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.
DEC Duke Energy Carolinas, LLC
DENC Dominion Energy North Carolina
DEP Duke Energy Progress, LLC
DOE U.S. Department of Energy
DSM demand-side management
EDF Environmental Defense Fund
EE energy efficiency
EGU electric generating unit
EMC electric membership corporation
EnergyUnited EnergyUnited EMC
EPA U.S. Environmental Protection Agency
EPAct 2005 Energy Policy Act of 2005
FERC Federal Energy Regulatory Commission
GreenCo GreenCo Solutions, Inc.
GridSouth GridSouth Transco, LLC
G.S. General Statute
GWh gigawatt-hour/s
Halifax Halifax EMC
IOU investor-owned electric utility
IRP integrated resource 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

ABBREVIATIONS AND ACRONYMS (continued)

NCEMC North Carolina Electric Membership Corporation
NCEMPA North Carolina Eastern Municipal Power Agency
NCMPA1 North Carolina Municipal Power Agency No. 1
NC-RETS North Carolina Renewable Energy Tracking System
NCSEA North Carolina Sustainable Energy Association
NCTPC North Carolina Transmission Planning Collaborative
NC WARN North Carolina Waste Awareness and Reduction Network
NERC North American Electric Reliability Corporation
NOPR Notice of Proposed Rulemaking
NRC Nuclear Regulatory Commission
OASIS Open Access Same-time Information System
OATT open access transmission tariff
OPSI Organization of PJM States, Inc.
PJM PJM Interconnection, LLC
PPA purchase power agreement/s
PURPA Public Utility Regulatory Policies Act of 1978
PV photovoltaic
REC renewable energy certificate/s
REPS Renewable Energy and Energy Efficiency Portfolio Standard
RFP request for proposals
ROE return on equity
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

TABLE OF CONTENTS

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 (DEP), whose corporate office is in Raleigh; Duke Energy Carolinas, LLC (DEC), whose corporate office is in Charlotte; and Virginia Electric and Power Company (VEPCO), whose corporate office is in Richmond, Virginia, and which does business in North Carolina under the name Dominion Energy North Carolina (DENC).

DEC and DEP, the two largest electric IOUs in North Carolina, together provide approximately 96% of the utility-supplied electricity consumed in the state. Approximately 22% of the IOUs' 2020 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: 2019-2020 Electricity Sales of Regulated Utilities in North Carolina

	NC Retail GWh*		NC Wholesale GWh*		Total GWh Sales* (NC Plus Other States) [1]	
	2020	2019	2020	2019	2020	2019
DEP	36,298	37,894	20,590	21,613	65,240	68,357
DEC	55,675	58,458	4,631	5,662	84,574	89,921
VEPCO	4,169	4,281	46	1,203	86,992	88,238

*GWh = 1 Million kWh (kilowatt-hours)

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

During the 2021 to 2034 timeframe, the average annual growth rate in summer peak demand for electricity in North Carolina is forecasted to be approximately between

0.5% - 1.0% compared to 0.7% - 1.0% for winter peak load growth. Table ES-2 illustrates the [i]system wide average annual growth rates forecast by the IOUs that operate in North Carolina. Each uses generally accepted forecasting methods and, although their forecasting models are different, the econometric techniques employed by each are widely used for projecting future trends.

Table ES-2: Forecast Annual Growth Rates for DEP, DEC, and VEPCO (With Energy Efficiency (EE) Included) (2021 – 2034)

	Summer Peak	Winter Peak	Energy Sales
DEP	1.0%	1.0%	0.9%
DEC	0.9%	0.7%	0.6%
VEPCO	0.5%	0.9%*	0.6%

* 2020 – 2034

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 2020

	DEP	DEC	VEPCO
Coal	9%	17%	9%
Nuclear	44%	50%	34%
Net Hydroelectric*	2%	3%	1%
Natural Gas and Oil	32%	19%	52%
Non-Hydro Renewable	9%	2%	2%
Other Purchased Power	4%	9%	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 (REPS). Under the REPS statute, codified at N.C. Gen. Stat. § 62-133.8, investor-owned electric utilities are required to increase their use of renewable energy resources and/or energy efficiency such that those sources meet 12.5% of their NC retail sales in 2021. EMCs and municipal electric suppliers are required to meet a similar requirement of 10% of their NC retail sales in 2018 and thereafter. The requirements under the law phase in over time, with the most recent increase in 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 efforts were published in early 2021.

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

On October 13, 2021, Governor Cooper signed into law House Bill 951 (S.L. 2021-165), directing the Commission to take all reasonable steps to achieve reductions in the emissions of carbon dioxide in this State from electric generating facilities owned or operated by certain electric public utilities. The Commission is directed to achieve a reduction of 70% from 2005 levels by the year 2030 and carbon neutrality by the year 2050. Session Law 2021-165 limits the applicability of this requirement to Duke Energy Progress and Duke Energy Carolinas, LLC. The Commission is directed to develop by December 31, 2022, a plan (the Carbon Plan) to achieve these emission reductions and to review the plan every two years thereafter. In addition to mandating carbon reduction, S.L. 2021-65 also authorizes the Commission to direct additional procurement of solar energy facilities in 2022 if needed to achieve the statutory carbon reduction goals.

In February 2020, Dominion Energy announced its commitment to net zero CO_2 and methane emissions across its nationwide electric generation and natural gas infrastructure operations by 2050. The goal covers CO_2 and methane emissions, the dominant greenhouse gases, from electricity generation and gas infrastructure operations. According to Dominion Energy, the strengthened commitment builds on Dominion Energy's strong history of environmental stewardship, while acknowledging the need to further reduce emissions. According to the Dominion Climate Report, as Dominion works toward Net Zero emissions by 2050, Dominion will focus on near-term progress. Under Dominion's Net Zero strategy, Dominion is committed to reducing carbon emissions 55 percent by 2030 from their power generation business (compared to 2005 levels). Dominion likewise expects to reduce methane emissions from their natural gas business by 65 percent by 2030 and 80 percent by 2040 (from 2010 levels). The Virginia Clean Economy Act (VCEA) was signed into law on April 11, 2020. The VCEA includes provisions that institute a mandatory renewable portfolio standard, enhance renewable generation and energy storage development, require the retirement of certain generation units, establish energy efficiency targets, and expand net metering. The VCEA formalizes the administrative policy goals set by Virginia Governor Northam in September 2019 through Executive Order 43: Expanding Access to Clean Energy and Growing the Clean Energy Jobs of the Future (EO43). EO43 established statewide goals and targets for reducing carbon emissions. Specifically, EO43 included a goal that by 2030, 30% of the Commonwealth's electric system would be powered by renewable energy sources. By 2050, the goal is for 100% of Virginia's electricity to be produced from carbon-free sources such as wind, solar, and nuclear. In establishing a mandatory RPS, the VCEA sets forth a framework to meet the goals of EO43.

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, 2020 Annual Report. It is based primarily on reports to the Commission by the regulated electric utilities serving North Carolina, but also includes information from other records and Commission files.

3. OVERVIEW OF THE ELECTRIC UTILITY INDUSTRY IN NORTH CAROLINA

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

DEC and DEP, the two largest IOUs, together provide approximately 96% of the utility-supplied electricity consumed in the state. In 2020, DEC provided electricity to 2,084,000 North Carolina customers and DEP to 1,448,000 customers. Each of the Duke utilities also has customers in South Carolina. DENC supplies approximately 4% of the State's utility-generated electricity. It has 122,000 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 2020 reporting period, the gigawatt-hour (GWh) sales for the electric utilities in North Carolina are summarized in Table 1.

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

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	2020	2019	2020	2019	2020	2019
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*GWh = 1 Million kWh (kilowatt-hours)

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

EMCs are independent, not-for-profit corporations that operate distribution grids. There are 31 EMCs serving metered customers in North Carolina. EMCs serve approximately 25% of the State's population. Twenty-six EMCs are headquartered in the State, and these 26 EMCs served 1,091,033 metered customers as of December 31, 2020. The other five EMCs are headquartered in adjacent states and provide service in limited areas across the border into North Carolina. EMCs serve customers in 95 of the State's 100 counties.

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

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

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

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

NCEMC and the EMCs are deploying (or facilitating the deployment of) distributed energy resources/technologies (DER) on their grids as well as edge-of-the-grid programs to promote reliability, affordability, sustainability, and resiliency for the benefit of the communities they serve.

NCEMC and its member distribution cooperatives have developed and implemented the NCEMC Distribution Operator (DO), a single entity that monitors, aggregates, and centrally coordinates distributed energy and demand response resources, bringing operational benefits to the distribution system, optimization to the market interface, and positive system impacts on the transmission systems upstream, including DEC, DEP, and Dominion. The DO provides access to over 250 MW of distributed energy and demand resources, including solar, storage, microgrids, consumer devices, and behind-the-meter generation, and will continue to grow as additional resources are integrated into the DO system and processes become more automated. NCEMC continues to discuss the DO Platform with Dominion, and with DEC and DEP to further evaluate how the DO Platform will interact with their Integrated System & Operations Planning (ISOP) process.

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

The service territories of NCEMC's member EMCs are located within the balancing authority areas of DEC, DEP, and 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 76 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. ElectriCities' largest activity is the management of these two power agencies. The remaining members buy their own power at wholesale.

One agency, the North Carolina Eastern Municipal Power Agency (NCEMPA), is the wholesale supplier to 32 cities and towns in eastern North Carolina. Since April 1982, NCEMPA had jointly owned portions of five DEP generating units (about 700 MW of coal and nuclear capacity). On July 28, 2014, DEP filed notice with the Commission of its intent to file with 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 DEP and NCEMPA closed on July 31, 2015. On August 13, 2015, the Commission issued an Order Transferring Certificate of Public Convenience and Necessity.

