).

- Mayo 1 coal unit in December 2028 (746 MW).

Planning assumptions for nuclear stations assume subsequent license renewal at the end of their current license extensions.

Retirement assumptions are for planning purposes only. Coal retirement dates represent the economic retirement dates determined in the Coal Retirement Analysis section of the Company's 2020 IRP. Other technology units represent retirement dates based on the depreciation study approved as part of the most recent DEP rate case.

Duke Generation

As of January 2020, Duke had 23,222 MW of installed generating capacity (winter rating), excluding purchases and non-utility owned capacity. That total includes generation jointly-owned with NCMPA1, NCEMC, and Piedmont Municipal Power Agency produced at Duke's Catawba Nuclear Facility in South Carolina.

Capacity additions include:

- Addition of 15 MW of cogeneration in 2020.

- Addition of 12 MW Catawba nuclear uprates in 2020 through 2021.

- Addition of 260 MW Bad Creek pumped storage uprates in 2021 through 2024.

- Addition of 45 MW Oconee uprates in 2022 through 2023.

- Addition of 402 MW of combustion turbine capacity in 2025 at Lincoln County.

- Addition of 1,224 MW of combined-cycle capacity in December 2034.

- Addition of 457 MW of combustion turbine capacity in December 2029.

- Addition of 457 MW of combustion turbine capacity in December 2030.

- Addition of 913 MW of combustion turbine capacity in December 2034.

- Addition of 150 MW of wind capacity in December 2034.

Retirements include:

- Allen coal units 2-4 (719 MW) and units 1&5 (442 MW) in December 2021 and 2023, respectively.

- Lee Unit 3 natural gas (173 MW) in December 2030.

- Cliffside unit 5 (546 MW) in December 2025.

- Marshall units 1-4 (2,078 MW) in December 2034.

- Belews Creek units 1-2 (2,220 MW) in December 2038.
- Cliffside unit 6 (844 MW) in December 2048.

Planning assumptions for nuclear stations assume subsequent license renewal at the end of their current licenses.

Retirement assumptions are for planning purposes only based on the Load, Capacity and Reserves tables in the 2020 IRP.

VEPCO Generation

As of May 2020, VEPCO had 19,802 MW of installed generating capacity (summer rating). This excludes purchases and non-utility capacity. Of this total, only 480 MW are located in North Carolina.

The Company obtained a Combined Operating License (COL) from the NRC in June 2017 to support a new nuclear unit, North Anna 3, at its existing North Anna Power Station located in Louisa County in central Virginia. The Company paused material development activity following receipt of the COL and is incurring minimal costs specific to the administrative functions of maintaining the COL.

Capacity additions include:

- Addition of 463 MW (nameplate) utility-scale solar in 2021 through 2022.

- Addition of 12 MW offshore wind (Coastal Virginia Offshore Wind) by 2021.
- Addition of 12 MW (nameplate) solar + storage by 2021.

- Addition of 970 MW combustion turbines in 2023 through 2024.
- Addition of 2,556 MW offshore wind in 2026 through 2027.
- Addition of 300 MW pump storage by 2030.

Retirements include:

- Gravel Neck combustion turbines in 2020 (28 MW)
- Possum Point 5 heavy fuel oil in 2021 (623 MW).
- Chesapeake combustion turbines in 2022 (39 MW).
- Lowmoor combustion turbine in 2022 (11 MW).
- Mt. Storm combustion turbine in 2022 (11 MW).
- Northern Neck combustion turbines in 2022 (47 MW).
- Possum Point combustion turbines in 2022 (72 MW).
- Yorktown 3 heavy fuel oil in 2022 (790 MW).
- Chesterfield coal units 5 & 6 in 2023 (1,014 MW).
- Clover coal units 1 & 2 in 2025 (439 MW).
- Rosemary combined cycle in 2027 (165 MW).
- Altavista biomass in 2028 (51 MW).
- Hopewell biomass in 2028 (51 MW).
- Southampton biomass in 2028 (51 MW).

The above list reflects retirement assumptions used for planning purposes, not firm Company commitments. In addition, planning assumptions for nuclear stations assume subsequent license renewal at the end of their current license extensions.

7. RELIABILITY AND RESERVE MARGINS

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

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

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

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

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

One major new interstate pipeline project into North Carolina is being built to serve both gas and electric generation customers. It is MVP Southgate, an extension of the Mountain Valley Pipeline LLC (MVP) project. MVP Southgate extends the MVP project from southern Pittsylvania County, Virginia down into Alamance County, North Carolina. The MVP pipeline, which terminates in Virginia, and the MVP Southgate pipeline which comes down into North Carolina, are scheduled to come on-line in the winter 2021-2022 season but could be delayed further due to litigation in the courts. Until MVP Southgate can come on-line, LDCs will have to contract for short-term capacity. This capacity will be expensive and cannot be depended upon to meet long term needs. Further delays in MVP Southgate are a matter of serious concern.

Another major development is the announcement by Piedmont Natural Gas of a decision to build a liquefied natural gas storage facility in Robeson County. This facility is anticipated to be completed in the summer of 2021 and filled in time to provide peaking support in the winter of 2021-2022. This will help meet both gas- and electric-peak demand.

8. RENEWABLE ENERGY AND ENERGY EFFICIENCY

Renewable Energy and Energy Efficiency Portfolio Standard (REPS)

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

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

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

On September 28, 2020, the Commission submitted its Annual Report Regarding Renewable Energy and Energy Efficiency Portfolio Standard in North Carolina, which is required pursuant to N.C.G.S. § 62-133.8. The report details Commission implementation of the REPS statute since its enactment in 2007. The report concluded that all electric power suppliers have met the 2012-2019 general REPS requirements and appear on track to meet the 2020 general REPS requirements. All electric power suppliers have met the 2012-2019 solar set-aside requirements and appear to be on track to meet the 2020 solar set-aside requirement. The Commission granted a joint motion to delay implementation of the 2019 swine waste set-aside requirement for one year - except for the electric public utilities – requiring them to meet a 0.04% swine waste set-aside for 2019. The electric public utilities met the 0.04% swine waste set-aside for 2019. The Commission's modification order also reduced the poultry waste set-aside requirements for 2019 for all electric power suppliers to 500,000 MWh. Most electric power suppliers have indicated that they will have difficulty meeting the swine waste set-aside requirements for 2020 and that they will request a modification in these requirements for 2020, as well as a delay in future increases in these requirements. Electric power suppliers cite the lack of technological progress for power production from swine waste and failure of counter parties to deliver RECs as anticipated as impediments to meeting future swine waste set-aside requirements. The report is available on the Commission's web site at www.ncuc.net.

