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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North Carolina Electric Membership Corporation

ElectriCities of North Carolina

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ABBREVIATIONS AND ACRONYMS

AP Advanced Passive
APWR Advanced Pressurized-Water Reactor
ARRA 2009 American Recovery and Reinvestment Act of 2009
Blue Ridge Blue Ridge EMC
CC combined-cycle
COD commercial operation date
COL construction and operating license
CPCN Certificate of Public Convenience and Necessity
CT combustion turbine
DOE U.S. Department of Energy
DSM demand-side management
Duke Duke Energy Carolinas, LLC
EE energy efficiency
EISPC Eastern Interconnection States Planning Council
EMC electric membership corporation
EnergyUnited EnergyUnited EMC
EPAct 2005 Energy Policy Act of 2005
ESP Early Site Permit
FERC Federal Energy Regulatory Commission
GreenCo GreenCo Solutions, Inc.
GridSouth GridSouth Transco, LLC
G.S. General Statute
GWh gigawatt-hour/s
Halifax Halifax EMC
Haywood Haywood EMC
IOU investor-owned electric utility
IRP integrated resource planning/integrated resource plans
kWh kilowatt-hour/s
MW megawatt/s
MWh megawatt-hour/s
NARUC National Association of Regulatory Utility Commissioners
NC Power Dominion North Carolina Power
NC-RETS North Carolina Renewable Energy Tracking System
NCEMC North Carolina Electric Membership Corporation
NCEMPA North Carolina Eastern Municipal Power Agency

ABBREVIATIONS AND ACRONYMS (continued)

NCMPA1 North Carolina Municipal Power Agency No. 1
NCTPC North Carolina Transmission Planning Collaborative
NERC North American Electric Reliability Corporation
NRC Nuclear Regulatory Commission
OASIS Open Access Same-time Information System
OATT open access transmission tariff
ODEC Old Dominion Electric Cooperative
OPSI Organization of PJM States, Inc.
Piedmont Piedmont EMC
PJM PJM Interconnection, LLC
Progress Progress Energy Carolinas, Inc.
PURPA Public Utility Regulatory Policies Act of 1978
PV photovoltaic
REC renewable energy certificate
REPS Renewable Energy and Energy Efficiency Portfolio Standard
RFP request for proposals
ROE return on equity
RTO regional transmission organization
Rutherford Rutherford EMC
Santee Cooper Public Service Authority of South Carolina
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
TOU time-of-use
TVA Tennessee Valley Authority
VEPCO Virginia Electric and Power Company
VCHEC Virginia City Hybrid Energy Center
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 Carolina Power & Light Company, doing business as Progress Energy Carolinas, 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 16% of the IOUs' 2011 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)	
	2011	2010	2011	2010	2011	2010
Progress	37,353	39,075	12,360	13,704	56,223	59,702
Duke	55,405	57,843	5,213	5,032	82,127	85,443
NC Power	4,177	4,330	914	868	82,325	84,605

*GWh = 1 Million kWh (kilowatthours)

During the 2012 to 2026 timeframe, the average annual growth rate in summer peak demand for electricity in North Carolina is forecasted to be approximately 1.7%. 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 and Demand-Side Management are Included) (2012 – 2026)

	Summer Peak	Winter Peak	Energy Sales
Progress	1.6%	1.8%	1.3%
Duke	1.8%	1.7%	1.8%
NC Power	1.4%	1.6%	1.6%

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. It should be noted that the purchased power listed in the table includes buyback transactions associated with jointly owned coal and nuclear plants.

Table ES-3: Total Energy Resources by Fuel Type for 2011

	Progress	Duke	NC Power
Coal	36%	42%	26%
Nuclear	43%	48%	28%
Net Hydroelectric*	1%	1%	0%
Oil and Natural Gas	13%	1%	12%
Wood/Biomass	0%	0%	1%
Purchased Power	7%	8%	33%

* 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 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.

This report is an update of the Commission's November 30, 2011 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. Much of the material was gathered in Docket No. E-100, Sub 128, Investigation of Integrated Resource Planning in North Carolina – 2010/2011.

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 Carolina Power & Light Company, doing business as Progress Energy Carolinas, 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, 2011, Duke had 1,854,000 customers located in North Carolina, and Progress had 1,279,000. 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 Dominion Virginia Power. About 16% of the IOUs' North Carolina electric sales are to the wholesale market, consisting primarily of electric membership corporations and municipally-owned electric systems.

Based on annual reports submitted to the Commission for the 2011 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)	
	2011	2010	2011	2010	2011	2010
Progress	37,353	39,075	12,360	13,704	56,223	59,702
Duke	55,405	57,843	5,213	5,032	82,127	85,443
NC Power	4,177	4,330	914	868	82,325	84,605

*GWh = 1 Million kWh (kilowatthours)

The Commission does not regulate the retail rates of municipally-owned electric systems or electric membership corporations. However, the Commission does have jurisdiction over the licensing of all new electric generating plants and large scale transmission facilities built in North Carolina. Commission Rule R8-60(b) specifies that the IRP process is 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.

EMCs are independent, non-profit corporations. There are 31 EMCs serving 1,047,000 customers in North Carolina, including 26 that are headquartered in the state. The other five are headquartered in adjacent states. These EMCs serve customers in 95 of the state's 100 counties. Twenty-five of the EMCs are members of NCEMC, an umbrella service organization. NCEMC is a generation and transmission services cooperative that provides wholesale power and other services to its 25 members. NCEMC's peak load growth is projected to be approximately 1.6% per year during the 2012-2026 summer seasons. Load data for NCEMC is shown in Appendix 6.

Six EMCs operating in the state are not members of NCEMC. As noted above, five are incorporated in contiguous states and provide service in limited areas across the border into North Carolina. The sixth is French Broad EMC, which has agreed to provide appropriate information to NCEMC for inclusion in NCEMC's IRP filings.

Since 1980, NCEMC has been a part owner in the baseload Catawba Nuclear Station located in York County, South Carolina. Duke operates and maintains the station, which has been operational since 1985. NCEMC's ownership share consists of 61.51% of Unit 1, approximately 704 megawatts (MW) and 30.754% in the common support facilities of the station. NCEMC's ownership entitlement is guaranteed through a reliability exchange between the Catawba Nuclear Station and Duke's McGuire Nuclear Station located in Mecklenburg County. The reliability exchange results in an effective guaranteed capacity of 681.9 MW. Additionally, Duke may purchase surplus energy generated from NCEMC's portion of the Catawba Nuclear Station. As an alternative, this surplus may be sold on a wholesale basis to a third party.

NCEMC owns and operates 622 MW of combustion turbines (CT) on a site in Anson County and a site in Richmond County (Hamlet CT Plant). These peaking resources operate on natural gas as primary fuel, with diesel storage on-site as a secondary fuel. These units have been in commercial operation since 2007.

On August 25, 2010, NCEMC received a Certificate of Public Convenience and Necessity (CPCN) for a sixth generating unit (56 MW) at the Hamlet CT Plant. NCEMC expects to achieve commercial operation of the sixth generating unit in Spring 2013. The addition of a sixth CT will result in a total Hamlet CT Plant output of 339 MW.

NCEMC also owns and operates two diesel-powered generating stations on the Outer Banks of North Carolina (located on Ocracoke Island and in Buxton). These peaking units, which began commercial operation in 1991, have a combined capacity of 18 MW and are used primarily for peak shaving and voltage support. Also, most EMCs receive an allocation of hydroelectric power from the Southeastern Power Administration (SEPA). NCEMC has no plans to retire any generating units at this time.

Exercising their right to cease full participation in NCEMC's power supply program, five members of NCEMC gave notice that they will be responsible for their future power supply resources. NCEMC refers to these EMCs as Independent Members. Blue Ridge EMC (Blue Ridge), EnergyUnited EMC (EnergyUnited), Piedmont EMC (Piedmont), Rutherford EMC (Rutherford), and Haywood EMC (Haywood) are Independent Members. Under a Wholesale Power Supply Agreement (WPSA), NCEMC is obligated to supply 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 from a third party, or parties.

On December 17, 2007, Blue Ridge EMC entered into a Full Requirements Power Purchase Agreement with Duke. As a result, the Blue Ridge electric load is now included in Duke's IRP. Load data for the other Independent Members is shown in Appendices 7, 8, 9, and 10.

The service territories of NCEMC's member EMCs are located within the control areas of Progress, Duke, 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 purchased power 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. 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, South Carolina Electric & Gas (SCE&G), Southern Power and SEPA. NCEMC and its Independent Member EMCs will continue to ensure system reliability through either purchasing reserves as part of their power supply contracts or procuring the necessary reserves independently.

NCEMC and Progress executed a Tolling Agreement whereby NCEMC will toll the output of NCEMC's Anson facility to Progress from January 1, 2013 through December 31, 2032. Under this agreement, NCEMC owns and maintains the Anson facility for the exclusive use of meeting the joint needs of NCEMC and Progress. Progress will purchase, schedule, and deliver natural gas and fuel oil in order to meet these dispatch requirements. In addition, NCEMC and Southern Power have a baseload sale agreement. Under this agreement NCEMC has agreed to sell 100 MW to Southern Power. This sale started on January 1, 2012 and ends on December 31, 2021.

In addition to the EMCs, there are about 75 municipal and university owned electric distribution systems serving approximately 570,000 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 owns portions of five Progress generating units (about 700 MW of coal and nuclear capacity). NCEMPA also has Supplemental Load Agreements with Progress that run through 2017. These contracts provide for additional power when load requirements exceed the capacity NCEMPA owns.

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, Georgia Power, and SEPA. NCMPA1 also owns 65 MW of diesel-fueled distributed generation located at certain city delivery points, and has contracts for an additional 88 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 gas 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 8,300 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 10 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.

2010 Biennial and 2011 Annual Update IRP Proceedings (Docket No. E-100, Sub 128)

2010 Biennial IRPs and 2011 Annual Update IRPs were filed by the following IOUs: Progress, Duke, NC Power, and the following EMCs: NCEMC, Rutherford, Piedmont, Haywood, and EnergyUnited. In addition, REPS compliance plans were submitted by the IOUs, GreenCo Solutions, Inc. (GreenCo),[1] Halifax EMC (Halifax), and EnergyUnited.

In addition to the Public Staff, the following parties intervened in this docket: the Carolina Industrial Group for Fair Utility Rates I, II, and III; the North Carolina Sustainable Energy Association; the Public Works Commission of the City of Fayetteville; Nucor Steel-Hertford; the North Carolina Waste Awareness & Reduction Network; the Southern Alliance for Clean Energy; and the Carolina Utility Customers

[1] GreenCo filed consolidated REPS compliance plans on behalf of Albemarle EMC, Brunswick EMC, Cape Hatteras EMC, Carteret-Craven EMC, Central EMC, Edgecombe-Martin County EMC, Four County EMC, French Broad EMC, Haywood, Jones-Onslow EMC, Lumbee River EMC, Pee Dee EMC, Piedmont, Pitt & Greene EMC, Randolph EMC, Roanoke EMC, South River EMC, Surry-Yadkin EMC, Tideland EMC, Tri-County EMC, Union EMC, and Wake EMC.

Association, Inc. The intervention of the Attorney General was recognized pursuant to G.S. 62-20.

Public Hearings were held for both the 2010 Biennial IRP and 2011 Annual Update IRP proceedings. The Commission's May 30, 2012 Order approving the 2011 Annual Update IRPs and 2011 REPS compliance plans, which includes the procedural history, can be found in the back of this report as Appendix 1. The October 26, 2011 Order approving the 2010 Biennial IRPs and 2010 REPS compliance plans is included as Appendix 2.

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 3, 4, and 5. 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 and Demand-Side Management are Included) (2012 – 2026)

	Summer Peak	Winter Peak	Energy Sales
Progress	1.6%	1.8%	1.3%
Duke	1.8%	1.7%	1.8%
NC Power	1.4%	1.6%	1.6%

North Carolina utility forecasts of future peak demand growth rates are somewhat higher than forecasts for the nation as a whole. The 2011-2021 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 the period is 1.23%. This number is in line with that shown in NERC's prior year report of 1.27%.

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 2007 (in MW)

	Progress		Duke		NC Power	
	Summer	Winter*	Summer	Winter*	Summer	Winter*
2007	12,656	11,991	18,988	16,460	19,688	17,028
2008	12,290	11,832	18,228	16,968	19,051	17,904
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

**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 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, CTs 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.

An additional source of renewable generation comes from a program called NC GreenPower, which is a voluntary effort that uses financial contributions from North Carolina citizens and businesses to help offset the cost of producing "green energy." This program is discussed in Section 8 of this report.

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 Generating Capacity by Fuel Type (Summer Ratings) for 2011

	Progress	Duke	NC Power
Coal	39%	36%	27%
Nuclear	26%	34%	20%
Hydroelectric	2%	15%	12%
Oil and Natural Gas	33%	15%	40%
Wood/Biomass	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 2011, is provided in Table 5.

Table 5: Total Energy Resources by Fuel Type for 2011

	Progress	Duke	NC Power
Coal	36%	42%	26%
Nuclear	43%	48%	28%
Net Hydroelectric*	1%	1%	0%
Oil and Natural Gas	13%	1%	12%
Wood/Biomass	0%	0%	1%
Purchased Power	7%	8%	33%

* See the paragraph on pumped storage in this section.

The purchased power amounts shown above include buyback transactions associated with jointly owned coal and nuclear plants.

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 2012, Progress had 12,958 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.

The Company’s 2012 resource plan proposes to add 4,722 MW of new capacity during the 2013-2027 period. This includes 920 MW of combined-cycle (CC) natural gas generation at the Company’s Wayne County facility scheduled to go into service in January, 2013, and 625 MW of CC generation at the Sutton Plant with an expected in-service date of December, 2013. Incremental nuclear baseload additions totaling 550 MW, through regional partnerships, is shown in the 2017/2023 timeframe. In addition, approximately 100 MW of planned uprates to existing facilities are projected through 2015.

Progress is currently in the process of retiring a number of existing coal units. It retired its coal-fired Weatherspoon facility, located near Lumberton, on October 1, 2011, the first retirement under the utility’s fleet-modernization plan. Progress then officially closed its Lee coal plant, located near Goldsboro, on September 15, 2012.

The Cape Fear Plant near Moncure, and the Robinson coal-fired unit near Hartsville, South Carolina, were retired on October 1, 2012. The Sutton Plant, located near Wilmington, is scheduled to close in late 2013. Once these retirements are complete, the utility will have retired all of its coal-fired units that do not have advanced environmental controls.

These retirements represent more than 1,600 MW, or approximately one-third of the utility's coal-generating fleet. The utility will replace the retiring coal-fueled generating capacity with CC plants fueled by natural gas.

The 2012 resource plan continues to contemplate the potential for regional partnerships rather than full ownership of a nuclear facility. For long range planning purposes, Progress assumed that shares of undesignated nuclear facilities would be available in the marketplace. This generation could come from partnerships in self-build nuclear facilities or from a partnership in another utility's regional nuclear project. Under this regional assumption, nuclear projects would be jointly undertaken by utilities in the region with participating utilities and load serving organizations taking ownership stakes in each others' projects. At this point in time, no specific plans for such partnerships have been entered into and the nuclear blocks totaling 550 MW that are shown in its resource plan simply represent undesignated baseload generation for planning purposes.

Progress had previously announced that it was pursuing development of a combined construction and operating license (COL) application to potentially construct new nuclear facilities. That announcement was not a commitment to build a nuclear unit, but a necessary step to keep open the option of building such a unit or units. In January 2006, Progress announced that it had selected a site at the existing Harris Plant to evaluate for possible future nuclear expansion. It selected the Westinghouse Advanced Passive (AP) 1000 reactor design as the technology upon which to base its application. In February 2008, Progress submitted its COL application to the NRC for the construction of two additional reactors at the Harris site. If Progress receives COL approval from the NRC and applicable state agency approvals, and if the decisions to build are made, Progress stated that a new plant would not be online prior to 2027. At this time, though, no definitive decision has been made to construct new nuclear facilities.

Duke Generation

As of September 2012, Duke had 21,030 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 has reported the following known or anticipated changes to its existing company-owned generation resources:

New Cliffside Pulverized Coal Unit

The 825 MW Cliffside Unit 6 pulverized coal unit is expected to operate at 50-100% output for systems and equipment guarantee testing through the summer of 2012. The unit is expected to be declared commercial in December of 2012.

Bridgewater Hydro Powerhouse Upgrade

Bridgewater Hydro Station generating upgrades were operational November 2011. The previous generating units were replaced by two 15 MW units and a small 1.5 MW unit representing an 8.5 MW increase in station capability. The new generating units will be used to meet continuous release requirements and system peak.

Buck CC Natural Gas Unit

The new Buck CC unit was operational November 2011. The 620 MW CC generating station utilizes state-of-the-art environmental control technology to minimize plant emissions.

Dan River CC Natural Gas Unit

The 620 MW Dan River CC unit is scheduled to be operational by the end of 2012.

Lee Steam Station Natural Gas Conversion

The Lee Steam Station was originally designed to generate with natural gas or coal as a fuel source. Switching fuel sources from coal to natural gas could prove to be an economic solution to avoid adding costly pollution control equipment or replacing the 370 MW of capacity with a more costly alternative. Previous plans were for conversion of all three Lee units to natural gas. However upon further evaluation, for IRP planning purposes, Lee Units 1 and 2 will be retired as coal units with no plans for conversion to natural gas in 2015. Lee Unit 3 is assumed to be retired as a coal unit in the fourth quarter of 2014 and converted to natural gas by January 1, 2015. Preliminary engineering and analysis has been completed. Detailed project development and regulatory efforts began in 2011, and will continue into 2012.

In addition, during the 2013-2027 timeframe, Duke is projecting the possible need for 800 MW of new CT generation in 2019, as well as 700 MW of new CC capacity in both 2016 and 2018. It is also considering nuclear uprates of 111 MW from 2013 to 2015, plus the possible addition of 2,234 MW of new nuclear capacity as discussed below.

Duke currently forecasts the retirement of up to 1,080 MW of additional existing coal-fired capacity in 2015. This retirement forecast is used by Duke for planning purposes rather than as firm commitments concerning specific units to be retired and/or their exact retirement dates. The conditions of the units are evaluated annually and decision dates are revised as appropriate. Duke will develop orderly retirement plans that consider the implementation, evaluation, and achievement of energy efficiency goals, system reliability considerations, long-term generation maintenance and capital spending plans, workforce allocations, long-term contracts including fuel supply and contractors, long-term transmission planning, and major site retirement activities.

In 2005, Duke began work to pursue additional nuclear capacity. The Westinghouse AP 1000 reactor technology was selected after an extensive review of multiple technologies, and a contractor was chosen to assist Duke with application preparation. In 2006, a site in Cherokee County, South Carolina, was selected for the project.

The Company submitted an application for a COL and an environmental report to the NRC on December 12, 2007. A supplement to the environmental report was filed September 24, 2009. The NRC issued its Draft Environmental Impact Statement for the William States Lee III Nuclear Plant in December 2011.

Duke plans to continue to support the NRC evaluation of the COL. In March of 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 that Duke update the Lee plant site-specific seismic analysis. This request impacted the schedule for NRC issuance of the Lee Combined Operating License, moving the projected Commercial Operation Date (COD) beyond the summer peak of 2021. Accordingly, Duke has moved the COD for the Lee Nuclear Unit 1 to 2022.

The Company continues to evaluate the optimal time to file the CPCN in South Carolina, as well as pursue other relevant regulatory approvals. Duke will continue to pursue available federal, state and local tax incentives and favorable financing options at the federal and state level.

Duke's analysis continues to affirm the potential benefits of new nuclear capacity in a carbon-constrained future. The Company's analysis considered a portfolio based on full ownership of the 2,234 MW Lee Nuclear Station by the summer of 2022 and 2024, as well as a portfolio that reflects regional nuclear generation equivalent to the MW associated with Lee Nuclear Station distributed over 2017 to 2028. Regional nuclear is where two or more partners plan collaboratively to stage multiple nuclear stations over a period of years and each partner would own a portion of each station. The regional nuclear portfolio is illustrative of the potential value to customers of a representative regional nuclear generation plan. Duke continues to strongly support regional nuclear opportunities and is actively pursuing this concept. As the Company announced in 2011, Duke has agreements with JEA, located in Jacksonville, Florida, and with the Public Service Authority of South Carolina (Santee Cooper). Duke has an agreement with Santee Cooper to perform due diligence and potentially acquire an option for a minority interest (5 to 10% of the capacity of two units) in Santee Cooper's 45% ownership of the planned new nuclear reactors at V.C. Summer Nuclear Generating Station in South Carolina. The new Summer units are scheduled to be online in 2017 and 2018. JEA has signed an option agreement to potentially purchase up to 20% of Lee Nuclear Station.

The Company's analysis indicates that the regional nuclear portfolio is lower cost to customers in the base case and in most scenarios. However, the full nuclear portfolio was chosen for the 2012 IRP preferred plan because there are no firm commitments in place at this time for the regional nuclear portfolio. Although the regional nuclear portfolio assumes

10% of the Summer station is purchased, the Company's decision on whether and how much to purchase will be based on many factors, including the results of the due diligence related to Summer, the capacity need at the time of the decision, and the financial implications of the purchase on the Company. Duke will continue to assess opportunities to benefit from economies of scale and risk reduction in new resource decisions by considering the prospects for joint ownership and/or sales agreements for new nuclear generation resources.

NC Power / VEPCO Generation

As of September 2012, NC Power had 17,603 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.

On July 10, 2012, Virginia City Hybrid Energy Center (VCHEC) located in Wise County, Virginia, came into service. Construction first began on this 585 MW clean coal unit in June 2008. VCHEC provides baseload capacity and energy to the Company's service territory. VCHEC's advanced design allows the plant to consume up to 20% biomass fuel such as wood waste and wood byproducts, which are renewable fuel resources. The Company plans to gradually increase VCHEC's consumption level of renewable fuel to 10% by 2020.

To meet expected load growth, the Company filed for a CPCN with the State Corporation Commission of Virginia (SCC) to construct and operate the Warren County Power Station, a 1,337 MW CC facility located in Warren County, Virginia. On February 27, 2012, the Company officially began construction of the station. The station will generate enough electricity for more than 300,000 homes at peak demand, which is critical to the Company's strategy to meet the growing need for electricity. The station is targeted for commercial operation by 2015.

In addition, the SCC granted approval to convert the Altavista, Hopewell and Southampton Power Stations from coal to biomass on March 16, 2012. Each baseload unit has a capacity of 51 MW. The three similar power stations went into operation in 1992. Conversion of these stations is expected to result in overall reductions of SO_2, NO_x, and particulate emissions. The conversions are projected to increase the capacity factors of these units, and provide economical baseload energy and environmental benefits to the Commonwealth of Virginia over the next 25 years. Construction of the Altavista conversion started on May 29, 2012. The repowered stations are expected to be fully operational as biomass units by the end of 2013. In addition, the Company has plans to repower two coal-fired units at its Bremo facility (227 MW) from coal to natural gas by 2014.

On February 28, 2012, the Company announced its plans to construct a new generating facility in Brunswick County, Virginia, which will be a highly efficient CC similar in design to the Company's Warren County Power Station. The Company expects to apply for a CPCN with the SCC later this year for approval to build the station. The

Brunswick County Power Station would have a generating capacity of more than 1,375 MW and could produce enough electricity to power over 300,000 homes. Based on the Company's current schedule; this plant will be available to meet 2016 peak capacity and energy demand.

On November 27, 2007, the NRC issued an Early Site Permit (ESP) to the Company's affiliate, Dominion Nuclear North Anna, LLC, for a site located at the Company's existing North Anna Power Station for a third unit. Also on November 27, 2007, the Company and Old Dominion Electric Cooperative (ODEC) filed an application with the NRC for a COL to build and operate a new nuclear reactor. On October 31, 2008, the NRC approved the transfer of the ESP to the Company and ODEC. The merger of Dominion Nuclear North Anna, LLC into the Company became effective on December 1, 2008.

In March 2009, the Company issued a Request for Proposals (RFP) to license, engineer, procure, and construct a third nuclear unit at the North Anna Power Station. The Company selected Mitsubishi Heavy Industry's United States Advanced Pressurized-Water Reactor (APWR) for the design of the planned nuclear unit, although no EPC contract has been signed to date. The Company filed its amended COL on June 30, 2010, with the NRC referencing the Mitsubishi technology for North Anna 3. In February 2011, ODEC informed the Company of its intent to no longer participate in the development of North Anna 3.

In April 2012, the Virginia State Water Control Board unanimously approved a permit to allow the planned North Anna 3 unit to withdraw water from Lake Anna to operate a new reactor at North Anna Power Station in Louisa County. The Company currently estimates that the NRC would be positioned to issue design certification during 2015 and that the North Anna 3 COL approval would then occur later in 2015.

To date, the Company has not committed to build North Anna 3 and does not expect it to be operational before 2024 if it does. The Company however intends to maintain the option for development of North Anna 3 for several key reasons.

a) North Anna 3 will provide 1,453 MW of much needed baseload capacity (summer rating) to the region in the latter portion of the Planning Period while enhancing system reliability;

b) Nuclear power is nearly emission-free, emitting little to no greenhouse gases;

c) North Anna 3 will assist with fuel diversity within the Company's generation portfolio, which in turn, promotes fuel price stability for customers; and

d) Nuclear power is the lowest cost fully dispatchable (non-gas) baseload generating option.

NC Power is currently forecasting the retirement of 918 MW of coal-fired generation at its Chesapeake Energy Center and Yorktown facility by 2015. It also has plans to retire additional CT generation through 2018. Prior to the actual retirement of any older coal and CT units, the condition and economics of these units will be evaluated by NC Power and the unit retirement dates may be revised**.**

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 provides 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.

In earlier years, 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 3, 4, and 5. The summer reserve margins currently projected by each IOU are illustrated in Table 6.

Table 6: Projected Summer Reserve Margins for Progress, Duke, and NC Power (2012-2026)

	Reserve Margins
Progress	14.0% – 27.0%
Duke	16.4% – 24.3%
NC Power	11.0% – 17.3%

While coal and nuclear continue to remain the most widely used fuels in our area, many of the generation facilities constructed in recent years use natural gas as their primary fuel, particularly for generators designed to provide intermediate and peaking capability, and recently, because of significantly lower natural gas prices. With relatively 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 Transco Gas Pipeline for its natural gas requirements.

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 come from solar energy resources. Additional requirements are effective in 2012 and subsequent years.

On September 27, 2012, the Commission submitted its fourth 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. In addition, on September 28, 2011, the Commission filed its second biennial report to the same entities regarding cost allocations as required by Senate Bill 3. That report discusses allocations of utility costs for renewable energy, demand-side management/energy efficiency, and fuel and fuel related charges. Both reports are 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 an RFP via which it selected a vendor, NYSE Blue, 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 information regarding REPS activities and NC-RETS account holders. NC-RETS also provides an electronic bulletin board where RECs can be offered for purchase.

As of October 26, 2012, NC-RETS had issued 8,273,500 renewable energy certificates and 1,504,390 energy efficiency certificates. In addition, 4,267,397 renewable energy certificates had been imported into NC-RETS accounts. (These certificates were issued by registries located outside of North Carolina.) About 255 organizations, including electric power suppliers and owners of renewable energy facilities, have established accounts in NC-RETS. About 468 renewable energy facilities participate as "projects" in NC-RETS, which means that NC-RETS issues renewable energy certificates to the facility owners based on the facilities' energy output.

<u>2010 and 2011 REPS Compliance</u>

For 2010 and 2011, each electric power supplier was subject to a .02% of retail sales REPS obligation. 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.

On August 23, 2011, the Commission approved 2010 REPS compliance for Duke, Blue Ridge, the City of Concord, the Town of Dallas, the Town of Forest City, the City of Highlands, the City of Kings Mountain and Rutherford. On November 10, 2011, the Commission approved 2010 REPS compliance for Progress, and the towns of Waynesville, Black Creek, Lucama, Sharpsburg and Stantonsburg. On December 15, 2011, the Commission approved 2010 REPS compliance for NC Power and the Town of Windsor. On May 14, 2012, the Commission approved 2010 REPS compliance for EnergyUnited, Fayetteville Public Works Commission, GreenCo, NCEMPA, NCMPA1, TVA (which complied on behalf of Tri-State EMC, Mountain EMC, Blue Ridge Mountain, and Murphy Electric Power Board), Halifax, the Town of Enfield and the Town of Fountain. All North Carolina electric power suppliers met their 2010 REPS obligation.

On August 15, 2012, the Commission approved 2011 REPS compliance for Duke, Blue Ridge, the City of Concord, the Town of Dallas, the Town of Forest City, the City of Highlands, the City of Kings Mountain and Rutherford.

On September 6, 2012, the Commission scheduled a hearing to be held on November 20, 2012, regarding the 2011 REPS compliance of NC Power and the Town of Windsor.

On September 18, 2012, the Commission held a hearing regarding the 2011 REPS compliance of Progress and the towns of Waynesville, Black Creek, Lucama, Sharpsburg and Stantonsburg. That matter remains pending before the Commission.

On September 28, 2012, the Commission issued an order requesting that the Public Staff review and file comments by December 7, 2012, regarding the 2011 REPS compliance of EnergyUnited, Fayetteville Public Works Commission, GreenCo, NCEMPA, NCMPA1, TVA (which filed on behalf of Tri-State EMC, Mountain EMC, Blue Ridge Mountain EMC, and Murphy Electric Power Board), Halifax (including the Town of Enfield), Oak City, and the towns of Fountain and Winterville.

<u>2012 REPS Compliance</u>

Starting in 2012, North Carolina's electric power suppliers are subject to an increased solar obligation of .07% of retail sales. In addition, starting in 2012 they are subject to: 1) a general REPS obligation of 3% of retail sales; 2) a swine waste resource obligation of .07% of retail sales, and 3) their pro-rata share of a 170,000 megawatt-hour statewide aggregated poultry waste resource obligation.

On May 16, 2012, the Commission issued an Order requiring all electric power suppliers to submit updates regarding their plans for meeting the 2012 swine and poultry waste REPS obligation. That Order stated that the REPS compliance plans that had been filed in 2011, and the Public Staff's comments regarding those plans, called into question whether the electric power suppliers would meet their 2012 swine and poultry waste resource obligations. Subsequently, the electric power suppliers requested that their 2012 and 2013 swine and poultry waste obligations be delayed by two years. The Commission held an evidentiary hearing in the matter on August 28 and 29, 2012, and this matter is pending before the Commission.

Energy Efficiency

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

On September 1, 2011, the Commission filed its second 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. All of the money is then simply passed over to NC GreenPower. Renewable energy funds are used to pay approved generators across the state for each kilowatt hour 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 N.C. jobs.

As of October 2012, NC GreenPower has agreements with 623 renewable energy generators, including 598 small solar photovoltaic (PV), 15 large solar PV, two small hydroelectric facilities, five wind facilities (down from nine in 2011), and three landfill methane facilities.

June 2012 reporting to the NC GreenPower Board of Directors showed a total of 11,366 North Carolina electric consumers are subscribed to the program. An estimated 22,557 100-kWh blocks of power per month – representing 27,068,014 kWh of renewable energy - is delivered to the electric grid in North Carolina in a year, which is enough to power about 2,000 homes. The Carbon Offset product had 415 customers subscribed to 993 blocks of greenhouse gas mitigation (1,000 pounds each), representing a total offset of 993,000 pounds of carbon dioxide equivalent per year. Annually, these donations are the environmental equivalent of planting 5,249,412 trees.

