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)

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

SUBMITTED BY
THE NORTH CAROLINA UTILITIES COMMISSION

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Duke Energy Carolinas

Dominion North Carolina Power

New River Light and Power Company

Western Carolina University

North Carolina Electric Membership Corporation

ElectriCities of North Carolina

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ABBREVIATIONS AND ACRONYMS

Blue Ridge Blue Ridge EMC
BREDL Blue Ridge Environmental Defense League
CC combined-cycle
CIGFUR Carolina Industrial Group for Fair Utility Rates
COL combined construction and operating license
CPCN Certificate of Public Convenience and Necessity
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
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
GEH GE-Hitachi Nuclear Energy Americas, LLC
GreenCo GreenCo Solutions, Inc.
GridSouth GridSouth Transco, LLC
G.S. General Statute
GWh gigawatt-hour/s
Halifax Halifax EMC
Haywood Haywood EMC
Invenergy Invenergy Wind Development, LLC and Invenergy Solar Development, LLC
IOU investor-owned electric utility
IRP integrated resource planning/integrated resource plans
kWh kilowatt-hour/s
MAREC Mid-Atlantic Renewable Energy Coalition
MW megawatt/s
MWh megawatt-hour/s
NC Power Dominion North Carolina Power
NC-RETS North Carolina Renewable Energy Tracking System
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
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.
Piedmont Piedmont EMC
PJM PJM Interconnection, LLC
Progress Duke Energy Progress, Inc.
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
Rutherford Rutherford EMC
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 Southeastern Electric 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
WPSA Wholesale Power Supply Agreement

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APPENDICES

1. EXECUTIVE SUMMARY

This annual report to the Governor and the General Assembly is submitted pursuant to 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, Inc. (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 North Carolina Power (NC Power).

Duke and Progress, the two largest electric IOUs in North Carolina, together supply about 96% of the utility-generated electricity consumed in the state. Approximately 21% of the IOUs' 2013 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)	
	2013	2012	2013	2012	2013	2012
Progress	36,887	36,589	16,485	15,298	60,204	58,390
Duke	55,282	54,709	8,787	4,519	85,790	81,362
NC Power	4,310	4,115	996	1,101	82,852	80,942

*GWh = 1 Million kWh (kilowatt hours)

During the 2014 to 2028 timeframe, the average annual growth rate in summer peak demand for electricity in North Carolina is forecasted to be in the range of 1.2% to 1.4%. Table ES-2 illustrates the systemwide 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. Under normal weather patterns, summer peak demand remains higher than winter peak demand for all three IOUs.

Table ES-2: Forecast Annual Growth Rates for Progress, Duke, and NC Power (After Energy Efficiency (EE) and Demand-Side Management (DSM) are Included) (2014 – 2028)

	Summer Peak	Winter Peak	Energy Sales
Progress	1.2%	1.4%	1.4%
Duke	1.4%	1.5%	1.4%
NC Power	1.2%	1.1%	1.4%

North Carolina's IOUs depend on coal-fired and nuclear-fueled steam generation to produce the overwhelming majority of their electric output, as illustrated in Table ES-3.

Table ES-3: Total Energy Resources by Fuel Type for 2013

	Progress	Duke	NC Power
Coal	24%	32%	29%
Nuclear	37%	48%	32%
Net Hydroelectric*	2%	2%	1%
Natural Gas and Oil	26%	10%	16%
Non-Hydro Renewable	0%	0%	1%
Purchased Power	11%	8%	21%

* See discussion of pumped storage in Section 6.

On August 20, 2007, with the signing of Session Law 2007-397 (Senate Bill 3), North Carolina became the first state in the Southeast to adopt a Renewable Energy and Energy Efficiency Portfolio Standard (REPS). Under this new law, 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), or 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, EMCs have been exempted from filing IRPs with the Commission, effective July 1, 2013.

This report is an update of the Commission's December 11, 2013 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, Inc. (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 North Carolina Power (NC Power). 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 supply about 96% of the utility-generated electricity consumed in the state. As of December 31, 2013, Duke had 1,878,000 customers located in North Carolina, and Progress had 1,303,000. Each also has customers in South Carolina. NC Power supplies approximately 4% of the state's utility-generated electricity. It has 119,000 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 21% 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 2013 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)	
	2013	2012	2013	2012	2013	2012
Progress	36,887	36,589	16,485	15,298	60,204	58,390
Duke	55,282	54,709	8,787	4,519	85,790	81,362
NC Power	4,310	4,115	996	1,101	82,852	80,942

*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, non-profit corporations. There are 31 EMCs serving 1,054,000 customers in North Carolina, including 26 that are headquartered in the state. The other five 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 NCEMC, a generation and transmission services cooperative 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 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. Finally, most EMCs receive an allocation of hydroelectric power from the Southeastern Power Administration (SEPA).

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 with electric power and energy from existing contract and generation resources. To the extent that the electric power and energy supplied under the WPSA is not sufficient to meet the electric energy requirements of its customers, the Independent Members must independently arrange for purchases of additional electric power.

The service territories of NCEMC's member EMCs are located within the control areas of Duke, Progress, and NC Power. Therefore, NCEMC's system consists of three distinct areas known as supply areas. Historically, NCEMC planned for each of these supply areas separately, primarily serving load with all-requirements power supply contracts with the control area power supplier, plus its ownership share of the Catawba Nuclear Station. Renegotiation of certain power supply contracts and the introduction of new resources into NCEMC's power supply portfolio have provided the flexibility to serve load in multiple supply areas using the same resource(s). To the extent that firm transmission access is obtained and maintained, NCEMC continues to serve all its members as a single integrated system. NCEMC currently purchases wholesale electricity from Progress, Duke, Dominion, American Electric Power, BP American, Inc., Southern Power, and SEPA.

In addition to the EMCs, there are about 75 municipal and university-owned electric distribution systems serving approximately 575,000 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. NCEMPA currently owns portions of five Progress generating units (about 700 MW of coal and nuclear capacity).[1] NCEMPA also has Supplemental Load Agreements with Progress that run through 2031. These contracts provide for additional power when load requirements exceed the capacity NCEMPA owns. In addition, NCEMPA is installing 20 MW of distributed generation.

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.

NCMPA1 purchases power through bilateral agreements with other generators to obtain its requirements above its Catawba entitlement. To meet its supplemental power requirements, NCMPA1 has purchase power agreements with Duke, Southern Power,

[1] On July 28, 2014, Progress filed notice with the Commission in Docket No. E-2, Sub 1051 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 this Agreement, the final purchase and sale is subject to approval by the FERC, approval by the Commission of rate and certificate applications to be filed by Progress at a later date, and enactment of legislation by the North Carolina General Assembly.

and SEPA. NCMPA1 also owns 65 MW of diesel-fueled distributed generation located at certain city delivery points, and it has contracts for an additional 90 MW of generation owned by municipalities and retail customers which is available during times of high demand and spiking wholesale prices. NCMPA1 also owns two natural gas-fired turbine generators located in Monroe that provide an additional 24 MW of peaking and reserve capacity.

The Tennessee Valley Authority (TVA), which generates electricity from coal, nuclear, and hydroelectric plants, sells energy directly to the Murphy, North Carolina, Power Board, and to three out-of-state cooperatives that supply power to portions of North Carolina: Blue Ridge Mountain EMC, Tri-State EMC, and Mountain Electric Cooperative. These distributors of TVA power are located in six North Carolina counties and serve over 33,000 households and 8,200 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. TVA owns and/or maintains 11 substations and switchyards and nearly 119 miles of transmission line in North Carolina.

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 fifteen 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 Senate Bill 3 requirements.

2013 Integrated Resource Plan Annual Update Reports
(Docket No. E-100, Sub 137)

2013 Annual Update Reports were filed by Progress, Duke, and NC Power. In addition, each of the three IOUs filed 2013 REPS compliance plans.

The following parties intervened in this proceeding: Blue Ridge Environmental Defense League (BREDL); Carolina Industrial Group for Fair Utility Rates I, II, and III (CIGFUR); Carolina Utility Customers Association, Inc. (CUCA); Greenpeace; Invenergy Wind Development, LLC, and Invenergy Solar Development, LLC (Invenergy); Mid-Atlantic Renewable Energy Coalition (MAREC); North Carolina Sustainable Energy Association (NCSEA); North Carolina Waste Awareness and Reduction Network (NC WARN); Nucor Steel-Hertford; Sierra Club; and Southern Alliance for Clean Energy (SACE). 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.

A Public Hearing was held in Raleigh on April 28, 2014. The Commission's June 30, 2014 Order Approving Integrated Resource Plan Annual Update Reports and Related REPS Compliance Plans, which includes the procedural history of this proceeding, can be found in the back of this report as Appendix 1.

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 NC Power 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 NC Power. 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. Under normal weather patterns, the annual summer peak demand remains higher than the winter peak demand for the three IOUs serving North Carolina.

Table 2: Forecast Annual Growth Rates for Progress, Duke, and NC Power (After Energy Efficiency (EE) and Demand-Side Management (DSM) are Included) (2014 – 2028)

	Summer Peak	Winter Peak	Energy Sales
Progress	1.2%	1.4%	1.4%
Duke	1.4%	1.5%	1.4%
NC Power	1.2%	1.1%	1.4%

North Carolina utility forecasts of future peak demand growth rates are in the range of forecasts for the nation as a whole. The 2014-2023 Long-Term Reliability Assessment by the North American Electric Reliability Corporation (NERC) indicates that the national forecast of average annual growth in summer peak demand for that period is 1.23%.

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

Table 3: Summer and Winter Systemwide Peak Loads for Progress, Duke, and NC Power Since 2009 (in MW)

	Progress		Duke		NC Power	
	Summer	Winter*	Summer	Winter*	Summer	Winter*
2009	11,796	12,531	17,397	17,282	18,137	17,612
2010	12,074	12,230	17,358	17,570	19,140	17,689
2011	12,094	11,338	17,651	16,002	20,061	16,881
2012	12,770	12,376	17,610	15,307	19,249	17,623
2013	12,248	14,159	18,239	18,859	18,763	19,785

**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. These generating plants are usually classified by fuel type (nuclear, coal, gas/oil, hydro, 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 and large coal facilities, as well as combined-cycle natural gas units, 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.

NC Power 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 NC Power for the large-scale storage of electricity. 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 2013

	Progress	Duke	NC Power
Coal	32%	33%	30%
Nuclear	27%	33%	19%
Hydroelectric	2%	15%	12%
Natural Gas and Oil	39%	19%	38%
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 2013, is provided in Table 5.

Table 5: Total Energy Resources by Fuel Type for 2013

	Progress	Duke	NC Power
Coal	24%	32%	29%
Nuclear	37%	48%	32%
Net Hydroelectric*	2%	2%	1%
Natural Gas and Oil	26%	10%	16%
Non-Hydro Renewable	0%	0%	1%
Purchased Power	11%	8%	21%

* 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.

Progress Generation

As of September 2014, Progress had 12,922 MW of installed generating capacity (summer rating), including about 700 MW jointly-owned with NCEMPA. This does not include purchases and non-utility owned capacity.

In December of 2013, Sutton Steam Station Units 1 – 3, the last of Progress's coal units that lacked advanced emission controls, were shuttered. Since 2011, Progress has retired 1,600 MW at 12 older coal units in favor of cleaner burning natural gas plants. Over the 15-year planning horizon, the Company will continue to modernize its fleet with the planned retirements of older combustion turbine (CT) units including:

- Sutton CT Units 1, 2A and 2B, located in Wilmington, NC, totaling 61 MW, by 2017
- Darlington CT Units 1 - 11, located in Darlington County, SC, totaling 553 MW by 2020
- Blewett CT Units 1 – 4, located in Lilesville, NC, totaling 52 MW, by 2027
- Weatherspoon CT Units 1 – 4, located in Lumberton, NC, totaling 128 MW, by June 2027

The 2014 Progress IRP identifies a need for new natural gas plants. The planning document outlines the following relative to new natural gas resources. Locations for most of these facilities have not been finalized:

- Pursue 84-MW Sutton fast start/black start CT in 2017.
- Pursue 126-MW of fast start CT capacity in Asheville, NC, in 2018.
- Consider an 866-MW natural gas combined cycle plant (CC) in 2020.
- Consider 792-MW of CT capacity in 2021.
- Consider an 866-MW natural gas CC in 2022.

- Consider an 866-MW natural gas CC in 2027.
- Consider 396-MW of CT capacity in 2029.

Duke Generation

As of September 2014, Duke had 21,573 MW of installed generating capacity (summer 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.

Duke will soon be closing its last coal facility not equipped with advanced emission controls. In April 2015, Lee Steam Station Units 1 and 2 in Anderson County, SC will be shuttered. Unit 3 will be converted to natural gas. These closings are the last in a series of coal unit retirements totaling approximately 1,700 MW of cumulative retirements. In addition, Duke has retired approximately 400 MW of older CT units.

The 2014 Duke IRP identifies a need for new natural gas plants. The planning document outlines the following relative to new natural gas resources. Locations for most of these facilities have not been finalized:

- Convert 170 MW Lee Steam Unit 3 from coal to natural gas in 2015.
- Complete construction of the 770 MW natural gas combined cycle plant at Lee Steam Station, Anderson County, SC, expected to be commercially available by the end of 2017.
- Consider an 866 MW natural gas CC in 2020.
- Consider 792 MW of CT capacity in 2028.

As part of the 2014 IRP, new nuclear resources continue to be supported in Duke's resource plan in the 2024 and 2026 timeframe. As such, Duke remains on course to obtain the combined construction and operating license (COL) for the Lee Nuclear facility in 2016. The following is a summary of the activities relative to the COL for the Lee Nuclear facility, proposed to be built in South Carolina.

On Dec. 23, 2013, the NRC issued the Final Environmental Impact Statement for Lee Nuclear, and on Jan. 2, 2014, the South Carolina Department of Health and Environmental Control issued the final Water Quality Certification. With the National Pollutant Discharge Elimination System permit, which was issued in July 2013, all of the major, required environmental permits and certifications required for the COL have been received. The NRC's COL licensing schedule targets the Advanced Final Safety Evaluation Report to be issued in May 2015, the Advisory Committee on Reactor Safeguards review of Advanced Final Safety Evaluation Report in September of 2015, the Final Safety Evaluation Report to be issued in December of 2015, and the mandatory hearing in April 2016. If this schedule is met, the COL is expected shortly thereafter.

Several final issues must be completed prior to NRC licensure of Lee Nuclear.

- In March 2012, the NRC issued a "request for information" letter to operating power reactor licensees regarding recommendations of the Near-Term Task Force review of insights from the Fukushima Dai-ichi accident. In April 2012, the NRC staff subsequently requested Duke to update the Lee Nuclear site-specific seismic analysis to incorporate the new Central and Eastern United States Seismic Source Characterization model. Duke submitted the seismic hazard evaluation for the station that was required as a follow-up action from the Fukushima event.

- Westinghouse in late 2013 indicated that modifications are being made to the passive emergency cooling system of its AP1000 reactor design after an analysis showed that condensate flow would be lower than previously estimated. In February 2014 Duke Energy Florida submitted an update to the Levy Nuclear Plant COL to address the modifications to the passive emergency cooling system. The NRC is advancing on its review of proposed changes to the design of the condensate return system of Westinghouse's AP1000 reactor, which it expects to complete by the end of 2014.

NC Power / VEPCO Generation

As of September 2014, NC Power had 17,677 MW of existing Company owned generating capacity (summer rating). This excludes purchases and non-utility capacity. Of this total, only 480 MW is located in North Carolina.

NC Power completed the conversion of Altavista (51 MW) on July 12, 2013, Hopewell (51 MW) on October 18, 2013, and Southampton (51 MW) on November 28, 2013 from coal to biomass fuel. Further, the 610 MW Virginia City Hybrid Energy Center is expected to consume renewable biomass fuel of up to 3% in 2014 and gradually increase that level to 10% by July 2020. The conversion of Bremo Units 3 (71 MW) and 4 (156 MW) from coal to natural gas was completed on May 1, 2014, and June 23, 2014, respectively.

To meet expected load growth, the Company filed for a certificate of public convenience and necessity (CPCN) with the State Corporation Commission of Virginia (SCC) to construct and operate Warren County Power Station, a 1,337 MW natural gas-powered electric generation facility located in Warren County, Virginia. On February 2, 2012, the SCC granted the CPCN, and on February 27, 2012, the Company officially began construction of the station. The station is targeted for commercial operation by 2015.

On November 2, 2012, the Company filed an application for a CPCN with the SCC to construct and operate Brunswick County Power Station, a 1,375 MW natural gas powered electric generation facility located in Brunswick County, Virginia, and associated facilities. On August 2, 2013, the SCC issued an order granting the CPCN. The station is targeted for commercial operation by May 2016.

The Company is in the process of developing a new nuclear unit, North Anna 3, at its existing North Anna Power Station located in Louisa County in central Virginia, subject to obtaining all required approvals. Originally, Old Dominion Electric Cooperative, part owner of North Anna Units 1 and 2, was also a participant in the development of North Anna 3, but it informed the Company of its intent to no longer participate in February 2011. On January 30, 2013, the NRC approved the transfer of Old Dominion Electric Cooperative's interest to the Company. The Company has recently re-assessed the overall schedule for completion of North Anna 3. This re-assessment includes obtaining the COL, the SCC Rider Application process, and construction of the facility. Given this schedule re-assessment, it is now determined that the earliest possible in-service date for North Anna 3 is September 2027, with capacity being available to meet the Company's 2028 summer peak. The Company has not committed to build North Anna 3 and will not make a final decision until after the issuance of the COL. However, the Company continues to develop the project actively, given the proven operational, economic, and environmental benefits of nuclear power, and to assure that this supply-side resource option remains available to its customers.

The technology selection for North Anna 3 is GE-Hitachi Nuclear Energy Americas LLC's (GEH) ESBWR nuclear technology, which is consistent with the 2013 Plan. In July 2013, the Company submitted a revised COL application to the NRC to reflect the change in technology from the Mitsubishi Heavy Industries Advanced Pressurized Water Reactor that was identified in the 2012 Plan. This decision was based on a continuation of the competitive procurement process that began in 2009 to find the best solution to meet its need for future baseload generation. Since 2009, GEH has continued to refine its design and has made significant progress toward obtaining federal approval. In addition, GEH and its consortium partner, Fluor Enterprises, Inc., provided contract enhancements that are expected to benefit customers and stakeholders over the new unit's planned 60-year life.

The Company expects to receive the COL in 2016 and intends to maintain the development option of North Anna 3 for several key reasons. First, North Anna 3 will provide much needed baseload capacity to the region in the latter portion of the Planning Period while enhancing system reliability. Additionally, nuclear units are near emission-free generation. Next, North Anna 3 will enhance fuel diversity within the Company's generation portfolio, which will in turn, promote fuel price stability for customers.

The Company is also currently in the early stage of development of a natural gas-fueled CC facility. This facility is being developed for commercial operation prior to the summer of 2019.

Based on effective and anticipated environmental regulations, along with current market conditions, NC Power's 2014 Plan includes several coal units that will be retired. These units include the Chesapeake Energy Center Units 1 (111 MW), 2 (111 MW), 3 (149 MW), and 4 (207 MW) that will retire by 2015 and Yorktown Units 1 (159 MW) and 2 (164 MW) that will retire in 2016.

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.

Previously, 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. Forecasted yearly reserve margins for Progress, Duke, and NC Power are shown in Appendices 2, 3, and 4. The summer reserve margins currently projected by each IOU are shown in Table 6.

Table 6: Projected Summer Reserve Margins for Progress, Duke, and NC Power (2014-2028, after DSM)

	Reserve Margins
Progress	14.9% –19.6%
Duke	14.3% – 21.5%
NC Power	11.2% – 17.6%

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. Some regions of North America are served only by a few, or even a single, pipeline system. North Carolina, in fact, is almost entirely dependent on Transcontinental Gas Pipe Line Company, LLC (Transco) for its natural gas requirements.

Transco is expanding its system to bring shale gas to the State from the north. And Dominion is now working to build a large new pipeline into North Carolina to serve both gas and electric generation customers. That project, the Atlantic Coast Pipeline, is due to be ready for service in late 2018.

8. RENEWABLE ENERGY AND ENERGY EFFICIENCY

Renewable Energy and Energy Efficiency Portfolio Standard (REPS)

On August 20, 2007, with the signing of Senate Bill 3, North Carolina became the first state in the Southeast to adopt a REPS. Under this law, 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 needs in 2021. EMCs and municipal electric suppliers are subject to a 10% REPS requirement. The requirements under the law phase in over time. In 2010, electric power suppliers were required to ensure that 0.02% of their retail electric sales in North Carolina came from solar energy resources. In 2012, electric power suppliers were required to meet 3% of their sales via renewable energy and energy efficiency, and the solar energy requirement increased to 0.07%. Also in 2012, requirements related to swine waste and poultry waste took effect, although those requirements were delayed by the Commission as discussed below.

