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

REQUIRED PURSUANT TO G.S. 62-110.1(c)

DATE DUE: DECEMBER 31, 2017
SUBMITTED: NOVEMBER 21, 2017

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

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

ABBREVIATIONS AND ACRONYMS (continued)

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

TABLE OF CONTENTS

APPENDICES

1. EXECUTIVE SUMMARY

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

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

Duke and Progress, the two largest electric IOUs in North Carolina, together provide about 95% of the utility-supplied electricity consumed in the state. Approximately 20% of the IOUs' 2015 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: Electricity Sales of Regulated Utilities in North Carolina

	NC Retail GWh*		NC Wholesale GWh*		Total GWh Sales* (NC Plus Other States)	
	2016	2015	2016	2015	2016	2015
Progress	37,500	37,217	22,493	18,787	69,052	64,881
Duke	57,803	57,685	6,083	6,025	88,545	87,376
VEPCO	4,294	4,378	1,301	1,355	87,875	85,179

*GWh = 1 Million kWh (kilowatt-hours)

During the 2017 to 2031 timeframe, the average annual growth rate in summer peak demand for electricity in North Carolina is forecasted to be in the range of 1.0% to 1.5%. Table ES-2 illustrates the system wide average annual growth rates forecast by the IOUs that operate in North Carolina. Each uses generally accepted forecasting methods and, although their forecasting models are different, the econometric techniques employed by each are widely used for projecting future trends.

Table ES-2: Forecast Annual Growth Rates for Progress, Duke, and VEPCO (After Energy Efficiency (EE) and Demand-Side Management (DSM) are Included) (2017 – 2031)

	Summer Peak	Winter Peak	Energy Sales
Progress	1.0%	1.2%	0.9%
Duke	1.1%	1.3%	1.0%
VEPCO	1.5%	1.3%	1.5%

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 2016

	Progress	Duke	VEPCO
Coal	16%	27%	25%
Nuclear	41%	48%	32%
Net Hydroelectric*	1%	1%	1%
Natural Gas and Oil	32%	13%	33%
Non-Hydro Renewable	4%	1%	2%
Other Purchased Power	6%	10%	7%

* See discussion of pumped storage in Section 6.

Pursuant to G.S. 62-133.8 the Renewable Energy and Energy Efficiency Portfolio Standard (REPS), investor-owned utilities in North Carolina will be required to meet up to 12.5% of their energy needs through renewable energy resources or energy efficiency measures by 2021. Rural electric cooperatives and municipal electric suppliers are subject to a 10% REPS requirement. In general, electric power suppliers may comply with the REPS requirement in a number of ways, including the use of renewable fuels in existing electric generating facilities, the generation of power at new renewable energy facilities, the purchase of power from renewable energy facilities, the purchase of renewable energy certificates (RECs), and the implementation of energy efficiency measures. This issue is discussed further in Section 8.

A map showing the service areas of the North Carolina IOUs can be found at the back of this report.

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. G.S. 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 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 22, 2016 Annual Report. It is based primarily on reports to the Commission by the regulated electric utilities serving North Carolina, but also includes information from other records and Commission files.

3. OVERVIEW OF THE ELECTRIC UTILITY INDUSTRY IN NORTH CAROLINA

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

Duke and Progress, the two largest IOUs, together provide about 95% of the utility-supplied electricity consumed in the state. As of December 31, 2015, Duke had 1,921,000 customers located in North Carolina, and Progress had 1,339,000. Each also has customers in South Carolina. Dominion supplies approximately 5% of the State's utility-generated electricity. It has 120,000 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 20% 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 2015 reporting period, the gigawatt-hour (GWh) sales for the electric utilities in North Carolina are summarized in Table 1.

Table 1: Electricity Sales of Regulated Utilities in North Carolina

	NC Retail GWh*		NC Wholesale GWh*		Total GWh Sales* (NC Plus Other States)	
	2016	2015	2016	2015	2016	2015
Progress	37,500	37,217	22,493	18,787	69,052	64,881
Duke	57,803	57,685	6,083	6,025	88,545	87,376
VEPCO	4,294	4,378	1,301	1,355	87,875	85,179

*GWh = 1 Million kWh (kilowatt-hours)

The Commission does not regulate the retail rates of municipally owned electric systems or EMCs. However, the Commission does have oversight over EMC and municipal construction of generation and transmission facilities, through its jurisdiction over the licensing of all new electric generating plants and large-scale transmission facilities built in North Carolina.

EMCs are independent, not-for-profit corporations. There are 31 EMCs serving metered customers in North Carolina. EMCs serve approximately 25% of the State's population. Twenty-six EMCs are headquartered in the State, and these twenty-six EMCs served 1,039,557 metered customers in 2016. 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, that provides its member EMCs with wholesale power and other services. All 25 NCEMC members are headquartered and incorporated in North Carolina.

Since 1980, NCEMC has been a part owner in the Catawba Nuclear Station located in York County, South Carolina. Duke operates and maintains the station, which has been operational since 1985. NCEMC's ownership interests consist of 61.51% of Unit 1, approximately 700 megawatts (MW), and 30.754% in the common support facilities of the station. NCEMC's ownership entitlement is bolstered by a reliability exchange between the Catawba Nuclear Station and Duke's McGuire Nuclear Station located in Mecklenburg County, NC.

NCEMC is also a part owner in the 750 MW Lee Combined Cycle Plant located in Anderson, South Carolina. Duke owns approximately 650 MWs of the plant and NCEMC owns approximately 100 MWs. Once commercial operation commences, Duke will be responsible for project operation.

Additionally, NCEMC owns and operates about 680 MW of combustion turbine (CT) generation at sites in Anson and Richmond Counties. 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).

Finally, NCEMC has facilitated the development of 18 community solar facilities, operates a microgrid located on Ocracoke Island, and partners with its members to implement DSM/EE programs such as a demand response program for Wi-Fi enabled thermostats that currently has over 1,000 member-owner thermostats enrolled.

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

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

In addition to the EMCs, there are about 75 municipal and university-owned electric distribution systems serving approximately 595,000 customers in North Carolina. Most of these systems are members of ElectriCities, an umbrella service organization. ElectriCities is a non-profit organization that provides many of the technical, administrative, and management services needed by its municipally-owned electric utility members in North Carolina, South Carolina, and Virginia.

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

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

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

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

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

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

The Tennessee Valley Authority (TVA) sells energy directly to the Murphy Power Board and to three out-of-state cooperatives that supply power to portions of North Carolina: Blue Ridge Mountain EMC, Tri-State Membership Corporation, and Mountain Electric Cooperative. These distributors of TVA power are located in six North Carolina counties and serve over 33,000 households and 9,000 commercial and industrial customers. The North

Carolina counties served by distributors of TVA power are Avery, Burke, Cherokee, Clay, McDowell, and Watauga.

TVA owns and operates four hydroelectric dams in North Carolina with a combined generation capacity of 523 MW. The dams are Apalachia and Hiwassee in Cherokee County, Chatuge in Clay County, and Fontana in Swain and Graham counties.

4. THE HISTORY OF INTEGRATED RESOURCE PLANNING IN NORTH CAROLINA

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

Initial IRP Rules

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

2016 Biennial Integrated Resource Plans and Related 2016 REPS Compliance Plans (Docket No. E-100, Sub 147)

2016 IRP Reports and REPS compliance plans filed by Progress, Duke and Dominion provided updates to their current Biennial Reports (Docket No. E-100, Sub 141). A public hearing in this docket was held in Raleigh on February 27, 2017. Public witnesses addressed a broad range of IRP related issues but especially the role of renewable energy alternatives in North Carolina.

Based upon the record in the proceeding, and the comments of the Public Staff regarding the IRP Reports, the Commission concluded that the IOUs' forecasts of native load requirements and other system capacity or firm energy obligations, supply-side and demand-side resources expected to satisfy those loads, and reserve margins are reasonable for planning purposes, and the Commission accepted the IRP Reports as filed in the docket. In addition, the Commission approved the REPS compliance plans submitted by the utilities as recommended by the Public Staff. The Commission's June 27, 2017 Order can be found in the back of this report as Appendix 1.

Update reports were filed with the Commission in 2017 including current integrated resource plans and REPS compliance plans.

5. LOAD FORECASTS AND PEAK DEMAND

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

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

Table 2 illustrates the systemwide average annual growth rates in energy sales and peak loads anticipated by Progress, Duke, and VEPCO. These growth rates are based on the utilities' system peak load requirements. Detailed load projections for the respective utilities are shown in Appendices 2, 3, and 4.

Table 2: Forecast Annual Growth Rates for Progress, Duke, and VEPCO (After Energy Efficiency (EE) and Demand-Side Management (DSM) are Included) (2017– 2031)

	Summer Peak	Winter Peak	Energy Sales
Progress	1.0%	1.2%	0.9%
Duke	1.1%	1.3%	1.0%
VEPCO	1.5%	1.3%	1.5%

North Carolina utility forecasts of future peak demand growth rates are in the range of forecasts for the southeast as a whole. The 2016 Long-Term Reliability Assessment by the North American Electric Reliability Corporation (NERC) indicates a forecast of average annual growth in peak demand of approximately 1.1% through 2026.

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

Table 3: Summer and Winter Systemwide Peak Loads for Progress, Duke, and VEPCO Since 2012 (in MW)

	Progress		Duke		VEPCO	
	Summer	Winter*	Summer	Winter*	Summer	Winter*
2012	13,193	12,523	19,473	16,698	19,249	17,623
2013	12,404	14,215	18,239	20,799	18,763	19,785
2014	12,364	15,569	18,993	21,101	18,692	21,651
2015	12,849	13,298	20,003	19,377	18,980	18,948
2016	13,130	14,534	20,671	19183	19,538	19,661

**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, renewable purchases now make up a small percentage of summer load resources. Generating plants are usually classified by fuel type (nuclear, coal, gas/oil, hydro, renewable, etc.) and placed into three categories based on operational characteristics:

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

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

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

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

VEPCO operates two nuclear power stations with two units each. Both stations are located in Virginia. All four units have been issued license extensions by the NRC. The new license expiration dates range from 2032 to 2040.

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

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

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

Another type of non-utility generation is power generated by merchant plants. A merchant plant is an electric generating facility that sells energy on the open market. It is often constructed without a native load obligation, a firm long-term contract, or any other assurance that it will have a market for its power. These generating plants are generally sited in areas where the owners see a future need for an electric generating facility, often near a natural gas pipeline, and are owned by developers willing to assume the economic risk associated with the facility's construction.

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

Table 4: Installed Utility-Owned Generating Capacity by Fuel Type (Summer Ratings) for 2016

	Progress	Duke	VEPCO
Coal	28%	32%	22%
Nuclear	27%	33%	17%
Hydroelectric	2%	15%	11%
Natural Gas and Oil	43%	20%	49%
Non-Hydro Renewable	0%	0%	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 2016, is provided in Table 5.

Table 5: Total Energy Resources by Fuel Type for 2016

	Progress	Duke	VEPCO
Coal	16%	27%	25%
Nuclear	41%	48%	32%
Net Hydroelectric*	1%	1%	1%
Natural Gas and Oil	32%	13%	33%
Non-Hydro Renewable	4%	1%	2%
Other Purchased Power	6%	10%	7%

* See the paragraph on pumped storage in this section.

The Commission recognizes the need for a mix of baseload, intermediate, and peaking facilities and believes that conservation, energy efficiency, peak-load management, and renewable energy resources must all play a significant role in meeting the capacity and energy needs of each utility. In addition, the EPA's Clean Power Plan (CPP) continues to influence the development of the resource plans. While the CPP was stayed by the U.S. Supreme Court in 2016, each company continues to plan for a range of carbon dioxide (CO2) legislative outcomes assuming some level of carbon emission restrictions consistent with the CPP. The following highlights from utility generation planning exercises reflect information contained in the 2017 Integrated Resource Plan updates filed with the Commission.

Progress Generation

As of August 2017, Progress had 13,980 MW of installed generating capacity (winter rating). This does not include purchases and non-utility owned capacity.

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

As part of the Western Carolinas Modernization Project (WCMP), the combined 384 MW Asheville 1 and 2 coal units are planned to be retired by 2020. The retired units are expected to be replaced with two 280 MW natural gas combined-cycle (CC) units. Additionally, an undetermined amount of solar generation is planned for installation at the same site. The application for a Certificate of Public Convenience and Necessity (CPCN) for the new CC units was filed with the Commission in January 2016 and subsequently approved in March 2016.

Other capacity additions include:

- Planned nuclear uprates totaling 44 MW in 2017 through 2027.
- Addition of 100 MW Sutton Blackstart combustion turbines in Wilmington in 2017.
- Addition of 3,846 MW of combined-cycle capacity in 2022 through 2030.
- Addition of 44 MW of cogeneration in 2021 through 2022.
- Addition of 235 MW of combustion turbine capacity in 2027.

Other planned retirements include:

- Sutton combustion turbine units in 2017 (64 MW).
- Darlington combustion turbine units by 2020 (580 MW).
- Blewett combustion turbine units and Weatherspoon combustion turbine units in 2027 (232 MW).

- Planning assumptions for nuclear stations assume retirement at the end of their current license extension including Robinson 2 in 2030 (797 MW).

The ultimate timing of unit retirements can be influenced by factors that impact the economics of continued unit operations. Such factors include changes in relative fuel prices, operations and maintenance costs and the costs associated with compliance of evolving environmental regulations. As such, unit retirement schedules are expected to change over time as market conditions change.

Duke Generation

As of July 2017, Duke had 22,344 MW of installed generating capacity (winter rating), excluding purchases and non-utility owned capacity. That total includes generation jointly-owned with NCMPA1, NCEMC, and Piedmont Municipal Power Agency produced at Duke's Catawba Nuclear Facility in South Carolina.

As shown in recent Duke IRP plans, a capacity need has been identified in 2017/2018. In an Order dated May 2, 2014, the Company received a Certificate of Environmental Compatibility and Public Convenience and Necessity (CECPCN) from the Public Service Commission of South Carolina to build the Lee combined-cycle plant (Lee CC) at the Lee Steam Station site located in Anderson, S.C. The Lee CC facility is projected to be available by the end of 2017 at a capacity of 683 MW. This is the Duke capacity net of 100 MW to be owned by NCEMC.

Duke continues to evaluate utility-owned solar additions to support its compliance targets and operational flexibility. Duke has two new utility-scale solar projects under construction which will be available for the summer peak of 2017. These are Monroe Solar Facility (60 MW in Union County) and Mocksville Solar Facility (15 MW in Davie County).

Duke received the Combined Construction and Operating License (COL) for the W.S. Lee Nuclear Station (Lee Nuclear) on December 19, 2016. On August 25, 2017, Duke filed a request to cancel the Lee Nuclear Project as that project was originally envisioned and included in prior IRPs. That request is pending before the North Carolina Utilities Commission.

Other capacity additions include:

- Addition of 16 MW Hydro refurbishment in 2018 through 2019.
- Addition of 86 MW of cogeneration in 2019 through 2022.
- Addition of 186 MW Bad Creek pumped storage uprates in 2020 through 2023.
- Addition of 2,564 MW of combined-cycle capacity in 2024 through 2028.
- Addition of 402 MW of combustion turbine resources in 2024 at Lincoln County.
- Addition of 1,117 MW of nuclear in 2031.

Retirements include:

- Allen coal units 1-3 (604 MW) and units 4-5 (526 MW) in 2024 and 2028, respectively.

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

VEPCO Generation

As of May 2017, VEPCO had 20,768 MW of installed generating capacity (winter rating). This excludes purchases and non-utility capacity. Of this total, only 480 MW is located in North Carolina.

VEPCO issued a Request for Proposals (RFP) on November 3, 2014, for up to approximately 1,600 MW of new or existing intermediate or baseload dispatchable generation. The RFP requested purchase power agreements (PPA) with a term of 10 to 20 years, commencing in the 2019/2020 timeframe. Multiple proposals were received and evaluated. The Company's self-build 1,585 MW CC in Greensville County, Virginia provided superior customer benefits compared to all other options. The application for the Greensville County certificate of public convenience and necessity (CPCN) was filed with the State Corporation Commission of Virginia (SCC) on July 1, 2015 and approved March 2016. The combined cycle plant is expected to be online in 2019.

The Company obtained a Combined Operating License (COL) from the NRC in June 2017 to support a new nuclear unit, North Anna 3, at its existing North Anna Power Station located in Louisa County in central Virginia. However, the Company suspended development work while looking for the point at which it will be an economically viable project for its customers..

The Company continues to pursue offshore wind development in a prudent manner for its customers and for the state's economic development. Offshore wind has the potential to provide a reliable renewable resource if it can be achieved at reasonable cost to customers. To help determine how this can be accomplished, the Company is involved in two active projects: 1) VOWTAP and 2) commercial development in the Virginia Wind Energy Area, both of which are located approximately 27 miles off the coast of Virginia.

Other capacity additions include:

- Addition of 1,374 MW of combustion turbine resources through 2032.

Based on the current and anticipated environmental regulations along with current market conditions, Yorktown Units 1 (159 MW) and 2 (164 MW) ceased operations on April 15, 2017 to comply with the Mercury and Air Toxics Standards (MATS) rule.

Currently under evaluation is the potential retirement of Yorktown Unit 3 in 2022 (790 MW of oil-fired generation). Also under evaluation are the retirements of Chesterfield Units 3 (98 MW) and 4 (163 MW) each modeled for retirement by 2022.

7. RELIABILITY AND RESERVE MARGINS

An electric system's reliability is its ability to continuously supply all of the demands of its consumers with a minimum interruption of service. It is also the ability of an electric system to withstand sudden disturbances, such as short circuits or sudden loss of system components due to scheduled or unscheduled outages. The reliability of an electric system is a function of the number, size, fuel type, and age of the utility's power plants; the different types and numbers of interconnections the utility has with neighboring electric utilities; and the environment to which its distribution and transmission systems are exposed.

There are several measurements of reliability utilized in the electric utility industry. Generally, they are divided between probabilistic measures (loss of load probability and the frequency and duration of outages) and non-probabilistic measures (reserve margin and capacity margin). One of the most widely used measures is the reserve margin.

The reserve margin is the ratio of reserve capacity to actual needed capacity (i.e., peak load). It is an indicator of the ability of an electric utility system to continue to operate despite the loss of a large block of capacity (generating unit outage and/or loss of a transmission line), deratings of generating units in operation, or actual load exceeding forecast load. A similar indicator is capacity margin, which is the ratio of reserve capacity to total overall capacity (i.e., reserve capacity plus actual needed capacity). Although reserve margin was the exclusive industry standard term for many years, capacity margin has also been widely used in recent years. This report continues to utilize reserve margin terminology.

It is difficult, if not impossible, to plan for major generating capacity additions in such a manner that constant reserve margins are maintained. Reserve margins will generally be lower just prior to placing new generating units into service and greater just after new generating units come online.

Some years ago, a 20% reserve margin was considered appropriate for long-range planning purposes. In recent years, the Commission has approved IRPs containing reserve margins lower than 20%. Adequate reliability can be preserved despite these lower reserve margins because of the increased availability of emergency power supplies from the interconnection of electric power systems across the country, the increasing efficiency with which existing generating units have been operated, and the relative size of utility generating units compared to overall load. The reserve margins currently projected by each IOU are shown in Table 6.

Table 6: Projected Winter Reserve Margins for Progress, Duke, and Summer for VEPCO (2017-2031, after DSM)

	Reserve Margins
Progress	17.0% – 26.0%
Duke	17.0% – 22.0%
VEPCO	13.0% – 23.0%[1]

[1] Dominion is a PJM member and signatory to PJM's Reliability Assurance Agreement. The Company is obligated to maintain a reserve margin (12.46%) for its portion of the PJM coincident peak load. Also, the Company participates in PJM's capacity auction which results in short-term reserves in excess of the target level.

While coal and nuclear continue to remain the most widely used fuels in our area, most of the generation facilities constructed in recent years use natural gas as their primary fuel. With relatively low fuel costs and short construction lead times, natural gas generating units are efficient and produce relatively low emissions. Fuel deliverability, however, is a concern because of the nature of the infrastructure that delivers natural gas to the generating stations. North Carolina 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 provide limited volumes, only Transco crosses the State generally along the I-85 corridor, which means that long intrastate lines must be built to serve generating plants in other parts of the State.

Transco historically delivered gas up from the Gulf Coast. Transco is expanding its system to bring shale gas to the State from the north. In addition, four major U.S. energy companies (Dominion, Duke Energy, Piedmont Natural Gas and AGL Resources) formed a joint venture – Atlantic Coast Pipeline (ACP) - to build and own a new large pipeline into North Carolina to serve both gas and electric generation customers. ACP will come down along the I-95 corridor and will bring shale gas from the north and provide a better interstate pipeline footprint in the State. ACP was scheduled to come on line in November 2018, but has been delayed until the second half of 2019.

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 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 2015, requiring investor-owned utilities to meet 6% of their NC retail sales renewable and EE sources. 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, 2017, the Commission submitted its 10th Annual Report Regarding Renewable Energy and Energy Efficiency Portfolio Standard in North Carolina required pursuant to G.S. 62-133.8. The report details Commission implementation of the REPS Statute since its enactment in 2007. As described in more detail below, the report concluded that all of the electric power suppliers have met the 2012-2016 general REPS requirements and the solar resource requirements, and appear on track to meet those requirements in 2017. Although the electric power suppliers also met the modified poultry waste resource requirements in 2016, most electric suppliers could not meet the swine waste resource requirements despite making reasonable efforts to do so. Again, that prompted the Commission in 2017 to delay the swine waste resource requirements and to modify the poultry waste requirements. The report is available on the Commission's web site, www.ncuc.net.

Renewable Energy and Energy Efficiency Portfolio Standard (REPS) Compliance

As described above, each electric power supplier serving retail customers in the State is subject to the REPS requirements, including the specific requirements for producing or purchasing electricity from solar, swine, and poultry waste resources. In 2015, the general REPS requirement increased to 6% of 2014 NC retail sales and the solar resource requirement increased to 0.14% of NC retail sales. In 2017, the Commission maintained the current modified statewide aggregate poultry waste resource requirement at 170,000 MWh, and the swine waste resource requirement was again delayed.

The Commission monitors compliance with the REPS requirements through each electric power supplier's annual filing of a compliance report and compliance plan. The compliance report looks back at the previous year and provides details on the electric power supplier's compliance efforts. The compliance plan is a forward-looking forecast of an electric power supplier's REPS requirements and its plan for meeting those requirements. When the Commission concludes its review of each electric power supplier's REPS compliance report, the associated RECs are permanently retired. In addition, the Commission holds annual proceedings to consider approval of a REPS rider for each electric public utility, allowing for recovery of REPS compliance costs subject to the annual per account limits in G.S. 62-133.8(h) (cost caps).

As described in the Commission's October 1, 2017 report, the electric power suppliers met the 2012-2016 general REPS requirements and the solar resource requirements, and appear on track to meet those requirements in 2017. Although the electric power suppliers also met the modified poultry waste resource requirements in 2016, most electric suppliers could not meet the swine waste resource requirements despite making reasonable efforts to do so. On August 25, 2017, in Docket No. E-7, Sub 1131, the Commission issued an Order approving Duke's 2016 compliance report and retiring the RECs in Duke's 2016 compliance sub-account. On December 20, 2016, in Docket No. E-22, Sub 535, the Commission issued an order approving Dominion's 2015 compliance report and retiring the RECs in Dominion's compliance sub-account. On January 17, 2017, in Docket No. E-2, Sub 1109, the Commission issued an order approving DEP's 2015 REPS compliance report. The EMCs and Municipalities, filed their 2015 REPS compliance reports and 2016 REPS compliance plans in Docket No. E-100, Sub 149. On June 14, 2017, the Commission issued an order in that docket approving the reports filed by the EMCs and Municipalities, with the exception of Halifax EMC. The Commission required Halifax to provide additional information on its REPS compliance report, and approval of Halifax's report is pending before the Commission. The EMCs and Municipalities filed their 2016 REPS compliance reports and 2017 REPS compliance plans in Docket No. E-100, Sub 152. The Commission has requested comments on these reports and plans, but the EMCs and Municipalities appear to be on track to meet the REPS requirements within the cost limits.

On October 16, 2017, in Docket No. E-100, Sub 113, the Commission issued an Order Modifying the Swine and Poultry Waste Set-Aside Requirements and Providing Other Relief, delaying the swine waste resource requirements by one year and modifying the poultry waste resource requirement by maintaining the current requirement that the electric power suppliers, in the aggregate, produce 170,000 MWh from poultry waste resources and delaying scheduled increases in that requirement. That Order represents the sixth time that the Commission has taken similar action since enactment of the REPS statute. In that Order, the Commission found that the electric power suppliers made a reasonable effort to comply with the 2017 swine and poultry waste requirements but will not be able to do so. The inability to meet these requirements is largely due to the fact that the technology of power production from animal waste, particularly, swine waste continues to be in its early stages of development. The Commission's Order continued to require electric power suppliers to participate in semiannual reporting and stakeholder meetings, and noted encouraging developments that could allow compliance in future years.

Energy Efficiency

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

NC GreenPower

Founded in 2003, NC GreenPower was launched as a voluntary program to supplement the state's existing power supply with more green energy – electricity generated from renewable energy sources like the sun, wind, water, and organic matter. NC GreenPower is a nonprofit improving our state's environment not only by supporting renewable energy, but also carbon offset projects and by providing grants for solar installations at North Carolina K-12 schools.