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

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

The Tennessee Valley Authority (TVA) sells energy directly to the Murphy Power Board and to three out-of-state cooperatives that supply power to portions of North Carolina: Blue Ridge Mountain EMC, Tri-State Membership Corporation, and Mountain Electric Cooperative. These distributors of TVA power are located in six North Carolina counties and serve over 34,000 households and about 9,000 commercial and industrial customers. The North Carolina counties served by distributors of TVA power are Avery, Burke, Cherokee, Clay, McDowell, and Watauga.

TVA owns and operates four hydroelectric dams in North Carolina with a combined generation capacity of 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 DEP, DEC and DENC; 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 DEP (DEP). A public hearing in this docket was held in Raleigh on March 9, 2020, for the purpose of receiving non-expert public witness testimony. Six public witnesses testified at the hearing.

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

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

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

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

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

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

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

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

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

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

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

5. LOAD FORECASTS AND PEAK DEMAND

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

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

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

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

	Summer Peak	Winter Peak	Energy Sales
DEP	1.0%	1.0%	0.9%
DEC	0.9%	0.7%	0.6%
VEPCO	0.5%	0.9%*	0.6%

* 2020 – 2034

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 2020 Long-Term Reliability Assessment by the North American Electric Reliability Corporation (NERC) indicates a forecast of average annual growth in peak demand of approximately 0.43% through 2030.

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

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

	DEP		DEC		VEPCO	
	Summer	Winter*	Summer	Winter*	Summer	Winter*
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
2020	13,233	12,258	20,398	17,830	20,087	17,867

**Winter peak following summer peak*

6. GENERATION RESOURCES

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

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

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

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

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

VEPCO operates two nuclear power stations, Surry and North Anna, with two units each. Both stations are located in Virginia. All four units have been issued license extensions by the NRC. For Surry, the licenses for Units 1 and 2 were renewed on May 4, 2021, permitting continued operation for Units 1 and 2 through 2052 and 2053, respectively, but approval by the Virginia State Corporation Commission will also be required for extending the licenses for Surry Units 1 and 2. North Anna's second license renewal was submitted to the NRC on August 24, 2020, and was accepted for review in October 2020. The issuance of the renewed license is expected by May 2022. This renewal will preserve the option to continue operation of North Anna units 1 and 2 until 2058 and 2060, respectively.

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

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

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

Another type of non-utility generation is power generated by merchant plants. A merchant plant is an electric generating facility that sells energy on the open market. It is often constructed without a native load obligation, a firm long-term contract, or any other assurance that it will have a market for its power. These generating plants are generally sited in areas where the owners see a future need for an electric generating facility, 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 2020

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

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

Generally, actual plant use is determined by the application of economic dispatch principles, meaning that the start-up, shutdown, and level of operation of individual generating units is tied to the incremental cost incurred to serve specific loads in order to attain the most cost-effective production of electricity. The actual generation produced and power purchased for each utility, based on monthly fuel reports filed with the Commission for 2020, is provided in Table 5.

Table 5: Total Energy Resources by Fuel Type for 2020

	DEP	DEC	VEPCO
Coal	9%	17%	9%
Nuclear	44%	50%	34%
Net Hydroelectric*	2%	3%	1%
Natural Gas and Oil	32%	19%	52%
Non-Hydro Renewable	9%	2%	2%
Other Purchased Power	4%	9%	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, DEP and DEC jointly initiated a multi-year Integrated Systems and Operations Planning Project (ISOP). This effort is an important and necessary evolution in electric utility planning processes to address the trends in technology development, declining cost projections for energy storage and renewable resources, and customer adoption of electric demand modifying resources such as roof-top solar and electric vehicles. The anticipated growth of Distributed Energy Resources necessitates moving beyond the traditional distribution and transmission planning assumption of on-way power flows on the distribution system and analysis based on limited snapshots of peak or minimum system conditions. As the grid becomes more dynamic, analysis of the distribution and transmission systems will need to account for increasing variability of generation and two-way power flows on the distribution system, which requires significant changes to modeling inputs and tools.

Merchant Generating Facilities

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

In the most recent period, the Commission has begun to experience a noticeable increase in applications for CPCNs from a third type of merchant generating facility that are not seeking to sell their capacity and energy as qualifying facilities under PURPA and are not participants in the competitive procurement process under Section 62-110.8. These new merchant facilities are instead seeking to sell their capacity and energy output either by negotiated bilateral contracts with regulated public utilities or, quite often, by selling into an organized RTO market, such as PJM. Often, though not always, this new type of merchant facility, though located in North Carolina, will be selling to buyers and consumers located outside North Carolina. In 2021, three solar facilities (one with battery storage) with a combined capacity of 909 MW and one on-shore wind facility with 189 MW of capacity filed CPCN applications with the Commission to operate as electric merchant plants. Three of them would interconnect to the transmission grid owned by DENC while the fourth would interconnect with DEP. Their applications cited several sales opportunities for the facilities themselves and / or the output of the plants. It is uncertain whether any of that output will ultimately serve electricity customers in North Carolina. Those four CPCN applications remain pending before the Commission.

Five additional electric merchant plants have CPCN applications pending before the Commission. Several have requested and been granted stays while they await the results of studies addressing possible need for transmission system upgrades associated with or occasioned by the proposed facilities. These five solar facilities total 654 MW and would interconnect with DENC. From their applications, it appears that all of them would bid their power into the PJM market pursuant to hedging contracts with corporate counterparties.

During 2021, the Commission approved CPCN applications for two electric merchant solar facilities totaling 220 MW. Again, both facilities will interconnect with DENC's grid. For these two facilities, it is clear that the owners intend to bid the output into the PJM market.

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

7. RELIABILITY AND RESERVE MARGINS

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

DEP and DEC each utilize a minimum winter planning reserve margin of 17%. VEPCO is a PJM member and signatory to PJM’s Reliability Assurance Agreement. The Company is obligated to maintain a reserve margin (11.7%) for its portion of the PJM coincident peak load. The PJM reserve requirement for years 2021-2035 for its adjusted load forecast is approximately 15%, and this satisfies the NERC and Reliability First Corporation Adequacy Standard BAL-502-RFC-02, Planning Resource Adequacy

Analysis, Assessment, and Documentation. 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 summer of 2022 and spring of 2023, respectively, 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.

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

8. RENEWABLE ENERGY AND ENERGY EFFICIENCY

Renewable Energy and Energy Efficiency Portfolio Standard (REPS)

In 2007, North Carolina became the first state in the Southeast to adopt a Renewable Energy and Energy Efficiency Portfolio Standard. Under the REPS statute, codified at N.C.G.S. § 62-133.8, investor-owned electric utilities are required to increase their use of renewable energy resources and/or energy efficiency such that those sources meet 12.5% of their NC retail sales in 2021. 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 October 1, 2021, 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 2012-2020 general REPS requirements and appear on track to meet the 2021 general REPS requirements. All electric power suppliers have met the 2012-2020 solar set-aside requirements and appear to be on track to meet the 2021 solar set-aside requirement. The Commission granted a joint motion to delay implementation of the 2020 swine waste set-aside requirement for one year for the EMCs and the Munis. The electric public utilities met the 0.07% swine waste set-aside for 2020. The Commission's modification order also reduced the poultry waste set-aside requirements for 2020 for all electric power suppliers to 700,000 MWh. Most EMCs and Munis have indicated that they will have difficulty meeting the swine waste set-aside requirements for 2021 and that they may request a modification in these requirements for 2021, 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. Following Commission approval of the CPRE Program, DEC and DEP issued CPRE Tranches 1 and 2.

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 contracting period for Tranche 1 concluded on July 8, 2019. As a result of Tranche 1, DEC procured 435 MW of new cost-effective renewable energy capacity and DEP procured 86 MW of new cost-effective renewable energy capacity.

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 for Tranche 2 concluded on October 15, 2020.

As a result of Tranche 2, DEC procured 589 MW of new cost-effective renewable energy capacity and DEP procured 75 MW of new cost-effective renewable energy capacity. In total, Duke has procured 1,185 CPRE Program MW through Tranches 1 and 2. A proposal to implement Tranche 3 of the CPRE Program during the first quarter of 2022 is pending before the Commission.

Energy Efficiency

Electric power suppliers in North Carolina are required to implement demand-side management (DSM) and energy efficiency (EE) measures and use supply-side resources to establish the least cost mix of demand reduction and generation measures that meet the electricity needs of their customers. Energy reductions through the implementation of DSM and EE measures may also be used by the electric power suppliers to comply with REPS. DEC, DEP, 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. NC GreenPower's partner, the State Employees' Credit Union (SECU) Foundation, will provide an additional grant of $10,000-$20,000 per school for up to 10 schools in 2022 to help support the program. 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.

Last year was the first time that NC GreenPower expanded its Solar+ Schools program to 10 schools — each of the previous five years awarded a maximum of five. This year, NC GreenPower selected 15 schools and plans to award up to 20 schools in 2022. By the end of 2021, the NC GreenPower Solar+ Schools program will have reached a total of 56 North Carolina schools in 38 counties, bringing solar energy and STEM education to nearly 43,000 students. To date, the schools have collectively produced an estimated 615,798 kilowatt hours of green energy, a savings of about $58,000.

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 DEC and DEP, 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." [2] This Order requires transmission owners to participate in regional and inter-regional transmission planning efforts. DEC and DEP have complied with Order No. 1000 by participating in the Southeastern Regional Transmission Planning (SERTP)[3] process.

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

State Generator Interconnection Standards

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

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

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

The Commission issued an Order Approving Revised Interconnection Standard on May 15, 2015. That Order made substantial changes to the procedures for requesting to interconnect a generator to the electric grid. Most of these changes were recommended by the stakeholders with the intent of addressing a 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

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

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

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

in August of 2021, and the utility is now transitioning from operating its interconnection queue on a first-come first-served basis to a grouping study process.