Competitive Procurement of Renewable Energy (CPRE)

On July 27, 2017, the Governor signed into law House Bill 589 (S.L. 2017-192). Part II of S.L. 2017-192 enacted N.C.G.S. § 62-110.8, which requires DEC and DEP to file for Commission approval on or before November 27, 2017, a program for the competitive procurement of energy and capacity from renewable energy facilities with the purpose of adding renewable energy to the State's generation portfolio in a manner that allows the State's electric public utilities to continue to reliably and cost-effectively serve customers' future energy needs (CPRE Program). Under the CPRE Program, DEC and DEP will issue requests for proposals to procure energy and capacity from renewable energy facilities in the aggregate amount of 2,660 MW, over the course of the 45-month program. This aggregate amount of capacity may be reduced based on certain provisions in the statute. Since House Bill 589 was signed into law, the Commission has adopted rules implementing the requirements of the CPRE Program and approved, with modifications, the CPRE Program proposed by DEC and DEP. In addition, the Commission approved Accion Group, LLC, as the Independent Administrator (IA) of the CPRE Program.

On July 10, 2018, the IA opened the period for the submission of proposals for the first RFP Solicitation under the CPRE Program, seeking proposals for 600 MW in DEC's service territories and 80 MW in DEP's service territories. Proposals were received through October 9, 2018, when the Proposal submission period closed. Proposals included a balanced representation from North Carolina and South Carolina and ranged in size from seven to 80 MW. While market participants had the ability to provide renewable energy from a number of technologies, the IA received proposals for only solar photovoltaic generation. Four of the projects proposed storage integration. The IA evaluated the bids resulting in 465.50 MW procured in DEC and 85.72 MW procured in DEP.

The CPRE Tranche 2 RFP opened on October 15, 2019, and reflected modifications based on stakeholder input and lessons learned in Tranche 1. For DEC, 37 proposals were submitted ranging from 15 to the maximum 80 MW AC generating capacity. A total of 1,853.7 MW AC of capacity was proposed, which is over three times the requested amount for CPRE Tranche 2 (600 MW AC). All proposals were for solar photovoltaic generation. Three proposals were submitted with energy storage systems integrated with PV systems. For DEP, six proposals were submitted ranging from 56 to the maximum 80 MW AC of generating capacity. A total of 440.9 MW was proposed, representing over five times the requested MW for Tranche 2 (80 MW AC). All Proposals were for solar photovoltaic generation. One proposal was submitted with an energy storage system integrated with the PV system.

On July 17, 2020, the IA completed the evaluation of proposals for Tranche 2 for both DEC and DEP. On that date the IA delivered to the Duke Evaluation Team the best ranked proposals ending the Tranche 2 RFP evaluation process. CPRE Tranche 2 successfully identified 689 MW of renewable resources at prices below the Tranche 2 Avoided Cost Cap (which cap included a reduction for Solar Integration Services Charge as directed by the Commission). The contracting period is underway, and the IA will prepare a final report at the conclusion of the contracting period.

Energy Efficiency

Electric power suppliers in North Carolina are required to implement demand-side management (DSM) and energy efficiency (EE) measures and use supply-side resources to establish the least cost mix of demand reduction and generation measures that meet the electricity needs of their customers. Energy reductions through the implementation of DSM and EE measures may also be used by the electric power suppliers to comply with REPS. Duke, Progress, Dominion, EnergyUnited, Halifax, and

NCEMC (which has assumed compliance responsibility from the now-dissolved GreenCo for REPS compliance for its member cooperatives) all administer EE and DSM programs.

NC GreenPower

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

Introduced on April 1, 2015, NC GreenPower Solar+ Schools uses donations to provide grants for educational solar PV packages at North Carolina schools. All K-12 schools are eligible, though preference may be given to those in economically distressed counties as defined by the NC Department of Commerce. Following a five-year pilot, the program was made official by the NC Utilities Commission in 2019 and offers top-of-pole mounted systems and roof-mounted systems. Each educational solar package includes a 5-kW solar PV array, a weather station, data monitoring equipment, a STEM curriculum and training for educators.

The NC GreenPower Solar+ Schools program gives teachers valuable tools to educate students about renewable energy. Selected schools are tasked with raising a small portion of the costs, between $6,000 and $12,000. Partnering with the State Employees' Credit Union (SECU) Foundation, selected public schools may receive a challenge grant worth $10,000 - $20,000, enabling them to increase their system from 3 kilowatts (kW) to 5 kW. NC GreenPower donations provide the remainder of funding needed, including $14,000 in additional program benefits.

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

This year was the first time that NC GreenPower is expanding its Solar+ Schools program to 10 schools — each of the previous five years awarded a maximum of five. NC GreenPower hopes to install at 15 schools in 2021 and up to 20 schools in 2022. By the end of 2020, the NC GreenPower Solar+ Schools program will have reached a total of 42 North Carolina schools in 33 counties, bringing solar and energy STEM education to nearly 31,600 students. To date the schools have collectively produced an estimated 391,560 kWh of green energy, a savings of about $39,000.

9. TRANSMISSION AND GENERATION INTERCONNECTION ISSUES

Transmission Planning

The North Carolina Transmission Planning Collaborative (NCTPC) was established in 2005. Participants (transmission-owning utilities, such as Duke and Progress, and transmission-dependent utilities, such as municipal electric systems and EMCs) identify the electric transmission projects that are needed to be built for reliability and estimate the costs of those upgrades. The NCTPC's January 22, 2020 report stated that 14 major (greater than $10 million each) transmission projects are needed in North Carolina by the end of 2029 at an estimated cost of $591 million. For more information, visit the NCTPC's website at www.nctpc.org.

On July 21, 2011, the FERC issued Order No. 1000, entitled "Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities." [1] This Order requires transmission owners to participate in regional and inter-regional transmission planning efforts. Duke and Progress have complied with Order No. 1000 by participating in the Southeastern Regional Transmission Planning (SERTP)[2] process.

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

State Generator Interconnection Standards

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

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

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

[2] For more information about the Southeastern Regional Transmission Planning process, see http://southeasternrtp.com/. Other members 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.

however, that the Commission shall adopt, if appropriate, federal interconnection standards."

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

The Commission issued an Order Approving Revised Interconnection Standard on May 15, 2015. That Order made substantial changes to the procedures for requesting to interconnect a generator to the electric grid. Most of these changes were recommended by the stakeholders with the intent of addressing a back-log of interconnection requests. The more significant changes in the State's interconnection standards were: 1) a project's ability to be expedited is now based not only on the project's size, but also on the size of the line it would connect to, and its distance from a substation; 2) a new process for addressing "interdependent" projects was added, where one generator needs to decide whether it is going to move ahead in order for the utility to determine that capacity exists to interconnect a second generator; 3) developers must provide a deposit of at least $20,000; 4) developers must demonstrate that they have site control; and 5) developers must pay for upgrades before the utility begins construction. The utilities are required to file a quarterly report to the Commission reporting on their progress in addressing the interconnection queue backlog.