NC GreenPower announced on April 1, 2015 a new pilot program to provide matching grants for the installation of solar photovoltaic (PV) arrays at schools, providing them with clean, green renewable energy. NC GreenPower will divert a portion of its current donations to help North Carolina K-12 schools acquire a solar PV system. The NC GreenPower Solar Schools pilot gives teachers valuable tools to educate students about renewable energy. Currently in its third year, the pilot program has recently awarded five schools in 2017 with a solar PV array, monitoring equipment and curriculum for educators. In addition, the State Employees' Credit Union (SECU) members via the SECU Foundation will provide a total investment of up to $140,000 for the pilot program, awarding a $10,000 matching challenge grant to 14 K-12 public schools that meet NC GreenPower's program requirements for the installation of a pole-mounted solar PV system on school campuses. The Foundation's matching challenge grant will increase each school's solar array to a 5 kW system. Year one of the pilot successfully funded four schools with grants to install solar PV systems and year two awarded five schools. By the end of this year, NC GreenPower will have brought solar education to nearly 10,000 students statewide.

On September 20, 2016, Duke Energy Carolinas announced that it will provide $300,000 to NC GreenPower for "Schools Going Solar," which aims to provide 100% of the cost of solar installations for up to 10 schools in its North Carolina service territory. NC GreenPower is administering the program in conjunction with and in addition to its statewide Solar Schools pilot program. Installations will start later this year and continue into 2018 for the seven schools who have been awarded the funds.

Contributions to NC GreenPower continue to help support the generation of green energy and reduction of greenhouse gases but also help to provide 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 utility bill or directly to NC GreenPower on its website: www.ncgreenpower.org. All current projects are located within North Carolina. NC GreenPower is a 501(c)(3) nonprofit organization.

9. TRANSMISSION AND GENERATION INTERCONNECTION ISSUES

Transmission Planning

The North Carolina Transmission Planning Collaborative (NCTPC) was established in 2005. Participants (transmission-owning utilities, such as Duke and Progress, and transmission-dependent utilities, such as municipal electric systems and EMCs) identify the electric transmission projects that are needed to be built for reliability and estimate the costs of those upgrades. The NCTPC's January 14, 2016 report stated that 8 major (greater than $10 million each) transmission projects are needed in North Carolina by the end of 2025 at an estimated cost of $156 million. In July 2016, the NCTPC issued a report updating the 2015 Collaborative Plan indicating that the total cost estimate of the 2015 Reliability Projects has changed from $156 million to $144 million due to the removal of one project and reduced project costs for five other projects. Two new projects were added to the 2016 Plan to accommodate two open access transmission tariff (OATT) generator interconnections requests. For more information, visit the NCTPC's website at www.nctpc.net/nctpc.

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

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

State Generator Interconnection Standards

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

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

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

In 2007 as part of REPS legislation codified at 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's Order required regulated utilities to update any affected rate schedules, tariffs, riders, and service regulations to conform with the revised standard.

The Commission issued an Order Approving Revised Interconnection Standard on May 15, 2015. That Order made substantial changes to the procedures for requesting to interconnect a generator to the electric grid. Most of these changes were recommended by the stakeholders with the intent of addressing a back-log of interconnection requests. The more significant changes in the State's interconnection standards were: 1) a project's ability to be expedited is now based not only on the project's size, but also on the size of the line it would connect to, and its distance from a substation; 2) a new process for addressing "interdependent" projects was added, where one generator needs to decide whether it is going to move ahead in order for the utility to determine that capacity exists to interconnect a second generator; 3) developers must provide a deposit of at least $20,000; 4) developers must demonstrate that they have site control; and 5) developers must pay for upgrades before the utility begins construction. The utilities are required to file a quarterly report to the Commission reporting on their progress in addressing the interconnection queue backlog. The Public Staff is to convene a workgroup of interested parties on or before May 2017 to discuss whether the State's small generator interconnection standards require additional revisions.

The Public Staff convened an initial planning meeting for the stakeholder process on May 9, 2017, followed by larger stakeholder meetings on June 1, July 14, August 8, and September 6, 2017. The Public Staff will submit a report on the stakeholder process on December 15, 2017.

As of September 30, 2017, a combined total of 3,217 MW of renewable generation resources was included in DEC and DEP's interconnection queues with 3,177 MW of that total being solar. Dominion had 204 MW of solar capacity in the N.C. interconnection queue as of October 31, 2017.

Net Metering

"Net metering" refers to a billing arrangement whereby a customer that owns and operates an electric generating facility is billed according to the difference over a billing period between the amount of energy the customer consumes and the amount of energy it generates. As part of REPS legislation, codified at G.S. 62.133.8(i)(6), the General Assembly required the Commission to consider whether it is in the public interest to adopt rules for electric public utilities for net metering of renewable energy facilities with a generation capacity of one megawatt or less.

On March 31, 2009, in Docket No. E-100, Sub 83, following hearings on its then-current net metering rule, the Commission issued an Order requiring Duke, Progress, and Dominion to file revised riders or tariffs that allow net metering for any customer that owns and operates a renewable energy facility that generates electricity with a capacity of up to one megawatt. The customer shall be required to interconnect pursuant to the approved generator interconnection standard, which includes provisions regarding the study and implementation of any improvements to the utility's electric system required to accommodate the customer's generation, and to operate in parallel with the utility's electric distribution system. The customer may elect to take retail electric service pursuant to any rate schedule available to other customers in the same rate class and may not be assessed any standby, capacity, metering, or other fees other than those approved for all customers on the same rate schedule. Standby charges shall be waived, however, for any net-metered residential customer with electric generating capacity up to 20 kW and any net-metered non-residential customer up to 100 kW. Credit for excess electricity generated during a monthly billing period shall be carried forward to the following monthly billing period, but shall be granted to the utility at no charge and the credit balance reset to zero at the beginning of each summer billing season. If the customer elects to take retail electric service pursuant to any time-of-use (TOU) rate schedule, excess on-peak generation shall first be applied to offset on peak consumption and excess off-peak generation to offset off-peak consumption; any remaining on-peak generation shall then be applied against any remaining off-peak consumption. If the customer chooses to take retail electric service pursuant to a TOU demand rate schedule, it shall retain ownership of all RECs associated with its electric generation. If the customer chooses to take retail electric service pursuant to any other rate schedule, RECs associated with all electric generation by the facility shall be assigned to the utility as part of the net-metering arrangement. Since the Commission's March 31, 2009 Order, the Commission has not altered the substantive net-metering policy for the State's electric public utilities.

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 North Carolina Utilities 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. That request was granted 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).

Transmission Rate Filings

In 2010, the Commission and the Public Staff jointly intervened in a Dominion transmission rate case before the FERC, arguing that some transmission costs should not be passed on to all transmission customers. Specifically, the Commission and the Public Staff argued that North Carolina citizens should not be required to pay the incremental cost of undergrounding several electric transmission lines located in Virginia when viable, less-costly overhead options were available. FERC agreed that it was unjust and unreasonable for wholesale transmission customers with loads outside Virginia to be allocated the incremental costs of undergrounding these projects and ordered a hearing and settlement judge procedures to establish the specific dollar values that should be excluded from wholesale transmission rates. Subsequently an administrative law judge issued his initial decision on February 16, 2016, determining the amount of the incremental costs of undergrounding certain projects and requiring Dominion to refund certain Virginia customers and North Carolina customers this incremental cost that has been paid. On October 19, 2017, FERC approved this decision and directed Dominion to pay refunds back to March 17, 2010.

Cyber Security

Federal and State regulators are increasingly concerned about cyber security and physical threats to the nation's bulk power system. Cyber security threats may be posed by foreign nations or others intent on undermining the United States' electric grid. North Carolina's utilities are working to comply with federal standards that require them to identify critical components of their infrastructure and install additional protections from cyberattacks. The NC Utilities Commission meets with utility officials periodically to understand the cyber threats the utilities are facing and the actions they are taking to address these threats.

Physical Security

In April of 2013 a substation near San Jose, California, sustained a well-planned attack during which firearms were used to severely damage electric equipment. In response to this and other incidents, the FERC on March 7, 2014, required NERC to develop new reliability standards that would require each owner and operator of the bulk electric system to perform a risk assessment of its systems to identify critical facilities; evaluate potential threats to, and vulnerabilities of those facilities; and develop and implement a security plan to protect against attacks on those facilities. NERC developed Reliability Standard CIP-014-2 (effective 10/2/2015) to identify and protect transmission stations and transmission substations, and their associated primary control centers that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation or cascading within an interconnection. In addition, the determination was made that it was not necessary to include generator operators and generator owners in the Reliability Standard.

EPA's Proposal to Regulate Carbon Emissions From Existing Power Plants

On August 3, 2015, the U.S. Environmental Protection Agency (EPA) finalized regulations for reducing CO_2 emissions from existing power plants, relying on authority from the Clean Air Act. These regulations establish CO_2 emission levels for existing power plants in each State based upon three "building blocks": (1) altering coal-fired power plants to increase their efficiency; (2) substituting natural gas combined cycle generation for generation from coal; and (3) substituting generation from low or zero-carbon energy generation, such as wind and solar, for generation from fossil fuels. On October 23, 2015, the EPA published its final Clean Power Plan (CPP) rule to regulate emissions of greenhouse gases, specifically carbon dioxide from existing fossil fuel-fired power plants.

In North Carolina, the Department of Environmental Quality (NCDEQ) is the lead agency for compliance with the Clean Air Act. NCDEQ joined with 24 other like states to petition the US Court of Appeals for a stay of the regulations, as well as expedited consideration of a petition for review of those regulations. These states argue that EPA over-stepped its authority in promulgating the rules, that EPA lacks expertise and authority to regulate the energy grid, and that these states will experience irreparable harm if they must begin to comply with the regulations pending the outcome of legal challenges. The outcome of this litigation, and the ultimate disposition of federal CO_2 controls, could have a major impact on the electric generation fleet, reliability of service, and electricity prices in North Carolina. On February 9, 2016, the U.S. Supreme Court placed a “stay” on EPA’s implementation of the rule, until an appeals court can consider its legality. The case was argued before the D.C. Circuit Court of Appeals on September 27, 2016, and remains pending.

On March, 28, 2017, President Trump issued an Executive Order establishing a national policy in favor of energy independence, economic growth, and the rule of law. The purpose of that Executive Order is to facilitate the development of U.S. energy resources and to reduce unnecessary regulatory burdens associated with the development of those resources. Pursuant to the Executive Order, EPA initiated its review of the CPP. EPA will be reviewing the compliance dates that were set in the CPP. Under the Supreme Court’s stay of the CPP, states and other interested parties have not been required nor expected to work toward the compliance dates set in the CPP.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 147

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of 2016 Biennial Integrated Resource Plans and Related 2016 REPS Compliance Plans	))))	ORDER ACCEPTING INTEGRATED RESOURCE PLANS AND ACCEPTING REPS COMPLIANCE PLANS

HEARD: Monday, February 27, 2017, at 7:00 p.m. in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding, and Commissioners Bryan E. Beatty, ToNola D. Brown-Bland, Don M. Bailey, James G. Patterson, and Lyons Gray.

APPEARANCES:

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

E. Brett Breitschwerdt, McGuireWoods LLP, 434 S. Fayetteville Street, Suite 2600, Raleigh, North Carolina 27601

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

Lawrence B. Somers, Deputy General Counsel, Duke Energy Corporation, NCRH 20/P.O. Box 1551, Raleigh, North Carolina 27602

For North Carolina Waste Awareness & Reduction Network:

John D. Runkle, 2121 Damascus Church Road, Chapel Hill, North Carolina 27516

For Southern Environmental Law Center:

Nadia Luhr, Southern Environmental Law Center, 601 West Rosemary Street, Suite 220, Chapel Hill, North Carolina 27516

For the Using and Consuming Public:

> Lucy Edmondson, Staff Attorney, and Heather Finnell, Staff Attorney, Public Staff-North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

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

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

G.S. 62-2(a)(3a) declares it a policy of the State to:

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

Session Law (S.L.) 2007-397 (Senate Bill 3), signed into law on August 20, 2007, amended G.S. 62-2(a) to add subsection (a)(10) that provides that it is the policy of North Carolina "to promote the development of renewable energy and energy efficiency through the implementation of a Renewable Energy and Energy Efficiency

Portfolio Standard (REPS)" that will: (1) diversify the resources used to reliably meet the energy needs of North Carolina's consumers, (2) provide greater energy security through the use of indigenous energy resources available in North Carolina, (3) encourage private investment in renewable energy and energy efficiency, and (4) provide improved air quality and other benefits to the citizens of North Carolina. To that end, Senate Bill 3 further provides that "[e]ach electric power supplier to which G.S. 62-110.1 applies shall include an assessment of demand-side management and energy efficiency in its resource plans submitted to the Commission and shall submit cost-effective demand-side management and energy efficiency options that require incentives to the Commission for approval."[1]

Senate Bill 3 also defines demand-side management (DSM) as "activities, programs, or initiatives undertaken by an electric power supplier or its customers to shift the timing of electric use from peak to nonpeak demand periods" and defines an energy efficiency (EE) measure as "an equipment, physical or program change implemented after 1 January 2007 that results in less energy being used to perform the same function."[2] Energy Efficiency measures do not include DSM.

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

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

Within 150 days after the filing of each utility's biennial report and within 60 days after the filing of each utility's annual report, the Public Staff or any other intervenor may file its own plan or an evaluation of, or comments on, the utilities' biennial and annual reports. Furthermore, the Public Staff or any other intervenor may identify any issue that

[1] G.S. 62-133.9(c).

[2] G.S. 62-133.8(a)(2) and (4).

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

it believes should be the subject of an evidentiary hearing. The Commission must schedule one or more hearings to receive public testimony.

2016 BIENNIAL REPORTS

This Order addresses the 2016 biennial reports (2016 IRPs) filed in Docket No. E-100, Sub 147, by Duke Energy Progress, LLC (DEP); Duke Energy Carolinas, LLC (DEC); and Dominion North Carolina Power (DNCP) (collectively, the investor-owned utilities, utilities or IOUs). In addition, this Order also addresses the REPS compliance plans filed by the IOUs.

The following parties have been allowed to intervene in this docket: Alevo USA, Inc. (Alevo); Carolina Industrial Group for Fair Utility Rates I, II, and III (CIGFUR); Carolina Utility Customers Association, Inc. (CUCA); Environmental Defense Fund (EDF); Grant Millin; Mid-Atlantic Renewable Energy Coalition (MAREC); North Carolina Sustainable Energy Association (NCSEA); North Carolina Waste Awareness and Reduction Network (NC WARN); Nucor Steel-Hertford (Nucor); and jointly, Southern Alliance for Clean Energy, Sierra Club, and the Natural Resources Defense Council (SACE, NRDC, and the Sierra Club). The Public Staff's intervention is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e). The Attorney General's intervention is recognized pursuant to G.S. 62-20.

PROCEDURAL HISTORY

On April 29, 2016, DNCP filed its 2016 biennial IRP report and REPS compliance plan. DEC and DEP (collectively, Duke) filed their 2016 biennial IRP reports and REPS compliance plans on September 1, 2016.

On June 22, 2016, DNCP filed corrected pages to its IRP report.

On September 30, 2016, DEC and DEP filed corrected pages to their IRP reports.

On December 16, 2016, the Commission issued an Order Scheduling Public Hearing on 2016 IRP Plans and Related 2016 REPS Compliance Plans. That Order set the public witness hearing for 7:00 p.m. on February 27, 2017, in Raleigh.

On January 19, 2017, the Public Staff filed a motion for extension of time for the filing for petitions to intervene and initial comments to February 17, 2017, and the final date for serving discovery requests to January 24, 2017. The Commission granted this motion on January 20, 2017.

On January 19, 2017, DEC and DEP filed corrections to their 2016 REPS Compliance Plans.

On February 16, 2017, DEC and DEP filed late testimony on natural gas issues.

On February 17, 2017, initial comments were filed by the Public Staff, Grant Millin, NC WARN, NCSEA, MAREC, and jointly by SACE, NRDC and the Sierra Club.

On February 20, 2017, SACE, NRDC and the Sierra Club jointly filed Attachments A&B to their initial comments.

On February 22, 2017, the Public Staff filed an update to its February 17, 2017 comments regarding the DSM activations of DNCP.

On February 27, 2017, the public witness hearing was held in Raleigh, as scheduled.

On March 10, 2017, DEP filed notice that Sutton CT 1 was retired effective March 1, 2017, rather than in June 2017, as included in its IRP.

On April 17, 2017, NC WARN filed reply comments addressing DEC and DEP's late-filed testimony on natural gas issues.

On May 10, 2017, SACE, NRDC and the Sierra Club jointly filed reply comments, including the report "Duke Energy's Resource Plans for the Carolinas: Supplemental Analysis." Also on May 10, 2017, SACE, NRDC and the Sierra Club jointly filed a corrected version of Attachment D to its initial comments.

On May 10, 2017, reply comments were filed by DNCP and jointly by DEC and DEP.

PUBLIC HEARING

Pursuant to G.S. 62-110.1(c) the Commission held a public hearing in Raleigh on Monday, February 27, 2017, at 7:00 p.m., where 32 public witnesses spoke. In summary, the testimonies of the public witnesses focused on the need to encourage energy efficiency and clean renewable resources, such as solar and wind. A few of the witnesses commented on the value of integrating batteries, and other storage technologies, with the utilities' distributed resources. In addition, the witnesses encouraged the Commission to promote an economy and energy future focused on renewables and distributed energy systems. For example, one witness testified that the utilities are planning to build too much unnecessary and unjustified capacity without first maximizing clean energy and energy efficiency that has known benefits for clean air, clean water, and reduced cost for consumers. Other witnesses contended that coal and gas perpetuate climate issues because of greenhouse gas emissions, and further, that the utilities should stop investing in hydraulic fracked gas infrastructure, including the Atlantic Coast Pipeline.

DISCUSSION

The Commission finds and concludes that the record in this proceeding includes sufficient detail to allow the Commission to decide all contested issues without the necessity of a further hearing. The Commission commends the utilities and intervenors for the quality of presentation and analyses. The following sections summarize issues significant to the Integrated Resource Plans filed by the utilities and reflect the full record in the proceeding.

PEAK AND ENERGY FORECASTS

Public Staff Comments - Peak and Energy Forecasts

The Public Staff reviewed the 15-year peak and energy forecasts (2017–31) of DEP, DEC, and DNCP. The compound annual growth rates (CAGRs) for the forecasts are within the range of 0.9% to 1.5%. The Public Staff noted that all of the utilities used accepted econometric and end-use analytical models to forecast their peak and energy needs. They commented that with any forecasting methodology, there is a degree of uncertainty associated with models that rely, in part, on assumptions that certain historical trends or relationships will continue in the future.

In assessing the reasonableness of the forecasts, the Public Staff first compared the utilities' most recent weather-normalized peak loads to those forecasted in their 2015 IRP updates. The Public Staff then analyzed the accuracy of the utilities' peak demand and energy sales predictions in their 2009 IRPs by comparing them to their actual peak demands and energy sales. They commented that a review of past forecast errors can identify trends in the IOUs' forecasting and assist in assessing the reasonableness of the utilities' current and future forecasts. Finally, according to the Public Staff's comments, they reviewed the forecasts of other adjoining utilities in the VACAR region and the SERC Reliability Corporation.

The Public Staff commented that for the last 30 years, all three utilities predicted that their system peaks would occur in the summer. However, during January 2014, the IOUs reported several hourly peak loads that were greater than the summer peak loads that occurred later that year. In February 2015, DEC, DEP, and DNCP experienced all time system peaks. Following these events, DEC and DEP conducted a new resource adequacy study (reserve margin study) in 2015 and 2016, which was included with their 2016 IRPs. DEP and DEC's 2016 IRPs now forecast that the utilities are transitioning to winter peaking systems, with DEP turning winter peaking in 2017, and DEC becoming winter peaking in 2027. The Public Staff goes on to note that DNCP continues to predict that it will be a summer peaking system. In addition, SERC is reporting that its VACAR-South[4] (Carolinas region) winter peak after EE programs will exceed the summer peak until 2018, at which time the summer peak becomes dominant through 2025.

[4] 2016 SERC Regional Electricity Supply and Demand Projections, http://serc1.org/docs/default-source/committee/ec-reliability-review-subcommittee//rrs-annual-report/2016-regional-supply-and-demand-projections.pdf?sfvrsn=2.

The Public Staff commented that in the 1980s a series of extremely cold winter days caused several winter peaks to be greater than the following summer peaks. This pattern was relatively short-lived, however, and the summer peaks returned to being the system peaks. The abnormally cold winter weather events in recent years and customers' responses to these temperatures have contributed to a sharp growth in winter electricity demands that lends support to the expectation that DEP and DEC may be transitioning towards becoming dual peaking or winter peaking systems. The Public Staff suggests, however, that caution is warranted before making conclusions on this trend.

According to the Public Staff, it is becoming apparent that both summer and winter peak demands have distinct impacts on the operation of the utility systems. Planning decisions going forward will need to evaluate how the IOUs respond to the unique characteristics of seasonal peak demands. The Public Staff notes that each IOU has attempted to independently address their winter and summer peak demands, in part by planning for future resources that can accommodate both winter and summer peak demand loads, as well as the energy requirements of its customers throughout the year.

Public Staff Comments - DEP's Peak and Energy Forecasts

The Public Staff commented that unlike previous years, DEP no longer considers its summer peak to be its system peak. DEP's 2016 IRP predicts its summer peak loads will have a lower Compound Annual Growth Rate (CAGR) of 1.0% as compared to the 1.2% CAGR of the winter peaks that include load reductions associated with projected EE programs and prior to the activation of any DSM programs. DEP's 2014 and 2012 IRPs predicted that its summer peaks would grow at a CAGR of 1.3% and 0.9%, respectively. Without the reduction in peak demand from implementation of its EE programs, DEP expects its summer peaks to grow at an average rate of 1.3%. DEP predicts that in 15 years, the load reductions from its cumulative new EE programs will reduce its annual summer peak load by approximately 7%, which is similar to its projection in its 2014 IRP. DEP assumes that it can actively reduce its summer peak load by using its DSM resources, which it considers a capacity resource.

DEP's forecast of its winter peak loads reflects a slightly higher CAGR of 1.2% than the CAGR of 1.0% for its summer peaks, with the annual difference in the seasonal peaks of approximately 200 MW. DEP predicts that in 15 years, the load reductions from its cumulative new EE programs will reduce its annual winter peak load by approximately 3% in 2031, which is significantly less than the 7% reduction predicted to be available for the summer peak. DEP projects that it will have less than half of the DSM resources to reduce its winter peak loads as compared to the DSM capacity available in summer.

DEP's energy sales, including reductions associated with its EE programs, are predicted to grow at a CAGR of 0.9%, which is similar to prior forecasts. DEP predicts that over the next 15 years, the MWh reductions from its EE programs will reduce its annual energy sales by approximately 1% in 2017, increasing to 3% in 2031.

The Public Staff commented that given the similarity of DEP's summer and winter peaks throughout the forecast period, their review of forecasting accuracy was focused on comparing the annual peak demand, whether summer or winter, with the previously forecasted peak demand. According to the Public Staff, a review of DEP's actual and weather adjusted peak load forecasting accuracy for one year shows that the forecasts in DEP's 2015 IRP underestimated the actual 2016 summer peak load by 1% and underestimated the actual 2016 winter peak load by 1%. However, a similar review of DEP's five-year peak load forecasting accuracy, based on the forecasts (2010-16) filed in its 2009 IRP, indicates a forecast error of 6%, resulting in an average annual overestimation of 766 MW. The Public Staff goes on to state that in regard to DEP's energy sales forecast, the 2009 forecast also reflects a 6% overestimation error.

The Public Staff commented that it believes the economic, weather-related, and demographic assumptions underlying DEP's peak and energy forecasts are reasonable and that DEP employed accepted statistical and econometric forecasting practices. Accordingly, the Public Staff found that DEP's peak load and energy sales forecasts are reasonable for planning purposes.

Public Staff Comments - DEC's Peak and Energy Forecasts

The Public Staff commented that similar to DEP, DEC no longer considers its summer peak to be its system peak. DEC's forecasted summer peak loads reflect a lower CAGR of 1.1% as compared to the 1.3% CAGR of the winter peaks that include load reductions associated with projected EE programs and prior to the activation of any DSM programs. On average for the next 15 years, the summer peaks are projected to be approximately 67 MW lower than the forecasted winter peaks. According to the Public Staff, it is evident that DEC has reduced its forecasts of electricity demand when the current projections are compared with the 2014 projected growth of 1.4% and the 2012 projected growth of 1.7%. DEC predicts that in the next 15 years, its summer season DSM programs will reduce load by 6% and its EE programs will reduce its summer peak demands by another 3% by 2031.

DEC's 15-year forecast predicts that its winter peaks will grow at a CAGR of 1.3%, as compared to the 1.5% forecast in its 2014 IRP and 1.7% growth rate projected in its 2012 IRP. Without the reduction in peak demand resulting from the implementation of its EE programs, DEC expects its winter peaks to grow at an average rate of 1.4% each year for the next 15 years. The average annual growth of its winter peak, which DEC considers its system peak, is forecasted to be 258 MW for the next 15 years. DEC predicts that over the planning horizon, the load reductions from its cumulative new EE programs will reduce its annual winter peak load by approximately 2%, as opposed to the 3% reduction projected from EE programs for its summer peak. The plan also assumes that DEC can reduce 3% of its load by 2031 by using its winter season DSM resources. While DSM is considered a capacity resource, it is projected to contribute significantly less in capacity savings in the winter as opposed to the 7% reduction in load projected during its summer peaks.

The Public Staff commented that DEC's energy sales, including the effects of its EE programs, are expected to grow at a CAGR of 1.0%. This growth rate is the same as predicted in 2014, but is considerably lower than the 1.7% predicted in its 2012 IRP.