9. TRANSMISSION AND GENERATION INTERCONNECTION ISSUES

Transmission Planning

The North Carolina Transmission Planning Collaborative (NCTPC) was established in 2005. Participants (transmission-owning utilities, such as Duke and Progress, and transmission-dependent utilities, such as municipal electric systems and EMCs) identify the electric transmission projects that are needed to be built for reliability and estimate the costs of those upgrades. The NCTPC's January 2012 report stated that 11 major transmission projects are needed in North Carolina by the end of 2021 at an estimated cost of $296 million.

The NCTPC's report also provided the results of transmission studies regarding various hypothetical future scenarios: 1) the impact of 5,000 MW of renewable wind generation located off of the North Carolina coast; 2) the impact of 14 different power transfers, ranging in size from 600 to 1,200 MW, across the Duke and Progress boundaries with neighboring utilities; and 3) the impact of 1,000 MW of new generation located near Duke's existing Buck plant. The complete report is available at http://www.nctpc.net/nctpc/home.jsp .

Pursuant to G.S. 62-101, a certificate of environmental compatibility and public convenience and necessity from the Commission is needed before building a transmission line of 161 kilovolts or more in size. On March 31, 2010, the Citizens to Protect Kituwah Valley and Swain County jointly filed a complaint against Duke. The complaint asserted that Duke should have been required to obtain such a certificate prior to upgrading an existing single circuit 66-kV transmission line to a double circuit 161-kV transmission line in the same location. On April 13, 2011, the Commission issued an order finding that Duke was not required to obtain a CPCN prior to building a tie station or upgrading the related transmission line. However, the Commission scheduled a hearing on the issue of whether Duke acted in a reasonable and appropriate manner in its siting and construction of the transmission line. The hearing was held August 2, 2011, in Bryson City. On December 28, 2011, the Commission issued an Order Ruling on Complaint in which it found that Duke had not acted unreasonably and inappropriately in its decisions and actions concerning the upgrade of the Wests Mill Transmission Line.

In addition to their work within the NCTPC, Duke and Progress are part of an inter-regional transmission planning initiative called the Southeast Interregional Participation Process. This effort allows a transmission customer, such as a municipal utility, to request a study of the transmission that would be required to be built to facilitate a hypothetical request to transport electric power across multiple regional planning areas. Other participating utilities include Alabama Electric Cooperative, Santee Cooper, Dalton Utilities, SCE&G, South Mississippi Electric Power Association, Entergy, Georgia Transmission Corporation, the Southern Companies, Municipal Electric Authority of Georgia, TVA, and E.ON U.S.

On February 16, 2007, the Federal Energy Regulatory Commission (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 North Carolina Transmission Planning Collaborative as their mechanism and forum for assuring open transparent planning with opportunity for involvement by stakeholders. In order to address the FERC's requirements relative to inter-regional coordination, Duke and Progress cited their participation in the Southeast Interregional Participation Process. The FERC issued its order on September 18, 2008, finding the geographic scope of Duke and Progress's joint regional planning to be sufficient, but ordering Duke and Progress to file numerous modifications within 90 days, including a methodology for allocating transmission construction costs for projects that involve multiple utilities.

In 2010 a new organization was created to focus on electric transmission planning on an even larger scale, at the "interconnection wide" level. The United States has three electric interconnections. North Carolina is part of the eastern interconnection, which is the region east of the Rocky Mountains, minus most of Texas. Largely due to increased interest in renewable energy development, the federal government launched an effort to develop coordinated, long-term transmission expansion plans on an interconnection-wide basis. This effort received funding in 2009 via the American Recovery and Reinvestment Act of 2009 (ARRA 2009). Pursuant to ARRA 2009, the U.S. Department of Energy (DOE) offered grants for transmission planning, including funds for "Cooperation Among States on Electric Resource Planning and Priorities." The National Association of Regulatory Utility Commissioners (NARUC) worked with all of the states in the eastern interconnection to develop and submit a DOE funding request, which was approved in 2010. Under the NARUC proposal, a new entity was established, the Eastern Interconnection States Planning Council (EISPC). Each of the 39 states in the eastern interconnection, as well as Washington, D.C., participates in the EISPC. North Carolina is represented by the Chairman of the Utilities Commission and the Assistant Secretary of Energy (Department of Commerce). The grant funds a small staff and meetings and research to assist the states in reaching consensus regarding studies to be conducted regarding future sources of electric energy, and by extension, the new electric transmission infrastructure needed to move that energy to consumers. In 2011, the effort focused on the development and prioritization of future scenarios. In 2012, the high-priority scenarios were studied further, and EISPC is expected to issue a report in early 2013 estimating their total cost and the electric transmission that would be needed under each.

In 2010, FERC opened a rulemaking regarding how to allocate the costs of large transmission projects in order to encourage development of renewable energy. The Commission and the Public Staff intervened in the proceeding, representing North Carolina electricity consumers. On July 21, 2011, the FERC issued a final rule entitled "Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities," also known as "Order 1000. [2]" The Utilities Commission and the Public Staff jointly filed a request for rehearing, arguing that the rule infringes on state jurisdiction by mandating regional and inter-regional transmission planning processes and cost allocation methods. North Carolina's rehearing request is pending before FERC.

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 amend their federal OATTs to establish criteria and procedures for considering regional transmission projects[3] that would be sponsored, built and owned by non-incumbent transmission owners.[4] FERC's Order No. 1000 required that transmission operators file such tariff amendments by October 11, 2012.[5] North Carolina's three public utility transmission owners, specifically Duke, Progress, and NC Power are subject to Order No. 1000 (although NC Power's compliance will be via its regional transmission operator, PJM Interconnection, Inc. (PJM)).

On October 11, 2012, the Commission issued a report to the Governor and the General Assembly regarding this issue.[6] The Commission's report found that North Carolina law does not appear to preclude construction and ownership of electric transmission facilities by a non-incumbent transmission owner. Both the siting statutes (G.S. 62-100 thru 107) and the eminent domain statutes (G.S. 40A) allow essentially any person or organization to build and own an electric transmission line in North Carolina. Such construction and ownership is not limited to traditional franchised electric public utilities, municipal electric suppliers, or electric membership corporations.

Today, most electric transmission lines in North Carolina are owned and operated by Duke and Progress, with a much smaller percent owned by NC Power.[7] These three organizations are franchised electric public utilities and are fully regulated by the Commission. That is, the Commission has statutory authority over the rates they

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[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 filing by Duke and Progress was made on October 11, 2012, and is pending before the FERC in Docket No. ER13-83.

[6] The report is filed in Docket No. E-100, Sub 132.

[7] In addition, some independent electric generating facilities own short spans of electric transmission facilities that provide inter-connection to the electric transmission system.

charge customers and over the quality of service that they provide North Carolina's citizens and businesses. Simply put, in return for having monopoly retail franchises, these three electric transmission owners are obligated to provide reliable electric service, and the Commission has statutory authority to compel service improvements should they be necessary.

In contrast, the Commission's jurisdiction over non-incumbent transmission owners is limited to Chapter 62, Article 5A (Siting of Transmission Lines). Electric transmission ownership by non-incumbent developers would present new kinds of risks for North Carolina's electric customers, and the Commission's investigation concluded that it may not have the statutory authority to fully address these risks. Therefore, the Commission recommended that the General Assembly and the Governor address the issues raised by non-incumbent transmission development via legislation.

The Commission's investigation found that electric transmission ownership by non-incumbent transmission developers presents the following risks for the State's electricity consumers:

(1) The risk that electric customers will 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 has been granting relatively high ROEs in order to reward transmission construction. Under the filed-rate doctrine,[8] 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.

(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 has recouped its investment and no longer has any 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."

(3) The risk that a non-incumbent developer would build a transmission project in a substandard or inherently unreliable 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

[8] 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.

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 will encourage non-incumbent transmission development, and thereby increase the occurrence of the risks outlined above.

Because of the risks posed to electric customers by the ownership of electric transmission facilities by non-incumbent developers, the Commission recommends that the Governor and the General Assembly pursue statutory changes that would either:

(a) preclude transmission construction and ownership by non-incumbent transmission owners; or

(b) give the Commission additional jurisdiction to regulate the service quality and emergency operations of non-incumbent transmission owners.

On October 11, 2012, Duke and Progress jointly submitted an Order No. 1000 compliance filing to FERC, in Docket No. ER13-83. That submission included proposed revisions to the utilities' OATTs that would (1) allow for third party ownership of regional transmission projects (as discussed above), (2) provide for the express consideration of "public policies" in the transmission planning process, and (3) provide that the costs of regional transmission projects would be allocated between the two companies based on the avoided cost of local transmission projects.

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 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.

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 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.

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.

Subsequently, Duke received approval from the FERC to engage an independent entity to administer its OATT. Starting in January 2007, the Midwest ISO began acting as Duke's independent entity. In that role, the Midwest ISO evaluates and approves transmission service requests; calculates the amount of transmission that is available for third party use; operates and administers Duke's OASIS; and evaluates, processes, and approves generation interconnection requests and coordinates transmission planning. In addition, Duke has retained Potomac Economics to act as its independent market monitor. Duke forwards Potomac Economics' quarterly reports to the Commission.

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 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, which remains pending before the FERC.

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 have focused especially on two compliance areas that have been implicated in large regional bulk power system outages: (1) the 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 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, which includes soliciting public comments, publishing a draft study with a 60-day comment period, and publishing a final report. DOE is expected to release the draft 2012 congestion study for comment sometime in late 2012. An August 2012 presentation of DOE's preliminary findings stated that "data about transmission usage and congestion in the Southeast are too thin to support meaningful conclusions."

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 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 incentive proceedings before the FERC in order to protect the interests of North Carolina consumers.

Cyber Security

Federal regulators are increasingly concerned about cyber security 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.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 128

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In The Matter of Investigation of Integrated Resource Planning in North Carolina – 2010 - 2011	)))	ORDER APPROVING 2011 ANNUAL UPDATES TO 2010 BIENNIAL INTEGRATED RESOURCE PLANS AND 2011 REPS COMPLIANCE PLANS

HEARD: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on Tuesday, January 17, 2012, at 7 p.m.

BEFORE: Commissioner William T. Culpepper, III, Presiding; Chairman Edward S. Finley, Jr.; and Commissioners Bryan E. Beatty; Susan W. Rabon; ToNola D. Brown-Bland; and Lucy T. Allen

APPEARANCES:

For Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc.:

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

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For North Carolina Electric Membership Corporation and GreenCo Solutions, Inc.:

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For North Carolina Sustainable Energy Association:

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For the Using and Consuming Public:

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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 ratepayers consistent with 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.

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). G.S. 62-110.1 further requires the Commission to consider this analysis in acting upon any petition for construction. 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: (1) a report of the Commission's analysis and plan; (2) the progress to date in carrying out such plan; and (3) the program of the Commission for the ensuing year in connection with such plan. G.S. 62-15(d) requires the Public Staff to assist the Commission in this analysis and plan.

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....

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' IRP. Commission Rule R8-60 requires that each of the investor-owned utilities, the North Carolina Electric Membership Corporation, and any individual electric membership corporation to the extent that it is responsible for procurement of any or all of its individual power supply resources (hereinafter, collectively, the electric utilities) furnish the Commission with a biennial report in even-numbered years that contains the specific information set out in that Rule. 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 Renewable Energy and Energy Efficiency Portfolio Standard (REPS) compliance plan as part of its IRP report. Within 150 days after the filing of each electric utility's biennial report, and within 60 days after the filing of each electric utility's annual report, the Public Staff or any other intervenor may file its own plan or an evaluation of, or comments on, the electric utilities' IRP reports. Furthermore, the Public Staff or any other intervenor may identify any issue that it believes should be the subject of an evidentiary hearing.

2011 ANNUAL REPORTS

This Order addresses the 2011 updates to the 2010 biennial reports (2011 IRPs) filed by the following investor-owned utilities (IOUs): Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc. (Progress); Duke Energy Carolinas, LLC (Duke); Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (NC Power); and the following electric membership corporations (EMCs): North Carolina Electric Membership Corporation (NCEMC),[1] Rutherford EMC (Rutherford), Piedmont EMC (Piedmont), Haywood EMC (Haywood), and EnergyUnited EMC (EnergyUnited).[2] In addition, this Order addresses the REPS compliance plans filed by the IOUs, GreenCo Solutions, Inc. (GreenCo),[3] Halifax EMC (Halifax), and EnergyUnited.

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[1] NCEMC indicated that it provides wholesale power to 25 of the 26 EMCs in North Carolina and is the full requirements power supplier for 20 of the cooperatives. NCEMC's 2011 IRP is filed on behalf of these 20 members. NCEMC provides partial requirements capacity and energy entitlements to 5 EMCs: Blue Ridge EMC, Rutherford EMC, Piedmont EMC, Haywood EMC, and EnergyUnited EMC (collectively, the independent EMCs). The 26th EMC, French Broad EMC, is not a member of NCEMC and is not required to file an individual IRP, as it has entered into a full requirements contract with Progress.

[2] Blue Ridge EMC contracts with Duke as its full requirements and REPS compliance service provider. Blue Ridge EMC, therefore, is not required to file an IRP.

[3] GreenCo filed a consolidated 2011 REPS compliance plan on behalf of Albemarle EMC, Brunswick EMC, Cape Hatteras EMC, Carteret-Craven EMC, Central EMC, Edgecombe-Martin County EMC, Four County EMC, French Broad EMC, Haywood, Jones-Onslow EMC, Lumbee River EMC, Pee Dee EMC, Piedmont, Pitt & Greene EMC, Randolph EMC, Roanoke EMC, South River EMC, Surry-Yadkin EMC, Tideland EMC, Tri-County EMC, Union EMC, and Wake EMC.

In addition to the Public Staff, the following parties have intervened in this docket: Carolina Industrial Group for Fair Utility Rates I, II, and III (CIGFUR); North Carolina Sustainable Energy Association (NCSEA); Public Works Commission of the City of Fayetteville (Fayetteville); Nucor Steel-Hertford (Nucor); North Carolina Waste Awareness & Reduction Network (NC WARN); Southern Alliance for Clean Energy (SACE); and Carolina Utility Customers Association, Inc. (CUCA). The intervention of the Attorney General is recognized pursuant to G.S. 62-20.

On March 3, 2011, Blue Ridge EMC (Blue Ridge) filed comments indicating that it had a long-term power supply agreement with Duke, its load would be reported for filing purposes within Duke's IRP, its renewable energy requirements for REPS compliance would be provided by Duke, and its REPS requirements would be reflected in Duke's 2011 REPS compliance plan. On August 17, 2011, Rutherford filed a letter indicating that its load would be included in Duke's IRP filing for reporting purposes, and its REPS compliance would be reflected in Duke's REPS compliance plan. On August 24, 2011, NCEMC and GreenCo filed a joint motion to extend the filing date for submission of their 2011 IRP and 2011 REPS compliance plan to September 19, 2011. The Commission granted the requested extensions by Order dated August 31, 2011.

On August 30, 2011, EnergyUnited filed its 2011 IRP and 2011 REPS compliance plan and Haywood filed its 2011 IRP. On August 31, 2011, Rutherford filed its 2011 IRP. On September 1, 2011, Duke, Progress, and NC Power filed their 2011 IRPs and 2011 REPS compliance plans, Halifax filed its 2011 REPS compliance plan, and Piedmont filed its 2011 IRP. On September 19, 2011, NCEMC filed its 2011 IRP and GreenCo filed its 2011 REPS compliance plan.

On October 7, 2011, NC WARN submitted its comments on the 2011 IRPs.

On October 20, 2011, the Public Staff filed a motion requesting that the deadline for the filing of comments on the 2011 IRPs be extended to January 13, 2012, which the Commission granted by Order dated October 25, 2011. This order also extended the deadline for reply comments to January 27, 2012.

On January 13, 2012, comments were submitted by SACE, NCSEA, and the Public Staff. On January 27, 2012, reply comments were submitted by Progress, Duke, and NC Power. Also, on January 27, 2012, Rutherford submitted a response to a Public Staff comment regarding Rutherford's new smart meter program.

PUBLIC HEARING

Pursuant to G.S. 62-110.1(c), the Commission scheduled and held a public hearing in this docket on Tuesday, January 17, 2012, solely for the purpose of taking nonexpert public witness testimony regarding the filed 2011 IRPs and 2011 REPS compliance plans. Three public witnesses spoke at the hearing, including the North Carolina field organizer for Greenpeace. The witnesses discussed the impacts that coal plants have on people's lives and the opportunity for increased usage of alternative resources, such as wind and solar energy and energy efficiency (EE), as well as the threat of climate change. One witness asked the Commission to consider different types of business models that might be used as coal plants are retired, including some that might encourage more use of solar energy and other cleaner types of technology.

INTERVENOR ISSUES

As the 2011 IRPs are in fact updates to the 2010 biennial IRPs, this Order will not repeat the basic analysis of the means and methods used by the utilities in developing their overall IRP processes which were approved in the most recent Order. This Order notes the issues raised by the parties, but does not reanalyze those issues that were previously decided by the Commission in this biennial proceeding.

NC WARN

In its comments, NC WARN brought up the following issues in regard to the 2011 IRPs submitted by Duke and Progress:

1) Both Duke and Progress have significantly overestimated the need for baseload power plants over the IRP planning horizon.

2) At the same time, reliance on new nuclear plants and large existing coal plants is environmentally harmful and ruining crucial climate protection efforts.

3) The 2011 IRPs of Duke and Progress do not reflect even the minimum EE and renewable energy requirements in the REPS.

These issues have been addressed by the Commission in this docket in its Order Approving the 2010 Biennial IRPs, issued on October 26, 2011, and need not be addressed again here. The Public Staff in its comments stated that, while NC WARN maintained that the growth projections by Duke and Progress are overly optimistic, the growth rates cited by NC WARN for Duke and Progress appear to relate only to the retail sales class and exclude any wholesale sales. Also, according to the Public Staff, the issues that relate to generation planning for a utility's retail native load customers and its historically served wholesale customers have been litigated and resolved in Docket Nos. E-100, Sub 85A[4] and E-7, Sub 858.[5] The growth rates for Duke and Progress are very similar to growth rates in recent IRPs approved by the Commission, and the Public Staff believes they are reasonable for planning in this proceeding.

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[4] Investigation of the Priority of Electric Service Provided to Off-System Loads Versus Native Retail Loads.

[5] Joint Petition with City of Orangeburg, SC for Declaratory Ruling with Respect to Rate Treatment of Wholesale Sales of Electric Power at Native Load Priority.

The Public Staff also noted that, in its comments, NC WARN contends that Duke's and Progress's IRPs use unrealistically low construction costs for planned nuclear plants. The Public Staff has reviewed the inputs and forecasts in the models used for planning by the utilities and believes that these inputs and forecasts are reasonable for planning purposes.

Regarding NC WARN's issues related to REPS requirements, the Public Staff observed that, in its comments, NC WARN expressed concern that certain graphs in the IRPs of Duke and Progress indicate that these utilities do not in fact plan to meet their general REPS requirements. The graphs, which appear on page 90 of Duke's IRP and page 28 of Progress's IRP, are in the form of pie charts, showing the percentages of generation that will come from various sources in 2012 for each utility, in 2031 for Duke, and in 2026 for Progress. NC WARN pointed out that Duke's graphs do not show the 3% of renewable generation or EE required by the general REPS obligation in 2012 or the 12.5% required in 2031, and Progress's graphs do not show any renewable generation or EE at all.

The Public Staff stated that it has discussed these graphs with Duke and Progress. Duke advised the Public Staff that the graphs represent its total generation, including wholesale and South Carolina retail sales; the 3% of North Carolina retail sales required by the general REPS obligation equates to well under 3% of Duke's total system sales. Moreover, many of the renewable energy certificates (RECs) that Duke will use for REPS compliance are unbundled from the underlying electrical energy and, thus, are not accounted for in the graphs. Finally, some of the RECs Duke will use for REPS compliance appear in the sections of the pie chart marked "DSM/EE" and "Hydro."

Progress indicated to the Public Staff that the renewable energy it intends to use for general REPS compliance in 2012 is purchased from third parties. Thus, it is shown in the section of the pie chart marked "Purchases," and the graph indicates that purchases are expected to make up 4.1% of Progress's generation mix for 2012. Moreover, even though EE can be used for compliance with the REPS requirements, it is not a type of generation and it is not included in the pie charts in Progress's IRP. Lastly, even though Progress fully expects to comply with the REPS requirements in 2026, it has entered into very few contracts that call for delivery of RECs or bundled renewable energy in that year; it intends to enter into such contracts closer to the time they will be needed. Since very few contracts for 2026 are currently in place, the "Purchases" section of the 2026 pie chart is quite small.

Based on these discussions with Duke and Progress, the Public Staff is satisfied that they do intend to comply with the general REPS requirements through 2026 (or in Duke's case 2031), and the pie charts in their IRPs should not be taken as an indication to the contrary.

SACE

As was the case with NC WARN, the issues raised by SACE in its comments cover only the IRPs submitted by Duke and Progress. Those issues are:

1) Duke's high demand-side management (DSM) portfolios would result in a lower revenue requirement, lower risk, and lower rates as compared to the preferred plan.

2) Duke and Progress failed to properly consider energy efficiency in their long-term resource planning.

3) Duke overstates its need for new capacity.

4) Duke and Progress should evaluate the prudency of continued operation of their scrubbed coal units.

5) Duke and Progress have unrealistic assumptions about nuclear generation.

The issues raised by SACE in its comments were raised in the biennial report portion of this proceeding and were discussed and ruled on by the Commission in the October 26, 2011 Order.

Public Staff

The Public Staff listed seven recommendations in its comments on the 2011 IRPs. They are as follows:

1) In the air quality permit issued by the North Carolina Department of Environment and Natural Resources, Division of Air Quality (DAQ) for Cliffside Unit 6, Duke agreed to retire the 800 MW of additional coal capacity without regard to achieving a commensurate level of MW savings from new EE and DSM programs. Duke filed a Greenhouse Gas Reduction Plan with DAQ, which can be revised with DAQ's approval if the Commission determines that the scheduled retirement of any unit will have a material impact on the reliability of Duke's system. Duke included, as Appendix J in its 2011 IRP, a Carbon Neutrality Plan that projects retirements that would exceed its Greenhouse Gas Reduction Plan by close to 50%.

In its Application filed on July 1, 2011, in Docket No. E-7, Sub 989, Duke sought to accelerate the depreciation of certain plants slated for early retirement. In the Stipulation filed by Duke, Time-Warner, and the Public Staff on December 2, 2011, the depreciation schedule for these plants was left unchanged. The Public Staff recommends that the actual timing of the retirements and the accounting treatment Duke proposes to follow with respect to the unrecovered cost of generating units projected to be retired be addressed in one or more separate dockets.

- According to Duke, the air quality permit specifies that any cost recovery related to Duke's execution of its proposed Qualifying Actions to comply with its Cliffside Carbon Neutrality Plan shall also be subject to Commission review and approval. Duke is not asking for any cost recovery of any kind through its 2011 IRP relating to any of the proposed Qualifying Actions set forth in the Cliffside Carbon Neutrality Plan. As such, the Company agrees with the Public Staff that any such applications for related cost recovery belong in a separate docket.

2) Duke also requests approval from the Commission of its proposed method of calculating the Emission Reduction Requirements and emissions offset values of certain Qualifying Actions as set out in Table J.3. The Public Staff proposes that this issue also be addressed in a separate docket.

- Duke submits that the Cliffside Carbon Neutrality Plan is appropriately before the Commission in this docket and should be approved as part of the 2011 IRP. As part of the Greenhouse Gas Reduction Plan included within the air quality permit issued by the DAQ for Cliffside Unit 6, Duke is required to file its plan to offset the carbon emissions of Cliffside Unit 6 with the Commission for approval. Pursuant to this requirement, Duke included the Cliffside Carbon Neutrality Plan in Appendix J of its 2011 IRP and requested the Commission's approval, as contemplated by the permit. As noted by the Public Staff in its comments, the carbon dioxide emissions avoided through the Qualifying Actions proposed within the Cliffside Carbon Neutrality Plan will exceed the projected emissions of Cliffside Unit 6 by approximately 50%. The Cliffside Carbon Neutrality Plan sets forth exactly what the permit requires and provides a reasonable path for Duke's compliance with the carbon emission reduction standards of the permit. Duke will certainly provide updates to the Commission through future IRPs as Qualifying Actions are implemented and Duke's compliance with the requirements of the permit is achieved, but Duke submits that its plan is ripe for approval at this time. No party has contested Duke's methods of calculating projected carbon dioxide emissions for Cliffside Unit 6 or emissions to be avoided through implementation of the proposed Qualifying Actions.

The Commission agrees with Duke that the Cliffside Carbon Neutrality Plan is appropriately before the Commission for approval as part of Duke's IRP. As noted above, Duke agrees with the Public Staff that any related cost recovery applications do belong in a separate docket. At this time, the Commission is only approving the Plan itself as a reasonable path for Duke's compliance with the carbon emission reduction standards of the air quality permit and is not approving any individual specific activities nor expenditures for any activities shown in the plan. Also, as noted by Duke in its Plan, it shall also be submitted to the Division of Air Quality, which will evaluate the effect of the plans on carbon, and provide its conclusions to this Commission.

3) The Public Staff further recommends that the Commission require Duke to continue to provide updates in future IRPs regarding its obligations related to the Cliffside Unit 6 air quality permit to: (a) retire 800 MW of coal capacity in North Carolina in accordance with the schedule set forth in Duke's Table J.1, (b) accommodate to the extent practicable the installation and operations of future carbon control technology at Cliffside 6, and (c) take additional actions to make Cliffside 6 carbon neutral by 2018.

- Duke agreed with this request.

4) The Public Staff also recommends that Duke and NC Power include in their reply comments the information required by Rule R8-60(i)(3) regarding reserve margins that differ in a given year by plus or minus three percent from target margins in regard to their 2011 IRP and comply with this requirement in future IRPs.

- Both Duke and NC Power complied with this request in their reply comments.

5) The Public Staff recommends that the Commission require the utilities to include a discussion of significant variances in projected EE savings in future IRPs. The Public Staff proposes that a variance of 10% in projected EE savings from one IRP report to the next trigger the requirement that the utility address the reason for the variance.

- Duke did not address this issue in its reply comments.
- Progress does not object to this proposal.
- NC Power does not oppose this recommendation.

The Commission agrees with the Public Staff's position on this issue and directs that each IOU shall include a discussion of a variance of 10% or more in projected EE savings from one IRP report to the next.

6) The Public Staff recommends that the Commission require the utilities to include a discussion of the status of market potential studies or provide updates in their 2012 IRPs.

- Duke did not address this issue in its reply comments.
- Progress does not object to this proposal.
- NC Power does not oppose the Public Staff's recommendation to require a discussion of its use of market potential studies or updates in

the next IRP, to the extent they decide to use market potential studies. NC Power notes that it currently requests data from its outside consultant to annually identify and propose new cost-effective DSM/EE programs based on its consultant's assessment of market potential in their North Carolina and Virginia service territories.

The Commission finds that the Public Staff position is reasonable and directs that each IOU shall include a discussion of the status of market potential studies or updates in their 2012 and future IRPs.

7) The Public Staff recommends that the Commission require the IOUs to evaluate no-carbon alternative plans or scenarios in their 2012 IRPs and future IRPs.

- Duke believes that, over the long-term planning horizon, the federal government will, through legislation or regulation, create specific limitations and restrictions on allowable emissions of carbon dioxide from electric generating facilities and establish some form of a market for carbon emission allowances. Duke stated that it has, since 2006, incorporated certain assumptions relating to carbon pricing into its IRPs and has continually emphasized that it needs to plan resources over the long-term for a carbon-constrained future. Duke continues to evaluate and adjust its assumptions around carbon and has significantly reduced its allowance pricing projections in light of the uncertainty referenced by the Public Staff. However, Duke disagrees with the Public Staff regarding the relative plausibility of future carbon legislation, and does not believe it would be reasonable or prudent to plan as if carbon emissions will not be regulated.

  Additionally, eliminating considerations of CO_2 constraints and clean energy legislation would have far reaching impacts on the economics of Duke's resource selection and costs. Without constraints, new coal resources may well be selected as components in the proposed resource mix. Gas and coal prices, energy efficiency economics, energy usage, and renewable resources economics would all be affected. Further, providing a load, capacity, and reserves table that excludes the impacts of CO_2 would require the development of a load forecast without CO_2 considerations. All of Duke's load forecasts available at this time have CO_2 considerations embedded in them. Simply removing the CO_2 allowance impacts as sensitivity cases applied to portfolios developed in the IRP only provides a limited indication of the present value revenue requirements impacts of CO_2. Such runs remove this cost from unit dispatch and the resultant operating costs. A full analysis of this impact would require repeating the IRP process with new assumptions. To do as the Public Staff requests, Duke explained that it would effectively have to generate two separate IRPs, one with carbon, one without carbon. This outcome would be wasteful of time and resources, and as the Commission concluded in its Order Approving Integrated Resource Plans and REPS Compliance Plans issued in this docket on the 2010 IRPs, "the current scenarios relating to carbon emissions, as provided in the IRPs, are responsive and appropriate for the purposes of this proceeding." Duke submits that the additional no-carbon scenario planning recommended by the Public Staff is unnecessary at this time and should not be required for future IRPs.

- Progress does not object to this recommendation.

- NC Power does not oppose the Public Staff's recommendation. Should the Commission adopt the Public Staff's recommendation, however, NC Power urges the Commission to maintain the flexibility set forth in the recommendation that the IOU can evaluate the no-carbon view either through alternative plans or scenarios. This flexibility would allow each IOU to present the no-carbon results in the manner that most accurately shows the effect, in its opinion, of such a no-carbon view.

The Commission stands by its earlier finding of fact in this docket that "the current scenarios relating to carbon emissions, as provided in the [2010] IRPs, are responsive and appropriate for purposes of this proceeding." Since the filing of comments and reply comments, the federal Environmental Protection Agency (EPA) has proposed a Carbon Pollution Standard for New Power Plants. This proposed standard was issued by the EPA on March 27, 2012, and would limit carbon dioxide emissions from new fossil fuel-fired power plants to 1,000 pounds per megawatt-hour.

<u>NCSEA</u>

NCSEA raised two questions in its comments: (1) whether the levelized busbar information provided by the IOUs is sufficient for IRP reporting purposes, and (2) whether the REPS information designated as confidential by the IOUs should be made public. NCSEA asserts that additional candor by the IOUs will provide "citizens, businesses and governments confidence that we are, in fact, on a path to an affordable electricity future."

A. <u>Sufficiency of Levelized Busbar Information.</u>

With regard to levelized busbar information, NCSEA seeks two additional types of information in the IRPs of Duke, Progress and NC Power:

(i) The levelized cost of energy – in a standardized metric, cents per kilowatt-hour – for each resource option for each year in the planning period and the delivered fuel costs for each resource option for each year in the planning period; and

(ii) The quantitative data used in creating the levelized busbar cost curves present in the IRPs, including (i) projected delivered fuel costs during the planning period, (ii) the utility's fixed charge rates, (iii) technology specific unit capacity factors, and (iv) data for the remaining variables needed to create a levelized busbar cost curve.