On October 1, 2014, the Commission submitted its sixth annual report to the Governor, the Environmental Review Commission, and the Joint Legislative Commission on Governmental Operations regarding Commission implementation of, and electric power supplier compliance with, the REPS. The report is available on the Commission's web site, www.ncuc.net.

Senate Bill 3 requires the Commission to monitor compliance with REPS and to develop procedures for tracking and accounting for renewable energy certificates (RECs). 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 web site 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.

As of October 20, 2014, NC-RETS had issued 19,700,811 RECs and 5,066,987 energy efficiency certificates. In addition, 9,753,562 RECs had been imported into NC-RETS accounts. (These certificates were issued by registries located outside of North Carolina.) About 375 organizations, including electric power suppliers and owners of renewable energy facilities, have established accounts in NC-RETS. About 811 renewable energy facilities and utility energy efficiency programs participate as "projects" in NC-RETS, which means that NC-RETS issues RECs or energy efficiency certificates to the project owners based on the facilities' energy output, or the savings achieved by the energy efficiency program.

Renewable Energy and Energy Efficiency Portfolio Standard (REPS) Compliance

For 2010 and 2011, each electric power supplier was subject to a solar obligation of 0.02% of retail sales. At the end of 2010 and 2011, each electric power supplier was required to have placed solar RECs that they acquired to meet their 2010 and 2011 REPS solar set-aside obligation into a compliance account within NC-RETS. When the Commission concluded its review of each electric power supplier's REPS compliance report, the associated RECs were permanently retired.

Starting in 2012, North Carolina's electric power suppliers were subject to an increased solar obligation of 0.07% of retail sales. In addition, starting in 2012 they were subject to: 1) a general REPS obligation of 3% of retail sales; 2) a swine waste resource obligation of 0.07% of retail sales, and 3) their pro-rata share of a 170,000 MWh statewide aggregated poultry waste resource obligation. With the exception of the swine and poultry waste requirements (discussed below), all of the electric power suppliers have complied with their 2010-2013 REPS obligations, with the exception of one power supplier whose 2013 compliance remains under review.

In 2012, the electric power suppliers requested that their 2012 and 2013 swine and poultry waste obligations be delayed by two years. On November 29, 2012, the Commission issued an Order eliminating the 2012 requirement for swine waste resources and delaying for one year the requirement for poultry waste resources. In

2013, the electric power suppliers requested an additional one-year delay to both the swine and poultry waste obligations, which was granted by the Commission on March 26, 2014. In 2014, the electric power suppliers requested an additional delay to the swine waste requirement, but not the poultry waste requirement. On November 13, 2014, the Commission issued an Order Modifying the Swine Waste Set-Aside Requirement and Providing Other Relief in Docket No. E-100, Sub 113. This Order delayed the swine waste requirement until 2015; requested the Public Staff to facilitate two stakeholder meetings in 2015; and required electric power suppliers to file tri-annual reports detailing their efforts to secure swine waste resources.

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, NC Power, EnergyUnited, Halifax, and GreenCo have filed for and received approval for EE and DSM programs.

On August 30, 2013, the Commission filed its third biennial report to the Governor and the Joint Legislative Commission on Governmental Operations regarding proceedings for electric utilities involving EE and DSM cost recovery and incentives. That report lists the DSM and EE programs that have been reviewed by the Commission and is available on the Commission's web site.

NC GreenPower

Formed in 2003, NC GreenPower is a statewide, nonprofit organization, the first in the nation of its kind, working to help improve the quality of the environment in North Carolina. NC GreenPower accepts voluntary contributions from residents and businesses that donate directly or through their utility bills to support local renewable energy and carbon offset projects. NC GreenPower partners with nearly all electric utilities across the State. They help by marketing the program to their customers and collecting donations for NC GreenPower through utility bills. Renewable energy funds are used to pay approved generators across the State for each kWh of green energy they produce and put onto the electric grid from their project. Carbon offset contributions are used to pay carbon mitigation projects, like landfill and animal waste methane capture, for every pound of greenhouse gas that is mitigated from their project. Funds support local projects and help create North Carolina jobs.

As of November 2014, NC GreenPower had agreements with 564 small solar photovoltaic (PV) projects, 12 large solar PV projects, one small wind facility, and four landfill methane facilities.

A July 2014 report to the NC GreenPower Board of Directors showed nearly 10,000 North Carolina individuals and businesses were donating to the program through their utility bills. Since the launch of the program, NC GreenPower renewable energy projects have generated nearly 511 billion kWh of green power, and donors have helped provide about $6 million in incentive payments to the owners of more than 900 renewable energy projects in almost every county across the State. Carbon offset projects have mitigated 15,300 tons of greenhouse gases – equivalent to the emissions from driving 48 million miles.

On November 1, 2014, NC GreenPower filed with the Commission for review and approval a proposal to conduct two pilot programs that may ultimately serve as transitional programs for NC GreenPower. The two programs are the 50/50 Hybrid Pilot and the Investor and Crowd-Source Funded Renewable Energy Pilot. The 50/50 Hybrid pilot will continue to pay incentives to those eligible green power generators who are installing projects across the state. In addition, NC GreenPower will expand financial support to those who cannot afford renewable energy or cannot take advantage of tax credits, such as schools. The second pilot is one where a renewable project already has some investors to pay for the actual equipment and installation but needs NC GreenPower's marketing assistance to crowd-source additional funds.

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 December 31, 2013 report stated that 9 major transmission projects are needed in North Carolina by the end of 2023 at an estimated cost of $223 million. For more information, visit the NCTPC's website at www.nctpc.net/nctpc.

On February 16, 2007, FERC issued Order No. 890, adopting changes to the pro-forma open access transmission tariff (OATT) to be used by transmission owners, including a new requirement for transmission providers to participate in a coordinated, open, and transparent planning process on both a local and regional level. The FERC required each transmission provider to file the details of its planning process, which had to satisfy nine planning principles: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional coordination, economic planning studies, and cost allocation. Duke and Progress both referred to the NCTPC as their mechanism and forum for assuring open transparent planning with opportunity for involvement by stakeholders.

On July 21, 2011, the FERC issued Order No. 1000, entitled "Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities". [2] On May 21, 2012, the Commission issued an Order Scheduling Public Meeting and Requesting Comments on one issue raised by the FERC's Order No. 1000. Specifically, the Commission sought information relative to the legal and policy implications of Order No. 1000's requirement that public utility electric transmission service providers establish criteria and procedures for considering regional transmission projects[3] that would be sponsored, built, and owned by non-incumbent transmission owners.[4]

On October 11, 2012, the Commission issued a report to the Governor and the General Assembly regarding this issue.[5] The Commission's report found that North Carolina law did not appear to preclude construction and ownership of electric transmission facilities by a non-incumbent transmission owner, and that electric transmission ownership by non-incumbent transmission developers presented the following risks for the State's electricity consumers:

> (1) The risk that electric customers would pay more for a transmission line than they would otherwise pay if the line were owned by Duke or Progress because the return on equity (ROE) for the project would be set by the FERC, and the FERC grants relatively high ROEs in order to reward transmission construction. Under the filed-rate doctrine,[6] the Commission would be required to honor FERC's ROE decision and allow retail electric utilities to pass on to their retail customers the non-incumbent transmission developer's transmission charges.
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> (2) The risk that a non-incumbent transmission developer would abandon its transmission project, either mid-way in the construction process, or many years later when the developer had recouped its investment and no longer had an incentive to maintain the project. Because such a developer would not be a traditional, franchised electric utility, it would have no on-going "obligation to serve."
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> (3) The risk that a non-incumbent developer would build a transmission project in a substandard or inherently unreliable

[2] FERC issued Order No. 1000 on July 21, 2011, in its Docket No. RM10-23-000.
[3] A regional transmission project is one that benefits two or more transmission owners and generally spans or connects two or more companies' electric transmission systems.
[4] FERC's Order No. 1000 defines a non-incumbent transmission developer as an entity that does not have a retail electric distribution service territory as well as a public utility that proposes transmission projects outside of its existing retail service territory.
[5] The report is filed in Docket No. E-100, Sub 132.
[6] The "filed rate doctrine" holds that once the FERC sets rates to be charged interstate wholesale electric customers, a State may not conclude in setting retail rates that the FERC-approved wholesale rates are unreasonable. In other words, rates established by the FERC must be given binding effect by State utility commissions.

manner, or fail to maintain the line over time, thus threatening service reliability. All transmission developers are subject to federal reliability standards. However, a non-incumbent transmission owner would not be subject to G.S. 62-42, which gives the Commission the authority to compel a public utility to upgrade its facilities if necessary to provide reliable service, or the Commission's Rules R8-40 and 41, which establish public utility requirements for addressing bulk electric system emergencies.

(4) The risk that, during a widespread grid outage or system emergency, system restoration or defensive operations would be delayed while Duke, Progress, or NC Power coordinated restoration or operations decisions with the non-incumbent transmission owner.

(5) The risk that FERC's Order No. 1000 compliance orders for Duke, Progress and PJM would encourage non-incumbent transmission development, and thereby increase the occurrence of the risks outlined above.

The Commission recommended that the Governor and the General Assembly take action to address these concerns.

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.

On October 11, 2012, Duke and Progress jointly submitted an Order No. 1000 compliance filing to FERC in Docket No. ER13-83. On February 21, 2013, FERC issued an order in which it rejected the Duke/Progress compliance filing, ruling that the Companies' combined footprint could no longer be considered a "region." The FERC reasoned that due to the merger of Duke Energy Corp. and Progress Energy, Inc., the two utilities are no longer separate transmission providers. As such, FERC found that the NCTPC is no longer a viable transmission planning region (although the NCTPC could still be operated as a "local" transmission planning process). FERC required Duke and Progress to file a further compliance filing via which they would become part of a compliant transmission planning region.

On May 22, 2013, Duke and Progress filed, under protest, a proposal to comply with Order No. 1000 by participating in the Southeastern Regional Transmission Planning (SERTP)[7] process. On December 19, 2013, FERC issued its order on the

[7] 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,

Duke/Progress rehearing request filed on March 25, 2013. FERC denied the request for rehearing of its previous order (which rejected the NCTPC as an Order No. 1000 "region"). FERC approved Duke/Progress joining the SERTP for its Order No. 1000 compliance, and keeping the NCTPC for "local" planning. On June 19, 2014, FERC issued its order on the second regional compliance filing of the SERTP members, requiring additional changes to the SERTP Order No. 1000 plan. This order allowed SERTP's regional transmission planning process to recognize state and local laws and regulations, such as laws related to rights-of-way and transmission ownership (this had been disallowed in FERC's previous order). FERC also approved SERTP's proposal to allocate the costs of new regional transmission projects based on the costs of local transmission projects that are avoided due to the regional project, as well as the impact of the new project on line losses.

The SERTP submitted its third regional compliance filing on August 18, 2014, and it remains pending before FERC.[8]

State Generator Interconnection Standards

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

In Session Law 2007-397, the General Assembly, among other things, directed the Commission to "[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."

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.

On July 9, 2008, Duke filed a motion for reconsideration regarding whether an external disconnect switch should be required for certified inverter-based generators up to 10 kW. On December 16, 2008, the Commission issued an Order in which it granted Duke's motion for reconsideration and gave electric utilities the discretion to require external disconnect switches for all interconnecting generators. However, if a utility

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Indiana-Kentucky Electric Corporation, Associated Electric Cooperative, Inc., and the Tennessee Valley Authority.

[8] For more information, see http://www.ferc.gov/, Docket No. ER13-83.

requires such a switch for a certified, inverter-based generator under 10 kW, the utility shall reimburse the generator for all costs related to that installation.

On April 8, 2014, the North Carolina Sustainable Energy Association (NCSEA) requested that the Commission consider revising its small generator interconnection standards in light of changes that have been made at the federal level and in other states. On April 11, 2014, the Commission issued an Order requesting that the Public Staff facilitate a meeting of interested parties to discuss potential changes to North Carolina's interconnection standards. The Order also established a schedule for parties to file comments and reply comments. This matter remains pending before the Commission.[9]

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. In Senate Bill 3, 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, following hearings on its then-current net metering rule, the Commission issued an Order requiring Duke, NC Power, and Progress 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

[9] For more information, see Docket No. E-100, Sub 101.

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.

On February 24, 2014, NCSEA filed a Motion for Disclosure and Equitable Relief requesting that the Commission direct Duke and Progress to: (1) guarantee, at a minimum, the continued availability of the current net-metering terms and conditions for 10 years for each residential and commercial customer who installs a net-metered rooftop solar system prior to issuance of a final order in any net-metering proceeding initiated in the coming year; and (2) disclose the analysis upon which Duke was basing its messaging that net metering in North Carolina is unfair. The Commission requested comments on NCSEA's motion.

On May 28, 2014, the Commission issued an Order Denying Motion stating that there is no petition before the Commission to change the current net-metering policy, and that NCSEA's request for disclosure had become moot because Duke's analysis had become public.

10. FEDERAL ENERGY INITIATIVES

Open Access Transmission Tariff

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, NC Power's parent, 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.

The Commission has continued to provide oversight over NC Power 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 an NC Power 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. On September 17, 2012, the Commission joined with NCEMC, Old Dominion Electric Cooperative, and the Virginia Municipal Electric Association No. 1 to file a reply brief in this case. A FERC-appointed administrative law judge convened settlement negotiations, but the parties were not able to reach a settlement. On December 2, 2014, FERC assigned the dispute to an administrative law judge who is expected to schedule a hearing.[10]

Energy Policy Act of 2005

The Energy Policy Act of 2005 (EPAct 2005), which became law on August 8, 2005, gave the FERC responsibility to oversee mandatory, enforceable reliability standards for the bulk power system. In the summer of 2006, it approved the NERC as the entity responsible for proposing, for FERC review and approval, standards to protect the reliability of the bulk power system. NERC may delegate certain responsibilities to "Regional Entities" subject to FERC approval. In the southeast, those responsibilities, including auditing for compliance, have been delegated to the Southeastern Electric Reliability Corporation (SERC), headquartered in Charlotte, North Carolina. In March 2007, the FERC approved the first set of mandatory, enforceable reliability standards. Violations can result in monetary penalties of up to $1 million per day per violation. The FERC, NERC, and SERC initially focused on two compliance areas that had been implicated in large regional bulk power system outages: (1) the

[10] For more information, see www.ferc.gov, Docket No. EL10-49-003.

need for more thorough vegetation management below and near high-voltage power lines and (2) the need for more rigorous design and maintenance of the relays that determine whether the electric grid "rides through" disturbances or "separates," potentially contributing to cascading outages. More stringent federal requirements for vegetation management have reduced the flexibility North Carolina utilities have traditionally exercised in working with communities and landowners.

EPAct 2005 added a new Section 216 to the Federal Power Act, providing for federal siting of interstate electric transmission facilities under certain circumstances. States retain primary jurisdiction to site transmission facilities, and federal transmission siting effectively supplements a State siting regime. Section 216 requires the Secretary of the U.S. Department of Energy (DOE) to study electric transmission congestion and to designate, as a national interest electric transmission corridor, any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers. The DOE is required to prepare a report to Congress every three years on the status of transmission congestion nationwide. On November 10, 2011, the DOE announced its plan for conducting a 2012 Congestion Study. The draft report was issued for public comments on August 19, 2014, with a deadline of October 20, 2014. The final report has not yet been published.

Section 216 also authorized the FERC to site transmission facilities if a State withholds approval of a project for more than one year. The FERC interpreted this provision to include instances where a State has denied construction of a proposed project. This interpretation was appealed to the United States Court of Appeals for the Fourth Circuit, which in 2009 ruled that the FERC had, in fact, interpreted the law too broadly.

EPAct 2005 required the FERC to establish incentive-based wholesale rate treatments for transmission facilities. Congress specified that these incentives were "for the purpose of benefitting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion." In July 2006, the FERC issued Order No. 679, which allows utilities to seek wholesale rate incentives such as: (1) incentive rates of return on equity for new investment in transmission facilities; (2) full recovery of prudently incurred transmission-related construction work in progress costs in rate base; and (3) full recovery of prudently incurred pre-commercial operation costs. The FERC allows these incentives based on a case-by-case analysis of individual transmission projects. The Commission has intervened in NC Power incentive proceedings before the FERC and joined an appeal before the Fourth Circuit Court of Appeals in order to protect the interests of North Carolina consumers. The appeal was ultimately unsuccessful, but useful nonetheless in that NC Power has not sought any additional incentives for its transmission construction program.

Cyber Security

Federal 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 cyber attacks. The FERC believes its legal authority is inadequate to address potential threats to the bulk power system and has asked Congress to enact legislation to address this deficiency. In addition, NERC is leading an effort to develop more stringent cyber security standards.

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 quickly 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 the physical security standards and filed them with FERC on May 23, 2014. On July 17, 2014, FERC proposed modifications to the draft standards, including the ability for governmental authorities to add or subtract facilities from the list of critical facilities for which physical security measures would be required. After receiving comments, on November 20, 2014, FERC issued Order No. 802. That order requires NERC to remove wording that FERC believes could reduce the number of "critical facilities" that would be subject to the rule. The order did not adopt FERC's earlier proposal that would have allowed governmental authorities to add or remove facilities from the list of critical facilities. The rules become effective June 1, 2015.[11]

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

On June 2, 2014, the U.S. Environmental Protection Agency (EPA) proposed regulations for reducing CO_2 emissions from existing power plants. Under EPA's proposal, each State would be required to submit a compliance plan under which the State would reach a specific CO_2 standard. For North Carolina, the proposed standard would be 1,077 pounds of CO_2 per MWh by 2020, and 992 pounds of CO_2 by 2030, about a 40% reduction from 2012 emissions.

EPA proposed a "best system of emissions reduction" that is comprised of four building blocks: 1) improve by 6% the efficiency of existing coal-burning plants; 2) operate combined-cycle gas-burning plants at a 70% capacity factor; 3) offset production at CO_2 emitting power plants with renewable energy; and 4) offset production at CO_2 emitting power plants with energy efficiency.

In North Carolina, 23 power plants are affected by the proposed rules. The North Carolina Department of Environment and Natural Resources and the Public Staff filed

[11] For more information, go to http://www.ferc.gov/, Docket No. RM14-15.

comments regarding the proposal, on December 1, 2014 (See www.ncair.org/rules/EGUs for more information.)

The EPA states that its final rule will be issued by June 1, 2015. For more information, visit the EPA's website at http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 137

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of 2013 Integrated Resource Plan Annual Update Reports and Related 2013 REPS Compliance Plans	)))))	ORDER APPROVING INTEGRATED RESOURCE PLAN ANNUAL UPDATE REPORTS AND REPS COMPLIANCE PLANS

HEARD: Monday, April 28, 2014, at 7:00 p.m. in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Bryan E. Beatty, Presiding; Chairman Edward S. Finley, Jr., and Commissioners Susan W. Rabon, ToNola D. Brown-Bland, Don M. Bailey, Jerry C. Dockham, and James G. Patterson

APPEARANCES:

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

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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] EE 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 (collectively, the utilities),[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

[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.

short-term action plan that discusses those specific actions currently being taken by the utility to implement the activities chosen as appropriate per the applicable biennial and annual reports and (2) incorporate information concerning the construction of transmission lines pursuant to Commission Rule R8-62(p).

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

2013 ANNUAL UPDATE REPORTS

This Order addresses the 2013 annual update reports (2013 IRPs) filed in Docket No. E-100, Sub 137, by Duke Energy Progress, Inc. (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 lOUs.

The following parties have been allowed to intervene in this docket: Blue Ridge Environmental Defense League (BREDL); Carolina Industrial Group for Fair Utility Rates I, II, and III (CIGFUR); Carolina Utility Customers Association, Inc. (CUCA); Greenpeace; Invenergy Wind Development, LLC and Invenergy Solar Development, LLC (Invenergy); Mid-Atlantic Renewable Energy Coalition (MAREC); North Carolina Sustainable Energy Association (NCSEA); North Carolina Waste Awareness and Reduction Network (NC WARN); Nucor Steel-Hertford; Sierra Club; and Southern Alliance for Clean Energy (SACE). 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 August 22, 2014, DEP and DEC moved for an extension of time to file their 2013 IRPs to October 1, 2013. The Commission granted this motion by Order dated August 28, 2013. On September 23, 2013, DEP and DEC filed a motion for a further extension until October 15, 2013. This motion was granted by the Commission on September 24, 2013.

On August 30, 2013, DNCP filed its 2013 annual update IRP and REPS compliance plan. On October 15, 2013, DEC and DEP filed their 2013 annual update IRP's and REPS compliance plans.

On October 11, 2013, the Commission issued an Order establishing February 4, 2014, as the date by which interested parties may file petitions to intervene in this docket, and the Public Staff and other intervenors may file initial comments on the utilities' IRPs and REPS compliance plans. Further, the Order set February 18, 2014, as the date by which all parties may file reply comments.