FERC Transmission Planning and Cost Allocation Proceedings

In June 2021, the Federal Energy Regulatory Commission (FERC) established a Joint Federal-State Task Force on Electric Transmission and solicited nominations for state utility commission representation on the Task Force. (FERC Docket No. AD21-15) Subsequently, NC Commissioner Kimberly Duffley was appointed to the Task Force and presented her views during its first meeting, November 10, 2021. The Task Force will focus on topics related to efficiently and fairly planning and paying for electric transmission, including transmission to facilitate generator interconnection, and exploring opportunities for states to voluntarily coordinate to identify, plan, and develop regional transmission. The Task Force will expire in three years, but its term may be extended by agreement between FERC and state regulators.

In July 2021, the FERC issued an advance notice of proposed rulemaking in which it sought comments on a wide range of proposals relating to planning and paying for regional transmission and facilitating generator interconnections. (FERC Docket No. RM21-17) The NCUC filed comments in that proceeding. A major focus of the Commission's comments was transmission cost allocation inequities that result in DEP customers paying for transmission upgrades that are needed due to electric generators interconnecting with Dominion Energy North Carolina in order to export their power to the PJM Regional Transmission Operator that operates the power grid north and west of North Carolina. The NCUC also argued for the retention of "participant funding," wherein the generator that causes the need for a transmission upgrade should bear the full cost. The FERC is expected to issue a rulemaking proposal in 2022 that addresses the issues of transmission planning, cost allocation, and generator interconnections.

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, DEC and DEP filed an advance notice with the Commission stating their intention to file with the Federal Energy Regulatory Commission revisions to their Open Access Transmission Tariff in order to establish an energy-only electricity market in the Southeast, known as the Southeast Energy Exchange Market (SEEM). Membership in the SEEM is open to publicly owned utilities, and the North Carolina Electric Membership Corporation is also a member of SEEM. The market is designed to facilitate short-term, bi-lateral, automated energy sales across the region. Recently, the SEEM members received clearance from FERC to enter into the SEEM agreements and modify their respective federal tariffs. The SEEM members expect the market to be operational in the third quarter of 2022. Cost savings 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.

On January 19, 2021, the D.C. Circuit vacated the ACE rule and remanded to the EPA for further proceedings consistent with its opinion. Since then, EPA Regional staff have received requests from multiple states seeking clarity regarding their obligations in light of the court decision. According to EPA, the court's opinion did not result in any obligation for states to submit Clean Air Act section 111(d) State Plans under the Clean Power Plan, nor do states have any obligations under the now-vacated ACE rule.

APPENDIX 1

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 165

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of 2020 Biennial Integrated Resource Plans and Related 2020 REPS Compliance Plans	)))))	ORDER ACCEPTING INTEGRATED RESOURCE PLANS, REPS AND CPRE PROGRAM PLANS WITH CONDITIONS AND PROVIDING FURTHER DIRECTION FOR FUTURE PLANNING

HEARD: March 9, April 14, and 19; May 5, 12, 17, and 26; September 30; and October 1, 2021, remotely via Webex.

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

BY THE COMMISSION: Pursuant to N.C. Gen. Stat. § 62-110.1, the integrated resource planning (IRP) process is intended to identify electric resource options that will ensure adequate and reliable electric service, can be obtained at least cost, and are in harmony with the environment. Specifically, under § 62-110.1(c) the Commission is required to "develop, publicize, and keep current an analysis of the long-range needs" for electricity in this State. The Commission's analysis includes: (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, the statute requires the Commission to submit annually to the Governor and to the appropriate committees of the General Assembly the following: (1) a report of the Commission's analysis and plan for the future requirements of electricity for North Carolina; (2) the progress to date in carrying out such plan; and (3) the program of the Commission for the ensuing year in connection with such plan.

In addition, several other General Statutes and Commission Rules guide the Commission's review of the electric utilities' IRP processes. Pursuant to N.C. Gen. Stat. § 62-15(d) the Public Staff-North Carolina Utilities Commission (Public Staff) is required to assist the Commission in IRP analysis and planning. Moreover, N.C.G.S § 62-2(a)(3a) vests the Commission with the duty to regulate public utilities and their expansion in relation to long-term energy conservation and management policies. These policies include assuring that "resources necessary to meet future growth through the provision of adequate, reliable utility service include 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." As a result, in addition to electric generation and other supply-side alternatives, the utilities'

IRPs consider conservation, efficiency and load management as resources for meeting the electric utilities' planning goals.

Finally, Commission Rule R8-60 defines an overall framework within which the Commission conducts its annual investigation into the electric utilities' IRPs. To meet the directives of N.C.G.S §§ 62-110.1 and 62-2(a)(3a), Commission Rule R8-60 requires that each of the electric utilities furnish the Commission with a biennial report in even-numbered years that contains the specific information set out in that Commission Rule. In odd-numbered years, each of the electric utilities must file an update 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 Renewable Energy and Energy Efficiency Portfolio Standard compliance plan (REPS compliance plan) as part of its IRP report.

I. PROCEDURAL HISTORY

On May 1, 2020, Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina (DENC or Dominion) filed its 2020 biennial IRP and 2020 REPS Compliance Plan in this docket, in compliance with N.C.G.S. § 62-110.1(c) and Commission Rule R8-60. Likewise, on September 1, 2020, Duke Energy Progress, LLC (DEP), and Duke Energy Carolinas, LLC (DEC, and collectively with DEP sometimes Duke or the Duke Utilities), each filed their IRPs and REPS Compliance Plans.

Petitions to intervene were filed by and were granted for the Commission for Broad River Energy, LLC (Broad River); Carolinas Clean Energy Business Association (CCEBA); Carolina Industrial Groups for Fair Utility Rates (CIGFUR); Carolina Utility Customers Association, Inc. (CUCA); City of Asheville and Buncombe County; City of Charlotte; jointly ElectriCities of North Carolina, Inc. (ElectriCities), North Carolina Eastern Municipal Power Agency (NCEMPA), and North Carolina Municipal Power Agency Number 1 (NCMPA1, collectively ElectriCities); jointly NC WARN, Inc., and Center for Biological Diversity (CBD, collectively NC WARN); North Carolina Sustainable Energy Association (NCSEA); jointly The Southern Alliance for Clean Energy (SACE), Sierra Club, and Natural Resources Defense Council (NRDC, collectively SACE/NRDC/Sierra); jointly Apple Inc., Facebook, Inc., and Google LLC (Tech Customers); and Vote Solar.

The participation of the Public Staff and the North Carolina Attorney General's Office (AGO) is recognized by N.C. Gen. Stat. §§ 62-15 and 62-20, respectively.

Extensive written comments on the IRPs have been filed by the Public Staff, AGO, CCEBA, City of Asheville and Buncombe County, City of Charlotte, NC WARN, NCSEA, SACE/NRDC/Sierra, Tech Customers, and Vote Solar. Replies to these comments have been filed by DENC, the Duke Utilities, Public Staff, AGO, CCEBA, CIGFUR, NC WARN, NCSEA; SACE/NRDC/Sierra, and Tech Customers.

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

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

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

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

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

Appearances of counsel were made for Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, Virginia Electric and Power Company d/b/a Dominion Energy North Carolina, the Public Staff, the North Carolina Attorney General's Office, and several intervenors, with all such appearances noted in the official records of the hearings.

II. STANDARD OF REVIEW

The IRPs are first and foremost planning tools. The IRP statute, N.C. Gen. Stat. § 62-110.1(c), establishes a planning process that is an exercise of the Commission's legislative function, as opposed to an exercise of the Commission's judicial function. In *State ex rel. Utilities Commission v. North Carolina Electric Membership Corp.*, 105 N.C. App. 136, 412 S.E.2d 166 (1992), addressing the character of proceedings relating to utilities' integrated resource plans, the Court of Appeals, stated: "…[W]e believe that the least-cost planning proceeding should bear a much closer resemblance to a legislative hearing, wherein a legislative committee gathers facts and opinions so that informed decisions may be made at a later time." *Id.* at 144, 412 S.E.2d at 170.

In addition, N.C. Gen. Stat. § 62-94 authorizes the Commission to consider the whole record when making its decisions. As a result, the Commission views the IRP information and data received through public witness testimony, comments and reply comments, consumer statements of position, and technical conferences to be information and data to be considered by the Commission and used in its IRP investigation and decision-making process. The Commission is the sole judge of the weight to be given to any particular piece of information or data presented during its review and consideration of the utilities' IRPs.

III. THE UTILITIES' INTEGRATED RESOURCE PLANS

DEC's and DEP's IRPs include what they call "base case" plans, not including any consideration of carbon policy, that represent existing policies under least-cost planning principles. To show the impact potential new policies may have on future resource configurations the 2020 IRPs also introduced a variety of alternative resource portfolios that evaluate more aggressive carbon emission reduction targets. As described throughout the two IRPs, these portfolios have trade-offs between the pace of emission reductions weighted against both associated cost and operational considerations. The 2020 IRPs project potential pathways for how the resource portfolios may evolve over the 15-year period through 2035 based on current data and assumptions across a variety of scenarios. The analyses developed compare the carbon emission reduction trajectory, cost, operability and execution implications of each portfolio to support the regulatory process and inform public policy dialogue. The 2020 IRPs include two resource portfolios that illustrate potential pathways to achieve by 2030 a 70% reduction in carbon dioxide emissions, measured against a base year of 2005. All portfolios keep the Duke Utilities on a trajectory to support the carbon-reduction goal of at least 50% by 2030 and long-term goal of net-zero by 2050, an enterprise-wide goal declared by their common parent, Duke Energy Corporation.