NCSEA states that Commission Rule R8-60(i)(9), which directs the IOUs to "provide information on levelized busbar costs for various generation technologies," was intended to enable the Commission to compare projected costs, on an apples-to-apples basis, across technologies and across IRPs. NCSEA acknowledges that each IOU has provided some information on levelized busbar costs, but contends that the information is presented in a conclusory fashion and is not standardized for comparison among the IOUs, citing Duke's IRP Report at 138-142 in comparison with Progress' IRP Report at 12-16. NCSEA submits that if the IOUs provided the information identified in (i) and (ii) above in a standardized format, it would enable the Commission, the Public Staff and other parties to perform cost comparisons across technologies and IOUs.

NCSEA offers as an example Duke's statement that there has been a "downward trend in solar equipment costs over the past several years" (Duke's IRP Report at 15), asserting that it is unclear if this trend has been fully factored into Duke's levelized busbar cost curve for solar. NCSEA says that this trend could have major implications for energy delivery within this proceeding's analytical timeframe. For example, a high-solar scenario brought on by rapidly declining solar PV costs could result in reduced on-peak energy needs, which could in turn dramatically reduce the need for new gas-fired peaking generation investments and the corresponding capital and fuel costs. NCSEA says this does not appear to be accounted for in any scenario presented in any of the IOUs' IRPs.

With regard to quantitative data under (ii) above, NCSEA cites Commission Rule R8-60(g), which states in pertinent part:

> [e]ach utility shall consider and compare a comprehensive set of potential resource options, including both demand-side and supply-side options, to determine an integrated resource plan that offers the least cost combination (on a long-term basis) of reliable resource options for meeting the anticipated needs of its system ... taking into account the sensitivity of its analysis to variations in ... significant assumptions, including ... the risks associated with ... fuel costs[.]

NCSEA states that such sensitivity analyses enable the Commission to gauge the robustness of the IOUs' planned handling of likely variations in fuel costs and that each IOU has provided some measure of sensitivity analysis. However, according to NCSEA the analyses are presented in a conclusory fashion and not in a standardized manner among the IOUs. It submits that if the IOUs were to provide the delivered fuel costs underlying their various projections and plans, then the Commission, the Public

Staff and other parties could evaluate the IRPs' least cost representations. Absent this standardized information, NCSEA contends that interested parties will remain skeptical of the IRPs' usefulness as a foundation for affordable long-range planning, particularly in light of what NCSEA sees as divergent future scenarios being espoused by the IOUs in various dockets.

As an example, NCSEA states that Duke's IRP includes two sensitivity analyses of coal, one in which a 25% coal cost increase is modeled and another in which a 40% coal cost decrease is modeled (Duke's IRP Report at 100). According to NCSEA, this choice of alternate scenarios appears inconsistent with Duke's testimony in Docket No. E-7, Sub 989, where Duke states that the cost of Central Appalachian (CAPP) coal, with which most of Duke's plants are currently fired, increased 39% for Duke and 15% for Progress between 2007 and 2010 (Duke's Late-Filed Exhibit No. 1, December 12, 2011). Further, Duke projects the cost of coal to rise an additional 20%-50% by 2012 (Duke's IRP Report at 51). NCSEA states that even if Duke's sensitivity modeling choices reflect the possibility of switching from CAPP coal to an alternative type of coal, that appears to be an inadequate explanation in light of testimony in Duke's general rate case. Duke indicated that it will work to diversify its coal purchases to include supplies procured from other areas, but a Duke witness suggested that further diversification as a result of the upward trend in CAPP coal costs would be a "difficult" process that could require North Carolina coal plant operators to undertake costly retrofits of and "test burn" studies at units currently optimized to consume CAPP coal (Docket No. E-7, Sub 989, T, Vol. 2, at 190-91, Dhiaa Jamil testimony on November 29, 2011). This same witness also noted that transporting coal over longer distances exposes plant operators to greater coal transportation costs (Id. at 192).

NCSEA notes that long-term delivered coal and natural gas cost projections were provided by NC Power in its 2010 IRP Report and 2011 update. It contends that without such long-term delivered coal and natural gas cost projections from Duke and Progress it is difficult for NCSEA and other interested parties to give credence to these IOUs' assertions that the more or less "business as usual" plans selected by them are in fact reliably least-cost. NCSEA believes a higher, more standardized degree of openness and transparency on the part of the IOUs will foster collaboration between the IOUs and those evaluating their IRPs and increase the quality of information in the IRPs.

Progress responded that, generally speaking, more information may be better that less information. However, the question is how much relevant information should be included in the IRP filing, above and beyond that required by Commission Rules, and what information should be left for discovery. NCSEA, or any other party to the IRP proceedings, is free to conduct discovery to obtain data from the utilities supporting the filed IRPs. Progress notes, however, that many of NCSEA's members are commercial businesses selling renewable energy products and energy efficiency services. Thus, Progress states that it must be mindful when providing confidential information to NCSEA that some of the information should not be provided to NCSEA's members.

Progress states that the basis for NCSEA's comments appears to be the assumption that the filing of certain IRP information confidentially harms persons and companies who have chosen not to intervene in the IRP proceeding because they do not have access to this information. Progress submits that NCSEA's assumption is wrong and its request should be denied for several reasons. First, a person or company that has chosen not to intervene in an IRP proceeding is not foreclosed from contacting a utility and asking to review the information in question pursuant to a confidentiality agreement. Second, all persons or companies can petition to intervene in the Commission's IRP proceeding, sign a confidentiality agreement and conduct discovery. Third, NCSEA has not challenged the confidentiality of the information in question. Before information which has previously been filed by a utility as confidential and accepted by the Commission as confidential is publicly disclosed, there must be a showing that the information in question is not confidential or the utility's consent must be obtained. For example, in Docket No. E-7, Sub 819, by order issued June 6, 2008, the Commission ruled that Duke was not required to disclose cost estimates for the proposed Lee nuclear unit. The parties supporting disclosure had argued that a "public interest component" must be considered along with the trade secret analysis. Citing State ex rel. Utilities Comm'n v. MCI Telecommunications Corp., 132 N.C. App. 625, 635, 514 S.E. 2d 276, 283 (1999), the Commission rejected that argument, holding that:

> ... the "confidential information" provision of the Public Records Act cannot be construed differently in the context of a regulated industry. See MCI, 132 N.C. App. at 635. The Commission concludes that there is no "public interest" exception to the "confidential information" provisions of G.S. 132-1.2(1). If the cost estimates qualify as a "trade secret" under G.S. 66-152(3), and if they also meet the other conditions of G.S. 132-1.2(1) (which, in this case, is not disputed), then the Commission is not authorized to order that they be publicly disclosed, even if it were otherwise inclined to do so based upon the "public interest" argument.

Finally, Progress asserts that NCSEA does not have standing to make this request as it has not demonstrated that it is authorized to represent unnamed non-parties or that it has suffered a direct harm as a result of information being filed confidentially. Thus, NCSEA's request to publicly disclose the confidential information in question should be denied.

Duke states that NCSEA's proposal should be rejected because it would require the public disclosure of market and commercially sensitive information that would impair the IOU's bargaining positions in various aspects of their core business. Duke states that in prior dockets NCSEA's position has been rejected by the Commission. See, e.g., Order Approving REPS and REPS EMF Riders and 2010 REPS Compliance, Docket No. E-7, Sub 984 (August 23, 2011); Order Approving Decision to Incur Project Development Costs, Docket No. E-7, Sub 819 (June 11, 2008) ("2008 Project Development Order").

Duke is also concerned about various market participants gaining the value and advantage of commercially sensitive information to the detriment of Duke's customers. Duke and other IOUs operate under a least cost mandate for resource planning and operation of system resources. Market information directly impacts pricing and negotiating position. Detailed market information related to a utility's capital cost estimates and projected expenditures for fuel and REPS compliance can significantly impact pricing on major expenditures that are ultimately paid by an IOU's customers. Thus, disclosing specific information that may impair the IOU's ability to negotiate and transact at favorable prices is not in the best interest of customers. Indeed, NCSEA specifically states that its proposal is not intended to benefit customers, but rather to provide non-intervening business persons with "access to information critical to their investment decisions" (NCSEA Comments at 9). Duke asserts that NCSEA's proposal seeks to benefit investors at the expense of the customers of North Carolina's IOUs.

Duke states, as referenced above, that the Commission has held that commercial information regarding the cost estimate of new generation resources constitutes a trade secret under G. S. 66-153, and thus warrants confidential treatment under G.S. 132-1.2. In its 2008 Project Development Order, the Commission determined that the North Carolina Public Records Act, through its "confidential information" exception, G.S. 132-1.2(1), prohibits disclosure of confidential commercial information, such as the information Duke redacts from its IRP reports and REPS compliance plans. Information that (a) meets the definition of a "trade secret" found in G.S. 66-152(3), (b) is the property of a "private person," (c) was disclosed to the Commission in compliance with law, and (d) was designated as "confidential" when disclosed is not a public record and is entitled to confidential treatment by the Commission.

Duke states that the IRP information that NCSEA seeks to have publicly disclosed concerning the IOU's delivered fuel costs, capital cost estimates and other underlying data supporting busbar projections is clearly a "compilation of information ... that [has] ... actual or potential commercial value ...." See G.S. 66-153. Moreover, as the Commission acknowledged in the 2008 Project Development Order, "the 'confidential information' provision of the Public Records Act cannot be construed differently in the context of a regulated industry." Id. at 6 (citing State ex rel. Utilities Comm'n v. MCI Telecommunications. Corp., 132 N.C. App. 625, 635, 514 S.E. 2d 276, 283 (1999)). The Commission concluded that there is no public interest exception to the confidential information provision of G.S. 132-1.2(1). Id. In addition, Duke asserts that the only portions of its 2011 IRP that were redacted relate to the specific $/kW estimates for generating resources and undesignated wholesale load projections, which continued to be the subject of commercial negotiations at the time of the IRP filing.

Finally, Duke notes that the Public Staff, NCSEA, SACE, NC WARN, and many other interveners have routinely been granted access to the IOUs' confidential information and data supporting the IOUs' IRP reports and REPS planning documents, including all of the information NCSEA seeks to have publicly disclosed through its recommendations, subject to the execution of reasonable and appropriate non-disclosure agreements. Thus, intervenors have been able to fully participate in the IRP review process, as contemplated by Commission Rule R8-60, and have been able to conduct their own review and analysis of the IOUs' methodology and data in biennial proceedings.

NC Power asserts that the existing IRP requirements provide sufficiently detailed information to allow the Commission, the Public Staff, and other interested parties to evaluate the IRPs. Further, the additional disclosures proposed by NCSEA are not suitable for providing detailed comparisons of projected costs. According to NC Power, a screening curve (also known as a Levelized Busbar Cost curve or LBC curve) is a plot of annualized cost of electricity generation as a function of unit utilization level (capacity factor). NC Power's LBC curves are shown in Figures 5.2.1 and 5.2.2 of its 2011 IRP Report. According to NC Power, screening curves are useful aids for narrowing the range of possible new supply-side and demand-side alternatives to be considered in more detailed analysis that occurs later in the IRP process. They are primarily used for screening out options with obvious high economic cost, distinguishing possible dispatch order in modeling, and testing the validity of the model outputs at certain stages of expansion.

NC Power contends, however, that screening curve analysis is not an adequate substitute for detailed production cost or expansion planning analysis because it provides rough approximations and is not appropriate for evaluations requiring a greater degree of accuracy. Important factors such as forced outages, maintenance requirements, unit sizes, unequal asset lives and system reliability are not addressed by screening curves. As such, the specific costs underlying the screening curves would not be appropriate for conducting an "apples-to-apples" comparison across technologies and across IOUs, as NCSEA suggests. For these reasons, NC Power opposes NCSEA's request that the Commission require IOUs to provide additional information with regard to screening curves.

Pursuant to the North Carolina Public Records Act, G.S. 132-1.2(1), a person has the right to file information under seal when the information constitutes a trade secret. A "person" is defined in G.S. 66-152(2) to include a corporation or other commercial entity. A "trade secret" is defined in G.S. 66-152(3) to include:

> [B]usiness or technical information, including but not limited to a formula, pattern, program, device, compilation of information, method, technique, or process that:
>
> a. Derives independent actual or potential commercial value from not being generally known or readily accessible through independent development or reverse engineering by persons who can obtain economic value from its disclosure or use.
>
> b. Is the subject of efforts that are reasonable under the circumstances to maintain its secrecy.

As the Commission concluded in its Order Approving Decision to Incur Project Development Costs, Docket No. E-7, Sub 819 (June 11, 2008), "the 'confidential information' provision of the Public Records Act cannot be construed differently in the context of a regulated industry." Order at 6 (citing State ex rel. Utilities Comm'n v. MCI Telecommunications. Corp., 132 N.C. App. 625, 635, 514 S.E. 2d 276, 283 (1999). Further, the Commission concluded that there is no public interest exception to the confidential information provision of G.S. 132-1.2(1). Id.

Thus, the confidential information exception to the Act allows a public utility to file information with the Commission under seal when the information (a) meets the definition of a "trade secret" found in G.S. 66-152(3), (b) is the property of a "person," (c) was disclosed to the Commission in compliance with law, and (d) was designated as "confidential" when disclosed. The Commission concludes that information regarding an IOU's projected expenditures for fuel and estimated capital costs is within the ambit of business or technical information covered by the trade secret exception to the Act. Further, the public disclosure of such information could negatively impact the bargaining position of an IOU that is attempting to negotiate a contract to obtain the lowest cost fuel or capital addition. In the end, it is the IOU's ratepayers that would be harmed by such an impact on the utility's bargaining position.

Balancing, on the one hand, the sensitive nature of projected fuel and capital costs, the need for the IOUs to negotiate effectively for lowest costs and the ability of any party in an IRP docket to obtain this information by signing a confidentiality agreement, against, on the other hand, a blanket requirement of public disclosure of this information, the Commission concludes that it should decline to require a blanket public disclosure of the information identified by NCSEA because such a blanket public disclosure is not in the public interest.

Further, the Commission is not persuaded that it should adopt NCSEA's suggestion that the IOU's be required to file their busbar analyses in one standardized format. The IOU's have developed their particular systems for analysis over many years of planning, selecting the format and computer software that meets the needs of each IOU and training their staffs to use those formats and the corresponding software. The expense and inefficiency of requiring changes in the IOUs' analytic approaches would not be justified by any ease of comparison that might be achieved by ordering the IOUs to standardize their analytical formats and processes.

B. Designation of REPS Information as Confidential.

With regard to NCSEA's request that the REPS information designated as confidential by the IOUs be made public, NCSEA maintains that improving the results of the IRP process requires that people other than the parties have access to the information to be scrutinized. However, the IOUs frustrate this purpose by confidentially filing key portions of their IRPs so that they are not accessible by the general public.

NCSEA challenged this practice in Duke's 2010 REPS Compliance Report, with Duke providing the following response:

> Duke Energy Carolinas will comprehensively review and revisit the necessity to maintain the confidentiality of all of the redacted information contained within its REPS compliance filings. To the extent the Company believes that its customers will not be harmed by the disclosure of certain information relating to REPS, we commit to make any appropriate adjustments in our next REPS compliance plan filing, to be made on September 1, 2011.

Docket No. E-7, Sub 984, T, Vol. 1, at 62-63 (Emily O. Felt testimony on June 8, 2011).

NCSEA states that it is unclear whether the comprehensive review took place and, if it did, whether it yielded any changes in Duke's practices.

NCSEA states that it understands the need for a certain level of guardedness on the part of the IOUs. However, "At the same time, NCSEA believes non-intervening business-persons are being deprived of access to information critical to their investment decisions, and in this way the REPS law's private business development purpose, *see* N.C. Gen. Stat. 62-2(a)(10), is being thwarted by the nondisclosure (NCSEA Comments, at 9).

NCSEA notes that in Docket No. E-7, Sub 819, the Commission entered an Order on June 11, 2008 in which it stated that "the Commission believes that it is in the public interest for [future cost] estimates to be disclosed at the earliest possible time that disclosure will no longer prejudice Duke's negotiations." (Order Approving Decision to Incur Project Development Costs, at 6). It believes that the same considerations of public interest apply in the IRP proceedings and should be supported by directing the IOUs to review all, or some older portions, of their REPS confidential filings and show cause why they should not be made public at this time. In the alternative, NCSEA requests the Commission's specific guidance as to whether an IRP docket is an appropriate setting in which to file a motion for public disclosure.

In addition to Progress's comments discussed in Section A above, Progress states that it is not the purpose of the IRP proceedings to convey price signals or other information to third parties to facilitate their business decisions for their own gains.

Duke states that in response to its commitments made in Docket No. E-7, Sub 984 last year, it revisited the portions of its 2010 REPS Compliance Plan that were marked confidential and significantly reduced the redacted sections of the updated 2011 REPS plan. Duke's 2011 plan had only one attachment including any redactions, a table showing specific pricing and projected REC volume acquisition.

Duke maintains that the information sought by NCSEA is clearly protected from public disclosure as a trade secret under North Carolina law, and the risk of potential negative impact on utility customers is not outweighed by the benefits to NCSEA's allegedly disadvantaged investors.

NC Power submits that its REPS compliance plans contain competitive, market sensitive information which if disclosed to third party developers, bidders and other REC market participants could harm NC Power and its customers. Specifically, the REPS filings contain information related to terms, conditions and pricing of competitively negotiated and secured REC contracts, forecasted REPS compliance expenditures and projected energy savings from energy efficiency programs. If known by third parties engaged in the REC market, this information would give them market intelligence that they could use to their competitive advantage to the detriment of NC Power and its customers, including giving them an advantage over other vendors or developers.

NC Power also maintains that the passage of time does not negate the need for confidential treatment of REPS information. In particular, the REPS filings contain sensitive forecasted information which should remain confidential into the future. Therefore, NC Power opposes NCSEA's recommendation that the Commission require past REPS filings to be unsealed.

In Duke's 2010 REPS proceeding, Docket No. E-7, Sub 984, NCSEA witness Urlaub commented on a need for more transparency in the filings made at the Commission. He stated that a meaningful analysis of Duke's approach to compliance would be impossible based solely on the non-confidential information filed by Duke and that the public would have a difficult time determining if the public interest is served based on such non-confidential information. In response, Duke witness Felt stated that Duke would comprehensively review the necessity to maintain the confidentiality of all of the redacted information contained in its REPS compliance filing and, to the extent the Company believed that its customers would not be harmed by the disclosure of certain information, make appropriate adjustments to the Company's next REPS compliance plan filing in September 2011. The Commission's Order, in Finding of Fact No. 11, stated that Duke had appropriately made information available about the research and administrative costs it was seeking to recover through the REPS rider and had not acted improperly in filing some information under seal.

In Duke's 2010 REPS Compliance Plan, Duke included several items that it designated as confidential. These included "Table 4: FLS Hot Water Installations," "Table 5: Solar Set-Aside Compliance Projections," and "Exhibit B: Duke's Renewable Resource Procurement from 3rd Parties (signed contracts)." In its 2011 REPS Compliance Plan, Duke omitted Table 4 and Table 5, but included the list of third-party contracts designated as confidential. However, other information, including projected energy efficiency savings, was filed as public information (Duke IRP Report, at 33-35).

Progress's 2011 REPS Compliance Plan also includes a confidential list of third-party contracts (Progress IRP Report, Appendix D, Exhibit 1). All other information was filed as public information.

NC Power's 2011 REPS Compliance Plan includes several tables in which portions of the information for 2011, 2012 and 2013 is designated as confidential, including:

- Figure 1.2.1 Company's REPS Compliance Plan Summary
- Figure 1.3.2 Company's Solar REC Compliance by Year
- Figure 1.3.4 Company's Swine REC Compliance by Year
- Figure 1.4.1 North Carolina Energy Efficiency Programs Energy Savings
- Figure 1.7.1 Company's Compliance Cost Summary
- Figure 1.8.1 Company's Comparison of Annual Caps

The information designated as confidential includes projections of the energy efficiency savings to be achieved by specific programs; total energy efficiency savings to be achieved; number of general, solar, swine and poultry RECs purchased and number needed; number of retail customers by customer class, annual cost cap per customer class, total annual cost cap per customer class; cost of REPS compliance and projected administrative costs.

Similar tables are provided for the Town of Windsor, with much of the information designated as confidential (Figure 1.2.2, Figure 1.5.3, Figure 1.5.4, Figure 1.7.2 and Figure 1.8.2).

As the Commission has previously concluded, there is merit in the IOUs' concerns about third-party developers and bidders obtaining access to market-sensitive REPS information, such as a utility's need for additional solar RECs or a utility's willingness to pay for a particular resource to meet the poultry or swine set-aside. Third parties could use such information to bid up prices of renewable resources and RECs to the detriment of a utility's customers. Further, the Commission is not persuaded that the intent of the policy statement in G.S. 62-2(a)(10)(c), to "[E]ncourage private investment in renewable energy and energy efficiency," is to provide private investors with commercially valuable information that is developed by IOUs, the cost of which is paid by ratepayers.

The IOUs have an obligation under Senate Bill 3 to meet their REPS requirements in the most reasonable and prudent manner under the circumstances. In order to assist the IOUs in satisfying this obligation, the Commission must regulate them in a manner that maximizes their ability to secure resources at favorable prices and terms and, at the same time, recognizes and supports the right of the public to scrutinize their activities. On balance, the Commission concludes that the disclosure of specific information concerning REPS contract prices, REC quantities and prices, and other terms would impair the IOUs' ability to negotiate and transact business on favorable terms. Therefore, it is not in the public interest to adopt a blanket requirement to disclose this information.

Under G.S. 132-1.2, a utility has the right to file information under seal when the information constitutes a trade secret. State ex. rel. Utilities Commission v. MCI Telecommunications Corp., 132 N.C. App. 625, 514, S.E. 2d 276 (1999). The Commission has previously recognized that disclosure of certain information could affect a public utility's ability to negotiate with providers of renewable energy products, and, therefore, supported the continued maintenance of the proprietary nature of some of this information. The Commission has also recognized the value of making more of this information public so as to improve customer confidence in the expenditures that are being made, as well as to potentially prompt future innovations and reductions in the cost of REPS compliance. Therefore, the Commission concludes that the IOUs should continue to review and appropriately reduce the confidential portions of their future REPS filings.

In addition, portions of the REPS information designated as confidential by NC Power appear not to be trade secret or sensitive commercial information within the meaning of G.S. 132-1.2. Further, in some respects it is information that is already public, being included in other sections of NC Power's IRP Report, or being information that could be derived from that which is included as public information. For example, Figure 4.2.2.1 Peak Load Forecast & Reserve Requirements (IRP Report at 47); Appendix 2C – North Carolina Sales by Customer Class (IRP Report at AP-4); Appendix 2F – North Carolina Customer Count (IRP Report at AP-7); Figure 4.3.2.1 North Carolina REPS Requirements, showing projected annual GWh requirements to meet the general REPS targets from 2012 through 2021 (IRP Report at 49); Figures 4.3.2.2, 4.3.2.3. and 4.3.2.4 North Carolina Solar, Swine Waste and Poultry Waste REPS Requirements, showing the projected annual GWh requirements to meet the solar, swine waste, and poultry waste set-aside REPS targets from 2012 through 2021 (IRP Report at 50-51); Appendices 3O and 3P, showing approved energy efficiency programs, projected system energy savings from each program and projected number of system participants in each program (IRP Report at AP-37 and 38); and Appendices 3S and 3T, showing proposed energy efficiency programs, projected system energy savings from each program and projected number of system participants in each program (IRP Report at AP- 41 and 42)

The Commission concludes that there is a question as to whether some of the information designated as confidential by NC Power is trade secret information under G.S. 132-1.2. Therefore, the Commission will require NC Power to review the information discussed above and file an explanation as to why this information should be maintained under seal.

Finally, the Commission notes that NCSEA and other parties can by appropriate motion in any Commission proceeding identify and request public disclosure of specific information that they believe was inappropriately filed under seal or should no longer be maintained under seal.

2011 REPS COMPLIANCE PLANS

Commission Rule R8-67(b) requires each electric power supplier to annually file a REPS compliance plan. The plan is to cover the current calendar year, as well as the subsequent two calendar years, and it is to demonstrate the electric power supplier's plan for complying with REPS. The plans are to be included with the IRP filing for those electric power suppliers that are required to file IRPs.

The Commission appreciates the REPS compliance plan comments provided by the Public Staff. At this time, the Commission finds that the Public Staff's comments raise a significant issue that needs to be addressed. Specifically, the REPS compliance plans filed in 2011 in this docket as well as in E-100, Sub 131 call into question whether North Carolina's electric power suppliers will meet their 2012 and 2013 REPS obligations relative to the swine waste and poultry waste set-asides established in G.S. 62-133.8(e) and (f). Quoting from the Public Staff's comments filed on January 13, 2012:

> Duke, PEC [Progress], DNCP [NC Power], GreenCo, North Carolina Eastern Municipal Power Agency (NCEMPA), North Carolina Municipal Power Agency No. 1 (NCMPA1), and the Public Works Commission of the City of Fayetteville (Fayetteville) have formed a group (collectively, the Swine Group) to jointly request proposals for energy or RECs derived from swine waste to meet the requirements of the swine waste set-aside in G.S. 62-133.8(e). This statute requires that the State's electric power suppliers must collectively procure energy or RECs from swine waste resources to meet 0.07% of sales in 2012 and 2013. Duke has taken a leadership role for the Swine Group and executed four long-term purchase agreements with swine waste REC suppliers on behalf of the group. These four contracts will result in as many as 25 swine waste-to-energy facilities in North Carolina. Despite these contracts, the Swine Group does not believe it can obtain enough swine waste resources to meet the 2012 requirements for the group. However, the group believes that it can meet the requirements for 2013 and beyond. Uncertainties remain in procuring swine RECs, such as the following: (1) providers of swine waste RECs are few, (2) the production of energy from swine waste at a commercial scale is unproven, and (3) swine waste-to-energy facilities are small and highly distributed compared to traditional generation and the set-aside requirement.

Again, citing from the Public Staff's comments filed on January 13, 2012:

> Progress, NC Power, GreenCo, EU [Energy United], Halifax, NCEMPA, NCMPA1, and Fayetteville (but not Duke) formed a group (collectively, the Poultry Group) to jointly pursue energy or RECs derived from poultry waste to meet the requirements of G.S. 62-133.8(f). This statute requires that the State's electric power suppliers must collectively procure energy

from poultry waste resources in the amount of 170,000 MWH or equivalent in 2012 and 700,000 MWH or equivalent in 2013. Progress has taken a leadership role for the Poultry Group. Meeting the poultry waste set-aside has presented challenges to the Poultry Group; some are similar to those of meeting the swine waste set-aside. However, several actions by the General Assembly and the Commission in 2010 and 2011 have made compliance with the poultry waste set aside easier to achieve than the Public Staff anticipated before 2010.

Duke indicated that the poultry waste-to-energy market is still new and indicated that it is optimistic but uncertain about compliance. Progress is more confident that it can meet the poultry waste requirement. In April 2011, Progress signed a contract to purchase energy and RECs from a 36-MW poultry waste-to-energy facility that should be able to deliver 200,000 poultry waste RECs per year. GreenCo also plans to obtain poultry waste RECs from this facility. However, the owners of the facility have not filed an application for a certificate of public convenience and necessity. NCEMPA has not secured enough poultry waste RECs to meet the 2012 requirement but is continuing to pursue them. NCMPA1 has secured enough poultry waste RECs to meet the 2012 requirement but is still pursuing resources to meet the requirement for 2013. The Public Staff also noted that no electric power supplier has filed with the Commission to modify or delay the swine waste or poultry waste set-asides under the "off-ramp" provision of Senate Bill 3.[6] The Commission determines that the issue of whether electric power suppliers will comply with the REPS poultry waste and swine waste set-asides implicates all of the State's electric power suppliers, not only those that file IRPs. Therefore, the Commission on May 16, 2012, issued an order in the generic Docket No. E-100, Sub 113 and required that all electric power suppliers submit to the Commission within 30 days an update of their plans for complying with the swine waste and poultry waste set-asides in 2012 and 2013.

IT IS, THEREFORE, ORDERED as follows:

1. That this Order shall be adopted as a 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 2011 update IRP reports filed in this proceeding by the IOUs, NCEMC, Piedmont, Rutherford, EnergyUnited, and Haywood are hereby approved.

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[6] Senate Bill 3 authorizes the Commission to modify or delay its provisions if it is in the public interest to do so. Commission Rule R8-67(c)(5) states: "In any year, an electric power supplier or other interested party may petition the Commission to modify or delay the provisions of G.S. 62-133.8(b), (c), (d), (e) and (f), in whole or in part. The Commission may grant such petition upon a finding that it is in the public interest to do so. If an electric power supplier is the petitioner, it shall demonstrate that it has made a reasonable effort to meet the requirements of such provisions. Retroactive modification or delay of the provisions ... shall not be permitted. The Commission shall allow a modification or delay only with respect to the electric power supplier or group of electric power suppliers for which a need for a modification or delay has been demonstrated."

3. That the 2011 REPS compliance plans filed in this proceeding by the IOUs, GreenCo, Halifax, and EnergyUnited are hereby approved.

4. That future IRP filings by all utilities 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 utilities 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 utilities 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 Duke's Cliffside Carbon Neutrality Plan, as contained in Appendix J of its 2011 IRP, is appropriately before the Commission for approval as part of Duke's IRP. As such, the Commission is approving only the Plan itself as a reasonable path for Duke's compliance with the carbon emission reduction standards of the air quality permit and is not approving any individual specific activities nor expenditures for any activities shown in the Plan. As noted by Duke, this Plan shall also be submitted to the Division of Air Quality, which will evaluate the effect of the plans on carbon, and provide its conclusions to this Commission.

8. That each IOU shall include a discussion of a variance of 10% or more in projected EE savings from one IRP report to the next.

9. That each IOU shall include a discussion of the status of market potential studies or updates in their 2012 and future IRPs.

10. That Duke, Progress and NC Power shall continue to review and appropriately reduce the confidential portions of their future REPS filings.

11. That within 30 days of the date of this Order, NC Power shall review the following information designated as confidential in its 2011 REPS Compliance Plan and provide an explanation as to why it considers this information to be confidential under G.S. 132-1.2: (a) projections of the energy efficiency savings to be achieved by specific programs; (b) total energy efficiency savings to be achieved; (c) number of general, solar, swine and poultry RECs purchased and number needed; (d) number of retail customers by customer class; (e) annual cost cap per customer class; (f) total annual cost cap per customer class; (g) cost of REPS compliance; and (h) projected administrative costs.

12. That all ordering paragraphs listed in the Order Approving 2010 Biennial Integrated Resource Plans and 2010 REPS Compliance Plans, issued in this same docket, on October 26, 2011, remain in effect.

ISSUED BY ORDER OF THE COMMISSION.

This the 30th day of May, 2012.

NORTH CAROLINA UTILITIES COMMISSION

Gail L. Mount

Gail L. Mount, Chief Clerk

je053012.01

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 128

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Investigation of Integrated Resource Planning in North Carolina - 2010	)))	ORDER APPROVING 2010 BIENNIAL INTEGRATED RESOURCE PLANS AND 2010 REPS COMPLIANCE PLANS

HEARD: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on Monday, January 24, 2011, at 7 p.m.