On January 6, 2014, the Commission issued an Order scheduling a public hearing to be held on March 3, 2014, for the purpose of taking non-expert public witness testimony with respect to the filed annual updated IRPs and REPS compliance plans. Due to inclement weather on March 3, 2014, the Commission canceled the public hearing.

On January 16, 2014, the Public Staff filed a Motion requesting that the Commission extend the date for petitions to intervene and initial comments to Friday, March 14, 2014, and the date for reply comments to Friday, March 28, 2014. This Motion was granted by an Order dated January 16, 2014.

On March 6, 2014, the Commission issued an Order rescheduling the public hearing for April 28, 2014.

On March 7, 2014, DEC and DEP filed a corrected inputs supplement to their 2013 IRPs.

On March 10, 2014, NC WARN filed a Motion requesting that the Commission review costs of the DEC proposed Lee Combined Cycle Plant in South Carolina. On March 11, 2014, DEC filed a Response to the NC WARN Motion. On March 21, 2014, the Commission issued an Order denying that motion.

On March 12, 2014, SACE and the Sierra Club filed a Motion requesting that the dates for comments and reply comments be extended to April 11, 2014, and April 25, 2014, respectively. This request was granted by an Order dated March 13, 2014.

On April 11, 2014, comments on the electric utilities IRPs were filed by the Sierra Club and SACE jointly, NCSEA, MAREC, the Public Staff and NC WARN. NC WARN in its comments also requested that the Commission hold an evidentiary hearing regarding DEC’s growth forecasts.

On April 15, 2014, DEP, DEC and DNCP filed a Joint Motion requesting that the date for reply comments be extended to May 23, 2014. On April 17, 2014, the Commission issued an Order extending the time for the utilities to file reply comments until May 23, 2014.

On May 16, 2014, NCSEA submitted corrected comments to correct an analytical error in its comments filed on April 11, 2014. NCSEA stated that the corrected comments do not in any way alter or change its arguments or recommendations made in its original comments.

On May 22, 2014, Sierra Club and SACE submitted joint reply comments. On May 23, 2014, DNCP filed reply comments and DEC and DEP filed joint reply comments.

On June 10, 2014, NC WARN submitted a Motion to File Additional Comment containing additional and clarifying comments in response to the reply comments filed jointly by DEC and DEP.

On June 18, 2014, DEC and DEP filed a response to NC WARN's additional reply comments.

Public Hearing

Pursuant to G.S. 62-110.1(c) the Commission held a public hearing in Raleigh on Monday, April 28, 2014, at 7:00 p.m., where 11 public witnesses spoke. The witnesses discussed the negative environmental impacts of coal plants and other fossil fuel generation versus the positive benefits of using renewable types of generation, especially solar and wind. Reducing carbon emissions, the removal of toxic coal ash from pond sites, energy efficiency, energy conservation, and demand-side management were issues brought up by the witnesses.

Request for Evidentiary Hearing on Projected Load Growth

In its April 11, 2014 comments, NC WARN stated that both DEC and DEP (collectively, Duke or Duke Energy) base their 15-year IRPs on growth in the use of electricity increasing 1.4 – 1.5% each year, even though actual growth in electricity demand has been flat for more than a decade. Further, NC WARN stated that each of the projections include the impacts of the utility’s energy efficiency programs, so the actual growth Duke Energy maintains in the IRPs is even higher -- almost 1.9%. According to NC WARN, the forecasts are based on a full economic recovery and a booming growth in population, and the utilities plan to meet new growth for electricity with continued use of polluting fossil fuel plants and extremely costly nuclear plants.

NC WARN asserted that what are troublesome are the surprising inconsistencies in the forecasted growth in demand and sales stated in the IRPs and what Duke Energy officials told shareholders and the business press just weeks after the IRPs were filed. For example, NC WARN stated that in her earnings conference call with Duke Energy shareholders on November 6, 2013, Lynn Good, Duke Energy’s CEO, stated that the utility actually expects growth to be in the 0.5 to 1.0% range for the foreseeable future. According to NC WARN, this information was summarized in an article by Bruce Henderson in the Charlotte Observer. The article stated that “long-term, CEO Lynn Good told financial analysts, Duke expects sales to grow only 0.5 percent to 1 percent a year. In recent years, annual growth has been about 1 percent.”

NC WARN further stated that in a presentation to the Legislative Study Committee at the General Assembly on January 7, 2014, Paul Newton, Duke Energy's President for North Carolina, testified that the growth rate would be between 0.5 and 0.9%.

In addition, NC WARN stated that in an interview with Industrial Info Resources on December 16, 2013, Jim Rogers, former chairman and CEO of Duke Energy, stated that he expects electric growth to be flat for the foreseeable future. According to NC WARN, he is quoted as stating "over the next couple of decades, we're not going to be building central station generation, particularly when you factor in the effect of state renewable portfolio standards, more efficient appliances, more efficient building and new technologies that will help customers reduce electric usage." The article then summarizes his position as follows: "going forward, he said state renewable portfolio standard (RPS) policies would absorb most of what growth there will be in customer demand for electricity." NC WARN stated that Rogers subsequently repeated his forecast in other forums.

NC WARN stated that it is unable to determine which of these annual growth forecasts Duke actually believes to be accurate. According to NC WARN, one rationale given by Duke Energy officials to business reporters for the considerably lower forecasts is that they are for the Duke Energy system in its entirety. However, NC WARN maintained that this falls flat after reviewing the IRPs (or similar documents) in each of the other states that Duke Energy serves. According to NC WARN, the weighted average is a forecasted 1.33% growth rate, with only Indiana projected as significantly lower than other states. NC WARN stated that the other rationale given for the lower growth forecasts is they do not include growth in sales to wholesale customers. NC WARN submitted that this also falls flat in that there are not many potential wholesale customers in the North Carolina service area left, and their growth will not be any higher than the rest of the system.

NC WARN argued that of these differing forecasts Rogers's forecast of zero growth is in line with the most recent growth projections by the U.S. Energy Information Administration (EIA) as well as actual growth for the past decade. During 2013, EIA estimates the average U.S. residential customer used 10,870 kilowatt hours (kWh) of electricity, which is 2.2% lower than the average level of consumption between 2008 and 2012. In part due to improvements in appliance and lighting efficiency, "the overall growth trend has been slowing in recent years."

NC WARN noted that another recognized source for energy forecasts, the American Council for an Energy-Efficient Economy (ACEEE) also projects a zero or potential negative growth future for utilities. According to NC WARN, the ACEEE report states that electricity sales fell by 1.9% in 2012 over 2007's figures, and sales in the first ten months of 2013 have fallen even lower. NC WARN, submitted that the economic recession explains the decline in sales in 2008 and 2009, but it is much less clear why sales have continued to fall. Further, NC WARN stated that the ACEEE suggests that energy-efficient buildings, lighting and appliances have successfully reduced consumption, as well as energy efficiency programs and policies, warmer weather, changes in gross domestic product, changes in electricity prices, and long-term trends in energy efficiency.

NC WARN asserted that the differences between the IRP, EIA and ACEEE projections are significant in scope and the real world impacts are substantial. Together for both DEC and DEP, Duke Energy forecasts a need for 7,029 megawatts (MW) of new capacity and 34,691 MWh of additional energy sales. A forecast in the 1% to 0.5% range reduces the need for new generating plants down to a range of 2,267 MW to 4,686 MW (with similar reductions in energy). NC WARN stated that the zero growth scenario forecast propounded by Rogers, and supported by the EIA and the ACEEE, eliminates the need for additional capacity and energy entirely. NC WARN further contended that this forecast eliminates the need for the Lee Nuclear Station and all other proposed new Duke generating plants, and allows the utility to shut down all coal plants and reduce use of natural gas with a stronger commitment to energy efficiency, renewable energy resources, cogeneration and other distributed generation. Thus, NC WARN argued that the debate could and should be about how fast we can shut down coal plants and which natural gas plants should be closed.

NC WARN concluded that in light of the diverse and contradictory forecasts between those provided in the IRPs and those propounded by Duke Energy executives to shareholders, legislative commissions and the business press, an evidentiary hearing is required, and that the ramifications of following the Duke Energy IRP forecast, in rate impacts and costs to ratepayers caused by new plant construction and continuing use of coal and its associated risks, are highly significant.

In their joint May 22, 2014 reply comments, Sierra Club and SACE noted that NC WARN addressed the conflict between the load forecasts in the IRPs and remarks by Duke Energy representatives, as well as national efficiency experts. They point out that NC WARN then proposes an alternative energy future that eliminates all coal plants and new conventional generation, replacing it with energy efficiency, solar power and other forms of distributed generation and that this approach can provide an estimated annual savings for customers of more than $2 billion.

The Sierra Club and SACE state that they have not had an opportunity to review in detail the assumptions and methodology underlying NC WARN's comments; however, they agree with general points made by NC WARN that the DEC and DEP load forecasts are overstated, and that the IRPs should include higher levels of renewable energy and energy efficiency, which are consistent with the points made in their initial comments. They state that if the Commission allows NC WARN's motion, SACE and the Sierra Club respectfully submit the issues raised in their initial comments for the Commission's consideration as possible additional issues for an evidentiary hearing.

Regarding NC WARN's request for an evidentiary hearing, DNCP noted that NC WARN does not focus any of its comments on DNCP's 2013 IRP. DNCP stated that NC WARN's request for an evidentiary hearing focused solely on whether the IRPs submitted by DEC and DEP are in the best interest of North Carolina ratepayers. While DNCP recognizes the Commission's discretion under Commission Rule R8-60 to hold an evidentiary hearing on the utilities' IRPs, DNCP does not view NC WARN's generic request for an evidentiary hearing as presenting compelling issues or reasoning to hold such a hearing, and, to the extent the Commission determines otherwise, DNCP believes that the hearing itself, similar to NC WARN's comments, should be limited to DEC's and DEP's plans.

In the joint May 23, 2014 reply comments of DEC and DEP, Duke asserted that NC WARN rehashes its previous IRP contentions and yet again makes the completely false assertion that DEC and DEP's IRP updates are based upon exaggerated load forecasts. Duke opined that NC WARN advances unsupported hyperbole that the resource plans filed by DEC and DEP would "bankrupt North Carolina's economy," simply because Duke relies upon a mix of resources that include reliable and cost-effective baseload nuclear, gas and coal generation. Without apparent regard to cost, reliability or feasibility, NC WARN instead proposes that its allegedly superior alternate energy future can be achieved by "eliminating all coal plants and all new generation." Duke argues that as in past IRP dockets the Commission should dismiss NC WARN's meritless contentions.

According to Duke, NC WARN's criticism of "differing" load forecasts is entirely misplaced. NC WARN alleges that the load forecasts contained in the 2013 DEC and DEP IRP updates are higher than various general load growth comments attributed to Duke Energy CEO Lynn Good, Duke Energy State President-North Carolina Paul Newton, and former Duke Energy Corporation CEO Jim Rogers in various public or media comments from November 2013, January 2014, and December 2013, respectively. Duke argued that NC WARN insinuated that Duke Energy filed one set of load forecasts with the Commission, yet told other audiences that the true load forecast is much lower. According to Duke, it is disturbing that NC WARN apparently fails to understand that Duke Energy operates utilities in six states, and that the referenced Duke Energy executives were not speaking about the DEC and DEP 2013 load forecasts in their comments. Duke noted that the load forecasts for DEC and DEP in North Carolina and South Carolina are different than the outlook for the Duke Energy utilities in Indiana, Ohio, Kentucky or Florida; are different than the outlook for the aggregated Duke Energy utilities (referred to by Duke Energy as Franchised Electric & Gas); and are different than the reported outlook for the United States electric industry in general - - which were the subject of the various comments by the Duke Energy executives. According to Duke, the comparison among different utilities or data from national organizations such as EIA is complicated due to different terminology, different forecast horizons or different load definitions, and NC WARN's comments at best fail to attempt a true "apples-to-apples" comparison. Duke stated that the facts are that DEC's and DEP's loads are projected to grow at a faster pace than the Duke Energy

U.S. Franchised Electric & Gas load or the U.S. (USFE&G) electric industry load, due to the higher population growth rate and growing wholesale load contribution in North Carolina and South Carolina. Duke maintained that former CEO Rogers often spoke in terms of the U.S. electric industry as a whole and often discussed negative load growth in terms of national use-per-customer trends, not total sales and certainly not as to DEC and DEP load forecasts. DEC and DEP's projected growth in number of customers (driven by population growth or migration of population from other parts of the country) more than offsets any decline in per-customer usage growth. In order for DEC or DEP to have "zero growth" as NC WARN asserts, average electric use per customer would have to decline by negative one percent (- 1.0%) or more each and every year over the planning horizon to 2028.

Duke pointed out that NC WARN did not prepare a true load forecast, but simply assumed "zero growth." Duke stated that such an assumption is entirely inconsistent with the actual data utilized to prepare the load forecasts for the Duke's 2013 IRP updates. Duke stands by the reasonableness of the load forecasts contained in its 2013 IRP updates, which have been reviewed by and are supported by the Public Staff.

According to Duke, NC WARN's "Model" and Zero Growth Scenario are unrealistic. In its comments, NC WARN touted its own proposed resource plan as superior to those contained in DEC and DEP's 2013 IRP updates and stated that its "analysis shows that a zero growth scenario allows for phase out of all coal plants, eliminates the need to construct new nuclear plants and reduces the need for some existing natural gas." Duke asserted, however, that when information is sought about the support for NC WARN's allegations, no substantive analysis is forthcoming. Duke stated that in response to a data request seeking a copy of NC WARN's "plan" and "model," and the specific inputs used in the production cost simulation models and screening models supporting the NC WARN comments, NC WARN responded,

> NC WARN's "plan" (used interchangeably with "model") is described in the comments, paragraphs 25-29, and is based on the charts in Appendix A and the NC WARN's report filed in last year's initial Comments on the IRPs....NC WARN has not prepared production cost simulation models and screening models of the NC WARN plan or model, nor developed any of the inputs listed in the request, except recently looked at natural gas price forecasts as part of the preparation of the [NC WARN avoided cost testimony filed in E-100, Sub 140].[4]

On June 10, 2014, NC WARN filed a Motion for Leave to File Additional Comment. In support of its motion, NC WARN asserted that in its reply comments filed May 23, 2014, Duke aggressively replied to NC WARN’s comments by stating

[4] NC WARN Response to Duke Energy Data Request 10, May 1, 2014.

> NC WARN insinuates that Duke Energy filed one set of load forecasts with this Commission, yet told other audiences that the true load forecast is much lower. It is disturbing that NC WARN apparently fails to understand (or wilfully ignores) that Duke Energy operates utilities in six (6) states, *and that the referenced Duke Energy executives were not speaking about the DEC and DEP 2013 load forecasts in their comments.* (emphasis in original)

NC WARN stated that this ignores NC WARN's paragraph 8, footnote 8 in its comments, which clearly contradicts Duke Energy's comment that the much lower forecasts by Duke Energy officials do not conflict with the IRPs filed in this docket, as they were addressing the entire Duke Energy system, and not just North Carolina. Footnote 8 reads:

> One rationale given by Duke Energy officials and floated to business reporters for the considerably lower forecasts is that they are for the Duke Energy system in its entirety. This falls flat after reviewing the IRPs (or similar documents) in each of the other states Duke Energy serves – the weighted average is a forecasted 1.33% growth rate, with only Indiana projected as significantly lower than other states. The other rationale given for the lower growth forecasts is they do not include growth in sales to wholesale customers. This also falls flat in that there just are not many potential wholesale customers in the North Carolina service area left, and their growth will not be any higher than the rest of the system.

NC WARN noted that the worksheet showing the weighted average of growth rates in the various states Duke Energy serves was attached to its comments, and that the growth rates reported in the most recent IRPs (or equivalent planning documents) were reviewed in each of the states from utility commission websites. NC WARN stated that the number of customers came directly from the Duke Energy website to provide a weighted average of a forecast of 1.33% for the entire Duke Energy service areas. NC WARN noted that a fundamental assumption was that the mix of customer classes was approximately similar in each of the states as classification of customer classes varied.

NC WARN contended that the weighted average of 1.33% was still considerably higher than the 0.5 to 1.0% range given by CEO Good in her earnings conference call with Duke Energy shareholders on November 6, 2013, and the 0.5 and 0.9% given by Duke President Newton in January 2014 to a legislative committee in which he discussed Duke Energy in North Carolina. Given the disparity between the comments by the Duke Energy officials, some of which were under oath to regulatory commissions, NC WARN stood by its comments that the Commission should investigate why differing forecasts were used in different forums, and what forecast Duke Energy is actually using for planning purposes.

NC WARN submitted that whether these discrepancies were intentional or inadvertent the difference between a forecast in the 1.33 to 1.5% range and the considerably lower forecasts by Good and Newton, and especially that of Rogers, results in billions of dollars of new plant construction.

On June 18, 2014, Duke filed additional reply comments in response to those of NC WARN. Duke stated that in its May 23, 2014 Joint Reply Comments Duke completely refuted NC WARN's assertions that Duke has made conflicting load growth projections. Duke further stated that it does not agree with NC WARN's aggregate load forecast for all of Duke's USFE&G. However, assuming that NC WARN's calculations are correct, Duke noted that its USFE&G forecast is irrelevant to the examination of North Carolina's future electric needs that the Commission is conducting in this docket. Further, Duke submitted as attachments the transcript of the November 6, 2013 earnings call and a slide used in the presentation. Duke pointed out that the transcript and slide confirm that CEO Good and others were discussing Duke's USFE&G, rather than forecasts specific to North Carolina. Duke also attached page 7 of the presentation made by Duke President Newton in January 2014 to a legislative committee. Duke explained that this page shows that Newton was referring to the growth of electricity usage in the United States from 1950 to 2040. In addition, Duke cited its confidential Table C-1 in its IRPs showing wholesale customer load growth, including a new contract with an existing wholesale customer that adds more than 800 MW of additional load by 2022.[5] In conclusion, Duke stated that Duke has not submitted or used differing load forecasts and it stands by the accuracy of the forecasts included in its IRPs.

Discussion

As previously noted, G.S. 62-110.1(c), in pertinent part, requires the Commission to “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.” Thus, the Commission's analysis in this docket with regard to future use of electricity is focused on an estimate of future use in North Carolina. Although regional and national forecasts of electricity usage are helpful in understanding trends and potential impacts on an individual state's needs, they are not a substitute for the type of North Carolina focused analyses that Duke provided in its IRPs. Further, as more fully discussed below, the Public Staff has reviewed the economic, weather-related, and demographic assumptions underlying Duke's peak and energy forecasts. The Public Staff found that Duke has employed accepted statistical and econometric forecasting practices, and it believes that Duke's conclusions are reasonable for planning purposes.

In addition, one of NC WARN's contentions is that the 750-MW Lee combined cycle plant to be built by Duke in South Carolina (Lee CC Plant) is not needed. As previously stated, on March 10, 2014, NC WARN filed a Motion to Review Costs of

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[5] Duke noted that NC WARN did not request to sign a confidentiality agreement and, therefore, did not have this information.

Proposed Plant in South Carolina in this docket. By its motion, NC WARN requested that the Commission conduct a review of the costs and need for the Lee CC Plant. On March 21, 2014, after reviewing Duke's response to the motion and the applicable statutes, the Commission issued an order concluding that there was no basis for the Commission to make a determination at this time of the need for or estimated cost of the Lee CC Plant.

On April 28, 2014, the Commission held a public hearing in Raleigh for the purpose of receiving testimony from ratepayers. Several witnesses attended the hearing and provided the Commission with their views and concerns regarding least cost and environmentally sound electric generating resources. In addition, the Commission has received numerous consumer statements of position from ratepayers on these and other subjects. The evidence from the public hearing, the IRPs, the consumer statements of position and the parties' comments and reply comments provide the Commission with an extensive record in this docket. Having reviewed the record and considered the parties' arguments, the Commission concludes that the substantive issues raised by ratepayers at the hearing and in their statements of position, as well as those raised by NC WARN in its comments, motion for an evidentiary hearing and additional reply comments, have been adequately addressed by Duke in its comments, reply comments and additional reply comments. As a result, the Commission 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 evidentiary hearing.

The Commission fully supports the use of an evidentiary hearing in situations where it is warranted. However, no reasonable basis for convening an evidentiary hearing has been demonstrated in this case. Therefore, the Commission is not persuaded that there is good cause to grant NC WARN's motion that the Commission hold an evidentiary hearing in this docket. As a result, the motion should be denied.

Based on the foregoing, the comments of the parties, and the entire record in this proceeding, the Commission makes the following

FINDINGS OF FACT

1. The IOUs' 15-year 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 and should be approved.

2. The IOUs included a full discussion of their DSM programs and their use of these resources as required by Rule R8-60(i)(6).