Dominion's operations in North Carolina are very different from those of the Duke Utilities. Dominion's North Carolina territory has a small amount of generation and only approximately 5% of Dominion's total electric load. The remaining load, and most of the generation, is located in Virginia. In addition, Dominion is part of the PJM Regional Transmission Organization (RTO). In April 2020, the Virginia Clean Economy Act (VCEA) became law in Virginia, and among other things, requires Dominion to produce 100 percent of its electricity from renewable sources by 2045. In July 2020, Virginia joined the Regional Greenhouse Gas Initiative (RGGI), which is a market-based program implemented by several Northeast and Mid-Atlantic states to reduce greenhouse gas emissions. RGGI is a state-implemented program, not a utility-implemented program, and requires its member states to cap CO_2 emissions and buy allowances for any CO_2 that is emitted. Dominion modeled the effects of RGGI in all plans but Plan A. The effect of RGGI on future Dominion operations is uncertain, and the future establishment of mandatory federal CO_2 compliance could influence the RGGI market. Similarly to the Duke Utilities, Dominion has committed to achieve net zero CO_2 and methane emissions by 2050. The VCEA and Virginia's membership in RGGI is a clear mandate for CO_2 reduction and renewable energy. For its IRP, Dominion developed a Plan A, which is a pure least-cost scenario but is not compliant with the VCEA. Dominion's Plan B includes significant development of solar, wind, and energy storage resources, and is compliant with the VCEA renewable energy requirements within the study period (2021 to 2045).

IV. SUMMARY AND GENERAL CONCLUSIONS

The written comments and reply comments of the parties, accompanied by reports, analyses, studies, and compilations, run to several thousand pages. The Commission has read and given due consideration to all these written submissions. In this Order, however, the Commission will not attempt to provide summaries or recitations of each of the points made by the parties in their filings. As noted earlier, the purpose of the IRP process is to inform the report required by N.C.G.S. § 62-110.1(c) and to serve as a guide to Commission decisions in other dockets.

The Commission's Additional Proceedings Order revised this year's IRP process with regard to the Duke Utilities by eliminating the requirement that they file an updated IRP in September 2021. Instead, the Commission expanded its analysis of DEC's and DEP's 2020 IRPs by delving more deeply into several issues that were presented by those IRPs. The Commission is satisfied that the revised procedure has enhanced the value of the 2020 biennial process as a planning tool. In particular, the Commission found the parties' presentations at the First and Second Technical Conferences to be informative and helpful to the Commission's understanding of issues.

Based on the entire record, the Commission's summary and general conclusions with respect to the 2020 biennial IRPs are as follows:

1. The 2020 biennial IRPs submitted by DEC, DEP, and DENC comply with the filing requirements of Commission Rule R8-60 and with the Commission's August 27, 2019, and April 6, 2020, orders relative to the preparation of the 2020 IRPs with respect to the topics and elements required to be contained in such plans.

2. DENC's 2020 biennial IRP is adequate and reasonable for planning purposes and for the Commission's use pursuant to N.C.G.S. § 62-110.1(c).

3. Except as may be discussed hereafter, DEP's and DEC's 2020 biennial IRPs are adequate and reasonable for planning purposes with respect to matters concerning system overview (Chapter 2); load forecasting methodologies and load forecasts (Chapter 3); energy efficiency, demand side management and voltage optimization (Chapter 4); energy storage and electric vehicles (Chapter 6); screening of generation alternatives (Chapter 8); resource adequacy and reserve margins (Chapter 9); nuclear and subsequent license renewal (Chapter 10); identification of first new resource need (Chapter 13); and ISOP (Chapter 15). While several commenters questioned the Duke Utilities approaches to some of these topics, the Commission is not inclined at this time to revisit the conclusions

it reached with respect to those issues in connection with its review of the two utilities' 2018 biennial IRPs and the 2019 updates. The Commission takes note that the Duke Utilities, in reply to suggestions made in the Public Staff's comments, have committed to continue to assess their load forecasting process in order to enhance the normalization of peak-weather forecasting during extreme cold winter peaks.

4. With respect to the modeling, analysis and results of the base case and alternative resource portfolios in the DEC and DEP 2020 IRPs, the Commission receives these as presented but declines to accept them for future planning purposes.[1] The Commission notes that the first new resource need identified in DEC's 2020 IRP is for the year beginning January 1, 2026, and that the first new resource need identified in DEP's 2020 IRP is for the year beginning January 1, 2025. Both these dates are beyond the timeframe of the short-term action plans contained in the two IRPs (Chapter 14), and neither utility anticipates a new supply resource will be required during that time period, notwithstanding the retirement of several existing generating units. The Commission's position on this point is based on the recent enactment of S.L. 2021-165. That new statutory directive establishes an explicit goal for carbon emission reductions by 2030 for the Duke Utilities' North Carolina generating assets and further establishes a requirement that the two utilities' North Carolina resource portfolio be net neutral as to carbon emissions by 2050. The present record in this docket does not permit a conclusion at this time as to whether these new directives will change the schedule for coal plant retirements proposed in either the base case or any of the alternative case scenarios in the DEC and DEP 2020 biennial IRPs and, further, whether they will require revision of the two utilities' technology screening and resource selection modeling for additional resources over the IRP planning period. The Commission wishes to be clear that this Order should not be interpreted as passing judgment on any of the resource scenarios presented in the 2020 IRPs; it should instead be understood as a recognition of the carbon emission reduction mandate and associated process created by the enactment of S.L. 2021-165.

5. On an interim basis and for immediate planning purposes only, the Commission finds that the short-term action plans (STAPs) contained in the DEC and DEP 2020 IRPs (Chapter 14) are reasonable and adequate, pending preparation by DEC and DEP of Carbon Plans, as is required by Section 1 of S.L. 2021-165.

V. FURTHER DISCUSSION AND GUIDANCE

In addition to the Commission's general findings and conclusions set forth above

[1] These matters are addressed primarily in Chapters 5, 11, 12, and 16 of the IRPs.

the Commission has determined that it would be appropriate to provide additional guidance with respect to the preparation and submission of the Carbon Plan required by S.L. 2021-165 and future IRPs. The matters addressed here arise out of the comments and reply comments of various participants and have been deemed by the Commission to be of particular interest as they may affect the utilities' near-term and long-term planning for new or replacement resources. In its review and evaluation of the 2020 IRP Reports the Commission has given particular attention to five topics: (1) natural gas supply and pricing issues, (2) methodology for evaluating economic retirement dates for coal-fired generating units, (3) grid impacts of different resource portfolios, (4) potential use of all-source procurement process, and (5) energy efficiency and demand-side management. DEC and DEP should adhere to the guidance provided for each of these topics in developing their Carbon Plan and for future IRPs.

A. Natural gas issues

The availability and pricing of natural gas to fuel combustion turbine (CT) and combined cycle (CC) generating plants is a matter that strongly affects whether such technologies are selected relative to other alternatives to meet future resource needs. It is also a matter that has implications for the methodology by which the utilities determine their avoided cost rates for purposes of PURPA. For the period 2021 through 2030 DEC and DEP use ten years of monthly pricing from the observable market. This market pricing period is followed by four years of transition from market prices to fundamental prices by blending the forward natural gas prices for 2031 through 2034 with a fundamental forecast from I Markit, Inc. The full fundamental forecast is in effect starting in 2035. Dominion utilizes commodity price forecasts provided by ICF Resources, LLC (ICF) in all periods except the first 36 months of the Study Period. The forecasts used for natural gas prices rely on forward market prices as of December 31, 2019, for the first 18 months of the Study Period and then blended forward prices with ICF estimates for the next 18 months. Beyond the first 36 months, the Company used the ICF commodity price forecast exclusively.

In their comments NCSEA and CCEBA contend that the Duke Utilities' natural gas price forecasts and sensitivities are seriously flawed and significantly underestimate future gas prices. They posit that Duke's near-term forecast is well below the fundamentals-based models. They concede that while the Duke Utilities did perform a low and high natural gas fuel cost forecast sensitivity, they also assumed that sufficient firm capacity to deliver natural gas to its new CC units would be available from "new or upgraded [pipeline] capacity" at a constant price. However, given the recent cancellation of the Atlantic Coast Pipeline and the still-undetermined status of the Mountain Valley Pipeline project, they contend that it is increasingly unlikely that sufficient new or upgraded pipeline capacity will be available to provide firm supply to the proposed new CC units modeled in several of the Duke IRP resource portfolios.

Second, NCSEA and CCEBA observe that Duke does not plan to contract for firm natural gas delivery to its CT units, despite adding substantial amounts of new CT capacity. These proposed CTs will be utilized during cold winter mornings and evenings – the exact same time when the natural gas distribution system will be under stress from building heating loads. The parties stated that the recent events in Texas have highlighted this concern and emphasize the need for Duke to include firm natural gas delivery in its models.

Third, according to NCSEA and CCEBA, Duke's natural gas pricing assumptions can dramatically impact the capacity additions selected during the IRP modeling process. It is therefore essential for ratepayers that gas price projections be subjected to very close scrutiny. As detailed by Mr. Lucas, such scrutiny shows that Duke's forward market forecast, compared to a pricing forecast based more on fundamentals, provides less realistic and less reliable natural gas price projections for the mid-2020s through the mid-2030s, when the utilities' needs for new capacity first arise. Furthermore, they point out that that Duke locked in market price forecasts on April 9, 2020, in the midst of a period of major futures market volatility, and very near to the lowest price point in the market in several years. According to NCSEA and CCEBA, if pricing had been locked in on a different day, the natural gas prices for the first 15 years of the IRP would have been substantially different.