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

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

1. The utilities were required to file additional information explaining their need for generators' production profiles. The Commission subsequently approved this new requirement on September 23, 2019.
2. Duke was required to file a proposal for an expedited study process for battery storage being added to an existing solar generator. This issue remains pending.
3. Duke was required to consult with the Electric Power Research Institute as to ways to improve the fast track / supplemental review processes and file a report with the Commission. Duke filed that report October 23, 2019.
4. The utilities were required to host stakeholder meetings about the adoption of Interconnection Standard IEEE-1547 and file a report with the Commission. This report was filed April 1, 2020 and is still being reviewed by the Commission.
5. Duke was required to establish a stakeholder process to discuss transitioning the interconnection process from a first-come first-served process to a grouping study

process. Duke subsequently filed a queue reform proposal, which the Commission approved October 15, 2020. Parallel changes must be approved by the South Carolina Public Service Commission and the Federal Energy Regulatory Commission before queue reform will take effect.

10. FEDERAL ENERGY INITIATIVES

Open Access Transmission Tariff (OATT)

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

Regional Transmission Organizations (RTOs)

In December 1999, the FERC issued Order No. 2000 encouraging the formation of RTOs, independent entities created to operate the interconnected transmission assets of multiple electric utilities on a regional basis. In compliance with Order No. 2000, Duke, Progress, and SCE&G filed a proposal to form GridSouth Transco, LLC (GridSouth), a Carolinas-based RTO. The utilities put their GridSouth-related efforts on hold in June 2002, citing regulatory uncertainty at the federal level. The GridSouth organization was formally dissolved in April 2005.

Dominion filed an application with the Commission on April 2, 2004, in Docket No. E-22, Sub 418, seeking authority to transfer operational control of its transmission facilities located in North Carolina to PJM Interconnection, an RTO headquartered in Pennsylvania. The Commission approved the transfer subject to conditions on April 19, 2005. On March 31, 2016, Dominion filed a rate increase request with the Commission (Docket No. E-22, Sub 532) in which it requested relief from all of the conditions that had been imposed upon the Company (and that it had agreed to) pursuant to its joining PJM. The Commission relieved Dominion of compliance with most of the PJM conditions in the Commission's order dated December 22, 2016.

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

Southeast Energy Exchange Market (SEEM)

On December 11, 2020, Duke Energy Carolinas and Duke Energy Progress filed an advance notice with the Commission stating their intention to file with the Federal Energy Regulatory Commission revisions to their Open Access Transmission Tariff in order to establish an energy-only electricity market in the Southeast. This market would have 19 utility participants and would facilitate short-term, bi-lateral, automated energy sales across the region. Benefits would flow to retail customers via the fuel rider, which the Commission adjusts annually.

PURPA Reform

In September, 2019, the Federal Energy Regulatory Commission (FERC) issued a Notice of Proposed Rulemaking (NOPR) that constituted the FERC's first comprehensive review of its PURPA regulations. The proposed changes were intended to continue encouraging development of QFs while addressing concerns regarding how the current regulations work in today's competitive wholesale power markets.

In July, 2020, FERC issued a final rule which is the first major change to regulations it issued in 1980. 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 modified the "one-mile rule" and reduced the rebuttable presumption for "nondiscriminatory access" to power markets - from 20 MW to 5 MW - for small power production but not cogeneration facilities. Finally, in order for a QF to establish a legally enforceable obligation, the final rule requires that the QFs must demonstrate commercial viability and financial commitment to build under objective and reasonable state-determined criteria.

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

Affordable Clean Energy Rule (ACE Rule)

The Environmental Protection Agency (EPA) released the final version of the Affordable Clean Energy Rule (ACE Rule) on June 19, 2019, which replaced and repealed the Clean Power Plan. The ACE Rule was published on July 8, 2019, and applies to existing coal-fired power plants greater than or equal to 25 MW.

Under the ACE Rule, the EPA set the best system of emissions reduction (BSER) for existing coal-fired steam electric generating units (EGUs) as heat rate efficiency improvements based on a range of “candidate technologies” and improved O&M practices that can be applied at the unit level. States are directed to determine which of the candidate technologies apply to each covered EGU and establish standards of performance (expressed as an emissions rate in CO2 pounds per MWh) based on the degree of emission reduction achievable with the application of BSER. The EPA required that each state determine which of the candidate technologies apply to each coal-fired unit based on consideration of remaining useful plant life and other factors such as reasonable cost of the candidate technologies. The ACE Rule requires compliance at the unit level; it does not allow averaging across units at the same facility or between facilities as a compliance option. In addition, it does not allow states to use alternative carbon mitigation programs, such as a cap-and-trade program, to demonstrate compliance as part of their state plans.

The ACE Rule requires states to develop plans by July 2022. The EPA must approve these state plans by January 2024. If states do not submit a plan or if their submitted plan is not acceptable, the EPA will have two years to develop a federal plan.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 157

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of 2019 Integrated Resource Plan Update Reports and Related 2019 REPS Compliance Plans	))))	ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS

HEARD: Monday, March 9, 2020, at 7:00 p.m. in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

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

APPEARANCES:

For Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina:

Nicholas A. Dantonio, McGuireWoods LLP, 434 S. Fayetteville Street, Suite 2600, Raleigh, North Carolina 27603

For Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC:

Lawrence B. Somers, Deputy General Counsel, Duke Energy Corporation, 410 South Wilmington Street, NCRH 20, Raleigh, North Carolina 27602

For the Using and Consuming Public:

Lucy E. Edmondson, Staff Attorney; Layla Cummings, Staff Attorney; and Nadia Luhr, Staff Attorney; Public Staff-North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: Integrated Resource Planning (IRP) is intended to identify those electric resource options that can be obtained at least cost to the utility and its ratepayers consistent with the provision of adequate, reliable electric service. IRP considers demand-side alternatives, including conservation, efficiency, and load management, as well as supply-side alternatives in the selection of resource options. Commission Rule R8-60 defines an overall framework within which the IRP process takes place in North Carolina. Analysis of the long-range need for future electric generating capacity pursuant to N.C. Gen. Stat. § 62-110.1 is included in the Rule as a part of the IRP process.

N.C.G.S. § 62-110.1(c) requires the Commission to "develop, publicize, and keep current an analysis of the long-range needs" for electricity in this State. The Commission's analysis should include: (1) its estimate of the probable future growth of the use of electricity; (2) the probable needed generating reserves; (3) the extent, size, mix, and general location of generating plants; and (4) arrangements for pooling power to the extent not regulated by the Federal Energy Regulatory Commission (FERC). Further, N.C.G.S. § 62-110.1 requires the Commission to consider this analysis in acting upon any petition for the issuance of a certificate for public convenience and necessity for construction of a generating facility. In addition, N.C.G.S. § 62-110.1 requires the Commission to submit annually to the Governor and to the appropriate committees of the General Assembly a report of its: (1) analysis and plan; (2) progress to date in carrying out such plan; and (3) program for the ensuing year in connection with such plan. N.C.G.S. § 62-15(d) requires the Public Staff to assist the Commission in making its analysis and plan pursuant to N.C.G.S. § 62-110.1.