3. The IOUs included a full discussion of REPS compliance and their plans should be approved.

4. The 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.

5. DEP and DEC in future IRPs should provide information on the number, resource type and total capacity of the facilities currently within the respective utility's interconnection queue as well as a discussion of how the potential QF purchases would affect the utility's long-range energy and capacity needs.

6. DEP, DEC and DNCP have adequately addressed the issues raised by the intervenors.

DISCUSSION AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-2

<u>PEAK AND ENERGY FORECASTS</u>

The Public Staff has reviewed the 15-year peak and energy forecasts (2014–2028) of DEP, DEC, and DNCP. The compound annual growth rates (CAGR) for the forecasts are within the range of 1.2% to 1.4%.

The Public Staff found that all of the utilities used accepted econometric and end-use analytical models to forecast their peak and energy needs. As 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 most recent weather-normalized peak loads to the utilities' forecasts in the 2012 IRPs. Second, the Public Staff analyzed the accuracy of the utilities' peak demand and energy sales predictions in their 2008 IRPs in comparison to their actual peak demands and energy sales. 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, the Public Staff reviewed several of the assumptions that underlie the forecasts of other adjoining utilities and the SERC Reliability Corporation (SERC).

<u>DEP</u>

DEP's 15-year forecast predicts that its adjusted summer peaks will grow at a CAGR of 1.2%, as compared to a 0.9% growth rate in the 2012 IRP. Without the reduction in peak demand resulting from the implementation of its EE programs, DEP expects its summer peaks to grow at a rate of 1.7%. The increase in the growth rate in peaks is partially due to DEP's adoption of DEC's methods of forecasting load and calculating reserve margins, which considers DSM as a resource rather than as a decrement to the load forecast. In prior IRPs, DEP deducted the DSM load reductions from its forecasted peak loads. The average annual growth of its summer peak, which is considered its system peak, is forecasted to be 171 MW for the next 15 years, in comparison to the 130 MW forecast in last year's IRP. DEP predicts that in 15 years, the load reductions from its DSM programs will reduce its peak load by approximately 4%, as compared to a 9% reduction forecast in the 2012 IRP.

DEP's energy sales, including the impacts from its EE programs, are predicted to grow at a CAGR of 1.4% as compared to 1.0% in the 2012 IRP. DEP predicts that in 15 years, the MWh reductions from its EE programs will reduce its energy sales by approximately 4%, which is similar to its projection in its 2012 IRP.

The Public Staff's review of DEP's weather adjusted peak load forecasting accuracy for one year shows that the predictions in the 2012 IRP had a forecast error of 2%, caused in part by the relatively mild summer temperatures in 2013.[6] The Public Staff's review of DEP's actual peak load over five years (2009-2013), as compared to its forecasts, shows a forecast error of 3%. This 3% forecast error results in an average annual overestimation of 407 MW. A comparison of DEP's actual energy sales over the same five years with those predicted in its 2008 IRP reflects a 5% forecast error.

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

<u>DEC</u>

DEC's 15-year forecast predicts that its adjusted summer peaks will grow at a CAGR of 1.4%, as compared to the 1.7% growth rate projected in the 2012 IRP. Without the reduction in peak demand resulting from the implementation of its EE programs, DEC expects its summer peaks to grow at 1.9%. The average annual growth of its summer peak, which is considered its system peak, is forecasted to be 283 MW for the next 15 years, in comparison to the 321 MW forecast in last year's IRP. DEC predicts that load reductions from the activation of its DSM programs will reduce its peak load by approximately 6% in 2028.

DEC's energy sales, including the effects of its EE programs, are expected to grow at a CAGR of 1.4%. This growth rate in energy sales is less than the 1.7% predicted in the 2012 IRP. DEC predicts that the MWh savings from its EE programs will reduce its energy sales by approximately 7% in 2028.

The Public Staff's review of DEC's weather adjusted peak load forecasting accuracy for one year shows that its 2012 IRP forecast had a 1% forecast error.

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[6] The Mean Absolute Error is used to calculate the forecast error. The one-year review incorporates weather normalized peak demands while the five-year review incorporates actual unadjusted peak demands.

However, a review of DEC's actual peak loads for five years (2009-2013), as compared to its forecasts, indicates a forecast error of 11%. This 11% forecast error indicates an average annual overestimation of 1,884 MW of capacity, 1,680 MW of capacity when adjusted for weather. In regard to DEC's energy sales forecasts, a comparison of its actual energy sales over the same five years with those predicted in 2008 prediction indicates an 8% forecast error.

The Public Staff's review indicates that DEC's forecasts for both peak demand and energy sales have been consistently higher than actual loads and sales since 2008.

The Public Staff believes that the economic, weather-related, and demographic assumptions underlying DEC's 2013 peak and energy forecasts are reasonable, and that DEC has employed accepted statistical and econometric forecasting practices. However, the Public Staff is concerned with DEC's pattern of over-forecasting more often than under-forecasting its load. DEP's IRP indicates that DEP has adopted DEC's forecasting methods, even though DEP's forecasting of its energy sales and its peak demands has generally been more accurate than DEC's forecasting. For its energy sales forecasts, DEP has typically relied on the monthly-based econometric model with end-use data over a span of ten or more years of historical data. This model has been used for over 30 years, and during these years, DEP has relied on the load factor method to forecast its peak demands. While DEC has also used econometric models, it has made various modifications to the general econometric equations used for its energy sales and peak demand forecasts over the last 30 years. In response to inquiries from the Public Staff, DEC indicated that it is currently preparing to incorporate statistically adjusted end-use data in its models to improve the accuracy of its forecasts in future IRPs. While the Public Staff believes that DEC's 2013 forecasts are reasonable for planning purposes, the Public Staff recommends that DEC carefully review and incorporate the best forecasting practices of DEP and DEC.

<u>DNCP</u>

DNCP's 15-year forecast predicts that its adjusted[7] summer peaks will grow at a CAGR of 1.2%, a decrease from the projected 1.5% growth rate in its 2012 IRP. Without the reduction in peak demand resulting from the implementation of its EE programs, DNCP expects its summer peaks to grow at 1.6%. The average annual growth of its summer peak is forecasted to be 239 MW for the next 15 years, in comparison to the 285 MW forecast in the 2012 IRP. DNCP predicts that load reductions from its DSM programs will reduce its 2028 peak load by approximately 1%.

DNCP's energy sales are predicted to grow at an average annual rate of 1.4%, which is a decrease from the projected 1.6% growth rate in the 2012 IRP. DNCP predicts that the MWh savings from its EE programs will reduce its energy sales by approximately 3% in 2028.

[7] Adjusted for new and existing DSM programs and load reductions associated with new EE programs as reported in Appendix 2H, p. AP-9, 2013 DNCP IRP.

The Public Staff's review of DNCP's weather adjusted peak load forecasting accuracy for one year shows that the predictions in its 2012 IRP had a forecast error of 3%. The Public Staff's review of DNCP's actual peak loads over the last five years (2009-2013), as compared to its 2008 predictions, indicates a forecast error of 5%. This 5% forecast error results in an average annual overestimation of 787 MW. In regard to DNCP's energy sales forecasts, an annual comparison of its actual sales with its predicted sales in its 2008 IRP indicates a forecast error of 3%.

The Public Staff believes that 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. In conclusion, the Public Staff believes that DNCP's peak load and energy sales forecasts are reasonable for planning purposes.

SUMMARY OF GROWTH RATES

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

2014- 2028 Growth Rates

(After New EE and DSM)

	Summer Peak	Winter Peak	Energy Sales	Annual MW Growth
DEP	1.2%	1.4%	1.4%	171
DEC	1.4%	1.5%	1.4%	283
DNCP	1.2%	1.1%	1.4%	239

The Commission has reviewed the 2013 IRP update reports submitted by the IOUs in this docket as well as their related reply comments to various issues raised by the Public Staff and other intervenors. The Commission finds and concludes that the 15-year forecasts of native load requirements and other system capacity or firm energy obligations, supply-side and demand-side resources expected to satisfy these loads, and reserve margins are reasonable and should be approved for purposes of updating the information contained in the biennial plans submitted in this docket.

The Public Staff in its comments went into detail describing the peak and energy forecasts submitted by DEP, DEC and DNCP. It found that the economic, weather-related, and demographic assumptions underlying DEP and DNCP's peak and energy forecasts are reasonable, and that both have employed accepted statistical and econometric forecasting practices. It concluded that DEP and DNCP's peak load and energy forecasts are reasonable for planning purposes. The Commission concurs with the Public Staff.

In regard to the forecasts submitted by DEC, the Public Staff's review indicated that DEC's forecasts for both peak demand and energy sales have been consistently higher than actual loads and sales since 2008.

As was the case with DEP and DNCP, the Public Staff believes that the economic, weather-related, and demographic assumptions underlying DEC's 2013 peak and energy forecasts are reasonable, and that DEC has employed accepted statistical and econometric forecasting practices. However, the Public Staff is concerned with DEC's pattern of over-forecasting more often than under-forecasting its load. DEP's IRP indicates that DEP has adopted DEC's forecasting methods, even though DEP's forecasting of its energy sales and its peak demands has generally been more accurate than DEC's forecasting. For its energy sales forecasts, DEP has typically relied on the monthly-based econometric model with end-use data over a span of ten or more years of historical data. This model has been used for over 30 years, and during these years, DEP has relied on the load factor method to forecast its peak demands. While DEC has also used econometric models, it has made various modifications to the general econometric equations used for its energy sales and peak demand forecasts over the last 30 years. In response to inquiries from the Public Staff, DEC indicated that it is currently preparing to incorporate statistically adjusted end-use data in its models to improve the accuracy of its forecasts in future IRPs. While the Public Staff believes that DEC's 2013 forecasts are reasonable for planning purposes, the Public Staff recommends that DEC carefully review and incorporate the best forecasting practices of DEP and DEC.

In its reply comments, DEC agreed that the DEC forecast developed in 2008 was too high; however, it was important to note that most of the forecast error was due to the severe economic downturn that occurred in 2009 and which no one reasonably foresaw. In 2009, instead of experiencing load growth, the DEC peak dropped over 500 MW due to the considerable loss of industrial load. DEC suffered more than DEP and most utilities in the 2009 recession due to its large amount of industrial load, particularly from textiles. Since 2009, the DEC weather adjusted peak has grown an average of 1.1% despite a very sluggish economic recovery. Also, the DEC peak forecast developed in 2010 projected a 2013 value that was only 131 MW different than the actual weather adjusted value for the year 2013. Thus, DEC acknowledges the anomaly in the load forecast caused by the severe economic downturn, but believes the 2013 load forecast is reasonable. However, DEC and DEP note that their forecasting methodology is always evolving in an effort to further improve the process, as a result of post-merger best practices and otherwise.

The Commission is satisfied with DEC's explanation of this issue for purposes of this update proceeding and agrees with the Public Staff that DEC's peak load and energy forecasts are reasonable for planning purposes.

SYSTEM PEAKS AND USE OF DSM RESOURCES

DEP's 2013 annual system peak was 12,166 MW, as compared to 12,770 MW in 2012. At the time of the peak, which occurred on August 12, 2013, at the hour ending 4:00 p.m., DEP activated its EnergyWise Home and Commercial, Industrial, and Government Demand Response programs, which reduced peak load by 87 MW and 15 MW, respectively. DEP activated its DSM programs on five of its ten highest summer loads in 2013 for an average load reduction of 96 MW. DEP's 2012 IRP projected that it would have 828 MW available from its DSM, EE, and voltage control programs, of which 728 MW could be activated to reduce its 2013 summer peak.

DEC's system peaked at 16,482 MW on August 16, 2013, at the hour ending 5:00 p.m. The 2012 system peak was 17,740 MW. DEC did not activate its DSM or load curtailment programs at the time of its 2013 system peak; rather, DEC activated its DSM at only two of its top ten highest summer loads for an average load reduction of 111 MW. DEC's 2012 IRP projected the availability of 872 MW from its DSM programs to reduce its summer peak.

DNCP's 2013 annual system peak of 16,366 MW occurred on July 19, 2013, at the hour ending 4:00 p.m. Its 2012 system peak was 16,787 MW. At the time of the summer peak, DNCP called on its Distributed Generation Pilot[8] for a load reduction of 14 MW and its Air Conditioning Cycling Program for a reduction of 50 MW. DNCP activated these two DSM programs on seven of its ten highest summer loads in 2013 for an average reduction of 63 MW. DNCP's 2012 IRP projected the availability of 83 MW from its DSM programs to reduce its 2013 summer peak.

The Commission agrees with the Public Staff's conclusion that DNCP and DEP generally appear to have maximized their available DSM resources to reduce their peak demands. While the temperatures during the summer of 2013 were relatively mild and may have reduced the need for use of DSM, all three utilities should maximize these DSM resources in the future.

RESERVE MARGINS AND RESERVE MARGIN ADEQUACY

In its comments, the Public Staff noted that in 2012 DEP and DEC contracted with Astrape Consulting to conduct a detailed resource adequacy assessment that included an evaluation of their resource margins. Astrape's study provided DEP and DEC each with a recommended system reserve margin based on the Loss of Load

[8] The Distributed Generation Pilot operates only in Dominion's Virginia jurisdiction.

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. A greater frequency of loss load probability is generally considered to be inadequate system reliability. Based on Astrape's analyses, the reserve margins that correlate with this LOLE are 14.5% for DEP and 14% for DEC. Additional analysis is planned by Astrape to verify the adequacy of the target reserve margins now that the Joint Disptach Agreement (JDA) has been implemented.

According to the Public Staff, DNCP utilizes the PJM capacity planning process for long- and short-term planning of capacity needs. The current (2012) study recommends use of a reserve margin of 15.6% 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 determine its ability to meet its PJM reserve requirements. This coincidence factor reduces DNCP's reserve margin requirement to 11.2%. DNCP also includes a 16.2% upper margin, which is commensurate with the upper bound that PJM's Reliability Pricing Model (RPM) market auction has historically cleared. The DNCP planning reserve margin remains at 11%.

For the planning period 2014 to 2028, the range of summer reserve margins reported by the electric utilities continues to be similar to those used in previous annual reports. For this time period, the planned reserves are:

Utility	Target Reserve Margin	Planned Reserve
DEP	14.5%	14.9% to 19.6%
DEC	14.5%	14.3% to 21.5%
DNCP	11%	11.2% to 17.6%

The Public Staff explained DEP's IRP indicates that DEP will meet its projected reserve margin targets for the planning period and will exceed the minimum planning target of 14.5% by 3% or more in 2014-2016 due to a decrease in the load forecast. The IRP also states that the reserves exceed the minimum target by an average of approximately 3% to 5% in 2019, 2022, and 2023 as a result of the addition of large CC facilities. The Public Staff considers the planned reserves adequate.

DEC's IRP indicates that its reserve margins will meet its target reserve margin percentages for the planning period and will exceed the minimum planning target of 14.5% by an average of approximately 3% to 7% after the additions of large base load facilities in 2024 and 2026. The Public Staff concludes that DEC's planned reserves are adequate.

The Public Staff noted that differences in projected versus actual peak load growth can have a significant impact on the reserve margin. If the forecasted CAGR of DEC's peak loads grow at 1.0%, as opposed to the 1.4% rate projected in its 2013 IRP, the reserve margins will remain over 20% for most of the planning period.

The Public Staff, in its comments, expressed that DEP and DEC do not appear to be fully considering the large number of solar qualifying facilities (QFs) in the interconnection queue that could provide significant amounts of energy and capacity over the planning period, and the Public Staff has recommended that they include more realistic assumptions of potential solar energy and capacity. However, inclusion of these potential solar resources should not affect the short-term action plans.

The Public Staff stated that DNCP participates in the PJM market and, through the RPM auction, has obtained a commitment for additional capacity purchases above the existing identified firm purchases to ensure that its reserve margins meet the target of 11% reserves in 2013 and thereafter.

Based on its review of the IRPs, the Public Staff believes the reserve margins filed by the IOUs are reasonable for planning purposes.

In their April 11, 2014 joint comments, SACE and Sierra Club stated that while the 14.5% reserve margin appears reasonable, Duke Energy's method of calculating it is not. The treatment of demand response in the DEC and DEP reserve margin calculations raises concerns that the companies may be planning for excessive reserves.

According to SACE and Sierra Club, in their reserve margin calculations DEC and DEP treat demand response as a resource with its own reserve requirement, contrary to NERC definitions and guidance. In its October 14, 2013 order on the 2012 utility IRPs, the Commission stated that DEC "should consider demand response in programs that it is able to control or dispatch as adjustments to net internal demand, similar to DEP." Both 2013 IRPs (which, to be fair, were filed just days after the Commission's order) rely on the method previously used by DEC that was recently rejected by the Commission.

Astrape conducted both the DEC and DEP reserve margin studies; however, the treatment of demand response—specifically whether it requires backstand reserves—in the studies differed. In the DEP study, demand response is treated as a load adjustment, which does not require its own reserve requirement. In the DEC study, demand response is treated as a resource option with its own reserve requirement, thereby increasing the reserve capacity.

SACE and Sierra Club stated that for purposes of calculating reserve requirements, system generation resources (and net transactions with other systems) should be compared to net internal demand. As defined by NERC, net internal demand includes unrestricted, non-coincident peak adjusted for energy efficiency, diversity, stand-by demand, non-member load, and demand response. DEP's previous method of accounting for demand response by adjusting load appears to be more consistent with NERC guidance than the method still used by DEC and now adopted by DEP.

According to SACE and Sierra Club, while DEC claims that it has looked at program-specific data in making the determination as to the proper treatment of demand response programs, it has recently acknowledged that it has no actual data to offer in support of this claim. To the contrary, Duke Energy data actually indicate that both DEC and DEP demand response programs are dispatchable and controllable. In fact, DEC reports that its demand response programs have been activated a number of times, and most programs have achieved reductions consistent with (or even in excess of) expected reductions.

In summary, SACE and Sierra Club argued that with the exception of the DEC PowerManager (air conditioner) program, Duke Energy should evaluate demand response programs for purposes of calculating reserve requirements as adjustments to net internal demand. This would align DEC and DEP with the most straightforward interpretation of NERC guidance. With respect to the recent performance of its air conditioner demand response program only, its recent performance suggests that DEC should either model the program as a resource (which would require average backstand of 14.5%) or adjust the expected reduction to reflect the results of recent activations.

In their joint reply comments, DEC and DEP responded that while acknowledging that the Companies' reserve margins appear reasonable, SACE and Sierra Club contend that the Companies' reserve margins may be too high in light of treating demand response as a resource instead of an offset to load. SACE and Sierra Club erroneously believe the Company would keep the same target reserve margin with the change in methodology. This is an incorrect assumption. If DEC and DEP adopt the methodology to treat DSM as a reduction to load, the Companies will be required to raise their reserve margin to maintain the same level of reliability.

DEC and DEP explained that target reserve margins are developed to achieve a specific level of reliability, typically expressed in LOLE of one day in ten years. This LOLE level is the constant, irrespective of whether DSM is treated as a resource or as a load reduction. Below are results from DEC's most recent reserve margin study, conducted by Astrape Consulting (an energy consulting firm with a focus on resource adequacy and resource planning) in 2012. Astrape Consulting proposed a minimum target reserve margin of 14.5% if DSM (called DR for Demand Response by Astrape) is treated as a resource and 15.25% if treated as a reduction to load. The Company chose to treat DSM as a resource and used the 14.5% Reserve Margin. If the Company were to adopt the methodology to treat DSM as a load reduction as SACE and Sierra Club appear to desire, using the higher 15.25% minimum target planning reserve margin would be appropriate.

Based on its review of the IRPs, the Public Staff believes that the reserve margins filed by the IOUs are reasonable for planning purposes. SACE's and Sierra Club's joint comments stated that while DEP and DEC's 14.5% reserve margin appears reasonable, Duke Energy's method of calculating it is not. The treatment of demand response in the DEC and DEP reserve margin calculations raises concerns that the companies may be planning for excessive reserves. The details regarding this issue and DEP's and DEC's response are discussed above. The Commission is satisfied that the IOUs reserve margins and calculation methods are reasonable for purposes of this proceeding.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 3

REPS COMPLIANCE PLAN REVIEW

In its comments, the Public Staff reviewed and analyzed various aspects of the IOUs' DSM and EE forecasts and programs. The following information was provided by the Public Staff in regard to REPS compliance.

General Statute 62-133.8 requires all electric power suppliers in North Carolina to meet specified percentages of their retail sales using renewable energy and EE through the REPS. One 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[9] (or through DSM measures, in the case of EMCs and municipalities). Electric public utilities can use EE measures to meet up to 25% of the general requirements in G.S. 62-133.8(b). One MWh of savings from DSM, EE, or demand reduction creates one energy efficiency certificate (EEC), which is similar to a REC and is used to demonstrate compliance with the REPS. EMCs and municipalities may use DSM and EE to meet the requirements in G.S. 62-133.8(c) without any limits. They may also use energy from a hydroelectric power facility and allocations from SEPA to meet up to 30% of the general requirements. 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 100% of the requirements. The total amount of renewable energy or EECs that must be provided by an electric power supplier for 2013 and 2014 is equal to 3% of its North Carolina retail sales for the preceding year. For 2015, this amount increases to 6%.