BEFORE: Commissioner William T. Culpepper, III, Presiding; Chairman Edward S. Finley, Jr.; and Commissioners Lorinzo L. Joyner; Bryan E. Beatty; Susan W. Rabon; ToNola D. Brown-Bland; and Lucy T. Allen

APPEARANCES:

For Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc.:

Len S. Anthony, General Counsel, 410 South Wilmington Street, Post Office Box 1551, Raleigh, North Carolina 27602-1551

For Duke Energy Carolinas, LLC:

Charles A. Castle, Senior Counsel, Duke Energy Corporation, 526 South Church Street, EC03T/Post Office Box 1006, Charlotte, North Carolina 28201-1006

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

Robert W. Kaylor, Law Office of Robert W. Kaylor, P.A., 3700 Glenwood Avenue, Suite 330, Raleigh, North Carolina 27612

For North Carolina Electric Membership Corporation:

Robert Schwentker and Richard Feather, 3400 Sumner Boulevard, Raleigh, North Carolina 27616

For Southern Alliance for Clean Energy:

Gudrun Thompson, 601 West Rosemary Street, Suite 220, Chapel Hill, North Carolina 27516

For North Carolina Sustainable Energy Association:

Kurt Olson, 1111 Haynes Road, Suite 900, Raleigh, North Carolina 27604

For North Carolina Waste Awareness & Reduction Network:

John D. Runkle, Post Office Box 3793, Chapel Hill, North Carolina 27515

For the Using and Consuming Public:

Robert S. Gilliam, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

Leonard G. Green, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602-0629

BY THE COMMISSION: Integrated Resource Planning (IRP) is intended to identify those electric resource options that can be obtained at least cost to the ratepayers consistent with 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.

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). G.S. 62-110.1 further requires the Commission to consider this analysis in acting upon any petition for construction. 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: (1) a report of the Commission’s analysis and plan; (2) the progress to date in carrying out such plan; and (3) the program of the Commission for the ensuing year in connection with such plan. G.S. 62-15(d) requires the Public Staff to assist the Commission in this analysis and plan.

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….

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' IRP. Commission Rule R8-60 requires that each of the investor-owned utilities, the North Carolina Electric Membership Corporation, and any individual electric membership corporation to the extent that it is responsible for procurement of any or all of its individual power supply resources (hereinafter, collectively, the electric utilities) furnish the Commission with a biennial report in even-numbered years that contains the specific information set out in that Rule. 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 Renewable Energy and Energy Efficiency Portfolio Standard (REPS) compliance plan as part of its IRP report. Within 150 days after the filing of each electric utility's biennial report, and within 60 days after the filing of each electric utility's annual report, the Public Staff or any other intervenor may file its own plan or an evaluation of, or comments on, the electric utilities' IRP 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 2010 biennial integrated resource plans (IRPs) were filed by the following investor-owned utilities (IOUs): Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc. (PEC); Duke Energy Carolinas, LLC (Duke); Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (DNCP); and the electric membership corporations (EMCs): North Carolina Electric Membership Corporation (NCEMC); Rutherford EMC (Rutherford), Piedmont EMC (Piedmont), Haywood EMC (Haywood), and EnergyUnited EMC (EU). In addition, REPS compliance plans were submitted by the IOUs, GreenCo Solutions, Inc. (GreenCo),[1] Halifax EMC (Halifax), and EU.

In addition to the Public Staff, the following parties have intervened in this docket: the Carolina Industrial Group for Fair Utility Rates I, II, and III (CIGFUR); the North Carolina Sustainable Energy Association (NCSEA); the Public Works Commission of the City of Fayetteville (Fayetteville); Nucor Steel-Hertford (Nucor); the North Carolina Waste Awareness & Reduction Network (NC WARN); the Southern Alliance for Clean Energy (SACE); and the Carolina Utility Customers Association, Inc. (CUCA). The intervention of the Attorney General is recognized pursuant to G.S. 62-20.

Procedural History

On August 20, 2010, Rutherford filed a letter indicating that it had a long-term power supply agreement with Duke, its load would be reported for filing purposes within Duke's IRP, its renewable energy requirements under the REPS would be provided by Duke, and its REPS requirements would be reflected in Duke's 2010 REPS compliance plan. Also on August 20, 2010, PEC moved to extend the filing date for its IRP to September 12, 2010. This motion was granted by the Commission on September 1, 2010. On August 27, 2010, EU filed its 2010 IRP and its 2010 REPS compliance plan. On August 31, 2010, Halifax filed for an extension of time to file its 2010 REPS compliance plan. The Commission by Order issued on September 14, 2010, granted Halifax an extension up to and including October 15, 2010. On August 31, 2010, Haywood filed its 2010 IRP. On September 1, 2010, Duke and DNCP filed their 2010 IRPs and REPS compliance plans; GreenCo filed a compliance plan on behalf of its members; and Piedmont, NCEMC, and Rutherford filed their 2010 IRPs. On September 13, 2010, PEC filed its 2010 IRP and REPS compliance plan. On October 15, 2010, Halifax filed its 2010 REPS compliance plan.

By Order dated December 3, 2010, the Commission scheduled a public hearing for January 24, 2011, on the filed IRPs and REPS compliance plans. On December 13, 2010, SACE requested an evidentiary hearing on issues to be identified by the Commission. On December 17, 2010, NC WARN made a filing in support of SACE's request for an evidentiary hearing. On December 28, 2010, PEC moved that the Commission delay ruling on SACE's request until SACE and NC WARN had identified elements of the electric utilities' IRPs with which they disagree and allow parties to respond to the identification of issues. On January 13, 2011, the Public Staff moved that the deadline for the filing of comments on IRPs be extended to February 10, 2011. The Commission granted this Motion on January 19, 2011.

[1] GreenCo filed a consolidated 2010 REPS compliance plan on behalf of Albemarle EMC, Brunswick EMC, Cape Hatteras EMC, Carteret-Craven EMC, Central EMC, Edgecombe-Martin County EMC, Four County EMC, French Broad EMC, Haywood, Jones-Onslow EMC, Lumbee River EMC, Pee Dee EMC, Piedmont, Pitt & Greene EMC, Randolph EMC, Roanoke EMC, South River EMC, Surry-Yadkin EMC, Tideland EMC, Tri-County EMC, Union EMC, and Wake EMC.

The public hearing was held as scheduled on January 24, 2011. The public witnesses in attendance testified in support of energy efficiency (EE) and renewable energy technologies, in opposition to coal and nuclear generation, and against rate increases.

On February 9, 2011, DNCP filed an updated 2010 REPS compliance plan. On February 10, 2011, comments were filed by the Public Staff and SACE. On February 11, 2011, comments were filed by NC WARN. Both SACE and NC WARN requested that the Commission hold an evidentiary hearing on the IRPs of Duke and PEC.

On February 23, 2011 Duke moved that the deadline for filing reply comments be extended until March 1, 2011. The Commission granted the motion on February 24, 2011.

On March 1, 2011, reply comments were filed by Blue Ridge EMC (Blue Ridge), PEC, Duke, and DNCP addressing the comments of the Public Staff, SACE, and NC WARN. On March 3, 2011, Blue Ridge submitted a corrected version of its reply comments. On March 10, 2011, the Public Staff clarified two items in its February 10, 2011 comments.

On April 14, 2011, the Commission issued an Order Denying Request for Evidentiary Hearing. On April 29, 2011, NC WARN filed a Motion for Reconsideration of that order, to the limited extent of allowing parties to file proposed orders or briefs before the Commission issues its final order in this proceeding. On May 2, 2011, Duke filed a supplemental response to the Public Staff's initial comments. On May 5, 2011, the Commission issued an Order allowing parties to file proposed orders or briefs.

On June 6, 2011, the following parties submitted briefs or proposed orders: PEC, Duke, DNCP, NC WARN, and SACE. Also on June 6, 2011, NCSEA submitted comments. The Public Staff did not submit a brief or proposed order in this proceeding.

On June 14, 2011, Duke filed an Objection to NCSEA's Comments Filing. In Duke's objection, it requested that the Commission reject NCSEA's filing as grossly out of time. On June 17, 2011, NCSEA submitted a Reply to Duke's Objection to NCSEA's Comment Filing. According to NCSEA, its comments were firmly grounded in the record and, like a brief, consisted of contentions based on the record evidence. Upon review of these filings, the Presiding Commissioner concluded that NCSEA's comments should be treated as a brief. As such, NCSEA could not raise new issues in its filing because they should have been filed within the time allowed for comments on the utilities' IRPs. Therefore, only arguments asserted by NCSEA regarding issues previously raised in comments submitted by the Public Staff and the other intervenors were allowed and taken into consideration by the Commission in reaching its decision in this docket.

Based upon the foregoing, the information contained in the 2010 biennial IRPs, the 2010 REPS compliance plans, the comments and reply comments, and the Commission's entire record of 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 thus produced are reasonable for purposes of this proceeding and should be approved.

2. The IOUs' 2010 biennial IRP reports are reasonable and should be approved.

3. The IOUs' 2010 REPS compliance plans are reasonable and should be approved.

4. The 2010 biennial IRP reports and 2010 REPS compliance plans submitted by NCEMC, Piedmont, Rutherford, EU, Haywood, GreenCo, and Halifax are reasonable and should be approved.

5. PEC and Duke have adequately addressed the issues raised by SACE and NC WARN in this proceeding including the proper evaluation of EE and demand-side management (DSM) resources, least cost portfolio selection, peak demand and energy growth projections, baseload requirements, the cost of new nuclear generation, greenhouse gas (GHG) emissions, and the potential economic viability of existing scrubbed coal units.

6. PEC has provided adequate information in this proceeding related to the planned retirements of its coal-fired generating units.

7. PEC and Duke have provided adequate information in this proceeding regarding their reserve margins, as required by Rule R8-60(i)(3).

8. Duke should file in the respective dockets of each affected DSM program and pilot a calculation showing the difference between the avoided cost capacity and energy benefits, as originally filed, and the avoided cost benefits recalculated using the correct DSMore model calculation methodology.

9. The loads of French Broad EMC (French Broad) and Blue Ridge are reflected in the IRPs filed by NCEMC and Duke, respectively, and French Broad and Blue Ridge are not required to file individual IRPs.

10. All EMCs should include a full discussion in future biennial IRPs of their DSM programs and their use of these resources as required by Rule R8-60(i)(6).

11. If Piedmont determines that its smart meter program is an EE program, it should file for Commission approval of the program pursuant to Rule R8-68.

12. In future biennial IRPs, EU should provide a more detailed description of the participation and savings related to specific DSM and EE programs, particularly those its proposes to use to meet its REPS obligations.

13. PEC and Duke should each prepare a comprehensive reserve margin requirements study and include these as part of their 2012 biennial IRP reports. PEC and Duke should keep the Public Staff updated as they develop the parameters of the studies.

14. Each IOU and EMC should investigate the value of activating DSM resources during times of high system load as a means of achieving lower fuel costs by not having to dispatch peaking units with their associated higher fuel costs if it is less expensive to activate DSM resources. This issue should be addressed as a specific item in their 2012 biennial IRP reports.

15. Each electric utility should use appropriately updated DSM/EE market potential studies.

16. The current scenarios relating to carbon emissions, as provided in the IRPs, are responsive and appropriate for purposes of this proceeding.

DISCUSSION AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1 - 4

Peak and Energy Forecasts

In the Public Staff's comments, it stated that all of the electric utilities use 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.

The Public Staff has reviewed the electric utilities' 15-year peak and energy forecasts (2011–2025). The compound annual growth rates (CAGRs) for the forecasts of PEC, Duke, and DNCP are within the range of 1.2% to 1.8%. The CAGRs for NCEMC and the four independent EMCs that filed IRPs (EU, Haywood, Piedmont, and Rutherford) are within the range of 1.2% to 2.2%.

<u>PEC</u>

The Public Staff's one-year review of PEC's peak load accuracy shows that the predictions in the 2009 IRP represent a forecast with less than a 1% error.[2] The low forecast error rate was, in part, due to the system-wide average temperature of 96 degrees Fahrenheit, which was approximately equal to PEC's normal peak-day temperature. The Public Staff's five-year review of PEC's peak load and energy sales forecasting accuracy shows that the predictions in the 2005 IRP were reasonably accurate with less than a 5% forecast error.

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

<u>Duke</u>

The Public Staff's one-year review of Duke's peak load accuracy shows that the predictions in the 2009 IRP represent a forecast with less than a 2% error. The system-wide average temperature was 93 degrees Fahrenheit, which was approximately one degree cooler than the normal peak-day temperature. The Public Staff's five-year review of Duke's energy sales forecasting accuracy shows that the predictions in Duke's 2005 IRP were reasonably accurate with less than a 5% forecast error. However, the forecast accuracy of Duke's peak loads reflected a 5.7% forecast error. The above-average forecast error for the five-year period results from the relatively low actual peak loads reported in 2009 and 2010, which were more than 8% below the predicted peak loads. These two forecast errors were mainly due to a reduction in new customers in 2010 and an even larger reduction in new customers in 2009. Duke's 2010 forecast more accurately reflects the current economic environment.

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

<u>DNCP</u>

The Public Staff's one-year review of DNCP's peak load accuracy shows that the predictions in the 2009 IRP represent a forecast with less than a 1% error. The Public Staff's five-year review of DNCP's peak load and energy sales forecasting accuracy shows that the predictions in the 2005 IRP were reasonably accurate with less than a

[2] The Mean Absolute Error is used to calculate the forecast error.

5% forecast error.

The Public Staff believes that the economic, weather, and demographic assumptions that underlie 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.

NCEMC

The Public Staff's analysis of NCEMC's peak load forecasting accuracy over the past five years indicates that the forecasts in its 2005 annual report were on average 247 MW lower than its actual system load, which equates to a 8% forecast error. Its energy sales forecast has been reasonably accurate with less than a 5% error rate. In response to the Commission's Order in Docket No. E-100, Sub 124, NCEMC reworked its load forecasting method by partnering with SAS Institute, Inc., to develop new state-of-the-art statistical models. The new peak demand models implemented by NCEMC are based on usage per customer and allow for the quantification of changes in peak demand among each of its member cooperatives that are attributable to changes in weather conditions and other factors. The Public Staff is cautiously optimistic that its concerns expressed in prior IRP dockets about the accuracy of NCEMC's forecasting methods will be resolved by this new forecasting process; however, it will still be necessary to review the forecasts for several years, contrasted with actual peak loads realized, before the impact of the changes in forecasting methodology can be fully assessed. The Public Staff believes that the current forecasts by NCEMC are reasonable for planning purposes.

EU

EU's 15-year forecast predicts that its winter peak, which is considered its system peak, will grow at an average annual rate of 0.9%. Its energy sales are predicted to grow at an average annual rate of 1.2%. The average annual growth of the annual peak is 6 MW over the 15-year forecast. The Public Staff believes that the forecasts by EU are reasonable for planning purposes.

Haywood

Haywood's 15-year forecast predicts that its winter peak, which is considered its system peak, will grow at an average annual rate of 2.1%. Its energy sales are predicted to grow at an average annual rate of 2.0%. The average annual growth of the annual peak is 2 MW over the 15-year period. The Public Staff believes that the forecasts by Haywood are reasonable for planning purposes.

Piedmont

Piedmont's 15-year forecast predicts that its winter peak, which is considered its system peak, will grow at an average annual rate of 2.1%. The average annual growth of its summer peak is 3 MW over the 15-year period. Piedmont's energy sales are predicted to grow at an average annual rate of 2.1%. The Public Staff believes that the forecasts by Piedmont are reasonable for planning purposes.

Rutherford

Rutherford's 15-year forecast predicts that its winter peak, which is considered its system peak, will grow at an average annual rate of 1.4%. Its energy sales are predicted to grow at an average annual rate of 1.2%. The average annual growth of Rutherford's winter peak is 5 MW over the 15-year period. The Public Staff believes that the forecasts by Rutherford are reasonable for planning purposes.

Summary of Load Forecasts

The following table summarizes the growth rates for the electric utilities' system peaks and energy sales forecasts.

2011- 2025 Growth Rates
(After EE and DSM)

	Summer Peak	Winter Peak	Energy Sales	Annual MW Growth
PEC	1.6%	1.8%	1.2%	213
Duke	1.6%	1.6%	1.8%	322
DNCP	1.7%	1.8%	1.8%	342
NCEMC	1.8%	1.7%	1.7%	58
EnergyUnited	1.0%	0.9%	1.2%	6
Haywood	2.2%	2.1%	2.0%	2
Piedmont	2.1%	2.1%	2.1%	3
Rutherford	1.4%	1.4%	1.2%	5

Reserve Margins

PEC

A capacity margin is calculated by dividing reserves by the total supply resources, while a reserve margin is calculated by dividing reserves by the system firm load after the impact of DSM. PEC stated that a minimum capacity margin target range of approximately 11%-13% satisfies the one day in ten year Loss of Load Expectation (LOLE) criterion and provides an adequate level of reliability. PEC further stated that it considers 11% to be the minimum and acceptable capacity margin in the near term, but that 12-13% is appropriate to be used in the longer term due to forecast uncertainty.

The projected capacity margins range from 12% to 20% over the planning period. PEC stated that these capacity margin values are the equivalent of 14% to 25% reserve margins, which were validated by the Public Staff. This implies a reserve margin target of 14% to 15% over the long term planning period. As shown in PEC's IRP, projected reserve margins exceed this targeted level significantly during the planning period and particularly during the 2011 to 2014 period. While PEC's plan details the addition of 635 MW of generation (Richmond County) in 2011 and 920 MW of generation (Wayne County) in 2013, it does not provide for a corresponding rate of retirement of other facilities. PEC noted that additional resources cannot be brought online in the exact amount needed to match load growth.

<u>Duke</u>

Duke stated that its own historical experience has shown that a 17% target planning reserve margin is sufficient and necessary to provide reliable power supplies for its North and South Carolina service areas. Duke also stated that from July 2005 through July 2009, generating reserves never dropped below 450 MW, but noted that there are increased risks associated with reserve margins, which include (1) increasing age of units, (2) inclusion of a significant amount of renewable energy (which is generally less available than traditional supply side resources), (3) uncertainty related to increases in the Company's EE and DSM programs, (4) longer lead times for constructing base load units, (5) increasing environmental pressures, and (6) increases in derates of units due to hot weather and drought.

<u>DNCP</u>

PJM conducts an annual reliability assessment to determine an adequate level of capacity in its footprint to meet the target level of reliability measured with a LOLE that is equivalent to one day of outage in ten years. PJM's 2009 assessment recommended using a reserve margin of 15.3% for the entire PJM footprint. DNCP uses the PJM reserve margin guidelines in conjunction with its own load forecast to determine its long-term need for capacity. The reserve margins for the first three years of the planning period are 16.1% (2011), 16.7% (2012), and 13% (2013). Because DNCP is only obligated to maintain a reserve margin for its portion of the PJM coincidental peak load, it used a coincidence factor of 96.3% to derive an effective reserve margin of 11% for 2014 through 2025.

DSM and EE

The Public Staff's review of the DSM/EE portions of the 2010 IRPs indicates that there is little difference from those filed in 2009. Duke, DNCP, NCEMC, and the independent EMCs, Haywood, Piedmont, Rutherford, and EU, generally forecast fewer DSM/EE resources (in terms of MW and megawatt-hours (MWh)) over the planning horizon. PEC indicated a small increase in its forecast of DSM resources. All of the electric utilities rely almost exclusively on the portfolio of DSM/EE programs they have designed and adopted over the last couple of years to meet their forecasted

DSM/EE resources over the planning horizon, with only a few programs recently implemented or still under consideration.

Evaluation of Resource Options

PEC, Duke, and DNCP provided information describing their analysis and evaluation of resource options as required by Rule R8-60(i)(8). The IOUs use accepted production cost simulation models that have the ability to perform optimization analysis to select between different competing resource portfolios that potentially could be added in various combinations to satisfy the utility's future load requirements. The objective of these models is an identification of the least cost combination of resources as determined by an evaluation of the present value of revenue requirements for the various portfolios, while maintaining the target reserve margin. In addition to the review of the IOUs' load forecasts, future DSM and EE programs, and renewable resources, the Public Staff also reviewed forecasts of fuel prices, existing generation characteristics, and the projected capital costs associated with new generation facilities used in the resource optimization models. The investigation by the Public Staff indicates that the projected operating and capital costs used in the production models and the evaluation of resource options were conducted in a reasonable manner for purposes of this proceeding.

REPS Compliance Plan Review

G.S. 62-133.8 requires all electric power suppliers to provide specified percentages of their retail sales using renewable energy resources or reduced energy consumption through implementation of EE measures. Commission Rule R8-67(b) requires electric power suppliers to file a plan on or before September 1 of each year explaining how they will meet the requirements of G.S. 62-133.8(b), (c), (d), (e), and (f). The plans must cover the current year and the next two calendar years, or in this case 2010, 2011, and 2012.

Duke, PEC, and DNCP provided an assessment of alternative supply-side energy resources as part of their REPS compliance plans. All EMCs in North Carolina also provided plans.

The Public Staff noted that the electric power suppliers have had some difficulty obtaining sufficient resources from swine waste and poultry waste to meet the requirements of G.S. 62-133.8(e) and (f). The filings regarding the efforts of the electric power suppliers to meet these requirements are in Docket No. E-100, Sub 113.

Conclusions

Based upon the foregoing, the Commission finds 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 thus produced are reasonable for purposes of this proceeding and should be approved. The 2010 biennial IRP reports and 2010 REPS compliance plans submitted by the IOUs are reasonable and should be approved.

The Commission also finds that the 2010 biennial IRP reports and 2010 REPS compliance plans submitted by NCEMC, Piedmont, Rutherford, EU, Haywood, GreenCo, and Halifax are reasonable and should be approved.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 5

Least Cost Resource Portfolio Selection

In its comments, SACE stated that Duke modeled several resource portfolios in its IRP analysis. Some of these portfolios used a “High Energy Efficiency” or “High DSM” case, which includes the full target impacts of the save-a-watt bundle of programs for the first five years and then increases the load impacts at 1% of retail sales each subsequent year until the load impacts reach the economic potential identified by Duke’s 2007 market potential study, i.e., a 13% decrease in retail sales. Duke did not select a portfolio with the High DSM case, however, despite the fact that the portfolios incorporating Duke’s High DSM case cost less, have lower risk, and appear to result in lower average electricity rates than does the optimal plan. As a result, Duke’s plan does not result in the least cost mix of resources.

SACE argued that, in contrast to Duke’s failure to select an identified resource portfolio with a High EE case, PEC failed to even model a high efficiency case. In its IRP, PEC identifies three alternative resource plans that it considered for scenario analysis. However, PEC did not identify any scenario that included a portfolio with additional investments in EE (or renewable resources). Rather, these three alternative plans differed only in terms of the amount of gas-fired and nuclear capacity contained in each and in the timing for new additions of units with these technologies. SACE maintained that PEC’s failure to model different levels of EE reveals a critical flaw in the Company’s analysis. PEC did not conduct a similar sensitivity analysis even though the Commission’s 2010 order called for “full and robust analyses and sensitivities.”

In its reply comments, Duke stated that, as to the substantive aspects of Duke’s IRP, SACE initially criticized the Company’s portfolio analysis for not prioritizing its High DSM case in all of its portfolios. It noted that SACE alleged that the High DSM case, when applied to all of the Company’s potential portfolios, is lower cost to customers, lower risk to customers, and will result in lower rates to customers than Duke’s Optimal Plan, which is its selected portfolio of 2 Nuclear Units (2021/2023) and incorporates the Company’s Base Case. SACE also included confidential Attachment 1 to demonstrate the comparison of certain High DSM case portfolios to the Optimal Plan portfolio on a net present value basis. Duke submitted that it is notable that SACE did not include the cost comparison information for the High DSM case as applied to the 2 Nuclear Units (2021/2023) timeframe in Attachment 1. Duke argued that SACE’s comparison of the Company’s High DSM sensitivity cases to its Base Case portfolios is misleading and presents an “apples to oranges” comparison. Duke argued further that, SACE’s analysis disingenuously fails to acknowledge that the Company's 2 Nuclear Units (2021/2023) timeframe is the most cost-effective portfolio under the High DSM sensitivity.

Duke explained that it is unreasonable to compare the Company's model portfolios that incorporate Base Case impacts for EE and DSM with those portfolios that incorporate High DSM impacts. SACE's analysis is fundamentally flawed in that its analysis compares model portfolios with different load profiles and is useless for the purpose of making any meaningful comparisons for resource planning purposes. This rings true for comparisons of Clean Energy portfolios, High Fuel Cost portfolios, and any other sensitivity portfolios to Base Case portfolios. According to Duke, the basic fact underlying this assertion is that each of the model portfolios includes the same load, and the production simulation model will dispatch the model to meet that load with the selected resource mix. When sensitivities are applied to a certain aspect of the model portfolios, such as to EE and DSM impacts, fuel costs or load variations, it must be applied to each model portfolio so that the selected aspect of each portfolio will be impacted similarly and the production simulation model will run each portfolio under the same constraints.

Duke maintained that SACE conveniently failed to address that when Duke's model portfolios are properly compared to each other, such that each portfolio includes the High DSM sensitivity impacts, the portfolio with 2 Nuclear Units (2021/2023) is the least cost to customers on a net present value basis. SACE's Attachment 1 to its comments includes all of the other evaluated portfolios with the High DSM sensitivity except the 2 Nuclear Units (2021/2023). However, one need only look to Table A2 of the 2010 IRP to discover that the 2 Nuclear Units (2021/2023) is $1.6 billion lower in cost on a net present value basis than the Natural Gas portfolio under the High DSM sensitivity. Applying that information to the chart set forth in Attachment 1, which includes the Natural Gas portfolio, clearly demonstrates the cost-effectiveness of the 2 Nuclear Units (2021/2023) portfolio as compared to the other portfolios under the High DSM sensitivity. Duke concluded that, even under SACE's misleading analysis, one can still objectively understand that the selected portfolio within Duke's 2010 IRP supports the development of a clean, reliable and cost-effective resource plan to meet its customer's need over the planning horizon.

According to PEC in its proposed order, its comprehensive analysis of achievable energy efficiency potential was described in the rebuttal testimony of PEC witness Chris Edge in Docket No. E-100, Sub 124. He stated that PEC contracted with ICF International, an industry leader in the design, implementation, market assessment and evaluation of DSM and EE programs, to perform a comprehensive analysis of the cost-effective, achievable potential across PEC's service territory. Mr. Edge testified that the ICF study considered the PEC-specific factors that impact potential savings from utility administered DSM and EE programs including: demographic and customer composition; PEC electric rates and avoided costs; known regulatory factors (i.e., the significant effect of customer opt-out provisions); and other assumptions specific to PEC's service territory. Mr. Edge explained that the study was intended to identify the approximate amount of cost-effective savings that can realistically be achieved through utility DSM and EE programs within the PEC service area over an extended period of time (and under a stated set of assumptions). He further explained that it serves as the foundation for identifying general areas and programs that might warrant consideration in PEC's DSM and EE portfolio. PEC argued that the DSM and EE potential a utility should incorporate into its least cost resource plan should be based upon a specific set of conditions that are unique to the utility's service territory to facilitate the most accurate comparisons with alternative solutions and that the methodology for deriving demand-side reductions for resource planning purposes should be based on a detailed, investment grade analysis of achievable, cost-effective options, versus a generic, hypothetical comparative analysis.

Evaluation of EE

According to SACE, EE is the least-cost system resource. Unlike supply-side resources, EE, even at aggressive levels, reduces customer utility bills. Energy efficiency also moderates rate increases by reducing or delaying the need for new generating capacity. In fact, states with leading EE programs often have electricity rates that are comparable to, or even lower than, North Carolina.[3] In addition to lower customer bills and rate moderation, the numerous benefits of EE include environmental quality improvements, water conservation, energy market price reductions, lower portfolio risk, economic development and job growth, and assistance for low-income populations.[4]

SACE argued in its comments that, despite these benefits, Duke and PEC significantly underestimate the potential EE savings in their IRPs. The utilities failed to consider efficiency resources on an equivalent basis as supply-side resources, and therefore, their IRPs do not result in the least-cost mix of resource options. Together, PEC and Duke forecast cumulative energy savings of 5.2 percent of retail sales over the next fifteen years.

SACE stated that Duke limits its program potential to the economic potential identified by its 2007 market potential study. Duke witness Richard Stevie testified in the proceeding on the 2008 and 2009 IRPs, however, that this study is out of date and that Duke is continuing to look at additional programs that were not analyzed in the potential study. PEC limits its program potential to the cost-effective, realistically achievable potential in its updated potential study. While the scope of PEC's updated study does appear to be broader than the earlier version, it appears to suffer from the same fundamental shortcomings as the earlier study. For example:

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[3] John D. Wilson, Energy Efficiency Program Impacts and Policies in the Southeast (May 2009) at 4, http://www.cleanenergy.org/images/files/SACE_Energy_Efficiency_Southeast_May_20091.pdf.

[4] See, e.g., Marilyn A. Brown et al., Energy Efficiency in the South, Southeast Energy Efficiency Alliance (April, 12, 2010), http://www.seealliance.org/se_efficiency_study/full_report_efficiency_in_the_south.pdf.

- PEC's potential study mentions that the findings were benchmarked against other utilities, but such benchmarking, if it has been done, has not been disclosed.

- Energy savings practices, measures and entire sectors remain excluded from the scope of study.

- It is not evident from the resource plan that PEC has yet made effective use of the insights offered by its consultant in the potential study. It does not appear that PEC has adopted some highly cost-effective programs and strategies included in PEC's market potential study, such as an ENERGY STAR Appliance program and certain non-residential incentive programs.

Further, SACE argued that PEC effectively assumes no further technological progress or development of new energy-saving practices. Duke is more confident about advances in efficiency, although this confidence is not fully reflected in its long-term resource plans.

SACE alleged that PEC and Duke primarily evaluate renewable energy resources in the context of minimum compliance with the REPS. Renewable energy potential is barely varied among the strategies considered in the 2010 resource plans proposed by Duke and PEC. One exception to this limited perspective is that both utility plans discuss offshore wind development, which is likely to require more than a decade to develop. SACE noted that North Carolina's utilities are prudently evaluating this resource in order to determine the appropriate development path in light of its resource characteristics and forecast system resource needs.

Additionally, SACE maintained that Duke and PEC should conduct an analysis of the potential ancillary benefits or costs of integrating significant levels of on-system renewable energy resources, including:

- The potential benefits regarding grid stability;

- The potential efficiency gains in transmission and distribution associated with higher levels of distributed generation; and

- The reduced costs associated with greenhouse gas and air pollutant mitigation.

SACE stated that Duke and PEC assume that the benefit of renewable energy resources is limited to about 5 - 7 cents per kWh (avoided costs), which seems to be an underestimate. Moreover, these utilities spend about twice this amount to build and operate baseload, intermediate or peak power plants.

According to NC WARN, EE will play a significant role in North Carolina's energy future. In its April 29, 2010 presentation to the Energy Policy Council (EPC), the

American Council for an Energy-Efficient Economy (ACEEE) presented an EE market potential study that demonstrated that an annual electricity savings of 1.2 - 1.6% is achievable over the next decade. Energy savings in the 24 - 32% range were shown to be achievable in North Carolina by 2025. Several other studies that have been presented to the Commission in recent years have shown similar potential savings. Given these savings, it is apparent from the IRPs that Duke and PEC incorporated into their IRPs only the minimal amount of EE required under the REPS, rather than what was practical. Last year NC WARN argued that the IRPs do not reflect customers who would adopt the EE measure regardless of any utility-sponsored EE program.