Pursuant to N.C.G.S. § 62-2(a)(3a) it is a policy of the State to:

> assure that resources necessary to meet future growth through the provision of adequate, reliable utility service include use of the entire spectrum of demand-side options, including but not limited to conservation, load management and efficiency programs, as additional sources of energy supply and/or energy demand reductions. To that end, to require energy planning and fixing of rates in a manner to result in the least cost mix of generation and demand-reduction measures which is achievable, including consideration of appropriate rewards to utilities for efficiency and conservation which decrease utility bills....

Session Law (S.L.) 2007-397 (Senate Bill 3), signed into law on August 20, 2007, amended N.C.G.S. § 62-2(a) to add subsection (a)(10) that provides that it is the policy of North Carolina "to promote the development of renewable energy and energy efficiency through the implementation of a Renewable Energy and Energy Efficiency Portfolio Standard (REPS)" that will: (1) diversify the resources used to reliably meet the energy needs of North Carolina's consumers, (2) provide greater energy security through the use of indigenous energy resources available in North Carolina, (3) encourage private investment in renewable energy and energy efficiency, and (4) provide improved air quality and other benefits to the citizens of North Carolina. To that end, Senate Bill 3 further provides that "[e]ach electric power supplier to which N.C.G.S. § 62-110.1 applies shall include an assessment of demand-side management and energy efficiency in its resource plans submitted to the Commission and shall submit cost-effective demand-side management and energy efficiency options that require incentives to the Commission for approval."[1]

Senate Bill 3 also defines demand-side management (DSM) as "activities, programs, or initiatives undertaken by an electric power supplier or its customers to shift

[1] N.C.G.S. § 62-133.9(c).

the timing of electric use from peak to nonpeak demand periods" and defines an energy efficiency (EE) measure as "an equipment, physical or program change implemented after 1 January 2007 that results in less energy being used to perform the same function."[2] Energy Efficiency measures do not include DSM.

To meet the requirements of N.C.G.S. §§ 62-110.1 and 62-2(a)(3a), the Commission conducts an annual investigation into the electric utilities' IRPs. Commission Rule R8-60 requires that each utility, to the extent that it is responsible for procurement of any or all of its individual power supply resources,[3] furnish the Commission with a biennial report in even-numbered years that contains the specific information set out in Rule R8-60. In odd-numbered years, each of the electric utilities must file an annual report updating its most recently filed biennial report.

Further, Commission Rule R8-67(b) requires any electric power supplier subject to Rule R8-60 to file a REPS compliance plan as part of each biennial and annual report. In addition, each biennial and annual report should (1) be accompanied by a short-term action plan that discusses those specific actions currently being taken by the utility to implement the activities chosen as appropriate per the applicable biennial and annual reports, and (2) incorporate information concerning the construction of transmission lines pursuant to Commission Rule R8-62(p).

Within 150 days after the filing of each utility's biennial report and within 60 days after the filing of each utility's annual report, the Public Staff or any other intervenor may file its own plan or an evaluation of, or comments on, the utilities' biennial and annual reports. Furthermore, the Public Staff or any other intervenor may identify any issue that it believes should be the subject of an evidentiary hearing. The Commission must schedule one or more hearings to receive public testimony.

2019 Update Reports

This Order addresses the 2019 Update Reports (2019 Update Reports) filed in Docket No. E-100, Sub 157, by Duke Energy Progress, LLC (DEP); Duke Energy Carolinas, LLC (DEC); and Dominion Energy North Carolina (DENC) (collectively, the investor-owned utilities, utilities or IOUs). In addition, this Order also addresses the REPS compliance plans filed by the IOUs.

The following parties have been allowed to intervene in this docket: Alevo USA, Inc. (Alevo); Carolina Industrial Group for Fair Utility Rates I, II, and III (CIGFUR); Carolina Utility Customers Association, Inc. (CUCA); Environmental Defense Fund (EDF); Grant

[2] N.C.G.S. § 62-133.8(a)(2) and (4).0

[3] During the 2013 Session, the General Assembly enacted S.L. 2013-187 (House Bill 223), which exempted the electric membership cooperatives (EMCs) from the requirements of N.C.G.S. §§ 62-110.1(c) and 62-42, effective July 1, 2013. As a result, EMCs are no longer subject to the requirements of Rule R8-60 and are no longer required to submit IRPs to the Commission for review.

Millin; Mid-Atlantic Renewable Energy Coalition (MAREC); North Carolina Sustainable Energy Association (NCSEA); North Carolina Waste Awareness and Reduction Network (NC WARN); Nucor Steel-Hertford (Nucor); and jointly, Southern Alliance for Clean Energy, Sierra Club, and the Natural Resources Defense Council (SACE, NRDC, and the Sierra Club). The Public Staff's intervention is recognized pursuant to N.C.G.S. § 62-15(d) and Commission Rule R1-19(e). The Attorney General's intervention is recognized pursuant to N.C.G.S. § 62-20.

Procedural History

On August 27, 2019, the Commission entered its order in this docket accepting the 2018 biennial IRPs filed by DENC, DEC and DEP and directing the parties to file responses to certain questions relating to the 2018 IRPs. In addition, the order gave notice of an oral argument in this docket scheduled on Wednesday, January 8, 2020.

On August 29, 2019, DENC filed its 2019 IRP Update Report and 2019 REPS compliance plan.

On September 3, 2019, DEC and DEP filed 2019 IRP Update Reports and related REPS compliance plans.

On October 4, 2019, DEC and DEP filed notice that the stakeholder meeting to review their 2019 IRPs had been scheduled for November 19, 2019 in Raleigh.

On October 25, 2019, the Public Staff filed a motion requesting that the Commission: (1) authorize the Public Staff to make one filing that combines a report on the electric utilities' 2019 IRP updates and comments on the electric utilities' REPS compliance plans, and (2) designate Thursday, October 31, 2019, as the deadline for filing the combined report and comments. The motion was approved by Order of the Commission on October 28, 2019.

On October 28, 2019, DENC filed a 2019 IRP Update Supplemental Filing that included a rate impact analysis of the Alternative Plans contained in the 2019 Update and information regarding savings projections.

On October 29, 2019, DEC and DEP refiled IRPs and REPS Compliance Plans to correct certain missing page numbers and descriptive headers.

On October 30, 2019, the Public Staff requested an extension of time to file the combined report and comments. The extension request was granted by the Commission on October 30, 2019, with a revised due date of November 7, 2019.

On November 7, 2019, the Public Staff filed a report concluding that, based on its review, the IRP update reports submitted by DENC, DEP and DEC meet the requirements of Commission Rule R8-60(j). Also, on November 7, 2019, the Public Staff filed a report concluding that, based on its review, the Commission should approve the 2019 REPS Compliance Plans.

On December 23, 2019, the Commission issued an Order Providing Notice of Hearing Topics for the oral argument in this docket on Wednesday, January 8, 2020.

On January 30, 2020, the Commission issued an Order Scheduling Public Hearing on 2019 IRP Update Reports and Related 2019 REPS Compliance Plans. The order set the required public hearing for the night of March 9, 2020.

Oral Argument

The Commission held an Oral Argument on January 8, 2020 to discuss load forecast and reserve margin issues for DEC and DEP. As ordered, the Public Staff, NCSEA, and the Natural Resources Council, Southern Alliance for Clean Energy, and the Sierra Club participated in the proceeding with presentations and responses to Commission questions.