The Public Staff's review of DEC's actual and weather adjusted peak load forecasting accuracy for one year shows that the forecasts in its 2015 IRP over-predicted its 2016 summer peak load by 4% and over-predicted its 2016 winter peak load by 5%. However, the one-year forecast errors are reduced to 3% for the winter peak and 2% for the summer peak on a weather-adjusted basis. In addition, the Public Staff reviewed DEC's peak load forecasting accuracy based on the forecasts for 2010-16 filed in DEC's 2009 IRP. The review indicates a forecast error of 4%, resulting in an average annual overestimation of 629 MW of demand. DEC's 2009 energy sales forecast reflects a 2% overestimation error.

The Public Staff commented that it believes the economic, weather-related, and demographic assumptions underlying DEC's 2016 peak and energy forecasts are reasonable and that DEC has employed accepted statistical and econometric forecasting practices. Accordingly, the Public Staff finds DEC's peak load and energy sales forecasts to be reasonable for planning purposes.

Public Staff Comments - DNCP's Peak and Energy Forecasts

The Public Staff commented that DNCP's 15-year forecast predicts that its adjusted summer peaks will grow at a CAGR of 1.5%. DNCP's 2014 and 2012 IRPs predicted a CAGR of 1.3% and 1.5%, respectively. The average annual growth of its summer peak is forecasted to be 293 MW for the next 15 years. DNCP predicts that in the next 15 years, the load reductions from its EE programs will reduce its annual peak load by approximately 1%, a decrease from the 2% forecast in its 2014 IRP. DNCP predicts that load reductions from the activation of its DSM programs will reduce its peak load by approximately 1% by 2031. DNCP's forecast of its winter peak loads reflects a slightly lower CAGR of 1.3% relative to the CAGR of 1.5% for its summer peaks. On average, the winter peaks are approximately 2,728 MW less than the forecasted summer peaks.

The Public Staff commented that DNCP's energy sales are predicted to grow at an average annual rate of 1.5%, an increase from the 1.1% in the 2014 IRP and a decrease from the 1.6% growth rate predicted in its 2012 IRP. According to the Public Staff, DNCP predicts that the savings from its EE programs will reduce its energy sales by approximately 1% by 2031, which is less than the 3% reduction in energy sales previously forecasted in its 2014 IRP.

The Public Staff's review of DNCP's actual peak load forecasting accuracy for one year shows that its 2015 IRP over-predicted DNCP's 2016 summer peak load by 1% and under-predicted its 2016 winter peak load by 9%. According to the Public Staff, DNCP's forecast errors are somewhat similar to the errors observed with DEP and DEC. The forecast errors are partially attributable to the mild summer and winter peak-day temperatures for 2016. The Public Staff also reviewed DNCP's peak load forecasting accuracy based on the forecasts for 2010 - 2016 in DNCP's 2009 IRP. The Public Staff commented that their review indicates a forecast error of 6%, an average annual overestimation of 1,035 MW of capacity. They go on to state that in regard to DNCP's energy sales, the forecast provided in the 2009 IRP reflects a 6% overestimation error.

The Public Staff commented that it believes the economic, weather-related, and demographic assumptions underlying DNCP's peak and energy forecasts are reasonable and that DNCP has employed accepted statistical and econometric forecasting practices. Accordingly, the Public Staff concludes that DNCP's peak load and energy sales forecasts are reasonable for planning purposes.

Public Staff Conclusions - Peak and Energy Forecasts

The Public Staff commented that the importance of load forecast accuracy cannot be overstated given that the purpose of the IRP is to determine the most reasonable plan to serve the forecasted load at least cost. The Public Staff notes that these are the first IRPs where DEP and DEC project that they will be winter peaking. In the event that DEC's estimated winter peak loads and temperatures are overstated and their summer peaks remain dominant, the lower growth in peak demands combined with the predicted increase in solar generation eliminates or significantly reduces the need for 435 MW of combustion turbine (CT) capacity planned for 2025 in DEC's IRP.

The Public Staff expressed a concern revolving around the unexpectedly large increases in the demand for electricity for all three IOUs at the time of the 2014 and 2015 system peaks in January and February during periods of abnormally low temperatures. The Public Staff notes that the influence of these two extreme winters has the potential to bias the estimation incorporated in regression analysis, thereby producing less accurate forecasts. The Public Staff goes on to state that identifying and properly forecasting the shape of customers' responses to abnormally cold conditions can be challenging due to its non-linear nature and may not be fully captured in the current equations in the IOUs' peak forecast models. As such, the Public Staff recommended that the utilities continue to review their winter peak equations in order to better quantify the response of customers to low temperatures. The Public Staff also recommended that the IOUs continue to present CAGRs for both the summer and winter seasons.

Summary of Growth Rates

The following table summarizes the growth rates for the IOUs' system peak and energy sales forecasts in their IRP filings.

2017- 2031 Growth Rates
(After New EE and DSM)

	Summer Peak	Winter Peak	Energy Sales	Annual MW Growth
DEP	1.0%	1.2%	0.9%	172
DEC	1.1%	1.3%	1.0%	286
DNCP	1.5%	1.3%	1.5%	293

SACE, NRDC and the Sierra Club Comments - Peak and Energy Forecasts

SACE, NRDC and the Sierra Club retained James F. Wilson, an economist and independent consultant in the electric power and natural gas industries, to evaluate the peak load forecasts used in the 2016 IRPs. According to comments filed by SACE, NRDC and the Sierra Club, the load forecast is a major factor determining a utility's need for new resources to meet system energy and demand. Overstating load growth will result in excess capacity on the system, and excess costs borne by ratepayers. Mr. Wilson concluded in his report, Review and Evaluation of the Peak Load Forecasts for the Duke Energy Carolinas and Duke Energy Progress 2016 Integrated Resource Plans (Wilson Report)[5] that DEC's winter peak load forecast – which is critical due to the utility's new "winter peaking" paradigm – is high, and that there was not enough information to determine whether DEP's load forecast was reasonable.

Mr. Wilson concluded that the risk of very high loads, especially in winter, was substantially exaggerated in the reserve margin studies performed for DEC and DEP. He indicates the critical assumptions about the impact of extreme cold on load levels were chosen based on simple regressions over rather arbitrarily-chosen temperature ranges, despite the high sensitivity of the results to the chosen ranges. He goes on to state that this casual approach stands in contrast to the rigorous process and analysis that the load forecasters at PJM Interconnection, LLC, underwent to enhance their load forecasting methodology following the polar vortex experience. According to Mr. Wilson, the PJM load forecasters developed enhancements to more accurately represent the relationship between loads and extreme temperatures. PJM's enhanced methodology now employs additional "weather splines" in order to more accurately capture the relationships between load and temperature over different temperature ranges, including extreme hot and cold conditions. Among other things, Mr. Wilson suggested that for future IRP proceedings DEC and DEP should research the drivers of sharp winter load spikes under extreme cold conditions, and study the relationship between cold and load, to inform future reserve margin studies.

NCSEA Comments - Peak and Energy Forecasts

NCSEA commented that there are differing forecasts for DEP-West and DEP-East that are not accounted for in DEP's single IRP. According to NCSEA, DEP acknowledges the differing load forecasts in the two service territories, noting that "events in the East are not always coincident in the West…." NCSEA goes on to state that when the two service territories are analyzed in a single IRP, the resulting analysis shows that the combined service territories are already a winter peaking system, which masks the fact that DEP-East is not expected to become a winter peaking system until 2023.

Due to the extensive and drastic differences between DEP-West and DEP-East, NCSEA requested that the Commission direct DEP to provide separate analyses for its DEP-East and DEP-West service territories in future IRP filings.

[5] Comments of Southern Alliance for Clean Energy, Natural Resources Defense Council, and the Sierra Club, Attachment A (Docket No. E-100, Sub 147), dated February 17, 2017.

NC WARN Comments - Peak and Energy Forecasts

NC WARN commented that “it remains apparent in its IRPs that Duke continues to exaggerate its growth of electricity sales….” NC WARN notes that Duke’s peak and energy growth projections are about as high as they have been in the past several IRPs and comments that the growth estimates are unreasonably high. According to NC WARN, Duke admits per customer usage of electricity has been flat to negative, but baldly claims that increases in number of customers will cause the entirety of the growth in energy (See DEC IRP, p. 16). NC WARN commented that one of the most glaring deficiencies in the Duke IRPs filed in this docket is the continuing overestimation of population growth and its effect on electricity usage. NC WARN states that the Commission must closely scrutinize the validity of the analyses used by Duke to justify growth projections.

Duke Reply Comments - Peak and Energy Forecasts

Duke noted that the Public Staff concluded that both DEC and DEP’s load forecasts and methodologies were reasonable for planning purposes. Duke commented that DEC’s forecasting error rate in the 2008-2009 timeframe mostly resulted from the severe economic downturn that occurred in 2009 and which no one was able to reasonably foresee. According to Duke, DEC suffered more than DEP and most utilities in the 2009 recession due to its large loss of industrial load, particularly from textiles. In contrast, the DEC peak load forecast developed in 2010 projected a 2013 value that was only 131 megawatts different than the actual weather-adjusted value for the year 2013. Duke commented that its forecasting methodology is always evolving in an effort to further improve the process, as a result of best practices and otherwise.

In response to the Public Staff’s recommendation that DEC and DEP continue to review their winter peak equations in order to better quantify the response of customers to low temperatures, Duke commented that DEC and DEP regularly review their peak forecasting methodologies to ensure adherence to the latest industry standards. Duke goes on to state that given the increasing importance of efficiency trends on energy usage, DEC and DEP incorporate Statistically Adjusted End-Use Models (SAE) in their peak forecasting process. According to Duke, SAE models attempt to incorporate the effects of energy efficiency trends into the forecast as well as other end-use changes. This approach also has the advantage of generating a forecast for each month rather than a simple seasonal forecast. Duke commented that in the spring 2016 forecast, the SAE methodology produced a lower summer peak forecast, but a slightly higher winter peak forecast, which matches recent trends.

Duke addressed in its reply comments the fact that SACE, NRDC and the Sierra Club were critical of Duke’s load forecasts. As an initial matter, Duke commented that SACE, NRDC and the Sierra Club admitted in their response to DEC and DEP’s Data Request 1-5 that, “Mr. Wilson has not prepared any utility electric peak load forecasts.” Duke commented, however, that Mr. Wilson’s determination of peak load growth rates draws upon recent PJM trends reducing peak growth rates downward without consideration of the differences that may exist between PJM and North and South

Carolina. Duke concluded that a comparison of PJM forecast trends to all North and South Carolina forecast trends is of very limited value. Duke noted that while both DEC/DEP and PJM use Moody's Analytics for their economic projections, within the January 2017 PJM Load Forecast Report, Moody's highlights the weakness of the PJM territory compared to the stronger southern economy.[6] Duke further commented that using current Moody's projections, population growth rates in North and South Carolina are expected to grow 5 to 6 times as fast as PJM, and nearly twice the expected U.S. growth rate.

Duke notes that in paragraph 26 on page 13 of the Wilson Report, Mr. Wilson correctly points out that "the very high loads that have occurred on recent, extremely cold winter days occur for very few days and hours; loads in other hours and on other days are much lower. Peak load forecasts intended to represent median or mean values should be relatively unaffected by such rare events." According to Duke, actual peaks fluctuate greatly while the weather normal peaks are not influenced by the extremes, either to the upside or downside. According to Duke, this is illustrated in Mr. Wilson's figure, JFW-3.[7] Therefore, Duke contends that the DEC and DEP forecasts represent an appropriate median forecast.

In reply comments, Duke also addressed Mr. Wilson's suggested use of multiple cold weather splines based on similar analysis performed by PJM. Duke commented that after reviewing PJM's cold weather load forecast and spline development, Astrapé Consulting (Astrapé), and Duke only identified a single cold weather spline at temperatures less than 25 degrees which is almost identical to the method employed by Astrapé. According to Duke, this critique further demonstrates that Mr. Wilson does not understand the load modeling methods used by Astrapé, and thus his criticisms should be rejected.

In response to NCSEA's comments, Duke disagrees with NCSEA's recommendation that the Commission require DEP to complete separate analyses for the DEP-East and DEP-West service areas in future IRPs and updates. Duke commented that while generation units are important to support local energy, voltage and reliability needs, DEP also studies, plans, and adds generation to serve DEP's entire system needs. Duke noted that significant efforts are in place to address the needs of both the east and west portions of DEP's service territory. The Western Carolinas Modernization Plan is one of the efforts in place to address these needs. Duke asserted that there is no compelling reason to change the IRP process to a service-area specific basis, as NCSEA requests.

DNCP Reply Comments - Peak and Energy Forecasts

DNCP commented that the Public Staff's analysis found Dominion's forecasts to be reasonable. However, in response to the Public Staff's review of peak load forecasting

---

[6] http://www.pjm.com/~/media/library/reports-notices/load-forecast/2017-load-forecast-report.ashx, at 17-18.

[7] Id. at 7.

accuracy, DNCP explained that it contracts with Moody's Analytics to provide economic explanatory variables for use as input variables in its econometric load forecasting models. DNCP explained in its reply comments that Moody's has forecasted higher economic growth than what actually occurred in Virginia, the region primarily served by DNCP. According to DNCP, this lower than anticipated economic growth in Virginia has been a key reason why its forecasts have been higher than what has actually occurred. DNCP commented that DNCP reviews its load forecasting models and processes annually, and improves the process as appropriate. However, DNCP acknowledges that predicting customer demand during times of very low temperature conditions has historically been a challenge.

Commission Conclusions - Peak and Energy Forecasts

Based on the foregoing, the comments of the parties, and the entire record in this proceeding, the Commission concludes that the IOU's peak load and energy sales forecasts are reasonable for planning purposes. In reaching this conclusion, however, the Commission shares the concerns expressed by the Public Staff on issues related to statistical and econometric forecasting practices and by SACE that DEC's load forecast may be higher than reasonably justified. Therefore, as discussed in detail below, the Commission directs DEC to address this matter in its 2017 IRP update. Based on the fact that Duke studies, plans, and adds generation to serve DEP's entire system needs, the Commission is not persuaded by NCSEA's argument that DEP should alter its IRP planning to incorporate separate analyses for DEP-East and DEP-West.

The Public Staff commented that the economic, weather-related, and demographic assumptions underlying the utilities' peak and energy forecasts are reasonable and employed accepted statistical and econometric forecasting practices. The Commission finds no compelling evidence to the contrary. However, the Commission is aware of the challenges the utilities face to effectively forecast peak loads and appropriately incorporate recent extreme weather events. In particular, the Commission takes note of the Public Staff's comments that the 2014/2015 extreme winters have the potential to bias the estimation incorporated in regression analysis, thereby producing less accurate forecasts. The Public Staff goes on to state that identifying and properly forecasting the shape of customers' responses to abnormally cold conditions can be challenging due to its non-linear nature and may not be fully captured in the current equations in the IOU's peak forecast models.

The Commission further concludes that the DEC load forecast may be high. In reaching this conclusion, the Commission recognizes the Wilson Report. To quote from Mr. Wilson's report, "Overall, the DEC winter peak forecast seems somewhat high compared to the trend in the weather-adjusted peaks…." Mr. Wilson notes in his report on page 9 that for DEC, there has been a steady differential between the weather-adjusted summer and winter peaks during recent years, averaging 750 MW over 2009 to 2016, and averaging 683 MW over 2014 to 2016. The report states that DEC's current forecast breaks from this pattern, again suggesting that the winter peak forecast is high (see Figure JFW-6: DEC Summer and Winter Peaks, Historical and Forecast).

Continuing to address the DEC winter forecast, Mr. Wilson states in his report on page 7 that changes in end-use technologies may be affecting these brief, extreme winter peak loads under extreme cold conditions. The report points out that DEC stated it has not performed any formal analysis to determine which end uses are contributing to these load spikes on extremely cold winter mornings (response to Data Request SACE 2-11).

The Commission recognizes that it is important for each of the utilities to effectively address load response to temperature changes and especially extreme weather events when preparing peak load forecasts. Therefore, the Commission encourages the utilities to seek out and apply lessons learned to their forecasting methodologies wherever those best practices are identified.

Specifically, the Commission determines that DEC should address in its 2017 IRP Update, any refinements it makes to its forecasting methodology to better address load response in general, but especially the previous extreme winter weather events. In addition, DEC should clarify in its 2017 IRP Update how the 540 MW NCEMC backstand agreement is treated in its forecast.

RESERVE MARGINS

Public Staff Comments - Reserve Margins

The Public Staff noted in its comments that DEP, DEC, and PJM[8] use a recommended system reserve margin based on the Loss of Load Expectation (LOLE) probabilistic assessment. The LOLE is a metric that targets the probability of the loss of load on one day in a ten-year period, or one firm load shed event resulting in unserved energy for a firm customer on one day in a ten-year period. The reserve margins that correlate with this LOLE are approximately 17.0% for DEP and DEC, up from 14.5% in the 2014 IRP, and 16.5% for PJM. DEP and DEC's shift from being summer peaking systems to a winter peaking systems means that their reserve margins are designed to meet the winter peak.

PJM's 2015 Reserve Requirement Study recommends use of a reserve margin of 16.5% to satisfy the reliability criteria required by the North American Electric Reliability Corporation (NERC), Reliability First Corporation, and PJM's Planned Reserve Sharing Group. DNCP utilizes a coincidence factor to account for the historically different peak periods between DNCP and PJM, and, therefore, its ability to meet its PJM reserve requirements. This coincidence factor reduces DNCP's reserve margin requirement to 12.46%.

The Public Staff stated in its comments that for the planning period 2017 to 2031, the range of reserve margins reported by the electric utilities continues to be similar to those used in previous IRPs when adjusting for the lower than estimated load growth. For the period covered by the IOUs' 2016 IRPs, planned reserves are:

[8] DNCP utilizes the PJM capacity planning process for long- and short-term planning of capacity needs.

Electric Utility	Planned Reserve 2017-2031	Target Reserve Margin
DEP	17.0% to 27.0%	17.0%
DEC	17.0% to 24.0%	17.0%
DNCP	12.46% to 23.0%	12.46%

In their 2014 IRPs, DEP and DEC's target reserve margins were 14.5% and DNCP's was 11.2%. The increase in reserve margins is based on recent modeling results that demonstrated the volatility of loads during the winter months, generation resource availability, and overall electric generation and grid system response. DEP and DEC used Astrapé, to perform their reserve margin studies. The Public Staff commented that Astrapé has an extensive background in performing modeling and analysis for multiple utilities and regional transmission organizations (RTOs), including PJM. It also performed the modeling and analysis for DEP and DEC's reserve margin studies in 2012.

The Public Staff commented that DEP and DEC's operating reserves during the winter peaks in 2014 and 2015 fell below 1%, largely driven by extreme cold weather events in those years. The reduced operating margins were caused by a number of factors. The extreme cold resulted in unexpectedly high demand, in part due to additional use of resistive heaters such as electric strip heating and portable electric heaters. Increased load, however, was not the only factor that led to the reduced operating margins in 2014 and 2015. A number of plants in the system experienced forced outages because of the extreme cold due to controls and other essential systems being frozen or inoperable at those temperatures. Since that time, DEP and DEC have made capital and operational investments in freeze protection. According to the Public Staff, their systems should now be more resilient to cold weather and, therefore, less likely to experience such narrow operating margins. The Public Staff commented, however, that responses to its data requests indicate that the forced outage rates Astrapé assumed for the reserve margin study were not adjusted to reflect this additional freeze protection, potentially overestimating the likelihood of outages at winter peak and overestimating the recommended planning reserve margin percentage.

The Public Staff also expressed a concern that the approach used by Astrapé may overestimate the demand response associated with these low temperatures and thus the level of reserve margin needed.

The Public Staff addressed other concerns it has with methodologies employed in the Astrapé study. These additional concerns are documented on pages 46-50 in the Public Staff's comments. The Public Staff commented that it is not convinced that the recommended 17% reserve margin based on the winter peak is fully supported. The Public Staff recommends that the Commission direct DEP and DEC to continue to evaluate the methods and assumptions utilized in their 2016 reserve margin studies to try to better understand the relationships between extreme weather events and load response, as well as economic and load growth rates, and update this information as needed in their next IRPs.

Based on its review of the annual plans, the Public Staff commented that it believes that the reserves included in the utilities' IRPs are reasonable at this time for planning purposes. The Public Staff recommended that DEP and DEC continue to review their load forecasting methodology to ensure the assumptions and inputs remain current and that appropriate models quantifying customers' responses to weather, especially abnormally cold winter weather events, are employed.

The Public Staff also commented that to understand the impact of solar and other renewable generation on reserve margin adequacy, more precise modeling is needed. Analysis of the nature of solar power injected into the electrical system, or any other power source that is intermittent in nature, requires sub-hourly modeling with multiple and potentially complex scenarios. The Public Staff commented that sub-hourly modeling could necessitate more time and material intensive resources than currently used. The Public Staff recommends that IOUs in future IRPs evaluate the feasibility and benefits of advanced analytic techniques that incorporate sub-hourly modeling and more granular system performance data, and to the extent these advanced analytics are available at reasonable cost, utilize these resources to provide better information and understanding on optimizing reserve margin needs, as well as overall system operations.

SACE, NRDC, and the Sierra Club Comments - Reserve Margins

Based on conclusions in Mr. Wilson's Report entitled Review and Evaluation of the Reserve Margin Determinations for the Duke Energy Carolinas and Duke Energy Progress 2016 Integrated Resource Plans,[9] SACE, NRDC, and the Sierra Club commented that the reserve margins used in the 2016 IRPs were improperly inflated.

In his report, Mr. Wilson noted that the reserve margins used in the 2016 IRPs were based upon recommendations in the DEC and DEP 2016 reserve margin studies prepared by Astrapé and provided in response to data request SACE 1-8. Mr. Wilson's evaluation focused on three issues having to do with how loads were represented in the Astrapé studies and he concluded that these were inaccurate and unsupported.

First, according to Mr. Wilson, the reserve margin studies extrapolated the relationship between cold temperatures and winter loads that occurred in some hours in recent years over much lower temperatures that have not occurred for decades in a manner that greatly exaggerates the magnitude of the loads likely to occur under extreme cold conditions.

Second, Mr. Wilson notes that the economic load forecast uncertainty that was layered on top of the weather-related load distributions was also exaggerated, and is not supported by the underlying data it was based upon.

Finally, Mr. Wilson notes that the reserve margin studies relied upon the DEC and DEP peak load forecasts, and treated them as forecasts of mean or average peak loads; however, at least in the case of DEC, the forecast value apparently was not a mean value, and was likely several hundred megawatts in excess of the mean forecast, which would bias the reserve margin by making it higher.

[9] Comments of Southern Alliance for Clean Energy, Natural Resources Defense Council, and the Sierra Club, Attachment B (Docket E-100, Sub 147) dated February 17, 2017.

Mr. Wilson states that his review of these issues leads to the conclusion that the risk of very high loads, especially in winter, was substantially exaggerated in the reserve margin studies, and, therefore, the recommended increases in the DEC and DEP reserve margins are unsupported and should be rejected. Among other things, Mr. Wilson suggests that for future IRP proceedings, Duke should research the drivers of sharp winter load spikes under extreme cold conditions and study the relationship between cold and load to inform future reserve margin studies.

NC WARN Comments - Reserve Margins

NC WARN summarized the projected reserve margins over the planning period included in DEC and DEP's current IRP filings. NC WARN characterizes these reserve margins as "excessive" based in large part on a polar vortex in 2014. NC WARN goes on to state that witness Powers concluded at the certificate hearing for the NTE merchant plant in Docket No. EMP-92, Sub 0 that it is important to underscore that there is no reason to build any baseload capacity to meet once-in-a-generation polar vortex conditions that cause higher than expected winter peak loads.

NC WARN also noted in its comments that the most recent NERC report[10] on reliability factors and resource adequacy of utility regions around the country describes the anticipated reserve margin and recommends 15% as the reference margin.

Duke Reply Comments - Reserve Margins

Duke commented that it has appropriately addressed the Public Staff's concerns regarding the reserve margin studies, and Duke continues to fully support the findings recommending minimum 17% winter reserve margin targets for DEC and DEP.

Duke acknowledged in its reply comments that DEC and DEP have experienced significantly higher loads than projected during recent cold weather events. For example, Duke commented that DEP carried 21% summer planning reserve margins into 2015, but experienced real time operating reserves of -3% during the February 20, 2015 cold weather event. The significant load response to cold weather that DEC and DEP experienced in 2014 and 2015, along with the high penetration of solar resources on the Duke system and in the interconnection queues, were the primary drivers for conducting the new reserve margin studies in 2016.

Duke noted the following in its reply comments:

> The Public Staff expressed concerns that the regression equation modeling conducted in the reserve margin studies "may overstate the demand response associated with these low temperatures and thus the level of reserve margin needed." Specifically, Duke addresses the comments of the Public Staff that "This equation represents the peak daily load associated

[10] North American Electric Reliability Corporation, 2016 Long-Term Reliability Assessment, December 2016.

with the lowest temperature recorded that day, not necessarily occurring at the same hour. Astrapé appears to be using this peak day equation to determine hourly load for each hour of historic temperature data below 25 degrees. For example, if a day has 24 hours of temperature below 25 degrees, then this equation represents the load response at each of these hours regardless of the time of day." Duke commented that the Public Staff's assertion is not correct.

Duke replied that as discussed in its responses to Public Staff data request DEP 1-7 and DEC 17-7, the regression equations were based on peak hours on weekdays during the 2014 and 2015 time period. Duke noted that the actual filters placed on the data were reported in that data response. To correct the cold weather days in the synthetic load shapes, Duke commented that only the peak load hour of the day was modified using the regression equation and that the rest of the day was scaled up or down based on a standard cold weather day shape.

In order to ensure that demand response in the synthetic loads during cold temperatures was in line with the 2014 and 2015 actual peaks, Duke noted that Astrapé compared the weekday synthetic loads with the actual history. This comparison was provided in response to DEC-DEP SACE Data Request 1-11. According to Duke, the comparison demonstrates that the predicted loads calibrate well with the actual load response seen in 2014 and 2015.