The Public Staff in its Comments also raised concerns regarding the natural gas availability and pricing forecasts utilized by DEC and DEP. Specifically, the Public Staff criticized the use of Dominion Southpoint (DS) hub prices for all future and existing combined cycle (CC) generating facilities, beginning in 2026. The Public Staff noted that it had raised this issue in its Initial Comments filed in the 2020 avoided cost proceeding, Docket No. E-100, Sub 167. Other intervenors note that "[n]atural gas fuel price forecasts [by Duke] are lower for the newest, most efficient units than for older units" and that "[u]nderstating future gas prices could wrongly skew DEC's financial analysis in favor of gas generation to the exclusion of investments in fuel-free renewable generation." The Public Staff agreed with these intervenors that artificially low natural gas prices and constrained pipeline capacity for new CC generation plants is a serious matter. According to the Public Staff, total portfolio costs and the selection of natural gas capacity are both highly sensitive to fuel costs: the 'High Fuel' sensitivity analysis has the largest increase in costs relative to the base case of any sensitivity for both DEC and DEP, and the amount of new gas generation selected is also influenced by fuel prices. Therefore, the Public Staff stated that it believes the accuracy of the natural gas price forecast – which is inherently linked to the ability to transport sufficient gas into North Carolina – is of utmost importance. Based upon its review of Duke's IRPs, the Public Staff made the following two recommendations in its Initial Comments regarding the use of DS trading hub gas:

1. For the 2021 IRP update, Duke should re-evaluate its prediction that additional interstate pipeline capacity will be available. If Duke continues to believe that adequate capacity will be available, Duke should provide the Commission and stakeholders with a detailed narrative that identifies a specific timeline for completion, as well as identification of major challenges associated with potential new interstate pipelines, which require FERC approval. (See Recommendation # 21)

2. In order to assess the portfolio risk of Duke's natural gas pricing assumptions, Duke should consider developing an IRP portfolio that is

similar to its base case but includes natural gas import restrictions or less reliance on DS point gas. (See Recommendation # 22)

The Public Staff noted that while Duke has indicated it is willing to conduct the analysis recommended by the Public Staff, it believes the additional analysis is better suited for the comprehensive 2022 IRP filing. According to the Public Staff, this delay would result in the 2021 Avoided Cost proceeding utilizing a portfolio and natural gas price forecast that would be overly reliant on the assumption of DS trading hub gas being available in 2026. The overreliance on lower priced shale natural gas, sourced from the DS trading hub, would artificially distort the 2021 Avoided Cost proceeding's avoided energy cost rates, and PURPA standard offer contracts.

The Public Staff requested that based on the potential for limited availability of DS trading hub gas, the Commission order Duke to file a Limited DS Hub Gas Portfolio in its 2021 IRP Updates, or as a supplemental filing to Duke's 2020 IRPs, for potential use in calculating avoided energy rates in the 2021 Avoided Cost proceeding.

In reply, Duke stated that the use of ten years of market prices before transition to full fundamentals has been evaluated by the Public Staff in past IRP proceedings and has also been accepted by the Commission as reasonable for planning purposes since 2015. Duke points out that the Commission noted in its 2018 IRP Order Duke's comments that "using 10 years of forward market natural gas prices in their IRPs is appropriate for evaluating future generation needs and allows for an appropriate head-to-head comparison of long-term purchase power obligations from QFs required under PURPA" and that the Commission accepted the 2018 IRPs as reasonable for planning purposes. Further, Duke stated that the Public Staff's comments in this proceeding do not oppose the Companies' natural gas pricing forecast methodology, essentially finding that this aspect of the 2020 IRPs is again appropriate for IRP purposes in this docket.

The Companies disagreed with NCSEA and CCEBA's argument that the natural gas price forecast methodology is flawed and biased downward. In Section IV of the SEIA Lucas Report, Mr. Lucas is critical of the Companies' natural gas forecasts and claims that they are flawed because they incorporate actual market prices, despite the fact that this methodology has been previously reviewed and accepted by this Commission. Duke contended that the use of fundamental market prices that are in excess of actual market prices, as proposed by Mr. Lucas, is flawed and would result in significant risk of customer overpayments if the same logic was followed in the upcoming avoided cost docket.

Further, Duke stated that contrary to the SEIA Lucas Report's arguments, the use of near-term market prices that have a demonstrated liquidity is appropriate. Near term use of fundamental natural gas forecasts was thoroughly discussed in recent avoided cost Docket Nos. E-100, Sub 148 and Sub 158, and, in the last decade fundamental forecasts tend to lag the structural changes in the natural gas market. According to Duke, the lagging nature of these fundamental forecasts, which are only updated once or twice per year, have been demonstrated in recent history to overstate the forward market price of natural gas. Changes to the market as speculated by the fundamental forecasts can take longer to develop and are therefore more appropriate only in the absence of demonstrated liquid market-based pricing.

Finally, based upon discussions with the Public Staff since the filing of the Public Staff's Initial Comments in this docket, the Duke Utilities agreed to model in their 2021 IRP Updates a sensitivity portfolio, separate from the updates to the base planning cases, that would limit Dominion Southpoint Gas to levels that would only allow DEC to supply its existing gas combined cycle (CC) fleet plus one new CC with Dominion Southpoint trading hub gas and DEP to supply its existing 78 and future CC plants from Transco Zone 4 or Zone 5 gas, through 2030, as recommended by the Public Staff.

Conclusions – Natural gas issues

No party disputed that the availability and pricing forecasts used in DENC's 2020 IRP are reasonable, and accordingly the Commission finds them to be acceptable and reasonable for planning purposes by that company.

The Commission declines at this time to direct that the Duke Utilities abandon the use of actual market price information in their price forecasts. However, the Commission does agree that the natural gas price forecasts used by DEC and DEP should mirror those used by the Companies in the determination of avoided energy cost for PURPA purposes. Accordingly, DEC and DEP shall prepare their Carbon Plan for 2022 and their future IRPs to include no more than eight years of market-based forward natural gas prices before using fundamental forecast data for the remainder of the planning period, consistent with the Commission's Avoided Cost Order in Docket No. E-100, Sub 158. (Order dated April 15, 2020, Ordering Paragraph 20) [2]

Next, the Commission notes and accepts the agreement between the Duke Utilities and the Public Staff that it would be useful, not only for IRP purposes but also for purposes of the determination of avoided costs, to model at least one future resource portfolio in which the supply of natural gas at DS pricing is constrained. Cancellation of the Atlantic Coast Pipeline and the present status of the Mountain Valley Pipeline extension both counsel the need for consideration of such possibility. Accordingly, as a supplement to their 2020 biennial IRPs, DEC and DEP shall each prepare and shall file one additional iteration of their Base Portfolio with Carbon Policy portfolios that assumes limited DS Hub Gas, in the manner between Duke and the Public Staff, and also relies on no more than eight years of forward natural gas prices before using fundamental forecast data for the remainder of the planning period. Such supplemental filing should be made promptly and, in any event, not later than February 9, 2022.

[2] The Commission notes that in Docket No. E-100, Sub 167, in its Eighth Joint 45-Day Progress Report filed on October 22, 2021, Duke noted its agreement with the Public Staff to continue the use of forward natural gas prices for eight years before using fundamental forecast data for the remainder of the planning period in calculating avoided energy rates in the 2021 Avoided Cost Proceeding. (p. 10) Additionally, in Duke's Joint Initial Statement filed on November 1, 2021, in Docket No. E-100, Sub 175, Duke relied upon forward market price data for 8 years before transitioning to fundamentals forecast data in year nine in calculating its avoided cost energy rates. (p. 25)

B. Methodology for evaluating economic retirement of coal-fired generating units

Based on the comments and reply comments of the parties, the Commission considered this topic to be appropriate for more extensive review and consideration as part of the Second Technical Conference, during which the Commission focused not directly on the dates selected in the Duke Utilities' IRPs for retirement of their remaining coal generating fleet but on the question of the best methodology for determining the optimum date for such retirements. Although the 2020 IRPs and the Second Technical Conference preceded the enactment of S.L. 2021-165, the Commission believes that the foundation laid in those IRPs and in the technical conference will substantially advance the parties' ability to respond to the carbon reduction mandates in that new legislation. In many respects, the work done in connection with the 2020 biennial IRPs and the review and analysis of those results is a predicate for the preparation of their Carbon Plan.

In their 2020 IRPs DEC and DEP conducted coal facility retirement analyses in compliance with the Commission's previous IRP Orders in Docket No. E-100, Sub 157. These analyses involved a multi-step process that identified the most economic coal retirement dates for each of the utilities' coal assets. The resulting retirement dates were used in the Base Case Portfolios (with and without carbon policy). In addition, the Companies also determined the earliest practicable coal retirement dates for each unit, which were used in three of the IRP Portfolios. Most commenters on this methodology criticized Duke's use of its multi-step "Sequential Peaker Process."

The AGO relied on a report from Strategen Consulting to inform its comments. Based on that report the AGO contended that Duke's multi-step Sequential Peaker Method for selecting coal unit retirements is overly complicated and should be replaced by computer modeling that selects units for retirement from within the model. The NCSEA, CCEBA and SACE joint intervenors asked that the Commission direct Duke to replace its coal retirement study with a more transparent and detailed analysis that reflects the true costs of operating its existing coal fleet. Their comments were informed by the modeling effort and report by Synapse. The Public Staff recommended that Duke employ its EnCompass modeling capability to endogenously select the economically optimal plant retirement dates in future IRPs. According to the Public Staff the EnCompass model to which Duke is migrating has this ability. Instead of specifying the retirement dates by a complex external analysis based on assumptions and variables selected independently of the model, the model itself could determine when to shut the plant down and replace it with new capacity.