Public Hearing

Pursuant to N.C.G.S. § 62-110.1(c) the Commission held a public hearing in Raleigh on March 9, 2020. Testimony was provided by six public witnesses at the hearing. The witnesses testified on various topics, including climate change, the role renewable energy technologies and EE/DSM programs might play in reducing greenhouse gases, North Carolina's Clean Energy Plan (published October 2019), and Duke Energy's goals for reducing carbon dioxide emissions.

Discussion

In its review and evaluation of the 2019 Update Reports the Commission has given particular attention to four topics: (1) carbon dioxide emissions, (2) resource adequacy, expressed in terms of reserve margins for DEC and DEP, (3) the integrated systems and operations planning (ISOP) effort now underway for DEC and DEP (Duke utilities), and (4) utility statement of need. The Commission's observations on these topics are set forth in the following sections of this order.

Reduction of Carbon Dioxide Emissions

Dominion Energy

DENC's 2019 Update Report reflects the Company's belief that regulation of carbon dioxide emissions from electric generating plants is imminent, whether through federal or state initiatives, or both. At the federal level the U.S. Environmental Protection Agency released the final version of the Affordable Clean Energy (ACE) rule on June 19, 2019. The ACE rule, which supplants the earlier Clean Power Plan, requires heat rate efficiency improvements at existing coal-fired units based on a range of candidate technologies.

At the state level the Virginia Department of Environmental Quality (DEQ) published a final rule on May 27, 2019, that establishes a state cap-and-trade program for electric generating units in Virginia. The final rule includes a provision that accounts for delayed implementation based on language in the state budget bill signed by Virginia Governor Ralph Northam on May 2, 2019. Specifically, implementation of most elements of the program, including requirements for holding and surrendering carbon dioxide allowances, will likely be delayed to the calendar year following authorization for funding to implement the program. Nevertheless, the final regulation became effective on June 26, 2019. The regulation includes a starting (baseline) statewide carbon dioxide emissions cap of 28 million tons in 2020. The cap is reduced by about 3% per year through 2030, resulting in a 2030 cap of 19.6 million tons.

Because of the uncertainty regarding the final form of carbon emission regulations, DENC's 2019 Update Report presents options (Alternative Plans) representing plausible future long-term paths for meeting the energy needs of the Company's customers. The Company also offers a strategic plan for the next five years in its Short-Term Action Plan (STAP).

Between 2000 and 2018 the carbon dioxide emissions from the Company's units declined by 32% while power production from these units increased 12%. On March 25, 2019, the Company committed to an 80% reduction in greenhouse gas emissions by 2050. Simultaneous with that announcement the Company also put forth a five-year plan that includes development of offshore wind, a new pumped hydroelectric storage facility, additional solar photovoltaic resources, and distribution system modernization.

The Commission concludes that the Alternative Plans presented in DENC's Update Report are reasonable for planning purposes. The Commission finds useful the rate impact analysis and savings projections included in the Company's 2019 Integrated Resource Plan Update Supplemental Filing.

Duke Energy

The Commission recognizes Duke Energy Corporation's publicly announced systemwide goal to reduce carbon dioxide emissions by 2030 to at least 50% below 2005 levels. For DEC and DEP the Base Cases in both the 2018 IRPs and the 2019 IRP Update plans achieve at least a 50% reduction in carbon dioxide emissions by 2030, measured from 2005 baseline levels. This is aligned with Duke Energy Corporation's current climate strategy.[4]

As set forth in both the DEC and DEP 2019 IRP Update Reports, the two utilities present Base Cases assuming a tax on carbon emissions beginning in 2025. However, remaining consistent with the Commission's Order to plan for scenarios that both include and exclude costs associated with carbon regulation, the current assumption of a carbon tax is intended to serve as a placeholder for some form of potential future carbon

[4] *See* Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Response to Commission Questions in August 27, 2019 Order in Docket No. E-100, Sub 157, pp. 29-30.

regulation.[5] An additional case assuming no carbon legislation was also developed in both Companies' 2018 IRPs and carried forward to the 2019 Update Plans. While the timing and form of potential future carbon legislation is unknown, it is prudent to continue to plan for a scenario in which carbon emissions are taxed or otherwise regulated, as well as other potential future scenarios. Furthermore, a primary focus of the 2019 IRP Updates are the Short-Term Action Plans (STAP), which cover the period 2020 to 2024. DEC and DEP note that including a case which assumes a tax on carbon emissions beginning in 2025 thus does not have any significant impact on their STAPs.[6] The Commission finds the two Base Case Plans (i.e. Base CO_2 Future and Base No CO_2 Future) and other portfolios evaluated under multiple sensitivities to be appropriate for planning and encourages the Companies to carry forward both alternatives for their next IRPs due for 2020.

The Commission continues to support a focus on the STAPs but also recognizes the importance of properly vetting the longer-term components of the IRP, as those components might develop to support Duke Energy's carbon dioxide reduction goals. The Commission notes that for the long-term, past 2030, Duke Energy Corporation's corporate goal is to achieve a level of zero carbon dioxide emissions by 2050, measured on a net basis systemwide across all affiliated Duke Energy operating companies. This goal has thus far not been further refined at the individual operating company level, and the 2018 IRPs for DEC and DEP were developed and presented before the corporate goal had been established. The 2019 IRP Updates, which are based on the 2018 IRPs, accordingly and understandably do not analyze or present specific resource planning options for achieving the Duke utilities' systems longer-term goal. The Commission believes that meeting this longer-term target will likely require aggressive restructuring of the Companies' resource portfolios and that it is appropriate that DEC and DEP in their 2020 IRPs identify alternative resource portfolios that offer prospects for supporting and advancing the stated Duke Energy corporate goal.

On November 4, 2019, the Companies filed in this docket a joint response to certain questions posed in the Commission's August 27, 2019 Order accepting the Companies' 2018 biennial IRPs. In that response the Companies presented two potential scenarios for achieving reductions in carbon emissions beyond the 50% target announced for 2030. The Commission acknowledges that these two scenarios were offered as "illustrative" only and that they were not based on the same scope and depth of analysis as would occur if they were being modelled for the IRP. One of the scenarios presented in this filing included retirement of all coal generating units by 2030. This would require replacement of approximately 10,415 MW of existing capacity for the two Companies.

[5] Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans, Docket No. E-100, Sub 147, p. 35.

[6] *See* DEC 2019 IRP Update Report, pp. 10-11 and DEP 2019 IRP Update Report, pp. 11-12.

With respect to these “illustrative scenarios” the Companies cautioned that:

> The scenarios presented do not fully account for the real-world challenges that would be faced in adding a significant number of new grid resources in a short amount of time. Issues not addressed, but required to implement this pace of system transformation, include physical and regulatory challenges affecting the time to construct new assets and their associated interconnection and system upgrade requirements. Implementation would require addressing issues in the areas of supply-chain, siting, permitting, right-of-way acquisition, transmission queue studies, comprehensive network upgrades, gas pipeline expansion and acquiring facility certificates of public convenience and necessity (CPCN) for all new facilities. At a minimum, existing legislative and regulatory processes governing resource additions (including but not limited to, siting, permitting, and CPCN processes), may be needed to be modified to accommodate the pace of transition outlined in the scenarios studied.