Duke also addressed the Public Staff's comments that responses to its data requests indicate the forced outage rates Astrapé assumed for the reserve margin study were not adjusted to reflect operational investments in freeze protection, potentially overestimating the likelihood of outages at winter peak and overestimating the recommended planning reserve margin percentage. Duke noted that it explained the details of the cold weather outage modeling and related impacts on reserve margin study results in response to various Public Staff data requests. According to Duke, the outage data used in the 2016 reserve margin study was based on NERC Generating Availability Data System (GADS) data for years 2010-2014. As noted by the Public Staff, the outage assumptions were not adjusted to reflect the additional subsequent freeze protection investments in Duke's generating plants. Duke pointed out, however, that it is important to understand that the reserve margin studies captured the impact of unit outages through "random" Monte Carlo simulations, and although the outage draws are based on historic seasonal data, the outage draws are independent of temperature in the simulations.[11]

Further, Duke commented that the inclusion or exclusion of a couple of randomly occurring, short-term duration unit outages will not have a significant impact on the system equivalent forced outage rate (EFOR) values. Thus, the few hours that freezing problems may have occurred would typically have little impact on individual unit EFOR values or the reserve margin study results. Duke notes, however, that if unit outages were "forced" to occur on extreme cold days within the simulations similar to 2014 and 2015, then it would put upward pressure on the reserve margin. Duke commented that the key

[11] Unit outage modeling is described more fully in Section III.F of the reserve margin study.

is whether or not the outages are "forced" to occur concurrent with high winter peak loads. According to Duke, this is precisely what Astrapé modeled as a cold weather sensitivity. Astrapé forced additional units offline concurrent with cold temperatures and high loads similar to what was experienced in 2014 and 2015.[12] Duke commented that the results of the sensitivity analysis showed a significant impact on loss of load expectation and resulted in an increase in the reserve margin target of greater than 2%. As such, Duke did not force these cold weather outages into the base case of the reserve margin study.

Duke noted that the analysis shows that these outages were extremely isolated and short in duration. Because the outages are modeled independently from weather in the base case, removing the cold weather related outages has little to no impact on the overall reserve margin study results as reflected by the slight change in EFOR. Duke commented that if the cold weather outages were forced to occur at the same time as extreme cold weather and high load events, as reflected in the cold weather outage sensitivity, then the results change dramatically. According to Duke, based on the lessons learned in 2014 and 2015, Astrapé and Duke did not believe it prudent to force these outages to occur during the extreme cold temperatures in the base case analysis and thus only modeled the average EFOR across the winter.

Finally, Duke commented on the Public Staff's recommendation that utilities evaluate the feasibility and benefits of advanced analytic techniques that incorporate sub-hourly modeling and more granular performance data in order to better analyze the nature of solar power injected into the electrical system, or any other intermittent power source. Duke noted that the Duke IRP team is in the process of evaluating available model enhancements. Duke commented that the IRP utilizes hourly long-term models for system optimization and production cost modeling. The computational time to produce results in these models has generally not allowed these longer-term models to be developed at a sub-hourly granularity. According to Duke, sub-hourly analysis is more appropriately handled in shorter term production costing models utilized by the systems optimization group. As this group makes advancements in studying operational impacts, such as incremental ancillary service requirements, results will be shared with the IRP team as inputs to the IRP models.

DNCP Reply Comments - Reserve Margins

DNCP commented that it is already working to meet the Public Staff's recommendations relative to advanced analytic techniques that incorporate sub-hourly modeling and more granular system performance data. DNCP noted that in order to accommodate the anticipated growth of intermittent renewable generation, Dominion is in the process of integrating generation, transmission, and distribution planning more fully, and investigating more granularity in the modeling. According to DNCP, it anticipates that this effort will help ensure reliable system operations as the resource mix evolves in the future, especially concerning the addition of intermittent generation. DNCP commented that it intends to include the results of this work in future IRPs.

[12] The cold weather sensitivity can be found in Section VI of the reserve margin study with the underlying forced outage penalty found in the Confidential Appendix.

Commission Conclusions - Reserve Margins

Based on the foregoing, the comments of the parties, and the entire record in this proceeding, the Commission concludes that the reserve margins included in the utilities' IRPs are reasonable at this time for planning purposes. However, the Commission finds the analyses by the Public Staff and SACE's report by Mr. Wilson to be helpful regarding the question of whether DEC and DEP should move to a 17% winter reserve margin target. The Commission concludes that this move is not supported by the evidence in this proceeding. Nevertheless, the concerns outlined by the Public Staff, as well those discussed in Mr. Wilson's report, should be acknowledged by DEC and DEP and fully addressed in their 2017 IRP updates.

Further, the Commission is not persuaded by NC WARN's arguments relying on witness Power's testimony in Docket No. EMP-92, Sub 0. In the Order issued January, 19, 2017, in that docket, the Commission observed the following:

> On cross-examination, however, witness Powers acknowledged he undertook no independent modeling, no independent analysis of key economic factors, such as income, electricity prices, and industrial production indices, and no independent analysis or modeling of weather projections. He only looked at the last ten years of actual loads reported by DEC and DEP. He also testified on cross-examination that he did not consider population growth to be necessarily connected to load growth and that he made no assumptions about manufacturing output in North Carolina over the next 20 years.

Order Granting Certificate with Conditions, at p. 14 (January 19, 2017).

NC WARN noted in its comments that the most recent NERC report on reliability factors and resource adequacy of utility regions around the country describes the anticipated reserve margin and recommends 15% as the reference margin. Based on a review of the NERC report, the Commission acknowledges that NERC uses 15% as the "Reference Margin Level" for the SERC-E region. However, the Commission does not view NERC's Reference Margin Level as a recommendation for use as a reserve margin. The NERC definition of Reference Margin Level provided in the report, at page 171, is as follows:

> The assumptions of this metric vary by assessment area. Generally, the Reference Margin Level is typically based on load, generation, and transmission characteristics for each assessment area and, in some cases, the Reference Margin Level is a requirement implemented by the respective state(s), provincial authorities, ISO/RTO, or other regulatory bodies. If such a requirement exists, the respective assessment area generally adopts this requirement as the Reference Margin Level. In some cases, the Reference Margin Level will fluctuate over the duration of the assessment period, or may be different for the summer and winter seasons. If one is not provided by a given assessment area, NERC applies a 15% Reference Margin Level

for predominantly thermal systems and 10% for predominantly hydro systems.

The analyses regarding reserve margin targets is extremely technical and complicated, made even more so by the advent of winter peaking on DEP and DEC's systems. The Commission relies heavily on the Public Staff's review and analysis to make its decisions on this subject. Therefore, the Commission determines that DEC and DEP should work with the Public Staff to address the Public Staff's and Mr. Wilson's reserve margin concerns and to implement changes as necessary to help ensure that the reserve margin target(s) are fully supported in future IRPs. Further, the Commission requests that Duke and the Public Staff file a joint report summarizing their review and conclusions within 150 days of the filing of Duke's 2017 IRP updates. In addition to addressing the reserve margin concerns identified by the Public Staff and Mr. Wilson, the report should clearly define the support and basis for the targeted reserve margins incorporated into the IRPs. If the parties cannot reach consensus, then the report should outline their differences and recommend a procedure for the Commission to pursue in reaching a conclusion about the reserve margins recommended by DEC and DEP in their IRPs.

In addition, the Commission concurs with the Public Staff's recommendation that in future IRPs the IOUs should evaluate the feasibility and benefits of advanced analytic techniques that incorporate sub-hourly modeling and more granular system performance data. Further, to the extent that these advanced analytics are available at reasonable cost, the IOUs should utilize these resources to provide better information and understanding on optimizing reserve margin needs, as well as overall system operations.

SYSTEM PEAKS AND USE OF DSM RESOURCES

Public Staff Comments - DEP's System Peaks and Use of DSM Resources

The Public Staff noted that DEP's 2016 annual system peak of 13,244 MW occurred on January 19, 2016, at the hour ending 7:00 a.m., at a system-wide average temperature of 21 degrees Fahrenheit (ºF), which is above the normal peak day temperature of 17ºF. DEP's all-time peak of 15,515 MW occurred on February 20, 2015, at a temperature of 12ºF. Given the relatively mild peak-day winter temperature in 2016 and ample available reserves, DEP did not activate any of its DSM programs. This is in contrast to 2015, when a significant amount of generation was not available for dispatch on the morning of the winter peak. Due to the extreme temperatures, DEP activated its DSDR[13] program, reducing load by 290 MW; its commercial, industrial, and government (CIG) and EnergyWise demand response programs, reducing load by 26 MW; and its large load curtailment program, reducing load by 240 MW. The Public Staff commented, for that peak hour in 2015, DEP's operating margin fell to -1.6%. As a result, in order to prevent shedding of load DEP acquired 700 MW of non-firm energy, 500 MW from DEC and the remainder from PJM and others.

[13] The Commission has classified DSDR as an EE program, but DEP generally uses it as it would a DSM program.

Based on the Public Staff's comments, DEP's summer system peak of 13,033 MW occurred on July 26, 2016, at the hour ending 4:00 p.m., at a system-wide temperature of 94ºF, which is considered mild or slightly below average temperature. This peak was 211 MW less than the previous winter's peak, and ample available reserves led DEP to activate only 23 MW of its DSM resources.

The Public Staff noted that during DEP's ten highest peak loads in 2016, DEP activated its DSM programs twice during the summer season (23 MW and 2 MW). In response to the Public Staff's data request, DEP indicated that none of the ten highest 2016 peak loads warranted the drastic response to actual load conditions observed during the winters of 2014 and 2015 and the summer of 2015. DEP indicated that in 2016, reserves were more than adequate, and system energy costs (lambdas) were not significantly greater than average. As it has stated in prior IRP comments, the Public Staff commented that it believes the utilities should maximize the use of their DSM to reduce fuel costs, especially when marginal costs of energy are high, as well as to ensure reliability.

Public Staff Comments - DEC's System Peaks and Use of DSM Resources

The Public Staff noted that DEC's 2016 annual system peak of 18,037 MW occurred on July 25, 2016, at the hour ending 5:00 p.m., at a system-wide temperature of 96ºF. DEC's winter system peak of 17,136 MW occurred on January 19, 2016, at the hour ending 8:00 a.m., at a system-wide temperature of 16ºF. According to the Public Staff, DEC did not activate any of its DSM resources during the winter system peak, but it did activate some DSM resources during the summer peak, for a reduction in summer peak demand of 456 MW. During its ten highest peak loads in 2016, DEC activated its DSM programs five times during the summer season. DEC did not activate any DSM resources during the winter season peaks. In response to a Public Staff data request, DEC indicated that none of the winter peak loads in 2016 warranted the use of DSM.

The Public Staff further commented that given the relatively mild peak-day temperatures during much of 2016, ample available reserves, and system energy costs (lambdas) were not significantly greater than average, and DEC did not activate its DSM programs as much as in 2015. By contrast, in 2015 DEC reduced load by 468 MW with its commercial and industrial DSM programs at its highest peak load on February 20, 2015. At that time, DEC's operating margin fell to 1.2% due to higher than expected load conditions and generation resource outages. According to the Public Staff, during the 2015 summer season, DEC did not operate its DSM at the time of its highest summer peak load; however, there were several other days during the summer that DEC activated its Power Manager Program and reduced load by several hundred MW.

Public Staff Comments - DNCP's System Peaks and Use of DSM Resources

The Public Staff noted that DNCP's 2016 annual system peak of 16,914 MW occurred on July 25, 2016 at the hour ending 4:00 p.m. with an average temperature of 97ºF. DNCP activated its Non-Residential Distributed Generation (DG) Program and Air Conditioning (AC) Cycling Program to reduce load by 5.3 MW and 100 MW, respectively, during the summer peak. DNCP's winter peak of 16,173 MW occurred on January 19, 2016, at the hour ending 8:00 a.m., at a system-wide temperature of 17ºF. According to the Public Staff, DNCP did not activate its DSM resources during the 2016 winter peak, but did activate its DG Program and AC Cycling Program during several of its highest ten summer and winter peak days.

Public Staff Conclusions - System Peaks and Use of DSM Resources

The Public Staff acknowledges that load conditions, energy prices, generation resource availability, and customer tolerance for the use of DSM are all important considerations in determining which DSM resources should be deployed. Use of DSM resources is largely dependent on the circumstances and cannot be prescribed in any definitive manner. As previously noted, 2016 was a relatively mild year for temperatures, with lower loads and marginal costs of generation as compared to February 2015. Nevertheless, the Public Staff concluded that the utilities should maximize the use of their DSM to reduce fuel costs, especially when marginal costs of energy are high.

In its review of the DSM activations at the time of the 15 highest hourly peaks for each utility, the Public Staff notes an ongoing concern regarding the amount of DSM load reduction actually realized during a DSM event, versus the amount of DSM resource available for an event, as represented in the load forecast tables. The load forecast tables represent the total amount of DSM resource in the resource mix for each IOU. However, when the IOU activates the DSM resource, the IOU may only activate all or only a portion of the resource. The forecast tables do not indicate the response the IOU is likely to receive from customers when an activation takes place. According to the Public Staff, taking into account the expected response from customers when forecasting the availability of the DSM resource would provide a more accurate forecast.

A second area of concern for the Public Staff involved the difference in DSM resources available in the winter and the summer due to winter season DSM typically not being cost effective. The Public Staff commented that each North Carolina utility has a summer air conditioning load control program, customer-owned standby generation, and load curtailment programs. Standby generation and load curtailment resources are available to each utility in the winter season. The Public Staff commented, however, that DEP is the only utility that has any dispatchable DSM for use during the winter season (the Heat Strips and Water Heater measures in the EnergyWise program). They also noted that DSDR was also used by DEP several times in both the winter and summer seasons to reduce peak demand.

The Public Staff offered two recommendations to address their concerns regarding DSM. First, the DSM resources forecast to be available in the IRP should represent the reasonably expected load reductions that are available at the time the resource is called upon as capacity. Through evaluation, measurement, and verification (EM&V) of these DSM programs, utilities should identify the enrolled DSM capacity and the reasonably expected level of load reduction that can be reliably called on during a DSM event, winter and summer. To accomplish this, the Public Staff recommended that each IOU begin including in its discussion of the activations of DSM and curtailable resources the percentage of DSM or curtailable resources called upon (in terms of MW), and the load reduction response (MW reduced) for each event for each program. Second, the Public Staff recommended that each IOU investigate and implement any cost-effective DSM that would be available to respond to winter peak demands.

Duke Reply Comments - System Peaks and Use of DSM Resources

Duke replied to the Public Staff's conclusion that the utilities should maximize the use of their DSM to reduce fuel costs, especially when marginal costs of energy are high. Duke commented that this is a practice currently utilized by DEC and DEP. However, the program cost impact and lost capacity value associated with customer attrition are also taken into account. According to Duke, this ensures that each program activation provides a net positive benefit to customers.

Commission Conclusions - System Peaks and Use of DSM Resources

The Commission emphasizes that utilizing evaluation, measurement, and verification to help ensure that the impact of DSM programs is accurately represented in the IRPs. The Commission recognizes that the amount of DSM load reduction actually realized during a DSM event may be different than the totals included in IRP planning and included in the load forecast tables. However, the Commission is of the opinion that the planned reserve margin targets, in part, exist to address the difference in actual DSM achieved versus planned, in much the same way it covers generating capacity that is not available at the time of the peak. Therefore, the Commission does not find it necessary at this time to act on the recommendation of the Public Staff to instruct the IOUs to discuss DSM activations in terms of the percentage of DSM called upon versus actual response. In addition, the Commission acknowledges Duke's reply comments that state DEC and DEP have incorporated the percentage of DSM (or curtailable resources) in terms of capacity load reduction response (MW reduced) for each program into their DSM activation reporting process. Duke commented that this information will be included in future IRPs.

However, the Commission does share the concern expressed by the Public Staff about the difference in DSM resources available in the winter compared to the summer, especially given the increased sensitivity in planning for winter loads and resources. The Commission agrees with the Public Staff that additional emphasis should be placed on defining and implementing cost-effective DSM programs that will be available to respond to winter peak demands.

ENERGY EFFICIENCY (EE) FORECASTS AND PROGRAMS

Public Staff Comments - EE Forecasts and Programs

The Public Staff's review of the IOUs' DSM/EE forecasts and programs indicated that each IOU complied with the requirements of Commission Rule R8-60 and previous Commission orders[14] regarding the forecasting of DSM and EE program savings, as well

[14] Ordering paragraphs 8 and 9 of Order Approving 2011 Annual Updates to 2010 Biennial Integrated

as the presentation of data related to those savings. Each IOU included information about its respective DSM and EE portfolios that is largely the same as reported in the 2015 IRP updates. Each IOU appropriately addressed the changes in their respective forecast of DSM and EE resources and the peak demand and energy savings from those programs.

The Public Staff commented that several factors continue to affect the IOU's ability to develop and implement cost-effective EE programs. Technological changes are providing more efficient lighting measures for consumers. Additionally, there are potential changes to federal standards for future lighting measures that could make it difficult for an IOU-sponsored EE lighting program to be cost-effective. According to the Public Staff, changes in the avoided costs also are likely to make it more difficult to attain cost-effective programs in general. Further, the Public Staff opined that with lighting being a large portion of the EE portfolios, it is not likely that the amounts of EE savings from lighting measures will continue beyond one or two more years. Other technologies such as space heating/cooling and building envelop measures will continue to face similar headwinds as technologies improve, standards rise, and avoided costs decrease.

Public Staff Comments - DEP and DEC's EE Forecasts and Programs

The Public Staff commented that DEP and DEC's portfolios of EE programs are not materially different from those in the 2015 IRP updates. DEC and DEP have continued to merge their programs so that they mirror one another and have the same incentive structures, incentive amounts, and eligibility requirements. The Public Staff noted that the Commission has approved several requests to modify existing EE programs and to approve new programs, making DEP and DEC's programs virtually identical. The Public Staff commented that in the last few DSM/EE rider proceedings, both DEC and DEP's portfolios have been shifting the source of EE savings away from lighting measures toward behavioral programs (My Home Energy Report and Business Energy Report).

The Public Staff noted that DEP and DEC continue to rely on their 2012 market potential studies for input into EE program design and development. DEP and DEC are currently working to update their market potential study and expect to file their updated studies with their 2017 IRP updates.

The Public Staff noted that DEP and DEC provided a comparison of projected EE savings from their 2014 and 2016 IRPs. According to the Public Staff, DEC's projections did not vary more than 10% between 2014 and 2016; however, DEP's projections did. DEP attributes most of this variance to the addition of several new EE programs to its portfolio over the last two years. The Public Staff also compared the changes between the 2015 IRP update and the 2016 IRPs, and found similar results (11% decrease for DEP and a 9% decrease for DEC, when excluding historical and "rolled off" EE savings).

Resource Plans and 2011 REPS Compliance Plans, dated May 30, 2012, in Docket No. E-100 Sub 128, and ordering paragraphs 7 and 8 of Order Approving Integrated Resource Plans and REPS Compliance Plans, dated June 26, 2015, in Docket No. E-100, Sub 141.

The Public Staff concluded, however, that this comparison may not be appropriate in light of the changes in how the data are presented in the respective IRPs.

Prior to the 2015 IRP updates, the Public Staff compared the net EE savings from one year to another over each planning horizon. According to the Public Staff, this generalized view was sufficient to understand the changes made to EE between IRPs. However, in the 2015 IRP updates, DEP and DEC began removing savings that would "roll off" the EE portfolio. This roll off was a function of measures that had reached their measure life. The Public Staff commented that the rolled-off amount of savings is not easily calculated for years prior to 2015. Therefore, a comparison of data to understand the changes to the EE portfolio savings is not available with any degree of integrity.

The Public Staff noted that both DEP and DEC gave further explanation of this process in their responses to Public Staff data requests. Table C-3 in both DEC and DEP's IRPs explain the process used to move EE savings from the EE portfolio to the forecasted energy sales.[15] The Public Staff commented that it believes this process is reasonable and more accurately conveys the impact of EE on the load forecast of the IRP. These rolled-off EE savings eventually become part of the forecasted energy sales. According to the Public Staff, it is reasonable to expect these rolled-off or historical EE savings will continue to be embedded in the load forecast, as customers are unlikely to revert to less energy efficient habits after an EE measure expires. Further, it is reasonable to expect that consumers would continue to observe efficient habits and replace expiring measures with an equally, or more efficient measure. With changes in energy consuming behaviors, technologies, or appliance standards that will occur in the future, the Public Staff believes that EE measures reaching the end of their measure life and their savings should not be counted as EE portfolio savings. In other words, EE savings do not continue in perpetuity.[16] However, as noted by the Public Staff, the impact of those ongoing behaviors will be determined through future appliance saturation studies and other load research studies that will be captured and represented in DEP and DEC's load forecasts.

Public Staff Comments - DNCP's EE Forecasts and Programs

The Public Staff noted that DNCP's portfolio of EE programs is not significantly different from those in previous IRPs. Two new programs were recently approved (Small Business Improvement and Residential LED Retail Lighting programs) and included in the portfolio. DNCP also included the Residential Programmable Thermostat program in

[15] The process begins by determining the EE savings from all measures on a cumulative basis (measures installed prior to the current year and new measures installed in the current year.) Once cumulative EE savings are determined, the Companies then determine the savings that have reached the end of their measure life. Those expiring savings are then removed from the cumulative amount ("rolled-off"). The net impact on EE savings (savings from new measures installed in the current year, and savings expiring at the end of their measure life) are then subtracted from each company's load forecast.

[16] The Commission has recently ruled that for purposes of REPS compliance, once the utility EE measures reach the end of their measure life, they are not expected to produce continued EE savings in perpetuity that would be eligible for REPS compliance. See Order Approving REPS and REPS EMF Rider and REPS Compliance Report, at 26-27, Docket No. E-2, Sub 1109 (January 17, 2017).

its projections of future EE savings. However, the Public Staff commented that this program was rejected by the Virginia State Corporation Commission (VSCC).[17] Given the small impacts included in the IRP from the Residential Programmable Thermostat program on DNCP's EE portfolio, the Public Staff did not recommend an adjustment to the projected DSM/EE savings.

According to the Public Staff, the projected savings from DNCP's portfolio of EE and DSM programs are substantially less (more than 10% from the savings in the 2015 IRP update) than previous IRPs. There is an overall decrease in peak demand savings of 46% and in energy savings of 75% from the 2015 IRP update. The Public Staff commented that the primary reason relates to the removal of DNCP's Voltage Conservation program from its portfolio. DNCP indicates that this program is directly related to its deployment of automated meter infrastructure (AMI) across its system, and until it has made a more firm decision on AMI deployment, DNCP chose to remove the Voltage Conservation program from its DSM/EE portfolio. The Public Staff also noted that over the planning period, DNCP's EE savings projections indicate a significant shift away from EE savings associated with lighting measures to savings more associated with space heating/cooling.

The Public Staff noted that DNCP completed a market potential study in early 2015; however, DNCP did not incorporate the impacts related to the study until the 2016 IRP. According to the Public Staff, many of the programs discussed in the market potential study are already incorporated in some form in an approved EE program in DNCP's portfolio. The Public Staff commented that in response to its data request, DNCP indicated that it used the potential study as a "guidance tool" in designing future EE programs. Measures could be incorporated into the IRP based on market trends, but there is no direct link between the potential study and the IRP. DNCP also noted that the potential study serves as a first assessment of measures that may be integrated into the EE portfolio, but further review of the measure, as well as information from potential vendors, is used to develop a cost-benefit model. Only after these steps, and a determination that a program could be cost-effectively designed and implemented, would DNCP begin to incorporate the EE measure into its IRP.

The Public Staff further noted that the regulatory environment in Virginia is more stringent toward approving EE measures. The Public Staff commented that DNCP has indicated, in past DSM/EE rider proceedings, that it is more cost-beneficial to implement EE programs on a system-wide basis in Virginia and North Carolina. The Public Staff recommended that where DNCP and its Virginia affiliate cannot offer an EE program on a system-wide basis, DNCP should evaluate whether it could cost-effectively offer the program on a North Carolina-only basis. According to the Public Staff, this approach has allowed DNCP to include cost-effective programs in its North Carolina EE portfolio, the most recent being the Residential Retail LED (light emitting diode) Lighting Program.[18] The Public Staff noted that such a program is consistent with findings of the potential study, which included several LED measures. DNCP continues to evaluate a number of

[17] Final Order dated April 19, 2016, in Case No. PUE-2015-00089.
[18] Approved December 20, 2016, in Docket No. E-22, Sub 539.

options that would allow it to incorporate more of the measures identified in the market potential study into the IRP.

Public Staff Conclusions - EE Forecasts and Programs

Based on the Public Staff's review of the projected DSM/EE savings and DSM/EE portfolios discussed in the IRPs of DEP, DEC, and DNCP, the Public Staff recommended that the IOUs continue to explain any change of 10% or more in the savings projections from the previous IRP or IRP update. Additionally, the Public Staff recommended that the IOUs identify any changes in EE-related technologies, regulatory standards, or other drivers that would impact future projections of EE savings regardless of the 10% threshold. For example, changes in lighting technologies and standards will impact the IOU's ability to achieve cost-effective savings from lighting measures. According to the Public Staff, those changes and trends should receive more detailed discussion in the IRPs. Additionally, the Public staff recommended that the IOUs continue to pursue all cost effective EE and DSM. Finally, the Public Staff recommended that DNCP evaluate the potential to cost-effectively implement any DSM/EE program on a North Carolina-only basis if approval has been denied in Virginia to implement the program on a system-wide basis.