Commission Rule R8-67(b) provides the requirements for REPS Compliance Plans (Plans). Electric power suppliers must file their Plans on or before September 1 of each year and explain how they will meet the requirements of G.S. 62-133.8(b), (c),

[9] "Electricity demand reduction," as used here, is a technical term defined in G.S. 62-133.8(a)(3a).

(d), (e), and (f). The Plans must cover the current year and the next two calendar years, or in this case 2013, 2014, and 2015 (the planning period). An electric power supplier may have its REPS requirements met by a utility compliance aggregator as defined in R8-67(a)(5). The instant docket includes the plans filed by DEP, DEC, and DNCP, and their wholesale customers in North Carolina for which they are contracted to provide REPS compliance services.

DEP

DEP filed its 2013 Plan along with its IRP on October 15, 2013. DEP has contracted for and banked sufficient resources to meet the general REPS requirements of G.S. 62-133.8(b) and (c) for itself and the electric power suppliers for which it is providing REPS compliance services. DEP is contractually obligated to secure resources to meet all the REPS requirements of the City of Waynesville and the Towns of Sharpsburg, Stantonsburg, Black Creek, and Lucama (collectively, DEP's Wholesale Customers). After filing its Plan, DEP contracted to provide REPS compliance services to the Town of Winterville for 2013 and beyond.

DEP intends to use EE programs to meet 25% of its REPS requirements. Energy allocations from SEPA will be used to meet up to 30% of the general requirement of the City of Waynesville, the only DEP Wholesale Customer that receives energy from SEPA. Hydroelectric qualifying facilities will also provide RECs for DEP's other Wholesale Customers and its retail customers. DEP will continue to pursue wind energy, either through REC-only purchases or through energy delivered to its customers in North Carolina, to meet the general requirement. A portion of the general requirement of 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 facilities. DEP plans to use the increased availability of solar energy to help it meet the general requirement.

DEP will use the following methods to meet the solar set-aside: (1) its residential solar PV program, (2) in-state solar PV and thermal REC purchases, and (3) out-of-state solar REC purchases.

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 its measurement and verification plan for each EE program as part of its request for Commission approval of the program.

DEC

DEC filed its 2013 Plan along with its IRP on October 15, 2013. 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. DEC is contractually obligated to secure resources to meet all the REPS requirements of the following electric power suppliers: Rutherford EMC, Blue Ridge EMC, the City 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 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 and the increased capacity of DEC's Bridgewater hydroelectric facility, following its modification in 2012, will provide RECs for DEC's retail customers. DEC will continue to pursue wind energy, either through REC-only purchases or through energy delivered to its customers in North Carolina, to meet the general requirement. A portion of the general requirement of DEC 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 facilities. However, DEC has reduced its reliance on biomass for future REPS compliance because of the increased availability of solar energy and other renewable resources. DEC also expects to make some use of solar resources to satisfy the general requirement.

DEC will use the following methods to meet the solar set-aside: (1) self-owned distributed solar PV facilities, (2) in-state solar PV and thermal REC purchases, and (3) out-of-state solar REC purchases.

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.

DEC filed an update to its EM&V plan in its 2013 application for cost recovery of DSM and EE programs in Docket No. E-7, Sub 1032.

DNCP

DNCP's 2013 Plan was filed on August 31, 2013, as an addendum to its IRP. DNCP has contracted for and banked sufficient resources to meet the general REPS requirements of G.S. 62-133.8(b) and (c) for itself and the Town of Windsor (Windsor), for which it is providing REPS compliance services. DNCP plans to use EE, purchased RECs, and new self-generated renewable energy to meet the general REPS requirements of G.S. 62-133.8(b) and (c) for itself and Windsor. DNCP will rely on out-of-state RECs to meet most of its compliance requirements, as allowed by G.S. 62-133.8(b)(2)(e), but will obtain in-state RECs to meet Windsor's 75% in-state requirement. DNCP intends to purchase unbundled solar RECs for itself and Windsor to meet the solar set-aside requirements during the planning period. DNCP's total costs are the same as its incremental costs because it intends to purchase RECs that are not bundled with energy to meet its REPS requirements.

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 filed an update to its measurement and verification plan in its 2013 application for cost recovery of DSM and EE programs in Docket No. E-22, Sub 494.

REPS COMPLIANCE COMPARISON TABLES

The tables in this section are drawn from data submitted in the DEP, DEC, and DNCP 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 in the 2013 column are projected sales for calendar year 2012. 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	**2013**	**2014**	**2015**
DEC	58,562,512	59,161,845	59,743,779
DEP	36,737,450	37,217,015	37,722,745
DNCP	4,161,815	4,223,188	4,080,270
TOTAL	99,461,777	100,602,048	101,546,794

TABLE 2: Comparison of Incremental Costs to the Cost Cap

		DEC	DEP	DNCP
2013	Incremental Costs	8,575,016	21,026,450	557,326
	Cost Cap	63,600,083	42,520,860	3,947,064
	Percent of Cap	13%	49%	14%
2014	Incremental Costs	12,563,910	24,846,641	1,453,756
	Cost Cap	64,543,124	42,825,158	4,191,726
	Percent of Cap	19%	58%	35%
2015	Incremental Costs	15,104,036	22,550,528	1,487,743
	Cost Cap	106,425,364	68,889,101	6,660,020
	Percent of Cap	14%	33%	22%

SWINE WASTE AND POULTRY WASTE SET-ASIDES

Some electric power suppliers indicated in the Plans filed in 2011 that they had difficulty in obtaining RECs to comply with the swine and poultry waste set-asides in G.S. 62-133.8(e) and (f), which require them to meet a portion of their REPS obligations with energy derived from swine waste and poultry waste beginning in 2012.

In May 2012, the Commission issued an order in Docket No. E-100, Sub 113, requiring the electric power suppliers to file an update on their efforts to meet these compliance requirements. Most electric power suppliers responded and filed a joint motion seeking to delay the swine and poultry waste set-asides as allowed in G.S. 62-133.8(i)(2). The joint movants claimed that they were having difficulty acquiring RECs to meet the swine and poultry waste set-asides because the technology for waste-to-energy facilities was still in its infancy and would need more time to reach maturity.

In November 2012, the Commission issued an order that eliminated the swine waste set-aside for 2012 and delayed the poultry waste set-aside until 2013. This order required DEP and DEC to file tri-annual reports describing the state of their compliance with the set-asides and reporting on their negotiations with the developers of swine and poultry waste-to-energy projects. The order further required them to provide internet-available information to assist the developers of swine and poultry waste-to-energy projects in getting contract approval and interconnecting facilities.

On September 16, 2013, many of the electric power suppliers filed another joint motion to delay the swine and poultry waste set-asides, similar to the request they filed in 2012. In the proceedings on this motion, DEC indicated that it would not be able to comply with the poultry waste set-aside in 2013. DEP indicated that it expected to be able to comply with the poultry waste requirement in 2013, but in its Plan it states that compliance in 2014 or 2015 is unlikely. DNCP indicated that it has been able to secure enough out-of-state poultry waste RECs to meet its requirements for 2013 and 2014, but has not secured enough in-state poultry RECs for Windsor. All the utilities stated that they would be unable to comply with the swine waste set-aside in 2013.

On December 20, 2013, the Commission issued a Notice of Decision and Order in Docket No. E-100, Sub 113, which delayed the swine and poultry waste set-asides until 2014. The order extended the tri-annual reporting to DNCP and most other EMCs and municipal electric systems. It also requested that the Public Staff hold stakeholder meetings in 2014 and 2015 to facilitate compliance with the swine and poultry waste set-asides. On March 26, 2014, the Commission issued a Final Order Modifying the Poultry and Swine Waste Set-Aside Requirements and Providing Other Relief that details the Commission's findings of fact and conclusions in support of its December 20, 2013 Notice of Decision and Order.

The Public Staff believes the electric power suppliers will likely continue to have difficulty meeting the swine and poultry waste set-asides for at least the next one to two years. The swine waste-to-energy industry remains largely undeveloped, particularly relative to the need for approximately 92,000 MWh of swine waste energy each year in 2014 and 2015 to meet the Commission's Order of December 20, 2013. The poultry waste-to-energy industry has somewhat more potential to produce the 170,000 MWh of energy necessary in 2014 to comply with the same Order, but the currently operating biomass power plants that have successfully utilized poultry waste fuel do not have enough combined capacity to fulfill the entire requirement. Even if these plants reach their full operational potential in 2014, they will not have enough capacity to produce the 700,000 MWh of poultry waste energy necessary to meet the 2015 requirement. The lack of swine and poultry waste-to-energy facilities is the result of: (1) limited technology development and expertise because currently North Carolina is the only state with swine and poultry set-aside requirements; (2) the utilities' reluctance to commit to expensive purchase contracts for speculative technologies; and (3) the current uncertainty as to whether the General Assembly will alter the REPS requirements in ways that could leave the owners of these facilities with stranded costs.

PUBLIC STAFF CONCLUSIONS ON REPS COMPLIANCE PLANS

In summary, the Public Staff's conclusions regarding the REPS compliance plans of DEP, DEC, and DNCP are as follows:

1. The compliance plans of DEP, DEC, and DNCP indicate that they should be able to meet their REPS obligations, with the exception of the swine and poultry waste set-asides, during the planning period without nearing or exceeding their cost caps.

2. The utilities will have difficulty meeting the Commission's revised swine waste requirements in 2014 and 2015, and DEP and DEC will have difficulty meeting the poultry waste requirements, but they are actively seeking energy and RECs to meet these requirements.

3. The Commission should approve the REPS compliance plans filed by DEP, DEC, and DNCP in 2013.

The Commission concludes that the 2013 REPS compliance plans show that DEP, DEC and DNCP, as well as the electric power suppliers for whom the IOUs provide REPS compliance, are well-positioned to comply with their future REPS obligations, with the exception of the swine and poultry waste set-asides. Therefore, the Commission concludes that the 2013 REPS compliance plans filed in this docket by the IOUs and other electric power suppliers are satisfactory and should be approved.

DISCUSSION AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4-6

ADDITIONAL ISSUES RAISED IN INTERVENOR COMMENTS

The Public Staff, NC WARN, NCSEA, MAREC, and SACE/Sierra Club, in their April 11, 2014 comments, raised various issues related to the IRPs and REPS compliance plans submitted by the three IOUs. Many were specific to DEC and DEP, and some comments were addressed to the IRP process itself. In their May 23, 2014 joint reply comments DEC and DEP addressed these issues, as did DNCP in its reply comments. A third set of reply comments were jointly submitted by SACE and Sierra Club. The following responses were submitted by the IOUs to the issues raised by the various parties in their comments.

DEC and DEP Responses

Public Staff Issues

A. DEC Carbon Neutrality Plan

In its March 21, 2007 Order Granting Certificate of Public Convenience and Necessity with Conditions for DEC's Cliffside Unit 6, in Docket No. E-7, Sub 790, the Commission ordered DEC to retire, in addition to Cliffside Units 1-4, "older coal-fired generating units…on a MW-for-MW basis, considering the impact on the reliability of the entire system, to account for actual load reductions realized from [new EE and DSM] programs, up to the MW level added by" Cliffside Unit 6, which is 825 MW.[10] In addition, the air permit issued by the North Carolina Department of Environment and Natural Resources, Division of Air Quality (DAQ), for Cliffside Unit 6 includes a requirement that DEC implement a Greenhouse Gas Reduction Plan and retire 800 MW of additional coal-fired generation, without regard to DEC's achievement of a commensurate level of DSM and EE savings.

As the Public Staff noted in its comments, the Commission's order approving the 2012 DEC IRP contained a requirement that DEC continue to provide updates in future IRPs to its Cliffside Unit 6 Carbon Neutrality Plan (CNP) regarding its obligations related to the Cliffside Unit 6 air permit. However, DEC's 2013 IRP update filed on October 15, 2013, did not include the Cliffside Unit 6 CNP. Accordingly, DEC attached the CNP as a supplemental Appendix L to its reply comments filed on May 23, 2014.

In summary, the CNP shows that: (1) DEC proposes to retire up to 1299 MW of older coal-fired generation by the end of 2018; (2) DEC has allocated space at Cliffside Unit 6 to accommodate equipment potentially needed to meet future carbon reduction technologies; and (3) DEC has identified several system carbon reduction actions that DEC will implement that will exceed the approximately 5.3 million ton reduction required to make Cliffside Unit 6 carbon neutral in 2018.

The Commission concludes that DEC's Carbon Neutrality Plan should be approved as a reasonable plan for compliance with the Cliffside Unit 6 air permit conditions. However, this approval does not constitute Commission approval of the activities shown in DEC's Carbon Neutrality Plan or expenditures for those activities.

B. Interconnection and QF Information

DEC and DEP in their reply comments, and future IRPs, should provide both information on the number and resource type of the facilities currently within the respective utility's interconnection queue and a discussion of how the potential QF purchases would affect the utility's long-range energy and capacity needs.

In their joint reply comments, DEC and DEP stated that, if requested by the Commission in the Order on this IRP, the Companies will include the requested information on the interconnection queue in future IRP filings. As of April 30, 2014, DEC and DEP have the following potential projects in their interconnection queue:

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[10] Order Granting Certificate of Public Convenience and Necessity with Conditions, Docket No. E-7, Sub 790, at p. 140.

"In Queue" Qualified Facilities – as of April 30, 2014

	State	Energy Type	Number of Customers	Total Capacity (MW AC)
DEC	NC	Biomass	3	8.70
		Hydro	3	31.51
		Solar	132	754.92
	NC Total		138	795.13
	SC	Hydro	1	0.25
	SC Total		1	0.25
DEC Total			139	795.38

DEP	NC	Biomass	4	8.45
		Hydro	2	1.55
		Landfill Gas	3	17.75
		Solar	243	2297.07
	NC Total		252	2324.81
	SC	Biomass	1	73.00
		Solar	4	142.31
	SC Total		5	215.31
DEP Total			257	2540.12
Grand Total			396	3335.49

With regard to the potential impact of the projects in the interconnection queue on the DEC and DEP resource plans, it is the Companies' position that each Company's REPS compliance plans, as included in the 2013 IRP updates, are the best estimate of renewables adoption at this point in time. The plans reflect careful examination of the current interconnection queue and estimation of how much renewable capacity could be cost effectively converted to compliance resources. Based on this review, the Companies' 2013 IRP updates only utilized existing executed renewable contracts along with enough future renewable resources required to meet mandatory renewable targets under REPS, as well as a proxy for a future renewable energy standard for South Carolina beginning in 2018. Additional renewable resources are possible, but subjective, and as such are not appropriate for inclusion in the Companies' base resource plans. For planning purposes, DEC and DEP must ensure that they can meet peak load demand without relying upon on speculative unexecuted non-utility resources. Given DEC and DEP's experience with renewable projects proposed by developers, the utility cannot depend on potential projects that are in excess of its targets set in the above planning assumptions. As explained in the late filed exhibit in the recent avoided cost proceeding (Docket No. E-100 Sub 136), historically DEC and

DEP have seen approximately twenty-five (25%) of the capacity in the interconnection queue come to fruition. When viewed in the aggregate between DEC and DEP, this completion rate applied to the current interconnection queue would not exceed the REPS compliance plan for the IRP planning horizon.

The Commission agrees with the Public Staff that DEC and DEP's QF interconnection queue information has important value going forward. The number of QF interconnection requests, especially for solar, has increased exponentially and this queue has the potential to have a significant impact on the generation planning process. Therefore, DEP and DEC in future IRPs should provide information on the number, resource type and total capacity of the facilities currently within the respective utility's interconnection queue as well as a discussion of how the potential QF purchases would affect the utility's long-range energy and capacity needs.

C. Changes to IRP Process

DEC and DEP noted that the Public Staff's comments included discussion and inquiry regarding potential modifications to the IRP process and filing calendar that may be reasonable. The Companies' observation is that IRP process has expanded in scope over time through incremental annual IRP rulings, along with a growing number of special interest group intervenors participating in the IRP process. This is not surprising because the IRP essentially incorporates many facets of the utility business including energy efficiency, renewables compliance, fuel forecasts, new plant development, environmental compliance strategies, load forecasting, etc. Most of these intervenors focus only on issues of importance to their members or stakeholders, but lack the obligation for the provision of reliable power delivery and the obligation for least cost planning on behalf of all of DEC and DEP's customers that the IRP planning process requires. To a large extent many of the individual issues now being raised by intervenors within the context of an IRP docket have their own focused regulatory proceedings. For example, the IRP clearly has overlap with EE, REPS, fuel, CPCN, avoided cost and rate case proceedings. However, the IRP was never intended to supplant or supersede these more focused proceedings. Rather, the IRP process by its very nature is a planning process only that provides insights into factors that influence the utilities' future resource plans. To a large extent several of the recommendations expressed by intervenors in their IRP comments are the same recommendations made within the context of the more focused proceedings. To some degree, this moves the IRP process away from a big picture, long term planning process toward more of a shorter term operational focus. Should the Commission wish to consider refocusing the IRP to its original intent by moving to a bi-annual process or some other variation of an IRP process modification DEC and DEP would be supportive of working toward productive revisions to the process.

The Commission understands the time and complexity concerns that the parties have with the current IRP planning process. Between the time extension requests and the increasing complexity of the issues raised during the proceedings, it makes for drawn out IRP timelines. The Commission agrees that some modifications might be warranted, especially to these odd-year annual update proceedings. For this reason, the Commission intends to open a future docket which will request comments and reply comments on the specific issues of what might be done to streamline the annual update reporting process so that it does not simply become another biennial proceeding with a different name.

D. Environmental Analysis

DEC and DEP argued that the companies' IRPs include resource plans that comply with all known federal and state level environmental laws. Fixed and variable environmental compliance costs required for regulatory compliance are included and appropriately considered in the IRP planning process. The IRPs not only include the quantitative aspects of environmental compliance, but also include an extensive qualitative discussion surrounding existing and pending environmental regulations. Given the extent to which the Companies already consider environmental compliance in the IRP process, DEC and DEP do not believe that additional prescription concerning specific methods by which to incorporate environmental compliance costs are warranted. The Commission finds that no additional steps are required at this time.

E. Decommissioning Costs

DEC and DEP explained that decommissioning costs for existing coal, nuclear and gas units do not have a direct influence on the Companies' future expansion plans. Ultimately, these costs are sunk costs associated with exiting unit retirements and do not influence the selection of the future resource portfolio. Costs associated with the retirement of existing generating units that have been in service for many decades have existing mechanisms in place for review and cost recovery. Requiring the IRP process to address decommissioning costs of existing units will not alter the resource planning process, nor the selected expansion plan. While a consideration of decommissioning costs may have merit in appropriate dockets or proceedings, DEC and DEP assert that the IRP process is not the appropriate place to address this issue. The Commission agrees with DEC and DEP.

F. Quantifying Generation Diversity Benefits

The Public Staff recommends that the Companies develop a quantification method for fuel diversity as part of the IRP process. The Companies believe that recommendation is already captured as part of the existing IRP process commensurate with Commission Rule R8-60. The Companies' current IRP practices include modeling multiple sensitivities around fuel prices. Furthermore, the Companies show how different resource portfolios perform under these varying fuel prices. Both the quantitative impacts and the qualitative benefits of fuel diversity are fully presented in the IRPs. The Public Staff does not provide a specific recommendation as to what other quantitative metric or method they are recommending and as such it is difficult to ascertain the merits of such additional analysis. DEC and DEP believe that the current approach that both quantitatively and qualitatively addresses fuel diversity is fully adequate. The Commission finds that no further action is required at this time.

NCSEA Issues

DEC and DEP state that in its IRP comments, NCSEA does not appear to have any real criticism of the DEC and DEP IRP updates, and instead finds the Companies' increased diversification into renewable energy resources, including DSM/EE, to be "promising." NCSEA makes some unique policy suggestions, such as asking the Commission to "reaffirm the foundational importance" of the IRP proceeding, to which the Companies will not reply. NCSEA asks the Commission to endorse consistency across proceedings, and discusses assumptions used in the IRP and avoided cost proceedings. DEC and DEP strive for consistency in the underlying assumptions and methodologies used in their various proceedings, and have noted their post-merger emphasis on developing consistency and best practices where applicable. As an example, the avoided energy and avoided capacity values used in DEC and DEP's EE/DSM rider proceedings are taken directly from the IRP. NCSEA also asks that the utilities concisely state in one place in their IRPs "all of the key policy assumptions" which underlie its base case or recommended plan. DEC and DEP assert that their IRPs do explain the policy assumptions contained therein.