Acknowledging these factors and the high level nature of the November 4, 2019, submission, the Commission nonetheless finds good cause to direct that for their 2020 IRPs DEC and DEP present one or more alternative resource portfolios which show that the remainder of each Company’s existing coal-fired generating units are retired by the earliest practicable date. The Commission contemplates that the Companies will build upon the work that formed the basis of the November 4, 2019 submission, and the objective is to further develop the “illustrative” scenarios in that filing by subjecting them to the more rigorous IRP process. The “earliest practicable date” shall be identified based on reasonable assumptions and best available current knowledge concerning the implementation considerations and challenges identified in the quoted passage above.[7] In the IRPs the Companies shall explicitly identify all material assumptions, the procedures used to validate such assumptions, and all material sensitivities relating to those assumptions. The Companies shall include an analysis that compares the alternative scenario(s) to the Base Case with respect to resource adequacy, long-term system costs, and operational and environmental performance.

DEC and DEP stated in their November 4, 2019 submission that the “illustrative scenarios” did not identify or include the costs of network transmission upgrades and other major grid investments necessary to support an alternative resource portfolio in which all coal-fired generating units have been retired and the replacement resources that will include a much larger number of geographically dispersed renewable energy and energy storage resources, many of which will not be under direct control of the grid operator. The Commission expects that the “earliest practicable date” chosen by the Companies when developing their alternative portfolio(s) and the replacement resources included in the portfolio(s) should reflect the transmission and distribution infrastructure investments that will be required to make a successful transition. The Companies should also attempt to identify – with as much specificity as is possible in the circumstances - all major transmission and distribution upgrades that will be required to support the

[7] Among other inputs, the Companies should include the updated Market Potential Study for Energy Efficiency referenced in their November 4, 2019, submission, p. 33 note 6.

alternative resource portfolio(s) along with the best current estimate of costs of constructing and operating such upgrades.

The Commission recognizes the significant effort needed to undertake this work but determines that such an effort is essential for properly vetting any alternative scenarios and for comparing the alternatives to the Companies' proposed Base Case plans. Finally, the Companies should note that the directive in this order supplements and does not supersede the directive in the Commission's August 27, 2019 Order in this docket (at p. 31), requiring that the Companies in preparing and modeling their Base Case plans remove any assumption that existing coal-fired units will be operated for the remainder of their depreciable lives and, instead, include such existing assets in the Base Case resource portfolio only if warranted under least cost planning principles. In this Order the Commission's directive that the Companies present one or more "earliest practicable date" retirement portfolios is not constrained by least cost principles, and the Companies will be expected to discuss cost differences, if any, between such alternatives portfolios and the resource portfolios selected for their Base Cases.

DEC and DEP Resource Adequacy Issues

The Commission finds that the information developed during the January 8, 2020, Oral Argument was particularly helpful to the Commission's understanding of resource adequacy and reserve margin issues. Several participants in this docket and in the Oral Argument raised concerns, variously expressed, that DEC and DEP were using a flawed metric (LOLE.1) to characterize the risk of resource inadequacy. These participants suggested that there was insufficient support for the target reserve margins and/or errors affecting the underlying data and projections used to calculate the risk of a loss of firm load due to resource inadequacy. Finally, these participants suggested that the Companies' IRPs and supporting filings contained no information from which parties could evaluate the economic costs and benefits to customers and ratepayers of accepting levels of risk different from that embodied in the 17% planning reserve margins established in the IRP Base Cases.

At this point the Commission is disinclined to direct that in their 2020 IRPs DEC and DEP use some alternative measure of resource inadequacy other than the LOLE.1 standard. The information presented to the Commission at the hearing indicates that no single metric is unquestionably superior to all others but, instead, that each alternative metric reveals or discloses different considerations that bear on the question how much reserve generating capacity a utility should maintain.[8]

[8] From the information presented to the Commission at the hearing it could be concluded that setting reserve margins based on a risk neutral economically optimized analysis best balances the incremental costs of additional reserves against the benefit of reduced risk of loss of firm load. But the participants in the hearing confessed that finding the economically optimal level of reserves was a very difficult practical exercise, if it were possible at all. See for example economist James Wilson's discussion of economically optimal reserve margin where he states that "[t]he problem with the Economically Optimal Reserve Margin, is it rests on a lot of assumptions that, you know, are really kind of troubling." Hearing Transcript, pp. 19-20.

Physical reliability, which for purposes of long-term planning for generating assets is expressed in terms of resource adequacy, is of critical importance to utility planning, and the Commission would never suggest otherwise. Resource adequacy, however, is neither a concept that can be reduced to absolute mathematical precision nor, more importantly, can it be captured by a single metric to which all other resource planning values must necessarily be subordinate. To state the obvious example of this point, it might be possible to design a system with sufficient redundancies and excess facilities to offer 100% assurance that a load shed event due to inadequate resource capacity would never occur, but it is scarcely imaginable that such a system would prove to be "least cost" over the long term. A system may be considered reliable within a range of values and resulting reserve margins; the important matter is that the levels of risk or volatility and the costs associated with various points within a range of reserve capacity levels be understood and evaluated and that the tradeoffs between higher and lower reserve capacities and other system values be clearly and transparently discussed and explained.

As noted, the metric used by the Companies to quantify the risk of resource inadequacy – LOLE .1 – is a measure of physical risk only. The Commission believes that the most important conclusion to be drawn from the evidence and argument presented at the hearing is that for purposes of resource planning it is imperative that the economic costs of maintaining different levels of reserve capacity and the economic value of potentially unserved energy (lost load) be fully analyzed and transparently presented. On this point the Commission finds that the 2016 Astrapé Resource Adequacy Studies for DEC and DEP are useful in understanding the Companies' targeted reserve margins for planning. Particularly useful is the summary provided in Section VII relative to Base Case Economic Results. For example, Figure 13 presents a comparison of expected "Total System Costs" for various winter reserve margins and confidence levels. According to the report, Total System Energy Costs include Fuel Burn, O&M, Purchase Costs, Sales Revenues and the Cost of Unserved Energy. In addition, the carrying cost of capacity added to achieve various level of reserve capacity is included in Figure 13. The "bathtub curves" shown in this figure illustrate where Total System Costs are minimized based on the modeling. The Companies state that the reserve margin that optimizes Total System Costs, at an 85% confidence level, is approximately 17%. See Duke's response to questions contained in the Commission's August 27, 2019 Order in Docket No. E-100, Sub 157, at p. 7.