In its reply comments, PEC argued that NC WARN frequently comments on energy savings when discussing EE, without any real recognition of peak demand impact, implying that a 1% energy savings translates to 1% demand savings. This is a significantly flawed assumption. For example, NC WARN claims significant energy savings are realized through the replacement of incandescent light bulbs with compact fluorescents. While true that such actions produce energy savings, they have a negligible impact on summer peak demand which occurs late in the afternoon when lighting usage is insignificant.

PEC noted that SACE argued that PEC's long-term EE provisions lag significantly behind the "typical leading utility." SACE suggests that PEC should modify its IRP EE forecasts based on the arbitrary, aspirational goals of other utilities. In fact, SACE attempted to provide a comparative analysis of PEC and Duke with that of a generic "leading" utility. PEC offered that, as this is a fictional utility, SACE is unable to provide details as to where the utility is located, the composition of its customer base and its end-use load, the utility's rates, its avoided costs, etc. (all of which play a huge role in determining what DSM and EE programs it can cost-effectively offer). SACE then somehow determined the EE potential of this generic utility without any economic, technical, or market analysis. PEC then stated that, without any such supporting information, SACE concluded that PEC has significantly underestimated the potential EE savings in its IRPs and that "… Duke and PEC lag significantly behind the typical leading utility."

PEC noted that SACE also alleged that neither Duke nor PEC is using a comprehensive EE potential study in its IRP process. Regarding PEC, SACE stated: "PEC limits its program potential to the cost-effective, realistically achievable potential." PEC responded that it should only offer cost-effective, achievable DSM and EE programs. DSM and EE account for over 1,700 MW of load reduction in PEC's IRP. These projected impacts play a substantial role in PEC's ability to meet the future reliability needs of its customers. They must be real and achievable or the reliability of PEC's system will be impaired. Cost-effective, realistically achievable potential is the most prudent standard for resource planning purposes, versus a hypothetical potential derived from speculative, unsupported assumptions.

Duke argued that its projections relating to EE savings are not tied in any way to its REPS obligations. At present, the Company is statutorily limited to meeting up to

25% of its general REPS obligations under G.S. 62-133.8(b)(2)c through EE savings.[5] The Company's portfolio of programs are projected to achieve significantly more than 25% of the Company's general REPS requirements on an annual basis through the term of its 2010 REPS compliance plan. Under its REPS compliance plan, Duke stated that it intends to utilize EE to the fullest extent possible, accounting for 25% of the compliance requirement beginning in 2012, but this is not a limiting factor on the amount of EE the Company will be actively promoting. The Company's modified save-a-watt model, approved in the Commission's Order Approving Agreement and Joint Stipulation of Settlement Subject to Certain Commission-Required Modifications and Decisions on Contested Issues issued February 9, 2010, in Docket No. E-7, Sub 831, incentivizes it to attempt to achieve all cost-effective EE over the course of the pilot in order to achieve its stated savings targets.

Duke further added that, during the same meeting in which ACEEE presented its potential study to the EPC, Duke and PEC made a joint presentation which identified specific significant deficiencies in the ACEEE study. These deficiencies include:

- A lack of any adjustment for large customer statutory opt-out of utility EE and demand-side management programs, as permitted under G.S. 62-133.9;

- A lack of any adjustment for naturally occurring, customer-driven EE captured in the company load forecasts;

- Assumptions of unreasonably high participation rates that are not reflective of the current data for the utilities;

- Reliance on market potential studies completed before the passage of the Energy Independence and Security Act of 2007;

- A lack of any discussion of equipment life (also referred to as Rate of Turnover); and

- The inclusion of below efficiency standard impacts already captured in the utilities' load forecasts, thereby double-counting potential savings impacts.

Duke noted that SACE focused its criticism of the Company based on its comparison to what it deems a leading utility can achieve and alleged that Duke continues to underestimate its EE potential in its IRP. SACE also blamed the industrial opt-out provision of G.S. 62-133.9(f) for lost EE savings opportunities and criticized Duke for failing to perform a new market potential study for its IRP.

[5] In 2021, when the REPS obligation increases to 12.5%, this limitation on the use of EE savings increases to 40%.

Duke argued that, like NC WARN, SACE relied upon ACEEE data to support its market potential assessment and overlooked other current, region-specific information that informs reasonable expectations with respect to the realistic market potential for EE in Duke's service territory. The 2009 EPRI study estimated the economic potential for the Southern region to be 4.4% over 10 years, not the 7.2% to 13.6% cited by SACE in reliance upon ACEEE's analysis. Also, due to the lower than average electric rates and monthly bills that Duke's customer enjoy, some EE programs that work well in other markets may not be as attractive to customers or even cost effective. According to Duke, the ultimate driver of EE savings achievement is customer participation and choice. The Company is striving to achieve its High DSM case, which exceeds the estimated EE market potential developed by EPRI, but cannot assume it is going to happen without a track record of real results. For purposes of the 2010 IRP, the Company's Base Case for EE/DSM achievements represents a more reasonable and prudent input to the resource portfolio.

Baseload Requirements

NC WARN offered that, while there is no North Carolina definition of a baseload power plant, the Commission requires the electric utilities to file monthly Base Load Power Plant Performance Reports pursuant to Rule R8-53.[6] That rule requires reports on plant outages and generation capacity on each plant in the utility's nuclear fleet and listed coal plants, as well as all generating plants with greater than 500 MW maximum dependable capacity (MDC) utilizing coal or nuclear fuel. The 500 MW capacity limit clearly distinguishes between the baseload units that can be operated most of the time and the peaking units that are operated only when required. According to NC WARN, a useful distinction between the two resource types is that baseload units take time, up to days, to ramp up to full operation while peaking units, such as the natural gas combustion turbines (CT), can generate electricity in a far shorter period of time after being dispatched.

NC WARN explained that another way to view baseload is to include generating units that operate a certain percentage of the year, with rule-of-thumb estimates ranging from 35% up to 65% or more.[7] The U.S. Department of Energy, in its regulation, 10 C.F.R. 500.2, defines a baseload power plant as a power plant, the electrical generation of which in kilowatt-hours exceeds, for any 12-calendar-month period, such power plant's design capacity multiplied by 3,500 hours. This includes plants that operate for more than 40% of the year (3,500 hours divided by 8,760 hours in a year). In

[6] Duke currently is filing those reports in Docket E-7, Sub 935 and PEC in Docket E-2, Sub 971.

[7] NC WARN argued that, with increasing reliance on renewable energy sources, both the 500 MW definition and the 40% percentage definition may not hold up as combinations of solar and wind installations function as the equivalent to baseload. See Blackburn, "Matching Utility Loads with Solar and Wind Power in North Carolina: Dealing with Intermittent Electricity Sources," Institute for Energy and Environmental Research, March 2010. www.ieer.org/reports/NC-Wind-Solar.html.

order to reduce the costs of operating peak plants, the baseload plants should be operated at peak times.

NC WARN noted that in its February 2, 2011 Base Load Power Plant Performance Report filing in Docket E-7, Sub 935, Duke reported that it currently has 11,854 MW in baseload units.[8] These include the nuclear units, Oconee 1, 2 and 3; McGuire 1 and 2; and Catawba 1 and 2; and the coal units, Belews Creek 1 and 2; Marshall 1, 2, 3, and 4; and Cliffside 5. The addition of Cliffside 6, scheduled to begin operation in 2012, brings Duke's total to 12,679 MW. In its January 27, 2011 filing in Docket E-2, Sub 971, PEC reported that it currently has 6,359 MW in baseload units, including the nuclear units, Brunswick 1 and 2, Harris 1 and Robinson 2, and the coal units, Mayo 1 and Roxboro 2, 3, and 4.

According to NC WARN, these total baseload capacity figures are useful in looking at the load duration curves submitted in each of the IRPs. A load duration curve places the MW load on the system for each of the 8760 hours in the year and the resulting curve shows the annual range of load from the lowest load needed for an autumn night, as an example, to the highest peak on a summer afternoon.

NC WARN stated that Duke provided two load duration curves in its IRP, Figure 3.1 (without EE) on page 54, and Figure 3.2 (with EE) on page 57. The load range for 2010 is 4500 MW at the lowest end and almost 17,000 MW at the upper end, with the average 2010 hourly demand approximately 10,900 MW. NC WARN argued that an important factor emerges from reviewing Duke's load duration curves. When all of its baseload plants are in operation (12,679 MW), they provide more electricity than is needed for 87% of the hours in a year; in other words, not all of the existing baseload units can operate for most of the year. For most of the year, the plants are either shut down and idle or spinning (still operating but not connected to the grid).[9]

NC WARN explained that, in its load duration curves, Duke then forecasts increases in load for each of the hours for 2015, 2020 and 2025.[10] Even using the load duration curve without EE, Duke still has excessive baseload through 2025; with Duke's projected EE programs, the current baseload plants provide excessive load for more than 50% of the year. With additional EE measures or combined renewable energy sources, less and less baseload will be needed.

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[8] In its Base Load Power Plant Performance Report, Duke included Marshall 1 and 2, each having an MDC of 380 MW. These plants are operated primarily as baseload units and are included in the Duke totals used herein.

[9] Duke also uses baseload power as part of its pumped storage facilities, pumping water to an upper reservoir to release in peak periods. Duke includes a portion of these baseload plants as part of its reserve margin.

[10] NC WARN noted that the load duration curves show a substantially greater increase in growth for the hours requiring the lowest load than for peak hours.

NC WARN stated that, from its twelve-month summary in its January 27, 2011 filing in Docket E-2, Sub 971, PEC shows a total of 6,359 MW for its 500 MW-plus baseload units. In its IRP, at pages B-1 through B-4, PEC designated 7,373 MW as baseload resource type by including several smaller coal plants, Asheville 1 and 2, Robinson 1, in its baseload total. PEC's load forecast curves in its IRP, pages 26-28, show that for approximately 60% of the hours in the year 2010, not all of the designated baseload plants were required to meet its load.

According to NC WARN, in the IRPs, the utilities continue to show a need for baseload additions in their North and South Carolina jurisdictions. In its IRP, page 81, Duke is proposing two units at the Lee Nuclear Station in Gaffney, South Carolina, forecasted to be in operation in 2021 and 2023. Taking a more realistic approach, PEC advanced three scenarios in its IRP. While it has apparently backed away from its proposal to build new reactors at the Shearon Harris site, it still continues to include new baseload units in two of its three scenarios. PEC's preferred scenario, Plan A, proposes two jointly owned nuclear plants with it owning approximately 25% share of each plant. Plan B is a much more prudent approach assuming a fairly aggressive control of carbon dioxide. It contains no nuclear units, and the difference in generation consists of natural gas-fired combined cycle (CC) plants. Lastly NC WARN stated that Plan C shows two units at the Shearon Harris site in Wake County, but is highly unlikely as the scenario assumes, among other things, low nuclear construction costs.

In response, PEC stated that NC WARN's comments are based upon several incorrect assumptions. The first such assumption is that baseload generation is any supply-side resource with a capacity factor greater than 40%. Using this definition, NC WARN then creates a load duration curve that purports to support its claim that PEC and Duke have excess baseload generation. NC WARN's baseload definition sweeps in many intermediate load-following plants, including CC and intermediate coal plants. PEC's baseload coal plants are described in the testimony of PEC witness Dewey Roberts in Docket No. E-2, Sub 976. He stated that these plants have capacity factors of over 70%. Mr. Roberts also testified that PEC's baseload nuclear plants had capacity factors of over 91%. Finally, Mr. Roberts explained that even PEC's intermediate load following plants have capacity factors in excess of 50%. Thus, NC WARN's unique definition of baseload is so broad as to include all of PEC's plants except its simple cycle CT peaking units.

Importantly, according to PEC, resource planning does not hinge on administrative definitions of baseload, intermediate, or peaker. Instead, PEC's resource planning considers the load and energy needs of its customers, then models the dispatch of existing resources to meet these load and energy requirements, including necessary reserves, and identifies additional resources needed to reliably meet the remaining energy and load at lowest reasonable cost. The timing and characteristics of future capacity needs are determined by sophisticated industry-accepted modeling. NC WARN appears to be trying to define the capacity factor of baseload as low as 40% to include wind and solar as baseload. However, neither can achieve even that level of operation. Solar has, at best, a 25% capacity factor, while wind can generally achieve no greater than a 35% capacity factor.

PEC explained that, furthermore, wind and solar are each more expensive than PEC's current net asset value on a $/kW basis, and since PEC would have to add 2 MW of wind and solar generation to equal 1 MW of replaced capacity, the net effect for PEC would be at least a doubling of its capital costs. Further, the REPS structure recognizes that the cost of wind and solar each exceed avoided cost as demonstrated by actual contracts to date. Therefore, even considering that wind and solar provide free energy, a combination of the capital costs of wind and solar would far exceed avoided cost, without even taking into account the embedded cost of the generation to be shut down. NC WARN's approach overlooks the many important considerations in resource planning, including availability, reliability, dispatchability and overall cost of the resource mix.

In its reply comments, Duke stated that NC WARN's arguments are primarily based on a pessimistic view of load growth in the Company's service territory, its application of two outdated planning concepts, and several fundamental errors. NC WARN devoted four pages of comments to an argument that Duke already has excessive amounts of baseload capacity. NC WARN stated that, "[w]hen all of its baseload plants are in operation (12,679 MW) they provide more electricity than is needed for 87% of the hours in a year." NC WARN's 87% calculation results from determining the point where the 2010 Duke load duration curve, presented on pages 54 and 57 of the 2010 IRP, meets the 12,679 MW level.

Duke maintained that NC WARN's calculations and conclusion regarding Duke's alleged lack of need for baseload capacity are plainly wrong. First, NC WARN grossly miscalculated the Company's actual baseload capacity available to serve its customers. NC WARN's calculation included the full Cliffside Unit 6 capacity (825 MW), which was not available in 2010, and also included the entire capacity of Catawba Nuclear Station, of which Duke only owns 19.26%. Because the load duration curve in the 2010 IRP excluded that portion of the Catawba Owner's load for which Duke has no obligation to serve, the capacity calculation must also exclude the 1,109 MW portion of Catawba that is not retained by Duke. Correcting these two errors would remove 1,934 MW, reducing the 12,679 MW figure used by NC WARN to 10,745 MW. Instead of 87%, the corrected crossing point should result in a figure closer to 60%.

Duke argued that the use of load duration curves as a planning methodology has long been recognized as inaccurate and inadequate for determining optimal capacity mix for a generation system. The inaccuracy of this methodology is clearly illustrated through a simple examination of Duke's actual generation records for 2010. As a group, Duke's fourteen units that operate as baseload capacity for the system were in reserve shutdown (available, but shut down or idle) for 4,512 hours out of a total of 122,640 hours (14 x 8760) during the year. That represents 3.68% of the hours over an entire year when those baseload units were available, but not generating electricity for Duke's customers. When the actual data is compared to NC WARN's

87% miscalculation, as well as its patently false statement that "[f]or most of the year, the plants are either shut down and idle or spinning (still operating but not connected to the grid)," it is clear that NC WARN does not understand the facts that underpin the Company's resource planning and utilizes flawed methodology to criticize the Company's resource plan. Duke argued that these flawed conclusions presented by NC WARN are exactly why modern planning tools have replaced the use of load duration curves in determining an optimal capacity mix for resource planning purposes.

Cost of Additional Nuclear Generation

NC WARN argued that, regardless of the Commission's views on the risks and benefits from nuclear baseload units, the projected costs of this source of electricity have risen exponentially to the point they simply cannot be considered in the least cost mix. The cost of each new nuclear unit nationally is now in the $10 - 12 billion range, and very few are actively being considered.[11]

NC WARN reasoned that the IRPs, as filed with the Commission, contain little justification for the costs of the proposed nuclear units and even less discussion about the risks associated with proceeding with these large-scale projects. If the utilities continue to go ahead with the proposed plants, electricity bills will increase considerably over the next decade (or longer, given likely construction delays). These large nuclear units, each more than 1050 MW, would require large reserve capacity in case they are out of operation, increasing the costs even more. The construction and operation of these new nuclear plants are risky in terms of the costs to the ratepayers and taxpayers, as well to the overall economy of North Carolina. The risk is evident in that none of the current nuclear proposals are funded by financial institutions, i.e., Wall Street, and only a limited number of direct incentives, such as loan guarantees, have been made available from taxpayer-funded federal government programs.

NC WARN explained that, while nuclear costs are projected to continue to rise, the costs of renewable energy have consistently decreased. In his July 2010 paper, Dr. John O. Blackburn reviewed the costs of solar energy and nuclear power plants and determined that in 2010 solar energy has finally become less expensive than nuclear energy.[12] The study included all subsidies for both technologies and compared the cost per kWh generated by each. An important consideration in the Commission's review of the IRPs is that the cost of solar energy and other renewable energy sources is expected to continue to decrease while projected costs of nuclear power plants have risen steadily for the past decade and are expected to increase even more over time.

NC WARN argued that Dr. Blackburn's finding is confirmed in depth by the U.S. Energy Information Administration (EIA). The EIA, in its most recent Annual Energy

[11] See, e.g., Wald, "New Nuclear Plant Projects Stalled by Market Forces," February 8, 2011.

[12] Blackburn and Cunningham, "Solar and Nuclear Costs – The Historic Crossover: Solar Energy is Now the Better Buy," July 2010. Available at www.ncwarn.org/?p=2290.

Outlook, AEO2011, determined that the updated overnight capital cost estimates for nuclear power plants were 37% above those in the AEO2010, while photovoltaic technologies dropped by 25% in the same year. Using the definition of "overnight capital cost" from the World Nuclear Association, a supporter of nuclear energy worldwide,

> Capital costs comprise several things: the bare plant cost (usually identified as engineering-procurement-construction - EPC - cost), the owner's costs (land, cooling infrastructure, administration and associated buildings, site works, switchyards, project management, licenses, etc), cost escalation and inflation. Owner's costs may include transmission infrastructure. The term "overnight capital cost" is often used, meaning EPC plus owners' costs and excluding financing, escalation due to increased material and labor costs, and inflation.

NC WARN noted that the last items of financing, increased material and labor costs, and inflation are the components that raise the projected costs of nuclear power dramatically, and particularly if construction does not stay on schedule.

According to SACE, neither Duke nor PEC has provided, either in its IRP or in response to a data request, any supporting evidence or documents that form the basis for the nuclear cost estimate. There are a number of factors for the great uncertainty regarding the ultimate construction cost of Duke's proposed Lee Nuclear Station or any new nuclear power plants in the region.

PEC observed that, continuing with its attack on new nuclear generation, NC WARN stated, "These large nuclear units, each more than 1,050 MW, would require large reserve capacity in case they are out of operation, increasing the costs even more." PEC argued that NC WARN offered no support for this statement because it is unsupportable. These units require no more reserves than PEC's other units that are nearly 1,000 MW in size.

PEC continued, noting that NC WARN next suggested a cents/kWh comparison between EE and supply options. This is another example of a one-dimensional comparison of "apples and oranges" that may appear to support NC WARN's premise, but is meaningless and unsupportable in the context of an IRP proceeding. A CT, for instance, may cost 30 cents per kWh because it does not generate much electricity, but that does not mean PEC would never select it as the least cost resource. The only meaningful comparison for cost to customers is the final rates they pay (or as a proxy, revenue requirements when only supply-side resources are considered) based upon the total least cost resource mix proposed, including total system fuel impacts. In addition, the amount of EE reasonably and economically available must also be considered in this analysis.

PEC noted that SACE asserted that PEC did not consider nuclear construction cost uncertainty in its analysis. In response, PEC referred SACE to Appendix A of PEC's 2010 IRP, in which PEC presented sensitivities (see page A-4) that were

+/- 30%; and to page A-7, where PEC used the +30% figure for 2 of the 3 scenarios. Importantly, PEC's IRP does not include the construction of a new nuclear unit. The only new nuclear generation is the potential participation in a regional project, and PEC would have to obtain Commission approval prior to participating in such a project.

According to Duke, NC WARN continues to make the assertion that the projected costs of new nuclear resources "have risen exponentially to the point they simply cannot be considered in the least cost mix." The Company's analysis of its own proprietary and the publicly available information indicates otherwise. Duke's most recent projection of the overnight cost of building two twin AP1000 units at the proposed Lee Nuclear Station site in Cherokee County, SC, is $11 billion, in 2010 dollars, exclusive of financing costs and exclusive of the impacts of inflation. This estimate was developed for Duke by Westinghouse Electric Company, LLC, and its consortium partner Shaw, Stone and Webster, Inc. (collectively WEC/SN). WEC/SN Engineering, Procurement & Construction (EPC) consortium is the EPC contractor for the two other AP1000 projects in the United States, Southern Company's Vogtle Nuclear Plant (Vogtle) and South Carolina Electric & Gas's (SCE&G) V.C. Summer Nuclear Plant (Summer), and is similarly involved in the construction of the AP1000 units in China. There are currently four AP1000 units under construction in China, and both Vogtle and Summer are ahead of Duke's Lee Nuclear Station in both licensing and construction. Duke has been following all of this activity closely, and early experience suggests that the construction work is going well as the AP1000 projects remain within schedule and budget and are moving forward as expected. On October 21, 2010, SCE&G, at an allowable ex-parte briefing, provided an update to the Public Service Commission of South Carolina (PSCSC) on the construction of the Summer Nuclear Plant. At that update, Steve Byrne, SCE&G Chief Generation Officer, told the Commission that the Summer project was moving forward as expected and that SCE&G had just completed negotiations with WEC/SN to move additional costs from the target category to the firm/fixed category. According to Mr. Byrne, approximately two-thirds of the Summer plant cost is now in the firm/fixed category. Additionally, Mr. Byrne explained that due to lower escalation rates, the new project cost projections were reduced by approximately $1 billion to $9.6 billion versus the initial estimate of $10.6 billion.[13] Additionally, SCE&G's most recently filed quarterly report, filed on February 14, 2011, in Docket No. 2008-196-E pursuant to PSCSC Order No. 2009-104(A), indicates that it is on track to complete the two units at Summer on its scheduled completion dates within the original construction cost forecast.

Duke explained that additionally, the new nuclear licensing process, involving the Nuclear Regulatory Commission's (NRC) issuance of the combined construction and operating license (COL) for the Vogtle, Summer and Lee Nuclear Station projects, will also help with the cost certainty on new nuclear projects. By the time the Lee Nuclear Station project is ready to start construction, the NRC will have reached its decision

[13] The transcript of the SCE&G briefing is available on the PSCSC's website at the following web address: http://www.psc.sc.gov/exparte/epb-2010-10-21/epb-20101021 Transcript Presentation Materials.pdf.

regarding the approval of the AP1000 design, and engineering and design for the AP1000 will be close to 100% complete, thereby bringing greater certainty to construction plans.

Duke recognized that the cost estimates used in its planning models are very important, and as such Duke stated that it continues to monitor all available projects and industry data to ensure that its estimates are in line with recent experience and based on the best available information at that time. Duke further stated that it believes that all recent experience in China and at the two plants in the Southeast, as well as the recent trend in industry data of lower escalation rates, supports the current level of its cost estimates used for resource planning purposes. Additionally, Duke noted that it models various project risks specifically relating to increases in capital cost and incorporates such analysis into the IRP through the +20%/-10% Nuclear Capital Cost Sensitivity used in its IRP analysis.

Duke noted that SACE, like NC WARN, also questioned Duke assumptions regarding the cost and schedule for construction of a new nuclear generating facility. SACE pointed to the history of the initial nuclear build-up in the United States and certain isolated examples of current projects developing different technologies to assert that the Company's estimates are inaccurate. As articulated above in response to NC WARN's comments, Duke stated that it believes that its current estimates for the schedule and cost of the proposed Lee Nuclear Station are reasonable and based upon the best information available at this time from the appropriate industry sources.

With respect to the schedule, Duke stated that it is important to include a full description of the construction window as well as the window for start-up and fuel load. The Lee Nuclear Station schedule currently shows deployment to the site for construction in the summer of 2014 for two years of initial site construction activities. At the end of construction is a six month window for fuel load and initial start-up testing. When defining the construction window from site deployment to commercial operation, the Lee Nuclear schedule represents an overall construction schedule duration approaching seven years for Unit 1. Duke believes this is a very realistic schedule given:

- The AP1000 design and engineering will be substantially completed before construction starts;
- A stable NRC licensing platform avoids introduction of new requirements;
- The AP1000 design includes a simplified nuclear island design with passive safety features;
- Advanced modular construction techniques are currently being proven during construction of AP1000 reactors in China, and additional construction technique evaluation for the AP1000 in the United States will occur before the construction of Lee Nuclear Station begins;

- The extensive use of proven Pressurized Water Reactor (PWR) technologies; and

- The significant level of planning in coordination with the WEC/SN consortium that has gone into developing the current schedule.

According to Duke, a key consideration in Duke's selection of the AP1000 design was its simple passive design features and extensive use of proven PWR technologies. The passive design and use of proven technologies are strong mitigants to the asserted risks. The Company's approach is consistent with recently issued guidance from the Institute for Nuclear Power Operations (INPO), which states that "[m]odular design and construction, done correctly, can significantly reduce both overall construction cost and time. The decision to use modular construction techniques should be made at the very beginning of a project and factored into the overall design and constructability reviews. The use of modular construction can generally reduce the overall weight of steel by 20 to 40 percent."[14] Additionally, despite SACE's speculative remarks to the contrary, supply chain capacity has continued to expand while demand has reduced since the economic downturn of 2008.

Duke asserted that the NRC has recently affirmed the design certification schedule for the AP1000, which will lead to its certification of the AP1000 design, in its current revised design, in September 2011. The AP1000 reference COL for Vogtle is expected to be issued within months of the NRC certification of the AP1000 revised design. Duke stated that it continues to diligently monitor lead times for critical plant equipment, licensing activities and construction operations at all AP1000 design facilities both in the U.S. and abroad to stay current on the best available relevant information relating to the future construction of the Lee Nuclear Station. Based on its internal analysis and relevant industry information, Duke stated that it firmly believes that its current schedule for the proposed construction of Lee Nuclear Station is reasonable and prudent.

Greenhouse Gas Emissions

According to SACE in its comments, Duke acknowledged the risk that federal regulation will require reductions of GHG emissions. However, Duke did not present any evidence in its 2010 IRP that it has a realistic plan for reducing its GHG emissions during the planning period.

SACE stated that Duke recognized that it is likely that Congress will adopt mandatory GHG emission legislation at some point, although the timing and details are highly uncertain at this time. Duke also recognized that the Environmental Protection

[14] INPO 11-001, February 2011, INPO/Utility Benchmarking Current Domestic Modular Construction Facilities.

Agency (EPA) is undertaking actions to regulate emissions of GHG from new and modified major stationary sources, including power plants. Moreover, the air quality permit for the new Cliffside Steam Station Unit 6 requires that Duke retire Cliffside Units 1-4, plus an additional 800 MW of coal-fired units located in North Carolina by the end of 2018. In addition, the air permit requires the company to take additional actions to render Cliffside Unit 6 carbon neutral by 2018, subject to Commission approval and "appropriate cost recovery." Nonetheless, Duke currently projects that its system carbon dioxide (CO_2) emissions will increase between 2010 and 2030, whether it adds new nuclear units or just new natural gas-fired units.

SACE explained that it is not surprising that Duke is projecting that its annual CO_2 emissions will rise between 2010 and 2030. Even though Duke is planning to retire more than 1,600 MW of existing coal capacity, emissions reductions from those retirements will be more than offset by increased emissions from the new Cliffside Unit 6 coal plant. Cliffside Unit 6 will emit approximately six million tons of CO_2 each year, or more than two million tons of CO_2 per year more than the 2008 CO_2 emissions from all of the coal units that Duke proposes to retire. In addition, Duke is planning to add more than 4,000 MW of new gas-fired CC and CT capacity over the planning period. Although they emit significantly less per MWh than coal-fired facilities, gas-fired units do emit CO_2.

SACE noted that, like Duke, PEC recognized that it is likely that Congress will adopt mandatory GHG emission legislation at some point and that EPA is undertaking actions to regulate emissions of GHG from power plants. Despite this acknowledgment, PEC provided no evidence in its 2010 IRP that its proposed resource plan (or the two alternatives it considered) actually will result in any, let alone significant, reductions in the GHG emissions from the Company's generation fleet. Unlike Duke, PEC did not even include a figure in its IRP showing the trajectory of future annual CO_2 emissions under its proposed and alternative resource plans.

SACE observed that PEC is proposing to retire 1,500 MW of its existing coal-fired units and to replace those retired units with 1,500 MW of state-of-the-art gas-fired generation. Although natural gas-fired generation emits only about 60 percent as much CO_2 per MWh as coal-fired units, the new state-of-the-art gas units being added by PEC can be expected to operate more often than the coal units slated for retirement have operated in recent years, especially given projected low natural gas prices. This means that it is possible that the Company's replacement of existing coal by new gas CC units may not result in any significant reduction in PEC's system CO_2 emissions. At the same time, the Company's proposed resource plan will add thousands of MW of additional CC and CT capacity during the 2010 to 2030 planning period. SACE argued that, as a result, it is reasonable to expect that the Company's annual system CO_2 emissions will not go down much, if at all, during the planning period.

In its reply comments, PEC responded that, while SACE claimed neither Duke nor PEC has shown in its 2010 IRP that it has a realistic plan for reducing

GHG emissions, this is incorrect. Appendix A to PEC's 2010 IRP explicitly shows that PEC considered the potential impact of carbon regulation in performing its scenario analyses. Implicit in the high and low carbon regulation scenarios is the reduction of GHG emissions.

Regarding natural gas-fired generation, PEC stated that it is retiring 1,500 MW of coal generation and replacing it with new natural gas-fired generation. PEC noted that SACE did not object to PEC being awarded the certificates of public convenience and necessity to construct the new natural gas-fired generation, and supports PEC retiring the coal generation. Yet now, SACE in this proceeding argued that even though natural gas-fired generation emits only about 60 percent as much CO_2 per MWh as coal-fired units, PEC can be expected to operate the new natural gas-fired generation more often than the coal units it is replacing and, therefore, emit the same amount of greenhouse gases. PEC reasoned that one must first wonder, if a utility is not to use nuclear, coal, or natural gas, how can it possibly be expected to meet the electricity needs of its customers? But more to the point, in the certificate proceedings in which the Commission approved PEC constructing the new Wayne County and Sutton natural gas facilities, one of the key cost justifications was these new units would allow PEC to better comply with new or future GHG emissions requirements due to their reduced emissions.

According to Duke in its reply comments, SACE further criticized Duke for allegedly failing to have a realistic plan to reduce GHG emissions over the planning horizon and for failing to evaluate the economics of the continued operation of its coal generating facilities with environmental controls already installed. The Company disputed this contention. Duke's IRP has been designed and modeled to provide affordable, reliable, and clean resources to meet future customer needs in a carbon-constrained environment. From the time the Company began to incorporate potential GHG regulation into its resource planning process in 2006, Duke has assumed a cap-and-trade program would be enacted. Even now, with the change in leadership in Congress, many believe that GHG constraints in the form of regulation from the EPA are likely to be implemented. Under this assumption, the Company has sought to develop a cost-effective portfolio of resources that meets customer energy needs while complying with the assumed GHG regulation. Duke stated that its results consistently demonstrate that this is best achieved through a balanced portfolio that includes nuclear, coal, gas, hydro and renewable energy generation, end-use EE, and the purchase of GHG emission allowances. As the proposed emissions cap declines over time, the price of GHG allowances will likely increase. As the prices of GHG allowances increase, additional end-use EE, nuclear, natural gas, and renewable generation will likely be more cost-effective and, over time, will lead the Company to replace coal-fired generation resources as those resources near or reach the end of their economic lives.