SACE, NRDC, and the Sierra Club Comments - EE Forecasts and Programs

SACE, NRDC, and the Sierra Club commented that the Duke IRPs underutilize cost-effective energy efficiency. These comments rely, in part, upon a study prepared by Daymark Energy Advisors (Daymark) entitled Duke Energy's Resource Plans for the Carolinas: An Evaluation and Alternative Approach, (February 17, 2017), included as Attachment D to the initial comments of SACE, NRDC, and the Sierra Club. Daymark found that Duke prematurely limited the amounts of energy efficiency available as a resource to DEP and DEC through an overly restrictive screening process. According to SACE, NRDC, and the Sierra Club, screening out efficiency options prior to running the resource planning models biases the analysis in favor of supply-side options. SACE, NRDC, and the Sierra Club further commented that Duke's planning process does not allow energy efficiency to be easily compared with supply-side resources in a capacity expansion model.

The Daymark Study states that the screening process by Duke limits the amount of energy efficiency programs to between 60% and 90% of the economic potential (determined by avoided cost). The Daymark Study references Duke's 2012 EE Market Potential Study and noted that it incorporated estimates for the generation supply cost savings that energy efficiency could provide, avoided cost. The Daymark Study stated that this avoided cost level in 2012 was determined to be \$0.07/kWh and Duke's screening process considered energy savings associated with levelized cost of energy that is lower than \$0.07/kWh of the DSM supply curve to be economical. Thus, "economic potential" is defined as the energy savings associated with EE incremental and program cost being less than \$0.07/kWh. The Daymark Study notes that DEC considered 60% of the economic potential to be achievable and included in Duke's Base preferred case.

Duke's high EE case is approximately 1.5 times greater than the achievable level identified in the Base case.

The Daymark Study defines a new level of energy savings (i.e., strategic potential) to emphasize the possibility of additional EE savings to consider in the long-term planning. As noted in the Daymark Study, strategic potential is not a standard tem in the EE potential studies. However, according to the Daymark Study, use of the strategic potential in planning would not limit the amount of energy efficiency resource available by arbitrarily defining the limit of economic potential.

Duke Reply Comments - EE Forecasts and Programs

Duke commented that SACE/Daymark disagreed with DEC and DEP's estimate of economic and achievable EE potential, which was based on the most recent market potential study at the time of the IRP. Duke noted that the economic potential study employed by DEC and DEP is the cumulative savings up to a levelized cost (including program costs) of $0.07/kWh, a value derived from the avoided costs in effect at the time of the Market Potential study. Duke commented that this is the most logical way to estimate an economic potential because, as required by the regulations in the Carolinas, an EE program must be cost effective in order to be offered, with the exception of certain programs designed for income-qualified customers.

According to Duke, the Daymark Study contends that all of the EE Potential up to approximately $0.09/kWh should be included in the IRP because the levelized costs for this EE Potential "is still lower than the cost of additional nuclear generation." Duke commented that SACE's choice of the portion of the DSM supply curve that they consider to be "inelastic" is purely arbitrary and not relevant. In addition, Duke commented that the proposed "strategic potential" approach does not make sense because the purpose of estimating economic potential in a Market Potential Study is to determine what EE programs would be economically viable in the traditional sense that programs can be deployed at a levelized cost that is lower than the equivalent avoided cost used to value energy efficiency.

Duke commented that it is extremely pertinent and important to point out that, at the time of its Market Potential study, the levelized cost that was considered as the cutoff point for the economic potential was set at $0.07/kWh based upon the avoided costs in effect at the time. However, Duke noted that since that time the levelized costs used in the avoided cost filings have declined by almost 50% versus the costs at the time of the Market Potential study. Because DEC and DEP continued to use an economic potential that was based on the significantly higher avoided costs at the time of the Market Potential study, the forecast of future EE potential included in the 2016 IRPs could actually be considered overly optimistic because it was based on an economic potential that is significantly higher than what would be calculated using this method today.

Finally, Duke commented that DEC's 2016 IRP analysis showed that the inclusion of a portfolio which contained more EE (High Case) was found to be more expensive than the Base Case, as shown in Table 8-B on page 37 of the 2016 DEC IRP. In addition, Duke stated that even if the High Case were chosen, the impact on the resource plan was minimal, resulting only in the delay of a CT by one year during the next 15-year planning horizon. Therefore, SACE's contention that Duke "prematurely limited" the amount of EE in its IRP analysis is simply without foundation. Duke commented that the IRP report clearly shows that Duke evaluated the inclusion of additional EE in the High EE case and the resulting portfolio was found to be more expensive than the recommended IRP resource plan.

DNCP Reply Comments - EE Forecasts and Programs

DNCP noted that the Public Staff recommended that the utilities continue to explain any change of 10% or more in the savings projections from the previous IRP or IRP update; and identify any changes in EE-related technologies, regulatory standards, or other drivers that would impact future projections of EE savings regardless of the 10% threshold. DNCP commented that it will continue to explain changes of 10% or more in the savings projections from the previous IRP or IRP update. Further, DNCP commented that it would be challenging to identify "all" changes in EE-related technologies, regulatory standards, or other drivers that would impact future projections of EE savings regardless of the 10% threshold. According to DNCP, it is more reasonable to be required to include "major known" changes in regulations and manufacturing standards, rather than each one regardless of any type of materiality standard.

DNCP also noted that the Public Staff recommended that where Dominion and its Virginia affiliate cannot offer an EE program on a system-wide basis that DNCP evaluate whether it could cost-effectively offer the program on a North Carolina-only basis. DNCP commented that Dominion has previously offered North Carolina-only EE programs, such as its Residential Retail Lighting Program, and will continue to evaluate additional North Carolina-only programs, as may be appropriate.

Commission Conclusions - EE Forecasts and Programs

Based on the foregoing, the comments of the parties, and the entire record in this proceeding, the Commission concludes that the IOU's approach to utilizing economic and achievable EE potential, linked to avoided cost calculations, is appropriate to ensure the cost-effectiveness of EE Programs. The Commission agrees with the Public Staff's comments that the utilities complied with the requirements of Commission Rule R8-60 and previous Commission orders[19] regarding the forecasting of DSM and EE program savings, as well as the presentation of data related to those savings. However, the Commission does not agree with the position of SACE, NRDC, and the Sierra Club that the Duke IRPs underutilize cost-effective energy efficiency. Further, the Commission is not persuaded by SACE, NRDC, and the Sierra Club's argument for using a "strategic potential" approach to planning, as defined in the Daymark Study.

---

[19] See Ordering paragraphs 8 and 9 of Order Approving 2011 Annual Updates to 2010 Biennial Integrated Resource Plans and 2011 REPS Compliance Plans, dated May 30, 2012, in Docket No. E-100 Sub 128, and ordering paragraphs 7 and 8 of Order Approving Integrated Resource Plans and REPS Compliance Plans, dated June 26, 2015, in Docket No. E-100, Sub 141.

The Commission appreciates the Public Staff's assessment that several factors continue to affect the IOU's ability to develop and implement cost-effective EE programs. As noted in its comments, changes in avoided costs, including those pending before the Commission in Docket No. E-100, Sub 148, could make it more difficult to attain cost-effective programs in general. Still, the Commission finds the logical approach of the utilities, linked to avoided costs, valid for planning.

The Commission acknowledges the challenges described in the Public Staff's comments, including the "headwinds" associated with technology improvements, rising standards, and decreasing avoided costs. The IOUs should continue to explain changes of 10% or more in the savings projections from the previous IRP or IRP update. The Commission also finds it reasonable for the IOUs to continue to address major known changes in EE-related technologies, regulatory standards, and other drivers that would impact future projections of EE savings.

Finally, the Commission encourages DNCP to continue to evaluate additional North Carolina-only programs.

CARBON REGULATION AND CLEAN POWER PLAN

Public Staff Comments - Carbon Regulation and Clean Power Plan

On June 18, 2014, the United States Environmental Protection Agency (EPA) proposed a new rule under Section 111(d) of the Clean Air Act (Clean Power Plan or Plan) to limit carbon dioxide (CO_2) emissions from existing fossil fuel-fired electric generating units by requiring substantial reductions in CO_2 intensity. On August 3, 2015, the EPA finalized the Clean Power Plan, requiring states to submit to EPA by September 6, 2016, an initial state implementation plan designed to achieve the required CO_2 reductions, and a final plan by September 6, 2018. The Clean Power Plan established two rate-based and two mass-based compliance pathways for states to consider in the development of their state implementation plans. Under the Plan, the EPA should review and approve or disapprove state plans within 12 months of receipt. The emission limitations are scheduled to take effect beginning in 2022.

Petitions challenging the Clean Power Plan were filed with the U.S. Court of Appeals for the District of Columbia (D.C. Circuit). The U.S. Supreme Court issued a stay on implementation of the Clean Power Plan on February 9, 2016. The D.C. Circuit heard oral arguments on September 27, 2016. A decision from the DC Circuit is expected in 2017, and is likely to be appealed to the Supreme Court. Additional uncertainty as to how North Carolina and the EPA will proceed in regard to the Clean Power Plan has been introduced due to the recent change in administrations at both the state and federal level.

In their 2016 IRPs, DEP and DEC assert that they cannot assess the impact of the Clean Power Plan on their operations due to all the uncertainties surrounding the Plan's implementation. DEP and DEC utilized a mass-based compliance plan and other expansion plans that included a price for carbon emissions as a proxy for carbon regulation. DNCP chose to evaluate and plan for complying with the Clean Power Plan in its IRP, as the Commonwealth of Virginia has elected to continue the development of its state implementation plan.[20] As part of its 2016 IRP, DNCP included a least cost plan that was non-compliant with the Clean Power Plan as well as four compliance plans compliant with the rate-based and mass-based targets.

The Public Staff noted that DEP and DEC did not include expansion plans in their IRPs without a price for carbon. Both utilities (and DNCP) included plans in their 2014 IRPs without a price for carbon. According to the Public Staff, an expansion plan that does not include a price for carbon is more than merely informative. In the 2014 avoided cost proceeding in Docket No. E-100, Sub 140, the Commission held that the generation expansion plans used in avoided cost production cost models should be based on IRP expansion plans that take into account only known and quantifiable costs, and required DEP and DEC to recalculate their avoided energy rates utilizing generation expansion plan scenarios that did not include the costs of carbon. The Public Staff further commented that in the context of DSM and EE programs, the inclusion of carbon has rate implications to customers, both in the evaluation of the cost-effectiveness of programs and in determining the participant incentives to utilities.

The Public Staff commented that in the context of developing a robust long-term resource plan, the Public Staff continues to believe it is appropriate to evaluate the scenarios that both include and exclude explicit costs associated with carbon regulation. While there is currently no such explicit cost, the Public Staff suggested it is appropriate to include scenarios that assume carbon costs based on the possibility that a known and measurable cost of carbon may exist in the future. As such, the Public Staff recommended that the Commission require DEP and DEC, in future IRPs, to include scenarios that both include and exclude costs associated with carbon regulation.

Commission Conclusions - Carbon Regulation and Clean Power Plan

The Commission acknowledges the uncertainties with regard to carbon regulation generally, and specifically as to the Clean Power Plan. After the Public Staff filed its comments on February 17, 2017, President Trump signed an executive order directing the EPA to review the Clean Power Plan and other greenhouse gas regulations for the power sector.[21] This executive order, EPA's review required by the executive order, and the pendency of the legal challenge to the validity of the Clean Power Plan, continues the uncertainty associated with carbon and its impact on Integrated Resource Planning. The Commission, however, expects the utilities to continue to analyze the impacts of carbon emissions under different scenarios in their planning.

---

[20] In its 2014, 2015, and 2016 IRP proceedings, the Virginia State Corporations Commission (VSCC) directed the Virginia Electric and Power Company (operating as DNCP in North Carolina and Dominion Virginia Power in Virginia) to consider and include various options for complying with the Clean Power Plan because of its significance to electric utility resource planning. See VSCC Case No. PUE-2013-00088, Final Order dated August 27, 2014; VSCC Case No. PUE-2015-00035, Final Order dated December 30, 2015; and VSCC Case No. PUE-2016-00049, Final Order dated December 14, 2016.

[21] Exec. Order No. 13783, 82 Fed. Reg. 16093 (Mar. 31, 2017).

Duke commented that DEC and DEP did not include a scenario that excluded carbon costs in the scenario evaluation portion of their analyses; however, Duke agreed that, given the current political climate and lack of carbon legislation, including scenarios that both exclude and include carbon costs in future IRPs is reasonable until such time that a carbon policy is in place. Therefore, based on the recommendation of the Public Staff and Duke's comments above, the Commission concludes that DEP and DEC should include scenarios in future IRPs or IRP updates, that include and exclude costs associated with carbon regulation.

The Commission also finds and concludes that the methodologies utilized by the utilities to address carbon in their 2016 IRPs are appropriate for planning pending further federal and state actions that provide clarity on the possibility of carbon regulation.

PROJECTED PRICES FOR NATURAL GAS

Beginning with the 2015 IRPs, DEP and DEC migrated to a fuel forecasting methodology for natural gas that included market based prices for the first 10 years of the planning period. This was a change from the methodology utilized in the 2014 IRP where the first 5 years of natural gas prices were based on market data and the remaining years were based off of fundamental pricing. DEP and DEC discussed the rationale behind this move in their 2015 IRP updates. Consistent with the 2015 updates, DEP and DEC utilized the same methodology in their 2016 IRPs based on 10 years of market-based prices.[22]

DNCP utilized forward price for the first 18 months and then blended the forward prices with a fundamental price forecast for the next 18 months to transition to its long-term forecast developed by ICF International, Inc.

Public Staff Comments - Projected Prices for Natural Gas

The Public Staff commented that it appreciates the difficulty in forecasting long-term prices of natural gas as well as other fuel prices, and found reasonable DNCP's reliance on forecasts from ICP International, Inc. However, the Public Staff expressed concerns with the natural gas price forecasts utilized by DEP and DEC in their 2016 IRPs.

The Public Staff commented that the proposed use of forward natural gas prices for ten years by DEP and DEC leads to natural gas prices that it believes to be overly conservative and inappropriate for planning purposes. The Public Staff found more reasonable DNCP's approach of using forward price data for the short-term before transitioning to its long-term fundamental natural gas price forecast.

The Public Staff noted in its comments that the use of an excessively conservative natural gas price forecast is unlikely to alter DEP and DEC's generation expansion plan, however, the use of a low gas price forecast will depress the avoided energy costs that are paid to qualifying facilities, and also reduce the avoided energy costs that are used to evaluate the cost-effectiveness of DSM and EE programs.

[22] Rebuttal Testimony of Glen Snider, Docket No. E-100, Sub 148 (April 10, 2017), at 17.

The Public Staff recommended that DEP and DEC, in future expansion models, reflect the use of no more than five years of forward natural gas prices.

NCSEA Comments - Projected Prices for Natural Gas

NCSEA noted Duke's reliance on "forward prices" rather than fundamental fuel forecasts in developing IRPs, and by extension their avoided cost calculations. NCSEA requested that the Commission address or determine whether such significant reliance on forward prices in fuel forecasting is appropriate in the context of the avoided cost proceeding. NCSEA noted that in past proceedings, the Commission has addressed the interdependence of the utilities' long-term fuel forecasts and generation expansion plans and has discussed that fuel forecasts drive the utilities' generation planning and generation building decisions.[23]

NCSEA commented that the Commission has previously noted the shortcomings of forward market prices relative to the long-term forecasts, which are prepared by firms whose expertise is in long-term forecasting. According to NCSEA, the Commission has never directed the utilities to construct their respective fuel forecasts using a specific number of years of forward market prices and a specific number of years of fundamental, long-term forecasts even though the Commission has cautioned of the risks associated with the forward prices.

NCSEA noted that it has previously stated and supported its position on the construction of fuel forecasts using a blend of forward prices from futures markets and fundamental-based forecasts in future years through the Affidavit of Ben Johnson, Ph. D., filed in Docket No. E-100, Sub 140, on August 7, 2015. Based on Mr. Johnson's Affidavit, NCSEA contends that fundamental forecasts are an appropriate source of fuel cost data since they represent an estimate of the price that will be paid by the utility for specific types of fuel purchased at specific dates in the future.

NCSEA commented that in contrast, forward prices from the futures markets are not predictions or estimates of what prices will occur in the future. Rather, forward prices tend to systematically understate the true cost of acquiring fuel at future dates. The prices observed in the futures markets are generally not for the fuel itself, but for contracts that represent a carefully structured, highly standardized bundle of legal rights and obligations. According to NCSEA, utilities do not typically purchase fuel in futures markets in order to receive physical delivery of the fuel at future dates. But, if they were to do so, they would incur substantial additional carrying costs for fuel purchased in this manner, over and above the "forward price" paid for the futures contract itself. NCSEA goes on to state that these carrying costs include interest on their investment and the cost of equity capital during the entire time from the date when they purchase the futures contract until the date when they receive physical delivery of the fuel, months or years later. Therefore, according to NCSEA, futures prices tend to systematically understate the actual cost of

[23] Order Establishing Standard Rates and Contract Terms for Qualifying facilities, Docket No. E-100, Sub 140 (December 17, 2015), at 24-27.

acquiring fuel for future delivery, and the magnitude of this understatement becomes more serous the longer the time period over which future prices are being used.

NCSEA argued that fundamentals-based forecasts in future years are more representative of a utility's avoided cost and that it is not appropriate to rely on ten years of forward prices in estimating future avoided cost. NCSEA commented that to the extent forward prices are appropriately relied upon, rather than the fundamental long-term forecasts, it is particularly significant in the context of the biennial avoided cost proceeding, which is currently pending before the Commission in Docket No. E-100, Sub 148. Accordingly, NCSEA requested that the Commission address or determine whether such significant reliance on forward prices is appropriate in the context of the avoided cost proceeding. NCSEA commented that the appropriate reliance on fundamental forecast and future prices, and the appropriate time periods over which these data sources should be used, are issues that are best resolved in the context of the avoided cost proceeding.

Duke Reply Comments - Projected Prices for Natural Gas

Duke's reply comments addressed a number of the Public Staff's concerns, including the position taken by the Public Staff that forward markets are "overly conservative," or too low. Duke noted that in Docket No. E-100, Sub 148, Duke witness Glen Snider, Director of Carolinas Resource Planning and Analytics, presented extensive data demonstrating just the opposite. Duke commented that witness Snider shows that fundamental forecasts have systematically overestimated market prices over the last several years as continued advancements in natural gas fracturing drive down gas prices. Duke goes on to state that a transactable market is neither aggressive nor conservative; it is simply the prevailing market price for forward purchases of natural gas. In fact, over the last few years, both the forward prices and fundamental forecasts have been higher than realized prices, with fundamental forecasts overshooting the mark by a larger margin than forward prices.

Duke noted that the Public Staff recognizes that the forecast of the next 10 years of fuel prices will actually make very little difference in the context of an IRP that is evaluating 40-year generation assets that are projected to come online over the 15-year IRP planning horizon. However, the 10-year fuel price issue has the potential to directly impact contractual obligations to qualified facilities (QFs) under avoided cost ratemaking. As such, Duke commented that the Public Staff's recommendation to only use five years of liquid market data rather than 10 years of liquid market data is more appropriately addressed in the avoided cost docket as opposed to the IRP docket.

Duke also addressed in its reply comments NCSEA's concerns that forward prices drastically understate the true cost of acquiring fuel for future delivery, and that if utilities actually purchased fuel in futures markets to receive physical delivery at a future date, they would incur substantial carrying costs. Duke commented that purchasing natural gas forwards or futures does not involve substantial carrying costs. To the contrary, such transactions merely involve the contractual agreement of a future price for natural gas. According to Duke, these forward transactions do not involve a payment today for a commodity delivered in the future and as such they do not have "substantial carrying costs."

Commission Conclusions - Projected Prices for Natural Gas

In its March 22, 2016 Order Accepting Filing of 2015 Update Reports (Docket No. E-100, Sub 141), the Commission accepted the update reports filed by the IOUs as complete and fulfilling the requirements set out in Commission Rule R8-60. DEP and DEC utilized a fuel forecasting methodology for the 2015 IRP updates that included market based prices for the first 10 years of the planning period for natural gas. The following excerpt from DEP and DEC's 2015 IRP update reports summarizes the utilities' rationale behind use of this methodology.

> In the 2014 IRP, the first 5 years of natural gas prices were based on market data and the remaining years were based off of fundamental pricing. Market prices represent liquid, tradable gas prices offered at the present time, also called "future or forward prices." These prices represent an actual contractually agreed upon price that willing buyers and sellers agree to transact upon at a specified future date. As such, assuming market liquidity, they represent the markets view of spot prices for a given point in the future. Fundamental prices developed through external econometric models, on the other hand, represent a projection of fuel prices into the future taking into account changing supply and demand assumptions of the changing dynamics of the external marketplace. The natural gas market has become more liquid, and there are now multiple buyers and sellers of natural gas in the marketplace that are willing to transact at longer transaction terms. Due to the evolving natural gas market, DEP and DEC are using market based prices for the first 10 years of the planning period (2016 – 2025O. Following the 10 years of market prices, DEC and DEP transition to fundamental pricing over a 5 year period with 100% fundamental pricing in 2030 and beyond.

In the 2016 biennial proceeding on avoided cost rates (Docket No. E-100, Sub 148), Duke witness Snider provided extensive testimony on market vs. fundamental fuel prices. This matter is currently pending before the Commission.[24] In that docket, witness Snider commented as follows in his rebuttal testimony:

> In Phase 2 of the Sub 140 proceeding, Duke proposed to continue a trend initially begun in recent integrated resource plans of more heavily relying upon forward market price data as a more precise indicator of the near-term future commodity costs of natural gas for purposes of calculating Duke's avoided energy cost rates. Specifically, Duke proposed to rely upon 10 years of forward market price data as a more accurate indicator of the future commodity costs of natural gas and to then transition to fundamental forecast data starting in year 11. However, at the time Duke filed its

[24] Rebuttal Testimony of Glen Snider, Docket No. E-100, Sub 148 (April 10, 2017) at 5-8 and 15-28.

> proposed avoided cost rates in Sub 140 Phase 2, Duke's then pending 2014 IRPs had relied upon only five years of forward market price data before transitioning to reliance on fundamental forecast data for the remainder of the 30 year planning horizon. In its Sub 140 Phase 2 Order, the Commission recognized that changing market conditions supported Duke's increased reliance on forward market price data, acknowledging "the changing nature of the natural gas market and the fact that lower natural gas prices in the short- and long-term will result in benefits to ratepayers in the form of lower-cost electricity rates."[25]

Based on DEP and DEC's 2015 IRP updates and Duke witness Snider's extensive testimony on this subject in the 2016 avoided cost hearing, the Commission accepts that the fuel forecasting methodology utilized by DEP and DEC is appropriate for Integrated Resource Planning in this docket.

The Commission accepts that the fuel forecasting methodology utilized by DNCP is also appropriate for Integrated Resource Planning in this docket.

As discussed in its avoided cost Order in Docket No. E-100, Sub 140,[26] the Commission re-emphasizes the relationship between the IRP and avoided costs and the need for their inputs and assumptions to be consistent. The Commission recognizes, however, that generation expansion plans are less sensitive to changes in fuel forecasts compared to their impact on avoided energy costs that are also used to evaluate the cost-effectiveness of DSM and EE programs. Consistent with the comments of NCSEA and Duke's reply comments, the Commission determines that specific issues related to fuel forecasting methodologies employed by the utilities, are best resolved in the context of the avoided cost proceeding. Accordingly, the Commission's acceptance of fuel forecasting methodologies in the present IRP docket shall not be precedent for or in any manner prejudice decisions to be made in the pending avoided cost proceeding in Docket No. E-100, Sub 148.

Rather than address the Public Staff's recommendation that would require DEP and DEC to use no more than five years of forward natural gas prices in future expansion models, the Commission will defer to decisions pending in the avoided cost proceeding.

NATURAL GAS ISSUES

Ordering Paragraph No. 15 of the 2014 IRP Order, required that, consistent with the Commission's May 7, 2013 Order in Docket No. M-100, Sub 135, the IOUs shall continue to include with their future IRP submittals verified testimony addressing natural gas issues, as detailed in the body of that Order.

---

[25] Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, Docket No. E-100, Sub 140 (December 17, 2015), at 27.

[26] Id. at 28.

In the Commission's May 7, 2013 Order Approving Rules, Requesting Comments, and Establishing Requirements for Electric Integrated Resource Plans to be Filed in 2014, in Docket No. M-100, Sub 135 (Sub 135 Order), the Commission detailed these natural gas issues:

1. The potential risks inherent in their [the electric utilities'] increasing reliance on natural gas as a generation fuel and the long-term adequacy of North Carolina's gas infrastructure.
2. The electric utilities' plans for procuring the additional gas supplies that would be required by the generation proposed in their IRPs.
3. The electric utilities' plans to ensure long-term gas supply reliability and adequacy.
4. The electric utilities' understanding of how much additional pipeline infrastructure will be needed, and when, due to the combined needs of gas distribution companies and existing and proposed gas-fueled electric generation.
5. The advantages and disadvantages of a second major pipeline being built through North Carolina, and the electric utilities' understanding of the steps that would need to occur to effectuate such construction.

In response to the Commission's 2014 IRP Order, the three IOUs filed testimony in this Docket No. E-100, Sub 147, addressing the issues posed in the Sub 135 Order.

DNCP presented the testimony of Ted S. Fasca, Manager of Generation System Planning. Witness Fasca indicated that although Virginia Electric and Power Company (VEPCO), operating as DNCP in North Carolina and as Dominion Virginia Power in Virginia, has limited gas-fueled generation resources physically located in North Carolina, it plans for and operates its combined North Carolina and Virginia service territory as a single, integrated system. VEPCO manages a balanced mix of fuels that includes fossil (gas, coal, petroleum), nuclear, biomass, and renewable (hydro and solar).