Based on a review of the study results presented in the 2016 Astrapé Resource Adequacy Studies, the Commission recognizes that the differences in Total System Costs are not significant, especially around the central tendency and away from the tails of the cost curves, when compared to a typical annual spend by the utility. For example, based on Figure 13 in the DEC Report the difference in Total System Costs between an 18% winter reserve margin and a 13% winter reserve margin is approximately $18 million. This compares to DEC Power Production Expenses (O&M, Fuel, and Purchased Power) in 2018 of $2.8 billion. In terms of risk or volatility, the Commission does not view the differences in Total System Costs are enough to warrant a "hard and fast" minimum reserve margin for planning. This is not to say that the minimum reserve margins supported by the 2016 Astrapé Study are not valid for planning. Rather, the Commission's guidance is that the Companies should not be constrained in their planning to produce resource plans that meet the indicated minimum target reserve margin in each and every one of the plan years.[9]

The 2016 Resource Adequacy Studies should thus best be understood as supporting a range of values for the recommended minimum reserve capacity that cluster around a central point rather than as calculating a fixed and inflexible single point. This is an especially important consideration with respect to the STAPs in the IRPs. The Commission observes that all parties agree that the near and intermediate term periods will be marked by rapid technological change accompanied and reinforced by potentially dramatic changes in the costs of new generating technologies and compounded by an increasing emphasis on reduction in greenhouse gas emissions from electric power generation. The Commission's view is no different. For this reason it is important when applying the principle of long-term least cost planning for generation assets that the Companies avoid near term investments in long-lived generating assets that may, due to market forces and technological change, become economically stranded over the course of the longer planning period. Prudent investments in additional generating capacity in the short term must take this longer-term risk into account, and an absolute insistence on a single fixed and unvarying planning reserve margin does not, especially during the period covered by the STAP, permit sufficient flexibility to do so.

For example, the decision to include short-term market purchases in DEP's STAP should be fully vetted and evaluated relative to the probability and impact of alternative options that might provide for less physical reliability but would do so at lower cost to ratepayers and without unreasonably increasing the risk of a loss of load event. In other words, clarity around the risk or volatility which the plan hopes to address is important.

A number of participants in this docket offered critiques of the economic and weather inputs used to forecast system loads and capacity needs for the IRPs. The Commission notes with interest that the Companies appear to acknowledge that it is possible that short-term[10] reserve capacity could fall below the long-term target of 17% without posing a significantly increased risk of resource inadequacy. Duke stated in its response to questions contained in the Commission's August 27, 2019 Order that:

> DEP used an 11%-13% summer capacity margin target, rather than reserve margin target, prior to completion of the 2012 studies. This level of capacity reserves corresponds to reserve margins ranging from 12.4% to 14.9%. DEP determined that an 11% capacity margin (12.4% reserve margin) may

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[9] This point is implicit in Commission Rule R8-60(i)(3) which requires the utilities to provide an explanation in the IRP for any year in which the planned reserve margin will vary – up or down – by more than 3% from the established target. Note that R8-60(i)(3) does not address actual reserve margins achieved over the course of operations but speaks instead to the planned or targeted margins shown in the IRP.

[10] The Commission will not define "short-term" for this purpose but rather defer to the Utilities to evaluate short-term planning reserve margins as they impact Short-Term Action Plans which, according to the IRPs, identify actions to be taken over the next five years. *See* for example DEC's 2019 IRP Update Report starting at p. 71.

be acceptable in the near term when there is greater certainty in forecasts; however, a 12%-13% capacity margin (13.6%-14.9% reserve margin) is appropriate in the longer term to compensate for possible load forecasting uncertainty, uncertainty in DSM/EE forecasts, or delays in bringing new capacity additions online.

Duke's Responses, Docket No. E-100, Sub 157, at p.19.

Further, in response to questions about short-term reserve margins during the hearing, Duke witness Snider stated that "I think it's reasonable to say you have a short-term reserve margin that you could potentially have slightly less because you're not exposed to that economic uncertainty to the extent you are in the long run, and so, you know, I think there is some merit in considering that." Hearing Transcript, p.166.

As stated in the DEC and DEP 2019 IRP Update Reports, the Companies are committed to the development of new resource adequacy studies to support their 2020 IRPs. See for example DEC's 2019 IRP Update Report, p. 77. The Commission directs that these updated resource adequacy studies be filed along with the Companies' 2020 IRPs, together with all supporting exhibits, attachments and appendices subject to such confidentiality designations as the Companies deem warranted.

The Commission finds that in documenting the updated Resource Adequacy Study for 2020, the Companies should provide additional detail and support for both the study inputs and outputs. The Commission applauds the joint efforts of the Companies and Public Staff to delve into the details of the Resource Adequacy evaluation. Even though the 2016 Astrapé Resource Adequacy Study report provides great insights to the study's development, the Commission is limited in some regard by the information to which it has access. Therefore, the Commission will direct DEC and DEP to more fully explain and detail the study results. For example, so far as can be gleaned from the 2016 Study, it would appear that the costs of unserved energy are not significant to the determination of Total System Costs, but this is based solely on the single statement that "because expected unserved energy costs are so low near the economic optimum reserve margin, this value, while high in magnitude, is not a significant driver in the economic analysis." The updated Resource Adequacy Study should provide additional clarity around outputs such as these. At a minimum the Commission finds it helpful for results to be displayed in a graphic that clearly shows the various components to the Total System Costs such as included in the "Bathtub Curves." See for example Figure ES-1 included in the Brattle Group and Astrapé Consulting report for FERC, Resource Adequacy Requirements: Reliability and Economic Implications, by J. Pfeifenberger and K. Carden (2013), Executive Summary, p. v. As another matter, but evidence of the need for additional clarity in the study results, it is not clear in the Astrapé Resource Adequacy Study whether the Total System Energy Costs represent an annual figure or something else (such as the net present value of costs across the planning horizon.)

Finally, based on the Resource Adequacy Study report, the Commission recognizes that unlike typical production cost models, the SERVM model utilized by Astrapé does not use an Equivalent Forced Outage Rate (EFOR). Instead, historical

Generating Availability Data System (GADS) data events are entered in for each unit and SERVM randomly draws from these events to simulate the unit outages. The Commission directs the updated Resource Adequacy studies to address the sensitivity of modeling inputs such as Equivalent Forced Outage Rates (EFOR). For example, in developing the portfolio ordered by the Commission above that will reflect 100% of coal units retired, will the reliability of the fleet be improved overall and therefore result in reduced reserve margins for planning?

Integrated Systems and Operations Planning

The Commission finds the information on the ISOP effort included in DEC and DEP's 2019 IRP Update Reports useful and understands that the Companies will be in a position to report on further developments of this effort in their 2020 IRPs. The Commission recognizes the Companies' efforts to involve stakeholders in the multi-year process to advance the ISOP. As noted in the joint report summarizing the December 10, 2019, workshop facilitated by ICF, "stakeholders supported the need to implement ISOP and integrate planning tools and processes. They expressed appreciation for Duke proactively addressing this initiative with them and believe there are additional opportunities to more directly define how ISOP will create value." The Commission supports the ISOP effort as discussed to date.