Duke explained that coal-fired generation resources, particularly those with environmental controls, will continue to be an important part of the portfolio through at least 2030 over a range of potential GHG allowance prices. To the extent such resources become less economic to operate as part of the Company's portfolio in the future, Duke will make all necessary adjustments to ensure that its generation system is being planned, constructed, and operated at the least reasonable cost to its customers. The Company's current coal fleet includes some of the most economic units on the system, as evidenced by the high capacity factor projections in the 2010 IRP. As Cliffside Unit 6 comes online, the efficiency of Duke's coal fleet will improve even more as the older, less efficient units move even further up the dispatch stack and will ultimately be retired by 2015. Duke will continue to evaluate new GHG regulations as they develop and analyze their ultimate impact on its current generating system. At the present time, the Company believes the selected portfolio within the 2010 IRP, which includes a combination of new nuclear, natural gas, and renewable resources, as well as additional EE and the retirement of all coal generating units without environmental controls, represents the best plan to meet its customers energy needs in the most clean, affordable and reliable way possible over the planning horizon.

Existing Scrubbed Coal Units

According to SACE, neither Duke nor PEC presented in its 2010 IRP any specific analysis of the risks faced by its existing scrubbed coal plants, any assessment of what controls will be needed to be added at each of these units, or whether it will be more economic to add such needed controls than to retire the unit(s). SACE asserted in its comments that this is a serious flaw. Duke's responses to a SACE data request reveal that the Company has prepared some analyses of the costs of adding controls to some of its coal units with SO_2 scrubbers that it does not currently plan to retire. PEC also provided in response to a data request several studies of the cost and economics of retiring some of its older coal units. In addition to showing that retirement of the units at Cape Fear and Weatherspoon is the more economic option, these studies also showed that retirement of the Robinson coal plant by 2014 is the more economic option in almost all of the scenarios studied. SACE argued that the analyses prepared by Duke and PEC should be presented to the Commission in the companies' IRPs to allow the Commission and other parties a full opportunity to review and critique them. In addition, PEC should analyze the economics of the retirement versus continued operation of each of the existing coal units that the Company is not currently planning to retire in the near future.

In its reply comments, Duke explained that coal-fired generation resources, particularly those with environmental controls, will continue to be an important part of its portfolio through at least 2030, over a range of potential GHG allowance prices. To the extent such resources become less economic to operate as part of the Company's portfolio in the future, Duke stated that it would make all necessary adjustments to ensure that its generation system is being planned, constructed and operated at the least reasonable cost to its customers. According to Duke, the Company's current coal fleet includes some of the most economic units on the system as evidenced by the high capacity factor projections in the 2010 IRP.

In its reply comments, PEC stated that its analysis of retiring unscrubbed coal units in its Lee/Wayne and Sutton filings Docket No. E-2, Subs 960 and 968, demonstrated that a significant part of the cost of continued operation was the addition of scrubbers and Selective Catalytic Reduction (SCR) to those units. Scrubbed units would not face these costs, and the existing scrubbers do address, in part, future environmental requirements, including mercury.

Overly Optimistic Growth Projections

According to NC WARN, a review of past IRPs shows that both PEC and Duke have consistently lowered most of their successive projections of increased electricity demand. In comparing its 2005 and 2010 IRPs, Duke's forecasts for peak demand in 2015 decreased by 20.4%. During the same time, the projections for 2025 decreased by 2.0%. In comparing PEC's 2005 and 2010 IRPs, the utility showed no change in peak demand forecast for 2015, but it showed a 9.3% decrease in total sales in 2015. As the IRPs show, both Duke and PEC have experienced nearly flat growth in electricity demand for several years. PEC's actual retail sales grew only 0.3% annually from 2000-2009, and Duke's grew only 0.7% annually from 1994-2009. PEC expects its retail sales of electricity to increase by 1.4% annually through its 15-year planning period. Duke is optimistically projecting 1.5% through its 20-year planning horizon.

According to NC WARN, in its 2009 rate case, Docket E-7, Sub 909, Duke adjusted earlier projections to reflect the impact its rate hike would have on customer usage. The revised estimates projected a slightly negative trend in retail sales over the next five years. Notably, these projections were made in early 2009, before the worst impacts of the current economic recession. It seems likely that because of the current economic situation, consumers will remain cautious and growth in sales will remain flat or decrease, especially as any new purchases of appliances, homes, lighting, HVAC systems and turbines will be considerably more energy efficient than current stock.

According to PEC, NC WARN once again challenged the veracity of PEC's load forecast. In support of its attack, NC WARN asserted that PEC's retail sales only grew 0.3% annually from 2000 to 2009. PEC argued that NC WARN has taken this data out of context to create a very misleading picture of the forecast. PEC's industrial retail sales declined by almost 30% from 2000, (when industrial accounted for about 36% of total retail sales) to 2009. Over the same period, PEC's residential and commercial sales increased by 20%, or about 2.1% per year. In the forward looking years, PEC forecasts a smaller rate of growth in the industrial sector, about 0.8% per year. The growth in PEC's residential and commercial sectors amounts to about a 1.6% growth rate, which is entirely consistent with history. Unless NC WARN wants to present a scenario of continued decline in the industrial sector in NC, and its accompanying loss of jobs and economic health, there is no basis for this assertion.

PEC asserted that, furthermore, in 2008 the Commission conducted a hearing to evaluate the utilities' forecasting process and found it valid. The Public Staff, in its comments in this proceeding, concluded that the assumptions that underlie PEC's peak and energy forecasts are reasonable; that PEC has employed accepted statistical and econometric practices used in forecasting; and that PEC's peak load and energy sales forecasts are reasonable for planning purposes. The Public Staff's conclusions are consistent with the Commission's findings in the 2009, 2008, 2007 and 2006 IRP proceedings.

In its reply comments, Duke maintained that all customer EE activities are captured in the load forecast since that represents metered consumption and the actions of customers in determining how much energy to consume. All of the activities and customer decisionmaking processes associated with energy consumption highlighted by NC WARN are reflected in the historical data and thus represented in the forecasting models used to prepare the Company's load forecast. Similarly, it is an overstatement that load growth has been flat for the past several years. Recent economic events have primarily impacted the industrial sector. However, industrial load growth increased 7% from 2009 to 2010. In addition, excluding the industrial sector, retail load growth has been 1.5% per year for the period 2004 to 2009. It is incorrect to claim that recent slow growth in total sales should imply that it will continue into the future.

Duke stated that the recent declines relating to kWh sales are clearly related to the housing market bust in 2007-2008 and resulting recessionary impacts on the national and regional economies. It is, however, unreasonable to assume that its service territory will continue to experience such a reduction in growth over the entire planning horizon for this IRP. Duke stated that it believes that its load growth projections incorporated into the 2010 IRP are reasonable for planning purposes and that this view is shared by the Public Staff in its comments.

Convening a Workshop or Workgroup

SACE stated in its comments that, if the Commission elects not to schedule an evidentiary hearing on the utility IRPs, the Commission should consider convening a workshop on a limited set of issues. Such a workshop could provide an opportunity for the electric utilities to present their IRPs, and for intervenors to present their analysis of those IRPs to the Commission, and for the Commission to question the parties' representatives on the issues it identifies, without the need for formal witness testimony. In addition, or in the alternative, the Commission may wish to consider establishing a collaborative workgroup to discuss and report on certain issues related to the IRPs and the resource planning process. SACE suggested that such a workgroup would be more effective if it continued to meet after the conclusion of the present docket, so that the workgroup's suggestions and recommendations could inform the utilities' development of the 2011 annual reports and 2012 biennial reports. To enable the full participation of the Public Staff, the Commission may wish to engage a third-party facilitator if it decides to convene such a workgroup.

Duke asserted that it finds SACE's proposal for a technical workshop unnecessary at this time given the opportunity that the parties have had to review and comment upon the IOUs' IRPs.

PEC did not comment on this issue in its reply comments or proposed order.

Conclusions

The Commission finds that PEC and Duke have adequately addressed the issues related to EE, DSM, and portfolio selections in their reply comments. Likewise, both PEC and Duke have offered responses to the issues regarding baseload requirements, the cost of new nuclear generation, GHG emissions, and existing scrubbed coal units that the Commission finds satisfactory and appropriate.

The issue related to overly optimistic growth projections by both PEC and Duke, raised by NC WARN, was also raised by NC WARN in the 2010 evidentiary hearing on IRPs. The Public Staff has reviewed these current forecasts, as it does in every IRP proceeding, and found them to be reasonable for planning purposes. The Commission finds again, as it did in its Order in Docket No. E-100, Sub 124, issued on August 10, 2011, that the growth projections made by PEC and Duke and the resulting energy and peak load forecasts are reasonable and appropriate.

As to the SACE issue of convening a workshop or workgroup, the Commission agrees with Duke that such a process is unnecessary. The existing IRP process allows ample opportunity for intervenor comment and, in fact, allows an intervenor to file an integrated resource plan or report of its own as to any utility.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 6

In its comments, the Public Staff stated that, in addition to new generation to meet load growth, and facilities previously scheduled for retirement, PEC should have also incorporated retirement of additional coal-fired capacity as required by Commission Order dated January 28, 2010, in Docket No. E-2, Sub 960. The retirement plan submitted by PEC in this docket indicated that all unscrubbed coal generation would be retired by December 31, 2017. Robinson Unit 1 is not scrubbed and is not included in the planned retirements. PEC's filing should have included all required retirements.

In its reply comments, PEC responded that it does not understand this recommendation. PEC indicated in its 2010 IRP that it is still evaluating the best course of action for its Robinson coal plant in South Carolina. In contrast to PEC's Cape Fear, Sutton, Lee and Weatherspoon coal plants, all of which PEC has committed to retire by the end of 2014, PEC's Robinson coal plant does have some environmental controls. Also, the natural gas-fired generation to be constructed at PEC's Sutton and Lee plant sites is only sufficient to replace the coal generation at PEC's Lee, Sutton, Cape Fear and Weatherspoon sites. The retirement of PEC's Robinson coal plant would require the construction of additional natural gas-fired generation.

Conclusion

In the absence of continued opposition by the Public Staff, the Commission is of the opinion that PEC has adequately addressed this issue in its reply comments and, therefore, the Commission concludes that the response provided by PEC is satisfactory.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 7

In its comments, the Public Staff requested that PEC and Duke file with their reply comments the specific explanation required by Rule R8-60(i)(3) for each year in which the revised projected reserve margin exceeds plus or minus 3% of the target.

PEC

In its reply comments, PEC stated that the explanation is straightforward. PEC's reserve margin exceeds 3% in those years immediately following the addition of new generation resources, which is to be expected. Resource additions are inherently "lumpy." They cannot economically be added in the exact amount needed each year to maintain an exact reserve margin. PEC's forecasted reserves exceed 3% of PEC's minimum capacity margin target in 2011 and 2012 as a result of the economic addition of the Richmond CC unit as demonstrated in Docket No. E-2, Sub 916. Reserves exceed 3% of PEC's minimum capacity margin target in 2013 and 2014 as a result of the economic addition of the Wayne County CC unit as demonstrated in Docket No. E-2, Sub 960.

Duke

In its reply comments, Duke acknowledged that its system reserve margin is projected to exceed its target reserve margin of 17% by more than 3% over the course of the planning period in the years 2012, 2013, 2014, 2021, 2023, and 2024. These projected increases in reserve margin are driven by the recessionary impacts to load and timing of additions of necessary system generating capacity. Specifically, the additions of Cliffside Unit 6 (825 MW) and the Buck CC facility (620 MW) contribute to the increased reserve margin in 2012, and the addition of the Dan River CC facility (620 MW) further increases the reserve margin above the 17% target in 2013 and 2014. However, by 2015, due to the assumed retirement of over 1,600 MW of coal fired capacity and 370 MW of CT capacity, the reserve margin moves back to within 3% of the Company's target. In 2021, Lee Nuclear Unit 1 (1,117 MW) increases the reserve margin to over 20%. The second Lee Nuclear unit (1,117 MW) in 2023 also increases the reserve margin over 20% in 2023 and 2024. By 2025, the reserve margin is projected to move back within the target range due to continued load growth.

Conclusion

The Commission finds that PEC and Duke have adequately answered the Public Staff in their reply comments.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 8

In its comments, the Public Staff requested:

a) That Duke identify in its reply comments the period during which the double-counting of avoided capacity cost benefits occurred and provide an explanation of the effect of the issue, on any data filed with the Commission, including whether the error influenced Tables 4.1 and 4.2 of the IRP, and provide calculations or other necessary data supporting its response.

b) That Duke should provide in its reply comments a list of all dockets filed with the Commission since January 1, 2005, that included any information, input data, or output results from the DSMore model affected by the double-counting issue.

c) That within 30 days, Duke should file in the respective dockets of each DSM program and pilot approved by, or pending before the Commission, a calculation showing the difference between the avoided cost capacity and energy benefits as originally filed, and the avoided cost benefits recalculated using the correct calculation methodology.

In its reply comments, Duke explained that the Public Staff, in its review of Duke DSM and EE programs, specifically the cost-effectiveness test results of the Company's Power Share Call Option (Docket No. E-7, Sub 953) generated by the DSMore model, observed a calculation of avoided production (energy) costs which seemed relatively high for a DSM program. The cost-effectiveness of the Power Share Call Option and Duke's other Power Share and Power Manager programs, approved in Docket No. E-7, Sub 831, is largely based on avoided capacity costs, and as such, the elimination of the avoided energy cost benefits from the cost-effectiveness results would not change the overall cost-effectiveness of any of the programs.

Duke explained that through the discovery process in this docket, it explained to the Public Staff that the high level of avoided production cost benefits improperly included an amount of avoided capacity cost benefits which were embedded in the inputs used to calculate the avoided production cost benefits. As the Public Staff described in its comments, this DSMore calculation methodology error resulted in a "double-counting" of the avoided capacity cost benefits in Duke's cost-effectiveness evaluations for its Power Share Call Option DSM program. The Public Staff correctly noted that the Company has since corrected the calculation methodology within DSMore to prevent future model runs from performing this incorrect double-counting calculation. The Public Staff also indicated that, based on further discussions with Integral Analytics, LLC, the developer of the DSMore software, it believes that the double-counting of the avoided capacity cost benefits was limited to the overstatements of dollar savings from avoided production cost benefits in the cost-effectiveness tests and did not affect the assumptions of the kilowatt capacity savings from DSM programs represented in Duke's 2010 IRP. Further, the Public Staff stated that it did not believe that any EE program evaluations were impacted by this error, and that the Company's IRP did not need to be adjusted because of this issue. However, the Public Staff stated that it does believe that any erroneous cost-effectiveness test results filed with the Commission in connection with previous DSM program applications should be corrected and refiled in the appropriate dockets, along with an identification from Duke of the period during which the double-counting occurred and an explanation of the effect of the issue on any data filed with the Commission.

Duke has confirmed that the double-counting of avoided capacity cost benefits for its DSM programs occurred during the period of May 2007 to February 2011. As the Public Staff noted in its comments, only DSM programs were impacted, so any values related to EE programs were not impacted. Also, specifically relating to Tables 4.1 and 4.2 of the IRP, which show the respective base case and high case projected load impacts of the Company's EE and DSM portfolio of programs over the planning period, this double-counting did not impact the Company's EE and DSM forecasts as they contain only MW and MWh values. Only dollar amounts related to cost-based avoided production included in certain benefit/cost analyses for DSM programs were impacted. The resulting impact of the double-counting was that the subject DSM programs were shown to be more cost-effective than they otherwise should have been. In any future filings, Duke will remove any double-counting of benefits from all calculations of benefit/cost ratios for DSM programs.

In its reply comments, Duke stated that it will compile a listing of all dockets filed with the Commission since January 1, 2007, that included any information, input data, or output results from the DSMore model and will correct (1) any documents that contained incorrect avoided capacity cost benefits and (2) any documents that contained incorrect cost-effectiveness test evaluations resulting from the DSMore double-counting issue. However, due to the significant number of documents that must be reviewed to determine which may have been impacted, the Company proposed to submit such information within 60 days from the date of this filing. Duke submitted that this additional time was necessary to complete this request in order to properly identify all pertinent documents, correct any necessary miscalculations and supplement the relevant filings as necessary. Duke then filed this information on May 2, 2011.

Conclusion

Based on Duke's responses in its reply comments and its May 2, 2011 supplemental filing, the Commission concludes that Duke has adequately addressed the Public Staff's requests concerning this issue.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The Public Staff observed that French Broad and Blue Ridge did not file IRPs, although NCEMC did include French Broad's load forecast as an appendix to its IRP. Blue Ridge advised the Commission in a letter of July 6, 2009, that it would no longer file IRPs because it had entered into a full requirements power purchase agreement with Duke, and likewise French Broad purchases all of its power requirements from PEC. Prior to 2007, Commission Rule R8-60(b) provided that the requirement to file IRPs applied only to PEC, Duke, DNCP and NCEMC. In that year the Commission amended subsection (b), in Docket No. E-100, Sub 111, to state that the requirement also applied to "any individual electric membership corporation to the extent that it is responsible for procurement of any or all of its individual power supply resources." The Public Staff stated that it believes that French Broad and Blue Ridge, which are responsible for procuring their own power supply resources, are now required by subsection (b) to file IRPs and should begin filing them next year.

In its reply comments, Blue Ridge stated that on September 1, 2006, it entered into a partial requirements power purchase agreement with Duke. Thereafter, on December 17, 2007, Blue Ridge entered into a full requirements power purchase agreement with Duke (the Blue Ridge Agreement). On October 1, 2010, the Blue Ridge Agreement was amended to extend the term until December 31, 2031, and to obligate Duke to provide REPS compliance services for Blue Ridge. Blue Ridge's current and future load requirements are included in Duke's load obligation set forth in Duke's IRP, dated September 1, 2010.

Blue Ridge explained that pursuant to the Blue Ridge Agreement, and as shown in Duke's IRP, Duke's services to Blue Ridge include the delivery of renewable energy resources to Blue Ridge, as well as REPS compliance and reporting services. In accordance with G.S. 62-133.8(c)(2)(e), Blue Ridge may rely on Duke to provide such services. Accordingly, Duke has aggregated the information required under Commission Rule R8-67 for Blue Ridge into its 2010 REPS compliance plan.

Blue Ridge argued that the filing of an IRP by Blue Ridge, separate and apart from the filing of Duke's IRP, which includes the information for Blue Ridge, would be unnecessarily duplicative. The information required of Blue Ridge by Rule R8-60 and R8-67 is included in the IRP filing of Duke. To require a separate filing by Blue Ridge itself would be an unnecessary expenditure of the time and resources of Blue Ridge in having to prepare such a filing, and of the Public Staff and the Commission in having to review it.

French Broad did not respond to this issue. GreenCo's consolidated REPS compliance plan includes French Broad.

Conclusions

Because both Blue Ridge and French Broad have full requirements contracts with utilities that have an IRP filing obligation, the Commission finds Blue Ridge's argument persuasive. Both Blue Ridge and French Broad are adequately covered through inclusion of their data in existing IRPs and REPS compliance plans.

DISCUSSION AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 10 - 12

In its comments, the Public Staff requested:

a) That all EMCs include a full discussion in future IRPs of their DSM programs and their use of these resources as required by Rule R8-60(i)(6);

b) That Piedmont indicate in its reply comments whether its smart meter program is an EE program, and if so, file for Commission approval of the program pursuant to Rule R8-68; and

c) That EU provide in its reply comments and in future IRPs a more detailed description of the participation and savings related to specific DSM and EE programs, and more particularly any DSM or EE program it proposes to use to meets its REPS obligations.

Conclusions

None of the EMCs addressed these issues in reply comments. In fact, of the EMCs, only Blue Ridge filed any reply comments. The Commission agrees with the Public Staff and, therefore, requires that all EMCs shall include a full discussion in future biennial IRPs of their DSM programs and their use of these resources as required by Rule R8-60(i)(6); that if Piedmont determines that its smart meter program is an EE program, it shall file for Commission approval of the program pursuant to Rule R8-68; and that in future biennial IRPs, EU should provide a more detailed description of the participation and savings related to specific DSM and EE programs, particularly those its proposes to use to meet its REPS obligations.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The Public Staff stated in its comments that, during the 2010 summer, several instances occurred when PEC's reserve margins dropped to low single digit values. These instances coincided with both scheduled and non-scheduled maintenance of generation units, along with abnormally hot weather conditions. No actual emergency situations resulted from these events. The Public Staff argued that this illustrates the importance of the identification of the proper value to use for the reserve margin. At the same time, despite the abnormally hot weather, Duke's reserve margins stayed around 17%.

According to the Public Staff, an inadequate reserve margin results in emergency situations that may lead to expensive emergency purchases or the inability to carry full customer loads in some service areas. On the other hand, a higher than necessary reserve margin results in system costs that are greater than necessary to procure, operate, and maintain excess generation facilities, which results in higher customer rates.

The Public Staff noted that it has been a number of years since either Duke or PEC has conducted a comprehensive study to determine the appropriate reserve and capacity margin values to be used for the planning and operation of their respective systems, and prudent planning requires that such studies be conducted on a periodic basis. Therefore, the Public Staff recommended that the Commission require both Duke and PEC to conduct such studies as soon as practicable and incorporate the results in their IRP process and filings. The studies should determine the optimal level of reserves to provide generation reliability that considers the obligation to serve, the value of electricity, and the effect of outages, while minimizing the cost to ratepayers. It recommended that the studies include, but not be limited to, sensitivity analyses for factors such as the assumed levels of forced outages of generation facilities, assumed level of costs to customers for power outages, assumed values for reliable transmission capacity, and the assumed lead time for adding new generation units. The Public Staff further recommended that the utilities keep the Public Staff updated as they develop the parameters of the studies.

According to PEC, its 2003 reliability analysis formed the basis for its target capacity margin and the 2007 reliability analysis reaffirmed those findings. PEC argued that future updates should be driven by significant changes in input assumptions such as resource mix, outage rates, and load uncertainty. Given that there has not been a significant change in these assumptions, an updated study would produce results similar to the 2003 and 2007 analyses and, thus, an updated study is not warranted at this time.

With regards to PEC's reserve margin adequacy, the Public Staff commented: "Responses to the questions from the Public Staff indicated that the results of the analysis were not available for review and that the analysis had not been performed in a number of years." PEC stated that this comment was the result of a misunderstanding and that PEC did provide the requested data. Given the large amount of data the Public Staff had to review, PEC determined that the Public Staff just overlooked it. PEC provided the Public Staff its 2003 and 2007 Reliability Criteria Studies and the Excel files with supporting data used in developing the study reports.

PEC indicated that it conducts its reliability assessments based on maintaining a LOLE of less than one day in ten years. The one day in ten years LOLE criterion is widely accepted within the industry for establishing generation reliability. This type of analysis does not rely on the costs to customers for power outages. To PEC's knowledge, no utility attempts to capture and incorporate consideration of this variable in its reserve margin analyses. This is primarily due to the fact that any attempt to quantify such a variable would be very subjective. Customer outage costs would be extremely difficult to calculate and would require numerous detailed assumptions regarding individual customers' energy use, the value derived by the customer from that energy use, and the economic consequences of interruptions for individual customers. Such a complex and time-consuming hypothetical exercise would be of no value in determining an appropriate reserve margin.

In its reply comments, Duke stated that it does not dispute that it has not recently conducted a formal comprehensive reserve margin study as it has relied primarily upon historical experience to establish its target reserve margin for planning purposes. A 17% target planning reserve margin level has resulted in adequate reserve amounts in the past and has been deemed reasonable by the Commission in the context of prior IRPs filed by the Company. The Company currently deems such level of reserves to be sufficient to cover the foreseeable risk increases resulting from an aging generation system and resource mix with greater amounts of EE, conservation, DSM, and renewable resources. Duke maintained that, with historical reserves dropping to less than 2% of the peak load within the last five years, a 17% target reserve margin is appropriate. As such, Duke stated that it does not believe that a comprehensive study is required at this time. However, if the Commission believes a comprehensive reserve margin study is necessary, Duke would respectfully request that the Commission order the study be conducted for purposes of the Company's next biennial IRP filing in 2012 due to the fact that the 2011 IRP work will likely be substantially complete prior to an order on the 2010 IRP. In addition, given the proposed merger between the holding companies of Duke and PEC, it makes sense to consider the impact of the merger on the individual and joint reserve margin requirements of the two companies. The proposed merger will still be pending approval before various regulatory agencies at the time of the 2011 IRP filing, and the relevant state and federal regulatory approvals of the proposed joint dispatch arrangement between the operating companies will directly impact resource planning for both companies.

Conclusions

In general, the Commission finds the PEC and Duke responses to the Public Staff's request for a comprehensive study to be reasonable and adequate. However, the Commission is of the opinion that it is appropriate for PEC and Duke to perform an updated comprehensive reserve margin study. Therefore, the Commission directs PEC and Duke to prepare a comprehensive reserve margin requirements study and include it as part of its 2012 biennial IRP report. The Commission also directs Duke and PEC to keep the Public Staff updated as they develop the parameters of the studies.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 14

As it did in its testimony in Docket No. E-100, Sub 124, in regard to the IOUs, the Public Staff encouraged the utilization of DSM resources to achieve fuel savings during periods when the price of energy available for spot purchases is high. It is not evident to the Public Staff that in their IRPs the IOUs have fully considered the use of their DSM resources to achieve fuel savings. The Public Staff recommended that the Commission require both the IOUs and EMCs to investigate this use of their DSM resources and include a discussion of the results of their investigations in their next IRPs.

PEC was aware of the Public Staff's position on this issue and has been investigating the use of its DSM programs to reduce its fuel costs.

In its proposed order, Duke noted that the Public Staff is aware that Duke is continuing to investigate the feasibility of using its DSM resources for fuel savings.

Conclusions

The Commission does not see the correlation between fuel savings and the spot market, as such. The Commission does see the value of possibly activating DSM resources during times of high system load as a means of achieving lower fuel costs by not having to dispatch peaking units with their associated higher fuel costs if it is indeed less expensive to activate DSM resources. The Commission expects IOUs and EMCs to use DSM resources, where available, if such resources are less expensive than spot purchases. The Commission directs each IOU and EMC to address this issue, as a specific item, in their 2012 biennial IRP reports.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The Public Staff encourages each IOU and EMC to investigate, develop, and implement all available cost-effective DSM/EE. Changes being proposed to building codes and appliance standards, as well as federal legislation regarding lighting, will substantially impact the ability to implement cost-effective DSM and EE. These changes will have a profound impact on markets for products that consume electricity and may make reliance on older market potential studies unreliable. Therefore, the Public Staff recommended that any IOU or EMC relying on a DSM/EE market potential study older than two years update its study or perform a new study and file it with its next IRP.

PEC agreed that market potential studies should be periodically updated. However, such updates should be prompted by changed circumstances such as changes in building codes and appliance standards rather than simply the passage of time. PEC's Market Potential study, published in March 2009, incorporated projected Energy Independence and Security Act impacts, including new federal lighting standards. PEC stated that it is unclear whether the Public Staff is recommending that IOUs and EMCs should update their market potential studies every two years going forward, or rather, whether the Public Staff is recommending this specific action during this proceeding based on the recent historical developments outlined in their comments.

Duke also agreed with the Public Staff's assessment regarding older market potential studies and believes that an updated or new DSM/EE market potential study is a worthwhile investment of time and money. As Company witness Richard Stevie stated during the evidentiary hearing on the IRPs conducted in Docket No. E-100, Subs 118 and 124, market potential studies should generally be updated every 5 years. Duke stated that it intends to have a new market potential study completed prior to the filing of its IRP in 2012. However, due to the length of time to properly plan, submit for bid, evaluate and complete such a study, it will not be possible for Duke to have its updated market potential study ready for incorporation into its 2011 IRP. Duke stated that it intends to begin the process of designing and requesting bids for this study in early April, 2011. Should the Commission agree with Public Staff's assessment regarding an updated market potential study, the Company respectfully requested that such a study be required for submission with the next biennial IRP, which will be filed on September 1, 2012.

Conclusions

The Commission finds that the responses of PEC and Duke are adequate. PEC's most current study was published in 2009, and PEC appears unsure as to whether the Public Staff is asking for something more. Duke is planning to submit new information with its 2012 biennial IRP report. Since the Public Staff did not comment by way of a proposed order or brief, the Commission finds that no specific action is required at this time. The Commission does, however, direct each IOU and EMC to ensure that the DSM/EE market potential studies on which they rely are updated as necessary to address current legislation and standards.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The Public Staff stated that, while Duke considered scenarios that assumed the impact of enactment of legislation imposing limits on carbon emissions, it did not include a low- or no-carbon scenario in its development of the proposed expansion plans included in its IRP.

The Public Staff further contended that the filings made by NCEMC and the other EMCs did not indicate that their evaluation of resource options considered the effect of potential legislation placing limits on carbon emissions in conjunction with their individual IRPs. The Public Staff recommended that each electric utility be required to include in its 2011 IRP scenarios with no-carbon and low-carbon price impacts, as well as scenarios factoring in the impact of regulation of carbon emissions. These scenarios should also be included in future IRPs submissions until such scenarios are no longer plausible.

Duke explained in its reply comments that responses it gave to Public Staff data requests indicated that an assumption of no- or low-carbon limitations/costs results in the model selecting coal generation facilities. Based on Duke's policy decisions and perception that additional coal generation would be untenable, the Company decided not to include this type of scenario.

PEC responded that, as explained in PEC's 2010 resource plan, its scenario analyses do include a consideration of various carbon emissions reduction requirements.

Conclusions

Only Duke and PEC chose to comment on this issue. The Commission finds the responses of Duke and PEC to be adequate and that no additional specific action by the electric utilities is required at this time. The current scenarios relating to carbon emissions, as provided in the IRPs, are responsive and appropriate for the purposes of this proceeding.

IT IS, THEREFORE, ORDERED as follows:

1. That this Order shall be adopted as a 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 2010 biennial reports filed in this proceeding by the IOUs, NCEMC, Piedmont, Rutherford, EU, and Haywood are hereby approved.

3. That the 2010 REPS compliance plans filed in this proceeding by the IOUs, GreenCo, Halifax, and EU are hereby approved.

4. That future IRP filings by all utilities 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 utilities 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 utilities 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 French Broad and Blue Ridge shall not be required to file individual IRPs.

8. That all EMCs shall include a full discussion in future biennial IRPs of their DSM programs and their use of these resources as required by Rule R8-60(i)(6).

9. That in future biennial IRPs, EU shall provide a more detailed description of the participation and savings related to specific DSM and EE programs, particularly those its proposes to use to meet its REPS obligations.

10. That any EMC which seeks to implement, or is currently implementing, DSM or EE programs under which incentives are offered to customers (except those programs being filed for approval by GreenCo), shall file such programs for Commission approval under G.S. 62-133.9(c) and Commission Rule R8-68 if they were adopted and implemented after August 20, 2007.

11. That if Piedmont determines that its smart meter program is an EE program, it shall file for Commission approval of the program pursuant to Rule R8-68.

12. That each IOU and EMC shall investigate the value of activating DSM resources during times of high system load as a means of achieving lower fuel costs by not having to dispatch peaking units with their associated higher fuel costs if it is less expensive to activate DSM resources. This issue shall be addressed as a specific item in their 2012 biennial IRP reports.

13. That PEC and Duke shall prepare a comprehensive reserve margin requirements study and include it as part of its 2012 biennial IRP report. PEC and Duke shall keep the Public Staff updated as they develop the parameters of the studies.