Duke stated that although the utilities appreciated the conceptual idea of using the capacity expansion model to perform all resource optimization – both retirements and replacements -- in a single computational process, this approach was not practical due to limitations of the capacity expansion model, the complexity of analysis, and the magnitude of the coal retirements being contemplated. Furthermore, because the Duke Utilities are switching to the EnCompass model as discussed with interested parties in the stakeholder process, DEC and DEP will also continue to evaluate the capabilities and enhancements that the new modeling software will provide with respect to co-optimizing retirements of the Companies' coal fleet. To the extent the Duke Utilities determine that the EnCompass software can be leveraged to better optimize coal retirement dates and replacement options, the utilities will agree to perform that analysis in the comprehensive biennial IRP filings in 2022. The utilities believe given the capabilities of the current models, the approach used in the 2020 IRP yielded the most economic retirement dates. The Companies commit to further evaluating if EnCompass can provide the necessary functionality to accurately capture changing cost and value over time as done in the Companies' coal retirement analysis in the 2020 IRP.

Conclusions – Coal unit retirements

At the time of the Second Technical Conference the difference between the positions of the Duke Utilities on the one hand and the positions of the Public Staff, the Attorney General, and intervenors on the other hand centered on whether optimal plant retirement dates should be selected endogenously as part of the same model that also selected the most economic and appropriate replacement resources or whether plant retirement dates should be selected first and then the optimal replacement resources identified separately and sequentially through use of Duke's capacity expansion model. The Commission concludes that this dispute likely will be resolved by Duke's planned deployment of the EnCompass modeling system, which has the capability to determine both plant retirement dates and optimal replacement resources in a single modeling exercise.

The Commission concludes that the Duke Utilities should continue to refine their analyses of optimum coal plant retirement dates and incorporate the results of such refinement in their Carbon Plans and future IRPs by:

1. Leveraging the full capability of the EnCompass cost modeling and capacity expansion tools. If Duke continues to believe that the Sequential Peaker Method used for the 2020 IRPs is the most appropriate methodology for the Carbon Plan and for future IRPs, it shall nonetheless present an alternative coal unit retirement schedule using the capabilities of the EnCompass model to select the optimum retirement dates endogenously. The Commission notes that ultimately, the retirement dates for Duke's remaining coal generating plants must support achievement of a least cost path to compliance with the carbon emission reductions mandated by S.L. 2021-165.

2. Updating assumptions as appropriate (such as ordered for natural gas forecasts in Section V.A. above).

3. Developing coal unit retirement dates necessary to achieve the 2030 carbon reduction target established in Section 1 of S.L. 2021-165.

4. Finally, and indirectly related to the matter of the retirement of existing coal-fired units and the resulting replacement of those resources, the Commission has taken note of the Duke Utilities' discussion in Chapter 8 and Appendix G of their 2020 IRPS of their evaluation of several new generating technologies in order to meet future Zero-Emitting

Load-Following Resource (ZELFR) needs. Technologies considered typically fall under the broad categories of advanced nuclear, advanced renewables, advanced transmission and distribution, biofuels, carbon capture utilization and sequestration, fuel cells, hydrogen, long duration energy storage, and supercritical CO_2 Brayton Cycle gas generating plants. All of these technologies could potentially help Duke meet future carbon reduction goals if they reach commercial status and are economically competitive. In light of the enactment of S.L. 2021-165, the Commission believes that it will be imperative that full consideration of the commercial viability and cost parameters of these technologies be given prominence in the Carbon Plan and in future IRPs. In particular, the Commission is interested in and would benefit from additional analysis of high pressure Brayton cycle technologies employing supercritical CO_2 as the working fluid, which appear to be in early stages of commercialization and are showing some early promise as zero-emitting resources.

C. Grid impacts of different resource portfolios

Commission Rule R8-60(i)(5) states that each utility shall include in its biennial IRP a list of transmission lines and other associated facilities (161 kV or over) which are under construction or for which there are specific plans to be constructed during the planning horizon, including the capacity and voltage levels, location, and schedules for completion and operation. The utility shall also include a discussion of the adequacy of its transmission system (161 kV and above). Each of the utilities included the information required by Rule R8-60(i)(5) in their 2020 IRPs.

In its August 27, 2019, Order the Commission directed the Companies to include in their 2020 biennial IRPs a more extended discussion of the expected issues and impacts to the transmission grid arising from different resource portfolios modeled in the IRPs as alternatives to the base case. This material was contained in Chapter 7 of the 2020 IRPs. Several commenters on the 2020 IRPs focused on transmission issues, and this was also one of the topics selected for further investigation at the Second Technical Conference.

NCSEA and CCEBA filed as part of their comments a report entitled "Transmission Issues and Recommendations for Duke 2020 IRP" (Grid Strategies Report). According to the NCSEA and CCEBA, this report addresses inadequate and inappropriate assumptions in Duke's IRP regarding transmission planning, which the report asserts fail to capture the benefits of optimized and least cost transmission planning. In its comments the AGO stated that Duke's resource adequacy studies do not adequately investigate how neighbor assistance can reduce reserve margin and capacity costs. The AGO suggested that Duke should further examine the potential benefits of wholesale imports from neighboring utilities and contended that Duke has failed to pursue a number of promising options for transmission investments that would enhance the ability to rely on imported energy.

The Tech Customers emphasized a need to reevaluate the purported barriers to replacing coal plants with non-gas alternatives. Their comments suggested that the Duke

Utilities offer unsupported estimates of enormous transmission costs associated with wholesale power imports and with the addition of distributed renewable generation. Finally, the Public Staff's comments acknowledged that the number of permutations of generation types, geographic locations, timing, and capacity within generation scenarios and between scenarios can be significant, making their study complex. According to the Public Staff, the capacity expansion models used by the utilities in their IRPs trade off transmission specificity for reduced model complexity. The Public Staff stated that it is simply not possible at this time to solve a long-term capacity expansion model with sufficient generator site specificity and the typical power flow analyses to support detailed proposed transmission investments. The Public Staff believes the utilities can continue to improve the planning process without becoming too granular and time intensive. Further, the Public Staff stated that it believes future IRPs can improve how costs for required imports and exports are assigned to each portfolio, which the utilities acknowledge may be necessary to accommodate some future resource mixes. According to the Public Staff, the generic interconnection costs that are included in the existing capacity expansion model do not fully capture required transmission investments, and the evaluation of larger scale system impacts is critical to ensuring that capacity expansion portfolios presented in the IRP represent optimal solutions. The Public Staff recognizes that it would be too complex to include detailed power flow analyses associated with future capacity expansion plans and is open to input from the utilities and intervenors on how to address this concern in future IRPs.

In reply to the Public Staff and intervenors Duke responded that the two utilities' future transmission investment requirements are dynamic and are highly correlated to the timing of planned coal unit retirements as well as the type and location of replacement generation. Duke further stated that as more certainty is known regarding the timing of replacement and incremental resources, the options considered with respect to type and location, as well as capability (Megawatts, MVA), definitive transmission studies can be performed resulting in more accurate network upgrade cost estimates. In addition, further refinements around cost estimates for off-system capacity purchases will be included in future IRPs to the extent off-system purchases are contemplated in the plan. Finally, Duke stated in reply comments that no action is needed in response to the NCSEA/CCEBA Grid Strategies Report today and that future policy support would be needed to promote significant transmission expansions outside of least cost resource planning. Further, Duke noted that the Grid Strategies Report comments on the critical importance of transmission assumptions in the Companies' 2020 IRPs and suggests the "optionality provided by a strong electric transmission network is significant and will not be captured to the benefit of customers with incremental, least cost expansion planning, especially if planning models are based on known commitments and do not reflect expected conditions for the future." Duke stated that the Companies do not dispute the importance of a strong electric transmission network but disagree with the Grid Strategies Report's assertion that the Companies should deviate from least cost planning for their native load customers in order to significantly expand their transmission systems to increase import capability or support large-scale new renewable generation. According to Duke, DEC and DEP are bound to adhere to least cost integrated resource planning under the Public Utilities Act and Commission Rule R8-60 as a component of their IRPs' evaluation of resource options.

Conclusions – Grid impacts of different resource portfolios

The Commission recognizes and appreciates the expanded discussion by DEC and DEP in the new chapter on Grid Requirements included in the 2020 biennial IRPs, which was offered partly in response to the Commission's August 27, 2019 Order. Of particular interest is the discussion by DEC and DEP of transmission projects needed to facilitate carbon reduction targets and to support several of the alternative resource portfolios modeled in the IRPs. As noted in the IRPs, the portfolios presented included different assumptions for coal plant retirement dates along with a varying array of demand and supply-side resource requirements to reliably serve load over the planning horizon. DEC and DEP conducted high-level assessments to estimate the associated necessary transmission network upgrades for retiring the existing coal facilities and integrating each scenario's requisite incremental resources, including combinations of some or all of the following resources: solar, solar-plus-storage hybrid facilities, stand-alone battery storage, pumped-hydro generation/storage, onshore wind, offshore wind, increased off-system purchases, and dispatchable natural gas facilities. In addition, the Commission concludes that the information presented at the Second Technical Conference provided the transparency and education that the Commission intended to be the outcome of such a proceeding.

The Commission concludes that in developing their Carbon Plan for 2022 and for future IRPs DEC and DEP should:

1. Continue to follow the directive contained in the Commission's August 27, 2019, Order in Docket No. E-100 sub 157 that the IRPs contain an analysis of anticipated or likely grid impacts associated with each alternative resource portfolio modeled in the IRPs and continue to refine transmission network upgrade cost estimates for incremental resources to take into account the most recent system impact study results;

2. Determine the feasibility of providing a timeline for necessary critical transmission network upgrades required to enable interconnection of incremental resources identified in each alternative resource portfolio modeled in the IRPs;

3. Incorporate the results of the North Carolina Transmission Planning Cooperative (NCTPC) offshore wind study results and associated cost estimates;

4. Incorporate applicable results from the 2021 NCTPC Future Resource Scenario Study, as was referred to and discussed at the Second Technical Conference;

5. Refine import capability studies specifically for capacity purchase from PJM; and

6. Continue to assess costs, risks, and reliability aspects of potential off-system purchases.

Finally, the Commission expects that portfolios presented in the Carbon Plan and future IRP filings will reflect the transmission and distribution infrastructure investments that will be required to implement the capacity and additions contemplated in the plans. 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 alternative resource portfolio(s) along with the best current estimate of costs of constructing and operating such upgrades. These estimates should include the costs to secure firm transmission.