NCSEA also commented on DEC and DEP's "aspirational" 15 EE savings performance targets as contained in a settlement agreement filed with the Public Service Commission of South Carolina, and asks the Commission to push the Companies to innovate to meet their aspirational goal by encouraging collaborative efforts to develop new EE programs and measures, such as combined heat and power (CHP). The Companies note that related issues were already agreed to as part of the Stipulation and Agreement filed in Docket No. E-7, Sub 1032 and agreed to in Docket No. E-2, Sub 1030, and in fact a Duke Energy Collaborative meeting where CHP was discussed has already been held. Finally, NCSEA also raises an issue unrelated to the IRPs - -facilitating third party access to private customer usage data. NCSEA asks that the Commission require utilities to provide online forms for customers to authorize disclosure of their usage information to third parties. DEC and DEP responded that perhaps NCSEA is not aware, but DEC and DEP do have an online "Energy Data Request Form," for independent third parties with a need to use customer data. This website allows third parties to identify themselves and provide details about the specific data they seek. After completing the online form, such third parties are contacted electronically by Duke Energy with information about the process and requirements, including the cost of data, and are provided an electronic copy of the Duke Energy customer data release form. This process was developed with the Companies' Code of Conduct in mind and to ensure a consistent and cost-effective approach for handling third party requests. DEC and DEP assert that the current process works well.

As to the Companies' REPS Compliance Plans, NCSEA asks that the Companies be required to submit one-sentence certifications that prior REPS compliance plan reviews have been conducted, unless this is obvious from the filing of a revised past REPS compliance plan with redactions removed. DEC and DEP would not object to such a Commission requirement.

NCSEA also requests that the Commission require the utilities to create avoided cost projections in their 2014 REPS compliance plans using the methodological approaches approved in the 2012 avoided cost order, together with a statement from DEC and DEP indicating whether the effect of the JDA was incorporated. DEC and DEP pointed out that first, the Commission's February 21, 2014 Order Establishing Standard Rates and Contract Terms for Qualifying Facilities in Docket No. E-100, Sub 136 discussed the use of avoided costs in REPS Compliance Plans and held in Finding No. 18 that, "DEC and DEP henceforth should include actual projected avoided cost rates as of the date of the Compliance filings." Second, the Commission's rules already require the utilities to include the current and projected avoided cost rates for the years of the subject plan, so NCSEA's recommendation is all the more duplicative and unnecessary. See Rule R8- 67(b)(1)(v). Third, DEC and DEP's position is that avoided cost calculations are subject to their own regulatory proceedings in which stakeholders have opportunity for substantial input. In fact, NCSEA is a party to the currently pending Docket No. E-100, Sub 140 proceeding, wherein the Commission is examining the methodological approaches utilized in the 2012 avoided cost proceeding for the 2014 avoided cost proceeding. Filing avoided cost projections in the REPS Compliance Plans on September 1, 2014, based on 2012 methodologies that are currently under review could result in outdated and inaccurate projections.

The Commission is satisfied with the responses of DEC and DEP to these issues raised by NCSEA.

MAREC Issues

DEC and DEP stated that, as in its 2012 IRP comments, MAREC, a non-profit formed to advance renewable energy development primarily in the PJM Interconnection markets, makes the general allegation in its comments that DEC and DEP did not adequately consider wind energy in their IRPs. MAREC notes that DEC and DEP should not have been expected to comply with the Commission's requirement to consider additional resource scenarios that include larger amounts of renewable energy resources similar to DNCP's Renewable Plan, because that requirement was included in the Commission order approving the 2012 IRPs and issued the day prior to the filing of the DEC and DEP 2013 IRP updates. DEC's 2013 IRP update base case includes 849 MW of renewable resources by 2018 and 2,028 MW by 2028, which includes 150 MW of wind. DEP's 2013 IRP update base case includes 297 MW of renewable resources by 2018 and 802 MW by 2028, which includes 100 MW of wind. MAREC does not appear to appreciate, however, that both Companies' 2013 IRP updates also included an Environmental Focus Scenario (EFS), which evaluated an assumed requirement to serve approximately 8% of each Company's combined retail load with new renewable resources by 2028-- which represents approximately twice the amount of renewable energy as compared to the base case. The DEC EFS included 758 MW of nameplate wind and the DEP EFS included 505 MW of nameplate wind. The purpose of the scenario is to show how the Companies' resource plans would be affected in the event that additional cost-effective renewable and energy efficiency resources are identified or mandated. A key takeaway is that, in such an event, some traditional resources can be eliminated or deferred but significant levels of traditional resources such as new nuclear and natural-gas combined cycle are still needed.

In their joint reply comments, DEC and DEP argued that they have adequately considered wind and all other potential renewable energy resources in preparing their 2013 IRP updates. Duke Energy Corporation, the parent company of DEC and DEP, is one of the largest wind energy developers in the United States and recognizes the valuable potential that new wind energy resource development can provide. In their IRPs, however, DEC and DEP analyzed wind and other generation technologies and selected the resource plans that best met the Companies' needs to provide the reliable, least-cost resource mix as required by North Carolina's integrated resource planning and REPS laws.

MAREC also contended that the Companies should include a new annual RFP process that would solicit new renewables. Both DEC and DEP explained that they regularly assess the market place for competitive wind and other renewable resources, including through formal RFPs or the receipt of unsolicited bids. On February 14, 2014, DEP and DEC issued a RFP for 300 MW of new solar energy capacity to allow DEP and DEC to further their commitments to renewable energy, diversify their energy mix and meet their REPS requirements. Accordingly, they argue MAREC's proposed RFP requirement is unnecessary.

The Commission finds that no further action is required by DEC and DEP in response to the issues raised by MAREC.

<u>SACE and Sierra Club Issues</u>

DEC and DEP responded that, in their comments, SACE and Sierra Club generally critique the Companies' inclusion of EE and renewable resources, and without offering their own proposed mix of least cost and reliable resources, assert that the resource plans contained in the Companies' IRP update are inadequate. As set forth in detail below, DEC and DEP stand by their IRP methodologies and analyses of both supply and demand side resources and the selected plans contained in the 2013 IRP updates.

A. The Companies' Appropriately Evaluated and Included EE and Renewables in their 2013 IRP updates.

DEC and DEP commented that while noting that DEC "led the Southeast in energy savings from efficiency," in both 2011 and 2012, as in previous IRP comments, SACE and Sierra Club allege that DEC and DEP asserted that they are not planning to capture all cost-effective EE and maximize renewable energy opportunities. DEC and DEP have included significant levels of EE and renewable resources in their 2013 IRPs updates, surpassing the levels included in the 2012 IRPs. As to EE, DEC projects that it will have delivered over 10,510,000 MWh of EE savings between 2009 and 2028. The estimated peak load impact of these EE savings is 1,734 MW in that same timeframe. In addition, DEC projects over 1,060 MW of peak load savings from DSM programs by 2028. DEP projects that it will have delivered 4,403,000 MWh of EE savings between 2009 and 2028. The estimated peak load impact of these EE savings is 1,068 MW in that same timeframe. In addition, DEP projects 789 MW of peak load savings from DSM programs by 2028.

The Companies explained that they have included in their 2013 IRP updates the level of EE they believe is reasonably achievable and economic. In response to a data request seeking the feasibility assumptions of the increased EE levels asserted in their comments, SACE and Sierra Club admitted that they did not conduct a market potential study or make assumptions regarding participation (penetration) rates, or technology to achieve penetration rates, for purposes of preparing their comments, but that their comments were "informed" by their review of market potential studies performed for DEC and other southeastern electric utilities. DEC and DEP asserted that SACE and Sierra Club do not appear to realize that potential does not equal cost-effective or achievable. In their comments criticizing DEC's EE cost assumptions, SACE and Sierra Club rely upon the Lawrence Berkeley National Laboratory Study by Galen Barbose. While this study does make an attempt to adjust cost projections for size of first year impacts, it does not adjust for cumulative market penetration (i.e., the more that has been achieved on a cumulative basis, the higher must be the costs per kWh achieved). Furthermore, the study essentially relies on past spending and impacts to make its projection, which DEC and DEP assert is a very unreliable methodology.

DEC and DEP pointed out that SACE and Sierra Club complain about the EE costs assumed by the Companies in their 2013 IRP updates which deserves a brief response. On pages 27-28 of their comments, SACE and Sierra Club note four alleged flaws with DEC's EE cost assumptions and methods. As to the use of the 60% market saturation, this is based upon the market potential study prepared for DEC and is consistent with reasonable adoption curves for typical measures. As to the criticism that there is no provision for introduction of new EE technology or for reduction in costs of future EE technology, SACE and Sierra Club's comments ignore that generation technology is treated exactly the same way in the IRP (no assumptions are made that generation technology costs will decrease over time). As to their assertion that economies of scale serve to reduce EE program costs as more customers participate, DEC and DEP argued that this ignores the reality of EE program implementation: as less expensive EE measures are depleted (the "low hanging fruit"), more expensive measures must be offered. Finally as to the criticism of the 30% program overhead costs, this is a legitimate program expense (and which is approved through the cost recovery mechanism) based on the market potential study, that must be included or the total utility costs to implement EE will be understated. SACE and Sierra Club have a final criticism that the Companies' long-term EE cost forecast indicates cost escalation in excess of the rate of inflation. Again, these intervenors ignore the fact that as an initial low cost EE resource reaches its market potential, as in generation dispatch, the utility has to move "up the stack" to the next higher cost EE resource. The two drivers of costs are inflation and the incremental cost of the next EE resources. It is axiomatic, therefore, that the combination of these two factors will result in the projected increase in the unit cost of EE exceeding the rate of inflation.

DEC and DEP further noted that SACE and Sierra Club propose a list of EE programs that the Companies should consider. In response to a data request, these intervenors revealed that they "did not review the program costs, program participation, or perform participation studies" as to their proposed programs. As to specific EE programs, DEC and DEP have collaborative groups which discuss and vet all programs and would welcome the opportunity to discuss these programs at their collaborative groups. DEC and DEP have a bias toward EE, which is reflected in the IRP process by putting EE ahead of other resources and locking in the programs and impacts before any additional generation resources are considered. DEC and DEP make their projections of EE impacts in conjunction with an independent assessment of the market potential for EE for each utility's service territory, a critical component that cannot be overlooked.

B. SACE and Sierra Club's Environmental Compliance Cost Analysis and Resulting Conclusions are Flawed

According to DEC and DEP, in their comments SACE and Sierra Club also allege that their "analysis" of future environmental requirements "strongly suggests that retirement of a minimum 5,000 MW of coal capacity is likely to be the most cost-effective solution." In response to data requests, however, SACE and Sierra Club responded that they had not performed any analysis of which coal units DEC and DEP should retire or when. Appendix G to both the DEC and DEP 2013 IRP updates contains extensive discussion of potential future environmental requirements that will impact the Companies' operations in the coming years, including those related to the Cross-State Air Pollution Rule (CSAPR) and the Clean Air Interstate Rule, the Mercury and Air Toxics Standard (MATS), National Ambient Air Quality Standards, SO_2 Standards, Particulate Matter Standard, Greenhouse Gas Regulation, Cooling Water Intake Structures (CWA 316(b)), Steam Electric Effluent Guidelines, and Coal Combustion Residuals. The Companies' IRP models build in all known capital and O&M costs for environmental compliance. SACE and Sierra Club assert reliance upon a Coal Asset Valuation Tool (CAVT), which incorporates assumed environmental costs. All of DEC and DEP's coal units already have FGDs (or scrubbers), SCRs or SNCRs or baghouses, with the exception of the Lee Steam Station in South Carolina, which is scheduled for retirement in 2014 (and conversation of one unit to natural gas in 2015). As a result, DEC and DEP believe that their remaining coal units are compliant with MATS and CSAPR.

DEC and DEP asserted that SACE and Sierra Club's coal retirement analysis based upon the CAVT tool understates replacement generation costs and overstates future environmental compliance costs, which results in invalid conclusions. Based upon SACE and Sierra Club's responses to data requests, the Companies note that the future environmental control costs represented by the "medium scenario" of the CAVT tool relied upon by these intervenors are not representative of the Companies' expected outcome with MATS and 316(b) requirements. According to the CAVT information provided, it appears that costs for baghouses (except for Cliffside 6), activated carbon injection (ACI), Cooling Towers (except Mayo, Cliffside 5 & 6) were included for all DEC and DEP units. As noted previously, Duke Energy has tested all coal units for compliance with MATS and compliance can be met without the installation of baghouses and with limited ACI injection at Allen and Marshall 4. Also based on the 316(b) rule finalized in May 2014, cooling towers are not anticipated to be required. An example of the impact of SACE and Sierra Club's inclusion of baghouses, ACI and cooling towers is the overstatement of more than $1 Billion (in $2012) in environmental compliance costs for DEC's Belews Creek Steam Station alone. Accordingly, DEC and DEP argue that SACE and Sierra Club's assumptions regarding future environmental costs for the Companies' are invalid and their resulting conclusions must be disregarded.

The Commission is satisfied with the responses of DEC and DEP to the issues raised by SACE and Sierra Club.

<u>DNCP Responses</u>

<u>Public Staff Issues</u>

In its May 23, 2014 reply comments, DNCP stated that it agrees to most of the Public Staff's recommendations as they relate to the company. DNCP did, however, provide specific responses to six of the Public Staff's recommendations.

A. Biomass Conversions

The Public Staff noted that conversion of the Hopewell, Altavista, and Southampton Coal Stations to biomass-fueled facilities was scheduled to be implemented before the end of 2013. The Public Staff sought confirmation that these conversions were, in fact, completed during 2013. DNCP, in its reply comments, stated that it completed conversion of the above-referenced facilities to biomass on the following schedule:

Plant	Commercial Operation Date
Altavista	7/12/2013
Hopewell	10/18/2013
Southampton	11/28/2013

B. Extending Future Planning Period to 20 Years

The Public Staff recommended that "the planning period for future IRPs that foresee substantial nuclear retirements be at least 20 years." DNCP currently uses a 25-year Study Period (e.g., 2014-2038 in the 2013 Plan) and displays text, numbers, and appendices for a 15-year Planning Period (e.g., 2014-2028 in the current 2013 Plan). As explained in the 2013 Plan, the Company's customers today benefit substantially from the Company's prior investments in the four nuclear units, at North Anna and Surry, and the Company is mindful of the scheduled license expirations of these units between 2032 and 2040. However, DNCP notes that Commission Rule R8-60(c) and (h) direct the Company to present its IRP using a 15-year planning period. Further, the Company notes that its odd-year Virginia IRP filing is based on a 15-year Planning Period, and is filed pursuant to Va. Code§ 56-592 et seq. and the Virginia State Corporation Commission's Integrated Resource Planning Guidelines. The Company prefers to maintain consistency between the North Carolina and Virginia IRP filings (which both require 15-year planning periods) and, therefore, disagrees with presenting the IRP based on a 20-year planning period. However, upon request during discovery, the Company will provide the Public Staff with all the requisite information contained in the 25-year Study Period analysis, which should provide the Public Staff with the information sought.

The Commission is satisfied with the IOU’s current 15-year planning periods. However, the IOU’s should always supply additional forward looking comments in their IRPs when warranted to provide adequate background concerning critical infrastructure decisionmaking.

C. Quantifying Fuel Diversity Value

The Public Staff recommends that the utilities "continue to develop methods of quantifying the benefits of fuel diversity" and requests the utilities provide detailed support in future IRPs if a utility selects a fuel diversity plan over a plan that is otherwise lower in costs. Specifically, the Public Staff requests the utilities develop a "metric to quantify the value of diverse generation portfolios" such as the present value revenue requirement (PVRR) method.

DNCP noted that its 2013 Plan does not select its Fuel Diversity Plan over the least cost Base Plan. Instead, the Company recommends a path forward based upon the least-cost Base Plan, while concurrently continuing forward with reasonable development efforts of the additional resources identified in the Fuel Diversity Plan. As with any strategic plan, the Company will update its future Plans to incorporate new information as it becomes known.

In response to the Public Staff's specific recommendation to establish metrics to quantify the benefits of fuel diversity, DNCP agrees that more purposefully assessing the benefits of fuel diversity in future planning processes is a reasonable goal. Fuel diversity considerations represent increasingly important risk trade-offs between generally higher long-term operating cost risks under the Base Plan versus higher near-term project development cost risks under the Fuel Diversity Plan. The importance of quantifying this risk trade-off also increases as the percentage of gas-fired generation selected as the least- cost option in the Company's Base Plan trends higher. The Company agrees to further analyze this risk-trade off and to develop potential metrics to quantify the benefits of fuel diversity prior to filing its 2015 IRP update filing. The Company is also willing to work with the Public Staff in the coming months to develop appropriate analytical metrics that allow for quantification of the benefits of fuel diversity.

DNCP does, however, disagree with the Public Staff's further recommendation that PVRR should be used to represent the value of fuel diversity in the Company's future Plans. While the Public Staff's comments suggest that it has "no clear preferred method" to quantify fuel diversity at this time, this methodological ambivalence quickly transitions into a recommendation that the utilities graph PVRR for their resource portfolios by various scenarios similar to the Tennessee Valley Authority's (TVA) approach in its March 2011 IRP. The Company has reviewed the TVA approach to graphing PVRR, and would submit that this approach provides little additional value in assessing the risk of a given portfolio. Cost risk is assessed based on how a given portfolio performs relative to a base case under a series of scenarios and sensitivity cases. This is precisely what is reflected in the 2013 Plan. What is important is the difference between the base case PVRR cost and the PVRR of the scenario or sensitivity case in question. The absolute value PVRR in and of itself offers little relative insight.

DNCP also disagrees with the Public Staff's related recommendation that the utilities should estimate the annual rate impacts of their various plans over the life of the planned resource additions. While an estimate of annual rate impacts of resource additions on a levelized per kWh basis may provide some understanding of ratepayer impacts, the Company believes this value would be limited in comparison to the way bill impacts are provided in base rate, fuel, DSM and other ratemaking proceedings. In addition, the Company is concerned that such an additional requirement may be a source of confusion for customers since DNCP is not asking for actual cost recovery in the IRP proceeding.

In sum, while the Company disagrees with the Public Staff's specific recommendation to follow TVA's approach to presenting PVRR in analyzing its future Plans, the Company does agree in principle that quantifying the benefits of fuel diversity in its future Plans is of increasing importance and commits to provide appropriate metrics to show this analysis in its 2015 IRP update filing.

The Commission is satisfied with DNCP's response.

D. Anticipating Environmental Regulatory Constraints Impacting Planning

The Public Staff recommends that the 2014 and future IRPs "include an economic analysis of the costs of compliance with pending environmental regulations, both individually and in combinations, and an environmental compliance scenario that includes reasonable assumptions regarding the costs of compliance." The Company would like to clarify that its 2013 Plan (and prior Plans) do, in fact, consider both "effective and anticipated U.S. Environmental Protection Agency (EPA) regulations concerning air, water, and solid waste constituents." DNCP's planning process not only evaluates the risks associated with effective and anticipated EPA regulations, but also analyzes the cost of compliance with anticipated environmental regulations in developing all of its planning scenarios. Section 3.1.3 of the Company's 2013 Plan recognizes the effective and anticipated EPA regulations that DNCP considered in developing its Plan (as set forth in DNCP's Figure 3.1.3.1 cited to on page 68 of the Public Staff's comments). The Company's 2013 Plan then noted that the Company's 2012 Plan comprehensively reviewed and analyzed the costs to retrofit units with new environmental control equipment, repower units to natural gas, convert units to burn biomass as a fuel source, or retire the units from service. DNCP's 2013 Plan remains largely unchanged compared to its 2012 Plan regarding the costs of retrofitting, repowering, and retiring units affected by EPA regulations. However, the Company's Plan does update expected installation of environmental controls on Yorktown 3 and Possum Point 5, which have been delayed and will both be implemented in 2018.

As the foregoing shows, the potential economic impacts of both effective and anticipated EPA regulations on DNCP's current generating units and future planning scenarios are fully considered in the Company's planning process. The Company will continue to take this approach and will continue to provide the economic analysis through discovery supporting its planning scenarios to the Public Staff in the future. This includes the reasonably anticipated and quantifiable cost of ensuring its current generating unit options as well as planned resource options can comply with anticipated environmental regulations. The Company does, however, note that the focus of its planning process is on "resource planning"- meaning evaluating prudent and least- cost supply-side and demand-side resources available to reliably serve its customers- and is not designed to solely develop cost estimates of compliance with prospective individual environmental regulations.

Based on the foregoing, DNCP will continue its comprehensive approach to evaluate the cost of current and anticipated EPA regulatory compliance in its future resource planning process and urges denial of the Public Staff's recommendation as unnecessary.

The Commission finds that no further action is required.