ISSUED BY ORDER OF THE COMMISSION.

This the _____ day of October, 2011.

NORTH CAROLINA UTILITIES COMMISSION

Gail L. Mount, Deputy Clerk

kh102611.01

Progress Energy Carolinas

Table 1 2011 Annual IRP (Summer)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
GENERATION CHANGES															
Sited Additions		920	625												
Undesignated Additions (1)					126			176	276	628	782	176	176		606
Planned Project Uprates	50	20	9	14		10									
Retirements	(170)	(707)	(590)												
INSTALLED GENERATION															
Nuclear	3,540	3,540	3,549	3,563	3,563	3,573	3,573	3,573	3,573	3,573	3,573	3,573	3,573	3,573	3,573
Fossil	4,994	4,287	3,697	3,697	3,697	3,697	3,697	3,697	3,697	3,697	3,697	3,697	3,697	3,697	3,697
Combined Cycle	1,122	2,062	2,687	2,687	2,687	2,687	2,687	2,687	2,687	2,687	2,687	2,687	2,687	2,687	2,687
Combustion Turbine	3,195	3,195	3,195	3,195	3,195	3,195	3,195	3,195	3,195	3,195	3,195	3,195	3,195	3,195	3,195
Hydro	225	225	225	225	225	225	225	225	225	225	225	225	225	225	225
Undesignated (1)					126	126	126	302	578	1,206	1,988	2,164	2,340	2,340	2,946
TOTAL INSTALLED	**13,076**	**13,309**	**13,353**	**13,367**	**13,493**	**13,503**	**13,503**	**13,679**	**13,955**	**14,583**	**15,365**	**15,541**	**15,717**	**15,717**	**16,323**
PURCHASES & OTHER RESOURCES															
SEPA	95	109	109	109	109	109	109	109	109	109	109	109	109	109	109
NUG QF - Cogen	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
NUG QF - Renewable *	261	262	262	237	241	241	193	193	189	176	39	39	39	39	39
Butler Warner	220	220	220	220	220	220									
Anson CT Tolling Purchase		336	336	336	336	336	336	336	336	336	336	336	336	336	336
Broad River CT	812	812	812	812	812	812	812	812	812	331					
Southern CC Purchase - LT	145	145	145	145	145	145	145	145							
TOTAL SUPPLY RESOURCES	**14,629**	**15,214**	**15,258**	**15,247**	**15,376**	**15,386**	**15,118**	**15,294**	**15,421**	**15,555**	**15,869**	**16,045**	**16,221**	**16,221**	**16,827**
PEAK DEMAND															
Retail	9,149	9,298	9,475	9,633	9,808	9,977	10,146	10,313	10,485	10,642	10,802	10,964	11,134	11,295	11,464
Wholesale	3,090	3,944	4,001	4,055	4,105	4,155	4,226	4,238	4,295	4,351	4,403	4,447	4,502	4,560	4,618
Firm (Duke Area)	100	150	150	150	150	150	150	150	150	150	150	150	150	0	0
OBLIGATION BEFORE DSM	12,340	13,392	13,627	13,838	14,063	14,282	14,522	14,701	14,930	15,143	15,356	15,561	15,786	15,855	16,082
DSM & EE	803	901	1,003	1,085	1,160	1,228	1,292	1,354	1,415	1,470	1,523	1,578	1,634	1,686	1,737
OBLIGATION AFTER DSM	11,537	12,491	12,624	12,753	12,903	13,054	13,230	13,347	13,515	13,674	13,833	13,983	14,152	14,169	14,345
RESERVES (2)	3,092	2,722	2,633	2,494	2,473	2,332	1,888	1,947	1,906	1,881	2,036	2,063	2,069	2,052	2,482
Capacity Margin (3)	21%	18%	17%	16%	16%	15%	12%	13%	12%	12%	13%	13%	13%	13%	15%
Reserve Margin (4)	27%	22%	21%	20%	19%	18%	14%	15%	14%	14%	15%	15%	15%	14%	17%
ANNUAL SYSTEM ENERGY (GWh)	**64,225**	**65,849**	**66,662**	**67,382**	**68,254**	**69,117**	**69,922**	**70,790**	**71,708**	**72,571**	**73,406**	**74,166**	**75,071**	**75,698**	**76,608**

Notes:

* Renewables are assumed to be provided by sources that are dispatchable and/or high capacity factor sources and therefore are counted towards capacity margin. The MWs shown include potential sources that have not yet been identified but are expected to be obtained to meet PEC's Renewable Portfolio Standard requirements.

Footnotes:

(1) Undesignated capacity may be replaced by purchases, uprates, DSM; or a combination thereof. Joint ownership opportunities will be evaluated with baseload additions.
(2) Reserves = Total Supply Resources - Firm Obligations.
(3) Capacity Margin = Reserves / Total Supply Resources * 100.
(4) Reserve Margin = Reserves / System Firm Load after DSM * 100.

Progress Energy Carolinas

Table 2 2011 Annual IRP (Winter)

	11/12	12/13	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
GENERATION CHANGES															
Sited Additions		1,049	717												
Undesignated Additions (1)					147				201	281	683	875	201	201	
Planned Project Uprates		80	9		18		10								
Retirements	(201)	(417)	(939)												
INSTALLED GENERATION															
Nuclear	3,616	3,666	3,675	3,675	3,693	3,693	3,703	3,703	3,703	3,703	3,703	3,703	3,703	3,703	3,703
Fossil	5,103	4,686	3,747	3,747	3,747	3,747	3,747	3,747	3,747	3,747	3,747	3,747	3,747	3,747	3,747
Combined Cycle	1,240	2,319	3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036
Combustion Turbine	3,691	3,691	3,691	3,691	3,691	3,691	3,691	3,691	3,691	3,691	3,691	3,691	3,691	3,691	3,691
Hydro	227	227	227	227	227	227	227	227	227	227	227	227	227	227	227
Undesignated (1)					147	147	147	147	348	629	1,312	2,187	2,388	2,589	2,589
TOTAL INSTALLED	**13,877**	**14,589**	**14,376**	**14,376**	**14,541**	**14,541**	**14,551**	**14,551**	**14,752**	**15,033**	**15,716**	**16,591**	**16,792**	**16,993**	**16,993**
PURCHASES & OTHER RESOURCES															
SEPA	95	109	109	109	109	109	109	109	109	109	109	109	109	109	109
NUG QF - Cogen	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
NUG QF - Renewable *	258	262	262	237	237	241	193	193	189	189	39	39	39	39	39
Butler Warner		260	260	260	260	260									
Anson CT Tolling Purchase		365	365	365	365	365	365	365	365	365	365	365	365	365	365
Broad River CT	880	880	880	880	880	880	880	880	880	880	383				
Southern CC Purchase - LT	145	145	145	145	145	145	145	145							
TOTAL SUPPLY RESOURCES	**15,275**	**16,630**	**16,417**	**16,392**	**16,557**	**16,561**	**16,263**	**16,263**	**16,315**	**16,596**	**16,632**	**17,124**	**17,325**	**17,526**	**17,526**
OBLIGATION BEFORE DSM	11,655	12,684	12,906	13,106	13,318	13,526	13,753	13,922	14,139	14,341	14,542	14,736	14,949	15,006	15,222
DSM & EE	755	794	840	882	912	944	978	1,014	1,052	1,087	1,121	1,161	1,200	1,236	1,272
OBLIGATION AFTER DSM	10,900	11,890	12,066	12,224	12,406	12,582	12,775	12,908	13,087	13,254	13,421	13,575	13,749	13,770	13,950
RESERVES (2)	4,375	4,740	4,351	4,168	4,151	3,979	3,488	3,355	3,228	3,342	3,211	3,549	3,576	3,756	3,577
Capacity Margin (3)	29%	29%	27%	25%	25%	24%	21%	21%	20%	20%	19%	21%	21%	21%	20%
Reserve Margin (4)	40%	40%	36%	34%	33%	32%	27%	26%	25%	25%	24%	26%	26%	27%	26%

Notes:

* Renewables are assumed to be provided by sources that are dispatchable and/or high capacity factor sources and therefore are counted towards capacity margin. The MWs shown include potential sources that have not yet been identified but are expected to be obtained to meet PEC's Renewable Portfolio Standard requirements.

Footnotes:

(1) Undesignated capacity may be replaced by purchases, uprates, DSM; or a combination thereof. Joint ownership opportunities will be evaluated with baseload additions.

(2) Reserves = Total Supply Resources - Firm Obligations.

(3) Capacity Margin = Reserves / Total Supply Resources * 100.

(4) Reserve Margin = Reserves / System Firm Load after DSM * 100.

Table 8.A

Summer Projections of Load, Capacity, and Reserves for Duke Energy Carolinas 2011 Annual Plan

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Load Forecast																				
1 Duke System Peak	17,892	18,347	18,800	19,239	19,752	20,220	20,675	21,122	21,444	21,826	22,152	22,469	22,777	23,120	23,399	23,777	24,109	24,417	24,765	25,121
Reductions to Load Forecast																				
2 New EE Programs	(80)	(102)	(120)	(208)	(276)	(343)	(410)	(478)	(544)	(611)	(622)	(633)	(642)	(655)	(667)	(679)	(688)	(703)	(715)	(727)
3 Adjusted Duke System Peak	**17,812**	**18,245**	**18,680**	**19,032**	**19,476**	**19,877**	**20,265**	**20,644**	**20,901**	**21,214**	**21,530**	**21,836**	**22,135**	**22,465**	**22,732**	**23,099**	**23,420**	**23,714**	**24,050**	**24,393**
Cumulative System Capacity																				
4 Generating Capacity	19,762	20,404	21,070	21,088	20,378	20,388	20,415	20,495	20,525	20,525	20,525	20,525	20,525	20,525	20,525	20,525	20,525	20,525	20,525	20,525
5 Capacity Additions	1,465	666	18	370	10	27	81	30	0	0	0	0	0	0	0	0	0	0	0	0
6 Capacity Derates	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 Capacity Retirements	(824)	0	0	(1,080)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 Cumulative Generating Capacity	20,404	21,070	21,088	20,378	20,388	20,415	20,495	20,525	20,525	20,525	20,525	20,525	20,525	20,525	20,525	20,525	20,525	20,525	20,525	20,525
Purchase Contracts																				
9 Cumulative Purchase Contracts	270	211	123	100	100	100	100	100	97	96	87	87	87	87	87	87	87	87	87	87
Sales Contracts																				
10 Catawba Owner Backstand	0	0	(47)	(47)	(47)	(47)	(47)	(47)	(47)	0	0	0	0	0	0	0	0	0	0	0
11 Catawba Owner Load Following Agreement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12 Cumulative Future Resource Additions																				
Base Load	0	0	0	0	0	0	0	0	0	1,117	1,117	2,234	2,234	2,234	2,234	2,234	2,234	2,234	2,234	2,234
Peaking/Intermediate	0	0	0	740	1,480	1,480	2,130	2,130	2,870	2,870	2,870	2,870	2,870	2,870	2,870	2,870	2,870	3,520	3,520	4,190
Renewables	41	44	116	128	249	250	304	341	376	372	427	437	439	478	488	481	484	493	484	484
13 Cumulative Production Capacity	**20,715**	**21,326**	**21,281**	**21,300**	**22,171**	**22,198**	**22,983**	**23,050**	**23,822**	**24,980**	**25,027**	**26,154**	**26,156**	**26,195**	**26,205**	**26,198**	**26,201**	**26,860**	**26,851**	**27,521**
Reserves w/o Demand-Side Management																				
14 Generating Reserves	2,903	3,081	2,600	2,268	2,694	2,321	2,718	2,406	2,921	3,766	3,497	4,318	4,021	3,731	3,473	3,099	2,780	3,146	2,801	3,128
15 % Reserve Margin	**16.3%**	**16.9%**	**13.9%**	**11.9%**	**13.8%**	**11.7%**	**13.4%**	**11.7%**	**14.0%**	**17.8%**	**16.2%**	**19.8%**	**18.2%**	**16.6%**	**15.3%**	**13.4%**	**11.9%**	**13.3%**	**11.6%**	**12.8%**
16 % Capacity Margin	14.0%	14.4%	12.2%	10.6%	12.2%	10.5%	11.8%	10.4%	12.3%	15.1%	14.0%	16.5%	15.4%	14.2%	13.3%	11.8%	10.6%	11.7%	10.4%	11.4%
Demand-Side Management																				
17 Cumulative DSM Capacity	838	850	919	983	987	986	986	986	986	986	986	986	986	986	986	986	986	986	986	986
IS / SG	181	147	140	133	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126
Power Share / Power Manager	657	703	780	851	861	861	861	861	861	861	861	861	861	861	861	861	861	861	861	861
18 Cumulative Equivalent Capacity	21,553	22,175	22,200	22,283	23,157	23,184	23,969	24,036	24,808	25,967	26,013	27,140	27,142	27,182	27,191	27,184	27,187	27,847	27,837	28,507
Reserves w/ DSM																				
19 Generating Reserves	3,741	3,930	3,520	3,251	3,681	3,307	3,705	3,392	3,908	4,753	4,484	5,304	5,008	4,717	4,459	4,085	3,767	4,132	3,787	4,114
20 % Reserve Margin	**21.0%**	**21.5%**	**18.8%**	**17.1%**	**18.9%**	**16.6%**	**18.3%**	**16.4%**	**18.7%**	**22.4%**	**20.8%**	**24.3%**	**22.6%**	**21.0%**	**19.6%**	**17.7%**	**16.1%**	**17.4%**	**15.7%**	**16.9%**
21 % Capacity Margin	17.4%	17.7%	15.9%	14.6%	15.9%	14.3%	15.5%	14.1%	15.8%	18.3%	17.2%	19.5%	18.4%	17.4%	16.4%	15.0%	13.9%	14.8%	13.6%	14.4%

Winter Projections of Load, Capacity, and Reserves for Duke Energy Carolinas 2011 Annual Plan

	11/12	12/13	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	28/29	29/30	30/31
Load Forecast																				
1 Duke System Peak	17,425	17,869	18,303	18,746	19,180	19,665	20,123	20,539	20,868	21,128	21,482	21,782	22,080	22,379	22,649	22,922	23,280	23,584	23,885	24,186
Reductions to Load Forecast																				
2 New EE Programs	(67)	(96)	(126)	(204)	(289)	(360)	(429)	(497)	(564)	(636)	(647)	(658)	(668)	(681)	(693)	(706)	(716)	(730)	(743)	(756)
3 Adjusted Duke System Peak	**17,359**	**17,773**	**18,177**	**18,543**	**18,891**	**19,305**	**19,694**	**20,042**	**20,304**	**20,492**	**20,835**	**21,124**	**21,412**	**21,697**	**21,956**	**22,217**	**22,565**	**22,853**	**23,142**	**23,430**
Cumulative System Capacity																				
4 Generating Capacity	20,567	20,934	21,773	21,820	21,468	21,128	21,137	21,164	21,245	21,275	21,275	21,275	21,275	21,275	21,275	21,275	21,275	21,275	21,275	21,275
5 Capacity Additions	684	1,465	46	18	370	10	27	81	30	0	0	0	0	0	0	0	0	0	0	0
6 Capacity Derates	(6)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 Capacity Retirements	(311)	(626)	0	(370)	(710)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 Cumulative Generating Capacity	20,934	21,773	21,820	21,468	21,128	21,137	21,164	21,245	21,275	21,275	21,275	21,275	21,275	21,275	21,275	21,275	21,275	21,275	21,275	21,275
Purchase Contracts																				
9 Cumulative Purchase Contracts	277	218	123	100	100	100	100	100	97	96	87	87	87	87	87	87	87	87	87	87
Sales Contracts																				
10 Catawba Owner Backstand	0	0	(47)	(47)	(47)	(47)	(47)	(47)	(47)	0	0	0	0	0	0	0	0	0	0	0
11 Catawba Owner Load Following Agreement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12 Cumulative Future Resource Additions																				
Base Load	0	0	0	0	0	0	0	0	0	0	1,117	1,117	2,234	2,234	2,234	2,234	2,234	2,234	2,234	2,234
Peaking/Intermediate	0	0	0	0	740	1,480	1,480	2,130	2,130	2,870	2,870	2,870	2,870	2,870	2,870	2,870	2,870	2,870	3,520	3,520
Renewables	46	41	44	116	128	249	250	304	341	376	372	427	437	439	478	488	481	484	493	484
13 Cumulative Production Capacity	**21,257**	**22,032**	**21,940**	**21,638**	**22,049**	**22,920**	**22,947**	**23,732**	**23,796**	**24,618**	**25,721**	**25,776**	**26,903**	**26,906**	**26,945**	**26,954**	**26,947**	**26,950**	**27,610**	**27,601**
Reserves w/o Demand-Side Management																				
14 Generating Reserves	3,899	4,260	3,764	3,095	3,158	3,615	3,254	3,690	3,492	4,126	4,886	4,653	5,491	5,208	4,989	4,737	4,383	4,097	4,468	4,170
15 % Reserve Margin	**22.5%**	**24.0%**	**20.7%**	**16.7%**	**16.7%**	**18.7%**	**16.5%**	**18.4%**	**17.2%**	**20.1%**	**23.5%**	**22.0%**	**25.6%**	**24.0%**	**22.7%**	**21.3%**	**19.4%**	**17.9%**	**19.3%**	**17.8%**
16 % Capacity Margin	18.3%	19.3%	17.2%	14.3%	14.3%	15.8%	14.2%	15.5%	14.7%	16.8%	19.0%	18.1%	20.4%	19.4%	18.5%	17.6%	16.3%	15.2%	16.2%	15.1%
Demand-Side Management																				
17 Cumulative DSM Capacity	548	511	530	547	555	555	555	555	555	555	555	555	555	555	555	555	555	555	555	555
IS / SG	181	147	140	133	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126
Power Share / Power Manager	367	364	391	414	429	429	429	429	429	429	429	429	429	429	429	429	429	429	429	429
18 Cumulative Equivalent Capacity	21,806	22,544	22,471	22,184	22,604	23,475	23,502	24,287	24,351	25,172	26,276	26,331	27,458	27,460	27,499	27,509	27,502	27,505	28,164	28,155
Reserves w/ DSM																				
19 Generating Reserves	4,447	4,771	4,294	3,641	3,713	4,169	3,808	4,245	4,047	4,680	5,441	5,207	6,046	5,763	5,544	5,292	4,937	4,652	5,023	4,725
20 % Reserve Margin	**25.6%**	**26.8%**	**23.6%**	**19.6%**	**19.7%**	**21.6%**	**19.3%**	**21.2%**	**19.9%**	**22.8%**	**26.1%**	**24.7%**	**28.2%**	**26.6%**	**25.2%**	**23.8%**	**21.9%**	**20.4%**	**21.7%**	**20.2%**
21 % Capacity Margin	20.4%	21.2%	19.1%	16.4%	16.4%	17.8%	16.2%	17.5%	16.6%	18.6%	20.7%	19.8%	22.0%	21.0%	20.2%	19.2%	18.0%	16.9%	17.8%	16.8%

Assumptions of Load, Capacity, and Reserves Table

The following notes are numbered to match the line numbers on the Summer and Winter 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.

4. Generating Capacity must be online by June 1 to be included in the available capacity for the summer peak of that year. Capacity must be online by Dec 1 to be included in the available capacity for the winter peak of that year. Includes 91 MW Nantahala hydro capacity, and total capacity for Catawba Nuclear Station less 832 MW to account for NCMPA1 firm capacity sale.

5. Capacity Additions reflect an 8.75 MW increase in capacity at Bridgewater Hydro by summer 2012.
   Capacity Additions include Duke Energy Carolinas projects that have been approved by the NCUC (Cliffside 6, Buck and Dan River Combined Cycle facilities).
   Capacity Additions include the conversion of Lee Steam Station from coal to natural gas in 2015.
   Capacity Additions include Duke Energy Carolinas hydro units scheduled to be repaired and returned to service. These units are returned to service in the 2011-2017 timeframe and total 34 MW.
   Also included is a 204 MW capacity increase due to nuclear uprates at Catawba, McGuire, and Oconee. Timing of these uprates is shown from 2012-2019

6. No more Capacity Derates for existing units are expected at this time.

7. Buck units 3-4 (113 MW) were retired during the summer of 2011.
   The 824 MW capacity retirement in summer 2012 represents the projected retirement date for Dan River Steam Station units 1-3 (276 MW), Cliffside Steam Station units 1-4 (198 MW), and 350 MWs of old fleet CT retirements.
   The 1080 MW capacity retirement in summer 2015 represents the projected retirement date for Lee Steam Station (370 MW), Buck Steam Station units 5 and 6 (256 MW) and Riverbend Steam Station units 4-7 (454 MW).
   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.

9. Cumulative Purchase Contracts have several components:

   A. Piedmont Municipal Power Agency took sole responsibility for total load requirements beginning January 1, 2006. This reduces the SEPA allocation from 94 MW to 19 MW in 2006, which is attributed to certain wholesale customers who continue to be served by Duke.
   B. Purchased capacity from PURPA Qualifying Facilities includes the 88 MW Cherokee County Cogeneration Partners contract which began in June 1998 and expires June 2013 and miscellaneous other QF projects totaling 36 MW.

10-11. A firm wholesale backstand agreement up to 277 MW between Duke Energy Carolinas and PMPA starts on 1/1/2014 and continues through the end of 2020.

12. Cumulative Future Resource Additions represent a combination of new capacity resources or capability increases from the most robust plan.

15. Reserve Margin = (Cumulative Capacity-System Peak Demand)/System Peak Demand

16. Capacity Margin = (Cumulative Capacity - System Peak Demand)/Cumulative Capacity

17. The Cumulative Demand Side Management capacity includes new Demand Side Management capacity representing placeholders for demand response and energy efficiency programs.

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

Company Name: Virginia Electric and Power Company

I. PEAK LOAD AND ENERGY FORECAST

Schedule 1

	(ACTUAL)[1]			(PROJECTED)															
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
1. Utility Peak Load (MW)																			
A. Summer																			
1a. Base Forecast	16,758	15,917	16,783	16,705	16,999	17,447	17,952	18,388	18,686	18,973	19,295	19,604	20,035	20,413	20,771	21,125	21,409	21,765	22,201
1b. Additional Forecast																			
NCEMC	150	150	150	150	150	150	150	-	-	-	-	-	-	-	-	-	-	-	-
2. Conservation, Efficiency[5]	-	-	-17	-30	-21	-101	-242	-352	-448	-427	-417	-407	-395	-393	-397	-399	-402	-405	-407
3. Demand Response[2][5]	-	-	-21	-55	-38	-144	-224	-274	-325	-371	-410	-442	-468	-488	-501	-511	-519	-525	-530
4. Demand Response-Existing[2][3]	-22	-18	-9	-7	-7	-7	-7	-7	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5
5. Peak Adjustment	-	-	-	447	792	894	750	-	-	-	-	-	-	-	-	-	-	-	-
6. Adjusted Load	16,908	16,067	16,933	17,302	17,920	18,390	18,610	18,036	18,238	18,546	18,878	19,197	19,640	20,020	20,374	20,726	21,007	21,360	21,794
7. % Increase in Adjusted Load (from previous year)	-5.5%	-5.0%	5.4%	2.2%	2.2%	2.6%	1.2%	-3.1%	1.1%	1.7%	1.8%	1.7%	2.3%	1.9%	1.8%	1.7%	1.4%	1.7%	2.0%
B. Winter																			
1a. Base Forecast	14,637	15,427	15,184	14,859	15,291	15,593	15,917	16,365	16,669	16,951	17,236	17,424	17,679	18,093	18,375	18,676	18,960	19,140	19,569
1b. Additional Forecast																			
NCEMC	150	150	150	143	145	146	147	-	-	-	-	-	-	-	-	-	-	-	-
2. Conservation, Efficiency[5]	-	-	-14	-23	-15	-64	-150	-223	-289	-287	-282	-276	-269	-267	-270	-272	-274	-276	-278
3. Demand Response[2][5]	-	-	-12	-20	-	-19	-47	-50	-58	-66	-73	-78	-81	-84	-87	-91	-94	-95	-96
4. Demand Response-Existing[2][3]	-22	-18	-7	-7	-7	-7	-7	-7	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5
5. Adjusted Load	14,787	15,577	15,334	15,002	15,421	15,675	15,914	16,142	16,380	16,664	16,954	17,148	17,409	17,826	18,105	18,405	18,686	18,864	19,291
6. % Increase in Adjusted Load	-6.2%	5.3%	-1.6%	-2.2%	2.8%	1.6%	1.5%	1.4%	1.5%	1.7%	1.7%	1.1%	1.5%	2.4%	1.6%	1.7%	1.5%	1.0%	2.3%
2. Energy (GWh)																			
A. Base Forecast	83,547	82,501	86,663	84,766	88,583	90,994	93,165	95,097	97,449	98,805	100,468	102,280	104,422	106,027	107,902	109,779	111,955	113,537	115,447
B. Additional Forecast																			
NCEMC				619	645	658	676	-	-	-	-	-	-	-	-	-	-	-	-
ODECsupp[6]				-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
C. Conservation & Demand Response[4]	-	-	-265	-379	-623	-1,476	-2,516	-3,484	-4,285	-4,404	-4,614	-4,521	-4,414	-4,369	-4,383	-4,394	-4,402	-4,413	-4,423
D. Demand Response-Existing[2][3]	-3	-2	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1
E. Adjusted Energy	83,547	82,501	86,663	85,006	88,605	90,176	91,324	91,613	93,164	94,401	95,854	97,759	100,008	101,658	103,519	105,385	107,553	109,124	111,024
F. % Increase in Adjusted Energy	-2.6%	-1.3%	5.0%	-1.9%	4.2%	1.8%	1.3%	0.3%	1.7%	1.3%	1.5%	2.0%	2.3%	1.6%	1.8%	1.8%	2.1%	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 and 2011 represent modeled energy; actual historical data based upon measured and verified EM&V results is not yet available

(5) Values in 2010 and 2011 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.

(6) ODEC contract expired year end 2010.

APPENDIX 2I – REQUIRED RESERVE MARGIN

Company Name: Virginia Electric and Power Company

POWER SUPPLY DATA (continued)

Schedule 6

	(ACTUAL)			(PROJECTED)															
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
I. Reserve Margin[1]																			
(Including Cold Reserve Capability)																			
1. Summer Reserve Margin																			
a. MW[1]	1,312	1,964	3,397	3,218	3,425	3,407	2,121	1,984	2,006	2,040	2,077	2,112	2,161	2,202	2,241	2,280	2,311	2,350	2,398
b. Percent of Load	7.8%	12.2%	20.1%	18.6%	19.1%	18.5%	11.4%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%
c. Actual Reserve Margin[4]	N/A	N/A	N/A	9.07%	8.97%	6.80%	6.85%	15.28%	17.33%	12.25%	8.96%	13.37%	12.69%	12.64%	12.11%	12.21%	12.66%	12.71%	12.34%
2. Winter Reserve Margin																			
a. MW[1]	N/A	N/A	N/A	8,059	8,373	8,041	7,807	8,897	9,380	7,229	6,637	6,719	6,855	6,881	6,920	7,064	7,226	7,489	7,503
b. Percent of Load	N/A	N/A	N/A	53.7%	54.3%	51.3%	49.1%	55.1%	57.3%	43.4%	39.1%	39.2%	39.4%	38.6%	38.2%	38.4%	38.7%	39.7%	38.9%
c. Actual Reserve Margin[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
I. Reserve Margin[1][2][3]																			
(Excluding Cold Reserve Capability)																			
1. Summer Reserve Margin																			
a. MW[1]	1,312	1,964	3,323	3,050	3,288	3,333	2,047	1,984	2,006	2,040	2,077	2,112	2,161	2,202	2,241	2,280	2,311	2,350	2,398
b. Percent of Load	7.8%	12.2%	19.6%	17.6%	18.3%	18.1%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%
c. Actual Reserve Margin[4]	N/A	N/A	N/A	8.6%	8.2%	6.4%	6.5%	15.3%	17.3%	12.3%	9.0%	13.4%	12.7%	12.6%	12.1%	12.2%	12.7%	12.7%	12.3%
2. Winter Reserve Margin																			
a. MW[1]	N/A	N/A	N/A	7,919	8,233	7,964	7,730	8,897	9,380	7,229	6,637	6,719	6,855	6,881	6,920	7,064	7,226	7,489	7,503
b. Percent of Load	N/A	N/A	N/A	52.8%	53.4%	50.8%	48.6%	55.1%	57.3%	43.4%	39.1%	39.2%	39.4%	38.6%	38.2%	38.4%	38.7%	39.7%	38.9%
c. Actual Reserve Margin[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
III. Annual Loss-of-Load Hours[5]	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 has two units in cold reserve.
(3) The Company and PJM forecasts a summer peak throughout the Planning Period.
(4) Does not include spot purchases of capacity.
(5) The Company follows PJM reserve requirements which are based on LOLE.