Witness Fasca testified that VEPCO's Virginia electric generating assets are fueled by four major gas pipelines: Transcontinental Gas Pipe Line Company, LLC (Transco), Columbia Gas Transmission (TCO), Dominion Transmission, Inc. (DTI), and Dominion Cove Point LNG, LP (Cove Point). Transco spans from the Gulf of Mexico (GOM) along the east cost up to New York and Pennsylvania. Transco pulls supply from the GOM as well as shale areas in Ohio, Pennsylvania, and West Virginia and is currently the only major gas pipeline in North Carolina. TCO is supplied from the GOM and the Marcellus market areas. TCO does not have any new firm capacity available to supply VEPCO. DTI is primarily centralized in the northeast, spanning Ohio, Pennsylvania, New York, Maryland, Virginia, and West Virginia. DTI has ample supply from the Marcellus and Utica shale regions, but current firm transportation (FT) is limited in VEPCO's service territory. Cove Point connects Cove Point LNG (liquefied natural gas) facility to the Transco, TCO, and DTI pipelines.

According to witness Fasca, VEPCO currently only has one natural gas fueled electric generating unit in North Carolina – the Rosemary Power Station (Rosemary) located in Roanoke Rapids. Rosemary began operation in 1990 and is capable of generating 165 MW. It also has dual-fuel capacity, enabling operation on oil when gas supply is unavailable. Rosemary has 3,183 dekatherms per day (dt/day) of FT on Transco, and, due to the cost of additional FT service for this unit being uneconomic due to the existing air permit limit, VEPCO has no plans to acquire additional FT for this unit. Witness Fasca testified that DNCP intends to continue relying on interruptible transportation (IT) service and the unit's oil backup capability to operate, with limited FT primarily for start-up.

Witness Fasca testified that VEPCO recognizes the abundant supply and low cost of shale gas in recent years and is relying nearly exclusively on natural gas for meeting growth in its electric customer demand. VEPCO plans to continue acquiring FT service for all new large baseload and intermediate gas-fired generating resources. Specifically, he testified that VEPCO has two major CC projects under construction, both of which have FT contracts to fuel them: the Warren County Power Station[27] – 1,337 MW, and the Brunswick County Power Station – 1,375 MW, which is scheduled to be in service in 2016.[28] VEPCO is also planning an additional 3x1 CC plant to be in service in 2019 and is evaluating gas supply options and FT service.

Witness Fasca testified that DNCP executed a Precedent Agreement (PA) with Atlantic Coast Pipeline (ACP) for 300,000 dts/day of FT capacity. Witness Fasca concluded that this additional capacity will benefit DNCP's system portfolio by providing greater access to the Marcellus/Utica supply basins in close proximity to the Brunswick and Greensville CCs.

Witness Fasca presented DNCP's assessment of its natural gas reliability and supply adequacy. He stated that interruptions to a single pipeline are manageable, but additional actions are needed to ensure future reliability and rate stability. He noted DNCP's plans to increase the natural gas pipeline capacity into its service territory, acquire additional FT service on available pipelines, equip future CCs and CTs with dual fuel capability, and continue evaluating opportunities for incremental pipeline capacity. Mr. Fasca indicated that DNCP supports greenfield pipeline projects that allow for future, low-cost expansions that cannot be achieved easily on existing pipelines. He also pointed out that with the eventual reduced capacity constraints on pipelines, pricing should become less volatile and more reliable on peak demand days. Finally, witness Fasca noted that additional pipelines increase the operational flexibility of electric generating plants.

DEP and DEC presented the testimony of Swati V. Daji, Senior Vice President, Fuels & Systems Optimization for Duke Energy Corporation. Witness Daji presented Duke's assessment of the natural gas supply market. Specifically, she stated that the development of shale gas has created a fundamental shift in the nation's natural gas market and has contributed to substantial increases in the supply of natural gas in the United States. Witness Daji noted the Energy Information Administration's projection that

---

[27] The Warren County Power Station commenced commercial operation on December 10, 2014.

[28] The Brunswick County Power Station commenced commercial operation on April 25, 2016.

shale gas supply will provide over 69% of domestic natural gas production by the year 2040, and noted that the Marcellus and Utica shale gas supply basins are in a period of rapid growth, which should continue. She stated that electric utilities have the opportunity to diversify their gas supply sources across a growing supply.

Witness Daji indicated that DEP has natural gas fueled generation capability of approximately 2,391 MW of natural gas-fired CTs and 2,991 MW of CCs, and that DEC has a total of 3,204 MW of natural gas-fired CTs and 1,403 MW of CCs. Witness Daji indicated that the 2016 IRP base case shows that between 2017 and 2031, DEP is planning to add 5,409 MW of new natural gas-fired generation and DEC is planning an additional 2,481 MW.

In regard to its supply and transportation procurement plan, witness Daji indicated that DEP and DEC operate pursuant to an Asset Management Agreement (AMA) approved by the Commission. In the AMA, DEC is the designated Asset Manager that procures and manages the combined gas supply needs for DEP and DEC, including the scheduling and balancing functions. The AMA also includes a storage agreement. Duke Energy computes a five-year gas usage forecast four times a year and a 15-year forecast updated at least once a year. These forecasts incorporate system load forecasts, market fuel and emission prices, unit capacity ratings and heat rates, and maintenance schedules.

Duke Energy, along with Piedmont Natural Gas Company, Inc. (Piedmont), issued a joint RFP for 900,000 MMBtu (one million British thermal units) per day, pursuant to which 725,000 MMBtu/day would belong to DEP and DEC, beginning November 1, 2018, with an option for additional quantities. The winning bidder was the proposed Atlantic Coast Pipeline (ACP). Duke Energy believes a second major pipeline in the State would offer significant benefits to gas generation customers as well as other end users of natural gas. These benefits include the provision of needed infrastructure to support gas generation growth, a significant opportunity to enhance supply diversity and reliability, and enhanced flexibility, reliability, and integration into the North Carolina gas distribution infrastructure. According to Duke, additional benefits are the promotion of a long-term competitive environment for future pipeline capacity additions, diversification of the natural gas supply by accessing shale gas supplies in the Marcellus and Utica shale basins, and the introduction of an additional gas supplier, which would increase diversity of natural gas supply and credit portfolios. Duke Energy was unable to identify any disadvantages associated with this second major pipeline in the State.

Witness Daji indicated that the ACP project is pursuing its Final Environmental Impact Study, which is planned for completion by June 30, 2017, and final approval of need from the FERC by September 13, 2017. Based on this updated schedule, construction of the ACP should begin thereafter, with an in service date of late 2019 rather than late 2018 as originally projected.

Public Staff Comments - Natural Gas Issues

The Public Staff concluded that DEP, DEC, and DNCP made a reasonable assessment of their needs for natural gas infrastructure in order to meet their growing dependence on natural gas to provide electric generation. According to the Public Staff, the utilities also demonstrated their understanding of how an interstate pipeline is planned, approved, and built, including the open season period to determine the market for the pipeline and associated costs. Additionally, the Public Staff commented that the IOUs are knowledgeable about the natural gas supply market, as well as the pipeline planning and build-out in order to move the natural gas supply to their electric generation facilities. It appears that the ACP will indeed be the second major natural gas pipeline into the State of North Carolina. The utilities adequately set out the benefits of this additional pipeline.

The Public Staff recommended that the electric utilities and the natural gas distribution companies continue to work together with ACP in planning for adequate pipeline capacity to meet electric generation needs. The Public Staff also recommended that the electric utilities consider natural gas electric generation facilities that also can operate on an alternate fuel.

NC WARN Comments - Natural Gas Issues

NC WARN noted in its initial comments, that one of the most glaring deficiencies in the Duke IRPs filed in this docket is the proposed massive investment by both utilities in new natural gas infrastructure, which will further exacerbate the climate crisis.

NC WARN further commented that Duke remains heavily reliant on construction of new natural gas infrastructure, including power plants and new natural gas pipelines, such as the Atlantic Coast Pipeline. NC WARN stated that Duke Energy's increasing dependence on natural gas is troublesome because of the likely future cost increase from fuel supply and production limitations[29] and the impacts of methane from natural gas infrastructure on the climate crisis.[30] According to NC WARN, rather than addressing these issues squarely, the IRPs forecast the need for more and more natural gas plants.

---

[29] J. David Hughes, 2016 Shale Gas Reality Check, Fall 2016. http://www.postcarbon.org/2016-shale-gas-reality-check/.

[30] Dr. Robert W. Howarth, "Methane emissions: The greenhouse gas footprint of natural gas," September 2016. http://www.eeb.cornell.edu/howarth/summaries CH4 2016.php.

DEC plans to add 2,481 MW of new natural gas capacity by 2031 and DEP plans to add 5,409 MW of new natural gas capacity by 2031.

NC WARN also filed reply comments that specifically addressed the testimony on natural gas issues by Swati V. Daji. NC WARN noted that Nancy LaPlaca, J.D. drafted the reply comments which asserted that:

1. Future U.S. natural gas supplies are overestimated, which could result in stranded assets.
2. Purchasing gas from its own subsidiary will not provide Duke Energy with a “diverse” and reliable fuel supply.
3. Methane from natural gas has an enormous effect on climate change, as its greenhouse gas warming potential is 86 times worse than carbon dioxide over 20 years.

NC WARN’s basis and support for these assertions are detailed in their reply comments, including a number of references to studies, forecasts, papers, and other documents submitted in support of its positions. NC WARN commented that the supply of natural gas in the U.S. is seriously overestimated, putting ratepayers at risk of rising prices at best, and stranded assets at worst. NC WARN stated that historic production data shows that endless future supplies of shale gas are based on unrealistic forecasts by the U.S. Energy Information Administration (EIA). NC WARN commented that the EIA (and Duke Energy in its planning) expects natural gas production to continue to rise decades into the future, utterly ignoring the fact that shale gas wells decline very quickly over the first three years, and that the oldest U.S. shale gas plays, which have been producing for less than 20 years, are in the advanced stages of decline.

One source referenced by NC WARN is the work of Arthur E. Berman, a geological consultant with 37 years of experience in petroleum exploration and production, as well as financial analysis with a focus on the energy sector. NC WARN commented that Berman has been alerting investors for years that the “magical thinking” behind believing shale gas can continue to be cheap, abundant and profitable defies the rules of economics. According to NC WARN, Berman disputes the findings of the EIA’s 2016 Annual Energy Outlook saying that it “sparkles with pixie dust.”[31] According to NC WARN, Berman points out that although the Marcellus still has gas, and will for many years, the gas cannot be profitably brought to market at the current low prices. NC WARN commented that Berman clearly states that when gas prices are below the cost of production, companies cannot make a profit.

Finally, NC WARN commented that in an era of rapidly decreasing costs for clean energy, and the questionable future supplies and cost of natural gas, it is irresponsible for Duke Energy to promote further reliance on fracked gas in the IRPs. If the cost of

[31] www.albertman.com/shale-gas-magical-thinking-and-the-reality-of-low-gas-prices/.

natural gas either rises dramatically, or is not available over the 30-year life of the natural gas plants, ratepayers could be stuck with stranded assets.

Addressing methane, NC WARN commented that the huge increase in fracking in the U.S. is driving a spike in methane emissions and, according to the most recent report by the Intergovernmental Panel on Climate Change (IPCC) issued in 2013, methane's effect on the climate is 86 times that of carbon dioxide over a 20-year timeframe. According to NC WARN, decisions about the use of natural gas and its impacts on the climate should consider the 20-year timeframe, rather than the longer, 100-year timeframe which causes natural gas to appear to be promoted as more climate-friendly than it actually is.[32]

NC WARN commented that Duke Energy did not consider lifecycle GHG emissions that would result from the buildup of natural gas infrastructures presented in the IRPs. According to NC WARN, Duke Energy fails to provide reasoning or methodology for neglecting to address lifecycle GHG emissions estimates for nearly 8,000 MW of new natural gas power plants, making it impossible for the Commission to evaluate how large cumulative emissions will be over the next thirty years – the proposed lifetime of these projects. Duke Energy must analyze the possibility that additional natural gas infrastructure will lock-in fossil fuel use for decades to come and discourage or prevent the construction of carbon-free energy sources, which has significant implications for the climate. NC WARN further commented that because the construction and operation of new interstate natural gas infrastructure ultimately contributes to increased GHG emission, Duke Energy must fully evaluate these impacts, compare alternatives, and develop mitigation measures as part of its planning.

Duke Reply Comments - Natural Gas Issues

Duke noted that in its April 17, 2017 Reply Comments, NC WARN regurgitates the claims it has attempted to make in several recent past proceedings, including in Docket No. E-2, Sub 1089 (Western Carolinas Modernization Project) and Docket Nos. E-2, Sub 1095, E-7, Sub 100 and G-9, Sub 682 (the Duke Energy/Piedmont Natural Gas merger), that future natural gas supplies in the United States are overstated and that methane from natural gas has an impact on climate change. Rather than engaging in policy arguments that Duke contends are irrelevant to this IRP proceeding, Duke commented that it respectfully asserts that if NC WARN seeks to abolish the use of natural gas or seeks to change the laws and regulations governing the extraction or processing of natural gas or their attendant environmental regulations, those arguments should be made before Congress, the North Carolina General Assembly or the appropriate federal or state agency charged with implementing environmental policy.

Duke further submitted that NC WARN's IRP Comments and Reply Comments are not realistic proposals if the State of North Carolina wants to ensure reliable and affordable electricity is available to the residential, commercial and industrial customers over the IRP planning horizon, as Duke is obligated to do. According to Duke, renewable

[32] https://thinkprogress.org/how-the-epa-and-new-york-times-are-getting-methane-all-wrong-eba3397ce9e5#.s5zcjd205.

resources, EE and DSM are important and increasingly significant components of DEC and DEP's IRPs, but they simply cannot realistically be relied upon in the almost exclusive nature that NC WARN has alleged. In contrast to the NC WARN "plan," the Duke's IRPs present robust and balanced portfolios of diverse supply and demand-side resources that will cost-effectively and reliably serve customers' short and long-term needs across a range of many possible future scenarios. Duke stated that the comments of NC WARN should be disregarded.

Commission Conclusions - Natural Gas Issues

Based on a review of witnesses Fasca's and Daji's filed testimony in this docket, along with the review and comments of the Public Staff, the Commission finds that the IOU's responses to the issues raised in the Commission's Sub 135 Order adequately address the Commission's concerns. The Commission does not anticipate the need to have such detailed testimony to be filed in subsequent IRPs or IRP updates. This is not to detract from the importance the Commission places on the identification and implementation of plans to address natural gas issues, including those identified in the Sub 135 Order. The Commission has confidence in the ability of the IOUs to timely and effectively address natural gas issues related not only to technologies employed but also the science.

As the Commission concluded in the preceding section on Projected Prices for Natural Gas, the IOU's fuel forecasting methodologies are appropriate for Integrated Resource Planning. The Commission is of the opinion that the current scenario planning and risk analyses utilized by the IOU's effectively address key market drivers such as natural gas supplies.[33]

As also discussed above, the Commission expects the IOUs to continue to analyze the impacts of carbon emissions under different scenarios in their planning, despite the continuing uncertainties about future carbon regulation. In addition, the Commission notes that the impacts of carbon are based on cost assumptions relative to the Clean Power Plan or other carbon regulations. Therefore, the Commission is of the opinion that the current assessments of carbon included in the IRPs are sufficient for now without requiring a broader approach to assess lifetime GHG emissions (including methane) in the manner recommended by NC WARN.

The Clean Power Plan does not address methane. In fact, the EPA recently instituted a 90-day stay on the Obama administration's limits on methane emissions from oil and gas drilling sites, allowing the fossil fuels industry to submit another round of comments before the rule goes into effect. Moreover, NC WARN's concern with methane emissions is focused primarily on methane leakage and venting within the natural gas production and distribution process. The Commission does not regulate natural gas extraction or interstate transportation. However, the Commission does condition its issuance of CPCNs for electric generating plants - whether fueled by nuclear,

[33] DNCP stated on page 80 of its IRP, "Key drivers include market structure and policy elements that shape allowance, fuel and power markets, ranging from expected capacity and pollution control installations, environmental regulations, and fuel supply-side issues."

coal, natural gas or other sources - on compliance with all applicable laws and regulations, including any environmental permitting requirements. The Commission finds and concludes that such required regulatory approvals and compliance by the utilities are sufficient to address the environmental concerns raised by NC WARN.

The Commission supports the Public Staff's recommendation that the utilities continue to develop methods of quantifying the benefits of fuel diversity. The Commission also supports the Public Staff's recommendation that the utilities consider natural gas electric generation facilities that can also operate on an alternate fuel.

RELICENSING OF EXISTING NUCLEAR PLANTS

Public Staff Comments - Relicensing of Existing Nuclear Plants

The Public Staff commented that one of the significant issues faced by the utilities is the pending expiration of operating licenses for nuclear energy resources in the next 20 to 30 years. According to the Public Staff, current schedules call for retirement of approximately 5,900 MW in the 2030 to 2034 period and the loss of an additional approximately 8,400 MW in the 2036 to 2046 period. The following table summarizes the current license expiration dates for the utilities' nuclear facilities.

Name	Utility	Summer Capacity (MW)	License Expiration Date
Robinson Unit 2	DEP	741	July 2030
Surry Unit 1	DNCP	838	May 2032
Surry Unit 2	DNCP	838	January 2033
Oconee Unit 1	DEC	847	February 2033
Oconee Unit 2	DEC	848	October 2033
Oconee Unit 3	DEC	859	July 2034
Brunswick Unit 2	DEP	932	December 2034
Brunswick Unit 1	DEP	938	September 2036
North Anna Unit 1	DNCP	948	April 2038
North Anna Unit 2	DNCP	944	August 2040
McGuire Unit 1	DEC	1158	June 2041
McGuire Unit 2	DEC	1158	March 2043
Catawba Unit 1	DEC	1140	December 2043
Catawba Unit 2	DEC	1150	December 2043
Harris Unit 1	DEP	928	October 2046

The Public Staff noted that the Nuclear Regulatory Commission (NRC) is in the process of developing draft technical guidance for subsequent license renewal (SLR)[34] that may ultimately provide an option to operators of commercial nuclear power facilities for extension past the current 60-year licenses. The Public Staff commented that any additional license extension will be evaluated by the utility based on the specific risks and costs associated with each unit. The NRC has stated that it expects the first requests for extending unit life to 80 years to be filed in the 2018 to 2019 period.

The Public Staff noted that while there is uncertainty whether further license extensions may be granted, DEC's Oconee and DNCP's Surry and North Anna nuclear plants have been identified as candidates for license extension beyond 60 years.[35] On November 15, 2015, DNCP filed a letter of intent to pursue a second license renewal for Surry Units 1 and 2 by the end of first quarter 2019.[36] The Public Staff speculated that should license extensions for some or perhaps even all of the existing units be approved and be determined to be economic, the utilities' energy and capacity needs and forecasted construction schedule of new generation, as detailed in the 2016 IRPs, would be altered significantly. DEP has indicated that it does not currently plan to seek a second license extension for Robinson Unit 2. The 2016 IRP indicates that Robinson 2 is scheduled to be shut down following the expiration of its current operating license in July 2030.

The Public Staff recommends that the Commission direct the utilities in future IRPs to include a discussion and evaluation of potential subsequent license renewals for all of their existing nuclear units, including an evaluation of the risks and required costs for upgrades, and to reflect any such relicensing plans in future IRPs.

Duke Reply Comments - Relicensing of Existing Nuclear Plants

Duke commented that in making its recommendation, the Public Staff states that DEC's Oconee Nuclear Plant has been identified as a candidate for license extension, but other nuclear units, including DEP's Robinson Unit 2 have not. Duke stated that it would like to clarify, however, that they have made no decisions yet on which nuclear units will be considered as license extension candidates. Duke noted that for planning purposes, the IRP base case assumes retirement at the end of the current license for all nuclear units. Duke also noted that in the 2016 IRPs, it ran a license extension sensitivity which included an assumed 20-year extension of all nuclear units beyond the current 60-year license.[37] Duke commented that it is willing to include a sensitivity for license extensions for existing nuclear assets in future IRPs.

---

[34] Nuclear Regulatory Commission, Subsequent License Renewal, online at: https://www.nrc.gov/reactors/operating/licensing/renewal/subsequent-license-renewal.html.

[35] See, http://www.nytimes.com/2014/10/20/business/power-plants-seek-to-extend-life-of-nuclear-reactors.html?emc=eta1

[36] DNCP included the Letter of Intent as Exhibit 3Y in its 2016 IRP (see p. A-101).

[37] 2016 IRPs, at p. 65.

Duke commented that the nuclear industry is in the initial stages of pursuing SLR for the fleet of operating nuclear power plants. The NRC has determined that no changes are required to the License Renewal regulation (10 CFR Part 54) but regulatory guidance documents will need to be updated to address extending operating licenses to 80 years. These new guidance documents, NUREG-2191 and NUREG-2192, have been drafted by the NRC staff and are expected to be finalized and published in the Federal Register in July 2017. Duke noted that it is currently evaluating pursuing SLR for its nuclear fleet but, at this time, no decision has been made. Duke commented that DEC and DEP believe that the uncertainty regarding license extensions combined with the new nuclear long development cycle (10-15 years to license and construct) makes it imperative that DEC and DEP plan for these assets as if they will not be available, then adjust the IRPs as more information becomes available.

DNCP Reply Comments - Relicensing of Existing Nuclear Plants

DNCP commented that with respect to existing generating facilities, the Public Staff recommended that the Commission direct the IOUs in future IRPs to include a discussion and evaluation of potential SLRs for all of their existing nuclear units, including an evaluation of the risks and required costs for upgrades, and to reflect any such relicensing plans in future IRPs. DNCP commented that DNCP commits to include such discussion in its future IRPs and has already provided this type of information in Section 5.2.2 of its 2017 IRP filed in this docket on May 1, 2017.

Commission Conclusions - Relicensing of Existing Nuclear Plants

The Commission agrees with the Public Staff's recommendation that the utilities should include a discussion and evaluation of potential SLRs for all of their existing nuclear units, including an evaluation of the risks and required costs for upgrades, and to reflect any such relicensing plans in future IRPs. The Commission accepts the discussion and analyses included in the current docket as adequate. However, these should be expanded upon in future IRPs, consistent with the Public Staff's recommendation and especially as guidance documents on the requirements for an SLR are finalized.

NEW NUCLEAR PLANTS

The DEC and DEP IRP's continue to include new nuclear generation as a carbon-free, cost-effective, reliable option within Duke's resource portfolios. DEC's Base Case models commercial operation of the Lee Nuclear Units in 2026 and 2028. While DEP's Base Case does not call for DEP to construct additional self-owned nuclear generation before 2030, it is considered in the IRPs' alternative Joint Planning Case of DEC and DEP. The Joint Planning Case projects shared DEP-DEC ownership of the Lee Nuclear Units in 2026.

The DNCP IRP notes that DNCP is in the process of developing a new nuclear unit, North Anna 3. Based on the expected schedule for obtaining the Combined Operating License (COL) from the NRC, the Virginia State Corporation Commission certification and approval process, and the construction timeline for the facility, the earliest possible in-service date for North Anna 3 is now September 2028. This in-service date was delayed one year from the 2015 plan. The 2029 capacity year would support the option to develop North Anna 3 prior to the Clean Power Plan compliance plan date of 2030, if the Clean Power Plan comes to fruition.

SACE, NRDC, and the Sierra Club Comments - New Nuclear Plants

SACE, NRDC, and the Sierra Club contended that nuclear is not part of a least-cost portfolio. SACE, NRDC, and the Sierra Club commented that construction of new nuclear is fraught with risk and uncertainty, as demonstrated by the cost overruns and construction delays at the V.C. Summer and Vogtle nuclear plants. SACE, NRDC, and the Sierra Club noted that Daymark's analysis shows that despite the Lee Nuclear Units' inclusion in DEC's 2016 IRP, the Lee Nuclear Units are not economic. SACE, NRDC, and the Sierra Club noted that in multiple model runs, Daymark's Aurora model did not select even one nuclear unit. DEC instead "forced" the nuclear units into its IRP and appears to consider nuclear plants as necessary to achieve a System Mass Cap carbon-reduction scenario. However, SACE, NRDC, and the Sierra Club submitted that Daymark's analysis shows that this scenario can be achieved at a lower cost with alternatives to nuclear power.

Duke Reply Comments - New Nuclear Plants

Duke commented that it is apparent that most of SACE, NRDC and the Sierra Club's argument that the IRPs are not "least-cost" hinges on DEC's inclusion of new nuclear resources. As stated in the DEC IRP, Duke acknowledged that the portfolios that include Lee Nuclear are not the least cost from a revenue requirement perspective. Duke commented, however, that at the time the IRPs were developed the plight of carbon emission legislation was unclear, but it was reasonable to assume that some carbon restrictions would be in place in the early to mid-2020s based on the status of the Clean Power Plan at the time. Duke noted that with the potential for stringent carbon emission targets, the assumption that existing nuclear units would not be relicensed, uncertainty of future fuel prices, and in keeping with previous IRP filings, DEC decided that inclusion of new nuclear generation in the late 2020s would be prudent from a planning perspective. Further, the timing and reasonableness of the need for new nuclear generation continue to be evaluated as carbon legislation, natural gas prices, and nuclear relicensing costs change over time.

Commission Conclusions - New Nuclear Plants

The Commission finds that the analyses and methodologies incorporating additional nuclear capacity and energy into the utilities' IRPs are appropriate for planning in this docket. The Commission recognizes the significant uncertainties that must be addressed before any utility decides to move forward with building new nuclear generation. Recent developments with the V.C. Summer and Vogtle units only serve to reinforce the importance of the planning and inherent risk assessments as well as the on-going scrutiny of actions taken. Finally, in response to an intervenor's request for a show cause order, the Commission issued an Order on May 15, 2017, in Docket No. E-7, Sub 819 denying the request and requiring DEC to file additional information about its expenditures and planning for the Lee Nuclear Units.