E. Inclusion of Decommissioning Costs

The Public Staff recommends that the utilities "include the decommissioning costs associated with each resource type, including coal, nuclear, natural gas, and renewable resources in one or more of the scenarios evaluated." DNCP generally agrees that inclusion of material decommissioning costs in the development of its future resource plans is reasonable where such decommissioning costs are currently quantifiable and not de minimis. In its ongoing development of its 2014 Plan, the Company plans to recognize decommissioning costs associated with potential new nuclear, offshore wind, and onshore wind resources included in that Plan, as those resource options present quantifiable and non-de minimis decommissioning costs. Other future resource options including coal, natural gas, and solar/non-wind renewables are projected to be "decommissioned-in-place," and are not currently expected to cause material decommissioning costs in substantial excess of potential salvage value of the unit at the time of unit shut down. DNCP will continue to evaluate all future resource options to assess whether material decommissioning costs should be recognized in future Plans.

The Commission is satisfied with DNCP's response to this issue.

F. Stakeholder Participation and Streamlining IRP Update Process

The Public Staff makes recommendations about how the IRP process could be improved. First, the Public Staff suggests that the Commission solicit comments from the parties regarding changes to the IRP process to make it more "robust and meaningful." Second, the Public Staff advocates allowing stakeholder input prior to development of the IRPs by the utilities. Finally, the Public Staff suggests the Commission may wish to consider issuing expedited rulings on key inputs and assumptions to be included in the next IRP filing to be made by September 1, 2014.

In response to the Public Staff's first suggestion, DNCP noted that the current IRP process was established through revisions to Rule RS-60 approved on July 11, 2007 and reflected a consensus between the Public Staff, the utilities, and numerous other stakeholders regarding the structure of the revised IRP rule and process. The Company would welcome the opportunity to comment on the IRP process with any eye towards streamlining the IRP update in North Carolina (the odd-year filing) to make it less burdensome on the Company. DNCP noted that its resource planning process is an ongoing process designed to meet its biennial resource planning responsibilities in both Virginia and North Carolina. Because, by statute, the Company's IRP filing in Virginia is due on September 1 of each odd year, a streamlined update proceeding in North Carolina while the Company is supporting a fully-litigated proceeding in Virginia would help maximize and conserve the Company's planning resources.

Regarding stakeholder participation in the development of the Company's IRP, DNCP does not believe a "North Carolina-wide" stakeholder process is necessary or would benefit each of the utilities mandated to separately develop their own resource plan to serve its customers' future electricity needs. Development of DNCP's IRP is obviously a distinct process from DEC's or DEP's planning process. That said, the Company does not oppose allowing up front input into its own resource planning process arid, in fact, has had a stakeholder review process (SRP) in place in Virginia for several years. The Public Staff, Southern Environmental Law Center, Sierra Club and others routinely participate in the SRP and this forum could be made to be open to other interested parties from North Carolina as well.

Finally, regarding the Public Staff's recommendation that the Commission consider expedited rulings mandating the Utilities include "key inputs and assumptions" in their 2014 Plans, the Company has already began its 2014 Plan development process and is concerned that any ruling that is entered now by the Commission will not be able to be implemented in time for the 2014 Plan filing. Therefore, DNCP recommends the more prudent course is for the Commission to give due consideration to all the recommendations and comments received and issue a comprehensive ruling in due course that the Utilities can incorporate into their 2015 Plan filings.

The Commission's response to this IRP streamlining issue was discussed in the DEC/DEP comments section.

<u>NCSEA Issues</u>

A. Relationship to Avoided Cost Proceeding

DNCP, in its reply comments, argued that NCSEA's request for a "Commission endorsement" of "consistency across proceedings," is not necessary or appropriate. While the Company generally agrees that reasonable consistency is a laudable purpose and, in most instances, is appropriate, a formal statement such as NCSEA requests would ignore the distinct purposes of biennial avoided cost proceedings as opposed to IRP proceedings. Moreover, such a statement would unnecessarily restrict the utilities in developing their IRPs and avoided cost rates such that they could not account for those instances when consistency is either not possible or not reasonable under the circumstances. Finally, given that NCSEA and any other party may challenge IRP data inputs and avoided cost rates in their respective proceedings, it is unnecessary for the Commission to take this step.

DNCP further commented that, as NCSEA noted, the Commission has already rejected arguments similar to those made by NCSEA here. In its May 30, 2013 Order in DEP's 2012 general rate case, the Commission recognized that its responsibilities under the Public Utility Regulatory Policies Act of 1978 (PURPA) to set the utilities' avoided costs are functionally distinct from its ratemaking functions under Chapter 62. DNCP submits that the Commission's statutory resource planning process is also functionally distinct from the PURPA avoided cost rate-setting process. This is because the precision required to ensure the Utilities are meeting PURPA's goals of promoting the development of small power producers is fundamentally different than the Commission's oversight of long-term resource planning. Under PURPA, the Commission is prohibited from directing the utilities to pay QFs more than avoided cost. Recognizing the great importance and highly technical nature of this determination, the NCUC has initiated the 2014 avoided cost proceeding in Docket No. E-100, Sub 140, to consider whether refinements to the methodologies and calculations underlying the utilities' avoided costs are needed. In contrast to the mandated precision required to develop the utilities current avoided costs and promote efficient QF development, the Commission's long-term resource planning process is an evolving and dynamic process focused on the "probable future" generating needs of the State. Given the substantially different purposes of these two proceedings, while similar inputs may be used, where appropriate, to develop the utilities' avoided cost rates as are used in resource planning proceedings, justifiably reasonable differences may exist between the data used in the IRP proceeding and in the avoided cost proceedings.

For example, DNCP points out that an after-the-fact discovery of error or a demonstrated change in circumstances from those contemplated during the preparation of an IRP may result in the inputs and assumptions used for the IRP to be inappropriate for use in a utility's determination of avoided cost rates. NCSEA's proposal would result in utilities being unable to account for such changes and could result in inaccurate and potentially unlawfully excessive avoided cost rates.

In addition to being inappropriate, DNCP argues that no preemptory Commission endorsement of consistency is needed. If NCSEA or any other party concludes that data inputs used in either an IRP proceeding or an avoided cost proceeding are unreasonable, it would assuredly have a full and fair opportunity within the context of that specific proceeding to challenge the reasonableness of the IRP or avoided cost data for ultimate resolution by the Commission.

The Commission appreciates NCSEA's comments concerning consistency across multiple Commission proceedings. The Commission agrees that such consistency, where feasible, can be helpful in understanding components of multiple proceedings when the components remain static. However, the timing of the Commission's proceedings varies, and that variance can cause facts and projections to change from one proceeding to another. That point is often illustrated by the two proceedings that NCSEA used as an example, the IRP and the biennial avoided cost dockets. In particular, NCSEA cited the assumptions and projections made by the utilities regarding CT costs and capacity needs.

In the present docket, the utilities filed their IRPs in October 2013. On the other hand, the utilities' testimony in the current avoided cost docket, E-100, Sub 140, was not filed until April 2014. Assumptions and projections about material facts, including CT costs and capacity needs, can change over the span of several months. The Commission endorses consistency in information and projections across multiple proceedings, where appropriate. But more importantly, the Commission endorses the use of timely and accurate information in all proceedings.

B. Policy Landscape Assumptions

NCSEA recommends that the utilities "be required to concisely list in one place in its filed plan all of the key policy assumptions which underlie its "base case or recommended plan." DNCP respectfully responds that the policy and other assumptions underlying its 2013 Plan are already appropriately set forth in the Introduction and Chapter 1 Executive Summary and then articulated in greater detail throughout the remainder of its 2013 Plan. The Company's development of its 2013 Plan is fully consistent with the Commission's prior direction and the requirements of Rule R8-60(b). Unless a more precise explanation would assist the Commission in satisfying its statutory obligation to report to the Governor and the General Assembly, DNCP submits that nothing further or different should be required in presenting its future Plans.

The Commission finds that no changes are required at this time.

C. Customer Data Access

NCSEA notes that the Commission could encourage data access for the benefit of DNCP's customers by requiring the Company to make its data access form available electronically. The Company is working to make this form available electronically in the near future.

D. Request for Historical REPS Plan Review Certification

NCSEA recommends that each of the utilities be obligated to submit a letter verifying that they have reviewed their 2009 REPS Plan and then to include in future REPS compliance plans a certification that the historical review has been conducted. While the Company is not necessarily opposed to this requirement in its future plans, DNCP's cover letter submitting its 2013 Plan (in which the Company's 2013 REPS Plan was filed as NC Addendum I) stated:

> In accordance with Ordering Paragraph (3) of the Commission's June 3, 2013 Order Granting in Part and Denying in Part Motion for Disclosure, the Company has reviewed its 2009 REPS Compliance Plan filed in Docket No. E-100, Sub 124, and, as no information contained in that filing was designated confidential qualifying as

"trade secret" under N.C.G.S. § 66-52(3), there is no information to disclose as no longer requiring such designation.

DNCP has satisfied the Commission's prior direction from the above-referenced Order, and will continue to do so. Therefore, this recommendation for a specific certification is unnecessary. The Commission agrees with DNCP.

<u>MAREC Issue</u>

Proposed Competitive Renewables Solicitation

MAREC advocates that the Commission should obligate the utilities to engage in a competitive solicitation for new renewables to satisfy their REPS obligations. DNCP disagrees. First, DNCP does not require in-state RECs to meet its REPS obligation. Second, the Commission's resource planning process pursuant to G.S. 62-110.1(c) is not designed to "alter a given utility's operations" but, instead, should resemble "a legislative hearing, wherein a legislative committee gathers facts and opinions so that informed decisions may be made at a later time." Thus, MAREC's recommendation to mandate a competitive solicitation for renewables should be rejected as unnecessary and outside the scope of this proceeding. The Commission agrees with DNCP.

IT IS, THEREFORE, ORDERED, as follows:

1. That this Order shall be 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' 15-year 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 and are hereby approved.

3. That the 2013 REPS compliance plans filed in this proceeding by the IOUs are hereby approved.

4. That future IRP filings by all IOUs shall continue to include a detailed explanation of the basis and justification for the appropriateness of the level of the respective utility's projected reserve margins.

5. That future IRP filings by all IOUs shall continue to include a copy of the most recently completed FERC Form 715, including all attachments and exhibits.

6. That future IRP filings by all IOUs shall continue to: (1) provide the amount of load and projected load growth for each wholesale customer under contract on a year-by-year basis through the terms of the current contract, segregate actual and

projected growth rates of retail and wholesale loads, and explain any difference in actual and projected growth rates between retail and wholesale loads, and (2) for any amount of undesignated load, detail each potential customer's current supply arrangements and explain the basis for the utility's reasonable expectation for serving each such customer.

7. That the IOUs should continue to monitor and report any changes of more than 10% in the energy and capacity savings derived from DSM and EE between successive IRPs, and evaluate and discuss any changes on a program-specific basis. Any issues impacting program deployment should be thoroughly explained and quantified in future IRPs.

8. That each IOU shall continue to include a discussion of the status of EE market potential studies or updates in their future IRPs.

9. That all IOUs shall include in future IRPs a full discussion of the drivers of each customer class' load forecast, including new or changed demand of a particular sector or sub-group.

10. 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.

11. That DEC shall continue to provide updates in future IRPs regarding its obligations related to the Cliffside Unit 6 air permit.

12. That the Cliffside Unit 6 Carbon Neutrality Plan filed by DEC is approved as a reasonable path for DEC's compliance with the carbon emission reduction standards of the air quality permit; provided, however, this approval does not constitute Commission approval of individual specific activities or expenditures for any activities shown in the Plan.

13. That to the extent an IOU selects a preferred resource scenario based on fuel diversity, the IOU should provide additional support for its decision based on the costs and benefits of alternatives to achieve the same goals.

14. That future IRP filings by DEP and DEC shall provide information on the number, resource type and total capacity of the facilities currently within the respective utility's interconnection queue as well as a discussion of how the potential QF purchases would affect the utility's long-range energy and capacity needs.

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

16. That NC WARN's motion for an evidentiary hearing shall be, and is hereby, denied.

ISSUED BY ORDER OF THE COMMISSION.

This the 30th day of June, 2014.

NORTH CAROLINA UTILITIES COMMISSION

Paige J. Morris

Paige J. Morris, Deputy Clerk

Table 8-C Load, Capacity and Reserves Table - Summer

**Summer Projections of Load, Capacity, and Reserves
for Duke Energy Progress 2013 Annual Plan**

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Load Forecast															
1 DEP System Peak	13,078	13,338	13,582	13,823	14,054	14,299	14,548	14,797	15,049	15,274	15,522	15,764	16,003	16,243	16,484
2 Firm Sale	475	150	150	150	150	150	150	150	150	150	150	0	0	0	0
3 New EE Programs	(62)	(106)	(152)	(194)	(227)	(269)	(314)	(364)	(413)	(435)	(478)	(518)	(551)	(580)	(604)
4 Adjusted Duke System Peak	**13,491**	**13,382**	**13,580**	**13,779**	**13,977**	**14,180**	**14,384**	**14,583**	**14,786**	**14,989**	**15,194**	**15,246**	**15,451**	**15,662**	**15,881**
Existing and Designated Resources															
5 Generating Capacity	12,932	13,013	13,037	13,037	13,037	13,174	13,174	13,174	13,174	13,174	13,174	13,174	13,174	13,174	13,174
6 Designated Additions / Uprates	634	24			137										
7 Retirements / Derates	(553)														
8 Cumulative Generating Capacity	**13,013**	**13,037**	**13,037**	**13,037**	**13,174**	**13,174**	**13,174**	**13,174**	**13,174**	**13,174**	**13,174**	**13,174**	**13,174**	**13,174**	**13,174**
Purchase Contracts															
9 Cumulative Purchase Contracts	1,861	1,878	1,877	1,877	1,657	1,489	1,344	776	445	445	443	443	443	438	389
Undesignated Future Resources															
10 Nuclear	0	0	0	0	46	0	46	0	0	0	0	0	0	0	0
11 Fossil	0	0	0	0	126	843	0	843	843	0	0	0	0	403	0
Renewables															
12 Cumulative Renewables Capacity	196	205	208	208	214	265	281	248	312	373	402	421	440	460	436
13 Cumulative Production Capacity	**15,070**	**15,120**	**15,122**	**15,122**	**15,217**	**15,943**	**15,860**	**16,102**	**16,677**	**16,739**	**16,766**	**16,785**	**16,804**	**17,223**	**17,148**
Demand Side Management (DSM)															
14 Cumulative DSM Capacity	**827**	**849**	**869**	**885**	**910**	**935**	**958**	**979**	**1,000**	**1,020**	**1,037**	**1,054**	**1,073**	**1,089**	**1,105**
15 Cumulative Capacity w/ DSM	**15,897**	**15,969**	**15,991**	**16,007**	**16,127**	**16,878**	**16,818**	**17,081**	**17,677**	**17,759**	**17,803**	**17,839**	**17,877**	**18,312**	**18,253**
Reserves w/ DSM															
16 Generating Reserves	2,407	2,587	2,411	2,228	2,150	2,698	2,433	2,497	2,891	2,770	2,609	2,593	2,425	2,649	2,373
17 % Reserve Margin	**17.8%**	**19.3%**	**17.8%**	**16.2%**	**15.4%**	**19.0%**	**16.9%**	**17.1%**	**19.6%**	**18.5%**	**17.2%**	**17.0%**	**15.7%**	**16.9%**	**14.9%**

Table 8-D **Load, Capacity and Reserves Table - Winter**

Winter Projections of Load, Capacity, and Reserves
for Duke Energy Progress 2013 Annual Plan

	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28
Load Forecast															
1 DEP System Peak	12,376	12,627	12,859	13,090	13,312	13,547	13,787	14,026	14,269	14,510	14,749	14,983	15,217	15,450	15,684
2 Firm Sale	150	150	150	150	150	150	150	150	150	150	150	0	0	0	0
3 New EE Programs	(34)	(67)	(102)	(135)	(179)	(213)	(249)	(289)	(328)	(366)	(402)	(436)	(463)	(488)	(507)
4 Adjusted Duke System Peak	**12,492**	**12,710**	**12,908**	**13,106**	**13,282**	**13,484**	**13,688**	**13,888**	**14,091**	**14,293**	**14,497**	**14,547**	**14,753**	**14,962**	**15,177**
Existing and Designated Resources															
5 Generating Capacity	14,107	14,107	14,107	14,135	14,135	14,135	14,135	14,135	14,135	14,135	14,135	14,135	14,135	14,135	14,135
6 Designated Additions / Uprates			28												
7 Retirements / Derates															
8 Cumulative Generating Capacity	**14,107**	**14,107**	**14,135**	**14,135**	**14,135**	**14,135**	**14,135**	**14,135**	**14,135**	**14,135**	**14,135**	**14,135**	**14,135**	**14,135**	**14,135**
Purchase Contracts															
9 Cumulative Purchase Contracts	1,925	1,925	1,942	1,941	1,681	1,681	1,368	1,368	778	396	396	396	396	396	396
Undesignated Future Resources															
10 Nuclear	0	0	0	0	0	46	0	46	0	0	0	0	0	0	0
11 Fossil	0	0	0	0	147	0	875	0	875	875	0	0	0	443	0
Renewables															
12 Cumulative Renewables Capacity	146	146	154	158	158	155	200	195	143	188	230	240	240	240	240
13 Cumulative Production Capacity	**16,178**	**16,177**	**16,231**	**16,233**	**16,120**	**16,163**	**16,770**	**16,812**	**17,045**	**17,583**	**17,625**	**17,635**	**17,635**	**18,078**	**18,078**
Demand Side Management (DSM)															
14 Cumulative DSM Capacity	**506**	**506**	**506**	**505**	**512**	**518**	**525**	**530**	**537**	**543**	**549**	**554**	**561**	**567**	**574**
15 Cumulative Capacity w/ DSM	**16,684**	**16,684**	**16,737**	**16,738**	**16,632**	**16,681**	**17,295**	**17,342**	**17,583**	**18,127**	**18,174**	**18,189**	**18,196**	**18,645**	**18,652**
Reserves w/ DSM															
16 Generating Reserves	4,192	3,973	3,830	3,633	3,350	3,197	3,607	3,454	3,492	3,833	3,677	3,642	3,443	3,683	3,475
17 % Reserve Margin	**33.6%**	**31.3%**	**29.7%**	**27.7%**	**25.2%**	**23.7%**	**26.4%**	**24.9%**	**24.8%**	**26.8%**	**25.4%**	**25.0%**	**23.3%**	**24.6%**	**22.9%**

DEP - Assumptions of Load, Capacity, and Reserves Table

The following notes are numbered to match the line numbers on the Summer Projections of Load, Capacity, and Reserves table. All values are MW except where shown as a Percent.