D. Potential use of all-source procurement process

Commission Rule R8-60(g) states that the fundamental objective of resource planning is to identify a resource plan "… that offers the least cost combination (on a long-term basis) of reliable resource options for meeting the anticipated needs of … [the utility's] … system." Based on the experience of other utilities, all-source competitive solicitations (ASCS) are a tool that can support achieving this objective. ASCS selects the least-cost portfolio of resources that can meet the utility's overall need because it allows different technologies or combinations of technologies to compete to meet the overall need, rather than single solutions to discrete portions of it. A holistic view can find opportunities to meet need more efficiently. In addition, a competitively bid all-source procurement process permits the utilities, the Commission, and interested stakeholders to "market test" the planning assumptions relative to the maturity, commercial viability, and relative cost of new resource technologies and relative to whether existing resource assets continue to provide "least cost" solutions to capacity and energy requirements.

The value and feasibility of all-source procurements was most strongly advocated by intervenors SACE, et al. They argued that the Commission should adopt an all-source procurement approach to identifying the need for new resources and selecting the best resource mix to meet the need. The intervenors commissioned John D. Wilson of Resource Insight, Inc. to evaluate the feasibility of implementing all-source procurement in the Carolinas. Mr. Wilson is the lead author on a recent report on all-source procurement prepared for Energy Innovation and the Southern Alliance for Clean Energy. Mr. Wilson's report prepared for the instant proceeding illustrates the benefits of all-source procurement and offers a guide to implementing it in the Carolinas.

The Public Staff supported the use of all-source procurements and commented at the Second Technical Conference that:

1. The Commission could initiate a rulemaking proceeding to establish rules for all-source procurement

    a. Could be modeled off of R8-71 (CPRE rules) but would require substantial modifications to meet the requirements of an all-source procurement

b. Would likely require modifications of R8-60 (IRP rule) as well

2. Facilitate any required stakeholder discussions or revisions to North Carolina Interconnection Procedures (NCIP) in order to integrate with queue reform Resource Solicitation Clusters (NCIP Section 4.4.2)

Duke stated in reply comments that the all-source procurement proposal is a solution in search of a problem that would require enabling legislation, not regulatory approval in an IRP docket, and therefore should be rejected. At the Second Technical Conference Duke advocated continued reliance on the competitive procurement practices the utilities' currently use, even though such existing competitive procurements are employed only after a particular technology solution has been selected through other decision-making processes.

Conclusions – All-source procurement

The Commission appreciates the comments and participation of the parties in the Second Technical Conference where this subject was vetted. In addition, the Commission reviewed the report entitled *All-Source Competitive Solicitations: State and Electric Utility Practices* published in March 2021 for the Lawrence Berkeley National Laboratory (LBNL). The report points out that all-source competitive solicitations require significant investments in process design and implementation, and their design involves consideration of trade-offs in stakeholder participation, transparency, time, flexibility, and discretion. At this time and in recognition of the substantial commitment of resources that will be required to fulfill the requirement of S.L. 2021-165 that the Commission develop a Carbon Plan no later than December 31, 2022, the Commission declines to reach any conclusions regarding how, if at all, and in what ways all-source procurement might be incorporated into the utilities' future planning processes. The Commission may revisit this topic, as appropriate, once the initial Carbon Plan has been approved and is put in place.

E. Energy efficiency (EE) and demand-side management (DSM)

In 2019 the Duke Utilities retained Nexant, Inc. to conduct a comprehensive assessment of EE/DSM potential for DEC and DEP. Nexant's methods are industry-leading and its analysis relied on the best data available at the time to support the study. Its results were specific to the DEC and DEP service territories and were not generalizations drawn from other territories. The Nexant Market Potential Study (MPS) includes currently known technologies, estimated costs, and energy and demand reduction impacts for these EE and DSM measures and determines the Technical, Economic, and Achievable Potential of EE/DSM programs applicable to DEC and DEP customers.

In mid-2020 the Duke Utilities engaged Tierra Resource Consultants (Tierra) to perform a deeper analysis into the winter peak loads which are driving system capacity planning for DEC and DEP. Following the initial winter peak analysis, Tierra collaborated with Dunsky Energy Consulting to identify a range of potential winter peak focused DSM solutions for the DEC and DEP service territories. The Public Staff recognized in its comments, that “these reports incorporate traditional DSM/EE measures, non-traditional measures, and rate schedule and tariff-based DSM opportunities to provide increased winter peak reduction opportunities.”

Several participants in this proceeding took issue with the conclusions drawn from the MPS and the Tierra and Dunsky studies and then embodied in DEC’s and DEP’s 2020 IRPs. The NCSEA, CCEBA, and SACE intervenors contended that Synapse’s modeling corrects significantly flawed and inaccurate assumptions and inputs in Duke’s modeling and demonstrates that a very different resource plan than those developed by Duke is in the best interest of Duke ratepayers. With respect to energy efficiency, Synapse in its modeling assumed a higher but achievable level of energy efficiency savings than Duke. Synapse assumed that Duke would ramp up energy efficiency programs starting in 2022 from the 5-year EE plan levels and increase first year savings by 0.15% per year to 1.5%, and that this level of savings will persist through the study period. According to the intervenors, reaching a 1.5% annual savings level is a reasonable scenario for Duke, given that the American Council for an Energy Efficient Economy found that the implementation of energy efficiency policies and measures could increase energy efficiency savings by nearly double by 2030 over a business as usual case and that leading states in energy efficiency such as Massachusetts and Rhode Island have been achieving much higher savings ranging from 2% to 3% per year over the past decade. In contrast, Duke’s own savings have been at about 1% per year or less during that time frame.

The AGO’s expert witness, Strategen, applauded Duke for pursuing utility energy efficiency programs, as they are generally among the least-cost resources and can significantly reduce the need for more costly generation. However, Strategen also contends that Duke’s level of planned energy efficiency, while above average for the Southeast, could still be improved given the savings other utilities have achieved nationwide. Likewise, the Tech Customers also commended Duke for regional leadership in energy efficiency performance. Nonetheless, they recommended that Duke and this Commission look to and consider adopting examples set in other states and prioritize greater utilization of efficiency and advanced energy technologies to shave winter peak demand and build a more responsive grid. Finally, Appalachian Voices, relying on the modeling produced by Synapse Energy Economics, stated that it believes the Companies intentionally limited the potential impact of energy efficiency investments in order to argue a need for more new gas generation and to falsely claim that their scenarios that achieve the greatest carbon reductions would result in the highest cost to customers.

The Duke Utilities responded to these comments, replying that the current modeling methodology identifies the maximum achievable potential for utility-based DSM/EE based on the detailed analysis represented in the Market Potential Study and, going forward, additional innovative programs identified in the Winter Peak Study. Customer adoption of DSM/EE measures is not something that can be forced. The purpose of developing the Achievable Potential estimates in multiple scenarios in the MPS is to identify the amount of DSM/EE that can be reasonably included in resource planning where system reliability and resource adequacy are overriding requirements. Duke suggested that the intervenors are seeking to add additional, selectable DSM/EE above and beyond the Achievable Potential, presumably at an understated cost, in the hopes that the model would select this additional DSM/EE rather than other supply side resources. According to Duke, this methodology would completely disregard the fact that modeling outcomes do not affect customer adoption decisions and could result in a plan that artificially overstates the potential future of DSM/EE savings, and thereby understates the net load forecast and amount of traditional supply side resources required to reliably serve customer load.

Further, Duke stated that direct comparisons of EE savings as a percentage of load is of limited value across disparate service territories due to significant differences in factors influencing the cost effectiveness and adoption of EE programs including climate, age and type of housing stock, fuel types for space and water heat as well as other energy end uses, retail energy prices, avoided energy costs, EE program maturity, opt-out rules, and average usage per retail customer.

Conclusions – EE/DSM

The Commission recognizes the significant role that cost-effective EE and DSM programs must continue to play in North Carolina. In order to ensure that the Companies can reliably serve customers' future energy needs, it is critically important that EE assumptions utilized in system planning through an IRP be grounded in a market potential study or other credible and realistic analysis, especially in the near-term, because any overstatement of EE potential will directly result in an understatement of the load forecast, potentially leading to inadequate resources to serve load. For this reason, the Duke Utilities' reliance on the Nexant MPS, supplemented by the Tierra and Dunsky studies, is reasonable. No other party in these proceedings has provided information that calls into serious question the conclusions of that work. The Commission determines it useful for Duke to file the Tierra and Dunsky studies in this instant docket.

Accordingly, the Commission concludes that:

1. Duke's Market Potential Study produced reasonable results for long-range planning purposes for DEC and DEP.

2. DEC and DEP should continue to study the recommendations of the Winter Peak Study to develop new and enhanced DSM programs in conjunction with the Collaborative and other stakeholders.

3. Use of the Total Resource Cost (TRC) test for cost effectiveness screening continues to be appropriate.

Going forward, DEC and DEP's 2022 Carbon Plan and future IRPs shall include consideration of key trends observed and emerging technology or program developments that may have a meaningful impact on future EE/DSM forecasts, regardless of the 10% threshold previously ordered by the Commission.