SOLAR ENERGY

Public Staff Comments - Solar Energy

The Public Staff commented that for both DEP and DEC, the assumption about solar's contribution to peak capacity has a significant impact on future capacity requirements. According to the Public Staff, even a small adjustment in the percent of nameplate capacity available at peak demand has the potential to delay or even eliminate the need for additional capacity. As such, the Public Staff recommended that the issue of aggregate solar generation coincidence at peak for both winter and summer be evaluated further, given the growing importance of solar generation in North Carolina.

SACE, NRDC, and the Sierra Club Comments - Solar Energy

SACE, NRDC, and the Sierra Club commissioned expert analyses of the 2016 Duke IRPs and supporting documents. SACE, NRDC, and the Sierra Club commented that these expert consulting firms, such as Daymark Energy Advisors, concluded that Duke prematurely limited the amounts of solar photovoltaic energy.[38] Daymark's review of the Duke IRP identified constraints placed on the capacity expansion options as a key concern. To test the sensitivity of the results to these constraints, Daymark analyzed select scenarios with reduced constraints on the long-term capacity (retirements and additions) available to Duke. Based on these tests, Daymark determined that relieving constraints on the amount of solar PV led to the economic selection of additional solar capacity.[39] As noted in their report, Daymark utilized data from the Duke model and other publicly available data to construct additional local solar and imported wind configurations as supply options for the model to test against the nuclear and natural gas fired units already available for expansion. Up to seven 500 MW blocks of solar in both DEC and DEP was made available to the capacity expansion module. In addition, five blocks of 100 MW wind from Oklahoma and five blocks of 100 MW Tennessee wind were made available in DEC and five blocks of 50 MW wind from Oklahoma were made available for selection in DEP. For both DEC and DEP service areas, all blocks of solar and wind modeled for capacity selection were in fact selected. Overall, this scenario built approximately 3800 MW less thermal capacity while building approximately 8000 MW of additional renewables. According to the Daymark Report, this scenario indicates that there are higher volumes of renewable generation that would lower total system costs and reduce Duke's system carbon emissions.

---

[38] Duke Energy's Resource Plans for the Carolinas: An Evaluation and Alternative Approach, Daymark Energy Advisors (February 17, 2017) for Natural Resources Defense Council, Sierra Club and Southern Alliance for Clean Energy, Docket No. E-100, Sub 147 (May 10, 2017), Attachment D, pp. 2 & 7.

[39] Id. p. 9.

The Daymark Report noted that Duke appears to have more room on their system for solar PV, as Duke had limited it to 10%. The conclusion in the report was this limit did not result from detailed studies but was considered as judgement.

SACE, NRDC, and the Sierra Club commented that Duke undervalues the capacity that solar provides to the DEC and DEP systems. SACE Director of Research John D. Wilson conducted an analysis[40] of capacity equivalent values for solar energy resources, using data supplied by Duke and by Clean Power Research (CPR). The analysis compared the Duke and CPR data and found that both Duke's data and its method for calculating solar capacity values were severely flawed, resulting in a dramatic undervaluing of solar's capacity benefit to the DEC and DEP systems. The analysis concluded that solar contributes far more to summer and winter peak resource needs than Duke assumed in its IRPs. SACE, NRDC, and the Sierra Club commented that the results of this analysis have important implications not only for Duke's treatment of solar resources in its IRPs, but also for solar avoided costs.

Mr. Wilson's report stated that DEC and DEP undervalue solar because they assess its contribution to peak using what appears to be a simplistic seasonal average of solar capacity factors during certain hours. According to the report, this method is flawed because it gives the same weight to on-peak solar generation (e.g. during the hottest, sunniest hour of a peak load afternoon) as to off-peak generation. SACE's analysis of Clean Power Research's solar generation simulations shows that instead of 44-46%, the summer capacity equivalent value of solar power should be 47-65%, depending on utility and solar technology. For the winter capacity equivalent value, Duke's value of 5% should be increased to 15-26%. As noted in the report, these calculations are derived directly from two hourly datasets covering the 1998-2015 time period. One dataset includes the actual hourly system load and year-ahead peak load forecast for the DEC and DEP planning areas. According to the report, this data is filed on FERC Form 714. The second dataset is simulated hourly generation profiles for fixed mount and single axis tracking PV systems at six locations in the DEC and DEP service areas. This data was provided to SACE by Clean Power Research using its SolarAnywhere model.

By aligning historical system load data with simulated solar generation, the report states that actual performance of solar PV systems can be evaluated under a range of recent meteorological conditions. The 1998-2015 coverage allows for nearly 144,000 comparisons of hourly system load (for each utility) with hourly solar generation. The report notes that this provides an opportunity to conduct a robust statistical analysis of the correlation of solar generation to system load during peak periods.

The report states that taken together, the correlation of higher solar generation with peak load days and the omission of later morning winter peak hours from Duke's capacity equivalence method justifies a significant increase in both the summer and winter capacity equivalent values for fixed mount systems. Furthermore, for single axis tracking systems, the recommended capacity equivalence values are still higher, due to

[40] Analysis of Solar Capacity Equivalent Values for the Duke Energy Carolinas and Duke Energy Progress Systems, John D. Wilson (February 16, 2017) for Natural Resources Defense Council, Sierra Club and Southern Alliance for Clean Energy, Docket No. E-100, Sub 147 (February 17, 2017).

their superior performance in tracking the sun during early morning winter peaks and late afternoon summer peaks. The report concludes that Duke Energy's omission of any distinction by technology type is a significant oversight in its resource planning.

Duke Reply Comments - Solar Energy

Duke commented that DEC and DEP continue to evaluate solar generation profiles, and during winter months the data consistently points to a contribution to peak of approximately 5% during the winter peak hour of 7:00 a.m. to 8:00 a.m. for fixed tilt solar facilities. Duke noted that the majority of winter peaks occur before 7:30 a.m., and at this time in the morning, solar generation is at or near 0% output. Additionally, as single-axis tracking solar facilities become more prevalent on the Duke system, DEC and DEP will evaluate including those facilities, along with their solar generating profiles, in future IRPs. Duke further commented that to the extent solar tracking facilities provide more generating output during the peak hour of 7:00 a.m. to 8:00 a.m., that contribution to peak will be included for those facilities in the IRP evaluation. Duke noted that because DEC and DEP are winter planning, summer solar contribution to peak will not impact their needs for future capacity.

Duke commented that through data requests, Duke requested the inputs into SACE's study that they used to assert that DEC and DEP's 2016 IRPs were allegedly not compliant with Commission requirements and did not represent the "least-cost mix" of resources. Duke noted that when SACE responded that the number of inputs was too voluminous to provide, Duke simply requested the levelized cost of wind/solar energy and the capacity cost of wind/solar resources utilized in their Aurora model along with their corresponding capacity factors. Duke commented that it did not receive this data until after the close of business hours on May 9, 2017, and, therefore, have not had adequate time to quantitatively analyze SACE's assertions.

Duke commented that SACE, NRDC, and the Sierra Club argue that greater reliance on wind and solar generation, along with increased reliance on EE programs, would defer the need for new natural gas generation and would provide for a lower cost portfolio. Duke commented that these arguments are misplaced and noted that DEC and DEP have shown that they are now winter planning utilities, and as such, solar generation does not have the ability to defer the need for new generation. Additionally, a sensitivity of higher levels of solar penetration led to higher revenue requirements. Finally, Duke commented that in the 2016 IRP process, the System Optimizer was allowed to select additional solar generation, and it only selected incremental generation in the stringent carbon scenarios much later in the planning horizon.

Commission Conclusions - Solar Energy

Based on the foregoing, the comments of the parties, and the entire record in this proceeding, the Commission concludes that the utilities' modeling of solar energy and capacity as presented in the 2016 IRPs are reasonable and appropriate for planning purposes in this docket.

However, the Commission finds merit in the Public Staff's recommendation that the issue of aggregate solar generation coincidence at peak for both winter and summer be evaluated further, given the growing importance of solar generation in North Carolina. SACE's Director of Research, Mr. Wilson, utilized in his analysis a methodology that may provide for a more robust statistical analysis of the correlation of solar generation to system load during peak periods. Without taking a position on the merits of this approach, the Commission considers that a more rigorous analysis similar to that employed by Mr. Wilson, may be warranted and consistent with the Public Staff's recommendation. The Commission notes Duke's position that it did not have adequate time to quantitatively analyze SACE's assertions. Therefore, the Commission concludes that Duke should include in a future IRP, an analysis of the methodology employed by Mr. Wilson and any recommended changes to DEC and DEP's current approach.

WIND ENERGY

MAREC Comments - Wind Energy

MAREC commented that wind energy costs have fallen by 66% over the past seven years,[41] and wind energy represents an increasingly competitive form of energy. In addition, by acting quickly to incorporate wind, the full benefits of federal tax credits can be realized.

MAREC noted that the DEC and DEP filings include no wind energy project additions in their forecasts. Further, MAREC commented that the only statements by DNCP in its 2016 IRP with respect to the viability of onshore wind resources were as follows:

> In the past two years, DNCP has evaluated approximately 310 MW of onshore wind third party alternatives, none of which were located in Virginia. While these projects would be less expensive than DNCP's self-build wind options (both onshore and offshore), they were not competitive against new gas-fired generation and at the time of evaluation, were not expected to contribute toward the Commonwealth meeting its CPP requirements and therefore rejected.[42]
>
> DNCP continues to pursue onshore wind development; however, there is a limited amount of onshore wind available within or near its service territory. Only three feasible sites have been identified by DNCP for consideration of onshore wind facilities. These sites are located in Virginia, on mountaintop locations.[43]

---

[41] Lazard's Levelized Cost of Energy – Version 10.0, December 2016 at p. 10: https://www.lazard.com/media/438038/levelized-cost-of-energy-v100.pdf.

[42] DNCP IRP at 103.

[43] DNCP IRP at 110.

MAREC commented that the likely explanation for failure of DNCP to incorporate any onshore wind energy capacity in any of its study plans is DNCP's use of a price of $104.02 per MWh, when comparing wind energy to solar and other resources. MAREC commented that this price for wind for purposes of planning is excessively inflated and therefore not at all representative of wind pricing. According to MAREC, the price of wind utilized by DNCP in its IRP modeling is not based in reality. MAREC commented that the same could be said about the prices utilized by DEC and DEP, as wind did not make it out of the screening process in their IRP analyses. DNCP uses estimates in its IRP that are 3-4 times higher than documented market prices for wind energy contracts. MAREC noted that if DNCP performed a true evaluation of market based wind energy prices, it would have found that the pricing for wind is competitive with other generating resources and, in particular, other renewable energy resources.

The bottom line, according to MAREC, is the utilities failed to carefully consider wind for its competitive pricing, its fuel hedge value, the value it provides as a component of a diverse generation supply resource and the economic development value it provides to North Carolina.

MAREC recommended:

1. That the Commission direct the IOUs to evaluate the market prices for all renewable energy resources for REPS compliance, including seeking additional renewable energy diversity when prices of the various renewable resources are comparable.
2. That the Commission direct the IOUs to conduct RFPs for renewable energy as soon as possible to get the maximum value of the Production Tax Credit. The RFPs should be conducted for long-term PPAs that bundle wind energy and renewable energy certificates to give consumers the benefit of stable pricing and the hedge value of wind energy pricing. The RFPs can be conducted in a manner that successful bids should not be in excess of a price limitation approved by the Commission.
3. That the Commission direct DEC and DEP to include energy pricing for wind and other resource in future cost sensitivity analyses.
4. That the Commission should direct DNCP to reevaluate the pricing it has utilized for purposes of its 2016 IRP. DNCP should be required to conduct a market analysis of wind pricing that should be sufficiently detailed and reviewable.

Duke Reply Comments - Wind Energy

Duke commented that the main locations for wind energy generation in the Carolinas are the North Carolina mountains and onshore coastal regions. With ridge laws prohibiting wind turbine construction in the North Carolina mountains and siting issues along the coast, there are real physical limitations to the amount of wind power that could be built in the Carolinas currently. Duke further noted that while the National Renewable Energy Laboratory study cited by MAREC may have determined a large potential for

North Carolina wind projects, the prohibitive laws and siting issues continue to hinder wind facility construction in North Carolina.

Further, Duke commented that its wind energy pricing is representative of a facility with 100-meter plus towers and larger turbines in order to gain the energy yield necessary to potentially justify construction of a facility. According to Duke, more difficulty lies in locating a wind energy project near a load center with adequate, useful land potential. Duke notes that the Department of Energy and the U.S. Energy Information Administration pricing is very generic and does not account for many of the intricacies of locating a wind farm or any other project.

Duke concluded that DEC and DEP adequately considered wind and all other potential renewable energy resources in preparing their 2016 IRPs. Duke commented that it recognizes the valuable potential that new wind energy resource development could provide. However, DEC and DEP analyzed wind and other generation technologies and selected the resource plans that best meet Duke's needs to provide the reliable, least-cost resource mix as required by North Carolina's Integrated Resource Planning and REPS laws.

DNCP Reply Comments - Wind Energy

DNCP commented that it disputes MAREC's arguments that the wind energy resource pricing presented in the 2016 IRP is overstated. DNCP noted that the installed cost of wind energy in its plan is based on its self-build wind options. These potential projects are located in the mountainous regions of Virginia where expected capital construction costs are projected to be higher than an equivalent project located on a relatively flat, open site, similar to those cited by MAREC which are located in the Great Lakes region or the interior region of the United States. DNCP also cited the 310 MW of third-party alternative projects which were evaluated over the 2015-2016 period in the 2016 IRP. DNCP commented that these projects, while less expensive than DNCP's self-build wind options, did not yield a positive net present value for customers in the analyses performed on the proposals received. Because the projects did not produce overall net benefits in their individual proposal analyses based on economics, they would not be chosen in an IRP study.

DNCP also noted that the wind energy prices used in the 2016 IRP are consistent with the processes and methods utilized in prior IRPs that have been accepted as reasonable for planning purposes by the commissions in North Carolina as well as Virginia. DNCP commented that in contrast, many of the wind energy costs cited by MAREC are either national or regional averages that cannot be applied to the expected cost of installing wind on a specific site in North Carolina or Virginia. Further, DNCP commented that among all available supply-side resources, onshore wind is expected to provide the lowest capacity value, or the lowest contribution to meeting peak demands.

Based on the foregoing, DNCP commented that it continues to find the wind energy pricing and resource analysis presented in the 2016 IRP to be reasonable and appropriate for planning purposes. MAREC's recommendation that DNCP be required to perform additional market analysis of wind pricing should be rejected.

Finally, DNCP noted that the 2016 IRP explains that both DNCP self-build and third-party alternative wind energy resources were not competitive against new gas-fired generation at the time of evaluation. However, DNCP stated that it has and continues to evaluate all forms of third-party market alternatives, including wind, as part of its ongoing resource planning process. Accordingly, MAREC's recommendation that the Commission order it to develop a wind resource-focused RFP is not necessary and should be rejected at this time.

Commission Conclusions - Wind Energy

Based on the foregoing, the comments of the parties, and the entire record in this proceeding, the Commission concludes that the utilities' wind energy pricing and resource analyses presented in the 2016 IRPs are reasonable and appropriate for planning in this docket. The Commission finds merit in the reply comments of DNCP concerning the 310 MW of third-party alternative project proposals evaluated over the 2015-2016 period in the IRP. DNCP specifically commented that these projects did not yield a positive net present value for customers in the analyses performed on the proposals received.

As circumstances exist today and as it stands on this record, the Commission is not persuaded that it should require the utilities to conduct RFPs for renewable energy as soon as possible in order to get the maximum value of the Production Tax Credit (PTC). This was the recommendation by MAREC. However, the Commission determines that this issue is best resolved within the overall context of least cost planning for the production of an adequate and reliable supply of electricity. Indeed, the Commission does not want the utilities to plan on building a particular generation resource mainly because a PTC is available for that resource this year, but may not be available next year. In conclusion, the Commission finds and concludes that the utilities have adequately responded to the issues raised by MAREC related to wind energy and that no further action is necessary at this time.

BATTERY STORAGE

Duke Integrated Resource Plans - Battery Storage

According to the Duke IRPs, DEC and DEP are assessing technologies such as battery storage. Duke notes that battery storage costs are expected to decline significantly which may make it a viable option in the long-run to support operational challenges caused by uncontrolled solar penetration. In the short-run, battery storage is expected to be used primarily to support localized distribution based issues.

Duke included battery storage in its screening analysis for the 2016 IRP. As noted in the DEC and DEP IRPs, the ultimate goal of screening is to pass the best alternatives to the integration process. As in past years, the reason for the initial screening analysis is to determine the most viable and cost-effective resources for further evaluation. Duke reviews generation resource alternatives on a technical and economic basis. The resources that are found to be both technically and economically viable are then passed to the detailed analysis process for further analysis.

Based on the results of Duke's screening analysis, battery storage did not advance to the quantitative analysis as a potential supply-side resource option to meet future capacity needs. However, Duke noted in its IRPs that:

> Beginning in 2016, Distributed Energy Resources formed an Energy Storage (ES) team to develop a fifteen year battery storage prediction model and begin the development of battery storage deployment plans for the next five year budget cycle. The ES team will focus their five year plan across multiple jurisdictions, however, the first two areas that will most likely provide deployment sites are Duke Energy Indiana and western NC, Asheville Regional area. Regional battery storage modeling is proceeding to establish battery system sites, use case designs and cost/benefit analysis. Regulatory approvals and cost recovery development will play a key role in the timing of full operational battery system deployment.

DNCP Integrated Resource Plan - Battery Storage

DNCP stated in its IRP that the need for co-located power storage is paramount to address the intermittency and non-dispatchable characteristics of solar generation resources. DNCP noted that energy storage represents a useful capability with regards to the intermittency of many forms of distributed generation, particularly those which rely on solar or wind power. According to DNCP, adoption of storage technologies at the present time has inherent challenges due to cost-effectiveness, reliability, and useful life. As noted in its IRP, DNCP is monitoring recent advances in energy storage technologies, including batteries.

DNCP noted in its IRP that consistent with the 2015 Plan, DNCP included a solar PV facility coupled with a battery as an entry to the dispatchable busbar curve analysis. At a zero capacity factor, the cost of a solar PV/battery facility is approximately $1,000/kW per year higher than a solar PV facility alone. This difference represents the proxy cost of making a solar PV facility dependable and dispatchable. DNCP stated that given the recent advancements in battery technology, it expects batteries will be a viable option for consideration in future integrated resource plans and, as such, deems it appropriate to begin reflecting that option in the busbar curve analysis.

NCSEA Comments - Battery Storage

NCSEA commented that the current IRP process undervalues the benefits that energy storage can provide both as a generation resource as well as to other aspects of the grid. While NCSEA commended the utilities for including some analysis of energy storage in their 2016 IRPs, NCSEA suggested they are still failing to recognize the full value of energy storage to the utilities and to their customers. NCSEA noted that the 2 MW / 8 MWh lithium ion battery storage system is the only type energy storage included in DEC and DEP's economic screening curve analysis model.[44] NCSEA stated that it believes this is a positive addition to Duke's economic screening analysis but it is disappointed that this relatively small and distribution-based application of energy storage was the only technology considered in the economic screening. NCSEA commented that this narrow consideration of energy storage technology and the failure to recognize the grid benefits of storage in the economic screening analysis resulted in all energy storage technologies being excluded from the quantitative analysis component of the IRPs as potential supply-side resource options to meet future capacity needs.

Quoting from a recent report, NCSEA commented that "A crucial component of the value of storage is its ability to support multiple applications, and their value streams, at the same time."[45] These benefits include: integration of renewables; peak load shaving; emergency response and resilience; grid stability; and energy cost reduction such as avoided transmission and distribution costs. NCSEA commented that the Duke IRPs only analyze the generational value of energy storage and do not quantify the value of these additional benefits.

NCSEA commented that if energy storage costs continue to decline at their anticipated rates of 12% - 15% annually,[46] utilities will be doing themselves and their customers a disservice if they continue to undervalue energy storage in their IRPs and therefore their future generation portfolio and grid services.

NCSEA further commented that in light of the fact that the utilities are already working on battery storage predictions and deployment plans, the Commission should direct the utilities to quantify and incorporate the full value stream that energy storage technologies provide in future IRPs and IRP updates. In addition, NCSEA suggested that the Commission should direct the utilities to identify the regulatory barriers or their interpretation of Rule R8-60 that currently prevents them from incorporating the full value of energy storage in their IRPs in a filing before the Commission.

Duke Reply Comments - Battery Storage

Duke commented that regional battery storage modeling is proceeding to establish battery system sites, use case designs and cost/benefit analysis. Regulatory approvals and cost recovery development will play a key role in the timing of full operational battery system development.

Duke noted that traditionally, IRP modeling has been focused on generation needs. According to Duke, energy storage technologies offer generation as a component of system needs; however, the greatest benefits of energy storage are in ancillary services, peak shaving, load shifting, etc. Duke commented that these stacked benefits

---

[44] See DEC's 2016 IRP, pp. 140-41 and DEP's 2016 IRP, pp. 137-38.

[45] American Council on Renewable Energy & ScottMadden, Inc., Beyond Renewable Integration: The Energy Storage Value Proposition, p. 20 (November 2016).

[46] Id. at p. 32.

are very location specific and cannot be generically applied. In addition, the battery technology selected for each application is very specific to the location need, and as a result, the pricing from application to application can vary dramatically.

According to Duke, battery technology as a generator cannot compete with other generation technologies from a price perspective based on the single benefit as a generation need. As a result, Duke noted that it is working to integrate their planning processes across transmission, distribution, and generation departments to better evaluate the potential for these stacked benefits.

DNCP Reply Comments - Battery Storage

DNCP noted that NCSEA's comments appear to be directed at Duke, however, NCSEA phrases its request in terms of the "utilities" generally. DNCP commented that DNCP already includes the full value of energy storage in its modeling. Therefore, no action is required on this issue with respect to Dominion's 2016 IRP based on NCSEA's comments.

<u>Commission Conclusions - Battery Storage</u>

The Commission recognizes the potential role that battery storage could play in regards to intermittent distributed generation such as solar and wind. However, the Commission also recognizes the current challenges due to cost-effectiveness, reliability, and useful lives of battery technologies. The Commission is of the opinion that evaluations of this technology, as documented in the IRPs, have not been fully developed to a level sufficient to provide guidance as to the role this technology should play going forward. As such, the utilities should provide in future IRPs or IRP updates a more complete and thorough assessment of battery storage technologies including the "full value" as discussed in the NCSEA comments.[47] If the standard technical and economic analyses of generation resources somehow preclude the complete and thorough assessment of battery storage technologies, then a separate discussion of this point should be included in the IRPs.

At a minimum, the utilities should provide pertinent information derived from their active or planned projects that utilize battery technologies. These projects include those identified by Duke that have been in operation since 2011.[48] In addition, Duke should include in its future IRPs or IRP updates, information summarizing the pertinent work and outputs of the Energy Storage Team referenced in its IRPs.[49]

---

[47] NCSEA's Comments, Docket No. E-100, Sub 147 (February 17, 2017), Storage in the Integrated Resource Plans at 5-15.

[48] <u>See</u> DEC's 2016 IRP, p. 139 and DEP's 2016 IRP, p. 136.

[49] <u>See</u> DEC's 2016 IRP, p. 140 and DEP's 2016 IRP, p. 137.

OTHER IRP MATTERS AND CONCLUSIONS

Risk Analysis

The Public Staff commented that DNCP included for the first time in its IRP, a comprehensive risk analysis based on a probabilistic approach that evaluates the risk with respect to future inputs including: natural gas prices, natural gas basis, coal prices, electricity load, CO_2 emission allowance prices, and capital cost for new generation. A probability distribution of future input values for key risk factors is created, as compared to simply assuming a certain future value for key risk factors, as performed in typical modeling of plans. According to the Public Staff, an advantage of this approach is that it allows for the quantification of high impact risk factors even though they have a low probability of occurrence. The Public Staff recommended that DEP and DEC develop similar analytical tools to those utilized by DNCP to determine the least cost plan that provides the lowest risk to its customers, while also providing operational and compliance flexibility to the utility.

The Commission recognizes that risk analyses, such as that utilized by DNCP, may better inform the Integrated Resource Planning process. However, the Commission is without sufficient evidence of the value derived from such risk analyses to require DEP and DEC to utilize similar analytical tools in the development of their IRPs.

Roxboro Retrofit Analysis per Docket No. E-2, Sub 1089

On November 16, 2015, the North Carolina Department of Environmental Quality (DEQ) released a draft rule entitled Standards of Performance for Existing Electric Utility Generating Units Under Clean Air Act Section 111(d).[50] If implemented, this draft rule would require heat rate improvements at many fossil-fueled electric generating units in North Carolina.

In its March 28, 2016 Order Granting Application in Part, With Conditions, and Denying Application in Part in Docket No. E-2, Sub 1089 allowing DEP to proceed with construction of a combined cycle plant near Asheville, the Commission directed DEP to conduct an investigation of retrofitting the four coal burning units at its Roxboro plant as proposed in the draft rule, and to include an assessment of the feasibility and cost-effectiveness of this retrofit in its 2016 IRP. DEP provided the results of its investigation in Appendix K of its IRP.