1. Planning is done for the peak demand for the Duke Energy Progress System
2. FERC 325 MW Mitigation Sale for summer of 2014
   Firm sale of 150 MW through 2024
3. Cumulative energy efficiency and conservation programs (does not include demand response programs)
4. Peak load adjusted for FERC mitigation sale, firm sale, and cumulative energy efficiency
5. Existing generating capacity reflecting designated additions, planned uprates, retirements and derates
   Includes total unit capacity of jointly owned units
6. Capacity Additions include Duke Energy Progress projects that have been approved by the NCUC (625 MW Sutton Combined Cycle unit in December 2013)
   Planned nuclear uprates totalling 9 MW in Q4 2013
   Planned nuclear uprates totalling 24 MW in 2015
   Planned combined cycle uprates totalling 137 MW in 2018
7. Capacity Retirement of 553 MW of Sutton Coal units in December 2013
8. Sum of lines 5 through 7
9. Cumulative Purchase Contracts have several components:
   Purchased capacity from PURPA Qualifying Facilities, Anson and Hamlet CT tolling, Butler Warner purchase, Southern CC purchase, and Broad River CT purchase
10. New nuclear resources economically selected to meet load and minimum planning reserve margin
    Capacity must be on-line by June 1 to be included in available capacity for the summer peak of that year and by December 1 to be included in available capacity for the winter peak of that year.
    10% share (allocated by load ratio basis with DEC) V.C. Summer Nuclear facility in 2018 and 2020 (46 MW in each year)
11. New fossil fuel resources economically selected to meet load and minimum planning reserve margin
    Capacity must be on-line by June 1 to be included in available capacity for the summer peak of that year and by December 1 to be included in available capacity for the winter peak of that year.
    Addition of 126 MW Fast-Start Combustion Turbine capacity in December 2017
    Addition of 843 MW Advanced Combined Cycle units in 2019, 2021 and 2022
    Addition of 403 MW of Combustion Turbine capacity in 2027
12. Cumulative solar, biomass, hydro and wind resources to meet NC REPS compliance
    Also includes a compliance plan for South Carolina as a placeholder to reflect a possible state or federal renewable standard beginning in 2018
13. Sum of lines 8 through 12
14. Cumulative Demand Side Management programs including load control and DSDR
15. Sum of lines 13 and 14
16. The difference between lines 4 and 15
17. Reserve Margin = (Cumulative Capacity-System Peak Demand)/System Peak Demand
    Minimum target planning reserve margin is 14.5%

Table 8-C Load, Capacity and Reserves Table - Summer

Summer Projections of Load, Capacity, and Reserves for Duke Energy Carolinas 2013 Annual Plan

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Load Forecast															
1 Duke System Peak	18,490	18,922	19,375	19,827	20,278	20,764	21,114	21,417	21,776	22,143	22,488	22,862	23,240	23,613	23,974
2 Firm Sale	150	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 Cumulative New EE Programs	(111)	(184)	(275)	(382)	(490)	(600)	(708)	(819)	(929)	(1,040)	(1,110)	(1,219)	(1,318)	(1,404)	(1,477)
4 Adjusted Duke System Peak	18,529	18,738	19,100	19,445	19,788	20,164	20,406	20,598	20,848	21,104	21,378	21,643	21,922	22,209	22,496
Existing and Designated Resources															
5 Generating Capacity	20,366	20,386	20,218	20,218	20,263	20,263	20,263	20,259	20,259	20,259	20,259	20,259	20,259	20,259	20,259
6 Designated Additions / Uprates	20.3	202	0	45	0	0	0	0	0	0	0	0	0	0	0
7 Retirements / Derates	0	(370)	0	0	0	0	(4)	0	0	0	0	0	0	0	0
8 Cumulative Generating Capacity	20,386	20,218	20,218	20,263	20,263	20,263	20,259	20,259	20,259	20,259	20,259	20,259	20,259	20,259	20,259
Purchase Contracts															
9 Cumulative Purchase Contracts	251	238	230	227	227	169	166	79	66	56	46	46	46	45	25
Undesignated Future Resources															
10 Nuclear	0	0	0	0	66	0	66	0	0	0	1,117	0	1,117	0	0
11 Fossil	0	0	0	680	0	843	0	0	403	0	0	0	0	0	0
Renewables															
12 Cumulative Renewables Capacity	185	287	316	340	425	519	572	626	668	718	760	818	847	866	921
13 Cumulative Production Capacity	20,823	20,744	20,764	21,510	21,661	22,540	22,653	22,819	23,051	23,091	24,240	24,298	25,444	25,462	25,497
Demand Side Management (DSM)															
14 Cumulative DSM Capacity	911	1,010	1,068	1,118	1,169	1,196	1,196	1,196	1,196	1,196	1,196	1,196	1,196	1,198	1,196
15 Cumulative Capacity w/ DSM	21,733	21,754	21,832	22,628	22,830	23,736	23,848	23,815	24,246	24,287	25,435	25,493	26,640	26,658	26,692
Reserves w/ DSM															
16 Generating Reserves	3,204	3,016	2,732	3,183	3,042	3,572	3,442	3,217	3,399	3,183	4,057	3,850	4,718	4,448	4,196
17 % Reserve Margin	17.3%	16.1%	14.3%	16.4%	15.4%	17.7%	16.9%	15.6%	16.3%	15.1%	19.0%	17.8%	21.5%	20.0%	18.7%

Table 8-D Load, Capacity and Reserves Table – Winter

Winter Projections of Load, Capacity and Reserves
for Duke Energy Carolinas 2013 Annual Plan

	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28
Load Forecast															
1 Duke System Peak	17,717	18,177	18,595	19,000	19,410	19,818	20,165	20,463	20,803	21,150	21,510	21,866	22,234	22,589	22,938
2 Firm Sale	25	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 Cumulative New EE Programs	(64)	(123)	(194)	(276)	(397)	(486)	(572)	(661)	(748)	(837)	(923)	(1,013)	(1,094)	(1,164)	(1,225)
4 Adjusted Duke System Peak	**17,678**	**18,053**	**18,401**	**18,724**	**19,013**	**19,332**	**19,593**	**19,802**	**20,054**	**20,313**	**20,588**	**20,853**	**21,140**	**21,425**	**21,713**
Existing and Designated Resources															
5 Generating Capacity	21,927	21,219	21,239	21,071	21,071	21,116	21,116	21,116	21,112	21,112	21,112	21,112	21,112	21,112	21,112
6 Designated Additions / Uprates	2	20	202	0	45	0	0	0	0	0	0	0	0	0	0
7 Retirements / Derates	(710)	0	(370)	0	0	0	0	(4)	0	0	0	0	0	0	0
8 Cumulative Generating Capacity	**21,219**	**21,239**	**21,071**	**21,071**	**21,116**	**21,116**	**21,116**	**21,112**	**21,112**	**21,112**	**21,112**	**21,112**	**21,112**	**21,112**	**21,112**
Purchase Contracts															
9 Cumulative Purchase Contracts	229	216	210	210	210	152	149	56	43	33	23	23	23	23	23
Undesignated Future Resources															
10 Nuclear	0	0	0	0	0	66	0	66	0	0	0	1,117	0	1,117	0
11 Fossil	0	0	0	0	711	0	875	0	0	443	0	0	0	0	0
Renewables															
12 Cumulative Renewables Capacity	62	112	119	127	134	168	214	221	234	238	252	260	270	268	263
13 Cumulative Production Capacity	21,509	21,567	21,400	22,119	22,171	23,088	23,131	23,107	23,550	23,544	23,548	24,673	24,683	25,797	25,793
Demand Side Management (DSM)															
14 Cumulative DSM Capacity	561	584	604	626	649	649	649	649	649	649	649	649	649	649	649
15 Cumulative Capacity w/ DSM	22,070	22,151	22,004	22,745	22,820	23,737	23,780	23,756	24,199	24,193	24,197	25,322	25,332	26,446	26,442
Reserves w/ DSM															
16 Generating Reserves	4,392	4,098	3,603	4,021	3,807	4,405	4,187	3,954	4,145	3,880	3,610	4,469	4,191	5,021	4,729
17 % Reserve Margin	24.8%	22.7%	19.6%	21.5%	20.0%	22.8%	21.4%	20.0%	20.7%	19.1%	17.5%	21.4%	19.8%	23.4%	21.8%

DEC - Assumptions of Load, Capacity, and Reserves Table

The following notes are numbered to match the line numbers on the Summer Projections of Load, Capacity, and Reserves tables. All values are MW except where shown as a Percent.

1. Planning is done for the peak demand for the Duke System including Nantahala. Nantahala became a division of Duke Energy Carolinas in 1998.
   A firm wholesale backstand agreement for 47 MW between Duke Energy Carolinas and PMPA starts on 1/1/2014 and continues through the end of 2020.

2. A firm sale of 150 MW summer and 25 MW winter for FERC market power mitigation in 2014.

3. Cumulative energy efficiency and conservation programs (does not include demand response programs)

4. Peak load adjusted for firm sale and cumulative energy efficiency

5. Existing generating capacity reflecting designated additions, planned uprates, retirements and derates
   Includes 101 MW Nantahala hydro capacity, and total capacity for Catawba Nuclear Station less 832 MW to account for NCMPA1 firm capacity sale.

6. Capacity Additions include the conversion of Lee Steam Station unit 3 from coal to natural gas in 2015 (170 MW).
   Capacity Additions include Duke Energy Carolinas hydro units scheduled to be repaired and returned to service.
   These units are returned to service in the 2012-2015 timeframe and total 2 MW.
   Also included is a 96.5 MW capacity increase due to nuclear uprates at Catawba, McGuire, and Oconee.
   Timing of these uprates is shown from 2014-2017

7. The 370 MW capacity retirement in summer 2015 represents the projected retirement date for Lee Steam Station.
   Capacity Derate of 4 MW associated with Marshall 4 SCR is included in 2020
   The NRC has issued renewed energy facility operating licenses for all Duke Energy Carolinas' nuclear facilities.
   The Hydro facilities for which Duke has submitted an application to FERC for licence renewal are assumed to continue operation through the planning horizon.
   All retirement dates are subject to review on an ongoing basis.

8. Sum of lines 5 through 7

9. Cumulative Purchase Contracts including purchased capacity from PURPA Qualifying Facilities, an 88 MW Cherokee County Cogeneration Partners contract which began in June 1998 and expires June 2020 and miscellaneous other QF projects.

10. New nuclear resources economically selected to meet load and minimum planning reserve margin
    Capacity must be on-line by June 1 to be included in available capacity for the summer peak of that year and by December 1 to be included in available capacity for the winter peak of that year.
    10% share (allocated by load ratio basis with DEP) V.C. Summer Nuclear facility in 2018 and 2020 (66 MW in each year)
    1117 MW Lee Nuclear Unit additions in 2024 and 2026

DEC - Assumptions of Load, Capacity, and Reserves Table cont.

11. New fossil fuel resources economically selected to meet load and minimum planning reserve margin
    Capacity must be on-line by June 1 to be included in available capacity for the summer peak of that year and by December 1 to be included in available capacity for the winter peak of that year.
    Addition of 680 MW of Combined Cycle capacity in 2017 (based on the need determined in 2012 IRP)
    Addition of 843 MW Advanced Combined Cycle units in 2019
    Addition of 403 MW of Combustion Turbine capacity in 2022

12. Cumulative solar, biomass, hydro and wind resources to meet NC REPS compliance
    Also includes a compliance plan for South Carolina as a placeholder to reflect a possible state or federal renewable standard beginning in 2018

13. Sum of lines 8 through 12

14. Cumulative Demand Side Management programs including load control and DSDR

15. Sum of lines 13 and 14

16. The difference between lines 4 and 15

17. Reserve Margin = (Cumulative Capacity-System Peak Demand)/System Peak Demand
    Minimum target planning reserve margin is 14.5%

APPENDIX 2H – PROJECTED SUMMER & WINTER PEAK LOAD & ENERGY FORECAST

Company Name: Virginia Electric and Power Company

Schedule 1

I. PEAK LOAD AND ENERGY FORECAST

	(ACTUAL)[1]			(PROJECTED)															
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
1. Utility Peak Load (MW)																			
A. Summer																			
1a. Base Forecast	16,783	17,521	16,787	17,039	17,244	17,695	18,070	18,351	18,576	18,825	19,106	19,391	19,665	19,955	20,248	20,538	20,836	21,151	21,439
1b. Additional Forecast																			
NCEMC	150	150	'150	150	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2. Conservation, Efficiency[5]	-19	-33	-40	-48	-69	-113	-172	-221	-264	-290	-290	-282	-277	-276	-279	-281	-282	-284	-286
3. Demand Response[2][5]	-14	-42	-66	-101	-129	-151	-176	-203	-228	-240	-243	-244	-245	-247	-248	-252	-254	-256	-259
4. Demand Response-Existing[2][3]	-9	-7	-7	-7	-7	-7	-7	-7	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5
5. Peak Adjustment	-	-	-	241	487	592	691	-	-	-	-	-	-	-	-	-	-	-	-
6. Adjusted Load	16,914	17,638	16,087	17,383	17,811	18,174	18,589	18,131	18,314	18,535	18,816	19,109	19,388	19,678	19,969	20,258	20,554	20,867	21,152
7. % Increase in Adjusted Load (from previous year)	5.3%	4.3%	-4.2%	2.9%	2.5%	2.0%	2.3%	-2.5%	1.0%	1.2%	1.5%	1.6%	1.5%	1.5%	1.5%	1.4%	1.5%	1.5%	1.4%
B. Winter																			
1a. Base Forecast	15,184	15,244	14,544	15,093	15,416	15,642	15,992	16,186	16,311	16,396	16,546	16,754	16,931	17,141	17,332	17,540	17,773	18,021	18,266
1b. Additional Forecast																			
NCEMC	150	150	150	150	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2. Conservation, Efficiency[5]	-23	-37	-40	-29	-30	-35	-73	-158	-203	-225	-224	-222	-219	-222	-224	-226	-228	-229	-230
3. Demand Response[2][4]	-	-	-14	-26	-34	-37	-41	-49	-55	-58	-59	-60	-61	-62	-63	-64	-65	-66	-67
4. Demand Response-Existing[2][3]	-7	-8	-6	-6	-6	-6	-6	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5
5. Adjusted Load	15,311	15,357	14,654	15,214	15,535	15,607	15,919	16,027	16,108	16,171	16,322	16,531	16,712	16,919	17,108	17,314	17,545	17,792	18,035
6. % Increase in Adjusted Load	-1.7%	0.3%	-4.6%	3.8%	2.1%	0.5%	2.0%	0.7%	0.5%	0.4%	0.9%	1.3%	1.1%	1.2%	1.1%	1.2%	1.3%	1.4%	1.4%
2. Energy (GWh)																			
A. Base Forecast	85,656	83,393	81,498	85,044	87,252	89,716	92,190	93,726	95,047	96,382	97,947	99,195	100,633	102,114	103,804	105,044	106,544	108,065	109,859
B. Additional Forecast																			
NCEMC	-	-	-	668	676	-	-	-	-	-	-	-	-	-	-	-	-	-	-
C. Conservation & Demand Response[4]	-184	-294	-342	-469	-558	-787	-1,234	-1,836	-2,373	-2,845	-3,034	-3,041	-3,080	-3,127	-3,135	-3,140	-3,142	-3,144	-3,149
D. Demand Response-Existing[2][3]	-1	-0.3	-0.4	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1
E. Adjusted Energy	86,471	83,099	81,156	85,234	87,370	88,920	90,958	91,891	92,674	93,517	94,913	96,154	97,554	98,987	100,669	101,904	103,402	104,922	106,710
F. % Increase in Adjusted Energy	4.8%	-3.9%	-2.3%	5.0%	2.5%	1.8%	2.3%	1.0%	0.9%	0.9%	1.5%	1.3%	1.5%	1.5%	1.7%	1.2%	1.5%	1.5%	1.7%

(1) Actual metered data.

(2) Demand response programs are classified as capacity resources and are not included in adjusted load.

(3) Existing DSM programs are included in the load forecast.

(4)Values for 2010, 2011 and 2012 represent modeled energy; actual historical data based upon measured and verified EM&V results is not yet available.

(5)Values for 2010, 2011 and 2012 represent modeled capacity; actual historical data based upon measured and verified EM&V results is not yet available. Projected values represent modeled DSM firm capacity.

APPENDIX 2I – REQUIRED RESERVE MARGIN

Company Name: Virginia Electric and Power Company

Schedule 6

POWER SUPPLY DATA (continued)

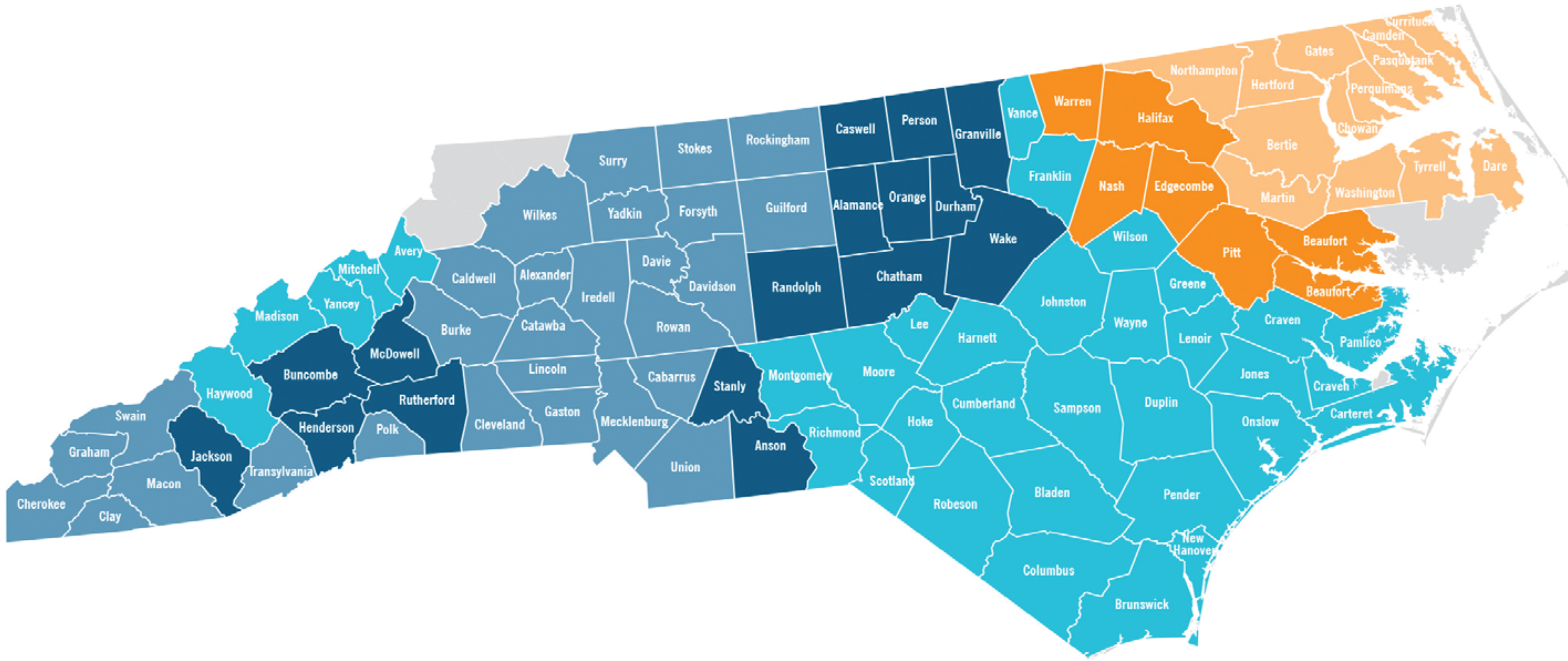
	(ACTUAL)			(PROJECTED)															
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
I. Reserve Margin(1)																			
(Including Cold Reserve Capability)																			
1. Summer Reserve Margin																			
a. MW(1)	3,397	3,240	4,668	2,771	3,144	3,080	2,930	2,025	2,045	2,445	2,121	2,287	2,248	2,416	2,230	2,262	2,295	2,611	2,362
b. Percent of Load	20.1%	18.4%	27.7%	15.9%	17.6%	16.9%	15.8%	11.2%	11.2%	13.2%	11.3%	12.0%	11.6%	12.3%	11.2%	11.2%	11.2%	12.5%	11.2%
c. Actual Reserve Margin(3)	N/A	N/A	N/A	12.76%	10.35%	8.53%	13.01%	11.58%	10.85%	15.83%	13.87%	14.49%	14.05%	14.70%	13.05%	11.46%	9.87%	14.83%	13.29%
2. Winter Reserve Margin																			
a. MW(1)	N/A	N/A	N/A	7,120	6,544	5,670	6,186	6,005	4,933	6,313	5,957	6,166	6,226	6,482	6,294	6,089	5,858	7,121	6,878
b. Percent of Load	N/A	N/A	N/A	46.8%	42.1%	36.3%	38.9%	37.5%	30.6%	39.0%	36.5%	37.3%	37.3%	38.3%	36.8%	35.2%	33.4%	40.0%	38.1%
c. Actual Reserve Margin(3)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
I. Reserve Margin(1)(2)																			
(Excluding Cold Reserve Capability)																			
1. Summer Reserve Margin																			
a. MW(1)	3,323	3,135	4,778	2,771	3,144	3,080	2,930	2,025	2,045	2,445	2,121	2,287	2,248	2,416	2,230	2,262	2,295	2,611	2,362
b. Percent of Load	19.6%	17.8%	28.4%	15.9%	17.6%	16.9%	15.8%	11.2%	11.2%	13.2%	11.3%	12.0%	11.6%	12.3%	11.2%	11.2%	11.2%	12.5%	11.2%
c. Actual Reserve Margin(3)	N/A	N/A	N/A	12.76%	10.35%	8.53%	13.01%	11.58%	10.85%	15.83%	13.87%	14.49%	14.05%	14.70%	13.05%	11.46%	9.87%	14.83%	13.29%
2. Winter Reserve Margin																			
a. MW(1)	N/A	N/A	N/A	7,120	6,544	5,670	6,186	6,005	4,933	6,313	5,957	6,166	6,226	6,482	6,294	6,089	5,858	7,121	6,878
b. Percent of Load	N/A	N/A	N/A	46.8%	42.1%	36.3%	38.9%	37.5%	30.6%	39.0%	36.5%	37.3%	37.3%	38.3%	36.8%	35.2%	33.4%	40.0%	38.1%
c. Actual Reserve Margin(3)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
III. Annual Loss-of-Load Hours(4)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

(1) To be calculated based on Total Net Capability for summer and winter.

(2) The Company and PJM forecast a summer peak throughout the Planning Period.

(3) Does not include spot purchases of capacity.

(4) The Company follows PJM reserve requirements which are based on LOLE.



SERVICE TERRITORIES
(counties served)

Duke Energy Carolinas

Duke Energy Progress

Duke Energy Carolinas/
Duke Energy Progress overlapping counties

Dominion North Carolina Power

Dominion North Carolina Power/
Duke Energy Progress overlapping counties