Table 1.3 NCEMC Projected Summer Load and Capacity (values in MW unless noted otherwise)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Load Requirements															
20 EMC Demand (1)	2,918	3,005	3,048	3,091	3,133	3,174	3,219	3,265	3,314	3,367	3,417	3,467	3,519	3,571	3,623
Existing DSM (2)	67	59	41	41	41	41	41	41	41	41	41	41	41	41	41
Net Peak Demand	2,851	2,945	3,007	3,051	3,092	3,133	3,178	3,224	3,273	3,326	3,376	3,426	3,478	3,530	3,582
Capacity Resources															
Catawba (3)	682	682	682	682	682	682	682	682	682	682	682	682	682	682	682
NCEMC CTs (4)	622	622	678	678	678	678	678	678	678	678	678	678	678	678	678
Diesels	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
Total Capacity Resources	1,322	1,322	1,378	1,378	1,378	1,378	1,378	1,378	1,378	1,378	1,378	1,378	1,378	1,378	1,378
Purchased Resources (5)															
AEP Purchases	250	250	100	100	100	0	0	0	0	0	0	0	0	0	0
PEC SORs	870	870	920	970	970	970	970	970	970	550	375	225	0	0	0
PEC PPAs	350	300	1,127	1,108	1,135	1,165	1,198	1,232	1,267	1,723	1,932	2,117	2,378	2,417	2,303
Duke PPAs	72	72	72	72	72	97	97	97	97	122	122	122	122	122	122
Southern PPAs	0	225	225	225	225	225	270	270	360	360	360	360	360	360	360
SCE&G PPA	250	250	0	0	0	0	0	0	0	0	0	0	0	0	0
Dominion PPA	150	150	150	150	0	0	0	0	0	0	0	0	0	0	0
SEPA Allocations (6)	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71
PJM UCAP (7)	119	126	97	49	143	145	147	151	154	156	159	161	164	167	169
Total Purchased Resources	2,132	2,314	2,762	2,745	2,716	2,673	2,753	2,791	2,919	2,982	3,019	3,056	3,095	3,137	3,025
Obligations															
Capacity Sale to Independent Members	376	376	259	260	216	216	216	216	216	209	206	203	199	199	196
Southern PSA	0	100	100	100	100	100	100	100	100	100	100	0	0	0	0
PEC Tolling	0	0	339	339	339	339	339	339	339	339	339	339	339	339	339
PJM Reserves (8)	48	49	49	50	50	50	50	51	51	51	52	52	52	53	53
Other Reserves (9)	81	99	62	62	62	62	67	67	79	79	79	91	91	91	91
Other Obligation (10)	10	6	13	13	15	15	15	15	15	15	15	16	16	16	16
Net Resources for Participating Members	2,939	3,006	3,318	3,299	3,312	3,269	3,344	3,381	3,497	3,567	3,606	3,733	3,776	3,817	3,708
Undesignated DS Programs / EE Resources (11)	21	26	30	33	35	36	34	32	32	34	34	35	37	39	40
Undesignated Renewable Resources (11)	1	19	19	19	21	48	50	108	114	130	151	152	154	157	159
Undesignated Future Conventional Resources	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Annual Energy (GWh) (12)	12,627	13,087	13,222	13,404	13,579	13,799	13,940	14,135	14,340	14,615	14,774	14,986	15,204	15,476	15,643
Annual Energy after EE (GWh) (12)	12,530	12,959	13,071	13,242	13,406	13,622	13,772	13,975	14,180	14,447	14,608	14,814	15,026	15,290	15,453

Notes:

(1) Total Demand is NCEMC's Participating Member coincident peak (NCEMC CP) measured at generation from the NCEMC 2009 Load Forecast (2011) and 2011 Load Forecast (2012 - 2025)
(2) "Existing DSM": Existing demand side management includes customer owned generation, interruptible load and residential load management resources
(3) "Catawba Resource": Catawba Nuclear Station ownership capacity reflects both Participating and Independent Members, along with the guaranteed capacity of the reliability exchange agreement
(4) Addition of sixth CT at Hamlet CT Plant with projected commercial operation date of May 2013
(5) Purchased Resources are 100% firm with reserves provided by the supplying entity unless otherwise noted
(6) SEPA allocations are for Participating Members
(7) PJM UCAP purchases reflect estimated PJM reserve requirements in total obligation for the PJM balancing area
(8) Estimated reserve requirements for NCEMC as a load serving entity in the PJM balancing area
(9) Other Reserves included for NCEMC CTs and Southern purchases as applicable
(10) Other Obligation includes generation losses for resources in NCEMC's portfolio used to serve load in multiple balancing areas
(11) Undesignated DS Programs / Energy Efficiency & Renewable Resources included in NCEMC's 2011 IRP
(12) Energy values are measured at generation for Participating Members from the NCEMC 2009 Load Forecast (2011) and 2011 Load Forecast (2012 - 2025)

Table 1.4 NCEMC Projected Winter Load and Capacity (values in MW unless noted otherwise)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Load Requirements															
20 EMC Demand (1)	2,878	3,201	3,245	3,290	3,332	3,375	3,422	3,470	3,521	3,577	3,629	3,681	3,736	3,790	3,845
Existing DSM (2)	56	52	41	41	41	41	41	41	41	41	41	41	41	41	41
Net Peak Demand	2,822	3,149	3,204	3,249	3,292	3,334	3,381	3,430	3,480	3,536	3,588	3,641	3,695	3,749	3,804
Capacity Resources															
Catawba (3)	682	682	682	682	682	682	682	682	682	682	682	682	682	682	682
NCEMC CTs (4)	622	622	622	678	678	678	678	678	678	678	678	678	678	678	678
Diesels	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
Total Capacity Resources	1,322	1,322	1,322	1,378	1,378	1,378	1,378	1,378	1,378	1,378	1,378	1,378	1,378	1,378	1,378
Purchased Resources (5)															
AEP Purchases	250	250	100	100	100	0	0	0	0	0	0	0	0	0	0
PEC SORs	870	870	920	970	970	970	970	970	970	550	375	225	0	0	0
PEC PPAs	350	450	1,441	1,426	1,457	1,490	1,528	1,566	1,606	2,067	2,281	2,471	2,737	2,781	2,672
Duke PPAs	72	72	72	72	72	97	97	97	97	122	122	122	122	122	122
Southern PPAs	0	225	225	225	225	225	270	270	360	360	360	360	360	360	360
SCE&G PPA	250	250	0	0	0	0	0	0	0	0	0	0	0	0	0
Dominion PPA	150	150	150	150	0	0	0	0	0	0	0	0	0	0	0
SEPA Allocations (6)	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71
PJM UCAP (7)	119	126	97	49	143	145	147	151	154	156	159	161	164	167	169
Total Purchased Resources	2,132	2,464	3,076	3,063	3,038	2,998	3,083	3,125	3,258	3,326	3,368	3,410	3,454	3,501	3,394
Obligations															
Capacity Sale to Independent Members	376	376	259	260	216	216	216	216	216	209	206	203	199	199	196
Southern PSA	0	100	100	100	100	100	100	100	100	100	100	0	0	0	0
PEC Tolling	0	0	339	339	339	339	339	339	339	339	339	339	339	339	339
PJM Reserves (8)	48	51	51	52	52	52	53	53	53	54	54	55	55	55	56
Other Reserves (9)	81	99	55	62	62	62	67	67	79	79	79	91	91	91	91
Other Obligation (10)	8	6	12	13	15	15	15	15	15	15	15	16	16	16	16
Net Resources for Participating Members	2,941	3,154	3,582	3,615	3,632	3,592	3,671	3,713	3,834	3,908	3,953	4,084	4,132	4,179	4,074
Undesignated DS Programs / EE Resources (11)	21	26	30	33	35	36	34	32	32	34	34	35	37	39	40
Undesignated Renewable Resources (11)	1	19	19	19	21	48	50	108	114	130	151	152	154	157	159
Undesignated Future Conventional Resources	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Annual Energy (GWh) (12)	12,627	13,087	13,222	13,404	13,579	13,799	13,940	14,135	14,340	14,615	14,774	14,986	15,204	15,476	15,643
Annual Energy after EE (GWh) (12)	12,530	12,959	13,071	13,242	13,406	13,622	13,772	13,975	14,180	14,447	14,608	14,814	15,026	15,290	15,453

Notes:

(1) Total Demand is NCEMC's Participating Member coincident peak (NCEMC CP) measured at generation from the NCEMC 2009 Load Forecast (2011) and 2011 Load Forecast (2012 - 2025)
(2) "Existing DSM": Existing demand side management includes customer owned generation, interruptible load and residential load management resources
(3) "Catawba Resource": Catawba Nuclear Station ownership capacity reflects both Participating and Independent Members, along with the guaranteed capacity of the reliability exchange agreement
(4) Addition of sixth CT at Hamlet CT Plant with projected commercial operation date of May 2013
(5) Purchased Resources are 100% firm with reserves provided by the supplying entity unless otherwise noted
(6) SEPA allocations are for Participating Members
(7) PJM UCAP purchases reflect estimated PJM reserve requirements in total obligation for the PJM balancing area
(8) Estimated reserve requirements for NCEMC as a load serving entity in the PJM balancing area
(9) Other Reserves included for NCEMC CTs and Southern purchases as applicable
(10) Other Obligation includes generation losses for resources in NCEMC's portfolio used to serve load in multiple balancing areas
(11) Undesignated DS Programs / Energy Efficiency & Renewable Resources included in NCEMC's 2011 IRP
(12) Energy values are measured at generation for Participating Members from the NCEMC 2009 Load Forecast (2011) and 2011 Load Forecast (2012 - 2025)

Table 1.2: Piedmont EMC Projected Summer Peak Loads, Resources and Annual Energy (2010 Load Forecast)

Piedmont EMC - Duke Control Area

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
PEAK (MW) (1)	99	101	103	105	107	109	111	113	116	118	120	123	125	128	130
ANNUAL ENERGY (GWh) (1)	133	135	137	140	142	145	148	151	154	157	160	163	166	170	173

Notes:
1. Peak and energy values are measured at generation.

2. Piedmont EMC's load requirements in the Duke Control Area are being met by a requirements agreement with Duke Power Company, LLC, thus Piedmont's loads and resources are integrated into Duke Power's 2010 Integrated Resource Plan. The initial term of the agreement with Duke Power is January 1, 2009 thru December 31, 2021. The contract has an automatic extension mechanism that allows the agreement to extend for additional 10 year periods and has since been extended through 2031. All current and future resources provided by Duke Power are firm; the Duke Power purchase is a network resource recognized by Duke Transmission. Resources provided by Duke Power will come from resources in the Duke control area or through imports made with firm transmission. Duke Power has operational control of Piedmont's demand-side programs, therefore the MWs associated with these programs are considered a Duke resource.

Piedmont EMC - Progress Energy (CP&L East) Control Area

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Load Requirements:															
PEAK (MW) (1)	33	33	34	35	35	36	37	37	38	39	40	41	41	42	43
Purchased Resources: (2)															
NCEMC WPSA	6	6	5	5	5	5	5	5	5	5	5	5	5	5	
SEPA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
Progress Energy Purchases (3)	26	26	28	29	29	30	31	31	32	33	34	35	35	36	43
TOTAL RESOURCES (MW)	33	33	34	35	35	36	37	37	38	39	40	41	41	42	43
RESERVE CAPACITY (MW) (2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ANNUAL ENERGY (GWh) (1)	416	423	431	438	446	454	463	472	482	492	502	512	522	532	542

Notes:
1. Peak and energy values are measured at generation.

2. All purchases are 100% firm with reserves provided by the supplying entity.

3. The initial term of the purchase with Progress Energy is thru December 31, 2021. Although this agreement does not have an automatic extension mechanism, it does contemplate an extension or replacement of the existing agreement. All current and future resources provided by Progress Energy are firm; the Progress Energy purchase is a network resource recognized by CP&L Transmission. Resources provided by Progress Energy will come from resources in the CP&L East control area or through imports made with firm transmission.

Piedmont EMC - TOTAL SUMMER LOAD

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
PEAK (MW) (1)	132	135	137	139	142	145	148	151	154	157	160	163	167	170	173
ANNUAL ENERGY (GWh) (1)	549	558	568	578	588	599	611	623	636	649	662	675	688	701	715
ANNUAL ENERGY (GWh) (1) (Including Impact of Energy Efficiency Programs)	542	549	557	565	574	583	594	605	617	628	641	654	667	680	693

Notes:
1. Peak and energy values are measured at generation.

Table 1.3: Piedmont EMC Projected Winter Peak Loads, Resources and Annual Energy (2010 Load Forecast)

Piedmont EMC - Duke Control Area

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
PEAK (MW) (1)	104	105	107	109	111	113	115	118	120	123	125	128	130	133	135
ANNUAL ENERGY (GWh) (1)	133	135	137	140	142	145	148	151	154	157	160	163	166	170	173

Notes:

1. Peak and energy values are measured at generation.
2. Piedmont EMC's load requirements in the Duke Control Area are being met by a requirements agreement with Duke Power Company, LLC, thus Piedmont's loads and resources are integrated into Duke Power's 2010 Integrated Resource Plan. The initial term of the agreement with Duke Power is January 1, 2009 thru December 31, 2021. The contract has an automatic extension mechanism that allows the agreement to extend for additional 10 year periods. All current and future resources provided by Duke Power are firm; the Duke Power purchase is a network resource recognized by Duke Transmission. Resources provided by Duke Power will come from resources in the Duke control area or through imports made with firm transmission. Duke Power has operational control of Piedmont's demand-side programs, therefore the MWs associated with these programs are considered a Duke resource.

Piedmont EMC - Progress Energy (CP&L East) Control Area

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Load Requirements:															
PEAK (MW) (1)	34	34	35	35	36	37	38	38	39	40	41	42	42	43	44
Purchased Resources: (2)															
NCEMC WPSA	6	6	5	5	5	5	5	5	5	5	5	5	5	5	
SEPA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
Progress Energy Purchases (3)	27	27	29	29	30	31	32	32	33	34	35	36	36	37	44
TOTAL RESOURCES (MW)	34	34	35	35	36	37	38	38	39	40	41	42	42	43	44
RESERVE CAPACITY (MW) (2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ANNUAL ENERGY (GWh) (1)	416	423	431	438	446	454	463	472	482	492	502	512	522	532	542

Notes:

1. Peak and energy values are measured at generation.
2. All purchases are 100% firm with reserves provided by the supplying entity.
3. The initial term of the purchase with Progress Energy is thru December 31, 2021. Although this agreement does not have an automatic extension mechanism, it does contemplate an extension or replacement of the existing agreement. All current and future resources provided by Progress Energy are firm; the Progress Energy purchase is a network resource recognized by CP&L Transmission. Resources provided by Progress Energy will come from resources in the CP&L East control area or through imports made with firm transmission.

Piedmont EMC - TOTAL WINTER LOAD

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
PEAK (MW) (1)	138	140	142	145	147	150	153	156	159	162	166	169	172	176	179
ANNUAL ENERGY (GWh) (1)	549	558	568	578	588	599	611	623	636	649	662	675	688	701	715
ANNUAL ENERGY (GWh) (1) (Including Impact of Energy Efficiency Programs)	542	549	557	565	574	583	594	605	617	628	641	654	667	680	693

Notes:

1. Peak and energy values are measured at generation.

Table 1.2: Rutherford EMC Projected Summer Peak Load, Resources and Annual Energy (2011 Load Forecast)

Rutherford EMC

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Load Requirements:															
PEAK (MW) (1)	301	312	324	336	348	362	375	390	405	421	437	454	471	489	508
Purchased Resources: (2)															
NCEMC WPSA	84	57	57	47	47	47	47	47	47	47	47	47	47	47	47
SEPA	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
Duke Energy Purchases (3)	193	231	243	265	277	291	304	319	334	350	366	383	400	418	437
TOTAL RESOURCES (MW)	301	312	324	336	348	362	375	390	405	421	437	454	471	489	508
RESERVE CAPACITY (MW) (2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ANNUAL ENERGY (GWh) (4)	1,328	1,341	1,355	1,368	1,382	1,396	1,410	1,424	1,438	1,453	1,467	1,482	1,497	1,513	1,528

1. Peak is Rutherford's peak measured at generation.
2. All purchases are 100% firm with reserves provided by the supplying entity.
3. The initial term of the purchase with Duke Energy is thru December 31, 2021 with an automatic extension mechanism that allows the agreement to extend for additional 10 year periods.
   All current and future resources provided by Duke Energy are firm; the Duke Energy purchase is a network resource recognized by Duke Transmission.
   Resources provided by Duke Energy will come from resources in the Duke control area or through imports made with firm transmission.
   Duke Energy has operational control of Rutherford's demand-side programs, therefore the MWs associated with these programs are considered a Duke Energy resource.
4. Energy values are measured at generation.

Table 1.3: Rutherford EMC Projected Winter Peak Load, Resources and Annual Energy (2011 Load Forecast)

Rutherford EMC	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Load Requirements:															
PEAK (MW) (1)	382	396	411	426	442	458	475	493	511	530	550	570	591	613	636
Purchased Resources: (2)															
NCEMC WPSA	84	57	57	47	47	47	47	47	47	47	47	47	47	47	47
SEPA	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
Duke Energy Purchases (3)	274	315	330	355	371	387	404	422	440	459	479	499	520	542	565
TOTAL RESOURCES (MW)	382	396	411	426	442	458	475	493	511	530	550	570	591	613	636
RESERVE CAPACITY (MW) (2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ANNUAL ENERGY (GWh) (4)	1,328	1,341	1,355	1,368	1,382	1,396	1,410	1,424	1,438	1,453	1,467	1,482	1,497	1,513	1,528

1. Peak is Rutherford's peak measured at generation.
2. All purchases are 100% firm with reserves provided by the supplying entity.
3. The initial term of the purchase with Duke Energy is thru December 31, 2021 with an automatic extension mechanism that allows the agreement to extend for additional 10 year periods.
   All current and future resources provided by Duke Energy are firm; the Duke Energy purchase is a network resource recognized by Duke Transmission.
   Resources provided by Duke Energy will come from resources in the Duke control area or through imports made with firm transmission.
   Duke Energy has operational control of Rutherford's demand-side programs, therefore the MWs associated with these programs are considered a Duke Energy resource.
4. Energy values are measured at generation.

Table 1.2: EnergyUnited Total Projected Summer Load and Capacity (2010 Load Forecast)

EnergyUnited

Load Requirements:	LOCATION	FUEL SOURCE	CAPACITY DESIGNATION	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
PEAK BEFORE ANTICIPATED ENERGY EFFICIENCY PROGRAMS (MW) (1)				561.5	563.7	566.8	570.3	574.0	578.0	582.1	586.3	590.6	595.0	599.5	604.1	608.7	613.4	618.2	623.1
Less: Impact of anticipated energy efficiency programs				(1.5)	(2.4)	(3.4)	(4.3)	(5.3)	(6.2)	(6.6)	(6.9)	(7.3)	(7.6)	(8.0)	(8.3)	(8.7)	(9.0)	(9.4)	(9.7)
PEAK NET OF ANTICIPATED ENERGY EFFICIENCY PROGRAMS				560.0	561.3	563.4	566.0	568.7	571.8	575.5	579.4	583.3	587.4	591.5	595.8	600.0	604.4	608.8	613.4
Purchased Resources (2)																			
NCEMC Existing Resources																			
Catawba Nuclear Station	Duke Control Area	Nuclear	Base	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79	79
SCE&G Intermediate Resource	Duke Control Area	Gas	Intermediate	32.0	32.0														
AEP Baseload Resource	Duke Control Area	Mix	Base	19.0	19.0														
Dominion PPA	Duke Control Area	Mix	Intermediate	19.0	19.0	19.0	19.0												
Total NCEMC Existing Resources				149.0	149.0	98.0	98.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0
SEPA (streamflow renewable resource)	Southeast		Base/Peaking	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16	16
Iredell Transmission, LLC	Iredell County, NC	Methane Gas	Base	3.0	3.0														
Duke Energy Generation Services Holding Company	Alexander County	Solar	Peaking	1.0	1.0	1.0	1.0	2.0	2.0	2.0	2.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Southern Power/Southern Company Purchases (3)																			
Total Southern Purchases	Various	Mix	Base/Intermediate/Peaking	391.0	392.3	448.4	451.0	471.7	474.8	478.5	482.4	486.3	489.4	493.5	497.8	502.0	506.4	510.8	515.4
TOTAL RESOURCES (MW)				560.0	561.3	563.4	566.0	568.7	571.8	575.5	579.4	583.3	587.4	591.5	595.8	600.0	604.4	608.8	613.4
RESERVE CAPACITY (MW) (3)			15% of EnergyUnited Peak	84.2	84.6	85.0	85.5	86.1	86.7	87.3	87.9	88.6	89.3	89.9	90.6	91.3	92.0	92.7	93.5
REPS Resources																			
Capacity from renewable resources(MW):																			
Iredell Transmission, LLC	Iredell County, NC	Methane Gas	Base	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Duke Energy Generation Services Holding Company	Alexander County	Solar	Peaking	1.0	1.0	1.0	1.0	2.0	2.0	2.0	2.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Other Anticipated Solar Renewable Resources	TBD	TBD			2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
SEPA	SouthEast		Intermediate/Peaking	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0
Total Anticipated Renewable Capacity				20.0	22.0	22.0	22.0	23.0	23.0	23.0	23.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0
Renewable Energy Credits-(RECS) in GWH equivalents-Committed/Contracted:		REC's (GWH) Carried Forward-2010 and Earlier																	
SOLAR CARVEOUT:																			
Duke Energy Generation Services Holding Company-Solar		0.072		1.75	1.75	1.75	1.75	2.60	2.60	2.63	2.63	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94
National Renewable-Solar-York-Chester Plaza Building, NC					0.95	0.95	0.95	0.94	0.94	0.93	0.93	0.92	0.92	0.91	0.91				
NOMAD Aquatic Fitness Center		0.002																	
SWINE CARVEOUT:																			
Swine-Orion Energy-Small Power Producers-Out of State RECS				2.00															
POULTRY CARVEOUT:																			
Poultry-Orion Energy-Small Power Producers-Out of State RECS					1.00	4.00													
Renewable Energy Credits		23		15.00															
ALL OTHER RECS:																			
Iredell Transmission LLC		55		23.00	23.00														
SEPA		73		21.02	21.02	21.02	21.02	21.02	21.02	21.02	21.02	21.02	21.02	21.02	21.02	21.02	21.02	21.02	21.02
Nextera Wind REC's(Out of State)		150																	
Salem Energy Systems LLC REC's		84		30.00	30.00	30.00	30.00	30.00											
Cardinal Energy-Small Hydroelectric Dams-NC				23.00	23.00	23.00	23.00	23.00	23.00										
Biomass-Int'l Paper Riegelwood, NC				250.00															
Total RECS already Committed/Contracted		385.074		365.774	100.73	80.725	76.72	77.565	47.561	24.584	24.579	25.889	25.884	25.88	25.875	24.966	24.966	24.966	24.966

Demand Side Management (5)

DEMAND SIDE MANAGEMENT PROGRAMS:(activated during peak hours)	# Customers	Demand Reduction(MW)	Hours in DSM	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Residential Water Heaters	23,659	7.58	50 hours	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6
Coincident Peak Commercial/Industrial Consumers	30	8.83	50 hours	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
Residential Air Conditioners	26,470	8.65	50 hours	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Total DSM				25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0

2010 Peak- July 25, 2010 HE 5:00pm --573 MW
2011 Peak- th, 2010 HE 0:00pm -- MW

1. Net Peak is EnergyUnited's peak net of load management measured at generation
2. All purchases are 100% firm with reserves provided by the supplying entity
3. The initial term of the purchase with Southern Power/Southern Company is September 1, 2008 thru December 31, 2025. All current and future resources provided by Southern are firm; the Southern purchase is a network resource recognized by Duke Transmission. Resources provided by Southern will come from resources in the Duke control area or through imports made with firm transmission at the Duke/Southern intertie. These firm transmission purchases have been designated in the application with the transmission provider or will be designated prior to the start of the start of applicable resource. Under this contract, Southern is obligated to provide all necessary reserve capacity up to 15% of EnergyUnited Peak Load
4. Energy values are measured at generation
5. Demand Side Management allows us to reduce 21MW during peak periods at our option using load management devices and backup generation.

Table 1.3: EnergyUnited Total Projected Winter Load and Capacity (2010 Load Forecast)

EnergyUnited

Load Requirements:	LOCATION	FUEL SOURCE	CAPACITY DESIGNATION	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
PEAK BEFORE ENERGY EFFICIENCY PROGRAMS (MW) (1) (5)				594.5	596.7	599.3	602.9	606.6	610.7	615.0	619.5	624.0	628.6	633.3	638.1	642.9	647.9	653.0	658.1
Less: Impact of anticipated energy efficiency programs				(1.5)	(2.4)	(3.4)	(4.3)	(5.3)	(6.2)	(6.6)	(6.9)	(7.3)	(7.6)	(8.0)	(8.3)	(8.7)	(9.0)	(9.4)	(9.7)
PEAK NET OF ANTICIPATED ENERGY EFFICIENCY PROGRAMS				593.0	594.3	595.9	598.6	601.3	604.5	608.4	612.6	616.7	621.0	625.3	629.8	634.2	638.9	643.6	648.4
Purchased Resources: (2)																			
NCEMC Existing Resources																			
Catawba Nuclear Station	Duke Control Area	Nuclear	Base	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79	79
SCE&G Intermediate Resource	Duke Control Area	Gas	Intermediate	32.0	32.0														
AEP Baseload Resource	Duke Control Area	Mix	Base	19.0	19.0														
Dominion PPA	Duke Control Area	Mix	Intermediate	19.0	19.0	19.0	19.0												
Total NCEMC Existing Resources				149.0	149.0	98.0	98.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0
SEPA*(stream flow renewable)	Southeast		Base/Peaking	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16	16
Iredell Transmission, LLC	Iredell County, NC	Methane Gas	Base	3.0	3.0														
Duke Energy Generation Services Holding Company	Alexander County	Solar	N/A	0.3	0.3	0.3	0.3	0.3	0.3	0.6	0.6	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Southern Power/Southern Company Purchases (3)																			
Total Southern Purchases	Various	Mix	Base/Intermediate/Peaking	424.7	426.0	481.6	484.3	506.0	509.2	512.8	517.0	520.8	525.1	529.4	533.9	538.3	543.0	547.7	552.5
TOTAL RESOURCES (MW)				593.0	594.3	595.9	598.6	601.3	604.5	608.4	612.6	616.7	621.0	625.3	629.8	634.2	638.9	643.6	648.4
RESERVE CAPACITY (MW) (3)			15% of Peak EU Load	89.2	89.5	89.9	90.4	91.0	91.6	92.3	92.9	93.6	94.3	95.0	95.7	96.4	97.2	98.0	98.7
Demand Side Management																			
DEMAND SIDE MANAGEMENT PROGRAMS: Activated during Peak Hours	# Customers	Demand Reduction	Hours in DSM																
Residential Water Heaters	23,659	7.56	0																
Coincident Peak Commercial/Industrial Consumers	30	8.83	8 hours	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Residential Air Conditioners	28,470	8.65	0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Total DSM				11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6
Annual Peak Demands(5)																			
2010 Peak-Dec 15th, 2010 HE 8:00am –642 MW																			
2011 Peak-Jan 14th, 2011 HE 8:00am –603 MW																			

1. Net Peak is EnergyUnited's peak net of load management measured at generation.
2. All purchases are 100% firm with reserves provided by the supplying entity.
3. The initial term of the purchase with Southern Power/Southern Company is September 1, 2006 thru December 31, 2025. All current and future resources provided by Southern are firm; the Southern purchase is a network resource recognized by Duke Transmission. Resources provided by Southern will come from resources in the Duke control area or through imports made with firm transmission at the Duke/Southern interface. These firm transmission purchases have been designated in the application with the transmission provider or will be designated prior to the start of the start of applicable resource. Under this contract, Southern is obligated to provide all necessary reserve capacity up to 15% of EnergyUnited Peak Load
4. Energy values are measured at generation.
5. Demand Side Management allows us to reduce 12MW during peak periods at our option using load management devices and backup generation.

Table 1.2: Haywood EMC Projected Summer Peak Loads, Resources and Annual Energy (2010 Load Forecast)

Haywood EMC - Duke Control Area

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
PEAK (MW) (1)	24	24	25	25	25	26	26	27	28	28	29	29	30	30	31
ANNUAL ENERGY (GWh) (1)	130	132	134	136	139	141	144	147	150	153	155	158	161	164	168

Notes:

1. Peak and energy values are measured at generation.

2. Haywood EMC's load requirements in the Duke Control Area are being met by a requirements agreement with Duke Power Company, LLC, thus Haywood's loads and resources are integrated into Duke Power's 2010 Integrated Resource Plan. The initial term of the agreement with Duke Power is January 1, 2009 thru December 31, 2021. The contract has an automatic extension mechanism that allows the agreement to extend for additional 10 year periods. All current and future resources provided by Duke Power are firm; the Duke Power purchase is a network resource recognized by Duke Transmission. Resources provided by Duke Power will come from resources in the Duke control area or through imports made with firm transmission. Duke Power has operational control of Haywood's demand-side programs, therefore the MWs associated with these programs are considered a Duke resource.

Haywood EMC - Progress Energy (CP&L East) Control Area

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Load Requirements:															
PEAK (MW) (1)	32	33	34	34	35	35	36	37	38	38	39	40	41	42	42
Purchased Resources: (2)															
NCEMC WPSA	15	14	14	14	15	15	15	15	15	15	11	9	7	5	5
SEPA	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Progress Energy Purchases (3)	15	17	18	18	18	18	19	20	21	21	26	29	32	35	35
TOTAL RESOURCES (MW)	32	33	34	34	35	35	36	37	38	38	39	40	41	42	42
RESERVE CAPACITY (MW) (2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ANNUAL ENERGY (GWh) (1)	201	204	208	211	215	219	223	227	232	236	241	246	250	255	260

Notes:

1. Peak and energy values are measured at generation.

2. All purchases are 100% firm with reserves provided by the supplying entity.

3. The initial term of the purchase with Progress Energy is January 1, 2009 thru December 31, 2021. Although this agreement does not have an automatic extension mechanism, it does contemplate an extension or replacement of the existing agreement. All current and future resources provided by Progress Energy are firm; the Progress Energy purchase is a network resource recognized by CP&L Transmission. Resources provided by Progress Energy will come from resources in the CP&L East control area or through imports made with firm transmission.

Haywood EMC - TOTAL SUMMER LOAD

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
PEAK (MW) (1)	56	57	58	59	60	61	63	64	65	67	68	69	71	72	73
ANNUAL ENERGY (GWh) (1)	331	336	342	347	353	360	366	374	381	389	396	404	412	419	427
ANNUAL ENERGY (GWh) (1) (Including Impact of Energy Efficiency Programs)	324	327	331	336	342	349	356	363	373	383	393	402	411	418	426

Notes:

1. Peak and energy values are measured at generation.

Table 1.3: Haywood EMC Projected Winter Peak Loads, Resources and Annual Energy (2010 Load Forecast)

Haywood EMC - Duke Control Area

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
PEAK (MW) (1)	33	33	34	35	35	36	36	37	38	39	40	40	41	42	43
ANNUAL ENERGY (GWh) (1)	130	132	134	136	139	141	144	147	150	153	155	158	161	164	168

Notes:

1. Peak and energy values are measured at generation.

2. Haywood EMC's load requirements in the Duke Control Area are being met by a requirements agreement with Duke Power Company, LLC, thus Haywood's loads and resources are integrated into Duke Power's 2010 Integrated Resource Plan. The initial term of the agreement with Duke Power is January 1, 2009 thru December 31, 2021. The contract has an automatic extension mechanism that allows the agreement to extend for additional 10 year periods. All current and future resources provided by Duke Power are firm; the Duke Power purchase is a network resource recognized by Duke Transmission. Resources provided by Duke Power will come from resources in the Duke control area or through imports made with firm transmission. Duke Power has operational control of Haywood's demand-side programs, therefore the MWs associated with these programs are considered a Duke resource.

Haywood EMC - Progress Energy (CP&L East) Control Area

Load Requirements:	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
PEAK (MW) (1)	55	56	57	58	59	60	62	63	64	65	67	68	69	71	72
Purchased Resources: (2)															
NCEMC WPSA	15	14	14	14	15	15	15	15	15	15	11	9	7	5	5
SEPA	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Progress Energy Purchases (3)	38	40	41	42	42	43	45	46	47	48	54	57	60	64	65
TOTAL RESOURCES (MW)	55	56	57	58	59	60	62	63	64	65	67	68	69	71	72
RESERVE CAPACITY (MW) (2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ANNUAL ENERGY (GWh) (1)	201	204	208	211	215	219	223	227	232	236	241	246	250	255	260

Notes:

1. Peak and energy values are measured at generation.

2. All purchases are 100% firm with reserves provided by the supplying entity.

3. The initial term of the purchase with Progress Energy is January 1, 2009 thru December 31, 2021. Although this agreement does not have an automatic extension mechanism, it does contemplate an extension or replacement of the existing agreement. All current and future resources provided by Progress Energy are firm; the Progress Energy purchase is a network resource recognized by CP&L Transmission. Resources provided by Progress Energy will come from resources in the CP&L East control area or through imports made with firm transmission.

Haywood EMC - TOTAL WINTER LOAD

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
PEAK (MW) (1)	88	90	91	93	94	96	98	100	102	104	106	108	111	113	115
ANNUAL ENERGY (GWh) (1)	331	336	342	347	353	360	366	374	381	389	396	404	412	419	427
ANNUAL ENERGY (GWh) (1) (Including Impact of Energy Efficiency Programs)	324	327	331	336	342	349	356	363	373	383	393	402	411	418	426

Notes:

1. Peak and energy values are measured at generation.

North Carolina Electric IOU Service Area Map