VI. REPS AND CPRE PROGRAM PLANS AND MISCELLANEOUS MATTERS

North Carolina General Statute § 62-133.8 requires all electric power suppliers in North Carolina to meet specified percentages of their retail sales using renewable energy and energy efficiency. The total amount of renewable energy that must either be generated by an electric power supplier, or must be evidenced by purchased renewable energy certificates (RECs) or energy efficiency certificates (EECs), for 2020, 2021, and 2022 is equal to 10% of its North Carolina retail sales for the preceding year.

Commission Rule R8-67(b) provides the requirements for REPS Compliance Plans. Electric public utilities must file their plans on or before September 1 of each year as part of their IRPs and explain their plans to meet the requirements of N.C. Gen. Stat. § 62-133.8(b)-(f) for the year of filing and the two calendar years thereafter, in this case 2020, 2021, and 2022 (the planning period). An electric power supplier may have its REPS requirements met by a utility compliance aggregator as defined in R8-67(a)(5).

The record in this proceeding shows that DEC, DEP, and DENC have each contracted for or procured sufficient resources to meet the general requirement and solar energy set-aside for the Planning Period, both for the utility and for the utilities' Wholesale Customers. DEC and DEP each intend to use the EE program to meet up to 25% of their REPS requirements in 2020, and up to 40% of REPS requirements in 2021 and 2022. DENC plans to use EE, purchased in-state and out-of-state RECs, and company-generated RECs to meet the general requirement for its retail customers. For the town of Windsor (Windsor), Dominion will use biomass RECs and Windsor's Southeastern Power Administration (SEPA) allocation. Dominion has purchased or plans to purchase solar RECs to meet the solar energy set-aside and has executed contracts with in-state solar facilities to satisfy Windsor's portion of the in-state solar energy set-aside.

DEP plans to meet a significant portion of the general requirement using RECs from solar facilities, including RECs acquired from its net-metered customers. A portion of the general requirement will be met through various biomass resources, including landfill gas to energy, combined heat and power, and direct combustion of biomass fuels. Hydroelectric facilities will also provide RECs for DEP's retail customers. DEP will continue to evaluate the use of wind energy for future REPS compliance. To meet the solar energy set-aside provided in the REPS statute, DEC will obtain RECs from its self-owned solar photovoltaic (PV) facilities and from other solar PV and solar thermal facilities.

DEC, DEP, and DENC each anticipate that its REPS compliance costs for the Planning Period will remain below the cost caps contained in N.C.G.S. § 62-133.8(h)(3) and (4). The state's electric power suppliers have encountered continuing difficulties in their efforts to comply with the swine and poultry waste requirement. In each year from 2012 through 2017, the electric power suppliers moved the Commission to delay the swine waste requirement until the following year, and the Commission granted each request. The requirement for all electric power suppliers is currently set at 0.07% in 2021 and 0.14% in 2022. With respect to poultry waste, the electric power suppliers annually requested from 2012 through 2019 that the requirement be delayed and modified. The

Commission granted these motions. The requirement increased to 700,000 MWh in 2020 and increases to 900,000 MWh in 2021 and 2022.

In its annual orders granting delays or reductions in the swine and poultry waste requirements, the Commission has required the suppliers to file reports describing the state of their compliance with the set-asides and their negotiations with the developers of swine and poultry waste-to-energy projects, on a semiannual basis in Docket No. E-100, Sub 113A. The Commission has further required the suppliers to provide internet-available information to assist the developers of swine and poultry waste-to-energy projects in obtaining contract approval and interconnecting facilities. Additionally, the Commission has directed the Public Staff to hold periodic stakeholder meetings to facilitate compliance with the swine and poultry waste set-asides. In response, the Public Staff organized bi-annual stakeholder meetings beginning in June of 2014. The attendees have included farmers, the North Carolina Pork Council, the North Carolina Poultry Federation, waste-to-energy developers, bankers, state environmental regulators, and the electric power suppliers. The state's electric power suppliers have been able to comply only to a limited extent with the poultry waste set-aside, and to an even lesser extent with the swine waste set-aside. Nevertheless, the REPS statute has served as a stimulus for several important advances in waste-to-energy technology.

Pursuant to Commission Rule R8-71(g) and the Additional Proceedings Order, DEC and DEP submitted their respective CPRE Plan Updates on September 1, 2021. The CPRE Plan Updates presented each Company's current plans for implementing its CPRE program. The Commission finds and concludes that the CPRE Plan Updates fulfill the requirements of Rule R8-71(g) and that they should, therefore, be accepted as filed.

CONCLUSIONS

The Public Staff in its comments noted that overall, the three utilities are better positioned to comply with all the requirements of the REPS statute, including the set-asides, than has been the case in previous years, and that none of the three utilities appears likely to exceed the cost caps for the planning period. No other party to this proceeding has taken issue with the compliance plans filed by the three utilities. Accordingly, the Commission concludes that the REPS Compliance Plans filed by DEC, DEP, and DENC contain the information required by Commission Rule R8-67(b). As such, and based on the recommendation of the Public Staff, the Commission accepts the REPS Compliance Plans filed in this docket.

Finally, the Commission takes note of the suggestion by the Public Staff, to which the Duke Utilities concur, that it would be appropriate and useful for the Commission to initiate a proposed rulemaking proceeding concerning the circumstances, if any, under which certificates of public convenience and necessity (CPCNs) should be required for battery-based energy storage facilities and, if it is determined that CPCNs should be required in at least some circumstances, the appropriate processes and standards for applying for, reviewing, and granting or denying CPCNs. The Commission appreciates this suggestion, will take it under further advisement, and will address the suggestion by separate order at a later time.

IT IS, THEREFORE, ORDERED as follows:

1. That the 2020 biennial IRP filed by Dominion Energy North Carolina is reasonable for planning purposes, and the Commission hereby accepts DENC's IRP, subject to adjustments based on its 2021 IRP Update;

2. That DEC's and DEP's 2020 biennial IRPs are adequate to be used for short-term planning purposes as discussed in the Companies' Short-Term Action Plans (STAPs);

3. That the 2020 REPS Program Plans filed by DENC, DEC and DEP are hereby accepted; and

4. That the 2020 CPRE Plan Updates filed by DEC and DEP are hereby accepted.

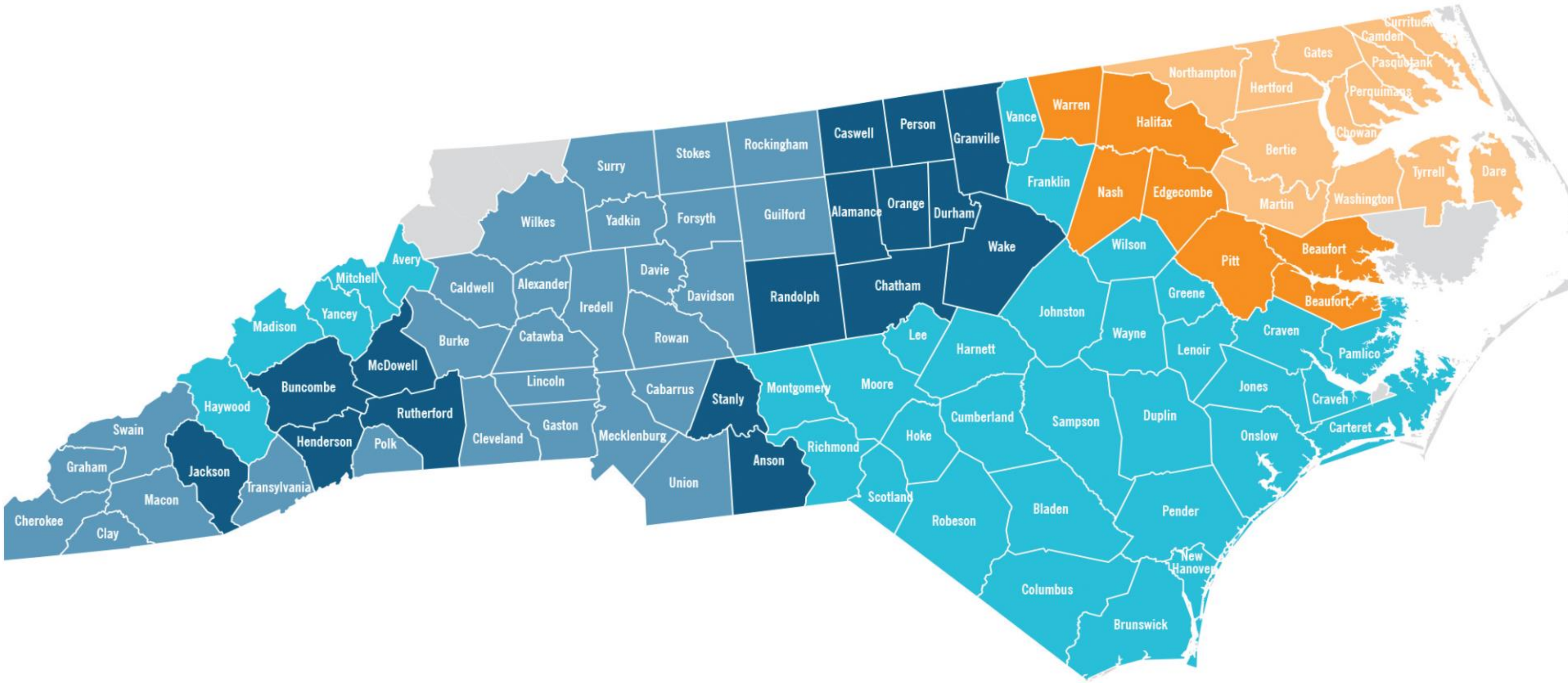
ISSUED BY ORDER OF THE COMMISSION.

This the 19th day of November, 2021.

NORTH CAROLINA UTILITIES COMMISSION

Erica N Green

Erica N. Green, Deputy Clerk



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