The two potential requirements identified for the Roxboro plant are the installation of an Intelligent Sootblowing (ISB) system and Variable Frequency Drives (VFDs) on boiler fans. DEP explained that ISB uses electronic monitoring to optimize the timing and amount of boiler cleaning, which reduces both wear on the boiler tubing and parasitic load caused by cleaning. The VFDs would reduce the boiler fan parasitic load by replacing the current airflow control that uses damper panels with airflow control that uses electronically

[50] Division of Air Quality, DEQ, Section 15A NCAC 02D .2700, Standards of Performance for Existing Electric Utility Generating Units Under Clean Air Act Section 111(d), available online at the following link: http://deq.nc.gov/about/divisions/air-quality/air-quality-rules/draft-rules.

regulated fan motors, which have their speed precisely matched to requirements of the boiler.

DEP's economic analysis indicated that including the installation and operation of the ISB and VFD projects beginning in 2020 would result in cost savings of approximately $3 million per project compared to the base case. The payback periods for the ISB and VFD projects would be approximately one and eight years, respectively. Due to the February 9, 2016 U.S. Supreme Court decision staying the federal Clean Power Plan, DEQ has not implemented its draft rule.

The Public Staff recommended that the Commission direct DEP to develop and file with the Commission, within the next six months, a plan to undertake the retrofits to its Roxboro plant identified in Appendix K of its IRP. In addition, the Public Staff recommended that DEP and DEC evaluate other efficiency retrofits included in the draft DEQ rule and include an analysis of their potential economic and emissions benefits in their 2017 IRP update.

In reply comments, Duke noted that both DEC and DEP regularly evaluate numerous potential upgrade and retrofit projects at their generation units on an ongoing basis. Requiring DEC and DEP to include such analyses in future IRPs would be burdensome, potentially voluminous, and in Duke's opinion, would not provide meaningful information that is required as part of the IRP process.

The Commission finds that Duke adequately responded to its March 28, 2016 Order.[51] However, the Commission is not persuaded that Duke should be required to develop and file a plan to undertake the Roxboro plant retrofits in future IRPs or IRP updates even if DEP decides to pursue these projects.

In addition, the Commission does not find that documenting internal analyses and decisions relative to individual efficiency retrofit projects is useful in the IRP and, therefore, does not accept the Public Staff's recommendation in this regard.

Cliffside Unit 6 Carbon Neutral Plan

Finding of Fact No. 3 of the 2014 IRP Order stated that "[t]he Cliffside Unit 6 Carbon Neutrality Plan filed by DEC is a reasonable path for DEC's compliance with the carbon emission reduction standards of its air quality permit." The 2014 IRP Order also required DEC to provide updates in future IRPs regarding its obligations related to the Cliffside Unit 6 air permit. DEC included the required update as Appendix K to its 2016 IRP. The original plan incorporated actions required under DEC's Cliffside Unit 6 air permit, including the implementation of a Greenhouse Gas Reduction Plan. The original plan also required DEC to: (1) retire 800 MW of coal capacity in North Carolina in accordance with the schedule set forth in Table K-1, which was in addition to the retirement of Cliffside Units 1-4; (2) accommodate, to the extent practicable, the

[51] Order Granting Application in Part, With Conditions, and Denying Application in Part, Docket No. E-2, Sub 1089, (March 28, 2016), Item 7, at p. 40.

installation and operation of future carbon control technology at Cliffside Unit 6; and (3) take additional actions as necessary to make Cliffside Unit 6 carbon neutral by 2018.

The Public Staff noted that the update submitted by DEC in its 2016 IRP is very similar to the one approved in the 2014 IRP Order, and incorporates the same implementation schedule, with updated values for the estimates of conservation, renewable energy, and nuclear uprates. The Public Staff commented that it believes this update represents a reasonable path for DEC's compliance with the carbon emission reduction standards of its air quality permit, and notes that the retirements listed in DEC's IRP, most of which have already taken place, would exceed the Greenhouse Gas Reduction Plan by close to 50%. The Public Staff recommended that the Commission no longer require DEC to include the Cliffside Unit 6 Carbon Neutral Plan in future IRP filings.

The Commission concludes that the Cliffside Unit 6 Carbon Neutral Plan filed by DEC is a reasonable path for DEC's compliance with the carbon emission reduction standards of the air quality permit. This conclusion, however, does not constitute Commission approval of individual specific activities or expenditures for any activities shown in the Plan.

Based on the Public Staff's recommendation, the Commission will no longer require DEC to include the Cliffside Unit 6 Carbon Neutral Plan in future IRP filings.

REPS COMPLIANCE PLANS

G.S. 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. One megawatt-hour (MWh) of renewable energy, or its thermal equivalent, equates to one renewable energy certificate (REC), which is used to demonstrate compliance. An electric power supplier may comply with the REPS by generating renewable energy at its own facilities, by purchasing bundled renewable energy from a renewable energy facility, or by buying RECs. Alternatively, a supplier may comply by reducing energy consumption through implementation of EE measures or electricity demand reduction.[52] The electric public utilities (DEP, DEC, and DNCP) may use EE measures to meet up to 25% of their overall requirements in G.S. 62-133.8(b). One MWh of savings from DSM/EE or demand reduction is equivalent to one energy efficiency certificate (EEC), which is a type of REC. All electric power suppliers may obtain RECs from out-of-state sources to satisfy up to 25% of the requirements of G.S. 62-133.8(b) and (c), with the exception of DNCP, which can use out-of-state RECs to meet its entire requirement. The total amount of renewable energy or EECs that must be provided by an electric power supplier for 2016 and 2017 is equal to 6% of its North Carolina retail sales for the preceding year. In 2018, the required amount increases to 10%.

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,

[52] "Electricity demand reduction," as used herein, is defined in G.S. 62-133.8(a)(3a).

as part of their IRPs, and explain how they will meet the requirements of G.S. 62-133.8(b), (c), (d), (e), and (f). The plans must cover the current year and the next two calendar years, or in this case 2016, 2017, and 2018 (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).

Public Staff Comments - REPS Compliance Plans

The Public Staff commented on DEP, DEC, and DNCP's plans to comply with G.S. 62-133.8(b), (c), and (d), the general[53] and solar energy requirements. The Public Staff also provided consolidated comments on the IOUs' plans to comply with G.S. 62-133.8(e) and (f), the swine and poultry waste set-asides.

Public Staff Comments - DEP's REPS Compliance Plans

According to the Public Staff, DEP has contracted for and banked sufficient resources to meet the REPS requirements of G.S. 62-133.8(b), (c), and (d) for itself and the electric power suppliers for which it is providing REPS compliance services, which includes the Towns of Sharpsburg, Stantonsburg, Black Creek, Lucama, and Winterville (collectively, DEP's Wholesale Customers).[54]

DEP intends to use EE programs to meet 25% of its REPS requirements. Hydroelectric facilities with a capacity of 10 MW or less and energy allocations from the Southeastern Power Administration (SEPA) will be used to meet up to 30% of the general requirement of DEP's Wholesale Customers.[55] Hydroelectric facilities of 10 MW or less will also provide RECs for DEP's retail customers. DEP may also use wind energy, through either REC-only purchases or energy delivered to its customers in North Carolina, to meet the general requirement. A portion of the general requirement for DEP and its Wholesale Customers will be met by executed purchased power agreements and REC-only purchases from landfill gas and biomass power providers, some of which are combined heat and power (CHP) facilities. DEP also plans to use the increased availability of solar energy to meet the general requirement.

[53] The overall REPS requirement of G.S. 62-133.8(b), less the requirements of the three set-asides established by G.S. 62-133.8(d)-(f), is frequently referred to as the "general requirement."

[54] In past years, DEP also provided REPS compliance services for the Town of Waynesville; Waynesville took responsibility for its own REPS compliance beginning in 2016.

[55] A hydroelectric facility with a generation capacity in excess of 10 MW is not considered a renewable energy facility under G.S. 62-133.8(a)(7). Under G.S. 62-133.8(c)(2)c, electric membership corporations (EMCs) and municipalities may not meet more than 30% of their REPS requirements with hydroelectric power.

To meet the solar set-aside, DEP will obtain RECs from its own solar facilities, its residential solar photovoltaic (PV) program, and other solar PV and solar thermal facilities.[56]

DEP anticipates that its REPS compliance costs will be well below the cost caps in G.S. 62-133.8(h)(3) and (4) for the planning period.

DEP files evaluation, measurement, and verification (EM&V) plans for each EE program in the respective program approval docket.

Public Staff Comments - DEC's REPS Compliance Plans

According to the Public Staff, DEC has contracted for or procured sufficient resources to meet the REPS requirements of G.S. 62-133.8(b), (c), and (d) for the planning period, both for itself and for the electric power suppliers for which it is providing REPS compliance services. These suppliers are Rutherford EMC, Blue Ridge EMC, the Town of Dallas, the Town of Forest City, the City of Concord, the Town of Highlands, and the City of Kings Mountain (collectively, DEC's Wholesale Customers).

DEC intends to use EE programs to meet 25% of its REPS requirements. Hydroelectric facilities with a capacity of 10 MW or less and energy allocations from SEPA will be used to meet up to 30% of the general requirement of DEC's Wholesale Customers. Hydroelectric qualifying facilities of 10 MW or less, together with DEC's Bridgewater hydroelectric facility, will provide RECs for DEC's retail customers. DEC will continue to use wind energy, either through REC-only purchases or energy delivered to its customers in North Carolina, to meet the general requirement. A portion of the general requirement for DEC and its Wholesale Customers will be met through executed purchased power agreements and REC-only purchases from landfill gas and biomass power providers, some of which are CHP facilities. DEC also expects to use solar resources to satisfy the general requirement.

To meet the solar set-aside, DEC will obtain RECs from its self-owned solar PV facilities and from other solar PV and solar thermal facilities.[57]

DEC anticipates that its REPS compliance costs will be well below the cost caps in G.S. 62-133.8(h)(3) and (4) for the planning period.

[56] DEP has acquired certificates of public convenience and necessity (CPCNs) for 140.7 MW of solar PV facilities to meet a portion of its REPS compliance obligations. See Order Transferring Certificate of Public Convenience and Necessity, Docket No. E-2, Subs 1054, 1055, and 1056 (Dec. 16, 2014); Order Issuing Certificate of Public Convenience and Necessity, Docket No. E-2, Sub 1063 (Apr. 14, 2015).

[57] DEC has acquired CPCNs for 81.4 MW of solar PV facilities for use to meet a portion of its REPS compliance obligations. See Order Amending Certificate of Public Convenience and Necessity, Docket No. E-7, Sub 1101 (June 16, 2016); Order Amending Certificate of Public Convenience and Necessity, Docket No. E-7, Sub 1079 (Dec. 7, 2016); and Order Transferring Certificate of Public Convenience and Necessity, Docket No. E-7, Sub 1098 (May 16, 2016).

DEC files EM&V plans for each EE program in the respective program approval docket.

Public Staff Comments - DNCP's REPS Compliance Plans

According to the Public Staff, DNCP has contracted for or procured sufficient resources to meet the REPS requirements of G.S. 62-133.8(b), (c), and (d) for the planning period for itself and the Town of Windsor (Windsor), for which it is providing REPS compliance services. While DNCP may use out-of-state RECs to meet all of its compliance requirements, Windsor may only use out-of-state RECs to meet 25% of its compliance requirements. DNCP plans to use EE, purchased out-of-state RECs, and RECs from its own new renewable energy facilities to meet the general REPS requirements of G.S. 62-133.8(b). For Windsor's general REPS requirement, DNCP will use out-of-state wind and hydroelectric RECs, in-state biomass and solar RECs, and Windsor's SEPA allocation. For the solar set-aside, DNCP plans to purchase in-state and out-of-state solar RECs for itself and Windsor. Its total costs are the same as its incremental costs because, unlike DEP and DEC, it plans to purchase only unbundled RECs, rather than RECs that are bundled with renewable electric energy, to meet its REPS requirements.

DNCP anticipates that it will incur research costs in 2016-18 for the continued development of its Microgrid Project. The Microgrid Project consists of wind, solar, and fuel cell energy generation and battery storage at DNCP's Kitty Hawk District Office. The costs in 2016-18 are primarily for operation and maintenance and fuel for the fuel cell electric generation system. DNCP anticipates that the REPS compliance costs for itself and Windsor will be well below the cost caps in G.S. 62-133.8(h)(3) and (4) for the planning period.

DNCP files EM&V plans for each EE program in the respective program approval docket.

REPS Compliance Summary Tables

The following tables are compiled from data submitted in DEP, DEC, and DNCP's Plans. Table 1 shows the projected annual MWh sales on which the utilities' REPS obligations are based. It is important to note that the figures shown for each year are the utilities' MWh sales for the preceding year; for instance, the sales for 2016 are MWh sales for calendar year 2015. The totals are presented in this manner because each utility's REPS obligation is determined as a percentage of its MWh sales for the preceding year. The sales amounts include retail sales of wholesale customers for which the utility is providing REPS compliance reporting and services. Table 2 presents a comparison of the projected annual incremental REPS compliance costs with the utilities' annual cost caps.

TABLE 1: MWh Sales for Preceding Year

	Compliance Year		
Electric Power Supplier	**2016**	**2017**	**2018**
DEP	37,572,645	37,409,094	37,637,337
DEC	61,307,708	60,661,074	61,110,288
DNCP	4,377,561	4,331,768	4,366,511
TOTAL	103,257,914	102,401,936	103,114,136

TABLE 2: Comparison of Incremental Costs to the Cost Cap

		DEP	**DEC**	**DNCP**
2016	Incremental Costs	$31,564,879	$22,018,825	$1,051,845
	Cost Cap	$71,367,582	$104,834,112	$6,309,402
	Percent of Cap	44%	21%	17%
2017	Incremental Costs	$47,596,387	$29,197,215	$1,202,736
	Cost Cap	$72,213,282	$105,412,270	$6,269,230
	Percent of Cap	66%	28%	19%
2018	Incremental Costs	$47,756,637	$32,322,034	$1,552,764
	Cost Cap	$73,066,326	$105,968,212	$6,285,600
	Percent of Cap	65%	31%	25%

Swine Waste and Poultry Waste Set-Asides

Beginning in 2012, electric power suppliers were required to meet 0.07% of their retail sales with energy derived from swine waste, pursuant to G.S. 62-133.8(e), and a combined total of 170,000 MWh or equivalent energy derived from poultry waste, pursuant to G.S. 62-133.8(f). The REPS statute provides for increases in these requirements, or set-asides, in later years. The electric power suppliers have had great difficulty in complying with the swine and poultry waste set-asides. From 2012 through 2016, the electric power suppliers have annually filed joint motions in Docket No. E-100, Sub 113, pursuant to G.S. 62-133.8(i)(2), seeking to delay the swine waste energy requirement, and the Commission has granted their requests. In its orders, the Commission has also required the electric power 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, initially on a tri-annual basis and now semiannually.[58] These reports are filed under seal in Docket No. E-100, Sub 113A. The Commission further required the electric power suppliers to provide internet-available information to assist the developers of swine and poultry waste-to-energy projects in getting contract approval and interconnecting facilities. Additionally, the Commission has

[58] The smallest electric suppliers were exempted from this requirement.

directed the Public Staff to hold periodic stakeholder meetings to facilitate compliance with the swine and poultry waste set-asides.

In their motions for relief under G.S. 62-133.8(i)(2) in 2012 and 2013, the electric power suppliers requested the Commission to delay the poultry waste set-aside requirements as well as the swine waste set-aside requirements, and the Commission granted their requests. In 2014, the electric power suppliers were able to comply with this set-aside as modified by the Commission. Among the reasons why the electric power suppliers did not request a delay in 2014 were the relatively low requirement of 170,000 MWh or equivalent energy in that year and the utilities' ability to bank RECs from earlier years. In addition, the availability of poultry waste RECs in the marketplace had increased by 2014 due to advances in the technology of power generation from poultry waste, the use of thermal energy to meet the set-aside as authorized by Session Law (S.L. 2011-309), and the availability of poultry waste RECs from "cleanfields renewable energy demonstration parks" as authorized by S.L. 2010-195.

In 2015, the statutory poultry waste requirement rose from 170,000 to 700,000 MWh, and the electric power suppliers were unable to comply with this major increase. Consequently, they filed a joint motion seeking again to delay both the swine and poultry waste set-asides. Instead of granting their motion in full, however, the Commission reduced the 2015 statewide aggregate poultry waste requirement to 170,000 MWh and set the requirements for 2016 and 2017 at 700,000 MWh and 900,000 MWh, respectively. The electric power suppliers successfully met the reduced 170,000-MWh requirement for 2015.

In their 2016 joint motion, the electric power suppliers proposed that the 700,000 MWh poultry waste requirement for 2016 be reduced to 170,000 MWh, and that the 2017 requirement be reduced from 900,000 MWh to 700,000 MWh. In its Order issued on October 17, 2016, in Docket No. E-100, Sub 113, the Commission granted their motion.

The State's electric power suppliers have been able to comply only to a very limited extent with the poultry waste set-aside requirement, and not at all with the swine waste requirement. Nevertheless, the REPS statute has served as a stimulus for several important advances in waste-to-energy technology.

First, several hog farms have installed anaerobic digesters at their swine waste lagoons and produced biogas that has been used as fuel to operate small electric generators at these farms. Electric power suppliers have purchased the electricity produced by these generators – or, alternatively, have purchased the RECs when the electricity was used on the farm where it was generated – and this represented the initial step toward compliance with the swine waste set-aside.

Second, poultry waste has been transported by truck to existing and new generation facilities, where it has been co-fired with wood or other fuels.

Third, large centralized anaerobic digestion plants have been built in areas where numerous hog farms are located. These plants receive swine waste from numerous sources, produce biogas from the waste by the digestion process, and eliminate impurities so that it is eligible to be transported in the natural gas pipeline system. A specified amount of this biogas, which is referred to as "directed biogas" or "renewable natural gas," is injected into a pipeline, and an equivalent amount of natural gas is delivered by the pipeline operator to a gas-fired utility generating plant. These directed biogas facilities were first built in Midwestern states with extensive hog farming activity, but on December 2, 2016, Carbon Cycle Energy, LLC, began construction of a directed biogas facility in Warsaw, North Carolina.

The Public Staff states that the electric power suppliers will likely continue to have difficulty meeting the swine and poultry waste set-asides. As advances in waste processing technology are made, the electric power suppliers may be able to achieve compliance with these requirements in the not too distant future. The supplier best positioned to reach full compliance is DNCP since it can obtain all of its RECs from out-of-state. DNCP has secured enough out-of-state poultry waste RECs for itself and for Windsor for the entire planning period, and in its Compliance Plan expresses confidence that it will also be able to comply with the in-State poultry waste requirement for Windsor. DNCP has obtained sufficient in-state and out-of-state swine waste RECs to meet Windsor's requirements for the entire planning period; it has enough swine waste RECs under contract to meet its own requirements, as well, but it may be unable to comply if its suppliers fail to fulfill their obligations.

As requested by the Commission, the Public Staff held stakeholder meetings on June 23, 2014, and five subsequent occasions. The attendees 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 meetings allowed the stakeholders to network and voice their concerns to the other parties.

Public Staff Conclusions - REPS Compliance Plans

In summary, the Public Staff concluded that:

1. DEP, DEC, and DNCP should be able to meet their REPS obligations during the planning period, with the exception of the swine and poultry waste set-asides, without nearing or exceeding their cost caps.
2. DEP and DEC would not have been able to meet the swine waste requirement in 2016 had it not been delayed by the Commission, and they met the poultry waste requirement only after the Commission reduced the aggregate statewide requirement to 170,000 MWh. They are uncertain about meeting the requirements in 2017 and 2018.
3. If the 2016 swine waste requirement had not been delayed, DNCP would have met it for the Town of Windsor, but not for itself. DNCP is confident of its ability to comply for the Town of Windsor in 2017 and 2018, and it expects to comply for itself if its suppliers fulfill their obligations.

4. DNCP will meet its own poultry waste requirement for 2016. It will also meet the out-of-state portion of Windsor's requirement, but may not meet the in-state portion. For 2017 and 2018, DNCP expects to meet its own poultry waste requirements, and the out-of-state portion of Windsor's requirements. It is reasonably confident of meeting the in-state portion.
5. DEP, DEC, and DNCP are actively seeking energy and RECs to meet the set-aside requirements for the years in which they expect to fall short of compliance. DEP is no longer purchasing solar and general RECs to meet its general obligation or solar set-aside obligation because it has sufficient solar RECs to comply with both obligations during the planning period.
6. The Commission should approve the 2016 REPS Compliance Plans filed by DEP, DEC and DNCP

Commission Conclusions - REPS Compliance Plans

The Commission concludes that the REPS Compliance Plans filed by the utilities 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.

COMMISSION CLOSING COMMENTS

Integrated Resource Planning is intended to identify those electric resource options that can be obtained at least cost to the utility and its ratepayers consistent with the provision of adequate, reliable electric service. Potential significant regulatory changes, particularly at the federal level, and evolving marketplace conditions create additional challenges for already detailed, technical, and data-driven IRP processes. The Commission finds the IRP processes employed by the utilities to be both compliant with State law and reasonable for planning purposes in the present docket. The Commission recognizes that the IRP process continues to evolve. The comments, findings, conclusions, and Commission directives included in this Order are intended to inform and guide the electric utilities and parties in their ongoing IRP processes and participation.

IT IS, THEREFORE, ORDERED, as follows:

1. That this Order shall be, and is hereby, adopted as part of the Commission's current analysis and plan for the expansion of facilities to meet future requirements for electricity for North Carolina pursuant to G.S. 62-110.1(c).

2. That the IOUs' forecasts of native load requirements and other system capacity or firm energy obligations, supply-side and demand-side resources expected to satisfy those loads, and reserve margins are reasonable for planning purposes, and the Commission accepts the IRP Reports as filed in this docket.

3. That the 2016 REPS compliance plans filed by the IOUs are hereby accepted.

4. That the IOUs, in the preparation of future IRPs, shall adhere to the conclusions and directives of the Commission documented in the body of this Order.

5. That pursuant to the Regulatory Conditions imposed in the Merger Order, DEC and DEP shall continue to pursue least-cost Integrated Resource Planning and file separate IRPs until otherwise required or allowed to do so by Commission order, or until a combination of the utilities is approved by the Commission.

ISSUED BY ORDER OF THE COMMISSION.

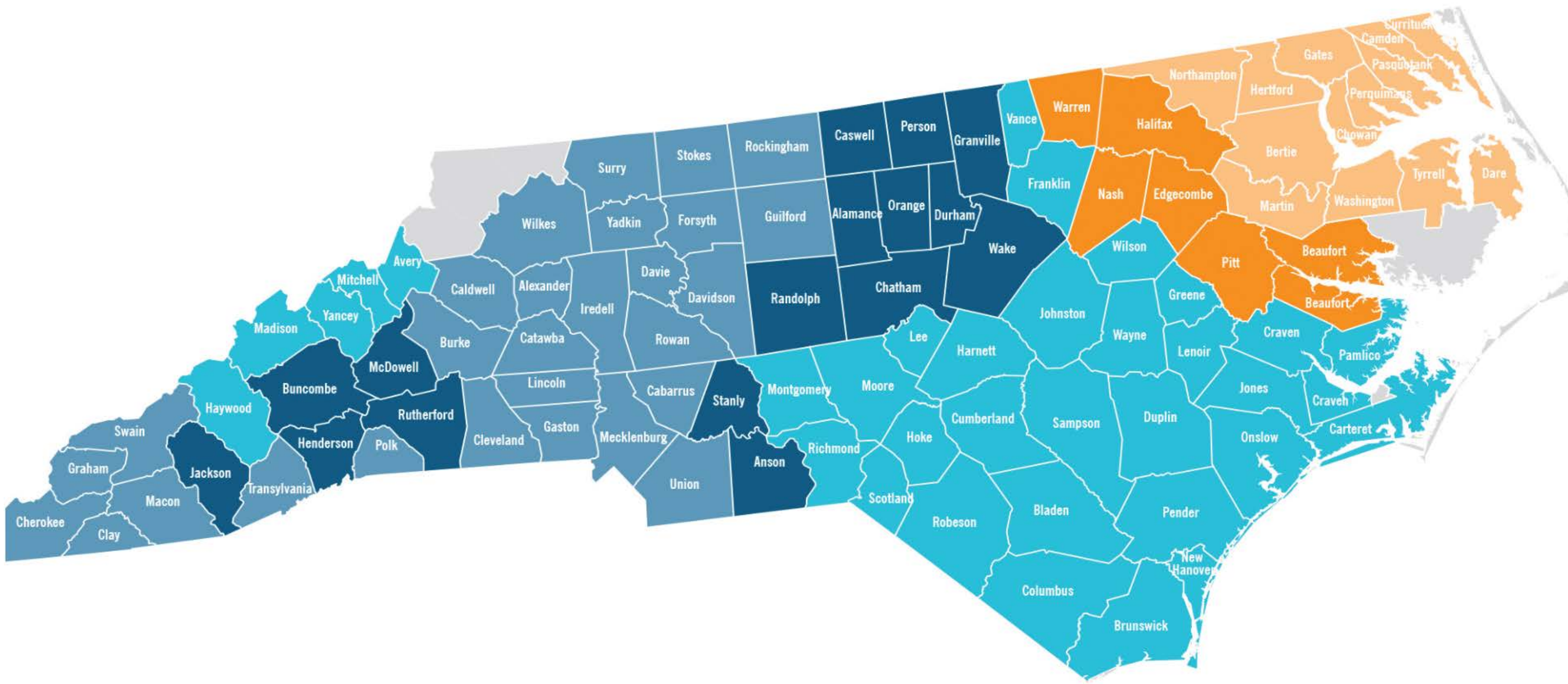
This the 27th day of June, 2017

NORTH CAROLINA UTILITIES COMMISSION

Janice H. Fulmore

Janice H. Fulmore, Deputy Clerk

Commissioner ToNola D. Brown-Bland did not participate in this decision.



SERVICE TERRITORIES
(counties served)

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