The Commission expects the Companies to continue to involve stakeholders in a meaningful way as the ISOP process advances. In particular, the Commission recognizes that there could be significant benefits to involving North Carolina's electric membership cooperatives and municipally owned and operated electric utilities in this effort. One stated goal of the ISOP process is to improve coordination of load forecasting, project and systems planning, and operational effectiveness between the transmission system operator and the distribution system operator. In North Carolina the transmission system operator is, in the main, either DEC and DEP, but in many parts of the State the distribution system operator will be an EMC or a municipally owned utility. The Commission views the ISOP program and stakeholder involvement in that program as an important opportunity to strengthen effective communication and interaction both in planning and in operations between the Companies and the non-regulated distribution system operators that serve a significant portion of the State.

The Commission determines that the 2020 IRPs should continue to report on the progress of the ISOP effort. As a minimum, the IRPs should communicate with some specificity the project plan and dates for the ISOP effort. In addition, the Commission will direct the utilities to discuss the expected outputs of the ISOP process and how they will be utilized in the IRP process.

Utility Statement of Need

As discussed in the Commission's 2018 IRP Order dated August 27, 2019, the Public Staff noted the fundamental link between each IOU's IRP and avoided costs, formalized with the passage of HB 589, which provided that a "future capacity need shall only be avoided in a year where the utility's most recent biennial [IRP] filed with the

Commission . . . has identified a projected capacity need to serve system load . . ." *See* amended N.C.G.S. § 62-156(b)(3). The Public Staff pointed out that a number of assumptions used by the IOUs in the avoided cost proceeding have not been clearly specified by each utility. To remedy this issue and mitigate the potential for paying for more capacity than what is needed, the Public Staff recommended that the utilities, in their IRP Update to be filed in 2019 and all future IRPs and updates, include a new Utility Statement of Need section. Duke agreed with the Public Staff's recommendations and stated that it will include a Statement of Need section to more clearly identify the undesignated capacity needs for each utility in DEC's and DEP's 2019 IRP Updates and in future biennial IRP filings. *See* 2018 IRP Order, at p. 65.

The Commission determines that the "First Resource Need" section of DEC's and DEP's 2019 IRPs is an appropriate output of the integrated resource planning processes and adequate to support future avoided cost calculations.

Conclusion

Based upon the record in this proceeding, the comments of the Public Staff regarding the IRP Update Reports and REPS compliance plans submitted by DEC, DEP and DENC, the Companies' written submissions in this docket dated November 4, 2019, and the materials and testimony presented at the January 8, 2020 hearing, the Commission hereby accepts the 2019 IRP Update Reports filed by the utilities as complete and fulfilling the requirements set out in Commission Rule R8-60. The Commission further accepts the REPS compliance plans submitted by DEC, DEP and DENC, as recommended by the Public Staff. In preparing their 2020 biennial IRPs the utilities shall follow the applicable guidance and directives set forth in this order and in the Commission's August 27, 2019 Order addressing the 2018 biennial IRPs.

IT IS, THEREFORE, SO ORDERED.

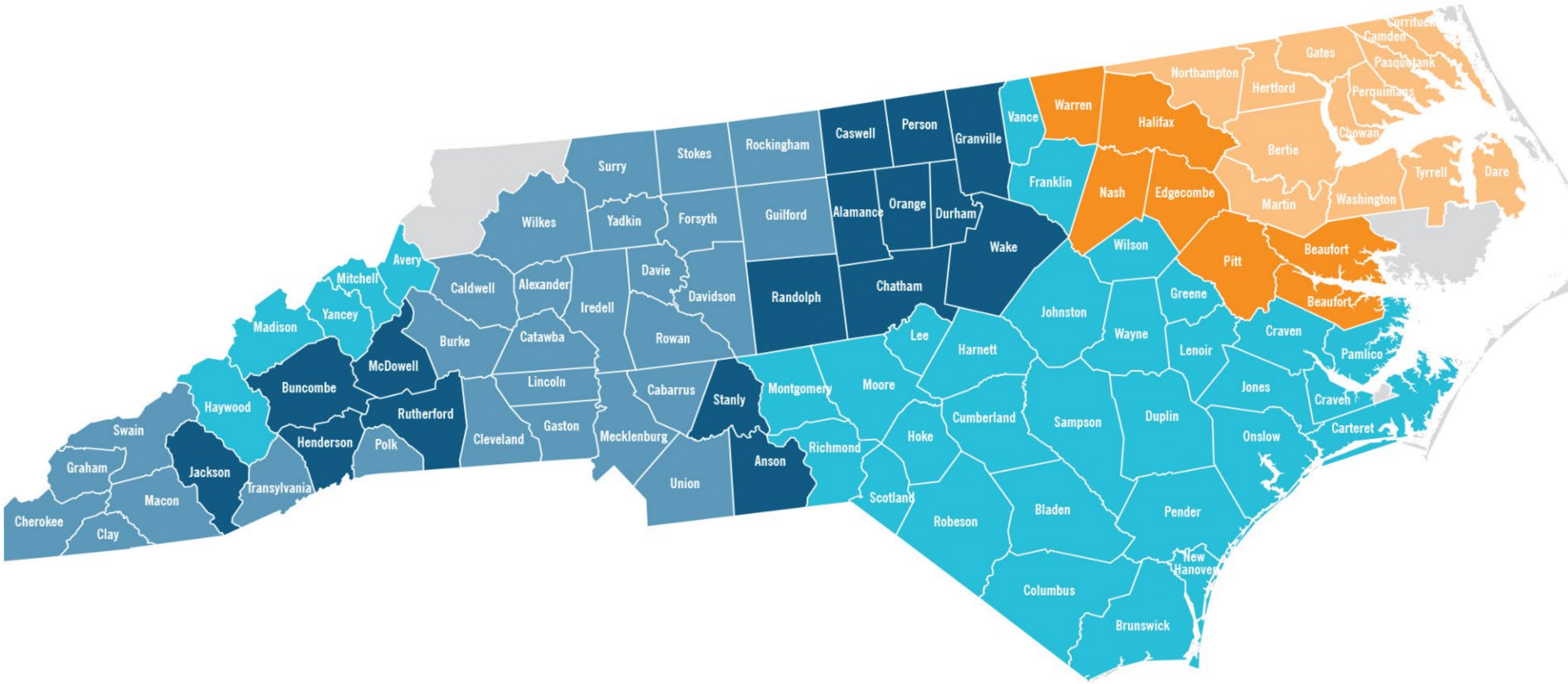
ISSUED BY ORDER OF THE COMMISSION.

This the 6th day of April, 2020.

NORTH CAROLINA UTILITIES COMMISSION

Janice H. Fulmore, Deputy Clerk

Commissioner Lyons Gray did not participate in this decision.



SERVICE TERRITORIES
(counties served)

Duke Energy Carolinas

Duke Energy Progress

Duke Energy Carolinas/
Duke Energy Progress overlapping counties

Dominion Energy North Carolina

Dominion Energy North Carolina/
Duke Energy Progress overlapping counties